ATTACHMENT 3

[Initial Comments of NC WARN and CBD]

Docket No. E-100, Sub 165

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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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 2019/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 2019/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)* 04/14/2020

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 L. Jacobs	03 Signature	04 Date Signed *(Mo, Da, Yr)*
02 Title SVP, CAO, Tax and Controller	Dwight L. Jacobs	04/14/2020

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	04/14/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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".

Stockholders' Reports Check appropriate box:

- [ ] Two copies will be submitted
- [ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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 L. 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	04/14/2020	End of 2019/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	04/14/2020	End of 2019/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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FOOTNOTE DATA

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

The remaining 1.0% is owned by CaroFund, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	675,000
2	President, Midwest and Florida Regions		
3	through 10/01/2019		
4	Executive Vice President, Energy Solutions and		
5	President, Midwest/Florida Regions and		
6	Natural Gas Buisness, effective 10/01/2019		
7			
8	Chief Executive Officer	Lynn J. Good	1,390,500
9			
10	Excecutive Vice President and Chief Operating Officer	Dhiaa M. Jamil	839,476
11			
12	Executive Vice President, External Affairs and Chief	Julia S. Janson	715,000
13	Legal Officer through 10/01/2019		
14	Executive Vice President, External Affairs and		
15	President, Carolinas Region, effective 10/01/2019		
16			
17	Executive Vice President, Customer and Delivery	Lloyd M. Yates	725,039
18	Operations and President, Carolinas Region		
19	through 09/30/2019		
20			
21	Executive Vice President, Administration and Chief	Melissa H. Anderson	538,274
22	Human Resources Officer through 10/01/2019		
23	Executive Vice President and Chief Human		
24	Resources Officer, effective 10/01/2019		
25			
26	President, North Carolina	Stephen Gerard De May	418,937
27			
28	President, South Carolina	Kodwo Ghartey-Tagoe	500,000
29	through 10/01/2019		
30	Executive Vice President and Chief Legal Officer		
31	effective 10/01/2019		
32			
33	President, South Carolina	Michael P. Callahan	281,589
34	effective 10/01/2019		
35			
36	Executive Vice President and President,	Franklin H. Yoho	529,935
37	Natural Gas Business through 10/03/2019		
38			
39	Executive Vice President and Chief Financial Officer	Steven Keith Young	738,738
40			
41	Senior Vice President, Chief Accounting Officer,	Dwight L. Jacobs	311,881
42	Tax and Controller		
43			
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	04/14/2020	End of 2019/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Senior Vice President, Business Transformation	Brian D. Savoy	455,559
2	and Technology through 10/01/2019		
3	Senior Vice President, Chief Transformation and		
4	Administrative Officer, effective 10/01/2019		
5			
6	Senior Vice President, Corporate Development	Karl W. Newlin	484,100
7	and Treasurer		
8			
9	Senior Vice President and Chief Distribution Officer	Harry K. Sideris	453,500
10	through 10/01/2019		
11	Senior Vice President, Customer Experience and		
12	Services, effective 10/01/2019		
13			
14	Senior Vice President, Legal, Chief Ethics and	David B. Fountain	418,842
15	Compliance Officer and Secretary		
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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	04/14/2020	End of 2019/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 and President,	
3	Midwest/Florida Regions and Natural Gas Business	
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	Kodwo Ghartey-Tagoe	550 South Tryon Street, Charlotte, NC 28202
13	Executive Vice President	
14	Chief Legal Officer, effective 10/01/2019	
15		
16	Julia S. Janson	550 South Tryon Street, Charlotte, NC 28202
17	Executive Vice President, External Affairs and President,	
18	Carolinas Region	
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20	Lloyd M. Yates	550 South Tryon Street, Charlotte, NC 28202
21	Executive Vice President, Customer and Delivery	
22	Operations and President, Carolinas Region	
23	through 09/30/2019	
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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	04/14/2020	End of 2019/Q4

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

Does the respondent have formula rates? [X] Yes [ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	Joint Open Access Transmission Tariff (OATT)	ER19-1576
2	Rate Schedule 172	ER19-1788
3	Rate Schedule 180	ER19-1786
4	Rate Schedule 182	ER19-1160
5	Rate Schedule 184	ER19-1476
6	Rate Schedule 197	ER19-865
7	Rate Schedule 200	ER19-818
8	Rate Schedule 210	ER19-835
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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	04/14/2020	End of 2019/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	20190515-5239	05/15/2019	ER09-1165	2019 Annual Transmission Update	Joint Open Access Transmission Tariff
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	04/14/2020	End of 2019/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	Accumulated Provision for Pension & Benefits	(c)	29
3	200	Intangible Amortization Reserve	(c)	21
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	Production Depreciation Reserve	(c)	20-24
9	219	General Depreciation Reserve	(c)	28
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 Expenses	(b)	80
14	323	Property Insurance	(b)	185
15	323	Total Administrative & General Expenses	(b)	197
16	335	Industry Dues, R&D, C-V Nuclear Power Association	(b)	1-3
17	336	Intangible Amortization	(f)	1
18	336	Production Depreciation Expense	(b)	2-6
19	336	General Depreciation Expense	(b)	10
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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	04/14/2020	End of 2019/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. A new capital lease for Duke Energy Progress has been entered into during the first quarter of 2019. Duke Energy Progress worked with the local natural gas distribution company to upgrade and lease an existing natural gas pipeline to serve the natural gas plant. The new lease is effective March 2, 2019 for 20 years. Payments are for $1,966,539 per month, and the construction cost was $174,863,277. The North Carolina Utilities Commission (NCUC) authorized the lease on the Asheville Western Carolinas Modernization Project, Docket No.E-2, Sub 1089.

5. None

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

7. None

8. During the first quarter of 2019, Duke Energy Progress granted an approximate 3% merit increase which resulted in $6,415,366, impacting 2,791 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 2019.

The changes in officer and director appointments and resignations for Duke Energy Progress, LLC that occurred during the fourth quarter 2019 are as follows:

Resignations Effective December 2019

Rodney E. Gaddy	Senior Vice President, Administrative Services
Tanya M. Hamilton	Site Vice President, Harris
James P. Henning	Senior Vice President, Customer Services
Emily G. Henson	Vice President Operations - Customer Delivery

Rufus Stanley Jackson	Vice President Operations - Customer Delivery
Jackie Joyner	Vice President Operations - Customer Delivery
Kim Maza	Vice President, Nuclear Corporate Operations
Lee T. Mazzocchi	Senior Vice President, Grid Solutions

Appointments Effective December 2019

Tanya M. Hamilton	Senior Vice President, Nuclear Corporate
Kim Maza	Site Vice President, Harris

Resignations Effective November 2019

Scott L. Batson	Regional Senior Vice President, Customer Delivery Carolinas
Donald E. Broadhurst	Vice President Operations - Customer Delivery
Eric S. Grant	Vice President, Fuels and Systems Optimization
Larry E. Hatcher	Senior Vice President, Customer Delivery Governance, Programs and Support
Forest W. Rogers Jr.	Vice President, Transmission Maintenance and Construction
L. Stanford Sherrill, Jr.	Vice President, Strategic HR Business Solutions, Employee and Labor Relations
Thomas Silinski	Vice President, Total Rewards and Human Resource Operations

Appointments Effective November 2019

Scott L. Baston	Senior Vice President and Chief Distribution Officer
Jeffrey W. Bramblett	Vice President, Nuclear Corporate Operations
William H. Fowler	Regional Senior Vice President, Customer Delivery - Carolinas
Eric S. Grant	Senior Vice President, Customer Delivery Governance, Programs

	& Support
Larry E. Hatcher	Senior Vice President, Customer Services
Forest W. Rogers Jr.	Senior Vice President, Transmission Maintenance and Construction
L. Stanford Sherrill, Jr.	Vice President, Human Resources and Employee & Labor Relations
Thomas Silinski	Vice President, Human Resources, Total Rewards & HR Operations
John A. Verderame	Vice President, Fuels and System Optimization
Bryan P. Walsh	Vice President, Central Services and Organizational Effectiveness

Resignations Effective October 2019

Melissa H. Anderson	Executive Vice President, Administration and Chief Human Resources Officer
Donna T. Council	Vice President, Accounts Payable Stabilization Project
Douglas F. Esamann	Executive Vice President, Energy Solutions and President, Midwest and Florida Regions
Kodwo Ghartey-Tagoe	President, South Carolina
Julia S. Janson	Executive Vice President, External Affairs and Chief Legal Officer
Louis E. Renjel	Senior Vice President, Federal Government Affairs and Strategic Policy
Brian D. Savoy	Senior Vice President, Business Transformation and Technology

Harry K. Sideris — Senior Vice President and Chief Distribution Officer

Peter E. Toomey — Senior Vice President, Enterprise Strategy and Planning

Appointments Effective October 2019

Melissa H. Anderson — Executive Vice President and Chief Human Resources Officer

Cari P. Boyce — Senior Vice President, Enterprise Strategy and Planning

Michael P. Callahan — President, South Carolina

Donna T. Council — Vice President, Administrative Services

Douglas F. Esamann — Executive Vice President, Energy Solutions and President Midwest/Florida Regions and Natural Gas Business

Kowdo Ghartey-Tagoe — Executive Vice President and Chief Legal Officer

Julia S. Janson — Executive Vice President, External Affairs and President, Carolinas Region

Louis E. Renjel — Senior Vice President, Federal Government and Corporate Affairs

Brian D. Savoy — Senior Vice President, Chief Transformation and Administrative Officer

Harry K. Sideris — Senior Vice President, Customer Experience and Services

Peter E. Toomey — Senior Vice President, Strategic Regulatory Initiatives

Resignations Effective September 2019

William R. Gideon — Site Vice President, Brunswick

Lloyd M. Yates — Executive Vice President, Customer and Delivery Operations

And President, Carolinas Region

Appointments Effective September 2019

John A. Krakuszecki — Site Vice President, Brunswick

Resignations Effective July 2019

Paul Draovitch — Senior Vice President, Environmental, Health and Safety

Jeffrey M. Stone — Vice President, Audit Services and Ethics and Compliance

James Wells — Vice President, Coal Combustion Products, Environmental, Health & Safety

Appointments Effective July 2019

Paul Draovitch — Senior Vice President, Environmental, Health and Safety and Operations Support

Amelia D. Hunter — Vice President, Corporate Audit Services

James Wells — Vice President, Environmental, Health and Safety Programs and Environmental Science

Resignations Effective June 2019

Richard W. Bagley — Vice President, Transmission Engineering and Asset Management

Appointments Effective June 2019

Ben I. Harrison Jr. — Vice President, Transmission Engineering and Asset Management

Bonnie B. Titone — Vice President and Chief Information Officer

Appointments Effective May 2019

Jon F. Kerin — Vice President Enterprise Operations Business Transformation

Martha S. Purser — Engineer (under First Mortgage Bond Indenture)

Resignations Effective March 2019

Louis E. Renjel — Vice President, Federal Government Affairs and Strategic Policy

Appointments Effective March 2019

Louis E. Renjel — Senior Vice President, Federal Government Affairs and Strategic Policy

Resignations Effective February 2019

Robert F. Caldwell — Senior Vice President and President, Duke Energy Renewables and Distributed Energy

Donna T. Council	Vice President, HR Strategic Business Solutions
Swati V. Daji	Senior Vice President, Customer Solutions
Joni Y. Davis	Vice President, Chief Diversity and Inclusion Officer
Joseph W. Donahue	Vice President, Nuclear Engineering
Clark S. Gillespy	Senior Vice President, Economic Development
Thomas Cooper Monroe III	Director, State Tax
L. Stanford Sherrill Jr.	Vice President, Talent Acquisition and Workforce Development
Jeffrey M. Stone	Vice President, Corporate Audit Services
Sandra S. Wyckoff	Vice President, Ethics and Compliance

Appointments Effective February 2019

Robert F. Caldwell	Senior Vice President and President, Duke Energy Renewables and Business Development
Donna T. Council	Vice President, Accounts Payable Stabilization Project
Swati V. Daji	Senior Vice President, Customer Solutions and Strategies
Joni Y. Davis	Vice President, Chief Diversity and Inclusion Officer, Talent Acquisition and Workforce Development
Thomas Cooper Monroe III	Vice President, Tax
L. Stanford Sherrill Jr.	Vice President, Strategic HR Business Solutions, Employee and Labor Relations
Steven M. Snider	Vice President, Nuclear Engineering
Jeffrey M. Stone	Vice President, Audit Services and Ethics and Compliance
Peter E. Toomey	Senior Vice President, Enterprise Strategy and Planning

Resignations Effective January 2019

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

Appointments Effective January 2019

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	33,518,551,321	29,287,780,541
3	Construction Work in Progress (107)	200-201	1,100,726,367	1,665,669,162
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		34,619,277,688	30,953,449,703
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	12,950,921,387	12,297,905,722
6	Net Utility Plant (Enter Total of line 4 less 5)		21,668,356,301	18,655,543,981
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	282,747,481	325,126,686
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		782,616,498	819,511,288
10	Spent Nuclear Fuel (120.4)		296,547,701	417,494,987
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	725,412,507	860,218,709
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		636,499,173	701,914,252
14	Net Utility Plant (Enter Total of lines 6 and 13)		22,304,855,474	19,357,458,233
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		37,037,412	37,914,817
19	(Less) Accum. Prov. for Depr. and Amort. (122)		16,328,772	16,451,815
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	27,607,249	27,726,543
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)		43,188,310	42,286,541
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		3,371,298,547	2,776,861,603
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		628,994	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	449,408
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,463,431,740	2,868,787,097
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		-3,906,582	-2,531,695
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)		403,856,685	432,169,365
41	Other Accounts Receivable (143)		105,896,450	68,114,949
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		8,289,266	7,357,981
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		130,479,518	110,020,232
45	Fuel Stock (151)	227	247,793,012	220,024,307
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	657,321,620	700,609,217
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	138,983	182,270
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	120,003,762	122,682,758

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	28,793,359	33,384,627
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)		86,149,956	90,940,901
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		50,413	94,136
61	Accrued Utility Revenues (173)		121,029,872	129,690,282
62	Miscellaneous Current and Accrued Assets (174)		544,697	10,148,021
63	Derivative Instrument Assets (175)		628,994	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		628,994	0
65	Derivative Instrument Assets - Hedges (176)		0	761,715
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	449,408
67	Total Current and Accrued Assets (Lines 34 through 66)		1,889,862,479	1,908,483,696
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		43,279,639	43,142,470
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	132,425,397	153,655,703
72	Other Regulatory Assets (182.3)	232	4,008,153,853	4,265,025,648
73	Prelim. Survey and Investigation Charges (Electric) (183)		9,418,905	8,201,316
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)		-766,937	6,938,847
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	729,367,553	544,504,452
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)		3,539,246	4,579,195
82	Accumulated Deferred Income Taxes (190)	234	2,261,603,593	1,864,956,280
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		7,187,021,249	6,891,003,911
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		34,845,170,942	31,025,732,937

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	04/14/2020	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	0	0
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	2,784,376,570	2,784,376,572
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	6,738,492,929	5,933,703,999
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-277,316,353	-277,197,059
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)	-168,748	-149,270
16	Total Proprietary Capital (lines 2 through 15)		9,245,384,398	8,440,734,242
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	7,623,485,000	7,623,485,000
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	1,025,000,000	350,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		16,599,506	15,293,974
24	Total Long-Term Debt (lines 18 through 23)		8,781,885,494	8,108,191,026
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		654,453,052	133,281,241
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		8,659,537	6,874,145
29	Accumulated Provision for Pensions and Benefits (228.3)		226,180,621	223,622,886
30	Accumulated Miscellaneous Operating Provisions (228.4)		16,069,963	17,201,995
31	Accumulated Provision for Rate Refunds (229)		115,434,909	123,351,482
32	Long-Term Portion of Derivative Instrument Liabilities		897,610	4,886,654
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		21,515,994	3,728,239
34	Asset Retirement Obligations (230)		5,892,923,800	4,819,759,728
35	Total Other Noncurrent Liabilities (lines 26 through 34)		6,936,135,486	5,332,706,370
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		685,096,757	723,822,837
39	Notes Payable to Associated Companies (233)		66,036,000	293,651,000
40	Accounts Payable to Associated Companies (234)		196,520,298	271,157,048
41	Customer Deposits (235)		145,011,121	137,270,708
42	Taxes Accrued (236)	262-263	17,572,238	59,278,673
43	Interest Accrued (237)		109,724,153	116,877,826
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [x] An Original (2) [ ] A Resubmission	04/14/2020	end of 2019/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		7,281,847	7,936,232
48	Miscellaneous Current and Accrued Liabilities (242)		254,686,252	227,936,822
49	Obligations Under Capital Leases-Current (243)		43,100,797	3,267,405
50	Derivative Instrument Liabilities (244)		1,853,913	16,120,103
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		897,610	4,886,654
52	Derivative Instrument Liabilities - Hedges (245)		47,194,206	6,466,582
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		21,515,994	3,728,239
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,551,663,978	1,855,170,343
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		25,036,208	22,775,276
57	Accumulated Deferred Investment Tax Credits (255)	266-267	136,579,241	142,161,990
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	41,746,684	19,844,812
60	Other Regulatory Liabilities (254)	278	3,477,753,428	3,120,844,123
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		3,231,230,832	2,695,677,136
64	Accum. Deferred Income Taxes-Other (283)		1,417,755,194	1,287,627,619
65	Total Deferred Credits (lines 56 through 64)		8,330,101,587	7,288,930,956
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		34,845,170,943	31,025,732,937

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	04/14/2020	End of 2019/Q4

STATEMENT OF INCOME

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

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	5,911,219,240	5,682,421,296		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,912,768,283	2,842,529,953		
5	Maintenance Expenses (402)	320-323	445,201,946	524,022,724		
6	Depreciation Expense (403)	336-337	825,101,906	746,423,281		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	52,681,881	42,090,299		
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)		28,943,779	29,040,562		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		428,088,788	365,010,904		
13	(Less) Regulatory Credits (407.4)		164,345,692	135,488,252		
14	Taxes Other Than Income Taxes (408.1)	262-263	174,038,713	153,362,211		
15	Income Taxes - Federal (409.1)	262-263	-37,966,838	-66,292,964		
16	- Other (409.1)	262-263	-3,576,975	-3,938,471		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,328,625,738	843,871,407		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,126,894,696	623,018,430		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,582,749	-3,355,660		
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)		500	165,404		
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)		4,869,842,317	4,726,850,893		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,041,376,923	955,570,403		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		Line No.
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)	
						1
5,911,219,240	5,682,421,296					2
						3
2,912,768,283	2,842,529,953					4
445,201,946	524,022,724					5
825,101,906	746,423,281					6
						7
52,681,881	42,090,299					8
12,758,733	12,758,733					9
28,943,779	29,040,562					10
						11
428,088,788	365,010,904					12
164,345,692	135,488,252					13
174,038,713	153,362,211					14
-37,966,838	-66,292,964					15
-3,576,975	-3,938,471					16
1,328,625,738	843,871,407					17
1,126,894,696	623,018,430					18
-5,582,749	-3,355,660					19
						20
						21
500	165,404					22
						23
						24
4,869,842,317	4,726,850,893					25
1,041,376,923	955,570,403					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,041,376,923	955,570,403		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		-161,220	-86,843		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,238	29,121		
33	Revenues From Nonutility Operations (417)		64,541,919	33,624,375		
34	(Less) Expenses of Nonutility Operations (417.1)		42,714,577	23,752,601		
35	Nonoperating Rental Income (418)		-650,628	-633,026		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-119,294	7,394,428		
37	Interest and Dividend Income (419)		-208,146	1,387,385		
38	Allowance for Other Funds Used During Construction (419.1)		60,137,413	56,812,523		
39	Miscellaneous Nonoperating Income (421)		11,944,022	9,121,726		
40	Gain on Disposition of Property (421.1)		-282,180	1,296,268		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		92,485,071	85,135,114		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		149,779	383,831		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,652,571	3,334,051		
46	Life Insurance (426.2)		-341,111	-1,642,235		
47	Penalties (426.3)		181,388	1,878,534		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		4,145,011	3,159,976		
49	Other Deductions (426.5)		13,337,704	34,603,501		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		20,125,342	41,717,658		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,457,531	1,961,060		
53	Income Taxes-Federal (409.2)	262-263	1,250,522	-5,144,014		
54	Income Taxes-Other (409.2)	262-263	268,398	-645,223		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	7,533,904	28,378,574		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	7,069,715	9,796,689		
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)		3,440,640	14,753,708		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		68,919,089	28,663,748		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		336,972,101	316,675,114		
63	Amort. of Debt Disc. and Expense (428)		5,360,187	5,814,338		
64	Amortization of Loss on Reaquired Debt (428.1)		1,039,948	1,030,335		
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)		7,450,374	8,649,424		
68	Other Interest Expense (431)		-17,002,068	10,728,365		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		28,183,440	25,699,616		
70	Net Interest Charges (Total of lines 62 thru 69)		305,637,102	317,197,960		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		804,658,910	667,036,191		
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)		804,658,910	667,036,191		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		5,927,348,283	5,443,461,024
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Transfer to Unappropiated RE (Account 216.1)			4,341
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			4,341
10				
11	Cumulative Effect Acct Change Tax	219	10,727	
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		10,727	
16	Balance Transferred from Income (Account 433 less Account 418.1)		804,778,204	659,641,763
17	Appropriations of Retained Earnings (Acct. 436)			
18	Hydro Project Reserve Amortization		-921,669	(758,845)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-921,669	(758,845)
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)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			(175,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		6,731,215,545	5,927,348,283
	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	04/14/2020	End of 2019/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)		7,277,384	6,355,716
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		7,277,384	6,355,716
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		6,738,492,929	5,933,703,999
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-277,197,059	(284,587,146)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-119,294	7,394,428
51	(Less) Dividends Received (Debit)			
52				(4,341)
53	Balance-End of Year (Total lines 49 thru 52)		-277,316,353	(277,197,059)

FOOTNOTE DATA

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 the 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 the 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	04/14/2020	End of 2019/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)	804,658,910	667,036,191
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	825,101,906	746,423,281
5	Amortization and Accretion	299,452,098	268,694,905
6	Net (Increase) Decrease in Mark-to Market Hedging Transactions	-9,023,792	15,075,058
7	Contributions to Company Sponsored Pension Plans	-3,496,262	-24,816,258
8	Deferred Income Taxes (Net)	202,195,231	239,434,862
9	Investment Tax Credit Adjustment (Net)	-5,582,749	-3,355,660
10	Net (Increase) Decrease in Receivables	822,518	-74,311,123
11	Net (Increase) Decrease in Inventory	20,153,448	63,221,722
12	Net (Increase) Decrease in Allowances Inventory	2,767,246	-13,436,486
13	Net Increase (Decrease) in Payables and Accrued Expenses	68,787,017	407,650,725
14	Net (Increase) Decrease in Other Regulatory Assets	251,943,003	-553,018,299
15	Net Increase (Decrease) in Other Regulatory Liabilities	-79,974,352	133,693,600
16	(Less) Allowance for Other Funds Used During Construction	60,137,413	56,812,523
17	(Less) Undistributed Earnings from Subsidiary Companies	-119,294	7,394,428
18	Other (provide details in footnote):	-545,930,479	-459,234,570
19	Accrued Pension and Other Post-Retirement Benefit Costs Adj to NI	4,429,471	14,543,544
20	Provision for Rate Period	12,000,000	123,351,482
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,788,285,095	1,486,746,023
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-2,058,110,168	-1,964,141,297
27	Gross Additions to Nuclear Fuel	-110,541,310	-175,835,579
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	877,405	-1,175,679
30	(Less) Allowance for Other Funds Used During Construction	-60,137,413	-56,812,523
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-2,107,636,660	-2,084,340,032
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Cost of Removal, net of Salvage	-85,288,992	-114,416,778
39	Investments in and Advances to Assoc. and Subsidiary Companies		-181,341
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)	-842,434,643	-1,235,790,237
45	Proceeds from Sales of Investment Securities (a)	809,880,887	1,210,064,019

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	411,749	-1,346,430
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-2,225,067,659	-2,226,010,799
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,269,084,591	849,884,000
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)	1,269,084,591	849,884,000
71	Other Financing Activities	-1,211,894	-5,557,602
72	Payments for Retirement of:		
73	Long-term Debt (b)	-604,850,020	-2,861,742
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Net Increase (Decrease) in Intercompany Notes	-227,615,000	53,665,000
78	Net Decrease in Short-Term Debt (c)		
79	Dividends to Parent		-175,000,000
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)	435,407,677	720,129,656
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-1,374,887	-19,135,120
87			
88	Cash and Cash Equivalents at Beginning of Period	-2,531,695	16,603,425
89			
90	Cash and Cash Equivalents at End of period	-3,906,582	-2,531,695

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

Change in other noncurrent assets	$ (575,760,650)
Asset retirement obligation liabilities settled	(389,617,296)
Change in prepaid and other current assets	3,684,845
Change in deferred credits and other long-term liabilities	411,087,635
Payment of charitable contributions related to Piedmont merger commitments	(7,260,313)
Gain on sale of assets	(431,458)
Impairment	12,366,757
	$ (545,930,479)

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

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.: 53 Column: b

Death proceeds from COLI and Rabbi Trust	$ 411,749

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

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

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

Primarily unamortized debt expenses associated with Master Credit Facility fees	$(1,211,894)

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

Primarily unamortized debt expenses associated with:

Issuances of LT Debt	$(4,812,993)
Master Credit Facility Fee	$(744,609)
	$(5,557,602)

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

Significant noncash transactions:

Accrued capital expenditures $ 174,950,296

Supplemental Disclosures:

Cash paid for interest, net of amount capitalized $ 331,071,163

Cash paid for income taxes, net $ (29,639,612)

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

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.: 88 Column: b

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

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

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

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

Cash (131) $ 16,603,425

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

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

Cash (131) $ (3,906,582)

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

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

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

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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) GAAP requires service cost related to pensions and Post-Retirement Benefits Other Than Pensions (PBOP) to be reported with other compensation costs arising from services rendered by employees during the period and included in a subtotal of income from operations on the income statement. Non-service cost components are presented separately outside the subtotal of income from operations on the income statement. For FERC reporting purposes, costs related to pensions and PBOP is included in the Net Utility Operating Income of the income statement.

The Combined Notes To Consolidated Financial Statements below are as published for the year ended December 31, 2019 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 20, 2020. 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, 2019 up to February 20, 2020, the date that Duke Energy Corporation’s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 14, 2020.

On March 11, 2020 the World Health Organization declared the novel strain of coronavirus (COVID-19) a global pandemic and recommended containment and mitigation measures worldwide. It is anticipated that COVID-19 will negatively impact global economies, including in the United States. The extent to which COVID-19 impacts our operations, including demand for electricity, will depend on future developments, which are highly uncertain and cannot be predicted, including new information which may emerge concerning the severity of the outbreak and the actions to contain COVID-19 or treat its impact, among others.

On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security (CARES) Act (the “Act”) was enacted. The CARES Act is an approximately $2 trillion emergency economic stimulus package in response to the Coronavirus outbreak, which among other things contains numerous income tax provisions. Some of these tax provisions are expected to be effective retroactively for years ending before the date of enactment. The Company is currently evaluating the implications of the Act and its impact on the financial statements and related disclosures has not yet been determined.

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**	**Total**
EDIT Detail by Customer	$ (881)	$ (157)	$ (338)	**$ (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):

In 2019, Duke Energy Progress recorded ADIT and EDIT in anticipation of filing an amended 2017 federal tax return and for the implementation of Accounting Standards Update 2018-02-Income Statement-Reporting Comprehensive Income.

As of December 2018 and 2019, the cumulative re-measurement, prior to amortization, is shown below (in millions):

	2018			**2019**		
Accounts	**EDIT**	**Gross ups**	**Total**	**EDIT**	**Gross ups**	**Total**
254	$(1,412)	$(426)	$(1,838)	$(1,413)	$(426)	$(1,839)
190	(772)	426	(346)	(772)	426	(346)
282	1548	-	1548	1549	-	1549
283	709	-	709	709	-	709
411.2	(21)	-	(21)	(21)	-	(21)
182.3/253/254	(52)	-	(52)	(52)	-	(52)
Total	**$-**	**$-**	**$-**	**$-**	**$-**	**$-**

EDIT Detail by Customer	**12/31/2018**	**12/31/2019**
NC Retail	$(904)	$(905)
SC Retail	(161)	(161)
Wholesale	(347)	(347)
Total	**$(1,412)**	**$(1,413)**

The amount of EDIT that is considered protected and unprotected as of December 31, 2019 and 2018 is reflected below (in millions):

EDIT Category	**12/31/18**	**12/31/19**
Protected:		
NC Retail	$(632)	$(657)
SC Retail	(113)	(117)
Wholesale	(245)	(252)
Unprotected:		
NC Retail	(272)	(248)
SC Retail	(48)	(44)
Wholesale	(102)	(95)
Total	**$(1,412)**	**$(1,413)**

On October 5, 2018 Duke Energy Progress received a regulatory order from the North Carolina Utilities Commission directing the company to maintain the EDIT in a regulatory liability for the next 3 years or until their next general rate case proceeding, whichever is sooner. On May 21, 2019 Duke Energy Progress received a regulatory order from The Public Service Commission of South Carolina directing the company to amortize EDIT liabilities as shown in the table below. The reduction in the EDIT 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 accounts that the amortization will be reported in is reflected below:

EDIT Category by Jurisdiction	Amortization Period	2018 Amortization Amounts	2019 Amortization Amounts
411.1			
Protected:			
NC Retail	In accordance with ARAM, which is generally between 25 and 50 years	-	-
SC Retail	In accordance with ARAM, which is generally between 25 and 50 years	-	$2.4
Wholesale - Production FERC	In accordance with ARAM, which is generally between 25 and 50 years	-	3.4
Wholesale - Transmission FERC	In accordance with ARAM, which is generally between 25 and 50 years	-	-
Unprotected:			
NC Retail	Rate case in process	-	-
SC Retail	20 years for Unprotected PPE, 5 years for Unprotected Non-PPE, both beginning 6/1/2019	-	1.7
Wholesale - Production FERC	20 years for Unprotected PPE, 5 years for Unprotected Non-PPE, both beginning 1/1/2019	-	1.5
Wholesale -Transmission FERC	In accordance with FERC Order 864.	-	-
Total Amortization		**$-**	**$9.0**

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**	**27**
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.

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 18 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 9 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% of total Current Assets or Current Liabilities on the Duke Energy Registrants' Consolidated Balance Sheets at either December 31, 2019, or 2018.

		December 31,	
(in millions)	**Location**	**2019**	**2018**
Duke Energy			
Taxes receivable	Current Assets	**$ 357**	$ 729
Accrued compensation	Current Liabilities	**862**	793
Duke Energy Carolinas			
Accrued compensation	Current Liabilities	**$ 271**	$ 251
Other accrued liabilities	Current Liabilities	**147**	55
Progress Energy			
Customer deposits	Current Liabilities	**$ 354**	$ 345
Duke Energy Florida			
Customer deposits	Current Liabilities	**$ 209**	$ 208
Other accrued liabilities	Current Liabilities	**89**	85
Duke Energy Indiana			
Income taxes receivable	Current Assets	**$ 44**	$ 9
Customer deposits	Current Liabilities	**49**	47

Discontinued 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, 2019, 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.

Noncontrolling Interest

Duke Energy maintains a controlling financial interest in certain less-than wholly owned non-regulated subsidiaries. As a result, Duke Energy consolidates these subsidiaries and presents the third-party investors' portion of Duke Energy's net income (loss), net assets and comprehensive income (loss) as noncontrolling interest. Noncontrolling interest is included as a component of equity on the Consolidated Balance Sheet.

Several operating agreements of Duke Energy's subsidiaries with noncontrolling interest are subject to allocations of tax attributes and cash flows in accordance with contractual agreements that vary throughout the lives of the subsidiaries. Therefore, Duke Energy and the other investors' (the owners) interests in the subsidiaries are not fixed, and the subsidiaries apply the HLBV method in allocating income or loss and other comprehensive income or loss (all measured on a pretax basis) to the owners. The HLBV method measures the amounts that each owner would hypothetically claim at each balance sheet reporting date, including tax benefits realized by the owners, upon a hypothetical liquidation of the subsidiary at the net book value of its underlying assets. The change in the amount that each owner would hypothetically receive at the reporting date compared to the amount it would have received on the previous reporting date represents the amount of income or loss allocated to each owner for the reporting period. During 2019, Duke Energy received $428 million for the sale of noncontrolling interests to tax equity members subject to the HLBV method for projects totaling 718 MW in nameplate capacity. Duke Energy allocated approximately $165 million of losses to noncontrolling tax equity members utilizing the HLBV method for the year ended December 31, 2019.

Other operating agreements of Duke Energy's subsidiaries with noncontrolling interest allocate profit and loss based on their pro rata shares of the ownership interest in the respective subsidiary. Therefore, Duke Energy allocates net income or loss and other comprehensive income or loss of these subsidiaries to the owners based on their pro rata shares.

During the third quarter of 2019, Duke Energy completed a sale of minority interest in a portion of certain renewable assets to John Hancock. John Hancock's ownership interest in the assets represents a noncontrolling interest. See Note 2 for additional information on the sale.

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 18 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, 2019			December 31, 2018		
	Duke Energy	Progress Energy	Duke Energy Florida	Duke Energy	Progress Energy	Duke Energy Florida
Current Assets						
Cash and cash equivalents	$ 311	$ 48	$ 17	$ 442	$ 67	$ 36
Other	222	39	39	141	39	39
Other Noncurrent Assets						
Other	40	39	—	8	6	—
Total cash, cash equivalents and restricted cash	$ 573	$ 126	$ 56	$ 591	$ 112	$ 75

Inventory

Inventory related to regulated operations is valued at historical cost. Inventory related to nonregulated operations is valued at the lower of cost or market. Inventory is charged to expense or capitalized to property, plant and equipment when issued, primarily using the average cost method. Excess or obsolete inventory is written-down to the lower of cost or net realizable 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, 2019, and 2018, respectively. The components of inventory are presented in the tables below.

	December 31, 2019							
(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	$ 2,297	$ 768	$ 1,038	$ 686	$ 351	$ 79	$ 318	$ 5
Coal	586	187	186	138	48	15	198	—
Natural gas, oil and other	349	41	199	110	90	41	1	67
Total inventory	$ 3,232	$ 996	$ 1,423	$ 934	$ 489	$ 135	$ 517	$ 72

	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

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 16 for further information.

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 12 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. 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 12 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,		
	2019	**2018**	**2017**
Duke Energy	**3.1%**	3.0%	2.8%
Duke Energy Carolinas	**2.8%**	2.8%	2.8%
Progress Energy	**3.1%**	2.9%	2.6%
Duke Energy Progress	**3.1%**	2.9%	2.6%
Duke Energy Florida	**3.1%**	3.0%	2.8%
Duke Energy Ohio	**2.6%**	2.8%	2.8%
Duke Energy Indiana	**3.3%**	3.3%	3.0%
Piedmont	**2.4%**	2.5%	2.3%

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). 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 11 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 24 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. In 2019, Duke Energy Florida entered into an agreement for the accelerated decommissioning of Crystal River Unit 3. See Note 4 for more information. 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 10 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 19 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 15 for further information.

Captive Insurance Reserves

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

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

Unamortized Debt Premium, Discount and Expense

Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the term of the debt issue. The gain or loss on extinguishment associated with refinancing higher-cost debt obligations in the regulated operations is amortized over the remaining life of the original instrument. 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.

Preferred Stock

Preferred stock is reviewed to determine the appropriate balance sheet classification and embedded features, such as call options, are evaluated to determine if they should be bifurcated and accounted for separately. Costs directly related to the issuance of preferred stock is recorded as a reduction of the proceeds received. The liability for the dividend is recognized when declared. The accumulated dividends on the cumulative preferred stock is recognized to net income available to Duke Energy Corporation in the EPS calculation. See Note 20 for further information.

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 23 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 21 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 8 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 22 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 24 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.

Duke Energy receives PTCs on wind facilities that are recognized as electricity is produced.

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. Taxes for which Duke operates merely as a collection agent for the state and local government are accounted for on a net basis. 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)	**2019**	**2018**	**2017**
Duke Energy	**$ 421**	$ 405	$ 376
Duke Energy Carolinas	**39**	35	36
Progress Energy	**256**	241	220

Duke Energy Progress	**21**	19	19
Duke Energy Florida	**235**	222	201
Duke Energy Ohio	**101**	105	98
Duke Energy Indiana	**23**	22	20
Piedmont	**2**	2	2

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, 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 due to conditions established by regulators in conjunction with merger transaction approvals. At December 31, 2019, and 2018, an insignificant amount of Duke Energy's consolidated Retained earnings balance represents undistributed earnings of equity method investments.

New Accounting Standards

Except as noted below, the new accounting standards adopted for 2019, 2018 and 2017 had no material impact on the presentation or results of operations, cash flows or financial position of the Duke Energy Registrants.

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. This resulted in a material impact on the presentation for the statement of financial position of the Duke Energy Registrants for the period ended December 31, 2019, and an immaterial impact to the Duke Energy Registrants' results of operations and cash flows for the year ended December 31, 2019.

Duke Energy elected the modified retrospective method of adoption effective January 1, 2019. Under the modified retrospective method of adoption, prior year reported results are not restated. For adoption, Duke Energy elected to apply the following practical expedients:

Practical Expedient	Description
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.
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.
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.
Hindsight expedient (when determining lease term)	Elect to use hindsight to determine the lease term.
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.
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 the new requirements to comparative periods, including disclosures.
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 evaluated the financial statement impact of adopting the standard and monitored industry implementation issues. Under agreements considered leases, where Duke Energy is the lessee, for the use of certain aircraft, space on communication towers, industrial equipment, fleet vehicles, fuel transportation (barges and railcars), land, office space and PPAs are now recognized on the balance sheet. The Duke Energy Registrants did not have a material change to the financial statements from the adoption of the new standard for contracts where it is the lessor. See Note 6 for further information.

The following new accounting standard has been issued but not yet adopted by the Duke Energy Registrants as of December 31, 2019**.**

Credit Losses. In June 2016, the FASB issued new accounting guidance for credit losses. This guidance establishes a new impairment model applicable to certain financial assets, including trade and other receivables, net investments in leases, and debt securities classified as held-for-sale investments. The model also applies to financial guarantees.

For Duke Energy, the guidance is effective for interim and annual periods beginning January 1, 2020. This 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 is recorded to retained earnings at January 1, 2020.

Upon adoption, Duke Energy will recognize an allowance for credit losses based on management's estimate of losses expected to be incurred over the lives of certain assets or guarantees. Duke Energy expects the impacts of this standard to be driven by the reserve for credit losses on financial guarantees, trade and other receivables, and insurance receivables. Duke Energy does not intend to adopt any practical expedients.

Duke Energy currently expects to record a reserve for credit losses as shown in approximate amounts in the table below:

	December 31, 2019					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Piedmont**
Total pretax impact to Retained Earnings	**$ 120**	**$ 16**	**$ 2**	**$ 1**	**$ 1**	**$ 1**

In addition to the reserve for credit losses, Duke Energy expects additional disclosures on management's evaluation of credit risks inherent in financial assets and how management monitors credit quality, changes in expected credit losses, and the appropriateness of the allowance for credit losses on a forward-looking basis. Duke Energy also expects additional disclosures around credit losses for new investments in leases, loan commitments, and other financial instruments.

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 billion and assumed Piedmont's existing long-term debt, which had a fair value of approximately $2 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 and $103 million for the years ended December 31, 2018, and 2017, 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.

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

DISPOSITIONS

On April 24, 2019, Duke Energy executed an agreement to sell a minority interest in a portion of certain renewable assets within the Commercial Renewables segment. The sale closed on September 6, 2019, and resulted in pretax proceeds to Duke Energy of $415 million. The portion of Duke Energy's commercial renewables energy portfolio sold includes 49% of 37 operating wind, solar and battery storage assets and 33% of 11 operating solar assets across the U.S. Duke Energy retained control of these assets, and, therefore, no gain or loss was recognized on the Consolidated Statements of Operations. The difference between the consideration received and the carrying value of the noncontrolling interest claim on net assets is $466 million, net of a tax benefit of $8 million, and was recorded in equity.

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 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. On April 24, 2019, Duke Energy executed an agreement to sell a minority interest in a portion of certain renewable assets. See Note 2 for additional information on the minority interest sale.

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 13 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, 2019						
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total Reportable Segments	Other	Eliminations	Total
Unaffiliated Revenues	$ 22,798	$ 1,770	$ 487	$ 25,055	$ 24	$ —	$ 25,079
Intersegment Revenues	33	96	—	129	71	(200)	—
Total Revenues	$ 22,831	$ 1,866	$ 487	$ 25,184	$ 95	$ (200)	$ 25,079
Interest Expense	$ 1,345	$ 117	$ 95	$ 1,557	$ 705	$ (58)	$ 2,204
Depreciation and amortization	3,951	256	168	4,375	178	(5)	4,548
Equity in earnings (losses) of unconsolidated affiliates	9	114	(4)	119	43	—	162
Income tax expense (benefit)	785	22	(115)	692	(173)	—	519
Segment income (loss)[a][b]	3,536	432	198	4,166	(452)	—	3,714
Add back noncontrolling interest[c]							(177)
Add back preferred stock dividend							41
Loss from discontinued operations, net of tax							(7)
Net income							$ 3,571
Capital investments expenditures and acquisitions	$ 8,263	$ 1,539	$ 1,423	$ 11,225	$ 221	$ —	$ 11,446
Segment assets	135,561	13,921	6,020	155,502	3,148	188	158,838

(a) Electric Utilities and Infrastructure includes a $27 million reduction of a prior year impairment at Citrus County CC related to the plant's cost cap. See Note 4 for additional information.

(b) Gas Utilities and Infrastructure includes an after-tax impairment charge of $19 million for the remaining investment in Constitution. See Note 13 for additional information.

(c) Includes the allocation of losses to noncontrolling tax equity members. See Note 1 for additional information.

	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)
Loss 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 24 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 13 for additional information.

(d) Commercial Renewables includes an impairment charge of $91 million, net of $2 million Noncontrolling interests, related to goodwill. See Note 12 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 Beckjord described below. For additional information, see Note 2 for the Piedmont Merger and Note 21 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.

(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 11 and 12 for additional information.

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

Geographical Information

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

Major Customers

For the year ended December 31, 2019, revenues from one customer of Duke Energy Progress are $635 million. Duke Energy Progress has one reportable segment, Electric Utilities and Infrastructure. No other Subsidiary Registrant has an individual customer representing more than 10% 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
2019					
Electric Utilities and Infrastructure	**$ 19,745**	**$ 2,231**	**$ —**	**$ 855**	**$ 22,831**
Gas Utilities and Infrastructure	**—**	**—**	**1,782**	**84**	**1,866**
Commercial Renewables	**—**	**389**	**—**	**98**	**487**
Total Reportable Segments	**$ 19,745**	**$ 2,620**	**$ 1,782**	**$ 1,037**	**$ 25,184**
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

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, 2019					
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Total Reportable Segments	Other	Eliminations	Total
Total revenues	$ 1,456	$ 484	$ 1,940	$ —	$ —	$ 1,940
Interest expense	$ 80	$ 29	$ 109	$ —	$ —	$ 109
Depreciation and amortization	182	83	265	—	—	265
Income tax expense (benefit)	20	21	41	(1)	—	40
Segment income (loss)/Net income	159	85	244	(5)	—	239
Loss from discontinued operations, net of tax						(1)
Net income						$ 238
Capital expenditures	$ 680	$ 272	$ 952	$ —	$ —	$ 952
Segment assets	6,188	3,116	9,304	34	—	9,338

	Year Ended December 31, 2018					
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Total Reportable Segments	Other	Eliminations	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

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)	2019	2018	2019	2018
Regulatory Assets				
AROs – coal ash	$ 4,084	$ 4,255	$ 1,843	$ 2,061
AROs – nuclear and other	739	772	668	601
Accrued pension and OPEB	2,391	2,654	897	1,074
Storm cost deferrals	1,399	1,117	1,214	953
Nuclear asset securitized balance, net	1,042	1,093	1,042	1,093
Debt fair value adjustment	1,019	1,099	—	—
Deferred fuel and purchased power	528	838	305	600
Deferred asset – Lee and Harris COLA	388	426	38	43
Hedge costs deferrals	356	204	129	74
Demand side management (DSM)/Energy Efficiency (EE)	343	449	241	256
Advanced metering infrastructure (AMI)	338	367	114	127
Retired generation facilities	331	402	266	324
Post-in-service carrying costs (PISCC) and deferred operating expenses	329	320	33	36
Vacation accrual	214	213	41	41
Derivatives – natural gas supply contracts	117	141	—	—
Nuclear deferral	107	133	40	46
Manufactured gas plant (MGP)	102	99	—	—
Deferred pipeline integrity costs	79	65	—	—
NCEMPA deferrals	72	50	72	50
East Bend deferrals	44	47	—	—
Transmission expansion obligation	36	39	—	—
Amounts due from customers	36	24	—	—
Grid modernization	28	31	—	—

Other	**896**	784	**349**	322
Total regulatory assets	**15,018**	15,622	**7,292**	7,701
Less: current portion	**1,796**	2,005	**946**	1,137
Total noncurrent regulatory assets	**$ 13,222**	$ 13,617	**$ 6,346**	$ 6,564
Regulatory Liabilities				
Net regulatory liability related to income taxes	**$ 7,872**	$ 8,058	**$ 2,595**	$ 2,710
Costs of removal	**5,756**	5,421	**2,561**	2,135
AROs – nuclear and other	**1,100**	538	**—**	—
Accrued pension and OPEB	**176**	301	**—**	149
Amounts to be refunded to customers	**34**	34	**—**	—
Deferred fuel and purchased power	**1**	16	**1**	16
Other	**1,109**	1,064	**398**	319
Total regulatory liabilities	**16,048**	15,432	**5,555**	5,329
Less: current portion	**784**	598	**330**	280
Total noncurrent regulatory liabilities	**$ 15,264**	$ 14,834	**$ 5,225**	$ 5,049

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 10 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 10 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 assets are expected to be recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.

Storm cost deferrals. Represents deferred incremental costs incurred related to major 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.

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.

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

Deferred asset – Lee and Harris COLA. Represents deferred costs incurred for the canceled Lee and Harris nuclear projects.

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.

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

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.

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

Post-in-service carrying costs (PISCC) 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.

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

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

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.

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.

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

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.

Transmission expansion obligation. Represents transmission expansion obligations related to Duke Energy Ohio's withdrawal from MISO.

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

Net regulatory liability related to income taxes. Amounts for all registrants include regulatory liabilities related primarily to impacts from the Tax Act. See Note 24 for additional information. Amounts have no immediate impact on rate base as regulatory assets are offset by deferred tax liabilities.

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.

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, 2019.

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, 2019.

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% of total capital.

Duke Energy Kentucky is required to pay dividends solely out of retained earnings and to maintain a minimum of 35% 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

Hurricane Florence, Hurricane Michael and Winter Storm Diego Deferral Filings

On December 21, 2018, Duke Energy Carolinas and Duke Energy Progress filed with the NCUC petitions for approval to defer the incremental costs incurred in connection with the response to Hurricane Florence, Hurricane Michael and Winter Storm Diego to a regulatory asset for recovery in the next base rate case. The NCUC issued an order requesting comments on the deferral positions. On March 5, 2019, the North Carolina Public Staff (Public Staff) filed comments. On April 2, 2019, Duke Energy Carolinas and Duke Energy Progress filed reply comments, which included revised estimates of approximately $553 million in incremental operation and maintenance expenses ($171 million and $382 million for Duke Energy Carolinas and Duke Energy Progress, respectively) and approximately $96 million in capital costs ($20 million and $76 million for Duke Energy Carolinas and Duke Energy Progress, respectively). On September 30, 2019, Duke Energy Carolinas requested that the NCUC consolidate its pending deferral request with its general rate case filed on that date. On October 30, 2019, Duke Energy Progress requested that the NCUC consolidate its pending deferral request with its general rate case filed on that date. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of these matters. Duke Energy Progress filed a deferral request for these storms 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, followed by an order issued on February 21, 2019. On March 15, 2019, Duke Energy Progress filed a request with FERC requesting permission to defer transmission-related storm costs that would be charged to wholesale transmission customers through Duke Energy Progress' Open Access Transmission Tariff (OATT) and to recover those costs from wholesale transmission customers over a three-year recovery period. FERC accepted the filing on May 14, 2019, which allows Duke Energy Progress to proceed with the proposed cost deferral and recovery.

Duke Energy Carolinas

Regulatory Assets and Liabilities

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

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash	**$ 1,696**	$ 1,725	(i)	(b)
Accrued pension and OPEB	**477**	581		(j)
Storm cost deferrals	**178**	160	Yes	(b)
Deferred fuel and purchased power	**222**	196	(f)	2021
Deferred asset – Lee COLA	**350**	383		(b)
Hedge costs deferrals[c]	**198**	101	Yes	2041
DSM/EE	**100**	169	(h)	(h)
AMI	**166**	176	Yes	(b)
Retired generation facilities[c]	**16**	21	Yes	2023
PISCC[c]	**33**	34	Yes	(b)
Vacation accrual	**80**	78	(e)	2020
Nuclear deferral	**67**	87		2021
Other	**327**	266		(b)
Total regulatory assets	**3,910**	3,977		
Less: current portion	**550**	520		
Total noncurrent regulatory assets	**$ 3,360**	$ 3,457		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes[d]	**$ 3,060**	$ 3,082		(b)
Costs of removal[c]	**1,936**	1,968	Yes	(g)
AROs – nuclear and other	**1,100**	538		(b)
Accrued pension and OPEB	**39**	38		(j)
Other	**543**	572		(b)
Total regulatory liabilities	**6,678**	6,198		

Less: current portion	**255**	199
Total noncurrent regulatory liabilities	**$ 6,423**	$ 5,999

(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) 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 24.
(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 23 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% increase in annual base revenues. The request for rate increase was driven by capital investments subsequent to the previous base rate case, including the W.S. Lee CC, 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 William States Lee III Nuclear Station.

On February 28, 2018, Duke Energy Carolinas 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% and a capital structure of 52% equity and 48% debt. As a result of the settlement, Duke Energy Carolinas recorded a pretax charge of approximately $4 million in the first quarter of 2018 to Operation, maintenance and other on the Consolidated Statements of Operations.

On June 22, 2018, the NCUC issued an order approving the Stipulation of Partial Settlement and requiring a revenue reduction.

As a result of the June 22, 2018, 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 was primarily related to the denial of a return on the Lee Nuclear Project and the assessment of a $70 million management penalty by reducing the annual recovery of deferred coal ash costs by $14 million per year over a five-year recovery period. 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 also filed Notices of Appeal to the North Carolina Supreme Court. On August 8, 2018, the Public Staff filed a Notice of Cross Appeal to the North Carolina Supreme Court, which contends the commission's June 22, 2018, 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. Appellant briefs were filed on April 26, 2019. The Appellee response briefs were filed on September 25, 2019. Oral arguments before the North Carolina Supreme Court are scheduled for March 11, 2020. Duke Energy Carolinas cannot predict the outcome of this matter.

2019 North Carolina Rate Case

On September 30, 2019, Duke Energy Carolinas filed an application with the NCUC for a net rate increase for retail customers of approximately $291 million, which represents an approximate 6% increase in annual base revenues. The gross rate case revenue increase request is $445 million, which is offset by an EDIT rider of $154 million to return to customers North Carolina and federal EDIT resulting from recent reductions in corporate tax rates. The request for rate increase is driven by major capital investments subsequent to the previous base rate case, coal ash pond closure costs, accelerated coal plant depreciation and deferred 2018 storm costs. Duke Energy Carolinas requests rates be effective no later than August 1, 2020. The NCUC has established a procedural schedule with an evidentiary hearing to commence on March 23, 2020. 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% increase in retail revenues. The request for rate increase was 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 included 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%. The request also included $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 (EDIT Rider).

Duke Energy Carolinas also requested approval of its proposed Grid Improvement Plan (GIP), 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. On March 8, 2019, the ORS moved to establish a new and separate hearing docket to review and consider the GIP proposed by Duke Energy Carolinas. Subsequently, on March 12, 2019, the ORS and Duke Energy Carolinas executed a Stipulation resolving the ORS's motion. The Stipulation provided that costs incurred for the GIP after January 1, 2019, would be deferred with a return, subject to evaluation in a future rate proceeding. The Stipulation was approved by the PSCSC on June 19, 2019. On December 16, 2019, Duke Energy Carolinas and Duke Energy Progress filed a Joint Petition to Establish an Informational Docket for Review and Consideration of Grid Improvement Plans through which Duke Energy Carolinas and Duke Energy Progress would provide interested stakeholders information on the companies' grid activities. The PSCSC requested parties comment on procedural matters by January 31; accordingly, various groups filed comments, none of which opposed an informational docket. Duke Energy Carolinas cannot predict the outcome of this matter.

After hearings in March 2019, the PSCSC issued an order on May 21, 2019, which included a return on equity of 9.5% and a capital structure of 53% equity and 47% debt. The order also included the following material components:

- Approval of cancellation of the Lee Nuclear Project, with Duke Energy Carolinas maintaining the Combined Operating License;
- Approval of recovery of $125 million (South Carolina retail portion) of Lee Nuclear Project development costs (including AFUDC through December 2017) over a 12-year period, but denial of a return on the deferred balance of costs;
- Approval of recovery of $96 million of coal ash costs over a five-year period with a return at Duke Energy Carolinas' WACC;
- Denial of recovery of $115 million of certain coal ash costs deemed to be related to the Coal Ash Act and incremental to the federal CCR rule;
- Approval of a $66 million decrease to base rates to reflect the change in ongoing tax expense, primarily the reduction in the federal income tax rate from 35% to 21%;

- Approval of a $45 million decrease through the EDIT Rider to return EDIT resulting from the federal tax rate change and deferred revenues since January 2018 related to the change, to be returned in accordance with the Average Rate Assumption Method (ARAM) for protected EDIT, over a 20-year period for unprotected EDIT associated with Property, Plant and Equipment, over a five-year period for unprotected EDIT not associated with Property, Plant and Equipment and over a five-year period for the deferred revenues; and

- Approval of a $17 million decrease through the EDIT Rider related to reductions in the North Carolina state income tax rate from 6.9% to 2.5% to be returned over a five-year period.

As a result of the order, revised customer rates were effective June 1, 2019. On May 31, 2019, Duke Energy Carolinas filed a Petition for Rehearing or Reconsideration of that order contending substantial rights of Duke Energy Carolinas were prejudiced by unlawful, arbitrary and capricious rulings by the commission on certain issues presented in the proceeding. On June 19, 2019, the PSCSC issued a Directive denying Duke Energy Carolinas' request to rehear or reconsider the commission's rulings on certain issues presented in the proceeding including coal ash remediation and disposal costs, return on equity and the recovery of a return on deferred operation and maintenance expenses. An order detailing the commission's decision in the Directive was issued on October 18, 2019. Duke Energy Carolinas filed a notice of appeal on November 15, 2019, with the South Carolina Supreme Court. On November 20, 2019, the South Carolina Energy Users Committee filed a Notice of Appeal and the ORS filed a Notice of Cross Appeal with the South Carolina Supreme Court. On January 8, 2020, Duke Energy Carolinas and the ORS filed a joint motion to extend briefing schedule deadlines. Appellant briefs are due on March 2, 2020, and Appellee response briefs are due on May 15, 2020. On February 12, 2020, Duke Energy Carolinas and the ORS filed a joint motion to extend briefing deadlines by 30 days. Based on legal analysis and the filing of the appeal, Duke Energy Carolinas has not recorded an adjustment for its deferred coal ash costs. 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. On April 2, 2019, FERC issued an order approving the settlement agreement as filed. Since then, Duke Energy Carolinas has implemented the terms of the settlement in rates with all wholesale customers, including non-intervening customers. On July 25, 2019, Duke Energy Carolinas received FERC approval for the accounting treatment requested for certain assets included in the settlement agreements. This is the final approval needed from FERC and concludes this proceeding.

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 was subject to approval from FERC for the four FERC-licensed plants, as well as other state regulatory agencies and was 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 the 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 June 5, 2019, the NCUC issued an order approving the transfer of the hydro plants from Duke Energy Carolinas to Northbrook, granting deferral accounting and denying the Public Staff's motion for reconsideration.

On August 28, 2018, Duke Energy Carolinas filed with PSCSC an 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. At its June 26, 2019, agenda meeting, the PSCSC voted to approve the transfer and sale subject to the recommendation of the ORS that the issuance of an Accounting Order will not preclude the ORS, the commission or any other party from addressing the reasonableness of these costs, any return sought and including any carrying costs in the next rate case.

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 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 December 27, 2018, 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. On February 14, 2019, FERC issued an order granting extensions until August 26, 2019, to comply with the requirements of the December 27, 2018, order.

The closing occurred on August 16, 2019. A regulatory asset was established for approximately $32 million, which represents the total deferral amount for North Carolina and South Carolina retail. The North Carolina retail portion will be amortized pursuant to an order from the NCUC. 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 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)	**2019**	**2018**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs – coal ash	**$ 1,834**	$ 2,051	(h)	(b)
AROs – nuclear and other	**509**	429		(c)
Accrued pension and OPEB	**423**	542		(k)
Storm cost deferrals[d]	**801**	571	Yes	(b)
Deferred fuel and purchased power	**266**	397	(f)	2021
Deferred asset – Harris COLA	**38**	43		
Hedge costs deferrals	**85**	54		(b)
DSM/EE[e]	**216**	235	(i)	(i)
AMI	**61**	67		(b)
Retired generation facilities	**83**	105	Yes	(b)
PISCC and deferred operating expenses	**33**	36	Yes	2054
Vacation accrual	**41**	41		2020
Nuclear deferral	**40**	46		2021
NCEMPA deferrals	**72**	50	(g)	2042
Other	**176**	147		(b)

Total regulatory assets		**4,678**	4,814		
Less: current portion		**526**	703		
Total noncurrent regulatory assets	**$**	**4,152**	$ 4,111		
Regulatory Liabilities[a]					
Net regulatory liability related to income taxes[l]	**$**	**1,802**	$ 1,863		(b)
Costs of removal		**2,294**	1,878	Yes	(j)
Accrued pension and OPEB		**—**	93		(k)
Other		**372**	299		(b)
Total regulatory liabilities		**4,468**	4,133		
Less: current portion		**236**	178		
Total noncurrent regulatory liabilities	**$**	**4,232**	$ 3,955		

(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 23 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% increase in annual base revenues. Subsequent to the filing, Duke Energy Progress adjusted the requested amount to $420 million, representing an approximate 13% increase. The request for rate increase was driven by capital investments subsequent to the previous base rate case, costs of complying with CCR regulations and the Coal Ash Act, costs relating to storm recovery, investments in customer service technologies and recovery of costs associated with renewable purchased power.

On November 22, 2017, Duke Energy Progress and the 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% and a capital structure of 52% equity and 48% debt. On February 23, 2018, the NCUC issued an order approving the stipulation.

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. 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 NCUC's February 23, 2018, order. The Public Staff contends the NCUC'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 also filed Notices of Appeal to the North Carolina Supreme Court from the February 23, 2018, order. 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. Appellant briefs were filed on April 26, 2019. The Appellee response briefs were filed on September 25, 2019. Oral arguments before the North Carolina Supreme Court are scheduled for March 11, 2020. Duke Energy Progress cannot predict the outcome of this matter.

2019 North Carolina Rate Case

On October 30, 2019, Duke Energy Progress filed an application with the NCUC for a net rate increase for retail customers of approximately $464 million, which represents an approximate 12.3% increase in annual base revenues. The gross rate case revenue increase request is $586 million, which is offset by riders of $122 million, primarily an EDIT rider of $120 million to return to customers North Carolina and federal EDIT resulting from recent reductions in corporate tax rates. The request for rate increase is driven by major capital investments subsequent to the previous base rate case, coal ash pond closure costs, accelerated coal plant depreciation and deferred 2018 storm costs. Duke Energy Progress seeks to defer and recover incremental Hurricane Dorian storm costs in this proceeding and requests rates be effective no later than September 1, 2020. The NCUC has established a procedural schedule with an evidentiary hearing to commence on May 4, 2020. Duke Energy Progress cannot predict the outcome of this matter.

Hurricane Dorian

Hurricane Dorian reached the Carolinas in September 2019 as a Category 2 hurricane making landfall within Duke Energy Progress' service territory. Approximately 270,000 North Carolina customers and 30,000 South Carolina customers were impacted by the slow-moving storm that brought high winds, tornadoes and heavy rain. With storm-response mobilization occurring in preparation for the storm and the assistance of mutual aid partners, full restoration was accomplished within four days for all customers able to receive service. Total estimated incremental operation and maintenance expenses incurred to repair and restore the system are approximately $205 million with an additional $4 million in capital investments made for restoration efforts. Approximately $179 million of the operation and maintenance expenses are deferred in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2019. 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, 2019. A request for an accounting order to defer incremental storm costs associated with Hurricane Dorian was included in Duke Energy Progress' October 30, 2019, general rate case filing with the NCUC. Duke Energy Progress cannot predict the outcome of this matter.

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% increase in annual base revenues. The request for rate increase was 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 included a decrease 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%. The request also included $10 million to return EDIT resulting from the federal tax rate change and deferred revenues since January 2018 related to the change (EDIT Rider) and a $12 million increase due to the expiration of EDITs related to reductions in North Carolina state income taxes allocable to South Carolina.

Duke Energy Progress also requested approval of its proposed GIP, 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. On March 8, 2019, the ORS moved to establish a new and separate hearing docket to review and consider the GIP proposed by Duke Energy Progress. Subsequently, on March 12, 2019, the ORS and Duke Energy Carolinas executed a Stipulation resolving the ORS's motion, and Duke Energy Progress agreed to the Stipulation, as did other parties in the rate case. The Stipulation provides that costs incurred for the GIP after January 1, 2019, would be deferred with a return, with all costs subject to evaluation in a future rate proceeding. The Stipulation was approved by the PSCSC on June 19, 2019. On December 16, 2019, Duke Energy Progress and Duke Energy Carolinas filed a Joint Petition to Establish an Informational Docket for Review and Consideration of Grid Improvement Plans through which Duke Energy Progress and Duke Energy Carolinas would provide interested stakeholders information on the companies' grid activities. The PSCSC requested parties comment on procedural matters by January 31; accordingly, various groups filed comments, none of which opposed an informational docket. Duke Energy Progress cannot predict the outcome of this matter.

After hearings in April 2019, the PSCSC issued an order on May 21, 2019, which included a return on equity of 9.5% and a capital structure of 53% equity and 47% debt. The order also included the following material components:

- Approval of recovery of $4 million of coal ash costs over a five-year period with a return at Duke Energy Progress' WACC;
- Denial of recovery of $65 million of certain coal ash costs deemed to be related to the Coal Ash Act and incremental to the federal CCR rule;
- Approval of a $17 million decrease to base rates to reflect the change in ongoing tax expense, primarily the reduction in the federal income tax rate from 35% to 21%;
- Approval of a $12 million decrease through the EDIT Tax Savings Rider resulting from the federal tax rate change and deferred revenues since January 2018 related to the change, to be returned in accordance with ARAM for protected EDIT, over a 20-year period for unprotected EDIT associated with Property, Plant and Equipment, over a five-year period for unprotected EDIT not associated with Property, Plant and Equipment and over a three-year period for the deferred revenues; and
- Approval of a $12 million increase due to the expiration of EDIT related to reductions in the North Carolina state income tax rate from 6.9% to 2.5%.

As a result of the order, revised customer rates were effective June 1, 2019. On May 31, 2019, Duke Energy Progress filed a Petition for Rehearing or Reconsideration of that order contending substantial rights of Duke Energy Progress were prejudiced by unlawful, arbitrary and capricious rulings by the commission on certain issues presented in the proceeding. On June 19, 2019, the PSCSC issued a Directive denying Duke Energy Progress' request to rehear or reconsider the commission's rulings on certain issues presented in the proceeding including coal ash remediation and disposal costs, return on equity and the recovery of a return on deferred operation and maintenance expenses, but allowing additional litigation-related costs. As a result of the Directive allowing litigation-related costs, customer rates were revised effective July 1, 2019. An order detailing the commission's decision in the Directive was issued on October 18, 2019. Duke Energy Progress filed a notice of appeal on November 15, 2019, with the South Carolina Supreme Court. The ORS filed a Notice of Cross Appeal on November 20, 2019. On January 8, 2020, Duke Energy Progress and the ORS filed a joint motion to extend briefing schedule deadlines. Appellant briefs are due on March 2, 2020, and Appellee response briefs are on May 15, 2020. On February 12, 2020, Duke Energy Progress and the ORS filed a joint motion to extend briefing deadlines by 30 days. Based on legal analysis and the filing of the appeal, Duke Energy Progress has not recorded an adjustment for its deferred coal ash costs. 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. Duke Energy Progress worked with the local natural gas distribution company to upgrade and lease an existing natural gas pipeline to serve the natural gas plant. The lease for the new pipeline became effective on March 2, 2019.

On March 28, 2016, the NCUC issued an order approving a CPCN for the new combined-cycle natural gas plants, but is requiring Duke Energy Progress to refile for CPCN approval for the contingent simple cycle unit. On March 28, 2019, 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.

On December 27, 2019, Asheville Combined Cycle Power Block 1 and the common systems that serve both combined cycle units went into commercial operation. Power Block 1 consists of the Unit 5 Combustion Turbine and Unit 6 Steam Turbine Generator (which together form the first combined cycle unit approved in the CPCN Order). Power Block 2 consists of the Unit 7 Combustion Turbine and Unit 8 Steam Turbine Generator (which together form the second combined cycle unit approved in the CPCN Order). Duke Energy Progress placed the Unit 7 Combustion Turbine portion of Power Block 2 into commercial operation in simple-cycle mode on January 15, 2020. Duke Energy Progress currently expects to place the Unit 8 Steam Turbine Generator into commercial operation in the first quarter of 2020, after final testing has been completed.

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 March 22, 2019, Duke Energy Progress and the Public Staff filed a Joint Proposed Order. On May 10, 2019, the NCUC issued an Order Granting Certificate of Public Convenience and Necessity with Conditions. On November 19, 2019, Duke Energy Progress filed a semiannual progress report for its Hot Springs Microgrid Solar and Battery Storage Facility. As required by an NCUC order issued December 6, 2019, an updated progress report was filed on January 15, 2020. Construction is expected to begin in March 2020 with commercial operation expected to begin in September 2020.

The carrying value of the 376-MW Asheville coal-fired plant, including associated ash basin closure costs, of $214 million and $327 million is included in Generation facilities to be retired, net on Duke Energy Progress' Consolidated Balance Sheets as of December 31, 2019, and 2018, 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. Duke Energy Progress retired the Asheville coal-fired plant on January 29, 2020.

FERC Return on Equity Complaint

On October 11, 2019, NCEMPA filed a complaint at FERC against Duke Energy Progress pursuant to Section 206 of the Federal Power Act (FPA). The complaint alleges that the return on equity component in the formula rate contained within the Full Requirements Power Purchase Agreement (FRPPA) is unjust and unreasonable. The FRPPA's return on equity is 11% as applied to the Production Capacity Rate for the full requirements service provided by Duke Energy Progress. The complaint does not definitively propose a replacement return on equity. Under FPA Section 206, the earliest refund effective date that FERC can establish is the date of the filing of the complaint. The complaint could raise risks across the Duke Energy Progress wholesale business because, depending on how FERC treats NCEMPA's complaint, other parties may come forward with similar complaints. Duke Energy Progress cannot predict the outcome of this matter.

Duke Energy Florida

Regulatory Assets and Liabilities

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

	December 31,		Earns/Pays	Recovery/Refund
(in millions)	**2019**	**2018**	**a Return**	**Period Ends**
Regulatory Assets[a]				
AROs – coal ash[c]	**$ 9**	$ 10		(b)
AROs – nuclear and other[c]	**159**	172		(b)
Accrued pension and OPEB[c]	**474**	532	Yes	(g)
Storm cost deferrals[c]	**413**	382	(e)	2021
Nuclear asset securitized balance, net	**1,042**	1,093		2036
Deferred fuel and purchased power	**39**	203	(f)	2021
Hedge costs deferrals	**44**	20		2038
DSM/EE[c]	**25**	21	Yes	2024
AMI[c]	**53**	60	Yes	2032
Retired generation facilities[c]	**183**	219	Yes	(b)

Other	**172**	176	(d)	(b)
Total regulatory assets	**2,613**	2,888		
Less: current portion	**419**	434		
Total noncurrent regulatory assets	**$ 2,194**	$ 2,454		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes[c]	**$ 793**	$ 847		(b)
Costs of removal[c]	**267**	257	(d)	(b)
Accrued pension and OPEB	**—**	56	Yes	(g)
Deferred fuel and purchased power[c]	**1**	16	(f)	2021
Other	**26**	20	(d)	(b)
Total regulatory liabilities	**1,087**	1,196		
Less: current portion	**94**	102		
Total noncurrent regulatory liabilities	**$ 993**	$ 1,094		

(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/pay 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 23 for additional detail.

Storm Restoration Cost Recovery

In September 2017, Duke Energy Florida's service territory suffered significant damage from Hurricane Irma, resulting in approximately 1 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. 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 sought 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. On April 3, 2019, the FPSC issued an Order abating all remaining filing dates. On April 9, 2019, Duke Energy Florida filed an unopposed motion to approve a settlement agreement resolving all outstanding issues in this docket. On June 13, 2019, the FPSC issued its order approving the settlement agreement. The Storm Cost Settlement Agreement obligates Duke Energy Florida to capitalize $18 million of storm costs and remove $6 million of operating and maintenance expense, thereby reducing the requested storm cost recovery amount by $24 million. Duke Energy Florida will also implement process changes with respect to storm cost restoration. At December 31, 2019, and December 31, 2018, Duke Energy Florida's Consolidated Balance Sheets included approximately $43 million and $217 million, respectively, 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.

In October 2018, Duke Energy Florida's service territory suffered damage when Hurricane Michael made landfall as a Category 5 hurricane with maximum sustained winds of 160 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. Total estimated incremental operation and maintenance and capital costs are $311 million. Approximately $107 million and $35 million of the costs are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2019, and December 31, 2018, respectively. Approximately $204 million and $165 million of costs are included in Regulatory assets within Current Assets and Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2019, and December 31, 2018, respectively, representing recoverable costs under the FPSC's storm rule and Duke Energy Florida's OATT formula rates.

Duke Energy Florida filed a petition with the FPSC on April 30, 2019, to recover the retail portion of incremental storm restoration costs for Hurricane Michael. On June 11, 2019, the FPSC approved the petition for recovery of incremental storm restoration costs related to Hurricane Michael. The FPSC also approved the stipulation Duke Energy Florida filed, which will allow Duke Energy Florida to use the tax savings resulting from the Tax Act to recover these storm costs in lieu of implementing a storm surcharge. Approved storm costs are currently expected to be fully recovered by approximately year-end 2021. On November 22, 2019, Duke Energy Florida filed a petition for approval of actual retail recoverable storm restoration costs related to Hurricane Michael in the amount of $191 million plus interest. An Order Establishing Procedure was issued on January 30, 2020, and hearings are scheduled to begin September 15, 2020. Duke Energy Florida cannot predict the outcome of this matter.

Hurricane Dorian

In September 2019, Duke Energy Florida's service territory was threatened by Hurricane Dorian with landfall as a possible Category 5 hurricane. For several days, various forecasts and models predicted significant impact to Duke Energy Florida's service territory; accordingly, Duke Energy Florida incurred costs to secure necessary resources to be prepared for that potential impact. Although Hurricane Dorian never made landfall in Florida, its effects were still felt, and outages did occur. Preparations were required so that, if Hurricane Dorian had made landfall and impacts had been more severe, Duke Energy Florida would have been prepared to restore its customers' power in a timely fashion.

Total current estimated incremental costs are approximately $167 million. These costs are included in Regulatory assets within Current Assets and Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2019, representing recoverable costs under the FPSC's storm rule and Duke Energy Florida's OATT formula rates. On December 19, 2019, Duke Energy Florida filed a petition with the FPSC to recover the estimated retail portion of these costs, consistent with the provisions in the 2017 Settlement. The request seeks recovery over a 12-month period beginning in March 2020. The final actual amount will be filed later in 2020 and a hearing will be held at the FPSC to determine the final amount of incremental costs. 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, which increased the total storm amortization from $151 million to $155 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 agreed to seek a Private Letter Ruling (PLR) from the IRS on its treatment of cost of removal (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. The IRS has communicated that it will not issue individual PLRs on the treatment of COR. Rather, the IRS is drafting a notice that will request comments on a number of issues, including COR, and the IRS plans to issue industrywide guidance on those issues. Duke Energy Florida cannot predict the outcome of this matter.

Citrus County CC

Construction of the 1,640-MW combined-cycle natural gas plant in Citrus County, Florida, began in October 2015 with an estimated cost of $1.5 billion, including AFUDC. Both units came on-line in the fourth quarter of 2018. The ultimate cost of the facility was 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. In the year ended December 31, 2019, Duke Energy Florida recorded a $36 million reduction to the prior-year impairment due to a decrease in the cost estimate of the Citrus County CC, primarily related to the settlement agreement with Fluor, the EPC contractor. This adjustment reduced the estimated cost of the facility to $1.5 billion.

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. 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, and revised customer rates became 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. On April 2, 2019, the commission approved both solar projects as filed.

On March 25, 2019, Duke Energy Florida petitioned the FPSC to include in base rates the revenue requirements for its next wave of solar generation projects, the Trenton, Lake Placid and DeBary Solar Projects, as authorized by the 2017 Settlement. The annual retail revenue requirement for the Trenton and Lake Placid Projects is $13 million and $8 million, respectively, and were placed into service in December 2019 with rates taking effect in January 2020. The DeBary Project has a projected annual revenue requirement of $11 million and a projected in-service date in the first half of 2020. The associated rate increase would take place with the first month's billing cycle after each solar generation project goes into service. On July 22, 2019, the FPSC issued an order approving Duke Energy Florida's request.

Crystal River Unit 3 Accelerated Decommissioning Filing

On May 29, 2019, Duke Energy Florida entered into a Decommissioning Services Agreement for the accelerated decommissioning of the Crystal River Unit 3 nuclear power station located in Citrus County, Florida, with ADP CR3, LLC and ADP SF1, LLC, each of which is a wholly owned subsidiary of Accelerated Decommissioning Partners, LLC, a joint venture between NorthStar Group Services, Inc. and Orano USA LLC. Closing of this agreement is contingent upon the approval of the NRC and FPSC. If approved, the decommissioning will be accelerated starting in 2020 and continuing through 2027, rather than the expected time frame under SAFSTOR of starting in 2067 and ending in 2074. Duke Energy Florida expects that the assets of the Nuclear Decommissioning Trust Fund will be sufficient to cover the contract price. On July 10, 2019, Duke Energy Florida petitioned the FPSC for approval of the agreement. 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.

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash	**$ 16**	$ 20	Yes	(b)
Accrued pension and OPEB	**155**	146		(g)
Storm cost deferrals	**7**	4		2023

Deferred fuel and purchased power	**1**	2		2020
Hedge costs deferrals	**6**	5		(b)
DSM/EE	**2**	10	(f)	(e)
AMI	**40**	46		(b)
PISCC and deferred operating expenses(c)	**17**	17	Yes	2083
Vacation accrual	**5**	5		2020
MGP	**102**	99		(b)
Deferred pipeline integrity costs	**17**	14	Yes	(b)
East Bend deferrals	**44**	47	Yes	(b)
Transmission expansion obligation	**40**	43		(e)
Grid modernization	**28**	31	Yes	(b) (c)
Other	**118**	75		(b)
Total regulatory assets	**598**	564		
Less: current portion	**49**	33		
Total noncurrent regulatory assets	**$ 549**	$ 531		
Regulatory Liabilities(a)				
Net regulatory liability related to income taxes	**$ 654**	$ 678		(b)
Costs of removal	**86**	126		(d)
Accrued pension and OPEB	**16**	18		(g)
Other	**71**	75		(b)
Total regulatory liabilities	**827**	897		
Less: current portion	**64**	57		
Total noncurrent regulatory liabilities	**$ 763**	$ 840		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) 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 23 for additional detail.

2017 Electric Security Plan Filing

On June 1, 2017, Duke Energy Ohio filed with the PUCO a request for a standard service offer in the form of an Electric Security Plan (ESP). 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 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 included 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 established a regulatory model for the next seven years via the approval of the ESP and continued 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, including the OCC, filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. The PUCO issued its Second Entry on Rehearing on July 17, 2019, upholding its December 19, 2018, order and denying all assignments of error raised by the non-stipulating parties. On October 11, 2019, the OCC filed its Third Application for Rehearing arguing the PUCO erred in finding OCC's Second Application for Rehearing as improper. Duke Energy Ohio filed its Memorandum Contra on October 21, 2019. The PUCO denied OCC's Third Application for Rehearing as a matter of law. On September 13, 2019, Interstate Gas Supply/Retail Supply Association filed appeals to the Ohio Supreme Court claiming the PUCO's order was in error because it approved unsupported charges to competitive suppliers and cost subsidies shopping customers pay for non-shopping customers. On September 16, 2019, the OCC filed an appeal challenging the PUCO's approval of OVEC recovery through Rider PSR alleging the FPA pre-empts the commission's jurisdiction and that the record does not support finding that Rider PSR results in a limitation on shopping. Appellant briefs were filed on January 6, 2020. Appellee briefs will be due March 16, 2020. 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%. 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% and 10.24%. 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 included a $19 million decrease in annual base distribution revenue with a return on equity unchanged from the current rate of 9.84% based upon a capital structure of 50.75% equity and 49.25% debt. Upon approval of new rates, Duke Energy Ohio's rider for recovering its initial SmartGrid implementation ended as these costs would be recovered through base rates. The Stipulation also renewed 14 existing riders, some of which were included in the company's ESP, and added 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 reduced 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 including the OCC filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. The PUCO issued its Second Entry on Rehearing on July 17, 2019, upholding its December 19, 2018, order and denying all assignments of error raised by the non-stipulating parties. On October 11, 2019, the OCC filed its Third Application for Rehearing arguing the PUCO erred in finding OCC's Second Application for Rehearing as improper. Duke Energy Ohio filed its Memorandum Contra on October 21, 2019. The PUCO denied OCC's Third Application for Rehearing as a matter of law. On September 13, 2019, Interstate Gas Supply/Retail Supply Association filed appeals to the Ohio Supreme Court claiming the PUCO's order was in error because it approved unsupported charges to competitive suppliers and cost subsidies shopping customers pay for non-shopping customers. On September 16, 2019, the OCC filed an appeal challenging the PUCO's approval of OVEC recovery through Rider PSR alleging the FPA pre-empts the commission's jurisdiction and that the record does not support finding that Rider PSR results in a limitation on shopping. Appellant briefs were filed on January 6, 2020. Appellee briefs will be due March 16, 2020. 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 Rider PSR 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 were 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 activated 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. The PSR rider became effective April 1, 2019. Several parties, including the OCC, filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. The PUCO issued its Second Entry on Rehearing on July 17, 2019, upholding its December 19, 2018, order and denying all assignments of error raised by the non-stipulating parties. On October 11, 2019, the OCC filed its Third Application for Rehearing arguing the PUCO erred in finding OCC's Second Application for Rehearing as improper. Duke Energy Ohio filed its Memorandum Contra on October 21, 2019. The PUCO denied OCC's Third Application for Rehearing as a matter of law. On September 13, 2019, Interstate Gas Supply/Retail Supply Association filed appeals to the Ohio Supreme Court claiming the PUCO's order was in error because it approved unsupported charges to competitive suppliers and cost subsidies shopping customers pay for non-shopping customers. On September 16, 2019, the OCC filed an appeal challenging the PUCO's approval of OVEC recovery through Rider PSR alleging the FPA pre-empts the commission's jurisdiction and that the record does not support finding that Rider PSR results in a limitation on shopping. Appellant briefs were filed on January 6, 2020. Appellee briefs will be due March 16, 2020. Duke Energy Ohio cannot predict the outcome of this matter.

On July 23, 2019, an Ohio bill was signed into law that became effective January 1, 2020. Among other things, the bill allows for recovery of prudently incurred costs, net of any revenues, for Ohio investor-owned utilities that are participants under the OVEC power agreement. The recovery shall be through a non-bypassable rider that is to replace any existing recovery mechanism approved by the PUCO and will remain in place through 2030. The amounts recoverable from customers will be subject to an annual cap, with incremental costs that exceed such cap eligible for deferral and recovery subject to review. See Note 18 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. The new rider will flow through to customers the benefit of the lower statutory federal tax rate from 35% to 21% 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 ratemaking 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 became 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% 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 established a procedural schedule and testimony was filed on July 31, 2019. An evidentiary hearing occurred on August 7, 2019. Initial briefs were filed on September 11, 2019. Reply briefs were filed on September 25, 2019. 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. On April 10, 2019, the PUCO issued an Entry on Rehearing denying the rehearing applications.

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 OCC'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. On October 15, 2019, the Ohio Supreme Court issued an Opinion regarding a similar cap on energy efficiency imposed by the PUCO on Ohio Edison Company finding the PUCO lacked statutory authority to impose a cap on cost recovery. On December 9, 2019, and in response to recent changes to Ohio Law, the OCC filed a motion to eliminate shared savings from Duke Energy Ohio's energy efficiency calculation beginning in 2020. Duke Energy Ohio filed a memorandum contra and a notice of additional authority on December 16, 2019, arguing OCC's interpretation is incorrect and that the commission should amend its September 27, 2017 order to comply with recent precedent. Duke Energy Ohio cannot predict the outcome of this matter.

2014 Electric Security Plan

On May 30, 2018, the PUCO approved an extension of Duke Energy Ohio's then-current ESP, including all terms and conditions thereof, excluding an extension of Duke Energy Ohio's Distribution Capital Investment Rider. Following rehearing, on July 25, 2018, the PUCO granted the request and allowed a continuing cap on recovery under Rider DCI. The orders were upheld on rehearing requested by the Ohio Manufacturers' Association (OMA) and OCC. The time period for parties to file for rehearing or appeal has expired.

In 2018, the OMA and OCC filed separate appeals of PUCO's approval of Duke Energy Ohio's ESP with the Ohio Supreme Court, challenging PUCO's approval of Duke Energy Ohio's Rider PSR as a placeholder and its Rider DCI to recover incremental revenue requirement for distribution capital since Duke Energy Ohio's last base rate case. The Ohio Supreme Court issued an order on March 13, 2019, for the appellants to show cause why the appeals should not be dismissed as moot in light of the commission's approval of Duke Energy Ohio's current ESP. The OCC and OMA made the requested filings on March 20, 2019, and Duke Energy Ohio filed its response on March 27, 2019. Subsequent to OCC and OMA making the requested filings, the Ohio Supreme Court dismissed the appeals as moot on May 8, 2019.

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 included a local public hearing on March 21, 2019. An evidentiary hearing began on April 9, 2019, and concluded on April 11, 2019. Briefs were filed on May 13, 2019, and reply briefs were filed on June 10, 2019. On November 21, 2019, the OPSB approved Duke Energy Ohio's application subject to 41 conditions on construction. Applications for rehearing were filed by several stakeholders on December 23, 2019, arguing that the OPSB approval was incorrect. Duke Energy Ohio filed a memorandum contra on January 2, 2020. On January 17, 2020, the OPSB granted rehearing for the purpose of further consideration. 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

As part of its 2012 natural gas base rate case, Duke Energy Ohio has approval to defer and recover costs related to environmental remediation at two sites (East End and West End) that housed former MGP operations. Duke Energy Ohio has made annual applications for recovery of these deferred costs. Duke Energy Ohio has collected approximately $55 million in environmental remediation costs between 2009 through 2012 through a separate rider, Rider MGP, which is currently suspended. Duke Energy Ohio has made annual applications with the PUCO to recover its incremental remediation costs consistent with the PUCO's directive in Duke Energy Ohio's 2012 natural gas rate case. To date, the PUCO has not ruled on Duke Energy Ohio's annual applications for the calendar years 2013 through 2017. On September 28, 2018, the staff of the PUCO issued a report recommending a disallowance of approximately $12 million of the $26 million in MGP remediation costs incurred between 2013 through 2017 that staff believes are not eligible for recovery. Staff interprets the PUCO's 2012 Order granting Duke Energy Ohio recovery of MGP remediation as limiting the recovery to work directly on the East End and West End sites. On October 30, 2018, Duke Energy Ohio filed reply comments objecting to the staff's recommendations and explaining, among other things, the obligation Duke Energy Ohio has under Ohio law to remediate all areas impacted by the former MGPs and not just physical property that housed the former plants and equipment. To date, the PUCO has not ruled on Duke Energy Ohio's applications. On March 29, 2019, Duke Energy Ohio filed its annual application to recover incremental remediation expense for the calendar year 2018 seeking recovery of approximately $20 million in remediation costs. On July 12, 2019, the staff recommended a disallowance of approximately $11 million for work that staff believes occurred in areas not authorized for recovery. Additionally, staff recommended that any discussion pertaining to Duke Energy Ohio's recovery of ongoing MGP costs should be directly tied to or netted against insurance proceeds collected by Duke Energy Ohio. An evidentiary hearing began on November 18, 2019, and concluded November 21, 2019. Initial briefs were filed on January 17, 2020, and reply briefs were filed on February 14, 2020. Duke Energy Ohio cannot predict the outcome of this matter.

The 2012 PUCO order also contained conditional deadlines for completing the MGP environmental investigation and remediation costs at the MGP sites. Subsequent to the order, the deadline was extended to December 31, 2019. On May 10, 2019, Duke Energy Ohio filed an application requesting a continuation of its existing deferral authority for MGP remediation and investigation that must occur after December 31, 2019. On September 13, 2019, intervenor comments were filed opposing Duke Energy Ohio's request for continuation of existing deferral authority and on October 2, 2019, Duke Energy Ohio filed reply comments. Duke Energy Ohio cannot predict the outcome of this matter.

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% average increase across all customer classes. The increase was net of approximately $5 million in annual savings as a result of the Tax Act. The drivers for this case were capital invested since Duke Energy Kentucky's last rate case in 2009. Duke Energy Kentucky also sought 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. The settlement provided for an approximate $7 million increase in natural gas base revenue, a return on equity of 9.7% and approval of the proposed Weather Normalization Mechanism. A hearing was held on February 5, 2019. The commission issued its order approving the settlement without material modification on March 27, 2019. Revised customer rates were effective April 1, 2019.

Duke Energy Kentucky Electric Base Rate Case

On September 3, 2019, Duke Energy Kentucky filed a rate case with the KPSC requesting an increase in electric base rates of approximately $46 million, which represents an approximate 12.5% increase across all customer classes. The request for rate increase is driven by increased investment in utility plant since the last electric base rate case in 2017. Duke Energy Kentucky seeks to implement a Storm Deferral Mechanism that will enable Duke Energy Kentucky to defer actual costs incurred for major storms that are over or under amounts in base rates. In response to large customers' desire to have access to renewable resources, Duke Energy Kentucky is proposing a Green Source Advantage tariff designed for those large customers that wish to invest in renewable energy resources to meet sustainability goals. Duke Energy Kentucky is proposing an electric vehicle (EV) infrastructure pilot and modest incentives to assist customers in investing in EV technologies. Additionally, Duke Energy Kentucky is proposing to build an approximate 3.4 MW distribution battery energy storage system to be attached to Duke Energy Kentucky's distribution system providing frequency regulation and enhanced reliability to Kentucky customers. The commission issued a procedural schedule with two rounds of discovery and opportunities for intervenor and rebuttal testimony. The Kentucky Attorney General filed its testimony recommending an increase of approximately $26 million. On January 31, 2020, Duke Energy Kentucky filed rebuttal testimony updating its rate increase calculations to approximately $44 million. Hearings began on February 19, 2020. Duke Energy Kentucky anticipates that rates will go into effect in the second quarter of 2020. Duke Energy Kentucky cannot predict the outcome of this matter.

Regional Transmission Organization Realignment

Duke Energy Ohio, including Duke Energy Kentucky, transferred control of its transmission assets from MISO to PJM, 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 MISO Transmission Expansion Planning (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, 2019, and 2018, $40 million and $43 million, respectively, are recorded in Regulatory assets on Duke Energy Ohio's Consolidated Balance Sheets.

(in millions)	**December 31, 2018**	**Provisions/ Adjustments**	**Cash Reductions**	**December 31, 2019**
Duke Energy Ohio	$ 58	**$ —**	**$ (4)**	**$ 54**

Regulatory Assets and Liabilities

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

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash	**$ 529**	$ 450		(b)
Accrued pension and OPEB	**243**	222		(f)
Deferred fuel and purchased power	**—**	40		2020
Hedge costs deferrals	**23**	24		(b)
DSM/EE	**—**	14	(e)	(e)
AMI[c]	**18**	18	Yes	(b)
Retired generation facilities[c]	**49**	57	Yes	2026
PISCC and deferred operating expenses[c]	**246**	233	Yes	(b)
Vacation accrual	**12**	11		2020
Other	**52**	88		(b)
Total regulatory assets	**1,172**	1,157		
Less: current portion	**90**	175		
Total noncurrent regulatory assets	**$ 1,082**	$ 982		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes	**$ 1,008**	$ 1,009		(b)
Costs of removal	**599**	628		(d)
Accrued pension and OPEB	**90**	67		(f)
Amounts to be refunded to customers	**—**	1		2020
Other	**43**	42		(b)
Total regulatory liabilities	**1,740**	1,747		
Less: current portion	**55**	25		
Total noncurrent regulatory liabilities	**$ 1,685**	$ 1,722		

(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) Refunded 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 23 for additional detail.

2019 Indiana Rate Case

On July 2, 2019, Duke Energy Indiana filed a general rate case with the IURC, its first general rate case in Indiana in 16 years, for a rate increase for retail customers of approximately $395 million. The request for rate increase is driven by strategic investments to generate cleaner electricity, improve reliability and serve a growing customer base. The request is premised upon a Duke Energy Indiana rate base of $10.2 billion as of December 31, 2018, and adjusted for projected changes through December 31, 2020. On September 9, 2019, Duke Energy Indiana revised its revenue request from $395 million to $393 million and filed updated testimony for the Retail Rate Case. The updated filing reflects a clarification in the presentation of Utility Receipts Tax, a $2 million reduction in the revenue requirement for revenues that will remain in riders and changes to allocation of revenue requirements within rate classes. The Utility Receipts Tax is currently embedded in base rates and rider rates. The proposed treatment is to include the Utility Receipts Tax as a line item on the customer bill rather than included in rates. The request is an approximate 15% increase in retail revenues and approximately 17% when including estimated Utility Receipts Tax. The rebuttal case, filed on December 4, 2019, updated the requested revenue requirement to result in a 15.6% or $396 million average retail rate increase, including the impacts of the Utility Receipts Tax. The commission determined to take two issues out of the rate case and place them in separate subdocket proceedings due to the complexity of the rate case. The commission moved the request for electric transportation pilot and future coal ash recovery issues to separate subdockets. Coal ash expenditures prior to 2019 are still included in the rate case. Hearings concluded on February 7, 2020 and rates are expected to be effective by mid-2020. Duke Energy Indiana cannot predict the outcome of these matters.

Edwardsport IGCC 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 was filed on July 2, 2019, with rates to be effective in mid-2020. An evidentiary hearing was held in December 2018, and on June 5, 2019, the IURC issued an order approving the 2018 Settlement Agreement.

Piedmont

Regulatory Assets and Liabilities

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

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – nuclear and other	**16**	19		(d)
Accrued pension and OPEB[c]	**90**	99	Yes	(f)
Vacation accrual	**12**	12		
Derivatives – natural gas supply contracts[e]	**117**	141		
Deferred pipeline integrity costs[c]	**62**	51	Yes	(b)
Amounts due from customers	**36**	24	Yes	(b)
Other	**30**	11		(b)
Total regulatory assets	**363**	357		
Less: current portion	**73**	54		
Total noncurrent regulatory assets	**$ 290**	$ 303		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes	**$ 555**	$ 579		(b)
Costs of removal	**574**	564		(d)
Accrued pension and OPEB[c]	**3**	1	Yes	(f)
Amounts to be refunded to customers	**34**	33	Yes	(b)
Other	**46**	41		(b)
Total regulatory liabilities	**1,212**	1,218		
Less: current portion	**81**	37		
Total noncurrent regulatory liabilities	**$ 1,131**	$ 1,181		

(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 23 for additional detail.

North Carolina Integrity Management Rider Filing

On April 30, 2019, Piedmont filed a petition under the IMR mechanism to update rates, based on the eligible capital investments closed to integrity and safety projects over the six-month period ending March 31, 2019. The NCUC approved the petition on May 29, 2019, and rates became effective June 1, 2019. The effect of the update was an increase to annual revenues of approximately $9 million. These revenues, along with eligible spending for the three months ended June 30, 2019, were subsequently included in base rates effective November 1, 2019, as part of the 2019 North Carolina Rate Case.

On October 31, 2019, Piedmont filed a petition under the IMR mechanism to update rates, based on the eligible capital investments closed to integrity and safety projects over the three-month period ending September 30, 2019. The NCUC approved the petition on December 3, 2019, and rates became effective December 1, 2019. The effect of the update was an increase to annual revenues of approximately $11 million.

Tennessee Integrity Management Rider Filing

In November 2019, Piedmont filed a petition with the TPUC under the IMR mechanism to collect an additional $4 million in annual revenues, effective January 2020, based on the eligible capital spending on integrity and safety projects over the 12-month period ending October 31, 2019. A procedural schedule has not yet been set for this matter. Piedmont cannot predict the outcome of this matter.

2019 North Carolina Rate Case

On April 1, 2019, Piedmont filed an application with the NCUC, its first general rate case in North Carolina in six years, for a rate increase for retail customers of approximately $83 million, which represents an approximate 9% increase in retail revenues. The request for rate increase was driven by significant infrastructure upgrade investments (plant additions) since the last general rate case through June 30, 2019, offset by savings that customers will begin receiving due to federal and state tax reform. Approximately half of the plant additions being included in rate base are categories of plant investment not covered under the IMR mechanism, which was originally approved as part of the 2013 North Carolina Rate Case.

On August 13, 2019, Piedmont, the Public Staff, and two groups representing industrial customers filed an Agreement and Stipulation Settlement resolving issues in the base rate proceeding, which included a return on equity of 9.7% and a capital structure of 52% equity and 48% debt. The North Carolina Attorney General's Office did not support the settlement. Other major components of the Stipulation included:

- An annual increase in revenues of $109 million before consideration of riders associated with federal and state tax reform;
- A decrease through a rider mechanism of $23 million per year to return unprotected federal EDIT over a five-year period and deferred revenues related to the federal rate reduction of $37 million to be returned over one year;
- A decrease through a rider mechanism of $21 million per year related to reductions in the North Carolina state income tax rate to be returned over a three-year period;
- An overall cap on net revenue increase of $83 million. This will impact Piedmont beginning November 1, 2022, only if the company does not file another general rate case in the interim;
- Continuation of the IMR mechanism; and
- Establishment of a new deferral mechanism for certain Distribution Integrity Management Program (DIMP) operations and maintenance expenses incurred effective November 1, 2019, and thereafter.

An evidentiary hearing began on August 19, 2019. On October 31, 2019, the NCUC approved the Stipulation and the revised customer rates were effective November 1, 2019.

OTHER REGULATORY MATTERS

Atlantic Coast Pipeline, LLC

On September 2, 2014, Duke Energy, Dominion Energy, Inc. (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%. Duke Energy owns a 47% interest, which is accounted for as an equity method investment through its Gas Utilities and Infrastructure segment. Southern Company Gas maintains a 5% interest. See Notes 13 and 18 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 and, 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. Due to legal challenges not directly related to the request for a Notice to Proceed in Virginia, this request is still pending.

ACP is the subject of challenges in state and federal courts and agencies, including, among others, challenges of the project's biological opinion (BiOp) and 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 project's air permit for a compressor station at Buckingham, Virginia, 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. Since December 2018, notable developments in these challenges include a stay in December 2018 issued by the U.S. Court of Appeals for the Fourth Circuit (Fourth Circuit) and the same court's July 26, 2019, vacatur of the project's BiOp and ITS (which stay and subsequent vacatur 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, the Fourth Circuit's remand to USACE of ACP's Huntington District 404 verification, the Fourth Circuit's remand to the National Park Service of ACP's Blue Ridge Parkway right-of-way and the most recent vacatur of the air permit for a compressor station at Buckingham, Virginia. ACP is vigorously defending these challenges and coordinating with the federal and state authorities which are the direct parties to the challenges. The Solicitor General of the United States and ACP filed petitions for certiorari to the Supreme Court of the United States on June 25, 2019, regarding the Appalachian Trail crossing and certiorari was granted on October 4, 2019. The Supreme Court hearing is scheduled for February 24, 2020, and a ruling is expected in the second quarter of 2020. ACP is also evaluating possible legislative and other remedies to this issue.

In anticipation of the Fourth Circuit's vacatur of the BiOp and ITS, ACP and the FWS commenced work in mid-May of 2019 to set the basis for a reissued BiOp and ITS. On February 10, 2020, FERC issued a letter to FWS requesting the re-initiation of formal consultation in support of reissuing the BiOp and ITS. ACP continues coordinating and working with FWS and other parties in preparation for a reissuance of the BiOp and ITS.

ACP triggered the Adverse Government Actions (AGA) clause of its agreements with its customers in December 2019. Formal negotiations have commenced regarding pricing and construction timing, among other items, and are expected to be finalized in the first quarter of 2020. The results of these negotiations will directly impact the expected future cash flows of this project.

Given the legal challenges and ongoing discussions with customers, ACP expects mechanical completion of the full project in late 2021 with in-service likely in the first half of 2022.

The delays resulting from the legal challenges described above have also impacted the cost for the project. Project cost is approximately $8 billion, excluding financing costs. This estimate is based on the current facts available around construction costs and timelines, and is subject to future changes as those facts develop. Abnormal weather, work delays (including delays due to judicial or regulatory action) and other conditions may result in cost or schedule modifications, a suspension of AFUDC for ACP and/or impairment charges potentially material to Duke Energy's cash flows, financial position and results of operations.

Duke Energy's investment in ACP was $1.2 billion at December 31, 2019. Duke Energy evaluated this investment for impairment at December 31, 2019, and determined that fair value approximated carrying value and therefore no impairment was necessary. Duke Energy also has a guarantee agreement supporting its share of the ACP revolving credit facility. Duke Energy's maximum exposure to loss under the terms of the guarantee is $827 million, which represents 47% of the outstanding borrowings under the credit facility as of December 31, 2019. See Note 13 for additional information.

Constitution Pipeline Company, LLC

Duke Energy owned a 24% ownership interest in Constitution, which is accounted for as an equity method investment. Constitution was 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 was to be constructed and operated by Williams Partners L.P., which had a 41% ownership share. The remaining interest was held by Cabot Oil and Gas Corporation and WGL Holdings, Inc. In December 2014, Constitution received approval from the FERC to construct and operate the proposed pipeline. However, since April 2016, Constitution had stopped construction and discontinued capitalization of future development costs due to permitting delays and adverse rulings by regulatory agencies and courts.

In late 2019, Constitution determined that its principal shipper would not agree to an amended precedent agreement. Without such an amendment, the project would no longer be viable and, as of February 5, 2020, the Constitution partners formally resolved to initiate the dissolution of Constitution, and to terminate the Constitution Pipeline project. In the fourth quarter of 2019, Duke Energy recorded an OTTI of $25 million related to Constitution within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Income, resulting in the full write-down of Duke Energy's investment in Constitution. See Notes 13 and 18 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. 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. Dollar amounts in the table below are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2019, 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	$ 152
Duke Energy Indiana		
Gallagher Units 2 and 4[b]	280	114
Gibson Units 1-5[c]	3,132	1,697
Cayuga Units 1-2[c]	1,005	974
Total Duke Energy	$ 5,002	$ 2,937

(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.

(c) On July 1, 2019, Duke Energy Indiana filed its 2018 IRP with the IURC. The 2018 IRP included scenarios evaluating the potential retirement of coal-fired generating units at Gibson and Cayuga. The rate case filed July 2, 2019, includes proposed depreciation rates reflecting retirement dates from 2026 to 2038.

Duke Energy continues to evaluate the potential need to retire generating facilities earlier than the current estimated useful lives, and plans to seek regulatory recovery, as necessary, for amounts that would not be otherwise recovered when any of these assets are retired. However, such recovery, including recovery of carrying costs on remaining book values, could be subject to future approvals and therefore cannot be assured.

Duke Energy Carolinas and Duke Energy Progress are evaluating the potential for coal-fired generating unit retirements with a net carrying value of approximately $721 million and $1.2 billion, respectively, included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2019.

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 $13.9 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 $13.5 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 98 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 Nuclear Electric Insurance Limited (NEIL), an industry mutual insurance company, which provides property damage, nuclear accident decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. Additionally, NEIL provides accidental outage coverage for 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, similar to 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% of the applicable weekly limits for 52 weeks and 80% of the applicable weekly limits for up to the next 110 weeks. Coverage is provided until these applicable weekly periods are met, where the accidental outage policy limit will not exceed $490 million for McGuire and Catawba, $462 million for Brunswick and Harris, $406 million for Oconee and $364 million for Robinson. NEIL sublimits the accidental outage recovery up 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 $155 million, $94 million and $1 million, respectively. Duke Energy Carolinas' maximum assessment amount includes 100% 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 laws regarding air and water quality, hazardous and solid waste disposal, coal ash and other environmental matters. These laws 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 10, 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	Piedmont
Balance at December 31, 2016	$ 98	$ 10	$ 18	$ 3	$ 14	$ 59	$ 10	$ 1
Provisions/adjustments	8	3	3	2	2	3	(4)	1
Cash reductions	(25)	(3)	(6)	(2)	(4)	(15)	(1)	—
Balance at December 31, 2017	81	10	15	3	12	47	5	2
Provisions/adjustments	26	3	2	3	(2)	21	1	1
Cash reductions	(30)	(2)	(6)	(2)	(4)	(20)	(1)	(1)
Balance at December 31, 2018	77	11	11	4	6	48	5	2
Provisions/adjustments	**33**	**6**	**9**	**2**	**5**	**11**	**—**	**7**
Cash reductions	**(52)**	**(6)**	**(4)**	**(2)**	**(2)**	**(40)**	**(1)**	**(1)**
Balance at December 31, 2019	**$ 58**	**$ 11**	**$ 16**	**$ 4**	**$ 9**	**$ 19**	**$ 4**	**$ 8**

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	**$ 59**
Duke Energy Carolinas	**11**
Duke Energy Ohio	**42**
Piedmont	**2**

LITIGATION

Duke Energy Carolinas and Duke Energy Progress

NCDEQ Closure Litigation

The Coal Ash Act requires CCR surface impoundments in North Carolina to be closed, with the closure method and timing based on a risk ranking classification determined by legislation or state regulators. The NCDEQ previously classified the impoundments at Allen, Belews Creek, Rogers, Marshall, Mayo and Roxboro as low risk. The Coal Ash Act allowed a range of closure options for low risk rated basins. On April 1, 2019, NCDEQ issued a closure determination (NCDEQ's April 1 Order) requiring Duke Energy Carolinas and Duke Energy Progress to excavate all remaining coal ash impoundments at these facilities. On April 26, 2019, Duke Energy Carolinas and Duke Energy Progress filed Petitions for Contested Case Hearings in the Office of Administrative Hearings to challenge NCDEQ's April 1 Order. On May 9, 2019, NCDEQ issued a supplemental order requiring that closure plans be submitted on December 31, 2019, but providing that the corrective action plans are not due until March 31, 2020. Duke Energy Carolinas and Duke Energy Progress filed amended petitions on May 24, 2019, incorporating the May 9, 2019, order.

On December 31, 2019, the parties executed a settlement agreement resolving the closure method for each of these sites. Duke Energy Carolinas and Duke Energy Progress agreed to excavate seven of the nine remaining coal ash basins at these sites with ash moved to on-site lined landfills, including two at Allen, one at Belews Creek, one at Mayo, one at Roxboro, and two at Rogers. At the two remaining basins at Marshall and Roxboro, uncapped basin ash will be excavated and moved to lined landfills. Those portions of the basins at Marshall and Roxboro, which were previously filled with ash and on which permitted facilities were constructed, will not be disturbed and will be closed pursuant to other state regulations. On February 5, 2020, the North Carolina Superior court entered a consent order, after which this litigation was dismissed on February 11, 2020.

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. Despite a stay of the litigation from May 2019 through September 2019 to allow the parties to discuss potential resolution, no resolution was reached, and litigation resumed. In February and March 2020, the Court will hear arguments on numerous cross motions filed by the parties to seek legal determinations concerning, among other issues, the appropriate insurance allocation methods, the trigger of the applicable coverages and several coverage defenses raised by the insurance providers. Trial is scheduled for February 2021. 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.

Pursuant to the terms of the December 31, 2019, settlement agreement, discussed above, between Duke Energy Carolinas, Duke Energy Progress, NCDEQ and the community groups represented by the SELC, this litigation was dismissed on February 5, 2020, upon entry of the consent order in the North Carolina Superior Court.

Federal Citizens Suits

On June 13, 2016, Roanoke River Basin Association (RRBA) filed a federal citizen suit in the Middle District of North Carolina alleging unpermitted discharges to surface water and groundwater violations at the Mayo Plant. On August 19, 2016, Duke Energy Progress filed a Motion to Dismiss. On April 26, 2017, the court entered an order dismissing four of the claims in the federal citizen suit. Two claims relating to alleged violations of National Pollution Discharge Elimination System (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.

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.

On May 8, 2018, on motion from Duke Energy Progress, the court ordered trial in both of the above matters to be consolidated. On April 5, 2019, Duke Energy Progress filed a motion to stay the case following the NCDEQ's April 1 Order. On August 2, 2019, the court ordered that this case is stayed.

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. On April 5, 2019, Duke Energy Carolinas filed a motion to stay the case following the NCDEQ's April 1 Order. On August 2, 2019, the court ordered that this case is stayed.

On December 31, 2019, Duke Energy Carolinas, Duke Energy Progress, the NCDEQ and various community groups including RRBA entered into a comprehensive settlement that, among other things, resolves the method of closure at the Mayo, Roxboro and Belews Creek ash basins. On February 5, 2020, the North Carolina Superior Court entered a consent order confirming the terms of the settlement agreement, upon which RRBA filed stipulations on February 11, 2020 voluntarily dismissing all three of these federal citizen suits with 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, 2019, there were 123 asserted claims for non-malignant cases with the cumulative relief sought of up to $32 million and 49 asserted claims for malignant cases with the cumulative relief sought of up to $16 million. Based on Duke Energy Carolinas' experience, it is expected that the ultimate resolution of most of these claims likely will be less than the amount claimed.

Duke Energy Carolinas has recognized asbestos-related reserves of $604 million and $630 million at December 31, 2019, and 2018, 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 2039 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 2039 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 $747 million in excess of the self-insured retention. Receivables for insurance recoveries were $742 million and $739 million at December 31, 2019, and 2018, 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 June 18, 2018, Duke Energy Progress and Duke Energy Florida sued the U.S. in the U.S. Court of Federal Claims for damages incurred for the period 2014 through 2018. 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 in the amount of $100 million and $203 million for Duke Energy Progress and Duke Energy Florida, respectively. Discovery is ongoing and a trial is expected to occur in early 2021.

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 CC 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 moved to dismiss all counts of Fluor's amended complaint, and on April 16, 2019, the court dismissed Fluor's complaint without prejudice. On April 26, 2019, Fluor filed a second amended complaint.

On August 1, 2019, Duke Energy Florida and Fluor reached a settlement to resolve the pending litigation and other outstanding issues related to completing the Citrus County CC. Pursuant to the terms of the settlement, Fluor filed a notice of voluntary dismissal, and on August 27, 2019, the court dismissed the case with prejudice. As a result of the settlement with Fluor, Duke Energy Florida recorded a $36 million reduction to a prior-year impairment within Impairment charges on Duke Energy's Consolidated Statements of Operations in 2019.

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. 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)	**2019**	**2018**
Reserves for Legal Matters		
Duke Energy	**$ 62**	$ 65
Duke Energy Carolinas	**2**	9
Progress Energy	**55**	54
Duke Energy Progress	**12**	12
Duke Energy Florida	**22**	24
Piedmont	**1**	1

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 uncapped maximum potential payments. See Note 8 for more information.

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, 2019						
(in millions)	**Contract Expiration**	**2020**	**2021**	**2022**	**2023**	**2024**	**Thereafter**	**Total**
Duke Energy Progress[a]	2021-2032	$ 46	$ 66	$ 63	$ 55	$ 56	$ 123	$ 409
Duke Energy Florida[b]	2021-2025	374	356	354	374	262	91	1,811
Duke Energy Ohio[c][d]	2021-2022	132	107	32	—	—	—	271

(a) Contracts represent either 100% of net plant output or vary.
(b) Contracts represent between 81% and 100% of net plant output.
(c) Contracts represent between 1% and 9% of net plant output.
(d) Excludes PPA with OVEC. See Note 18 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 15 years. The time periods for fixed payments under natural gas supply contracts are up to six years. The time period for the natural gas supply purchase commitments is up to 11 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, 2019.

(in millions)	Duke Energy	Duke Energy Ohio	Piedmont
2020	$ 297	$ 39	$ 258
2021	280	33	247
2022	225	14	211
2023	129	3	126
2024	118	—	118
Thereafter	714	—	714
Total	$ 1,763	$ 89	$ 1,674

6. LEASES

As described in Note 1, Duke Energy adopted the revised accounting guidance for Leases effective January 1, 2019, using the modified retrospective method of adoption, which does not require restatement of prior year reported results. Adoption of the new standard resulted in the recording of ROU assets and operating lease liabilities as follows:

	As of January 1, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
ROU assets	$ 1,750	$ 153	$ 863	$ 407	$ 456	$ 23	$ 61	$ 26
Operating lease liabilities – current	205	28	96	35	61	1	4	4
Operating lease liabilities – noncurrent	1,504	127	766	371	395	22	58	25

As part of its operations, Duke Energy leases certain aircraft, space on communication towers, industrial equipment, fleet vehicles, fuel transportation (barges and railcars), land and office space under various terms and expiration dates. Additionally, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Indiana have finance leases related to firm natural gas pipeline transportation capacity. Duke Energy Progress and Duke Energy Florida have entered into certain PPAs, which are classified as finance and operating leases.

Duke Energy has certain lease agreements, which include variable lease payments that are based on the usage of an asset. These variable lease payments are not included in the measurement of the ROU assets or operating lease liabilities on the Consolidated Financial Statements.

Certain Duke Energy lease agreements include options for renewal and early termination. The intent to renew a lease varies depending on the lease type and asset. Renewal options that are reasonably certain to be exercised are included in the lease measurements. The decision to terminate a lease early is dependent on various economic factors. No termination options have been included in any of the lease measurements.

Duke Energy Carolinas entered into a sale-leaseback arrangement in December 2019, to construct and occupy an office tower. The lease agreement was evaluated as a sale-leaseback of real estate and it was determined that the transaction did not qualify for sale-leaseback accounting. As a result, the transaction is being accounted for as a financing. For this transaction, Duke Energy Carolinas will continue to record the real estate on the Consolidated Balance Sheets within Property, Plant and Equipment as if it were the legal owner and will continue to recognize depreciation expense over the estimated useful life. In addition, a liability will be recorded for the failed sale-leaseback obligation within Long-Term Debt on the Consolidated Balance Sheets, with the monthly lease payments commencing after the construction phase being split between interest expense and principal pay down of the debt.

Duke Energy operates various renewable energy projects and sells the generated output to utilities, electric cooperatives, municipalities and commercial and industrial customers through long-term PPAs. In certain situations, these PPAs and the associated renewable energy projects qualify as operating leases. Rental income from these leases is accounted for as Nonregulated electric and other 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 $264 million, $268 million and $262 million for the years ended December 31, 2019, 2018, and 2017, respectively. Renewable energy projects owned by Duke Energy and accounted for as operating leases had a cost basis of $3,349 million and $3,358 million and accumulated depreciation of $721 million and $602 million at December 31, 2019, and 2018, respectively. These assets are principally classified as nonregulated electric generation and transmission assets.

Piedmont has an agreement with Duke Energy Carolinas for the construction and transportation of natural gas pipelines to supply its natural gas plant needs. Piedmont accounts for this pipeline lateral contract as a lessor and sales-type lease since the present value of the sum of the lease payments equals the fair value of the asset. As of December 31, 2019, the pipeline lateral assets owned by Piedmont had a current net investment basis of $4 million and a long-term net investment basis of $70 million. These assets are classified in Other, within Current Assets and Other Noncurrent Assets, respectively, on Piedmont's Consolidated Balance Sheets. Duke Energy Carolinas accounts for the contract as a finance lease. The activity for this contract is eliminated in consolidation at Duke Energy.

The following table presents the components of lease expense.

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Operating lease expense[a]	$ 292	$ 47	$ 161	$ 69	$ 92	$ 11	$ 20	$ 5
Short-term lease expense[a]	16	5	9	4	5	1	2	—
Variable lease expense[a]	47	22	22	16	6	—	1	1
Finance lease expense								
Amortization of leased assets[b]	111	6	21	5	16	1	—	—
Interest on lease liabilities[c]	61	15	42	33	9	—	1	—
Total finance lease expense	172	21	63	38	25	1	1	—
Total lease expense	$ 527	$ 95	$ 255	$ 127	$ 128	$ 13	$ 24	$ 6

(a) Included in Operations, maintenance and other or, for barges and railcars, Fuel used in electric generation and purchased power on the Consolidated Statements of Operations.
(b) Included in Depreciation and amortization on the Consolidated Statements of Operations.
(c) Included in Interest Expense on the Consolidated Statements of Operations.

The following table presents rental expense for operating leases, as reported under the former lease standard. 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**
Duke Energy	$ 268	$ 241
Duke Energy Carolinas	49	44
Progress Energy	143	130
Duke Energy Progress	75	75
Duke Energy Florida	68	55
Duke Energy Ohio	13	15
Duke Energy Indiana	21	23
Piedmont	11	7

The following table presents operating lease maturities and a reconciliation of the undiscounted cash flows to operating lease liabilities.

	December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
2020	**$ 268**	**$ 31**	**$ 123**	**$ 51**	**$ 72**	**$ 2**	**$ 5**	**$ 5**
2021	**216**	**19**	**99**	**44**	**55**	**2**	**4**	**5**
2022	**201**	**19**	**95**	**40**	**55**	**2**	**4**	**5**
2023	**191**	**17**	**95**	**41**	**54**	**2**	**4**	**5**
2024	**176**	**13**	**95**	**41**	**54**	**2**	**4**	**5**
Thereafter	**984**	**57**	**462**	**283**	**179**	**21**	**64**	**5**
Total operating lease payments	**2,036**	**156**	**969**	**500**	**469**	**31**	**85**	**30**
Less: present value discount	**(396)**	**(27)**	**(177)**	**(109)**	**(68)**	**(9)**	**(27)**	**(3)**
Total operating lease liabilities[a]	**$ 1,640**	**$ 129**	**$ 792**	**$ 391**	**$ 401**	**$ 22**	**$ 58**	**$ 27**

(a) Certain operating lease payments include renewal options that are reasonably certain to be exercised.

The following table presents future minimum lease payments under operating leases, which at inception had a noncancelable term of more than one year, as reported under the former lease standard.

	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 finance lease maturities and a reconciliation of the undiscounted cash flows to finance lease liabilities.

	December 31, 2019					
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana
2020	$ 181	$ 28	$ 69	$ 44	$ 25	$ 1
2021	186	23	69	44	25	1
2022	173	23	69	44	25	1
2023	175	23	69	44	25	1
2024	121	23	55	44	11	1
Thereafter	823	314	539	528	11	27
Total finance lease payments	1,659	434	870	748	122	32
Less: amounts representing interest	(690)	(255)	(465)	(441)	(24)	(22)
Total finance lease liabilities	$ 969	$ 179	$ 405	$ 307	$ 98	$ 10

The following table presents future minimum lease payments under finance leases, as reported under the former lease standard.

	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

The following tables contain additional information related to leases.

		December 31, 2019							
(in millions)	Classification	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Assets									
Operating	Operating lease ROU assets, net	$ 1,658	$ 123	$ 788	$ 387	$ 401	$ 21	$ 57	$ 24
Finance	Net property, plant and equipment	926	198	443	308	135	—	7	—
Total lease assets		$ 2,584	$ 321	$ 1,231	$ 695	$ 536	$ 21	$ 64	$ 24
Liabilities									
Current									
Operating	Other current liabilities	$ 208	$ 27	$ 95	$ 37	$ 58	$ 1	$ 3	$ 4
Finance	Current maturities of	119	7	24	6	18	—	—	—

	long-term debt								
Noncurrent									
Operating	Operating lease liabilities	1,432	102	697	354	343	21	55	23
Finance	Long-Term Debt	850	172	381	301	80	—	10	—
Total lease liabilities		$ 2,609	$ 308	$ 1,197	$ 698	$ 499	$ 22	$ 68	$ 27

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Cash paid for amounts included in the measurement of lease liabilities[a]								
Operating cash flows from operating leases	$ 285	$ 34	$ 131	$ 53	$ 78	$ 2	$ 7	$ 7
Operating cash flows from finance leases	61	15	42	33	9	—	1	—
Financing cash flows from finance leases	111	6	21	5	16	1	—	—
Lease assets obtained in exchange for new lease liabilities (non-cash)								
Operating[b]	$ 194	$ 44	$ 30	$ 30	$ —	$ —	$ —	$ 1
Finance	251	76	175	175	—	—	—	—

(a) No amounts were classified as investing cash flows from operating leases for the year ended December 31, 2019.
(b) Does not include ROU assets recorded as a result of the adoption of the new lease standard.

	December 31, 2019							
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Weighted average remaining lease term (years)								
Operating leases	11	9	10	12	8	17	18	6
Finance leases	13	19	16	18	11	—	26	—
Weighted average discount rate[a]								
Operating leases	3.9%	3.5%	3.8%	3.9%	3.8%	4.2%	4.1%	3.6%
Finance leases	8.1%	11.8%	11.9%	12.4%	8.3%	—%	11.9%	—%

(a) The discount rate is calculated using the rate implicit in a lease if it is readily determinable. Generally, the rate used by the lessor is not provided to Duke Energy and in these cases the incremental borrowing rate is used. Duke Energy will typically use its fully collateralized incremental borrowing rate as of the commencement date to calculate and record the lease. The incremental borrowing rate is influenced by the lessee's credit rating and lease term and as such may differ for individual leases, embedded leases or portfolios of leased assets.

7. DEBT AND CREDIT FACILITIES

Summary of Debt and Related Terms

The following tables summarize outstanding debt.

	December 31, 2019								
(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 2020-2078	4.02%	$ 22,477	$ 1,150	$ 3,650	$ 700	$ 350	$ 1,110	$ 405	$ 2,399
Secured debt, maturing 2020-2052	3.30%	4,537	544	1,722	335	1,387	—	—	—
First mortgage bonds, maturing 2020-2049[a]	4.13%	27,977	9,557	13,800	7,575	6,225	1,449	3,169	—
Finance leases, maturing 2022-2051[b]	6.60%	969	179	405	307	98	—	10	—
Tax-exempt bonds, maturing 2022-2041[c]	2.90%	730	243	48	48	—	77	362	—
Notes payable and commercial paper[d]	1.98%	3,588	—	—	—	—	—	—	—
Money pool/intercompany borrowings		—	329	1,970	216	—	337	180	476
Fair value hedge carrying value adjustment		5	5	—	—	—	—	—	—
Unamortized debt discount and premium, net[e]		1,294	(23)	(29)	(17)	(11)	(30)	(19)	(2)
Unamortized debt issuance costs[f]		(316)	(55)	(111)	(40)	(62)	(12)	(20)	(13)
Total debt	3.92%	$ 61,261	$ 11,929	$ 21,455	$ 9,124	$ 7,987	$ 2,931	$ 4,087	$ 2,860
Short-term notes payable and commercial paper		(3,135)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	(29)	(1,821)	(66)	—	(312)	(30)	(476)
Current maturities of long-term debt[g]		(3,141)	(458)	(1,577)	(1,006)	(571)	—	(503)	—

Total long-term debt(g)	$ 54,985	$ 11,442	$ 18,057	$ 8,052	$ 7,416	$ 2,619	$ 3,554	$ 2,384

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $44 million and $419 million of finance lease purchase accounting adjustments related to Duke Energy Progress and Duke Energy Florida, respectively, related to PPAs that are not accounted for as finance 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 classified as Long-Term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities that backstop these commercial paper balances, along with Duke Energy's ability and intent to refinance these balances on a long-term basis. The weighted average days to maturity for Duke Energy's commercial paper program was 14 days.
(e) Duke Energy includes $1,275 million and $137 million in purchase accounting adjustments related to Progress Energy and Piedmont, respectively.
(f) Duke Energy includes $37 million in purchase accounting adjustments primarily related to the merger with Progress Energy.
(g) Refer to Note 18 for additional information on amounts from consolidated VIEs.

	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	—
Finance 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 finance lease purchase accounting adjustments related to Duke Energy Progress and Duke Energy Florida, respectively, related to PPAs that are not accounted for as finance 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 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 18 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, 2019
Unsecured Debt			
Duke Energy (Parent)	June 2020	2.100%	$ 330
Duke Energy Progress	December 2020	2.510% (a)	700
First Mortgage Bonds			
Duke Energy Florida	January 2020	1.850%	250
Duke Energy Florida	April 2020	4.550%	250
Duke Energy Carolinas	June 2020	4.300%	450
Duke Energy Indiana	July 2020	3.750%	500
Duke Energy Progress	September 2020	2.065% (a)	300
Other[(b)]			361
Current maturities of long-term debt			$ 3,141

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

Maturities and Call Options

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

	December 31, 2019							
(in millions)	Duke Energy[(a)]	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
2020	$ 3,141	$ 458	$ 1,578	$ 1,006	$ 572	—	$ 503	$ —

2021	5,053	504	2,257	932	825	50	70	160
2022	4,334	830	1,048	508	90	—	94	—
2023	3,112	1,006	398	319	79	325	3	45
2024	1,965	306	227	160	67	25	154	40
Thereafter	39,542	8,875	14,267	6,190	6,427	2,261	3,272	2,155
Total long-term debt, including current maturities	$ 57,147	$ 11,979	$ 19,775	$ 9,115	$ 8,060	$ 2,661	$ 4,096	$ 2,400

(a) Excludes $1,448 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, 2019				
(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, 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

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

Summary of Significant Debt Issuances

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

			Year Ended December 31, 2019							
Issuance Date	Maturity Date	Interest Rate	Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unsecured Debt										
March 2019[a]	Mar 2022	2.538% [b]	$ 300	$ 300	$ —	$ —	$ —	$ —	$ —	$ —
March 2019[a]	Mar 2022	3.227%	300	300	—	—	—	—	—	—
May 2019[e]	Jun 2029	3.500%	600	—	—	—	—	—	—	600
June 2019[a]	Jun 2029	3.400%	600	600	—	—	—	—	—	—
June 2019[a]	Jun 2049	4.200%	600	600	—	—	—	—	—	—
July 2019[g]	Jul 2049	4.320%	40	—	—	—	—	40	—	—
September 2019[g]	Oct 2025	3.230%	95	—	—	—	—	95	—	—
September 2019[g]	Oct 2029	3.560%	75	—	—	—	—	75	—	—
November 2019[h]	Nov 2021	2.167% [b]	200	—	—	—	200	—	—	—
First Mortgage Bonds										
January 2019[c]	Feb 2029	3.650%	400	—	—	—	—	400	—	—
January 2019[c]	Feb 2049	4.300%	400	—	—	—	—	400	—	—
March 2019[d]	Mar 2029	3.450%	600	—	—	600	—	—	—	—
August 2019[a]	Aug 2029	2.450%	450	—	450	—	—	—	—	—
August 2019[a]	Aug 2049	3.200%	350	—	350	—	—	—	—	—
September 2019[f]	Oct 2049	3.250%	500	—	—	—	—	—	500	—
November 2019[i]	Dec 2029	2.500%	700	—	—	—	700	—	—	—
Total issuances			$ 6,210	$ 1,800	$ 800	$ 600	$ 900	$ 1,010	$ 500	$ 600

(a) Debt issued to pay down short-term debt and for general corporate purposes.
(b) Debt issuance has a floating interest rate.
(c) Debt issued to repay at maturity $450 million first mortgage bonds due April 2019, pay down short-term debt and for general corporate purposes.
(d) Debt issued to fund eligible green energy projects in the Carolinas.
(e) Debt issued to repay in full the outstanding $350 million Piedmont unsecured term loan due September 2019, pay down short-term debt and for general corporate purposes.
(f) Debt issued to retire $150 million of pollution control bonds, pay down short-term debt and for general corporate purposes.
(g) Debt issued to repay at maturity $100 million debentures due October 2019, pay down short-term debt and for general corporate purposes.
(h) Debt issued to fund storm restoration costs and for general corporate purposes.
(i) Debt issued to reimburse the payment of existing and new Eligible Green Expenditures in Florida.

In January 2020, Duke Energy Carolinas closed and funded $900 million of first mortgage bonds of which $500 million carry a fixed interest rate of 2.45% and mature February 2030 and $400 million carry a fixed interest rate of 3.20% and mature August 2049. The proceeds will be used to repay at maturity $450 million, 4.30% debentures maturing June 2020, and for general corporate purposes.

			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.

Available Credit Facilities

In March 2019, Duke Energy amended its existing $8 billion Master Credit Facility to extend the termination date to March 2024. The Duke Energy Registrants, excluding Progress Energy, have borrowing capacity under the Master Credit Facility up to a specified sublimit 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, 2019							
(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**	**$ 1,500**	**$ 1,250**	**$ 800**	**$ 600**	**$ 600**	**$ 600**
Reduction to backstop issuances								
Commercial paper[b]	**(2,537)**	**(1,119)**	**(325)**	**(207)**	**—**	**(296)**	**(176)**	**(414)**
Outstanding letters of credit	**(50)**	**(42)**	**(4)**	**(2)**	**—**	**—**	**—**	**(2)**
Tax-exempt bonds	**(81)**	**—**	**—**	**—**	**—**	**—**	**(81)**	**—**
Coal ash set-aside	**(500)**	**—**	**(250)**	**(250)**	**—**	**—**	**—**	**—**
Available capacity	**$ 4,832**	**$ 1,489**	**$ 921**	**$ 791**	**$ 800**	**$ 304**	**$ 343**	**$ 184**

(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 billion revolving credit facility. The facility had an initial termination date of June 2020, but in May 2019, Duke Energy extended the termination date of the facility to May 2022. Borrowings under this facility will be used for general corporate purposes. As of December 31, 2019, $500 million has been drawn under this facility. 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 facility 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 were used to pay storm-related costs, pay down commercial paper and to partially finance an upcoming bond maturity. As of December 31, 2019, the entire $700 million has been drawn under the term loan. This balance is classified as Current maturities of long-term debt on Duke Energy Progress' Consolidated Balance Sheets.

Piedmont Term Loan Facility

In May 2019, the $350 million Piedmont term loan was paid off in full with proceeds from the $600 million Piedmont debt offering.

Other Debt Matters

In September 2019, 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 and preferred stock by Duke Energy. The expired Form S-3 was amended in March 2019, to allow Duke Energy to issue preferred stock.

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, 2019, and 2018, was $1,049 million and $1,010 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.

Money Pool

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

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

Restrictive Debt Covenants

The Duke Energy Registrants' debt and credit agreements contain various financial and other covenants. Duke Energy's Master Credit Facility contains a covenant requiring the debt-to-total capitalization ratio not to exceed 65% for each borrower, excluding Piedmont, and 70% 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, 2019, 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, 2019, and 2018, Duke Energy had loans outstanding of $777 million, including $36 million at Duke Energy Progress and $741 million, including $37 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.

8. GUARANTEES AND INDEMNIFICATIONS

Duke Energy has various financial and performance guarantees and indemnifications with non-consolidated entities, which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, standby letters of credit, debt guarantees and indemnifications. Duke Energy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. At December 31, 2019, Duke Energy does 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 previously wholly-owned 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, 2019, the maximum potential amount of future payments associated with these guarantees were $65 million, the majority of which expires by 2028.

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 $827 million as of December 31, 2019. This amount represents 47% of the outstanding borrowings under the credit facility.

In addition to the Spectra Capital and ACP revolving credit facility guarantees above, 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. 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 these entities. The maximum potential amount of future payments required under these guarantees as of December 31, 2019, was $128 million, of which, $114 million expire between 2020 and 2030, with the remaining performance guarantees having no contractual expiration. Additionally, certain guarantees have uncapped maximum potential payments; however, Duke Energy does not believe these guarantees will have a material effect on its results of operations, cash flows or financial position.

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, 2019, Duke Energy had issued a total of $634 million in letters of credit, which expire between 2020 and 2022. The unused amount under these letters of credit was $81 million.

Duke Energy recognized $23 million as of December 31, 2019, and 2018, 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.

9. 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, 2019			
(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%**	**$ 1,011**	**$ 510**	**$ 21**
W.S. Lee CC[b]	**87.27%**	**609**	**32**	**1**
Duke Energy Indiana				
Gibson (unit 5)[c]	**50.05%**	**410**	**183**	**3**
Vermillion[d]	**62.50%**	**172**	**119**	**—**
Transmission and local facilities[c]	**Various**	**5,421**	**1,436**	**172**

(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 IMPA.
(d) Jointly owned with WVPA.

10. 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, 2019							
(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]	$ 6,633	$ 2,551	$ 4,028	$ 3,499	$ 529	$ —	$ —	$ —
Closure of ash impoundments	6,333	3,118	2,368	2,352	16	41	805	—
Other	352	65	75	42	33	39	27	17
Total asset retirement obligation	$ 13,318	$ 5,734	$ 6,471	$ 5,893	$ 578	$ 80	$ 832	$ 17
Less: current portion	881	206	485	485	—	1	189	—
Total noncurrent asset retirement obligation	$ 12,437	$ 5,528	$ 5,986	$ 5,408	$ 578	$ 79	$ 643	$ 17

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

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 or 2019 dollars, depending on the year of the cost study, and include costs to decommission plant components not subject to radioactive contamination.

(in millions)	Annual Funding Requirement[a]	Decommissioning Costs[a]	Year of Cost Study
Duke Energy	$ 24	$ 9,152	2018 and 2019
Duke Energy Carolinas[b][c]	—	4,365	2018
Duke Energy Progress[d]	24	4,181	2019
Duke Energy Florida[e]	—	606	2019

(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 was filed with the NCUC and PSCSC in 2019. A new funding study was also completed and filed with the NCUC and PSCSC in 2019.

(d) Duke Energy Progress' site-specific nuclear decommissioning cost study completed in 2019 is expected to be filed with the NCUC and PSCSC during the first quarter 2020. Duke Energy Progress will also complete a new funding study, which will be completed and filed with the NCUC and PSCSC in July 2020.

(e) During 2019, Duke Energy Florida reached an agreement to transfer decommissioning work for Crystal River Unit 3 to a third party. The agreement requires regulatory approval from the NRC and the FPSC. See Note 4 for more information.

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 17 for additional information related to the fair value of the Duke Energy Registrants' NDTFs.

	December 31,	
(in millions)	**2019**	**2018**
Duke Energy	**$ 6,766**	$ 5,579
Duke Energy Carolinas	**3,837**	3,133
Duke Energy Progress	**2,929**	2,446

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 2019, Duke Energy Florida entered into an agreement for the accelerated decommissioning of Crystal River Unit 3. The agreement is subject to the approval of the NRC and FPSC. See Note 4 for more information.

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 specific closure plans. 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 2019 and 2018.

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, 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	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
Accretion expense[a]	**508**	**235**	**252**	**227**	**25**	**3**	**28**	**1**
Liabilities settled[b]	**(895)**	**(329)**	**(499)**	**(460)**	**(39)**	**(12)**	**(54)**	**—**
Liabilities incurred in the current year	**25**	**18**	**7**	**—**	**7**	**—**	**—**	**—**
Revisions in estimates of cash flows[d]	**3,213**	**1,861**	**1,300**	**1,306**	**(6)**	**(4)**	**136**	**(3)**
Balance at December 31, 2019	**$ 13,318**	**$ 5,734**	**$ 6,471**	**$ 5,893**	**$ 578**	**$ 80**	**$ 832**	**$ 17**

(a) Substantially all accretion expense for the years ended December 31, 2019, and 2018, 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 closure estimates for certain ash impoundments as a result of the NCDEQ's April 1 Order and the related settlement agreement dated December 31, 2019. See Note 5 for more information. The amount recorded in the fourth quarter of 2019 for coal ash closures as a result of the settlement was not material.

11. PROPERTY, PLANT AND EQUIPMENT

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

		December 31, 2019							
(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		$ 2,091	$ 520	$ 884	$ 449	$ 435	$ 150	$ 117	$ 388
Plant – Regulated									
Electric generation, distribution and transmission	15-100	111,739	42,723	48,142	30,018	18,124	5,838	15,032	—
Natural gas transmission and distribution	4-73	9,839	—	—	—	—	2,892	—	6,947
Other buildings and improvements	23-90	1,810	714	401	162	239	269	278	148
Plant – Nonregulated									
Electric generation, distribution and transmission	5-30	5,103	—	—	—	—	—	—	—
Other buildings and improvements	25-35	488	—	—	—	—	—	—	—
Nuclear fuel		3,253	1,891	1,362	1,362	—	—	—	—
Equipment	3-25	2,313	546	665	452	213	319	205	128
Construction in process		6,102	1,389	2,149	1,114	1,035	504	381	531
Other	2-40	4,916	1,139	1,467	1,046	411	269	292	304
Total property, plant and equipment[a][e]		147,654	48,922	55,070	34,603	20,457	10,241	16,305	8,446
Total accumulated depreciation – regulated[b][c]		(43,419)	(16,525)	(17,159)	(11,915)	(5,236)	(2,843)	(5,233)	(1,681)
Total accumulated									

depreciation – nonregulated[d][e]	**(2,354)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Generation facilities to be retired, net	**246**	**—**	**246**	**246**	**—**	**—**	**—**	**—**
Total net property, plant and equipment	**$ 102,127**	**$ 32,397**	**$ 38,157**	**$ 22,934**	**$ 15,221**	**$ 7,398**	**$ 11,072**	**$ 6,765**

(a) Includes finance leases of $952 million, $211 million, $443 million, $308 million, $135 million and $10 million at Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana, respectively, primarily within Plant – Regulated. The Progress Energy, Duke Energy Progress and Duke Energy Florida amounts are net of $143 million, $17 million and $126 million, respectively, of accumulated amortization of finance leases.

(b) Includes $1,807 million, $1,082 million, $725 million and $725 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 finance leases of $6 million, $13 million and $3 million at Duke Energy, Duke Energy Carolinas and Duke Energy Indiana, respectively.

(d) Includes accumulated amortization of finance leases of $20 million at Duke Energy.

(e) Includes gross property, plant and equipment cost of consolidated VIEs of $5,747 million and accumulated depreciation of consolidated VIEs of $1,041 million at Duke Energy.

During the year ended December 31, 2019, Duke Energy evaluated recoverability of the wind and solar generation assets included in the minority interest sale as a result of the portfolio fair value of consideration received being less than the carrying value of the assets and determined the assets were all recoverable. Additionally, in 2019, Duke Energy evaluated recoverability of its renewable merchant plants principally located in the Electric Reliability Council of Texas West market due to declining market pricing and declining long-term forecasted energy prices, primarily driven by lower forecasted natural gas prices. Duke Energy determined that the assets were not impaired because the carrying value of $160 million approximates the aggregate estimated future cash flows. A continued decline in energy market pricing would likely result in a future impairment.

		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 finance 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 finance 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 finance 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.

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. 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)	**2019**	**2018**	**2017**
Duke Energy	**$ 159**	$ 161	$ 128
Duke Energy Carolinas	**30**	35	45
Progress Energy	**31**	51	45
Duke Energy Progress	**28**	26	21
Duke Energy Florida	**3**	25	24
Duke Energy Ohio	**22**	17	10
Duke Energy Indiana	**26**	27	9
Piedmont	**26**	17	12

12. 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, 2019, and 2018.

(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total
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
Goodwill Balance at December 31, 2019	**$ 17,379**	**$ 1,924**	**$ 122**	**$ 19,425**
Accumulated impairment charges[a]	—	—	**(122)**	**(122)**
Goodwill balance at December 31, 2019, adjusted for accumulated impairment charges	**$ 17,379**	**$ 1,924**	**$ —**	**$ 19,303**

(a) Duke Energy evaluated the recoverability of goodwill during 2018 and 2017 and recorded impairment charges of $93 million and $29 million, respectively, related to the Commercial Renewables reporting unit included in Impairment charges on Duke Energy's Consolidated Statements of Operations. The fair value of the reporting unit was determined based on the income approach and market approach in 2018 and 2017, respectively. See "Goodwill Impairment Testing" below for the results of the 2019 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, 2019, and 2018.

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. As the fair value for Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont exceeded their respective carrying values at the date of the annual impairment analysis, no goodwill impairment charges were recorded in 2019.

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, 2019, and 2018.

	December 31, 2019							
(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	172	53	118	118	—	1	—	—
Natural gas, coal and power contracts	24	—	—	—	—	—	24	—
Renewable operating and development projects	89	—	—	—	—	—	—	—
Other	2	—	—	—	—	—	—	—
Total gross carrying amounts	305	53	123	120	3	1	36	—
Accumulated amortization – natural gas, coal and power contracts	(21)	—	—	—	—	—	(21)	—
Accumulated amortization – renewable operating and development projects	(34)	—	—	—	—	—	—	—
Accumulated amortization – other	(1)	—	—	—	—	—	—	—
Total accumulated amortization	(56)	—	—	—	—	—	(21)	—
Total intangible assets, net	$ 249	$ 53	$ 123	$ 120	$ 3	$ 1	$ 15	$ —

	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	$ —

See Note 11 for information related to 2017 impairment charge.

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, 2019, 2018 and 2017, and are expected to be immaterial for the next five years as of December 31, 2019.

13. 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,					
	2019		2018		2017	
(in millions)	Investments	Equity in earnings	Investments	Equity in earnings	Investments	Equity in earnings
Electric Utilities and Infrastructure	**$ 122**	**$ 9**	$ 97	$ 6	$ 89	$ 5
Gas Utilities and Infrastructure	**1,388**	**114**	1,003	27	763	62
Commercial Renewables	**314**	**(4)**	201	(1)	190	(5)
Other	**112**	**43**	108	51	133	57
Total	**$ 1,936**	**$ 162**	$ 1,409	$ 83	$ 1,175	$ 119

During the years ended December 31, 2019, 2018 and 2017, Duke Energy received distributions from equity investments of $55 million, $108 million and $13 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, 2019, 2018 and 2017, Duke Energy received distributions from equity investments of $11 million, $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, 2019, 2018 and 2017, Piedmont received distributions from equity investments of $1 million, $1 million and $4 million, respectively, which are included in Other assets within Cash Flows from Operating Activities and $4 million, $3 million and $2 million, respectively, which are included within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

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

Electric Utilities and Infrastructure

Duke Energy owns a 50% 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.

Entity Name	Ownership Interest	Investment Amount (in millions) December 31, 2019	Investment Amount (in millions) December 31, 2018
Pipeline Investments			
ACP	47%	**$ 1,179**	$ 797
Sabal Trail	7.5%	**121**	112 (c)
Constitution	24%	**—**	25
Cardinal[a]	21.49%	**9**	10
Storage Facilities			
Pine Needle[a]	45%	**28**	13
Hardy Storage[a]	50%	**51**	46
Total Investments[b]		**$ 1,388**	$ 1,003

(a) Piedmont owns the Cardinal, Pine Needle and Hardy Storage investments.
(b) Duke Energy includes purchase accounting adjustments related to Piedmont.
(c) 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 8 for additional information. As a result of the financing, ACP returned capital of $265 million to Duke Energy.

During 2018 and 2019, 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 18.

Commercial Renewables

DS Cornerstone, LLC, which owns wind farm projects in the U.S. was part of a sale of minority interest in a certain portion of renewable assets to John Hancock in 2019. See Note 2 for more information on the sale. Prior to the sale, Duke Energy had a 50% interest in DS Cornerstone, LLC. After the sale, Duke Energy has a 26% interest in the investment.

In 2019, Duke Energy acquired a majority ownership in a portfolio of distributed fuel cell projects from Bloom Energy Corporation. Duke Energy is not the primary beneficiary of the assets within the portfolio and does not consolidate the assets in the portfolio.

Impairment of Equity Method Investments

Duke Energy recorded OTTIs of the Constitution investment within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Operations of $25 million and $55 million for the years ended December 31, 2019, and 2018, respectively. The current year charge resulted in the full write-down of Duke Energy's investment in Constitution. The impairments were primarily due to the continued delay in resolving project uncertainty through the courts and regulatory bodies, as well as recent pricing concerns between the customers and owners. For additional information on the Constitution investment, see Note 4.

Other

Duke Energy owns a 17.5% 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% with the successful startup of NMC's polyacetal production facility in 2017. Duke Energy retains 25% of the board representation and voting rights of NMC.

14. 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)	**2019**	**2018**	**2017**
Duke Energy Carolinas			
Corporate governance and shared service expenses[a]	**$ 841**	$ 985	$ 858
Indemnification coverages[b]	**20**	22	23
Joint Dispatch Agreement (JDA) revenue[c]	**60**	84	49
JDA expense[c]	**186**	207	145
Intercompany natural gas purchases[d]	**15**	15	9
Progress Energy			
Corporate governance and shared service expenses[a]	**$ 778**	$ 906	$ 736
Indemnification coverages[b]	**37**	34	38
JDA revenue[c]	**186**	207	145
JDA expense[c]	**60**	84	49
Intercompany natural gas purchases[d]	**76**	78	77
Duke Energy Progress			
Corporate governance and shared service expenses[a]	**$ 462**	$ 577	$ 438
Indemnification coverages[b]	**15**	13	15
JDA revenue[c]	**186**	207	145
JDA expense[c]	**60**	84	49
Intercompany natural gas purchases[d]	**76**	78	77
Duke Energy Florida			
Corporate governance and shared service expenses[a]	**$ 316**	$ 329	$ 298
Indemnification coverages[b]	**22**	21	23
Duke Energy Ohio			
Corporate governance and shared service expenses[a]	**$ 354**	$ 374	$ 363
Indemnification coverages[b]	**4**	5	5

Duke Energy Indiana			
Corporate governance and shared service expenses[a]	**$ 412**	$ 405	$ 370
Indemnification coverages[b]	**7**	7	8
Piedmont			
Corporate governance and shared service expenses[a]	**$ 138**	$ 170	$ 50
Indemnification coverages[b]	**3**	2	2
Intercompany natural gas sales[d]	**91**	93	86
Natural gas storage and transportation costs[e]	**23**	25	25

(a) 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.

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

(c) Duke Energy Carolinas and Duke Energy Progress participate in a JDA, which allows the collective dispatch of power plants between the service territories to reduce customer rates. Revenues from the sale of power 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.

(d) 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.

(e) 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.

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 7 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 18, 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, 2019							
Intercompany income tax receivable	**$ —**	**$ 125**	**$ 28**	**$ —**	**$ 9**	**$ 28**	**$ 13**
Intercompany income tax payable	**5**	**—**	**—**	**2**	**—**	**—**	**—**

December 31, 2018								
Intercompany income tax receivable	$ 52	$ 47	$ 29	$ —	$ —	$ 8	$ —	
Intercompany income tax payable	—	—	—	16	3	—	45	

15. 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 derivatives 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, 2019, 2018 and 2017 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 and forward-starting interest rate swaps not accounted for under regulatory accounting.

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.

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

	December 31, 2019					
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio
Cash flow hedges	$ 993	$ —	$ —	$ —	$ —	$ —
Undesignated contracts	1,277	450	800	250	550	27
Total notional amount[a]	$ 2,270	$ 450	$ 800	$ 250	$ 550	$ 27

December 31, 2018

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio
Cash flow hedges[a]	$ 923	$ —	$ —	$ —	$ —	$ —
Undesignated contracts	1,721	300	1,200	650	550	27
Total notional amount	$ 2,644	$ 300	$ 1,200	$ 650	$ 550	$ 27

(a) Duke Energy includes amounts related to consolidated VIEs of $693 million in cash flow hedges as of December 31, 2019, and $422 million in cash flow hedges and $194 million in undesignated contracts as of December 31, 2018.

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, 2019							
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Electricity (GWh)	**15,858**	**—**	**—**	**—**	**—**	**1,887**	**13,971**	**—**
Natural gas (millions of Dth)	**704**	**130**	**160**	**160**	**—**	**—**	**3**	**411**

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

U.S. EQUITY SECURITIES RISK

In May 2019, Duke Energy Florida entered into a Decommissioning Services Agreement for the accelerated decommissioning of Crystal River Unit 3 with ADP CR3, LLC and ADP SF1, LLC. See Note 4 for additional information on the accelerated decommissioning. Duke Energy Florida executed U.S. equity option collars within the NDTF in May 2019 to preserve the U.S. equity portfolio value in the Duke Energy Florida NDTF in the event the accelerated decommissioning is approved. These option collars were executed as a purchase of a put option and the sale of a call option on certain U.S. equity index funds. The put and call options create a collar to guarantee a minimum and maximum investment value for the Duke Energy Florida NDTF U.S. equity portfolio. The put and call options were entered into at zero-cost, with the price to purchase the puts offset entirely by the funds received to sell the calls. As of December 31, 2019, the aggregate notional amount of both the put and call options was 305,000 units in U.S. equity security index funds. The options are not designated as hedging instruments. Substantially all of Duke Energy Florida's NDTF qualifies for regulatory accounting. With regulatory accounting, the mark-to-market gains or losses on the options are deferred as regulatory liabilities or regulatory assets, respectively.

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, 2019**							
(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	$ 17	$ —	$ —	$ —	$ —	$ 3	$ 13	$ 1
Noncurrent	1	—	—	—	—	1	—	—
Total Derivative Assets – Commodity Contracts	$ 18	$ —	$ —	$ —	$ —	$ 4	$ 13	$ 1
Interest Rate Contracts								
Not Designated as Hedging Instruments								
Current	6	—	6	—	6	—	—	—
Total Derivative Assets – Interest Rate Contracts	$ 6	$ —	$ 6	$ —	$ 6	$ —	$ —	$ —
Equity Securities Contracts								
Not Designated as Hedging Instruments								
Current	1	—	1	—	1	—	—	—
Total Derivative Assets – Equity Securities Contracts	$ 1	$ —	$ 1	$ —	$ 1	$ —	$ —	$ —
Total Derivative Assets	$ 25	$ —	$ 7	$ —	$ 7	$ 4	$ 13	$ 1

Derivative Liabilities	**December 31, 2019**							
(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	$ 67	$ 33	$ 26	$ 26	$ —	$ —	$ 1	$ 7
Noncurrent	156	10	37	22	—	—	—	110
Total Derivative Liabilities – Commodity Contracts	**$ 223**	**$ 43**	**$ 63**	**$ 48**	**$ —**	**$ —**	**$ 1**	**$ 117**
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 19	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	21	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	8	6	1	1	—	1	—	—
Noncurrent	5	—	—	—	—	5	—	—
Total Derivative Liabilities – Interest Rate Contracts	**$ 53**	**$ 6**	**$ 1**	**$ 1**	**$ —**	**$ 6**	**$ —**	**$ —**
Equity Securities Contracts								
Not Designated as Hedging Instruments								
Current	24	—	24	—	24	—	—	—
Total Derivative Liabilities – Equity Security Contracts	**$ 24**	**$ —**	**$ 24**	**$ —**	**$ 24**	**$ —**	**$ —**	**$ —**
Total Derivative Liabilities	**$ 300**	**$ 49**	**$ 88**	**$ 49**	**$ 24**	**$ 6**	**$ 1**	**$ 117**

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	$ 18	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Contracts								
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

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, 2019							
(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	**$ 24**	**$ —**	**$ 7**	**$ —**	**$ 7**	**$ 3**	**$ 13**	**$ 1**
Gross amounts offset	**(1)**	**—**	**(1)**	**—**	**(1)**	**—**	**—**	**—**
Net amounts presented in Current Assets:								
Other	**$ 23**	**$ —**	**$ 6**	**$ —**	**$ 6**	**$ 3**	**$ 13**	**$ 1**

Noncurrent								
Gross amounts recognized	$ 1	$ —	$ —	$ —	$ —	$ 1	$ —	$ —
Gross amounts offset	—	—	—	—	—	—	—	—
Net amounts presented in Other Noncurrent Assets: Other	$ 1	$ —	$ —	$ —	$ —	$ 1	$ —	$ —

Derivative Liabilities	**December 31, 2019**							
(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	**$ 118**	**$ 39**	**$ 51**	**$ 27**	**$ 24**	**$ 1**	**$ 1**	**$ 7**
Gross amounts offset	**(24)**	**—**	**(24)**	**—**	**(24)**	**—**	**—**	**—**
Net amounts presented in Current Liabilities: Other	**$ 94**	**$ 39**	**$ 27**	**$ 27**	**$ —**	**$ 1**	**$ 1**	**$ 7**
Noncurrent								
Gross amounts recognized	**$ 182**	**$ 10**	**$ 37**	**$ 22**	**$ —**	**$ 5**	**$ —**	**$ 110**
Gross amounts offset	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net amounts presented in Other Noncurrent Liabilities: Other	**$ 182**	**$ 10**	**$ 37**	**$ 22**	**$ —**	**$ 5**	**$ —**	**$ 110**

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**						
	Duke	**Duke Energy**	**Progress**	**Duke Energy**	**Duke Energy**	**Duke Energy**	**Duke Energy**

(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	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

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, 2019			
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress
Aggregate fair value of derivatives in a net liability position	**$ 79**	**$ 35**	**$ 44**	**$ 44**
Fair value of collateral already posted	**—**	**—**	**—**	**—**
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	**79**	**35**	**44**	**44**

	December 31, 2018			
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress
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

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.

16. 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 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, 2019, and 2018.

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, 2019			December 31, 2018		
(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	$ —	$ —	$ 101	$ —	$ —	$ 88
Equity securities	3,523	55	5,661	2,402	95	4,475
Corporate debt securities	37	1	603	4	13	566
Municipal bonds	13	—	368	1	4	353
U.S. government bonds	33	1	1,256	14	12	1,076
Other debt securities	3	—	141	—	2	148
Total NDTF Investments	$ 3,609	$ 57	$ 8,130	$ 2,421	$ 126	$ 6,706
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 52	$ —	$ —	$ 22
Equity securities	57	—	122	36	1	99
Corporate debt securities	3	—	67	—	2	60
Municipal bonds	4	—	94	—	1	85
U.S. government bonds	2	—	41	1	—	45
Other debt securities	—	—	56	—	1	58
Total Other Investments	$ 66	$ —	$ 432	$ 37	$ 5	$ 369

Total Investments	**$ 3,675**	**$ 57**	**$ 8,562**	$ 2,458	$ 131	$ 7,075

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	**$ 372**
Due after one through five years	**550**
Due after five through 10 years	**452**
Due after 10 years	**1,252**
Total	**$ 2,626**

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

	Years Ended December 31,	
(in millions)	2019	2018
FV-NI:		
Realized gains	**$ 172**	$ 168
Realized losses	**151**	126
AFS:		
Realized gains	**94**	22
Realized losses	**67**	51

	Year Ended December 31,
(in millions)	2017
Realized gains	$ 202
Realized losses	160

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, 2019			December 31, 2018		
(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	**$ —**	**$ —**	**$ 21**	$ —	$ —	$ 29

Equity securities	**1,914**	**8**	**3,154**	1,309	54	2,484
Corporate debt securities	**21**	**1**	**361**	2	9	341
Municipal bonds	**3**	**—**	**96**	—	1	81
U.S. government bonds	**16**	**1**	**578**	5	8	475
Other debt securities	**3**	**—**	**137**	—	2	143
Total NDTF Investments	**$ 1,957**	**$ 10**	**$ 4,347**	$ 1,316	$ 74	$ 3,553

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2019**
Due in one year or less	**$ 51**
Due after one through five years	**253**
Due after five through 10 years	**181**
Due after 10 years	**687**
Total	**$ 1,172**

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

	Years Ended December 31,	
(in millions)	**2019**	**2018**
FV-NI:		
Realized gains	**$ 113**	$ 89
Realized losses	**107**	73
AFS:		
Realized gains	**55**	19
Realized losses	**38**	35

	Year Ended December 31,
(in millions)	**2017**
Realized gains	$ 135
Realized losses	103

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, 2019			**December 31, 2018**		
(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	$ —	$ —	$ 80	$ —	$ —	$ 59
Equity securities	1,609	47	2,507	1,093	41	1,991
Corporate debt securities	16	—	242	2	4	225
Municipal bonds	10	—	272	1	3	272
U.S. government bonds	17	—	678	9	4	601
Other debt securities	—	—	4	—	—	5
Total NDTF Investments	$ 1,652	$ 47	$ 3,783	$ 1,105	$ 52	$ 3,153
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 49	$ —	$ —	$ 17
Municipal bonds	3	—	51	—	—	47
Total Other Investments	$ 3	$ —	$ 100	$ —	$ —	$ 64
Total Investments	$ 1,655	$ 47	$ 3,883	$ 1,105	$ 52	$ 3,217

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	$ 311
Due after one through five years	256
Due after five through 10 years	211
Due after 10 years	469
Total	$ 1,247

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

	Years Ended December 31,	
(in millions)	2019	2018
FV-NI:		
Realized gains	$ 59	$ 79
Realized losses	44	53
AFS:		
Realized gains	36	3
Realized losses	29	15

	Year Ended December 31,
(in millions)	2017
Realized gains	$ 65
Realized losses	56

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, 2019			December 31, 2018		
(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	$ —	$ —	$ 53	$ —	$ —	$ 46
Equity securities	1,258	21	2,077	833	30	1,588
Corporate debt securities	16	—	242	2	3	171
Municipal bonds	10	—	272	1	3	271
U.S. government bonds	16	—	403	6	3	415
Other debt securities	—	—	4	—	—	3
Total NDTF Investments	$ 1,300	$ 21	$ 3,051	$ 842	$ 39	$ 2,494
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 2	$ —	$ —	$ 6
Total Other Investments	$ —	$ —	$ 2	$ —	$ —	$ 6
Total Investments	$ 1,300	$ 21	$ 3,053	$ 842	$ 39	$ 2,500

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	$ 34

Due after one through five years	**247**
Due after five through 10 years	**204**
Due after 10 years	**436**
Total	**$ 921**

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

	Years Ended December 31,	
(in millions)	**2019**	**2018**
FV-NI:		
Realized gains	**$ 38**	$ 68
Realized losses	**33**	48
AFS:		
Realized gains	**7**	2
Realized losses	**5**	10

	Year Ended December 31,
(in millions)	**2017**
Realized gains	$ 54
Realized losses	48

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, 2019			December 31, 2018		
(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	$ —	$ —	$ 27	$ —	$ —	$ 13
Equity securities	351	26	430	260	11	403
Corporate debt securities	—	—	—	—	1	54
Municipal bonds	—	—	—	—	—	1
U.S. government bonds	1	—	275	3	1	186
Other debt securities	—	—	—	—	—	2
Total NDTF Investments[a]	$ 352	$ 26	$ 732	$ 263	$ 13	$ 659
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 4	$ —	$ —	$ 1
Municipal bonds	3	—	51	—	—	47
Total Other Investments	$ 3	$ —	$ 55	$ —	$ —	$ 48
Total Investments	$ 355	$ 26	$ 787	$ 263	$ 13	$ 707

During the year ended December 31, 2019, Duke Energy Florida continued to receive reimbursements from the NDTF for costs related to ongoing decommissioning activity of the Crystal River Unit 3.

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	$ 277
Due after one through five years	9
Due after five through 10 years	7
Due after 10 years	33
Total	$ 326

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

	Years Ended December 31,	
(in millions)	2019	2018
FV-NI:		
Realized gains	$ 21	$ 11
Realized losses	11	5
AFS:		
Realized gains	29	1
Realized losses	24	5

	Year Ended December 31,
(in millions)	2017
Realized gains	$ 11

Realized losses	8

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, 2019			December 31, 2018		
(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	**$ 43**	**$ —**	**$ 81**	$ 29	$ —	$ 67
Corporate debt securities	**—**	**—**	**6**	—	—	8
Municipal bonds	**1**	**—**	**36**	—	1	33
U.S. government bonds	**—**	**—**	**2**	—	—	—
Total Investments	**$ 44**	**$ —**	**$ 125**	$ 29	$ 1	$ 108

The table below summarizes the maturity date for debt securities.

(in millions)	**December 31, 2019**
Due in one year or less	**$ 4**
Due after one through five years	**16**
Due after five through 10 years	**7**
Due after 10 years	**17**
Total	**$ 44**

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, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were insignificant.

17. 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 net asset value 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.

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 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. 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 12 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 15. See Note 16 for additional information related to investments by major security type for the Duke Energy Registrants.

	December 31, 2019				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
NDTF equity securities	**$ 5,684**	**$ 5,633**	**$ —**	**$ —**	**$ 51**
NDTF debt securities	**2,469**	**826**	**1,643**	**—**	**—**
Other equity securities	**122**	**122**	**—**	**—**	**—**
Other debt securities	**310**	**91**	**219**	**—**	**—**
Derivative assets	**25**	**3**	**7**	**15**	**—**
Total assets	**8,610**	**6,675**	**1,869**	**15**	**51**
NDTF equity security contracts	**(23)**	**—**	**(23)**	**—**	**—**
Derivative liabilities	**(277)**	**(15)**	**(145)**	**(117)**	**—**
Net assets (liabilities)	**$ 8,310**	**$ 6,660**	**$ 1,701**	**$ (102)**	**$ 51**

	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	

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

	December 31, 2019	December 31, 2018
(in millions)	**Derivatives (net)**	**Derivatives (net)**
Balance at beginning of period	**$ (113)**	$ (114)
Purchases, sales, issuances and settlements:		
Purchases	**37**	57
Settlements	**(44)**	(57)
Total gains included on the Consolidated Balance Sheet	**18**	1
Balance at end of period	**$ (102)**	$ (113)

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, 2019			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Not Categorized**
NDTF equity securities	**$ 3,154**	**$ 3,103**	**$ —**	**$ 51**
NDTF debt securities	**1,193**	**227**	**966**	**—**
Total assets	**4,347**	**3,330**	**966**	**51**
Derivative liabilities	**(49)**	**—**	**(49)**	**—**
Net assets	**$ 4,298**	**$ 3,330**	**$ 917**	**$ 51**

	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

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, 2019			December 31, 2018		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Total Fair Value**	**Level 1**	**Level 2**
NDTF equity securities	**$ 2,530 $**	**2,530 $**	**—**	$ 1,991 $	1,991 $	—
NDTF debt securities	**1,276**	**599**	**677**	1,162	427	735
Other debt securities	**100**	**49**	**51**	64	17	47
Derivative assets	**7**	**—**	**7**	4	—	4
Total assets	**3,913**	**3,178**	**735**	3,221	2,435	786
NDTF equity security contracts	**(23)**	**—**	**(23)**	—	—	—
Derivative liabilities	**(65)**	**—**	**(65)**	(44)	—	(44)
Net assets	**$ 3,825 $**	**3,178 $**	**647**	$ 3,177 $	2,435 $	742

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, 2019			December 31, 2018		
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Total Fair Value**	**Level 1**	**Level 2**
NDTF equity securities	**$ 2,077 $**	**2,077 $**	**—**	$ 1,588 $	1,588 $	—
NDTF debt securities	**974**	**297**	**677**	906	294	612
Other debt securities	**2**	**2**	**—**	6	6	—
Derivative assets	**—**	**—**	**—**	4	—	4
Total assets	**3,053**	**2,376**	**677**	2,504	1,888	616
Derivative liabilities	**(49)**	**—**	**(49)**	(27)	—	(27)
Net assets	**$ 3,004 $**	**2,376 $**	**628**	$ 2,477 $	1,888 $	589

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, 2019			December 31, 2018		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF equity securities	$ 453	$ 453	$ —	$ 403	$ 403	$ —
NDTF debt securities	302	302	—	256	133	123
Other debt securities	55	4	51	48	1	47
Derivative assets	7	—	7	—	—	—
Total assets	817	759	58	707	537	170
NDTF equity security contracts	(23)	—	(23)	—	—	—
Derivative liabilities	(1)	—	(1)	(9)	—	(9)
Net assets	$ 793	$ 759	$ 34	$ 698	$ 537	$ 161

DUKE ENERGY OHIO

The recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets were not material at December 31, 2019, and 2018.

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, 2019				December 31, 2018			
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
Other equity securities	$ 81	$ 81	$ —	$ —	$ 67	$ 67	$ —	$ —
Other debt securities	44	—	44	—	41	—	41	—
Derivative assets	13	2	—	11	23	1	—	22
Total assets	138	83	44	11	131	68	41	22
Derivative liabilities	(1)	(1)	—	—	—	—	—	—

Total assets	$ 137	$ 82	$ 44	$ 11	$ 131	$ 68	$ 41	$ 22

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)	2019	2018
Balance at beginning of period	$ 22	$ 27
Purchases, sales, issuances and settlements:		
Purchases	28	50
Settlements	(36)	(53)
Total losses included on the Consolidated Balance Sheet	(3)	(2)
Balance at end of period	$ 11	$ 22

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, 2019			December 31, 2018		
(in millions)	Total Fair Value	Level 1	Level 3	Total Fair Value	Level 1	Level 3
Derivative assets	$ 1	$ 1	$ —	$ 3	$ 3	$ —
Derivative liabilities	(117)	—	(117)	(141)	—	(141)
Net (liabilities) assets	$ (116)	$ 1	$ (117)	$ (138)	$ 3	$ (141)

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)	2019	2018
Balance at beginning of period	$ (141)	$ (142)
Total gains and settlements	24	1
Balance at end of period	$ (117)	$ (141)

QUANTITATIVE INFORMATION ABOUT UNOBSERVABLE INPUTS

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

	December 31, 2019				
Investment Type	**Fair Value (in millions)**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted Average Range**
Duke Energy Ohio					
FTRs	**$ 4**	RTO auction pricing	FTR price – per MWh	**$ 0.59 – $ 3.47**	**$ 2.07**
Duke Energy Indiana					
FTRs	**11**	RTO auction pricing	FTR price – per MWh	**(0.66) – 9.24**	**1.15**
Piedmont					
Natural gas contracts	**(117)**	Discounted cash flow	Forward natural gas curves – price per MMBtu	**1.59 – 2.46**	**1.91**
Duke Energy					
Total Level 3 derivatives	**$ (102)**				

	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)			

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, 2019	**December 31, 2018**

(in millions)	Book Value	Fair Value	Book Value	Fair Value
Duke Energy[a]	**$ 58,126**	**$ 63,062**	$ 54,529	$ 54,534
Duke Energy Carolinas	**11,900**	**13,516**	10,939	11,471
Progress Energy	**19,634**	**22,291**	18,911	19,885
Duke Energy Progress	**9,058**	**9,934**	8,204	8,300
Duke Energy Florida	**7,987**	**9,131**	7,321	7,742
Duke Energy Ohio	**2,619**	**2,964**	2,165	2,239
Duke Energy Indiana	**4,057**	**4,800**	3,782	4,158
Piedmont	**2,384**	**2,642**	2,138	2,180

(a) Book value of long-term debt includes $1.5 billion as of December 31, 2019, and $1.6 billion as of December 31, 2018, 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, 2019, and December 31, 2018, 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.

18. 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 the consolidated 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, 2019, 2018, and 2017, 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 LLCs 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% cash and 25% 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 is not held 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 summarizes the amounts and expiration dates of the credit facilities and associated restricted receivables described above.

	Duke Energy			
		Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida
(in millions)	**CRC**	**DERF**	**DEPR**	**DEFR**
Expiration date	February 2023	December 2022	February 2021	April 2021
Credit facility amount	$ 350	$ 475	$ 325	$ 250
Amounts borrowed at December 31, 2019	**350**	**474**	**325**	**250**
Amounts borrowed at December 31, 2018	325	450	300	225
Restricted Receivables at December 31, 2019	**522**	**642**	**489**	**336**
Restricted Receivables at December 31, 2018	564	699	547	357

Nuclear Asset-Recovery Bonds – Duke Energy Florida Project Finance, LLC (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.

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.

	December 31,	
(in millions)	**2019**	**2018**
Receivables of VIEs	**$ 5**	$ 5

Regulatory Assets: Current	**52**	52
Current Assets: Other	**39**	39
Other Noncurrent Assets: Regulatory assets	**989**	1,041
Current Liabilities: Other	**10**	10
Current maturities of long-term debt	**54**	53
Long-Term Debt	**1,057**	1,111

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 renewable assets 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 Commercial Renewables VIEs.

	December 31,	
(in millions)	**2019**	**2018**
Current Assets: Other	**$ 203**	$ 123
Property, Plant and Equipment: Cost	**5,747**	4,007
Accumulated depreciation and amortization	**(1,041)**	(698)
Other Noncurrent Assets: Other	**106**	261
Current maturities of long-term debt	**162**	174
Long-Term Debt	**1,541**	1,587
Other Noncurrent Liabilities: AROs	**127**	106
Other Noncurrent Liabilities: Other	**228**	212

NON-CONSOLIDATED VIEs

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

	December 31, 2019					
	Duke Energy				Duke	Duke
(in millions)	**Pipeline Investments**	**Commercial Renewables**	**Other VIEs[a]**	**Total**	**Energy Ohio**	**Energy Indiana**
Receivables from affiliated companies	**$ —**	**$ (1)**	**$ —**	**$ (1)**	**$ 64**	**$ 77**
Investments in equity method unconsolidated affiliates	**1,179**	**300**	**—**	**1,479**	**—**	**—**

Total assets	$ 1,179	$ 299	$ —	$ 1,478	$ 64	$ 77
Taxes accrued	(1)	—	—	(1)	—	—
Other current liabilities	—	—	4	4	—	—
Deferred income taxes	59	—	—	59	—	—
Other noncurrent liabilities	—	—	11	11	—	—
Total liabilities	$ 58	$ —	$ 15	$ 73	$ —	$ —
Net assets (liabilities)	$ 1,121	$ 299	$ (15)	$ 1,405	$ 64	$ 77

(a) Duke Energy holds a 50% equity interest in Pioneer. As of December 31, 2018, Pioneer was considered a VIE due to having insufficient equity to finance its own activities without subordinated financial support. In October 2019, Pioneer closed on a private placement debt offering that gave Pioneer sufficient equity to finance its own activities and, therefore, is no longer considered a VIE. Duke Energy's investment in Pioneer was $57 million at December 31, 2019.

	December 31, 2018					
	Duke Energy				Duke	Duke
(in millions)	Pipeline Investments	Commercial Renewables	Other VIEs	Total	Energy Ohio	Energy 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

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 PPA 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 $827 million, which represents 47% of the outstanding borrowings under the credit facility as of December 31, 2019. For more information on various guarantees, refer to Note 8.

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.

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 balances in these joint ventures.

Entity Name	Ownership Interest	VIE Investment Amount (in millions) December 31, 2019	VIE Investment Amount (in millions) December 31, 2018
ACP[a]	47%	$ 1,179	$ 797
Constitution[b]	24%	—	25
Total		$ 1,179	$ 822

(a) Duke Energy evaluated this investment for impairment as of December 31, 2019, and 2018, and determined that fair value approximated carrying value and therefore no impairment was necessary.

(b) During the years ended December 31, 2019, and 2018, Duke Energy recorded an OTTI of $25 million and $55 million, respectively, related to Constitution within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Income. The current year charge resulted in the full write-down of Duke Energy's investment in Constitution. See Notes 4 and 13 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. In 2019, Duke Energy acquired a majority ownership in a portfolio of distributed fuel cell projects from Bloom Energy Corporation. Duke Energy is not the primary beneficiary of the assets within the portfolio and does not consolidate the assets in the portfolio.

OVEC

Duke Energy Ohio's 9% ownership interest in OVEC is considered a non-consolidated VIE due to OVEC 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 Inter-Company Power Agreement (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 Corp. and an ICPA counterparty with a power participation ratio of 4.85%, 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% and a 20% 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	
	2019	2018	2019	2018
Anticipated credit loss ratio	**0.6%**	0.5%	**0.3%**	0.3%
Discount rate	**3.3%**	3.0%	**3.3%**	3.0%
Receivable turnover rate	**13.4%**	13.5%	**11.5%**	11.0%

The following table shows the gross and net receivables sold.

	Duke Energy Ohio		Duke Energy Indiana	
	December 31,		December 31,	
(in millions)	2019	2018	2019	2018
Receivables sold	**$ 253**	$ 269	**$ 307**	$ 336
Less: Retained interests	**64**	93	**77**	118
Net receivables sold	**$ 189**	$ 176	**$ 230**	$ 218

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)	2019	2018	2017	2019	2018	2017
Sales						
Receivables sold	**$ 1,979**	$ 1,987	$ 1,879	**$ 2,837**	$ 2,842	$ 2,711
Loss recognized on sale	**14**	13	10	**17**	16	12
Cash flows						
Cash proceeds from receivables sold	**1,993**	1,967	1,865	**2,860**	2,815	2,694
Collection fees received	**1**	1	1	**1**	1	1
Return received on retained interests	**6**	6	3	**9**	9	7

Cash flows from 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%.

19. REVENUE

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)	2020	2021	2022	2023	2024	Thereafter	Total
Progress Energy	$ 121	$ 92	$ 87	$ 44	$ 45	$ 58	$ 447
Duke Energy Progress	8	8	8	8	8	—	40
Duke Energy Florida	113	84	79	36	37	58	407
Duke Energy Indiana	10	5	—	—	—	—	15

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)	2020	2021	2022	2023	2024	Thereafter	Total
Piedmont	$ 69	$ 64	$ 64	$ 61	$ 58	$ 372	$ 688

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, 2019							
(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	$ 9,863	$ 3,044	$ 4,998	$ 2,144	$ 2,854	$ 733	$ 1,087	$ —
General	6,431	2,244	2,935	1,368	1,567	451	802	—
Industrial	3,071	1,215	934	675	259	147	774	—
Wholesale	2,212	462	1,468	1,281	187	46	235	—
Other revenues	770	276	548	317	231	80	89	—
Total Electric Utilities and Infrastructure revenue from contracts with customers	$ 22,347	$ 7,241	$ 10,883	$ 5,785	$ 5,098	$ 1,457	$ 2,987	$ —
Gas Utilities and Infrastructure								
Residential	$ 976	$ —	$ —	$ —	$ —	$ 315	$ —	$ 661
Commercial	508	—	—	—	—	130	—	378
Industrial	141	—	—	—	—	19	—	122
Power Generation	—	—	—	—	—	—	—	51
Other revenues	129	—	—	—	—	19	—	110
Total Gas Utilities and Infrastructure revenue from contracts with customers	$ 1,754	$ —	$ —	$ —	$ —	$ 483	$ —	$ 1,322
Commercial Renewables								
Revenue from contracts with customers	$ 223	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Other								

Revenue from contracts with customers	$ 24	$ —	$ —	$ —	$ —	$ —	$ —	—
Total revenue from contracts with customers	$ 24,348	$ 7,241	$ 10,883	$ 5,785	$ 5,098	$ 1,940	$ 2,987	$ 1,322
Other revenue sources[a]	$ 731	$ 154	$ 319	$ 172	$ 133	$ —	$ 17	$ 59
Total revenues	$ 25,079	$ 7,395	$ 11,202	$ 5,957	$ 5,231	$ 1,940	$ 3,004	$ 1,381

(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.

	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, Ohio and Kentucky 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, Tennessee and Kentucky 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)	**2019**	**2018**
Duke Energy	**$ 843**	$ 896
Duke Energy Carolinas	**298**	313
Progress Energy	**217**	244
Duke Energy Progress	**122**	148
Duke Energy Florida	**95**	96
Duke Energy Ohio	**1**	2
Duke Energy Indiana	**16**	23
Piedmont	**78**	73

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 account for the transfers of receivables as sales. Accordingly, the receivables sold are not reflected on the Consolidated Balance Sheets of Duke Energy Ohio and Duke Energy Indiana. See Note 18 for further information. These receivables for unbilled revenues are shown in the table below.

	December 31,	
(in millions)	**2019**	**2018**
Duke Energy Ohio	**$ 82**	$ 86
Duke Energy Indiana	**115**	128

20. STOCKHOLDERS' EQUITY

Basic EPS is computed by dividing net income available 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 available 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 stock, such as stock options and equity forward sale agreements, were exercised or settled. Duke Energy's participating securities are RSUs that are entitled to dividends declared on Duke Energy common stock during the RSUs vesting periods. Dividends declared on preferred stock are recorded on the Consolidated Statements of Operations as a reduction of net income to arrive at net income available to Duke Energy common stockholders. Dividends accumulated on preferred stock are a reduction to net income used in the calculation of basic and diluted EPS.

The following table presents Duke Energy's basic and diluted EPS calculations, the weighted average number of common shares outstanding and common and preferred share dividends declared.

	Years Ended December 31,		
(in millions, except per share amounts)	**2019**	**2018**	**2017**
Income from continuing operations available to Duke Energy common stockholders excluding impact of participating securities and including accumulated preferred stock dividends	**$ 3,694**	$ 2,642	$ 3,059
Weighted average common shares outstanding – basic and diluted	**729**	708	700
EPS from continuing operations available to Duke Energy common stockholders			
Basic and diluted	**$ 5.07**	$ 3.73	$ 4.37
Potentially dilutive items excluded from the calculation[a]	**2**	2	2
Dividends declared per common share	**$ 3.75**	$ 3.64	$ 3.49
Dividends declared on Series A preferred stock per depositary share	**$ 1.03**	$ —	$ —

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

Common Stock

In February 2018, Duke Energy filed a prospectus supplement and executed an Equity Distribution Agreement (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. Under the terms of the EDA, Duke Energy was allowed to issue and sell shares of common stock. The existing ATM offering program expired in September 2019.

In June 2018, Duke Energy marketed two separate tranches, each for 1.3 million shares, of common stock through equity forward transactions under the ATM program. 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.

In March 2018, Duke Energy marketed an equity offering of 21.3 million shares of common stock through an Underwriting Agreement. In connection with the offering, Duke Energy entered into equity forward sale agreements. The equity forwards required 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. 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.

In March and April 2019, Duke Energy marketed two separate tranches, each for 1.1 million shares, of common stock through equity forward transactions under the ATM program. The first tranche had an initial forward price of $89.83 per share and the second tranche had an initial forward price of $88.82 per share. In May and June 2019, a third tranche of 1.6 million shares of common stock was marketed and had an initial forward price of $86.23. The equity forwards required Duke Energy to either physically settle the transaction by issuing 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 2019, Duke Energy physically settled the equity forwards by delivering 3.8 million shares of common stock in exchange for net cash proceeds of approximately $331 million.

In November 2019, Duke Energy filed a prospectus supplement and executed an EDA under which it may sell up to $1.5 billion of its common stock through a new ATM offering program, including an equity forward sales component. Under the terms of the EDA, Duke Energy may issue and sell shares of common stock through September 2022.

In November 2019, Duke Energy marketed an equity offering of 28.75 million shares of common stock through an Underwriting Agreement. In connection with the offering, Duke Energy entered into equity forward sales agreements with an initial forward price of $85.99 per share. The equity forward sales agreements require Duke Energy to either physically settle the transaction by issuing shares in exchange for net proceeds at the then-applicable forward sale price specified by the agreement, or net settle in whole or in part through the delivery or receipt of cash or shares. The settlement alternatives are at Duke Energy's election. Settlement of the forward sales agreements are expected to occur on or prior to December 31, 2020. If Duke Energy had elected to net share settle these contracts as of December 31, 2019, Duke Energy would have been required to deliver 1.6 million shares.

For the years ended December 31, 2019, and 2018, Duke Energy issued 1.8 million and 2.2 million shares, respectively, through its DRIP with an increase in additional paid-in capital of approximately $160 million and $174 million, respectively.

Preferred Stock

On March 29, 2019, Duke Energy completed the issuance of 40 million depositary shares, each representing 1/1,000th share of its Series A Cumulative Redeemable Perpetual Preferred Stock, at a price of $25 per depositary share. The transaction resulted in net proceeds of $973 million after issuance costs with proceeds used for general corporate purposes and to reduce short-term debt. The preferred stock has a $25 liquidation preference per depositary share and earns dividends on a cumulative basis at a rate of 5.75% per annum. Dividends are payable quarterly in arrears on the 16th day of March, June, September and December, and began on June 16, 2019.

The Series A Preferred Stock has no maturity or mandatory redemption date, is not redeemable at the option of the holders and includes separate call options. The first call option allows Duke Energy to call the Series A Preferred Stock at a redemption price of $25.50 per depositary share prior to June 15, 2024, in whole but not in part, at any time within 120 days after a ratings event where a rating agency amends, clarifies or changes the criteria it uses to assign equity credit for securities such as the preferred stock. The second call option allows Duke Energy to call the preferred stock, in whole or in part, at any time, on or after June 15, 2024, at a redemption price of $25 per depositary share. Duke Energy is also required to redeem all accumulated and unpaid dividends if either call option is exercised.

On September 12, 2019, Duke Energy completed the issuance of 1 million shares of its Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, at a price of $1,000 per share. The transaction resulted in net proceeds of $989 million after issuance costs with proceeds being used to pay down short-term debt, repay at maturity $500 million senior notes due September 2019, and for general corporate purposes. The preferred stock has a $1,000 liquidation preference per share and earns dividends on a cumulative basis at an initial rate of 4.875% per annum. Dividends are payable semiannually in arrears on the 16th day of March and September, beginning on March 16, 2020. On September 16, 2024, the First Call Date, and any fifth anniversary of the First Call Date (each a Reset Date), the dividend rate will reset based on the then current five-year U.S. treasury rate plus a spread of 3.388%.

The Series B Preferred Stock has no maturity or mandatory redemption date, is not redeemable at the option of the holders and includes separate call options. The first call option allows Duke Energy to call the Series B Preferred Stock at a redemption price of $1,020 per share, in whole but not in part, at any time within 120 days after a ratings event. The second call option allows Duke Energy to call the preferred stock, in whole or in part, on the First Call Date or any subsequent Reset Date at a redemption price in cash equal to $1,000 per share. Duke Energy is also required to redeem all accumulated and unpaid dividends if either call option is exercised.

Dividends issued on its Series A and Series B Preferred Stock are subject to approval by the Board of Directors. However, the deferral of dividend payments on the preferred stock prohibits the declaration of common stock dividends.

The Series A and Series B Preferred Stock rank, with respect to dividends and distributions upon liquidation or dissolution:

- senior to Common Stock and to each other class or series of capital stock established after the original issue date of the Series A and Series B Preferred Stock that is expressly made subordinated to the Series A and Series B Preferred Stock;
- on a parity with any class or series of capital stock established after the original issue date of the Series A and Series B Preferred Stock that is not expressly made senior or subordinated to the Series A or Series B Preferred Stock;
- junior to any class or series of capital stock established after the original issue date of the Series A and Series B Preferred Stock that is expressly made senior to the Series A or Series B Preferred Stock;
- junior to all existing and future indebtedness (including indebtedness outstanding under Duke Energy's credit facilities, unsecured senior notes, junior subordinated debentures and commercial paper) and other liabilities with respect to assets available to satisfy claims against Duke Energy; and
- structurally subordinated to existing and future indebtedness and other liabilities of Duke Energy's subsidiaries and future preferred stock of subsidiaries.

Holders of Series A and Series B Preferred Stock have no voting rights with respect to matters that generally require the approval of voting stockholders. The limited voting rights of holders of Series A and Series B Preferred Stock include the right to vote as a single class, respectively, on certain matters that may affect the preference or special rights of the preferred stock, except in the instance that Duke Energy elects to defer the payment of dividends for a total of six quarterly full dividend periods for Series A Preferred Stock or three semiannual full dividend periods for Series B Preferred Stock. If dividends are deferred for a cumulative total of six quarterly full dividend periods for Series A Preferred Stock or three semiannual full dividend periods for Series B Preferred Stock, whether or not for consecutive dividend periods, holders of the respective preferred stock have the right to elect two additional Board members to the Board of Directors.

21. 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 was 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.

The following table presents the direct and allocated severance and related charges accrued for approximately 140 employees in 2019, 1,900 employees in 2018 and 100 employees in 2017 by the Duke Energy Registrants 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

Year Ended December 31, 2019	**$ 16**	**$ 8**	**$ 6**	**$ 3**	**$ 3**	**$ —**	**$ 1**	**$ 1**
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

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, 2018	$ 205	$ 100	$ 51	$ 41	$ 9	$ 2	$ 2	$ —
Provision/Adjustments	**24**	**4**	**11**	**2**	**10**	**1**	**1**	**—**
Cash Reductions	**(188)**	**(93)**	**(49)**	**(37)**	**(12)**	**(2)**	**(1)**	**—**
Balance at December 31, 2019	**$ 41**	**$ 11**	**$ 13**	**$ 6**	**$ 7**	**$ 1**	**$ 2**	**$ —**

22. STOCK-BASED COMPENSATION

The Duke Energy Corporation 2015 Long-Term Incentive Plan (the 2015 Plan) provides for the grant of stock-based compensation awards to employees and outside directors. The 2015 Plan reserves 10 million shares of common stock for issuance. Duke Energy has historically issued new shares upon exercising or vesting of share-based awards. However, Duke Energy may use a combination of new share issuances and open market repurchases for share-based awards that are exercised or vest in the future. Duke Energy has not determined with certainty the amount of such new share issuances or open market repurchases.

The following table summarizes the total expense recognized by the Duke Energy Registrants, net of tax, for stock-based compensation.

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Duke Energy	**$ 65**	$ 56	$ 43
Duke Energy Carolinas	**24**	20	15
Progress Energy	**24**	21	16
Duke Energy Progress	**15**	13	10
Duke Energy Florida	**9**	8	6
Duke Energy Ohio	**5**	4	3
Duke Energy Indiana	**6**	5	4
Piedmont	**3**	3	3

Duke Energy's pretax stock-based compensation costs, the tax benefit associated with stock-based compensation expense and stock-based compensation costs capitalized are included in the following table.

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
RSU awards	**$ 44**	$ 43	$ 41
Performance awards	**45**	35	27

Pretax stock-based compensation cost	**$ 89**	$ 78	$ 68
Stock-based compensation costs capitalized	**5**	5	4
Stock-based compensation expense	**$ 84**	$ 73	$ 64
Tax benefit associated with stock-based compensation expense	**$ 19**	$ 17	$ 25

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,		
	2019	**2018**	**2017**
Shares granted (in thousands)	**571**	649	583
Fair value (in millions)	**$ 51**	$ 49	$ 47

The following table summarizes information about RSU awards outstanding.

	Shares (in thousands)	**Weighted Average Grant Date Fair Value (per share)**
Outstanding at December 31, 2018	1,153	$ 77
Granted	**571**	**89**
Vested	**(631)**	**77**
Forfeited	**(83)**	**82**
Outstanding at December 31, 2019	**1,010**	**83**
RSU awards expected to vest	**951**	**83**

The total grant date fair value of shares vested during the years ended December 31, 2019, 2018 and 2017, was $49 million, $43 million and $42 million, respectively. At December 31, 2019, Duke Energy had $30 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of 23 months. 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 2016-2018 performance award cycle was approved subsequent to the Agreement and Plan of Merger between Duke Energy and Piedmont and was converted into a Duke Energy RSU award at the consummation of the acquisition.

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% of target shares, depending on the level of performance achieved.

Performance awards contain performance conditions and a market condition. The performance conditions are based on Duke Energy's cumulative adjusted EPS and total incident case rate (total incident case rate is one of our key employee safety metrics). The market condition is based on TSR of Duke Energy relative to a predefined peer group.

Relative TSR 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 2019, the model used a risk-free interest rate of 2.5%, which reflects the yield on three-year Treasury bonds as of the grant date, and an expected volatility of 14.8% 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,		
	2019	**2018**	**2017**
Shares granted assuming target performance (in thousands)	**320**	372	461
Fair value (in millions)	**$ 27**	$ 27	$ 37

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, 2018	1,117	$ 77
Granted	**320**	**86**
Vested	**(310)**	**75**
Forfeited	**(18)**	**81**
Outstanding at December 31, 2019	**1,109**	**80**
Stock-based performance awards expected to vest	**1,080**	**80**

The total grant date fair value of shares vested during the years ended December 31, 2019, and 2018, was $23 million and $13 million, respectively. No performance awards vested during the year ended December 31, 2017. At December 31, 2019, Duke Energy had $27 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of 22 months.

23. 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.

As a result of the application of settlement accounting due to total lump-sum benefit payments exceeding the settlement threshold (defined as the sum of the service cost and interest cost on projected benefit obligation components of net periodic pension costs) for one of its qualified pension plans, Duke Energy recognized settlement charges of $94 million, primarily as a regulatory asset within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2019 (an immaterial amount was recorded in Other income and expenses, net within the Consolidated Statement of Operations).

Settlement charges recognized by the Subsidiary Registrants as of December 31, 2019, which represent amounts allocated by Duke Energy for employees of the Subsidiary Registrants and allocated charges for their proportionate share of settlement charges for employees of Duke Energy's shared services affiliate, were $53 million for Duke Energy Carolinas, $26 million for Progress Energy, $20 million for Duke Energy Progress, $6 million for Duke Energy Florida, $4 million for Duke Energy Indiana, $2 million for Duke Energy Ohio and $8 million for Piedmont.

The settlement charges reflect the recognition of a pro-rata portion of previously unrecognized actuarial losses, equal to the percentage of reduction in the projected benefit obligation resulting from total lump-sum benefit payments as of December 31, 2019. Settlement charges recognized as a regulatory asset within Other Noncurrent Assets on the Consolidated Balance Sheets are amortized over the average remaining service period for participants in the plan. Amortization of settlement charges is disclosed in the tables below as a component of net periodic pension costs.

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 (except for amortization of settlement charges). These allocated amounts are included in the governance and shared service costs discussed in Note 14.

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 2020. 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
Contributions Made:								
2019	$ 77	$ 7	$ 57	$ 4	$ 53	$ 2	$ 2	$ 1
2018	141	46	45	25	20	—	8	—
2017	19	—	—	—	—	4	—	11

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	Year Ended December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Service cost	**$ 158**	**$ 49**	**$ 46**	**$ 26**	**$ 20**	**$ 4**	**$ 9**	**$ 5**
Interest cost on projected benefit obligation	**317**	**75**	**100**	**45**	**54**	**18**	**26**	**10**
Expected return on plan assets	**(567)**	**(147)**	**(178)**	**(88)**	**(89)**	**(28)**	**(43)**	**(22)**
Amortization of actuarial loss	**108**	**24**	**39**	**15**	**24**	**4**	**8**	**8**
Amortization of prior service credit	**(32)**	**(8)**	**(3)**	**(2)**	**(1)**	**—**	**(2)**	**(9)**
Amortization of settlement charges	**6**	**2**	**1**	**1**	**—**	**2**	**—**	**—**
Net periodic pension costs[a][b]	**$ (10)**	**$ (5)**	**$ 5**	**$ (3)**	**$ 8**	**$ —**	**$ (2)**	**$ (8)**

	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							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Service cost	$ 159	$ 48	$ 45	$ 26	$ 19	$ 4	$ 9	$ 10
Interest cost on projected benefit	328	79	100	47	53	18	26	14

obligation								
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

(a) Duke Energy amounts exclude $4 million, $5 million and $7 million for the years ended December 2019, 2018 and 2017, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(b) Duke Energy Ohio amounts exclude $2 million, $2 million and $3 million for the years ended December 2019, 2018 and 2017, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets

	Year Ended December 31, 2019							
(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)	**$ (212)**	**$ (156)**	**$ (79)**	**$ (59)**	**$ (20)**	**$ 12**	**$ 22**	**$ —**
Accumulated other comprehensive loss (income)								
Deferred income tax expense (benefit)	**$ 20**	**—**	**1**	**—**	**(1)**	**—**	**—**	**—**
Amortization of prior year service credit	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Amortization of prior year actuarial losses	**(15)**	**—**	**(2)**	**—**	**3**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive income	**$ 6**	**$ —**	**$ (1)**	**$ —**	**$ 2**	**$ —**	**$ —**	**$ —**

	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	$ 298	$ 170	$ 40	$ 31	$ 9	$ 10	$ 30	$ 8
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ (2)	$ —	$ 1	$ —	$ —	$ —	$ —	$ —
Prior year service credit arising during	1	—	—	—	—	—	—	—

the year								
Amortization of prior year actuarial losses	10	—	(4)	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ 9	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Net Amount Recognized

	Year Ended December 31, 2019							
(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	$ 7,869	$ 1,954	$ 2,433	$ 1,125	$ 1,295	$ 435	$ 618	$ 264
Service cost	150	47	43	25	18	4	8	5
Interest cost	317	75	100	45	54	18	26	10
Actuarial loss	716	101	223	87	135	54	87	33
Transfers	—	11	—	—	—	—	—	—
Benefits paid	(731)	(265)	(191)	(112)	(78)	(30)	(46)	(20)
Obligation at measurement date	$ 8,321	$ 1,923	$ 2,608	$ 1,170	$ 1,424	$ 481	$ 693	$ 292
Accumulated Benefit Obligation at measurement date	$ 8,262	$ 1,923	$ 2,578	$ 1,170	$ 1,392	$ 471	$ 686	$ 292
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 8,233	$ 2,168	$ 2,606	$ 1,268	$ 1,322	$ 405	$ 611	$ 305
Employer contributions	77	7	57	4	53	2	2	1
Actual return on plan assets	1,331	342	426	204	218	66	100	49
Benefits paid	(731)	(265)	(191)	(112)	(78)	(30)	(46)	(20)
Transfers	—	11	—	—	—	—	—	—
Plan assets at measurement date	$ 8,910	$ 2,263	$ 2,898	$ 1,364	$ 1,515	$ 443	$ 667	$ 335
Funded status of plan	$ 589	$ 340	$ 290	$ 194	$ 91	$ (38)	$ (26)	$ 43

	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

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2019							
(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]	$ 621	$ 340	$ 322	$ 194	$ 123	$ 38	$ 57	$ 43
Noncurrent pension liability[b]	$ 32	$ —	$ 32	$ —	$ 32	$ 76	$ 83	$ —
Net asset (liability) recognized	$ 589	$ 340	$ 290	$ 194	$ 91	$ (38)	$ (26)	$ 43
Regulatory assets	$ 1,972	$ 420	$ 717	$ 313	$ 404	$ 112	$ 204	$ 81
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (23)	$ —	$ (1)	$ —	$ (1)	$ —	$ —	$ —
Prior service credit	(3)	—	—	—	—	—	—	—
Net actuarial loss	111	—	3	—	3	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 85	$ —	$ 2	$ —	$ 2	$ —	$ —	$ —
Amounts to be recognized in net periodic pension costs in the next year								
Unrecognized net actuarial loss	$ 135	$ 29	$ 43	$ 19	$ 24	$ 7	$ 10	$ 9
Unrecognized prior service credit	(32)	(8)	(3)	(2)	(1)	(1)	(2)	(9)

	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 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)

(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, 2019	
(in millions)	**Duke Energy Ohio**	**Duke Energy Indiana**
Projected benefit obligation	**$ 155**	**$ 260**
Accumulated benefit obligation	**146**	**252**
Fair value of plan assets	**79**	**177**

	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

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 12 years for Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Florida, 13 years for Duke Energy Progress, Duke Energy Indiana and Duke Energy Ohio, and 9 years for Piedmont.

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

	December 31,		
	2019	**2018**	**2017**

Benefit Obligations			
Discount rate	**3.30%**	4.30%	3.60%
Salary increase	**3.50% – 4.00%**	3.50% – 4.00%	3.50% – 4.00%
Net Periodic Benefit Cost			
Discount rate	**4.30%**	3.60%	4.10%
Salary increase	**3.50% – 4.00%**	3.50% – 4.00%	4.00% – 4.50%
Expected long-term rate of return on plan assets	**6.85%**	6.50%	6.50% – 6.75%

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Years ending December 31,								
2020	$ 643	$ 167	$ 169	$ 89	$ 79	$ 37	$ 50	$ 28
2021	653	171	178	95	82	37	50	24
2022	649	177	176	92	84	37	49	22
2023	649	174	182	95	86	36	48	21
2024	638	168	184	96	87	35	48	20
2025-2029	2,851	714	871	419	448	156	220	87

NON-QUALIFIED PENSION PLANS

The accumulated benefit obligation, which equals the projected benefit obligation for non-qualified pension plans, was $318 million for Duke Energy, $15 million for Duke Energy Carolinas, $110 million for Progress Energy, $32 million for Duke Energy Progress, $45 million for Duke Energy Florida, $4 million for Duke Energy Ohio, $3 million for Duke Energy Indiana and $4 million for Piedmont as of December 31, 2019.

Employer contributions, which equal benefits paid for non-qualified pension plans, were $25 million for Duke Energy, $2 million for Duke Energy Carolinas, $9 million for Progress Energy, $3 million for Duke Energy Progress and $3 million for Duke Energy Florida for the year ended December 31, 2019. Employer contributions were not material for Duke Energy Ohio, Duke Energy Indiana or Piedmont for the year ended December 31, 2019.

Net periodic pension costs for non-qualified pension plans were not material for the years ended December 31, 2019, 2018 or 2017.

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, 2019, 2018 or 2017.

Components of Net Periodic Other Post-Retirement Benefit Costs

	Year Ended December 31, 2019							
(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**	**$ —**	**$ 1**	**$ —**	**$ 1**	**$ —**
Interest cost on accumulated post-retirement benefit obligation	**30**	**7**	**12**	**7**	**5**	**1**	**3**	**1**
Expected return on plan assets	**(12)**	**(7)**	**—**	**—**	**—**	**—**	**—**	**(1)**
Amortization of actuarial loss	**4**	**2**	**1**	**—**	**1**	**—**	**4**	**—**
Amortization of prior service credit	**(19)**	**(5)**	**(8)**	**(1)**	**(7)**	**(1)**	**(1)**	**(2)**
Net periodic post-retirement benefit costs (a)(b)	**$ 7**	**$ (2)**	**$ 6**	**$ 6**	**$ —**	**$ —**	**$ 7**	**$ (2)**

	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

Duke Energy amounts exclude $6 million, $7 million and $7 million for the years ended December 2019, 2018 and 2017, 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 2019, 2018 and 2017, 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.

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

	Year Ended December 31, 2019							
(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)	**$ (127)**	**$ —**	**$ (127)**	**$ (82)**	**$ (45)**	**$ —**	**$ (5)**	**$ —**
Regulatory liabilities, net increase (decrease)	**$ (152)**	**$ 1**	**$ (149)**	**$ (93)**	**$ (56)**	**$ (1)**	**$ (4)**	**$ 3**
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Amortization of prior year actuarial gain	**(4)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive income	**$ (4)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

	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 prior service credit	1	—	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

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

	Year Ended December 31, 2019							
(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	**$ 728**	**$ 174**	**$ 303**	**$ 166**	**$ 137**	**$ 29**	**$ 67**	**$ 30**
Service cost	**4**	**1**	**1**	**—**	**1**	**—**	**1**	**—**
Interest cost	**30**	**7**	**12**	**7**	**5**	**1**	**3**	**1**
Plan participants' contributions	**16**	**3**	**6**	**3**	**2**	**1**	**2**	**—**
Actuarial losses	**28**	**9**	**13**	**9**	**5**	**1**	**2**	**—**
Transfers	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Benefits paid	**(83)**	**(19)**	**(32)**	**(17)**	**(15)**	**(3)**	**(11)**	**(1)**
Accumulated post-retirement benefit obligation at measurement date	**$ 723**	**$ 175**	**$ 303**	**$ 168**	**$ 135**	**$ 29**	**$ 64**	**$ 30**
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	**$ 195**	**$ 115**	**$ —**	**$ —**	**$ —**	**$ 8**	**$ 5**	**$ 29**
Actual return on plan assets	**32**	**20**	**(1)**	**—**	**—**	**1**	**—**	**6**
Benefits paid	**(83)**	**(19)**	**(32)**	**(17)**	**(15)**	**(3)**	**(11)**	**(1)**
Employer contributions	**60**	**11**	**26**	**13**	**13**	**2**	**9**	**—**
Plan participants' contributions	**16**	**3**	**6**	**3**	**2**	**1**	**2**	**—**
Plan assets at measurement date	**$ 220**	**$ 130**	**$ (1)**	**$ (1)**	**$ —**	**$ 9**	**$ 5**	**$ 34**
Funded status of plan	**$ (503)**	**$ (45)**	**$ (304)**	**$ (169)**	**$ (135)**	**$ (20)**	**$ (59)**	**$ 4**

	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 losses (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 (reimbursements)	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)

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2019						
	Duke	Duke Energy	Progress	Duke Energy	Duke Energy	Duke Energy	Duke Energy

(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Current post-retirement liability[a]	$ 9	$ —	$ 5	$ 3	$ 2	$ 1	$ —	$ —
Noncurrent post-retirement liability[b]	494	45	299	166	133	19	59	(4)
Total accrued post-retirement liability	$ 503	$ 45	$ 304	$ 169	$ 135	$ 20	$ 59	$ (4)
Regulatory assets	$ 135	$ —	$ 135	$ 82	$ 53	$ —	$ 36	$ —
Regulatory liabilities	$ 149	$ 39	$ —	$ —	$ —	$ 17	$ 63	$ 3
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 3	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(2)	—	—	—	—	—	—	—
Net actuarial gain	(13)	—	—	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive income	$ (12)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	$ 5	$ 3	$ 1	$ —	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	(14)	(4)	(3)	(1)	(2)	(1)	(1)	(2)

	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 (gain) $	4 $	2 $	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 eight years for Duke Energy and Duke Energy Carolinas, seven years for Progress Energy, Duke Energy Florida, and Duke Energy Ohio, and six years for Duke Energy Progress, Duke Energy Indiana, and Piedmont.

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

	December 31,		
	2019	**2018**	**2017**
Benefit Obligations			
Discount rate	**3.30%**	4.30%	3.60%
Net Periodic Benefit Cost			
Discount rate	**4.30%**	3.60%	4.10%
Expected long-term rate of return on plan assets	**6.85%**	6.50%	6.50%
Assumed tax rate	**23%**	35%	35%

Assumed Health Care Cost Trend Rate

	December 31,	
	2019	**2018**
Health care cost trend rate assumed for next year	**6.00%**	6.50%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.75%**	4.75%
Year that rate reaches ultimate trend	**2026**	2024

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	Year Ended December 31, 2019							
(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)	(4)	(4)	(1)	(2)	(1)

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Years ending December 31,								
2020	$ 76	$ 18	$ 29	$ 16	$ 13	$ 4	$ 8	$ 2
2021	70	17	28	15	13	3	7	2
2022	66	16	27	14	12	3	7	2
2023	63	15	25	14	12	3	6	2
2024	59	15	24	13	11	3	6	2
2025-2029	246	60	101	55	46	11	23	11

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. Approximately 98% of the Duke Energy Master Retirement Trust assets were allocated to qualified pension plans and approximately 2% were allocated to other post-retirement plans (comprised of 401(h) accounts), as of December 31, 2019, and 2018. 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, 2019, Duke Energy assumes pension and other post-retirement plan assets will generate a long-term rate of return of 6.85%. 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% liability hedging assets and 42% 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 $351 million and $154 million at December 31, 2019, and 2018, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned at December 31, 2019, and 2018, respectively. Securities lending income earned by the Duke Energy Master Retirement Trust was immaterial for the years ended December 31, 2019, 2018 and 2017, 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, 2019, and the actual asset allocations for the Duke Energy Master Retirement Trust.

	Target Allocation	Actual Allocation at December 31, 2019	2018
U.S. equity securities	—%	**—%**	11%
Global equity securities	28%	**27%**	18%
Global private equity securities	1%	**1%**	2%
Debt securities	58%	**57%**	63%
Return seeking debt securities	4%	**5%**	—%
Hedge funds	3%	**3%**	2%
Real estate and cash	6%	**7%**	2%
Other global securities	—%	**—%**	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, 2019.

	Target Allocation	Actual Allocation at December 31, 2019	2018
U.S. equity securities	33%	**35%**	43%
Non-U.S. equity securities	7%	**9%**	8%
Real estate	2%	**2%**	2%
Debt securities	45%	**37%**	40%
Cash	13%	**17%**	7%
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 17.

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, 2019				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized[b]**
Equity securities	**$ 2,730**	**$ 2,712**	**$ —**	**$ —**	**$ 18**

Corporate debt securities	**3,999**	**—**	**3,999**	**—**	**—**
Short-term investment funds	**545**	**455**	**90**	**—**	**—**
Partnership interests	**104**	**—**	**—**	**—**	**104**
Hedge funds	**206**	**—**	**—**	**—**	**206**
Real estate limited partnerships	**—**	**—**	**—**	**—**	**—**
U.S. government securities	**1,231**	**—**	**1,231**	**—**	**—**
Guaranteed investment contracts	**11**	**—**	**—**	**11**	**—**
Governments bonds – foreign	**78**	**—**	**78**	**—**	**—**
Cash	**75**	**75**	**—**	**—**	**—**
Net pending transactions and other investments	**46**	**(43)**	**89**	**—**	**—**
Total assets[a]	**$ 9,025**	**$ 3,199**	**$ 5,487**	**$ 11**	**$ 328**

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana, and Piedmont were allocated approximately 26%, 31%, 15%, 17%, 5%, 7%, and 4%, respectively, of the Duke Energy Master Retirement Trust at December 31, 2019. 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, 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%, 31%, 15%, 16%, 5%, 7%, and 4%, respectively, of the Duke Energy Master Retirement Trust and Piedmont's Pension assets 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.

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)	2019	2018
Balance at January 1	$ 27	$ 28
Sales	(18)	(1)
Total gains and other, net	2	—
Transfer of Level 3 assets to other classifications	—	—
Balance at December 31	$ 11	$ 27

Other post-retirement assets

The following tables provide the fair value measurement amounts for VEBA trust assets.

	December 31, 2019	
(in millions)	Total Fair Value	Level 2
Cash and cash equivalents	$ 9	$ 9
Real estate	1	1
Equity securities	22	22
Debt securities	18	18
Total assets	$ 50	$ 50

	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

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% of employee before-tax and Roth 401(k) contributions of up to 6% 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% 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% 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
Years ended December 31,								
2019	**$ 214**	**$ 66**	**$ 58**	**$ 38**	**$ 20**	**$ 5**	**$ 11**	**$ 13**
2018	213	68	58	40	19	4	10	12
2017	179	61	53	37	16	3	9	7

24. 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%, 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% 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 Staff Accounting Bulletin (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 was 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. In 2019, Duke Energy received a refund of $573 million related to AMT credit carryforwards based on the filing of Duke Energy's 2018 income tax return in 2019 and reclassified $286 million of AMT credits from noncurrent deferred tax liabilities to a current federal income tax receivable.

Income Tax Expense

Components of Income Tax Expense

	Year Ended December 31, 2019							
(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	$ (299)	$ 164	$ (173)	$ (36)	$ (43)	$ (41)	$ (23)	$ (92)
State	10	13	(7)	(3)	18	(1)	1	(1)
Foreign	2	—	—	—	—	—	—	—
Total current income taxes	(287)	177	(180)	(39)	(25)	(42)	(22)	(93)
Deferred income taxes								
Federal	855	175	422	220	153	77	128	133
State	(38)	(37)	17	(18)	27	5	28	3
Total deferred income taxes[a]	817	138	439	202	180	82	156	136
ITC amortization	(11)	(4)	(6)	(6)	—	—	—	—
Income tax expense from continuing operations	519	311	253	157	155	40	134	43
Tax benefit from discontinued operations	(2)	—	—	—	—	—	—	—
Total income tax expense included in Consolidated	$ 517	$ 311	$ 253	$ 157	$ 155	$ 40	$ 134	$ 43

Statements of Operations

(a) Total deferred income taxes includes the generation of tax credit carryforwards of $8 million at Duke Energy Carolinas. In addition, total deferred income taxes includes utilization of NOL carryforwards and tax credit carryforwards of $243 million at Progress Energy, $35 million at Duke Energy Progress, $152 million at Duke Energy Florida, $25 million at Duke Energy Ohio, $60 million at Duke Energy Indiana, $90 million at Piedmont and $775 million at Duke Energy.

	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)
ITC 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
ITC 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.

Duke Energy Income from Continuing Operations before Income Taxes

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Domestic[a]	**$ 4,053**	$ 3,018	$ 4,207
Foreign	**44**	55	59
Income from continuing operations before income taxes	**$ 4,097**	$ 3,073	$ 4,266

(a) Includes a $16 million expense in 2017 related to the Tax Act impact on equity earnings included within Equity in earnings of unconsolidated affiliates on the Consolidated Statement of Operations.

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, 2019							
(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%	**$ 860**	**$ 360**	**$ 332**	**$ 202**	**$ 178**	**$ 59**	**$ 120**	**$ 51**
State income tax, net of federal income tax effect	**(22)**	**(19)**	**8**	**(17)**	**35**	**3**	**22**	**2**
Amortization of excess deferred income tax	**(121)**	**(29)**	**(64)**	**(10)**	**(54)**	**(12)**	**(6)**	**(10)**
AFUDC equity income	**(52)**	**(9)**	**(14)**	**(13)**	**(1)**	**(3)**	**(3)**	**—**
AFUDC equity depreciation	**34**	**19**	**10**	**5**	**5**	**1**	**4**	**—**
Renewable energy PTCs	**(120)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Other tax credits	**(23)**	**(11)**	**(9)**	**(7)**	**(2)**	**(1)**	**(1)**	**(1)**
Tax true up	**(64)**	**(9)**	**(8)**	**(3)**	**(5)**	**(7)**	**(1)**	**—**
Other items, net	**27**	**9**	**(2)**	**—**	**(1)**	**—**	**(1)**	**1**

Income tax expense from continuing operations	$ 519	$ 311	$ 253	$ 157	$ 155	$ 40	$ 134	$ 43
Effective tax rate	12.7%	18.1%	16.0%	16.3%	18.3%	14.3%	23.5%	17.6%

	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%	$ 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 PTCs	(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 NOLs, 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%	$ 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 PTCs	(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 NOLs, and valuation allowance on foreign tax credits.

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 State income tax, net of federal income tax effect, in the above tables.

Valuation allowances have been established for foreign 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 Tax Act in the above tables.

DEFERRED TAXES

Net Deferred Income Tax Liability Components

	December 31, 2019							
(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	$ 125	$ 24	$ 25	$ 49	$ —	$ 14	$ 5	$ 22
Lease obligations	462	72	193	92	102	5	17	6
Pension, post-retirement and other employee benefits	303	(5)	88	38	44	17	27	(3)
Progress Energy merger purchase accounting adjustments(a)	389	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	3,925	262	486	176	253	16	176	19
Regulatory liabilities and deferred credits	—	—	—	—	—	36	52	42
Investments and other assets	—	—	—	—	—	10	—	2
Other	97	5	8	3	2	8	1	6
Valuation allowance	(587)	—	—	—	—	—	—	—
Total deferred income tax assets	4,714	358	800	358	401	106	278	94

Investments and other assets	(1,664)	(981)	(577)	(390)	(190)	—	(12)	—
Accelerated depreciation rates	(10,813)	(3,254)	(3,798)	(1,918)	(1,913)	(1,028)	(1,416)	(802)
Regulatory assets and deferred debits, net	(1,115)	(44)	(887)	(438)	(477)	—	—	—
Total deferred income tax liabilities	(13,592)	(4,279)	(5,262)	(2,746)	(2,580)	(1,028)	(1,428)	(802)
Net deferred income tax liabilities	$ (8,878)	$ (3,921)	$ (4,462)	$ (2,388)	$ (2,179)	$ (922)	$ (1,150)	$ (708)

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

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

	December 31, 2019	
(in millions)	**Amount**	**Expiration Year**
General Business Credits	$ 1,821	2024 — 2039
AMT credits	286	Refundable by 2021
Federal NOL carryforwards[(a) (f)]	169	2024 — Indefinite
Capital loss carryforward[(e)]	87	2024
State carryforwards and credits[(b) (f)]	303	2020 — Indefinite
Foreign NOL carryforwards[(c)]	12	2027 — 2037
Foreign Tax Credits[(d)]	1,237	2024 — 2027
Charitable contribution carryforwards	10	2020 — 2024
Total tax credits and NOL carryforwards	$ 3,925	

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 $97 million has been recorded on the state NOL and credit 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 $387 million has been recorded on the foreign tax credits, as presented in the Net Deferred Income Tax Liability Components table.

(e) A valuation allowance of $87 million has been recorded on the Federal capital loss carryforward, as presented in the Net Deferred Income Tax Liability Components table.

(f) 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, 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
Finance 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 finance lease obligations and debt fair value adjustments.

UNRECOGNIZED TAX BENEFITS

The following tables present changes to unrecognized tax benefits.

	Year Ended December 31, 2019							
(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	**$ 24**	**$ 6**	**$ 9**	**$ 6**	**$ 3**	**$ 1**	**$ 1**	**$ 4**
Unrecognized tax benefit increases	**105**	**2**	**1**	**1**	**—**	**—**	**—**	**—**
Gross decreases – tax positions in prior periods	**(3)**	**—**	**(1)**	**(1)**	**—**	**—**	**—**	**—**
Total changes	**102**	**2**	**—**	**—**	**—**	**—**	**—**	**—**
Unrecognized tax benefits – December 31	**$ 126**	**$ 8**	**$ 9**	**$ 6**	**$ 3**	**$ 1**	**$ 1**	**$ 4**

	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 – tax positions in prior periods	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

The following table includes additional information regarding the Duke Energy Registrants' unrecognized tax benefits at December 31, 2019. It is reasonably possible that Duke Energy will reflect a $3 million decrease in unrecognized tax benefits within the next 12 months.

	December 31, 2019							
(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]	$ 122	$ 8	$ 9	$ 6	$ 3	$ 1	$ 1	$ 4

(a) The Duke Energy Registrants 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, 2019			
(in millions)	Duke Energy	Progress Energy	Duke Energy Progress	Piedmont
Net interest income recognized related to income taxes	$ 16	$ 1	$ 1	$ —
Interest receivable related to income taxes	1	—	—	—
Interest payable related to income taxes	1	—	—	1

	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	—

Duke Energy and its subsidiaries are no longer subject to U.S. federal examination for years before 2016. 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 2016.

25. 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, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Interest income	$ 31	$ 1	$ 11	$ —	$ 11	$ 10	$ 10	$ 1
AFUDC equity	139	42	66	60	6	13	18	—
Post in-service equity returns	29	20	7	7	—	1	—	—
Nonoperating income, other	231	88	57	33	31	—	13	19
Other income and expense, net	$ 430	$ 151	$ 141	$ 100	$ 48	$ 24	$ 41	$ 20

	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)

26. SUBSEQUENT EVENTS

For information on subsequent events related to the adoption of the new credit losses accounting standard, regulatory matters and debt and credit facilities, see Notes 1, 4 and 7, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1		(180,809)	(180,809)		
2		31,539	31,539		
3					
4		31,539	31,539	667,036,191	667,067,730
5		(149,270)	(149,270)		
6		(149,270)	(149,270)		
7	(51,014)	31,536	(19,478)		
8					
9	(51,014)	31,536	(19,478)	804,658,910	804,639,432
10	(51,014)	(117,734)	(168,748)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	26,658,157,550	26,658,157,550
4	Property Under Capital Leases	694,752,950	694,752,950
5	Plant Purchased or Sold		
6	Completed Construction not Classified	5,758,937,894	5,758,937,894
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	33,111,848,394	33,111,848,394
9	Leased to Others		
10	Held for Future Use	56,900,984	56,900,984
11	Construction Work in Progress	1,100,726,367	1,100,726,367
12	Acquisition Adjustments	349,801,943	349,801,943
13	Total Utility Plant (8 thru 12)	34,619,277,688	34,619,277,688
14	Accum Prov for Depr, Amort, & Depl	12,950,921,387	12,950,921,387
15	Net Utility Plant (13 less 14)	21,668,356,301	21,668,356,301
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	12,516,278,858	12,516,278,858
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	378,291,457	378,291,457
22	Total In Service (18 thru 21)	12,894,570,315	12,894,570,315
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	56,351,072	56,351,072
33	Total Accum Prov (equals 14) (22,26,30,31,32)	12,950,921,387	12,950,921,387

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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FOOTNOTE DATA

Schedule Page: 200 Line No.: 4 Column: c

Property Under Capital Leases includes Capital and Operating Leases. Net Capital Leases of $307,912,470 and Net Operating Leases of $386,840,479.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	24,394,578	35,534,037
3	Nuclear Materials	284,850,224	66,484,245
4	Allowance for Funds Used during Construction	15,881,884	8,523,028
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	325,126,686	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		152,920,515
9	In Reactor (120.3)	819,511,288	152,920,514
10	SUBTOTAL (Total 8 & 9)	819,511,288	
11	Spent Nuclear Fuel (120.4)	417,494,987	189,815,304
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	860,218,709	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	701,914,252	
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)		

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
	33,704,107	26,224,508	2
	111,742,776	239,591,693	3
	7,473,632	16,931,280	4
			5
		282,747,481	6
			7
	152,920,515		8
	189,815,304	782,616,498	9
		782,616,498	10
	310,762,590	296,547,701	11
			12
-177,895,205	312,701,407	725,412,507	13
		636,499,173	14
			15
			16
			17
			18
			19
			20
			21
			22

FOOTNOTE DATA

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 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 $310,762,590 of nuclear fuel assemblies retired from the reactor and $1,938,817 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	04/14/2020	End of 2019/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	717,237	
3	(302) Franchises and Consents	59,871,453	
4	(303) Miscellaneous Intangible Plant	466,781,700	98,273,139
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	527,370,390	98,273,139
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	32,663,725	
9	(311) Structures and Improvements	529,232,044	155,827,999
10	(312) Boiler Plant Equipment	2,749,086,829	142,547,854
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	376,051,043	1,893,155
13	(315) Accessory Electric Equipment	256,892,645	2,595,690
14	(316) Misc. Power Plant Equipment	67,934,703	2,215,248
15	(317) Asset Retirement Costs for Steam Production	827,197,089	607,027,086
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,839,058,078	912,107,032
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	68,358,438	328,499
19	(321) Structures and Improvements	3,086,886,142	92,188,370
20	(322) Reactor Plant Equipment	2,562,500,516	228,171,470
21	(323) Turbogenerator Units	1,326,899,045	103,495,557
22	(324) Accessory Electric Equipment	1,214,660,974	61,642,537
23	(325) Misc. Power Plant Equipment	651,865,769	32,506,877
24	(326) Asset Retirement Costs for Nuclear Production	876,137,782	698,852,568
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	9,787,308,666	1,217,185,878
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	2,828,917	
28	(331) Structures and Improvements	18,495,631	1,165,602
29	(332) Reservoirs, Dams, and Waterways	53,686,539	222,585
30	(333) Water Wheels, Turbines, and Generators	38,076,118	7,944,058
31	(334) Accessory Electric Equipment	25,819,454	933,476
32	(335) Misc. Power PLant Equipment	5,011,373	-105,246
33	(336) Roads, Railroads, and Bridges	21,205	
34	(337) Asset Retirement Costs for Hydraulic Production	1,734,118	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	145,673,355	10,160,475
36	D. Other Production Plant		
37	(340) Land and Land Rights	10,002,051	
38	(341) Structures and Improvements	319,136,806	122,041,943
39	(342) Fuel Holders, Products, and Accessories	123,941,092	180,581,209
40	(343) Prime Movers	1,939,465,328	210,700,998
41	(344) Generators	474,749,462	197,734,020
42	(345) Accessory Electric Equipment	324,145,151	38,479,640
43	(346) Misc. Power Plant Equipment	51,330,695	8,202,446
44	(347) Asset Retirement Costs for Other Production	7,642,435	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,250,413,020	757,740,256
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	18,022,453,119	2,897,193,641

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	190,816,035	236,317
49	(352) Structures and Improvements	108,528,777	50,995,600
50	(353) Station Equipment	1,070,174,832	102,265,520
51	(354) Towers and Fixtures	78,936,364	-13,185,745
52	(355) Poles and Fixtures	743,280,241	29,948,090
53	(356) Overhead Conductors and Devices	551,039,389	73,697,892
54	(357) Underground Conduit	32,286	226,197
55	(358) Underground Conductors and Devices	21,603,999	19,813
56	(359) Roads and Trails	312,523	511,812
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,764,724,446	244,715,496
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	75,495,426	3,048,116
61	(361) Structures and Improvements	127,079,158	4,953,915
62	(362) Station Equipment	683,055,386	63,551,913
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	855,785,431	63,604,207
65	(365) Overhead Conductors and Devices	1,208,423,459	106,320,478
66	(366) Underground Conduit	199,779,067	12,654,245
67	(367) Underground Conductors and Devices	1,134,635,171	121,787,612
68	(368) Line Transformers	1,131,254,323	70,419,836
69	(369) Services	681,775,180	38,240,480
70	(370) Meters	264,117,460	102,466,417
71	(371) Installations on Customer Premises	318,551,648	39,033,923
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	264,812,433	35,046,625
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,944,764,142	661,127,767
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	8,148,088	1
87	(390) Structures and Improvements	166,805,835	13,374,942
88	(391) Office Furniture and Equipment	86,307,055	14,882,375
89	(392) Transportation Equipment	69,975,817	61,626
90	(393) Stores Equipment	2,059,933	52,396
91	(394) Tools, Shop and Garage Equipment	90,247,660	4,861,074
92	(395) Laboratory Equipment	6,739,788	1
93	(396) Power Operated Equipment	5,679,687	1,698,648
94	(397) Communication Equipment	179,971,820	46,900,813
95	(398) Miscellaneous Equipment	23,040,258	1,192,526
96	SUBTOTAL (Enter Total of lines 86 thru 95)	638,975,941	83,024,402
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)	641,693,529	83,024,402
100	TOTAL (Accounts 101 and 106)	28,901,005,626	3,984,334,445
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)	28,901,005,626	3,984,334,445

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
148			717,089		2
			59,871,453		3
-2,722,006			567,776,845		4
-2,721,858			628,365,387		5
					6
					7
78,062			32,585,663		8
3,388,023			681,672,020		9
2,518,560			2,889,116,123		10
					11
2,133,999			375,810,199		12
-604,142			260,092,477		13
-230,773			70,380,724		14
-188,609,146			1,622,833,321		15
-181,325,417			5,932,490,527		16
					17
43,690			68,643,247		18
18,398,516	-1,854,279		3,158,821,717		19
83,959,484			2,706,712,502		20
21,109,181			1,409,285,421		21
5,685,743			1,270,617,768		22
133,035			684,239,611		23
			1,574,990,350		24
129,329,649	-1,854,279		10,873,310,616		25
					26
			2,828,917		27
-9,111			19,670,344		28
380,741			53,528,383		29
1,358,297			44,661,879		30
-944,076			27,697,006		31
-97,738			5,003,865		32
			21,205		33
	1		1,734,119		34
688,113	1		155,145,718		35
					36
			10,002,051		37
1,232,524	-105,999,098	-74,593	333,872,534		38
-4,794,824	105,137,210	-9,351	414,444,984		39
55,154,376		149,859	2,095,161,809		40
100,169		-8,395	672,374,918		41
4,224,288		-52,417	358,348,086		42
-576,775		-5,104	60,104,812		43
	3		7,642,438		44
55,339,758	-861,885	-1	3,951,951,632		45
4,032,103	-2,716,163	-1	20,912,898,493		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	04/14/2020	End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
-176,901			191,229,253		48
1,120,951	-34,546	-68,003	158,300,877		49
12,441,767		-2,808,358	1,157,190,227		50
100,500			65,650,119		51
1,762,636		-28,018	771,437,677		52
763,050		-40,139	623,934,092		53
-814			259,297		54
			21,623,812		55
			824,335		56
					57
16,011,189	-34,546	-2,944,518	2,990,449,689		58
					59
75,609			78,467,933		60
1,057,259		1,131,948	132,107,762		61
15,721,768		7,230,861	738,116,392		62
					63
9,236,140		28,018	910,181,516		64
14,541,361		578,432	1,300,781,008		65
14,468			212,418,844		66
5,821,480			1,250,601,303		67
11,623,597			1,190,050,562		68
226,191			719,789,469		69
55,849,165			310,734,712		70
2,692,073			354,893,498		71
					72
658,840			299,200,218		73
					74
117,517,951		8,969,259	7,497,343,217		75
					76
					77
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					81
					82
					83
					84
					85
282,389			7,865,700		86
6,359,918	1,824,653	-1,063,945	174,581,567		87
2,520,381			98,669,049		88
6,878,412			63,159,031		89
238,253			1,874,076		90
1,575,387			93,533,347		91
814,503			5,925,286		92
			7,378,335		93
1,168,947		-4,960,797	220,742,889		94
4,728,523			19,504,261		95
24,566,713	1,824,653	-6,024,742	693,233,541		96
					97
			2,717,588		98
24,566,713	1,824,653	-6,024,742	695,951,129		99
159,406,098	-926,056	-2	32,725,007,915		100
					101
					102
					103
159,406,098	-926,056	-2	32,725,007,915		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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					
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6					
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41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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 BROAD STREET 115KV SUBSTATION - WAKE COUNTY	02/2017	2025	1,968,531
8	GARNER EAST 230KV SUBSTATION - WAKE COUNTY	05/2011	2023	3,610,841
9	MAYO FOSSIL - ASH POND - PERSON COUNTY	03/1983	2020	1,458,908
10	MCDOWELL STREET SUBSTATION - BUNCOMBE COUNTY	06/2016	2020	2,305,226
11	WEATHERSPOON IC - FUTURE GEN - ROBESON COUNTY	07/2008	2021	633,647
12	CARVER STREET SUBSTATION - BUNCOMBE COUNTY	04/2018	2020	5,301,322
13	VOLVO DEALERSHIP FUTURE USE - BUNCOMBE COUNTY	12/2016	2021	16,444,917
14	GRANTS CREEK 230KV SUBSTATION	11/2016	2020	380,580
15	LINDEN 230/24 KV SUBSTATION LAND - HARNETT COUNTY	02/2017	2021	378,334
16	HARLOWE 230KV SUBSTATION - CARTERET COUNTY	05/2016	2020	477,595
17	ASHEVILLE FLAT CREEK 115KV SUBSTATION	02/2017	2020	963,966
18	KENLY 115KV SUBSTATION - JOHNSTON COUNTY	06/2011	2025	416,389
19	NEWPORT 230KV SWITCHING STATION - CRAVEN COUNTY	09/2017	2020	594,896
20	GREEN LEVEL 115KV - WAKE COUNTY	08/2018	2021	10,008,455
21	Other Property:			
22	Land and Land Rights (continued):			
23	ASHEVILLE PATTON SUBSTATION - BUNCOMBE COUNTY	10/2018	2024	1,267,446
24	CHATHAM PARK SUBSTATION - CHATHAM COUNTY	11/2016	2020	1,043,619
25	HARMON 230KV SUBSTATION - ONSLOW COUNTY	08/2016	2020	991,126
26	Other Land and Land Rights < $250K (29 Items)			1,196,851
27	Other Property:			
28	Other Property <$250K (3 Items)			1,421
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44				
45				
46				
47	Total			56,900,984

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	25,831,415
4	DISTRIBUTION LIGHTING INSTALLATION	8,866,153
5	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - SOUTH CAROLINA	6,183,389
6	RUSD ASHEVILLE PATTON SUBSTATION	6,095,394
7	PEACE & WEST ST. - SMOKEY HOLLOW DEVELOPMENT	5,444,566
8	CEDAR ISLAND POD	4,786,222
9	SCOTTS HILL - ADD 2ND FEEDER BANK	4,326,966
10	WILMINGTON OGDEN CAPACITY PLANNING	3,932,906
11	HOPE MILLS - CONSTRUCT BANK #2	3,874,378
12	ANGIER - ADD BANK #2	3,485,474
13	BYNUM 230 KV #2 - ADD 3RD FEEDER CIRCUIT BREAKER	3,235,626
14	CARY EVANS ROAD 230KV BANK 2	2,747,641
15	LINDEN 230 KV - CONSTRUCT SUB	2,721,529
16	PORTERS NECK 230KV - CONSTRUCT SUB	2,405,095
17	HIGHWAY 87 NORTH - FEEDER RELIEF	2,379,104
18	NON LOAD GROWTH - HIGHWAY 133 TO BOILING SPRINGS	2,343,382
19	GOLDSBORO LANGSTON - INCREASE CAPACITY	2,259,277
20	REEMS CREEK - SUBSTATION SITE PURCHASE	2,240,696
21	ROCKY POINT 230 KV - FEEDER ANALYSIS	2,203,638
22	SYSTEM IMPROVEMENT TYPE A WORK - CHERAW CITY	2,188,578
23	HAVELOCK 230 KV 4TH FEEDER	2,186,545
24	WILMINGTON ELEMENTIS SUBSTATION	2,104,835
25	CLEVELAND MATTHEWS ROAD SUBSTATION	1,979,981
26	RIEGELWOOD TRANSFORMER BANK	1,934,378
27	FLORENCE MARS BLUFF SUBSTATION	1,925,231
28	DISTRIBUTION OIL BREAKER	1,903,656
29	GRIFTON 115V - FLOOD SUBSTATION	1,844,835
30	DOWNTOWN RALEIGH DISTRIBUTION AUTOMATION	1,714,607
31	INTERNATIONAL CAPITAL PROJECT	1,569,061
32	BALD HEAD ISLAND IMPROVEMENTS	1,414,747
33	TWIN HARBOR PHASE 3 AND 4	1,360,999
34	SMART GRID DEP - FEEDER CAPACITY	1,320,604
35	SMARTGRID DEP TRANSFORMER RETROFIT	1,297,983
36	SMARTGRID DEP TARGETED OVERHEAD/UNDERGROUND CONVERSION	1,218,880
37	SMART GRID - RETAIL CAPACITY LINES	1,193,454
38	SMARTGRID DEP CABLE	1,118,521
39	DEP LONG DURATION OUTAGES	1,097,067
40	DEP HIGH IMPACT SITES	1,034,997
41	OTEEN 115KV - UPRATE CURRENT TRANSFORMER RATIO AT WEST ASHEVILLE	1,025,958
42	MADISON COUNTY - DEP HOT SPRING MICROGRID	1,006,563
43	TOTAL	1,100,726,367

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	PROJECTS LESS THAN $1 MILLION	39,389,058
2	TOTAL DISTRIBUTION PLANT $167,193,389	
3		
4	GENERAL PLANT	
5		
6	CENTRAL ABERDEEN CONSOLIDATION	26,168,249
7	CUSTOMER CONNECT FUNDING PROJECT	22,746,602
8	ESO CONTROL CENTER FACILITIES - CAROLINAS EAST	12,314,134
9	SYSTEM - NERC CIP LOW IMPACT SECURITY	9,482,559
10	PANASONIC UNITS - CAROLINAS EAST	7,993,495
11	FUNDING PROJECT FOR IT DEMAND	4,720,207
12	GENERIC CAPITAL COSTS	3,613,223
13	FUNDING PROJECT 2019 TELECOM MICROWAVE, RADIO, TRANSPORT & POWER	3,556,915
14	MICROWAVE PROJECTS - CAROLINAS EAST	2,741,734
15	TELECOM PROJECTS FOR POWER DELIVERY CAROLINA EAST - ELECTRIC	2,635,870
16	PROGRESS ENERGY CAROLINAS ACCRUAL	2,120,110
17	CARY-LINE & SERVICE BUILDING	2,014,665
18	REAL ESTATE PE CUSTOMER FUNDING	1,964,049
19	SMART GRID - DUKE ENERGY ENTERPRISE DISTRIBUTED MANAGEMENT SYSTEM ADMS	1,845,947
20	DEP STRATEGIC COMMUNICATION	1,845,158
21	DEP TOWERS, SHELTERS, & POWER SUPPLIES	1,267,096
22	DEF GRIDWAN	1,248,467
23	DEP MICROWAVE	1,222,827
24	DUKE ENERGY ENTERPRISE LAND MOBILE RADIO	1,162,596
25	DEP GRIDWAN CORE ROUTER UPFIT	1,072,023
26	PROJECTS LESS THAN $1 MILLION	4,107,056
27	TOTAL GENERAL PLANT $115,842,982	
28		
29	INTANGIBLE PLANT	
30		
31	CUSTOMER CONNECT FUNDING PROJECT	10,339,245
32	ARCOS SYSTEM OUTAGE STAFFING PROJECT	2,374,877
33	IT FUNDING PROJECT 50126	2,076,556
34	HARRIS NUCLEAR PLANT - FATIGUEPRO METAL MONITORING	1,305,522
35	SMART GRID - DUKE ENERGY ENTERPRISE DISTRIBUTED MANAGEMENT SYSTEM ADMS	1,284,303
36	DUKE ENERGY ENTERPRISE ADVNCED DISTRIBUTION PLANNING TOOL	1,283,588
37	SMART GRID - DUKE ENERGY ENTERPRISE SECURE ACCESS AND DEVICE MAN	1,084,738
38	PROJECTS LESS THAN $1 MILLION	7,442,374
39	TOTAL INTANGIBLE PLANT $27,191,203	
40		
41	PRODUCTION PLANT	
42		
43	TOTAL	1,100,726,367

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	ASHEVILLE COMBINED CYCLE	261,407,880
2	OPTIM CT HGP ROTOR EOL 6	26,546,907
3	BRUNSWICK UNIT 1 ALT DECAY PRI HEAT	22,589,909
4	BLEWETT HYDROELECTRIC FISH PASSAGE	13,984,631
5	HARRIS PERIMETER INTRUSION DETECTION	13,519,797
6	BRUNSWICK HSM PURCHASE	11,794,906
7	BRUNSWICK UNIT 2 PPC/ERFIS SOFTWARE	11,281,008
8	DARLINGTON - U13 HOT GAS PATH INSPECTION	9,495,165
9	SAFETY RELATED BATTERY CHARGERS	8,788,529
10	BRUNSWICK EMERGENCY WASTE PROCESSING SKID	7,555,294
11	BLEWETT FERC INSPECTION FOLLOW-UP ACTIVITIES	7,226,009
12	HF LEE ASH BENE ROADS & BRIDGES	7,009,563
13	EARLY WARNING & ASSESSMENT SYSTEM	6,454,648
14	SAFETY RELATED CHILLERS	6,022,105
15	ROXBORO DRY FLY ASH SYSTEM	5,667,178
16	ROBINSON PHASE IV DRY STORAGE	5,287,660
17	BRUNSWICK UNIT 1 START UP AUXILIARY TRANSFROMER	4,830,277
18	BRUNSWICK PERIMETER INTRUSION DETECTION	4,592,774
19	BRUNSWICK SERVICE WATER PUMP	4,004,633
20	BRUNSWICK NUCLEAR COMMON - FUNDING PROJECT FOR IT1800038 BUSINESS UNIT 50125	3,867,766
21	BRUNSWICK UNIT 2 TRAVEL SCREEN INSTRUMENT IMPROVEMENT	3,809,006
22	HARRIS FIRE DETECTION SYSTEM	3,768,706
23	BRUNSWICK UNIT 1 TRAVEL SCREEN INSTRUMENT IMPROVEMENT	3,646,140
24	HARRIS HEATER DRAIN SYSTEM TO DCS	3,559,321
25	BRUNSWICK NUCLEAR PLANT NORTH END ACCESS ROAD	3,282,274
26	BRUNSWICK UNIT 2 TURBINE CRANE	3,082,428
27	ALERT & NOTIFICATION SYSTEMS	2,988,916
28	SECURITY BREACHES AND DEFENSIVE POSITIONS	2,966,319
29	HARRIS PLANT PROCESS COMPUTER	2,939,837
30	ROBINSON PLANT PROCESS COMPUTERS	2,821,968
31	BRUNSWICK UNIT 1 FEEDWATER HEATER	2,742,196
32	ROBINSON CONDENSATE POLISHING DCS	2,674,089
33	BRUNSWICK NUCLEAR PLANT CASEWELL BEACH FEEDER	2,673,809
34	BRUNSWICK UNIT 2 MOISTURE SEPARATER REHEATER	2,617,998
35	BRUNSWICK NUCLEAR PLANT - UNIT 2 START UP AUXILIARY TRANSFORMER	2,532,009
36	LEACHATE & FLUE GAS DESULFURIZATION BASIN TREATMENT SYSTEM	2,518,731
37	BRUNSWICK UNIT 1 CW PUMP	2,409,448
38	BRUNSWICK NUCLEAR PLANT 2020 UNIT1 SERVICE REBUILD	2,406,721
39	ROXBORO UNIT 2 DISTRIBUTED CONTROL SYSTEM EVERGREEN AND IO HARDWARE	2,223,860
40	BRUNSWICK NUCLEAR PLANT - STATION BATTERIES	2,181,710
41	TILLERY HYDROELECTRIC - PH CRANE TROLLEY	2,040,328
42	ROBINSON UNDER VESSEL INSULATION	2,040,161
43	TOTAL	1,100,726,367

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	WALTERS HYDROELECTRIC UNIT 2 - WICKET GATE AND WEAR PLATE	1,845,347
2	BRUNSWICK ISFSI BANKING IMPROVEMENTS	1,783,112
3	ROBINSON NUCLEAR-REWIND SPARE RCP MOTOR	1,690,351
4	SECURE OWNER CONTROLLED AREA	1,550,184
5	ROBINSON UNIT 2 MAKE-UP WATER TREATMENT DCS	1,478,339
6	FIRE DETECTION SYSTEM	1,400,432
7	BRUNSWICK UNIT 1 REMOTE ELECTRIC LIFT & TRAVERSING CRANE	1,323,596
8	PROCESS SAFETY MANAGEMENT MAYO - AMMONIA CONVERSION	1,309,221
9	ROBINSON PENETRATION D-5 TEMP POWER	1,169,337
10	BRUNSWICK UNIT 2 REMOTE ELECTRIC LIFT & TRAVERSING CRANE	1,140,613
11	MADISON COUNTY - LOWER TURBINE BEARING	1,099,608
12	WAYNE COUNTY - CIRCULATING WATER BLEACH INJECTION	1,099,443
13	ROBINSON NUCLEAR PLANT - SPENT FUEL BUILDING WIRE ROPE/SHEAVE	1,063,318
14	BRUNSWICK UNIT 2 5A AND 5B FEEDWATER HEATER ACCESS PLUGS	1,030,991
15	BRUNSWICK NUCLEAR PLANT UNIT #1 RECRIC PUMP SEAL	1,001,096
16	PROJECTS LESS THAN $1 MILLION	49,407,256
17	TOTAL PRODUCTION PLANT $573,244,858	
18		
19	TRANSMISSION PLANT	
20		
21	ASHEVILLE COMBINED CYCLE	53,709,491
22	WALLACE 230KV - PERMENANT/TEMPORARY	43,338,431
23	GRANTS CREEK SUB-CONSTRUCT NEW SUBSTATION AND TAPS	21,766,580
24	WEATHERSPOON TO REAFORD LINES	20,363,481
25	CANTON-PISGAH FOREST-EXPAND ROW	9,667,194
26	CLEVELAND MATTHEWS ROAD SUBSTATION	7,143,739
27	SUTTON PLANT TO CASTLE HAYNE LINES	5,426,832
28	BLEWETT FALLS PLANT - ROCKINGHAM 115KV LINE	5,281,002
29	JACKSONVILLE-WOMMACK 115 - SWITCH 243	3,858,530
30	SYSTEM PROGRAM - CAPACITOR COUPLED VOLTAGE TRANSFORMERS	3,855,534
31	ASHEBORO TO ASHEBORO EAST LINES	2,651,188
32	JACKSONVILLE - ADD REDUNDANT	2,642,965
33	FAYETTEVILLE 230KV - ADD REDUNDANT	2,552,129
34	FLORENCE 230KV - ADD REDUNDANT BUS PROTECTION	2,513,348
35	FRIESIAN SOLAR Q380	2,354,720
36	CAPE FEAR TO SILER CITY LINES	2,319,650
37	FLORENCE MARION LINE CONSTRUCTION	1,872,802
38	NEWPORT TO HARLOWE - NEW LINES	1,641,279
39	OTEEN TO WEST ASHEVILLE LINES	1,562,513
40	VEGETATION MASTER PROJECT	1,126,972
41	PROJECTS LESS THAN $1 MILLION	21,605,555
42	TOTAL TRANSMISSION PLANT $217,253,935	
43	TOTAL	1,100,726,367

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	11,931,482,059	11,931,482,059		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	825,101,906	825,101,906		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	6,566,064	6,566,064		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-16,483,253	-16,483,253		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	815,184,717	815,184,717		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	161,711,932	161,711,932		
13	Cost of Removal	127,123,591	127,123,591		
14	Salvage (Credit)	41,940,978	41,940,978		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	246,894,545	246,894,545		
16	Other Debit or Cr. Items (Describe, details in footnote):	16,506,627	16,506,627		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	12,516,278,858	12,516,278,858		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,631,598,132	2,631,598,132		
21	Nuclear Production	4,807,149,852	4,807,149,852		
22	Hydraulic Production-Conventional	48,868,587	48,868,587		
23	Hydraulic Production-Pumped Storage				
24	Other Production	783,347,806	783,347,806		
25	Transmission	842,971,251	842,971,251		
26	Distribution	3,224,680,352	3,224,680,352		
27	Regional Transmission and Market Operation				
28	General	177,662,878	177,662,878		
29	TOTAL (Enter Total of lines 20 thru 28)	12,516,278,858	12,516,278,858		

FOOTNOTE DATA

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

ARO Depreciation Expense 108/182	$(4,128,727)
Storm Costs	2,155,343
SmartGrid Deferrals	382,131
Wayne and Sutton Depreciation	(682,488)
Transmission Expansion Projects Impairment Amortization	294,620
Rotable Fleet Spare Reg Liability AmoritizationSC Rate Case Impact Deferrals	124,995
SC Rate Case Impact Deferrals	1,301,065
Reserve transfer of Externally Funded Decontaminated Decommissioning Expense	(22,317,023)
ABSAT (Coal Ash) Assets Deferrals	5,890,396
AMI Meter Deferral	496,436
	$(16,483,253)

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

Intangible Retirements booked to reserve accounts 0111XXX	$2,721,858
Vehicle Gain/Loss	(416,024)
Total Variance between 219 & 204-207	$2,305,834

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

Wholesale Impairment Adjustment	$(434,107)
NC/SC Meter NBV Adjustment for Early Retirement	12,462,867
Net Gains on disposal of property	(40,460)
Non-AMI Meter NBV True-up	(833,995)
Meter Retirements to Reg Asset	8,020,334
ARO COR/Salvage	(2,668,012)
	$16,506,627

Schedule Page: 219 Line No.: 29 Column: c

Balance includes Capital Lease Amortization

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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			-8,108
4	Subtotal Capitan Corporation			3,079
5				
6	CaroFund, Inc.	8/15/1995		
7	Common Stock / Equity Contribution			1,678,508
8	Undistributed Earnings			838,617
9	Subtotal CaroFund, Inc.			2,517,125
10				
11	CaroHome, LLC	4/21/1995		
12	Common Stock / Equity Contribution			69,674,735
13	Undistributed Earnings			-44,981,435
14	Subtotal CaroHome, LLC			24,693,300
15				
16	Powerhouse Square, LLC	1/16/1998		
17	Common Stock / Equity Contribution			3,054,401
18	Undistributed Earnings			-2,541,362
19	Subtotal Powerhouse Square, LLC			513,039
20				
21	Duke Energy Progress Receivables, LLC	10/16/2013		
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	27,726,543

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
		-8,108		3
		3,079		4
				5
				6
		1,678,508		7
-3,324		835,293		8
-3,324		2,513,801		9
				10
				11
		69,674,735		12
-115,970		-45,097,405		13
-115,970		24,577,330		14
				15
				16
		3,054,401		17
		-2,541,362		18
		513,039		19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
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-119,294		27,607,249		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	220,024,307	247,793,012	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)	443,265,405	467,767,605	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	233,460,148	170,990,819	Generation
8	Transmission Plant (Estimated)	6,512,715	4,460,942	Transmission
9	Distribution Plant (Estimated)	17,370,949	14,102,254	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)	700,609,217	657,321,620	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	182,270	138,983	Customer Service
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	33,384,627	28,793,359	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	954,200,421	934,046,974	

FOOTNOTE DATA

Schedule Page: 227 Line No.: 5 Column: b

Assigned to Construction 2018:

Production	$354,813,509
Transmission	24,921,370
Distribution	63,530,526
Total	$443,265,405

Schedule Page: 227 Line No.: 5 Column: c

Assigned to Construction 2019:

Production	$380,095,201
Transmission	22,998,622
Distribution	64,673,782
Total	$467,767,605

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	911,349.00	2,254,148	130,958.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,666.00		15,635.00	
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	13,182.00	19,339		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Other Transfer	93.00			
23					
24					
25					
26					
27					
28	Total	93.00			
29	Balance-End of Year	899,740.00	2,234,809	146,593.00	
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)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
130,958.00		146,593.00		3,389,273.00		4,709,131.00	2,254,148	1
								2
								3
15,635.00				162,222.00		195,158.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						13,182.00	19,339	18
								19
								20
								21
						93.00		22
								23
								24
								25
								26
								27
						93.00		28
146,593.00		146,593.00		3,551,495.00		4,891,014.00	2,234,809	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
								44
								45
								46

FOOTNOTE DATA

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 $38,886,517 for renewable energy credits consumption expense represented in account 0509213

Schedule Page: 228 Line No.: 22 Column: b

Transfer of 93 allowances to Joint Owner

Schedule Page: 228 Line No.: 29 Column: b

Ending balance includes allowances for Cross State Air Pollution Rule and the Acid Rain program

Schedule Page: 228 Line No.: 29 Column: m

Does not include the $117,768,953 for renewable energy credits represented in account 0158120

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

Represents allowances withheld in 2019 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	04/14/2020	End of 2019/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)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	36,284.00		11,714.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,309.00			
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	8,313.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Other Transfers	72.00			
23	Other Sales	2,579.00			
24					
25					
26					
27					
28	Total	2,651.00			
29	Balance-End of Year	26,629.00		11,714.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		500		
34	Gains		500		
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
11,714.00		11,714.00				71,426.00		1
								2
								3
				11,710.00		13,019.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						8,313.00		18
								19
								20
								21
						72.00		22
						2,579.00		23
								24
								25
								26
								27
						2,651.00		28
11,714.00		11,714.00		11,710.00		73,481.00		29
								30
								31
								32
							500	33
							500	34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

FOOTNOTE DATA

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 $38,886,517 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 $117,768,953 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
Commonwealth Chesapeake	100	$0	$500

Schedule Page: 229 Line No.: 34 Column: c

Counterparty	Quantity	Cost of Goods Sold	Total Sales Price
Commonwealth Chesapeake	100	$0	$500

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Not Applicable					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Auth 7/14/1987					
22	Mayo Unit 2 WS, 07/88 to 08/23	34,309,199		407	70,766	259,476
23	Auth 6/19/1992					
24	Rob Nuc Des, 02/95 to 07/30	13,982,544		407	173,971	1,841,188
25	Bruns Nuc Des, 02/95 to 08/36	35,107,437		407	547,327	9,122,123
26	Auth 12/22/2014, Amor begun 01/14					
27	Cape Fear Fsl Ret, 10 yr	31,812,177		407	2,296,064	5,158,245
28	Cape Fear Fsl WS, 10-18 yr	9,694,680		407	642,390	6,228,199
29	Lee Fsl Ret, 10 yr	43,124,374	-50,251	407	2,943,086	6,765,025
30	Lee Fsl WS, 23-31 yr	10,603,827	-21,384	407	348,766	7,677,031
31	Rob Fsl Ret, 10 yr	47,168,423		407	6,440,284	16,195,905
32	Rob Fsl WS, 27 yr	14,636,691		407	553,700	11,903,031
33	Sutton Fsl Ret,10 yr	53,201,007	119,009	407	5,898,109	13,891,690
34	Sutton Fsl WS,10-27 yr	16,842,757	50,643	407	981,296	12,194,792
35	Weatherspoon Fsl Ret,10 yr	12,045,699		407	594,121	1,041,420
36	Weatherspoon Fsl WS, 22-28 yr	3,327,925		407	128,146	2,292,623
37	Cape Fear CT Ret, 10 yr	-661,277		407	78,228	-674,041
38	Cape Fear CT WS, 10 yr	-211,739		407	-27,690	-110,758
39	Lee CT Ret, 10 yr	1,359,740		407	309,540	549,685
40	Lee CT WS, 10 yr	435,384		407	92,701	370,803
41	Morehead CT Ret, 10 yr	-157,519		407	8,089	-100,441
42	Morehead CT WS, 10 yr	-50,437		407	-350	-1,399
43	Auth 3/31/2017					
44	Harris Nuc NC Ret, 03/18 to 03/26	34,542,645		407/421	4,317,831	26,806,530
45	Harris Nuc SC Ret, 06/19 to 05/27		6,087,363	407/421	443,870	5,643,491
46	Harris Nuc WS, 11/16 to 04/29	7,365,795		407/421	575,441	5,370,779
47						
48						
49	TOTAL	368,479,332	6,185,380		27,415,686	132,425,397

FOOTNOTE DATA

Schedule Page: 230 Line No.: 21 Column: a

Pg. 230b Column (a)
Abbreviations Used:

Auth - Authorized
WS - Wholesale
Rob - Robinson
Nuc - Nuclear
Des - Design
Bruns - Brunswick
Fsl - Fossil
Ret - Retail
CT - Combustion Turbine

Schedule Page: 230 Line No.: 27 Column: b

The amounts in column (b) lines 27 - 42 include 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	04/14/2020	End of 2019/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	PGSISQ331 - Infigen Energy SIS	12,695	0561700		
23	OASIS - 88232915	1,884			
24	DLR012130-Zinnia Q371 FERC LCIP	3,000			
25	GS180315-Cardinal Lateral Pipeline	72,581			
26	PGFACQ371 - Zinnia Solar CKLT	2,000			
27	PGFACQ380- Friesian Holdings Q380	(1,427)			
28	PGFACQ386 - NTE Carolinas Solar	80			
29	PGSISQ371 - Zinnia Solar CKLT	14,336			
30	PGSISQ383 - Slender Branch Solar	27,600			
31	PGSISQ385 - Palmetto Solar	(2,361)			
32	PGSISQ386 - NTE Carolina Solar	25,300			
33	PGSISQ394 - Summerton Solar	3,360			
34	PGSISQ398 - Cumberland Cty	44,401			
35	PGSISQ399 - Cumberland 500kV	34,680			
36	PGSISQ401 - Fresh Air Energy II	14,280			
37	PGSISQ402 - Fresh Air Energy Nash	13,440			
38	PGSISQ403 - Virginia Line Solar	9,960			
39	PGSISQ411 - Ellington Beach	3,840			
40	PGSISQ415 - Blackriver Solar	10,080			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	PGSISQ416 - Garisol Farm Study	10,080			
23	PGSISQ447 - Cherry Ridge -NextEra	13,240			
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	04/14/2020	End of 2019/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)	5,301,166	46,144,225			51,445,391
2						
3	SFAS 158 Regulatory Assets	541,738,017	(138,934,479)			402,803,538
4	(NC Docket E-100, Sub 913)					
5						
6	Grid South Deferral SC (SC Docket 218-318-E)	3,676,168		407	428,869	3,247,299
7	2019 to 2024 amortization period					
8	Deferred Fuel Clause NC Retail	372,796,386	(122,156,592)			250,639,794
9	(NC Docket E-2, Sub 1142)					
10						
11	Deferred Fuel Clause SC Retail	23,500,698	(8,214,896)			15,285,802
12	(SC Docket 2019-1-E)					
13						
14	NC REPS Deferral (NC Docket E-2, Sub 1175)	(2,910,744)	5,717,726	407	3,310,071	-503,089
15						
16	SFAS 143 Regulatory Assets	444,656,872	79,782,392			524,439,264
17	(NC Docket E-2, Sub 826,; SC Docket 2003-84-E)					
18						
19	SFAS 109 Regulatory Assets	172,984,319	18,135,223	282,283	7,099,180	184,020,362
20						
21	Accrued Vacation (NC Docket E-2, Sub 859)	41,419,154	56,959			41,476,113
22						
23	Gas Pipeline Upgrade	395,639		547	54,572	341,067
24	(Amortized over 25 years, ending 2026)					
25						
26	Pollution Control SC (SC Docket No. 2008-435-E)	30,164,101		407	2,513,675	27,650,426
27	(Amortized over 14 years, beginning 2017)					
28						
29	DSM/EE Deferral NC (NC Docket E-2, Sub 931)	219,773,951	(104,208,661)	440,442	(83,693,006)	199,258,296
30						
31	DSM/EE Deferral SC (SC Docket No. 2016-153-E)	15,329,740	(21,944,502)	440,442	(17,985,629)	11,370,867
32						
33	Wayne County Plant Deferred Costs NC					
34	(NC Docket E-2, Sub 1026)					
35	(Amortized over 5 years, beginning 2013)					
36						
37	Wayne County Plant Deferred Costs SC	20,326,798	(1,123,940)	Various	927,720	18,275,138
38	(SC Docket 2016-227-E)					
39	Amortized over 5 years, beginning 2017					
40	Rate Case Cost Deferral (NC Docket E-2, Sub 1142)	3,730,200		928	1,121,121	2,609,079
41	(Amortized over 5 years, beginning 2018)					
42						
43						
44	TOTAL	4,265,025,648	-52,506,687		204,365,108	4,008,153,853

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Rate Case Cost Deferral (SC Docket 2016-227-E)	91,761	672,885	928	99,016	665,630
2	(Amortized over 5 years, beginning 2017)					
3						
4	Nuclear Levelization Deferral NC and SC	46,314,328	34,906,631	Various	41,690,704	39,530,255
5	(SC Docket 2016-227-E)					
6	Sutton Plant Deferred Costs SC	10,243,212	81,413	Various	485,784	9,838,841
7	(SC Docket 2013-472-E)					
8						
9	Fukushima/Cyber Security Def-SC	5,299,351	54,364	407	618,219	4,735,496
10	(SC Docket 2018-318-E)					
11						
12	Coal Ash Deferred Costs	2,050,260,313	10,711,034	Various	227,438,226	1,833,533,121
13	(NC Coal Ash Management Act of 2014)					
14	(SC Docket 2016-227-E & NC Docket E-2 Sub 1142)					
15	Interest Rate Swap	4,886,654	(3,989,044)			897,610
16	(NC Docket E-2, Sub 1006; SC Docket 2015-95-E)					
17						
18	Storm Costs Deferral SC Ice Storms	14,713,413	566,973			15,280,386
19	(SC Docket 2014-482-E)					
20						
21	NCEMPA Purchase Deferral NC	44,392,628	21,907,842			66,300,470
22	(NC Docket E-2, Sub 1207)					
23						
24	NCEMPA Purchase Deferral SC	10,011,841		407,421	217,284	9,794,557
25	(SC Docket 2016-227-E)					
26						
27	DERP Deferral SC	12,824,788	1,091,848	229,407	6,420,530	7,496,106
28	(SC Docket 2015-53-E)					
29						
30	Regulatory Fee Deferral NC	1,836,556	(93,495)	928	375,831	1,367,230
31	(NC Docket M-100, Sub 142)					
32						
33	Deferred VOP Costs (SC Docket 2016-227-E)	1,732,192		920	577,396	1,154,796
34						
35	NC Storm Costs Deferral - Hurricane Matthew	28,067,622		407	10,206,408	17,861,214
36	(NC Docket E-2, Sub 1142)					
37						
38	SC Storm Costs Deferral - Hurricane Matthew	62,988,175				62,988,175
39	(SC Docket 2016-227-E)					
40						
41	Customer Connect Deferral NC	20,041,681	25,763,809			45,805,490
42	(NC Docket E-2, Sub 1142)					
43						
44	TOTAL	4,265,025,648	-52,506,687		204,365,108	4,008,153,853

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	468,992	407	179,509	1,249,802
2	(SC Docket 2018-206-E)					
3						
4	Pension Deferred Costs					
5						
6	Renewable Energy Certificate Biogas NC	335,740	1,182,280	509	1,388,770	129,250
7	(NC Docket E-2, Sub 1205)					
8						
9	EPA Emission Allowances	1,457,218		407	(2,291,666)	3,748,884
10	(NC Docket E-2, Sub 1142)					
11						
12	Coal Inventory Deferral NC	283,489	(26,238)	421,456	21,438	235,813
13	(NC Docket E-2, Sub 1142)					
14						
15	AMI Meter/Grid Deferred Costs SC	1,355,683	2,261,820	Various	40,605	3,576,898
16	(SC Docket 2018-318-E)					
17						
18	Competetive Procurement of Renewable Energy	442,248	394,675			836,923
19	(NC House Bill 589)					
20						
21	Excess Amortization Asset NC	1,747,700	(140,124)	407,928	(4,088,518)	5,696,094
22	(NC Docket E-2, Sub 1142)					
23						
24	Harris COLA SC (SC Docket 2018-318-E)	6,087,360	(6,087,360)			
25						
26	ABSAT Projects Deferred Costs NC	405,146	13,365,429			13,770,575
27	(NC Docket E-2, Sub 112)					
28						
29	ABSAT Projects Deferred Costs SC	63,517	1,703,991	Various	52,343	1,715,165
30	(SC Docket 2018-318-E)					
31						
32	COR Settlement NC	19,424,242		407	727,272	18,696,970
33	(NC Docket E-2, Sub 1142)					
34						
35	COR Settlement SC	17,967,424		407	672,727	17,294,697
36	(SC Docket 2018-318-E)					
37						
38	Depreciation Deferral SC - (SC Docket 2018-204-E)	5,296,825	2,787,804	403,407	1,572,011	6,512,618
39						
40	Amortized over 3 years, beginning 2019					
41	Interest Rate Hedge	(596,531)	61,710			-534,821
42						
43	NC Solar Rebate (NC House Bill 589)	3,208,288	5,690,807			8,899,095
44	TOTAL	4,265,025,648	-52,506,687		204,365,108	4,008,153,853

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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						
2	Rotable Fleet Spare - (NC Docket E-2 Sub 998A)		4,410,114	403	980,025	3,430,089
3						
4	Wholesale Storm Deferred Costs		13,148,000	571	2,556,554	10,591,446
5	(Docket No ER19-1339-000 & 001)					
6	SC H3659 Implementation - South Carolina Bill 3659		325,171			325,171
7						
8	SC CertainTeed ST Asset - (SC Docket 2018-318-E)		830,000			830,000
9						
10	SC CertainTeed LT Asset - (SC Docket 2018-318-E)		6,828,798	Various	484,169	6,344,629
11						
12	SC Grid LT Deferral - (SC Docket 2018-318-E)		1,123,868	Various	163,898	959,970
13						
14	SC Storm Costs - Michael, Florence, Diego		54,235,861			54,235,861
15						
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43						
44	TOTAL	4,265,025,648	-52,506,687		204,365,108	4,008,153,853

FOOTNOTE DATA

Schedule Page: 232 Line No.: 37 Column: d

403,407,408,421

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

403,407,408,421

Schedule Page: 232.1 Line No.: 12 Column: d

403, 407, 411, 421, 426, 431

Schedule Page: 232.2 Line No.: 15 Column: d

403,407,421

Schedule Page: 232.2 Line No.: 29 Column: d

403,407,421

Schedule Page: 232.3 Line No.: 10 Column: d

403,407,408

Schedule Page: 232.3 Line No.: 12 Column: d

403,407,408

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Interest Rate Hedges	33,533,639	7,309,307	427	9,682,647	31,160,299
2	Amortized over various periods					
3						
4	Accounts in Process of Reclass	164,535	2,041	N/A		166,576
5						
6	Deferred Rate Case Expenses	2,004,692	3,509,413	182	684,290	4,829,815
7						
8	Gas Pipeline Charges	3,486,924		547	480,955	3,005,969
9	2001-2026 amortization period					
10						
11	Workers Comp Insurance Reimb	4,824,490	-479,692			4,344,798
12						
13	Fukushima Pooled Inventory	1,805,782		N/A		1,805,782
14						
15	NCEMPA SC Equity Reserve	-4,127,594		421	165,336	-4,292,930
16	2017-2040 amortization period					
17						
18	Deferred Storm Costs	464,876,999	253,754,797	182	78,932,450	639,699,346
19						
20	Gypsum Settlement Agreement	29,172,679	-6,574,011	N/A		22,598,668
21						
22	Camp Lejeune Incremental Costs	8,343,921	-6,134,740	N/A		2,209,181
23						
24	ASC 842 Fixed Rate Leases		3,989,524	N/A		3,989,524
25						
26	SC ORS Consultant Costs		47,037			47,037
27						
28	Pension Settlement Costs		20,366,528	926	679,366	19,687,162
29	2019-2029 amortization period					
30						
31						
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43						
44						
45						
46						
47	Misc. Work in Progress	418,385				116,326
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	544,504,452				729,367,553

FOOTNOTE DATA

Schedule Page: 233 Line No.: 6 Column: d

Approved in DEP SC - 2019 Rate Case Docket No. 2018-318-E, Order No. 2019-341, May 21, 2019

Schedule Page: 233 Line No.: 18 Column: d

Approved in DEP SC - 2019 Docket No. 2018-26-E, Order No. 2019-126, February 21, 2019

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	1,864,956,280	2,261,603,593
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,864,956,280	2,261,603,593
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)	1,864,956,280	2,261,603,593

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	04/14/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1				
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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	04/14/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
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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	04/14/2020	End of 2019/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	04/14/2020	End of 2019/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	04/14/2020	End of 2019/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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21		
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	04/14/2020	End of 2019/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	48,485,000	603,686
4			
5	5.3% Series Due 1/15/2019		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	8,798,485,000	111,676,858

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	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 (2.114% at 12/31/2019)	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	DEP 600M 3.45% Issued 3/15/2019 Due 3/15/2029	600,000,000	3,281,921
10			3,900,000 D
11	SUBTOTAL - Account 221	7,623,485,000	109,496,531
12			
13	Account 222 - Reacquired Bonds		
14	None		
15			
16	Account 223 - Advances to Associated Companies:		
17	Commercial Paper Series Due 3/16/2024 (1.9165% at 12/31/2019)	150,000,000	
18			
19	SUBTOTAL - Account 223	150,000,000	
20			
21	Account 224 - Other Long-Term Debt:		
22	DEP Receivables 325M Due 2/22/2021	325,000,000	1,923,727
23			
24	700M Term Loan Due 12/31/2020 (2.5099% at 12/31/2019)	50,000,000	256,600
25	700M Term Loan Due 12/31/2020 (2.5099% at 12/31/2019)	250,000,000	
26	700M Term Loan Due 12/31/2020 (2.5099% at 12/31/2019)	400,000,000	
27			
28	SUBTOTAL - Account 224	1,025,000,000	2,180,327
29			
30			
31			
32			
33	TOTAL	8,798,485,000	111,676,858

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		1,532,383	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	18,183,714	9
						10
05/15/2012	05/15/2022	05/15/2012	05/15/2022	500,000,000	18,287,753	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	20,777,860	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	21,529,542	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
				8,798,485,000	340,085,071	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.
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	7,910,287	3
						4
8/9/2018	9/1/2023	8/9/2018	9/1/2023	300,000,000	10,125,000	5
						6
8/9/2018	9/1/2028	8/9/2018	9/1/2018	500,000,000	18,438,290	7
						8
3/07/2019	3/15/2029	3/07/2019	3/15/2029	600,000,000	17,488,062	9
						10
				7,623,485,000	307,537,291	11
						12
						13
						14
						15
						16
12/9/2015	3/16/2024	12/9/2015	3/16/2024	150,000,000	3,715,332	17
						18
				150,000,000	3,715,332	19
						20
						21
12/20/2013	2/22/2021	12/20/2013	2/22/2021	325,000,000	10,019,620	22
						23
12/14/2018	12/31/2020	12/14/2018	12/31/2020	50,000,000	1,489,264	24
01/24/2019	12/31/2020	01/24/2019	12/31/2020	250,000,000	6,957,124	25
02/15/2019	12/31/2020	02/15/2019	12/31/2020	400,000,000	10,366,440	26
						27
				1,025,000,000	28,832,448	28
						29
						30
						31
						32
				8,798,485,000	340,085,071	33

FOOTNOTE DATA

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	804,658,910
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	905,003,336
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-100,344,426
28	Show Computation of Tax:	
29		
30	21% of Line 27	-21,072,329
31	Prior Year Federal Tax Adjustment - Primarily Prior Year Tax True-Ups	-15,643,987
32		
33	Total Federal Income Tax	-36,716,316
34		
35		
36		
37		
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42		
43		
44		

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

Schedule Page: 261 Line: 20 Column: b

Provision for Deferred Income Taxes	(202,195,231)
Provision for Current Federal Income Taxes	36,716,316
Provision for Current State Income Taxes	3,615,476
AFUDC Equity	60,137,414
AFUDC Interest	28,183,440
Benefits Accruals	39,293,234
Book Depreciation/Amortization	(899,806,531)
Certain Teed Settlement Deferral	28,943,297
Certain Teed Settlement Accrual	7,666,975
Charitable Contribution Carryovers/Accruals	5,991,525
Coal Ash Spend, Net of Capitalized Portion	(14,474,514)
COLI Adjustments	1,600,967
Contributions in Aid of Construction	(58,895,470)
Cost of Removal	87,651,031
Deferred Compensation	919,712
Deferred Fuel	(129,987,592)
Deferred Revenue	(34,422,171)
Dividends Received Exclusion	1,857,980
Earnings of Subsidiaries	(119,294)
End of Life Nuclear Fuel Cost Reserve	(16,103,117)
Equipment/T&D Repairs	326,700,000
Impairment	(11,004,075)
Investment Tax Credit Amortization	5,582,749
Lawsuit Contingency	2,727,993
Lease Adjustments	(8,243,974)
Lobbying	(1,810,000)
Meals & Entertainment	(3,300,000)
Non-Cash Overhead Basis Adjustment	20,261,041
Non-Qualified Nuclear Decommissioning Contributions/Earnings	(192,304)
Nuclear Fuel Book Burned	(177,895,205)
Rate Refunds	7,742,188
Regulatory Asset - ABSAT	15,017,077
Regulatory Asset - AMI/Non-AMI Meters	19,013,164
Regulatory Asset - COR Settlement	(1,400,000)
Regulatory Asset - Customer Connect	8,859,960
Regulatory Asset - Depreciation Deferral	1,215,792
Regulatory Asset - Energy Efficiency	(24,474,529)
Regulatory Asset - Environmental	(29,172,679)
Regulatory Asset - FAS 158	(25,915,100)

FOOTNOTE DATA

Regulatory Asset - Grid Costs	2,191,352
Regulatory Asset - Harris COLA	(5,337,142)
Regulatory Asset - NCEMPA Purchase Deferrals	21,525,221
Regulatory Asset - Nuclear Levelization	(6,784,073)
Regulatory Asset - Plant Related Retirements	(27,323,202)
Regulatory Asset - Rate Case Expenses	6,226,264
Regulatory Asset - SC Pollution Control Deferral	(2,513,675)
Regulatory Asset - Wayne & Sutton Deferrals	(2,456,029)
Regulatory Asset - NC Solar Rebate Program	5,690,807
Regulatory Asset - EA Auction Proceeds Amortization	2,291,667
Regulatory Liability - Rate Case Expenses	(6,933,852)
Regulatory Liability - Job Retention Rider	(12,621,086)
REPs Incremental Costs	2,407,655
Renewable Energy Liability	(18,816,278)
Returns on State Excess Deferred Income Taxes	(1,492,022)
SC Distributive Energy Resource Program	(5,328,682)
Self Developed Software	49,590,350
Severance Accrual	35,650,524
Spent Fuel Canisters	(1,521,828)
Storm Cost Deferral	230,010,221
Surplus Materials Write-off	(4,104,395)
Tax Depreciation/Amortization	1,324,082,420
Tax Gains/Losses	29,800,000
Tax Interest Accrual	1,275,432
Tax Interest Capitalized	(48,361,302)
Unbilled Revenue	(3,403,929)
Net Operating Loss Utilization/Deferral	270,612,719
Other Items	360,654
Total Differences Between Book & Taxable Income	**905,003,336**

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	04/14/2020	End of 2019/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	5,008,230		-36,716,316	-32,731,501	-588,242
3	Unemployment	4,006		1,368,897	138,853	-1,230,380
4	Highway Use			64,560	64,560	
5	Social Security	4,725,075		35,258,557	36,330,871	794,440
6	SUBTOTAL	9,737,311		-24,302	3,802,783	-1,024,182
7						
8	NORTH CAROLINA:					
9	Income	562,458		85,459	2,780,431	2,132,513
10	Property	1,057,600		72,776,139	72,365,666	-1,468,073
11	Franchise	305,837		17,768,145	16,279,727	2,400,000
12	Unemployment	19,475		21,610	41,085	
13	Municipal License	-152,338		710,883	710,883	
14	Other Taxes			-105,599	-105,599	
15	SUBTOTAL	1,793,032		91,256,637	92,072,193	3,064,440
16						
17	SOUTH CAROLINA:					
18	Income			-655,568	1,222,346	1,877,914
19	Property	35,185,045		43,572,488	78,058,438	101,555
20	Public Utility Corp Licenses	53,164		723		
21	Unemployment	-1,856			-1,856	
22	KWH Electric Power			2,146,326	2,146,326	
23	Other Taxes			-185	-185	
24	Municipal License	8,436,539			12,387,668	11,235,810
25	Privilege License	1,962,812		1,800,620	1,396,357	-2,400,000
26	SUBTOTAL	45,635,704		46,864,404	95,209,094	10,815,279
27						
28	OTHER STATES:					
29	FIN 48	1,370,704		-1,370,704		
30	Income (FL)			-1,367,764		1,367,764
31	Unemployment	-17,619		105,840	88,591	
32	Other Taxes			7,015	7,015	
33	Franchise Tax			225	225	
34	SUBTOTAL	1,353,085		-2,625,388	95,831	1,367,764
35						
36	Total	58,519,132		135,471,351	191,179,901	14,223,301
37						
38						
39						
40						
41	TOTAL	58,519,132		135,471,351	191,179,901	14,223,301

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
435,173		-37,966,838			1,250,522	2
3,670		1,368,897				3
		64,560				4
4,447,201		35,258,557				5
4,886,044		-1,274,824			1,250,522	6
						7
						8
-1		-127,036			212,495	9
		71,235,036			1,541,103	10
4,194,255		17,768,145				11
		21,610				12
-152,338		710,883				13
		-105,625			26	14
4,041,916		89,503,013			1,753,624	15
						16
						17
		-711,471			55,903	18
800,650		43,656,086			-83,598	19
53,887		723				20
						21
		2,146,326				22
		-185				23
7,284,681						24
-32,925		1,800,620				25
8,106,293		46,892,099			-27,695	26
						27
						28
		-1,370,704				29
		-1,367,764				30
-370		105,840				31
		7,015				32
		225				33
-370		-2,625,388				34
						35
17,033,883		132,494,900			2,976,451	36
						37
						38
						39
						40
17,033,883		132,494,900			2,976,451	41

FOOTNOTE DATA

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

Offset to account 146	(6,718,837)
Offset to account 143	10,392,858
Offset to account 190	(4,262,262)
Rounding	(1)
Total	**(588,242)**

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

Offset to account 242	(1,230,380)

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

Offset to account 182	96,977
Offset to account 242	(2,081)
Offset to account 511	10,447
Offset to account 908/909	689,097
Total	**794,440**

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

Offset to account 146	2,132,513

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

Offset to account 146	(1,546,382)
Offset to account 182	78,309
Total	**(1,468,073)**

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

Jurisdictional reallocation NC to SC	2,400,000

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

Offset to account 146	1,877,914

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

Offset to account 146	(145,778)
Offset to account 182	247,333
Total	**101,555**

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

Offset to account 142	11,235,810

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

Jurisdictional reallocation NC to SC	(2,400,000)

Schedule Page: 262 Line No.: 30 Column: f

Offset to account 146	1,367,764

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

Per the instructions for page 262-263, which state, “Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged”, the following amounts have been excluded from Taxes Accrued balances:

FOOTNOTE DATA

Sales and Use Tax Payable – 759,541 Excluded from Balance at Beginning of Year (column b)
Sales and Use Tax Payable – 538,355 Excluded from Balance at End of Year (column g)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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%	2,279,052			411.4	1,400,127	
4	7%						
5	10%	52,097,884			411.4	3,506,578	
6	6%	125,361			411.4	-46,741	
7		87,659,693				722,785	
8	TOTAL	142,161,990				5,582,749	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	8%	5,034,246			411.4	722,785	
11	30%	82,625,447					
12	TOTAL	87,659,693				722,785	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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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	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
878,925			3
			4
48,591,306			5
172,102			6
86,936,908			7
136,579,241			8
			9
4,311,461			10
82,625,447			11
86,936,908			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
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			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	3,669,201	Various	3,665,363	4,150,746	4,154,584
4						
5	Environmental Reserve for					
6	Manufactured Gas Plants	295,784	462.5		-56,765	239,019
7						
8	Piedmont Natural Gas Merger					
9	Donation Commitment	7,260,313	426.1		-7,260,313	
10						
11	MYHER EE Program	5,795,684	456.5		-5,795,684	
12						
13	Extended Payment Plan					
14	Weather Protect	680,180	Various		-452,877	227,303
15						
16	Utility Energy Service Programs		Various		34,600,407	34,600,407
17						
18	Minor Items	609,524	Various		381,721	991,245
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						
45						
46						
47	TOTAL	19,844,812		3,665,363	25,567,235	41,746,684

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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)	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	04/14/2020	End of 2019/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		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)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	2,695,677,136	872,941,526	350,265,240
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,695,677,136	872,941,526	350,265,240
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	2,695,677,136	872,941,526	350,265,240
10	Classification of TOTAL			
11	Federal Income Tax	2,416,603,213	766,771,557	308,376,209
12	State Income Tax	279,073,923	106,169,969	41,889,031
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	04/14/2020	End of 2019/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 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		Balance at End of Year (k)	Line No.
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
6,803,270	3,638,924	254	787,579	182/254	10,500,643	3,231,230,832	2
							3
							4
6,803,270	3,638,924		787,579		10,500,643	3,231,230,832	5
							6
							7
							8
6,803,270	3,638,924		787,579		10,500,643	3,231,230,832	9
							10
5,996,955	3,207,644		420,929		9,209,230	2,886,576,173	11
806,315	431,280		366,650		1,291,413	344,654,659	12
							13

NOTES (Continued)

FOOTNOTE DATA

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

254 – North Carolina Rate Change Deferral	289,652
254 – Federal Rate Change Deferral	497,926
Rounding	1
Total	**787,579**

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

182 – Other Regulatory Assets	8,479,069
254 – Other Regulatory Liabilities	2,021,574
Total	**10,500,643**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		1,287,627,619	342,625,172	212,389,331
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,287,627,619	342,625,172	212,389,331
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)	1,287,627,619	342,625,172	212,389,331
20	Classification of TOTAL			
21	Federal Income Tax	1,135,019,747	301,991,864	187,217,222
22	State Income Tax	152,607,872	40,633,308	25,172,109
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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				Balance at End of Year	Line No.
		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)	(k)	
							1
							2
21,795	2,664,537	254	22,506	182/190	2,556,982	1,417,755,194	3
							4
							5
							6
							7
							8
21,795	2,664,537		22,506		2,556,982	1,417,755,194	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
21,795	2,664,537		22,506		2,556,982	1,417,755,194	19
							20
19,212	2,348,740		-5,982		2,253,933	1,249,724,776	21
2,583	315,797		28,488		303,049	168,030,418	22
							23

NOTES (Continued)

FOOTNOTE DATA

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

254 – NC Rate Change Deferral	22,506

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

182 – Other Regulatory Assets	2,556,973
190 – Accumulated Deferred Income Taxes	3
Other/Rounding	6
Total	**2,556,982**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Regulatory Liabilty Related to Income Tax	66,601,143	190, 410, 411	3,115,286	(2,021,574)	61,464,283
2	Amortization follows book depreciable asset lives					
3						
4	Deferred Fuel Clause SC Retail	383,896			(383,896)	
5	(SC Docket 2019-1-E)					
6						
7	SFAS 143 Regulatory Liabilities	15,264,104				15,264,104
8	(NC Docket E-2, Sub 826 ; SC Docket 2003-84-E)					
9						
10	Nuclear Decommissioning Trust - Unrealized Gains	803,712,544			463,727,630	1,267,440,174
11	(NC Docket E-2, Sub 826 ; SC Docket 2003-84-E)					
12						
13	NC REPS Deferral (NC Docket E-2, Sub 1144;	114,286,764	456	180,230	1,861,923	115,968,457
14	NC Docket E-2 Sub 1175; NC Docket E-2 Sub 1205)					
15	Amortized annually Dec - Nov each year					
16						
17	Nuclear Fuel Last Core Reserve	50,060,673	407		16,103,117	66,163,790
18	(NC Docket E-2, Sub 112, SC Docket 2018-318-E)					
19						
20	NC State Excess Def. Income Tax-Retail	123,024,902	190, 410, 411	30,815,531	377,846	92,587,217
21	NCUC Docket M-100,Sub148; NC Docket E-2,Sub1142)					
22	Amortized 4 years beginning March 2018					
23						
24	OPEB Regulatory Liability (Docket AI07-1-000)	93,332,216			(93,332,216)	
25						
26	Rotable Fleet Spare (NC Docket E-2, Sub 998A;	1,687,961	403, 182	1,105,020	1,226,534	1,809,475
27	NC Docket E-7, Sub 986A)					
28	Amortized annually various start thru the year.)					
29						
30	TCJA Federal Excess Def Income Tax-NC Retail	904,111,986			344,550	904,456,536
31	(General Rate Case in Process, Docket TBD)					
32						
33						
34	NC State Excess Deferred Income Taxes - SC Retail	5,382,366	190, 410, 411	4,906,523	47,296	523,139
35	PSC Docket No. 2018-318-E-Order No. 2019-341					
36	Amortization to be completed by June 2020					
37						
38	TCJA Federal Excess Defer Income Tax-Gross up	425,897,509	190	2,724,100	162,306	423,335,715
39						
40						
41	TOTAL	3,120,844,123		49,079,906	405,989,211	3,477,753,428

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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						
2	Levelized NC State EDIT Rider - NC Retail	2,515,760	407	4,133,796	5,625,818	4,007,782
3	NCUC Docket No. M-100, Sub 148					
4	NCUC Docket No. E-2, Sub 1142					
5	Amortized 4 yrs beg. March 2018					
6						
7	TCJA Federal Excess Def Income Taxes - SC Retail	161,209,747	410, 411	4,174,429	61,436	157,096,754
8	PSC Docket No. 2018-318-E-Order No. 2019-341					
9	Amortized beg. June 2019, PPE 20yrs, Non-PPE 5yrs					
10						
11	TCJA Federal Excess Def Income Tax - Wholesale	346,978,293	410, 411	4,858,843	132,231	342,251,681
12	Production Wholesale Amortization began Jan 2019					
13						
14						
15	Open Interest Rate Swap	1,193,870			(564,876)	628,994
16	(NC Docket E-2, Sub 1006 ; SC Docket 2015-95-E)					
17						
18	Excess Amortization Liability	5,200,389	407	(6,933,852)		12,134,241
19	(NC Docket E-2, Sub 1142)					
20	Amortized beg. 4-2018 ending 2020					
21						
22	Job Retention Rider				12,621,086	12,621,086
23	(NC Docket E-2, Sub 1153)					
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	3,120,844,123		49,079,906	405,989,211	3,477,753,428

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	2,169,136,266	2,100,384,584
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,340,418,584	1,282,477,747
5	Large (or Ind.) (See Instr. 4)	681,887,498	670,733,191
6	(444) Public Street and Highway Lighting	21,064,526	19,883,833
7	(445) Other Sales to Public Authorities	88,000,375	94,131,859
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,300,507,249	4,167,611,214
11	(447) Sales for Resale	1,468,268,974	1,511,358,379
12	TOTAL Sales of Electricity	5,768,776,223	5,678,969,593
13	(Less) (449.1) Provision for Rate Refunds	-1,974,555	118,958,671
14	TOTAL Revenues Net of Prov. for Refunds	5,770,750,778	5,560,010,922
15	Other Operating Revenues		
16	(450) Forfeited Discounts	10,652,500	8,582,371
17	(451) Miscellaneous Service Revenues	6,951,940	6,165,627
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	36,092,395	35,963,712
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,580,276	-1,014,686
22	(456.1) Revenues from Transmission of Electricity of Others	84,191,351	72,713,350
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	140,468,462	122,410,374
27	TOTAL Electric Operating Revenues	5,911,219,240	5,682,421,296

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
18,242,806	18,717,246	1,348,978	1,330,794	2
				3
13,945,036	14,139,566	236,544	234,714	4
10,473,676	10,420,725	4,026	4,064	5
76,758	76,562	1,416	1,434	6
1,452,708	1,473,179	5	5	7
				8
				9
44,190,984	44,827,278	1,590,969	1,571,011	10
24,165,841	24,505,471	9	9	11
68,356,825	69,332,749	1,590,978	1,571,020	12
				13
68,356,825	69,332,749	1,590,978	1,571,020	14

Line 12, column (b) includes $ -8,660,415 of unbilled revenues.

Line 12, column (d) includes -49,570 MWH relating to unbilled revenues

FOOTNOTE DATA

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

Includes 6,473,380 of service charges.

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

Includes the $5,795,684 of North Carolina Energy Efficiency Program Deferred Revenue reversal, $2,554,649 of Contribution In Aid of Construction revenue, $551,487 of REPS amortization and GSA Admin charges, $1,066,572 of electric revenue from cogeneration/small power producers offset by ($7,636,252) of Job Retention Rider over collection.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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31					
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33					
34					
35					
36					
37					
38					
39					
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	04/14/2020	End of 2019/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	18,093,442	2,122,696,793	1,345,372	13,449	0.1173
3	SLR	17,376	6,940,102	3,606	4,819	0.3994
4	ALS	65,969	21,628,135			0.3279
5	Unbilled Revenue	66,019	-2,802,183			-0.0424
6	TOTAL RESIDENTIAL	18,242,806	2,148,462,847	1,348,978	13,523	0.1178
7						
8	Commercial					
9	ALS	241,270	55,094,258			0.2284
10	APH-TES	1,085	86,520	3	361,667	0.0797
11	CH-TOUE	8,276	1,266,533	224	36,946	0.1530
12	CS	2,426	374,206	89	27,258	0.1542
13	LGS	1,207,517	91,568,065	96	12,578,302	0.0758
14	MGS	2,730,706	285,893,637	18,534	147,335	0.1047
15	SFLS	1,365	262,209	99	13,788	0.1921
16	SGS	9,720,922	878,449,360	214,757	45,265	0.0904
17	SI	62,519	7,767,414	1,120	55,821	0.1242
18	SLS	12,096	4,525,182	1,240	9,755	0.3741
19	TFS	495	84,989	263	1,882	0.1717
20	TSS	180	18,892	31	5,806	0.1050
21	GS	3,291	448,403	88	37,398	0.1363
22	Unbilled Revenue	-47,111	-4,224,100			0.0897
23	TOTAL COMMERCIAL	13,945,037	1,321,615,568	236,544	58,953	0.0948
24						
25	Industrial					
26	ALS	18,222	3,567,528			0.1958
27	LGS	8,096,442	481,685,247	255	31,750,753	0.0595
28	MGS	485,450	50,616,075	1,192	407,257	0.1043
29	SGS	1,928,939	145,300,296	2,533	761,523	0.0753
30	SI	4,810	535,323	23	209,130	0.1113
31	SLS	116	23,763	20	5,800	0.2049
32	GS	176	28,274	3	58,667	0.1606
33	Unbilled Revenue	-60,480	-1,425,032			0.0236
34	TOTAL INDUSTRIAL	10,473,675	680,331,474	4,026	2,601,509	0.0650
35						
36	Public Street Lighting					
37	SLS	72,088	20,430,106	587	122,807	0.2834
38	TSS	5,149	519,767	829	6,211	0.1009
39	Unbilled Revenue	-479	33,886			-0.0707
40	TOTAL PUBLIC STREET LIGHTING	76,758	20,983,759	1,416	54,208	0.2734
41	TOTAL Billed	44,240,554	4,309,167,669	1,590,969	27,807	0.0974
42	Total Unbilled Rev.(See Instr. 6)	-49,570	-8,660,415	0	0	0.1747
43	TOTAL	44,190,984	4,300,507,254	1,590,969	27,776	0.0973

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	229			0.1145
4	LGS	1,460,226	88,239,622	5	292,045,200	0.0604
5	Unbilled Revenue	-7,520	-242,986			0.0323
6	TOTAL OTHER PUBLIC	1,452,708	87,996,865	5	290,541,600	0.0606
7						
8						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	44,240,554	4,309,167,669	1,590,969	27,807	0.0974
42	Total Unbilled Rev.(See Instr. 6)	-49,570	-8,660,415	0	0	0.1747
43	TOTAL	44,190,984	4,300,507,254	1,590,969	27,776	0.0973

FOOTNOTE DATA

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 $20,673,419.

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 $18,803,016.

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 $1,556,024.

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 $80,767.

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 $3,510.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Duke Energy Carolinas, LLC	LF	45			
5	Duke Energy Carolinas, LLC	LF	198			
6	PJM Interconnection L.L.C.	OS	7			
7	PJM Interconnection L.L.C.	AD	7			
8	South Carolina Electric & Gas Company	OS	97			
9						
10	Requirement Sales					
11	Town of Black Creek, NC	RQ	174	0	0	0
12	Town of Black Creek, NC	RQ	174			
13	City of Camden, SC	RQ	197	40	40	40
14	City of Camden, SC	RQ	197			
	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	04/14/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PWC of the City of Fayetteville	RQ	184	372	380	372
2	PWC of the City of Fayetteville	RQ	184			
3	French Broad EMC	RQ	210	72	82	73
4	French Broad EMC	RQ	210			
5	Haywood EMC	RQ	180	12	23	8
6	Haywood EMC	RQ	180			
7	Town of Lucama, NC	RQ	175	0	0	0
8	Town of Lucama, NC	RQ	175			
9	NC Electric Membership Corporation	OS	4			
10	NC Electric Membership Corporation	AD	4			
11	NC Electric Membership Corporation	RQ	134	970	970	970
12	NC Electric Membership Corporation	RQ	134			
13	NC Electric Membership Corporation	RQ	182	764	792	764
14	NC Electric Membership Corporation	RQ	182			
	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	04/14/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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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	NC Eastern Municipal Power Agency	RQ	200	1114	1315	1114
2	NC Eastern Municipal Power Agency	RQ	200			
3	Piedmont EMC	RQ	172	20	21	20
4	Piedmont EMC	RQ	172			
5	Town of Sharpsburg, NC	RQ	176	0	0	0
6	Town of Sharpsburg, NC	RQ	176			
7	Town of Stantonsburg, NC	RQ	177	0	0	0
8	Town of Stantonsburg, NC	RQ	177			
9	Town of Winterville, NC	RQ	178	0	0	0
10	Town of Winterville, NC	RQ	178			
11	Wholesale Customers	RQ				
12						
13	Other Services					
14	NC Electric Membership Corporation	OS	134			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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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.
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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	NC Eastern Municipal Power Agency	OS	268			
2	North Carolina Municipal PA1	OS	259			
3	Piedmont EMC	OS	322			
4	Haywood EMC	OS	300			
5	Town of Black Creek, NC	OS	293			
6	City of Camden, SC	OS	309			
7	PWC of the City of Fayetteville	OS	324			
8	French Broad EMC	OS	326			
9	Town of Lucama, NC	OS	294			
10	Town of Sharpsburg, NC	OS	296			
11	Town of Stantonsburg, NC	OS	295			
12	Town of Waynesville	OS	303			
13	Industrial Power Generating Corp.	OS	288			
14	The Energy Authority	OS	70			
	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	04/14/2020	End of 2019/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.
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IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Macquarie Energy LLC	OS	120			
2	Town of Winterville	OS	342			
3	Other	OS	321			
4		AD				
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
5,388,471		132,136,617		132,136,617	2
-8,697		54,529,313		54,529,313	3
1,275		42,255		42,255	4
	206,116			206,116	5
30,164		754,524		754,524	6
		-1,106		-1,106	7
107		4,223		4,223	8
					9
					10
	21,198	-3,240		17,958	11
	340	-807		-467	12
202,499	9,501,543	5,408,286		14,909,829	13
-2	-80,108	-84,711		-164,819	14
18,641,160	783,769,249	485,225,353	0	1,268,994,602	
5,524,681	8,036,116	191,238,256	0	199,274,372	
24,165,841	**791,805,365**	**676,463,609**	**0**	**1,468,268,974**	

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.
2,129,686	95,415,600	56,889,103		152,304,703	1
-203	-648,670	-2,558,095		-3,206,765	2
532,775	14,958,810	14,114,397		29,073,207	3
-209	-2,182,949	-77,964		-2,260,913	4
78,057	2,339,308	2,077,631		4,416,939	5
-107	-134	-88,677		-88,811	6
	32,690	-4,860		27,830	7
	552	-1,256		-704	8
112,454	7,830,000	3,755,239		11,585,239	9
		-6,264		-6,264	10
6,972,146	186,044,743	181,473,884		367,518,627	11
-1,614	-211,526	2,183,495		1,971,969	12
951,410	189,195,496	24,809,554		214,005,050	13
678	1,001,036	304,374		1,305,410	14
18,641,160	783,769,249	485,225,353	0	1,268,994,602	
5,524,681	8,036,116	191,238,256	0	199,274,372	
24,165,841	**791,805,365**	**676,463,609**	**0**	**1,468,268,974**	

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.
7,707,612	285,217,559	205,241,695		490,459,254	1
-6,514	-1,839,813	-5,868,810		-7,708,623	2
74,974	4,855,772	1,997,676		6,853,448	3
-28	-6,336	-55,181		-61,517	4
	30,236	-4,860		25,376	5
	466	-1,206		-740	6
	34,127	-5,670		28,457	7
	768	-1,236		-468	8
	87,414	-13,770		73,644	9
	1,127	1,601		2,728	10
		-506,000		-506,000	11
					12
					13
908		24,103		24,103	14
18,641,160	783,769,249	485,225,353	0	1,268,994,602	
5,524,681	8,036,116	191,238,256	0	199,274,372	
24,165,841	**791,805,365**	**676,463,609**	**0**	**1,468,268,974**	

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.
		-334		-334	1
		-105		-105	2
		-8		-8	3
		-13		-13	4
		-1		-1	5
		-10		-10	6
		-98		-98	7
		-27		-27	8
		-1		-1	9
		-1		-1	10
		-1		-1	11
		-5		-5	12
		-1		-1	13
		-4		-4	14
18,641,160	783,769,249	485,225,353	0	1,268,994,602	
5,524,681	8,036,116	191,238,256	0	199,274,372	
24,165,841	**791,805,365**	**676,463,609**	**0**	**1,468,268,974**	

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.
		-33		-33	1
		-4		-4	2
-1		-2		-2	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
18,641,160	783,769,249	485,225,353	0	1,268,994,602	
5,524,681	8,036,116	191,238,256	0	199,274,372	
24,165,841	**791,805,365**	**676,463,609**	**0**	**1,468,268,974**	

FOOTNOTE DATA

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.: 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.

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.

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

FOOTNOTE DATA

Schedule Page: 310.2 Line No.: 14 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 1 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 2 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 3 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 4 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 5 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 6 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 7 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 8 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 9 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 10 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 11 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 12 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 13 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.3 Line No.: 14 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.4 Line No.: 1 Column: i

Other charge is for generation imbalance services

Schedule Page: 310.4 Line No.: 2 Column: i

Other charge is for generation imbalance services

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	5,637,433	7,049,768
5	(501) Fuel	378,266,997	328,260,022
6	(502) Steam Expenses	23,977,932	98,801,131
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	386	17,396
10	(506) Miscellaneous Steam Power Expenses	7,632,061	12,002,275
11	(507) Rents		360
12	(509) Allowances	38,905,856	18,471,594
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	454,420,665	464,602,546
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	4,750,806	5,198,104
16	(511) Maintenance of Structures	10,631,206	11,659,549
17	(512) Maintenance of Boiler Plant	23,802,308	35,112,387
18	(513) Maintenance of Electric Plant	3,549,102	4,379,740
19	(514) Maintenance of Miscellaneous Steam Plant	10,571,521	11,190,404
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	53,304,943	67,540,184
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	507,725,608	532,142,730
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	40,185,334	39,923,359
25	(518) Fuel	180,092,046	187,072,314
26	(519) Coolants and Water	20,339,491	20,912,447
27	(520) Steam Expenses	44,793,539	43,577,463
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	5,907,162	5,788,939
31	(524) Miscellaneous Nuclear Power Expenses	170,331,650	152,629,681
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	461,649,222	449,904,203
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	55,252,454	75,116,663
36	(529) Maintenance of Structures	11,474,537	15,092,706
37	(530) Maintenance of Reactor Plant Equipment	50,254,108	61,979,194
38	(531) Maintenance of Electric Plant	32,975,533	35,568,051
39	(532) Maintenance of Miscellaneous Nuclear Plant	44,372,915	47,439,313
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	194,329,547	235,195,927
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	655,978,769	685,100,130
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,341,902	2,131,313
45	(536) Water for Power	62,500	62,500
46	(537) Hydraulic Expenses	-304,559	-357,052
47	(538) Electric Expenses	111,080	109,004
48	(539) Miscellaneous Hydraulic Power Generation Expenses	851,087	678,683
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	3,062,010	2,624,448
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	302,665	245,085
54	(542) Maintenance of Structures	232,896	187,001
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,238,993	970,911
56	(544) Maintenance of Electric Plant	350,536	441,833
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,578,493	1,668,204
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,703,583	3,513,034
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	6,765,593	6,137,482

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	6,490,539	7,044,410
63	(547) Fuel	653,452,999	899,557,250
64	(548) Generation Expenses	2,120,284	3,422,683
65	(549) Miscellaneous Other Power Generation Expenses	13,880,215	15,412,682
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	675,944,037	925,437,025
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	6,032,201	6,901,548
70	(552) Maintenance of Structures	6,427,720	6,485,683
71	(553) Maintenance of Generating and Electric Plant	30,895,403	25,863,606
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	10,292,751	12,215,247
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	53,648,075	51,466,084
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	729,592,112	976,903,109
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	636,393,319	707,268,038
77	(556) System Control and Load Dispatching	1,712,851	1,738,960
78	(557) Other Expenses	217,123,170	-232,602,079
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	855,229,340	476,404,919
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,755,291,422	2,676,688,370
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	42,150	38,741
84			
85	(561.1) Load Dispatch-Reliability	3,284,038	2,109,710
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,638,831	2,450,505
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,011,698	1,008,598
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	318,960	281,847
90	(561.6) Transmission Service Studies		95,000
91	(561.7) Generation Interconnection Studies	313,049	-70,868
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,119,818	1,292,946
94	(563) Overhead Lines Expenses	789,800	870,995
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	6,727,988	6,829,258
98	(567) Rents	2,870,974	2,901,930
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,117,306	17,808,662
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	97	
102	(569) Maintenance of Structures	535,332	1,339,981
103	(569.1) Maintenance of Computer Hardware		11
104	(569.2) Maintenance of Computer Software	2,990,895	3,043,183
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,839,162	4,068,225
108	(571) Maintenance of Overhead Lines	14,579,117	12,479,175
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	6,321	96,575
111	TOTAL Maintenance (Total of lines 101 thru 110)	21,950,924	21,027,150
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	41,068,230	38,835,812

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	635,991	696,545
135	(581) Load Dispatching	4,378,366	4,689,874
136	(582) Station Expenses	576,917	851,607
137	(583) Overhead Line Expenses	2,108,720	1,879,064
138	(584) Underground Line Expenses	5,970,409	4,881,127
139	(585) Street Lighting and Signal System Expenses	4,602	8,088
140	(586) Meter Expenses	5,250,476	6,038,529
141	(587) Customer Installations Expenses	5,704,319	5,461,524
142	(588) Miscellaneous Expenses	28,846,331	28,453,526
143	(589) Rents	2,993,749	2,489,215
144	TOTAL Operation (Enter Total of lines 134 thru 143)	56,469,880	55,449,099
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,073,847	426,045
147	(591) Maintenance of Structures	2,865	887,430
148	(592) Maintenance of Station Equipment	2,618,254	2,084,060
149	(593) Maintenance of Overhead Lines	96,028,005	121,847,376
150	(594) Maintenance of Underground Lines	6,416,808	8,095,371
151	(595) Maintenance of Line Transformers	1,401,845	1,100,853
152	(596) Maintenance of Street Lighting and Signal Systems	7,767,797	8,256,330
153	(597) Maintenance of Meters	1,645,579	1,581,599
154	(598) Maintenance of Miscellaneous Distribution Plant	1,025,486	317,018
155	TOTAL Maintenance (Total of lines 146 thru 154)	117,980,486	144,596,082
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	174,450,366	200,045,181
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	127,256	59,759
160	(902) Meter Reading Expenses	4,492,542	5,525,904
161	(903) Customer Records and Collection Expenses	38,795,775	39,373,362
162	(904) Uncollectible Accounts	11,739,926	10,008,548
163	(905) Miscellaneous Customer Accounts Expenses	594,168	1,116,785
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	55,749,667	56,084,358

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	13,324	6,477
169	(909) Informational and Instructional Expenses	100,569	67,011
170	(910) Miscellaneous Customer Service and Informational Expenses	3,454,186	3,512,540
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	3,568,079	3,586,028
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	451	10,582
175	(912) Demonstrating and Selling Expenses	7,737,716	7,521,391
176	(913) Advertising Expenses	109,493	217,839
177	(916) Miscellaneous Sales Expenses	301,195	124,415
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	8,148,855	7,874,227
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	103,619,883	134,784,940
182	(921) Office Supplies and Expenses	60,182,845	54,554,016
183	(Less) (922) Administrative Expenses Transferred-Credit	-3,107	-3,396
184	(923) Outside Services Employed	45,664,657	53,579,046
185	(924) Property Insurance	-11,412,707	-774,442
186	(925) Injuries and Damages	9,765,326	6,373,182
187	(926) Employee Pensions and Benefits	87,774,392	115,350,507
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	11,103,140	8,596,196
190	(929) (Less) Duplicate Charges-Cr.	3,193,678	3,699,903
191	(930.1) General Advertising Expenses	2,007,460	3,591,669
192	(930.2) Miscellaneous General Expenses	-17,139,436	-19,847,613
193	(931) Rents	31,034,233	30,243,444
194	TOTAL Operation (Enter Total of lines 181 thru 193)	319,409,222	382,754,438
195	Maintenance		
196	(935) Maintenance of General Plant	284,388	684,263
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	319,693,610	383,438,701
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,357,970,229	3,366,552,677

FOOTNOTE DATA

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

Accounts 501007, 501008, and 501009 for Beneficial Reuse in the amount of $8,786,094 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 $7,051,178.64 are excluded from fuel totals allocated by plant on Form 1 pages 402 and 403.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	1529 Properties LLC	LU	1.00000	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	Albert Adcock	LU	1.00000	0.00000	0.00000	0.00000
6	Albertson Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Alice Rosser	LU	1.00000	0.00000	0.00000	0.00000
8	Alvin Easton	LU	1.00000	0.00000	0.00000	0.00000
9	AM Best Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Ambient Advisory Services INC	LU	1.00000	0.00000	0.00000	0.00000
11	Amy Underwood	LU	1.00000	0.00000	0.00000	0.00000
12	Anderson Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Andrew Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Angier Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Arba Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Archer Daniels	LU	1.00000	0.00000	0.00000	0.00000
3	Arden Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Argand Rooftop 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Argand Rooftop 3 LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Argand Rooftop 4 LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Argand SPP2 LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Aspen Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Atkinson Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Axiom Environmental INC	LU	1.00000	0.00000	0.00000	0.00000
11	B & K Timber LLC	LU	1.00000	0.00000	0.00000	0.00000
12	B.V. Hedrick Gravel & Sand Co	LU	1.00000	0.00000	0.00000	0.00000
13	Balsam Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Baltimore Church	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Barkley-Sexton Energy LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Barry Estes	LU	1.00000	0.00000	0.00000	0.00000
3	Battye Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Bayer Cropscience LP	LU	1.00000	0.00000	0.00000	0.00000
5	Bearford Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Beaufort Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Bertram Kalet	LU	1.00000	0.00000	0.00000	0.00000
8	Beulaville Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	BGE Carolina Sunsense I LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Billy Moon	LU	1.00000	0.00000	0.00000	0.00000
11	Biltmore Natural Resources INC	LU	1.00000	0.00000	0.00000	0.00000
12	Biscoe Solar	LU	1.00000	0.00000	0.00000	0.00000
13	Bizzell Church Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Bizzell Church Solar 2	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Black Creek	LU	1.00000	0.00000	0.00000	0.00000
2	Bladenboro Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Bladenboro Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Blueberry One	LU	1.00000	0.00000	0.00000	0.00000
5	Boaz Farm	LU	1.00000	0.00000	0.00000	0.00000
6	Bolton Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Boone Guyton	LU	1.00000	0.00000	0.00000	0.00000
8	Brandon Laroque	LU	1.00000	0.00000	0.00000	0.00000
9	BRE NC Solar 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Brenda Currin	LU	1.00000	0.00000	0.00000	0.00000
11	Broadway Solar	LU	1.00000	0.00000	0.00000	0.00000
12	Brooks Energy	LU	1.00000	0.00000	0.00000	0.00000
13	Bruce Ford	LU	1.00000	0.00000	0.00000	0.00000
14	Bruce J Rakay	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Buncombe County Landfill	LU	1.00000	0.00000	0.00000	0.00000
2	Bunn Level Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	C II METHANE MANAGEMENT IV LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Camp Rockmont for Boys INC	LU	1.00000	0.00000	0.00000	0.00000
5	Candace Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Carolina Solar Energy NCSU	LU	1.00000	0.00000	0.00000	0.00000
7	Carolina Solar Energy PCSP1	LU	1.00000	0.00000	0.00000	0.00000
8	Carolina Solar Energy-EMJ	LU	1.00000	0.00000	0.00000	0.00000
9	Carolina Tractor & Equipment Co	LU	1.00000	0.00000	0.00000	0.00000
10	Castalia Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Catherine Willis	LU	1.00000	0.00000	0.00000	0.00000
12	CB Bladen Solar	LU	1.00000	0.00000	0.00000	0.00000
13	CBC Alternative Energy LLC (NEW)	LU	1.00000	0.00000	0.00000	0.00000
14	CBC Alternative Energy LLC (OLD)	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Cedar Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Chadbourn Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Charles Lewis	LU	1.00000	0.00000	0.00000	0.00000
4	Chauncey Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Chei Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Choco Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Chocowinity Solar	LU	1.00000	0.00000	0.00000	0.00000
8	Christiansted Port Terminal Corp.	LU	1.00000	0.00000	0.00000	0.00000
9	Cirrus Solar	LU	1.00000	0.00000	0.00000	0.00000
10	City of Raleigh Parks Recreation Depar	LU	1.00000	0.00000	0.00000	0.00000
11	Clara Reed	LU	1.00000	0.00000	0.00000	0.00000
12	Clipperton Holdings	LU	1.00000	0.00000	0.00000	0.00000
13	Coats Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Cohen Farm Solar	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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	Corc Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Cornwall Solar	LU	1.00000	0.00000	0.00000	0.00000
3	Cotten Farm	LU	1.00000	0.00000	0.00000	0.00000
4	Covey Run Apartments LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Cox Lake Hydro Electric	LU	1.00000	0.00000	0.00000	0.00000
6	CP Energy Marketing (US) Inc. - Roxbo	LU	1.00000	0.00000	0.00000	0.00000
7	CP Energy Marketing (US) Inc. - South	LU	1.00000	0.00000	0.00000	0.00000
8	CPI Roxboro	LU	1.00000	0.00000	0.00000	0.00000
9	CPI Southport	LU	1.00000	0.00000	0.00000	0.00000
10	Craig Eury	LU	1.00000	0.00000	0.00000	0.00000
11	Craven County Wood Energy LP	LU	1.00000	0.00000	0.00000	0.00000
12	Creech Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Crestwood Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Crockett 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	04/14/2020	End of 2019/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	Currin Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
2	Custom Packaging Inc	LU	1.00000	0.00000	0.00000	0.00000
3	Darlington Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	David Tobin	LU	1.00000	0.00000	0.00000	0.00000
5	Daystar Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Debra Bapat	LU	1.00000	0.00000	0.00000	0.00000
7	Deep Branch Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Deep River Hydro	LU	1.00000	0.00000	0.00000	0.00000
9	Delco Farm	LU	1.00000	0.00000	0.00000	0.00000
10	Deltec Homes Inc	LU	1.00000	0.00000	0.00000	0.00000
11	Dement Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Dessie Solar Center	LU	1.00000	0.00000	0.00000	0.00000
13	DRPFC I LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Dunn 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	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Duplin Solar I LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Duplin Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
3	East Wayne Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Easters Holdings LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Eastover Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Elm Solar	LU	1.00000	0.00000	0.00000	0.00000
7	EnergyXchange INC	LU	1.00000	0.00000	0.00000	0.00000
8	Environmental Resources	LU	1.00000	0.00000	0.00000	0.00000
9	Erwin Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
10	ESA Four Oaks	LU	1.00000	0.00000	0.00000	0.00000
11	ESA NC Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
12	ESA Newton Grove 1 NC LLC	LU	1.00000	0.00000	0.00000	0.00000
13	ESA Princeton NC	LU	1.00000	0.00000	0.00000	0.00000
14	ESA RENEWABLES III 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	04/14/2020	End of 2019/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	Eva Anderson (James Anderson Barn)	LU	1.00000	0.00000	0.00000	0.00000
2	Eva Anderson (James Anderson House)	LU	1.00000	0.00000	0.00000	0.00000
3	EWP LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Exhibit Court Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Exum Farm Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
6	F & D Huebner LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Faison Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Farrington Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Ferguson Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
10	First Christian Church	LU	1.00000	0.00000	0.00000	0.00000
11	First Citizens Bank & Trust Co 1.14MW	LU	1.00000	0.00000	0.00000	0.00000
12	First Citizens Bank & Trust Co 566KW	LU	1.00000	0.00000	0.00000	0.00000
13	Floyd Solar	LU	1.00000	0.00000	0.00000	0.00000
14	FLS Owner 80 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	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	FLS Owner II LLC	LU	1.00000	0.00000	0.00000	0.00000
2	FLS Solar 10 LLC	LU	1.00000	0.00000	0.00000	0.00000
3	FLS Solar 100 LLC	LU	1.00000	0.00000	0.00000	0.00000
4	FLS Solar 110 LLC	LU	1.00000	0.00000	0.00000	0.00000
5	FLS Solar 170 LLC	LU	1.00000	0.00000	0.00000	0.00000
6	FLS Solar 20 LLC - Chatham (FLS Owner	LU	1.00000	0.00000	0.00000	0.00000
7	FLS Solar 20 LLC (Greensquare)	LU	1.00000	0.00000	0.00000	0.00000
8	FLS Solar 20 LLC - HCC	LU	1.00000	0.00000	0.00000	0.00000
9	FLS Solar 200 LLC	LU	1.00000	0.00000	0.00000	0.00000
10	FLS Solar 230 LLC - Warren Place	LU	1.00000	0.00000	0.00000	0.00000
11	FLS Solar 260 LLC	LU	1.00000	0.00000	0.00000	0.00000
12	FLS YK Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Foxfire Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Franklin Solar 2 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	04/14/2020	End of 2019/Q4

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1	Franklin Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Franklinton Solar	LU	1.00000	0.00000	0.00000	0.00000
3	Fremont Farms LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Fresh Air Energy - Carter	LU	1.00000	0.00000	0.00000	0.00000
5	Fresh Air Energy - Langley	LU	1.00000	0.00000	0.00000	0.00000
6	Fresh Air Energy - Pecan	LU	1.00000	0.00000	0.00000	0.00000
7	Fresh Air Energy XXXI - Little River	LU	1.00000	0.00000	0.00000	0.00000
8	Fresh Air Thornton (Fresh Air XVI LLC)	LU	1.00000	0.00000	0.00000	0.00000
9	Fuquay Farms LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Gainey Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Garrell Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
12	Gary Shaver	LU	1.00000	0.00000	0.00000	0.00000
13	Gary Spodnick	LU	1.00000	0.00000	0.00000	0.00000
14	Gaylond Owens	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	04/14/2020	End of 2019/Q4

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1	Gene Rainey	LU	1.00000	0.00000	0.00000	0.00000
2	Glen Raven Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Gordon Koncal	LU	1.00000	0.00000	0.00000	0.00000
4	Granville Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Greenfield Power GTP One LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Gregory Poole Equip Co	LU	1.00000	0.00000	0.00000	0.00000
7	Happy Solar	LU	1.00000	0.00000	0.00000	0.00000
8	Harrell's Hill Solar	LU	1.00000	0.00000	0.00000	0.00000
9	Harvest Beulaville	LU	1.00000	0.00000	0.00000	0.00000
10	Haywood Farm Solar	LU	1.00000	0.00000	0.00000	0.00000
11	HCE Johnston I LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Hector Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Hessler 115KW	LU	1.00000	0.00000	0.00000	0.00000
14	Hessler 153KW	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	04/14/2020	End of 2019/Q4

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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Hew Fulton Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Highland Community Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Highland Craftsmen INC	LU	1.00000	0.00000	0.00000	0.00000
4	Highland Solar Center	LU	1.00000	0.00000	0.00000	0.00000
5	Highwater Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Holstein Holdings	LU	1.00000	0.00000	0.00000	0.00000
7	Hood Farm Solar	LU	1.00000	0.00000	0.00000	0.00000
8	Howard Plemmons	LU	1.00000	0.00000	0.00000	0.00000
9	Hydrodyne-High Falls	LU	1.00000	0.00000	0.00000	0.00000
10	Hydrodyne-Little River	LU	1.00000	0.00000	0.00000	0.00000
11	Ideal Fastner Corp	LU	1.00000	0.00000	0.00000	0.00000
12	Ingenco Renewables	LU	1.00000	0.00000	0.00000	0.00000
13	Ingenco Wholesale	LU	1.00000	0.00000	0.00000	0.00000
14	Innovative Solar 10	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	04/14/2020	End of 2019/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	Innovative Solar 31 LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Innovative Solar 35 LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Innovative Solar 37 LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Innovative Solar 42	LU	1.00000	0.00000	0.00000	0.00000
5	Innovative Solar 43 LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Innovative Solar 44 LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Innovative Solar 46 LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Innovative Solar 47 LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Innovative Solar 48 LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Innovative Solar 59 LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Innovative Solar 6	LU	1.00000	0.00000	0.00000	0.00000
12	Innovative Solar 60 LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Innovative Solar 63	LU	1.00000	0.00000	0.00000	0.00000
14	Innovative Solar 64 LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Innovative Solar 65 LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Innovative Solar6 P1	LU	1.00000	0.00000	0.00000	0.00000
3	Innovative Solar6 P2	LU	1.00000	0.00000	0.00000	0.00000
4	International Paper	LU	1.00000	0.00000	0.00000	0.00000
5	J Godwin (John)	LU	1.00000	0.00000	0.00000	0.00000
6	Jack Bennett	LU	1.00000	0.00000	0.00000	0.00000
7	Jackson & Sons Inc	LU	1.00000	0.00000	0.00000	0.00000
8	James Hubbell	LU	1.00000	0.00000	0.00000	0.00000
9	James Thorpe	LU	1.00000	0.00000	0.00000	0.00000
10	James Young (Asheville Alternative)	LU	1.00000	0.00000	0.00000	0.00000
11	James Young (Asheville Alt Energy)	LU	1.00000	0.00000	0.00000	0.00000
12	Janet Dektor	LU	1.00000	0.00000	0.00000	0.00000
13	Jason Hibbets	LU	1.00000	0.00000	0.00000	0.00000
14	Jerry Sullivan	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
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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Jessica Larsen (Chris Larsen)	LU	1.00000	0.00000	0.00000	0.00000
2	John Hollingsworth	LU	1.00000	0.00000	0.00000	0.00000
3	John McDermott	LU	1.00000	0.00000	0.00000	0.00000
4	John Reese	LU	1.00000	0.00000	0.00000	0.00000
5	Johnson Breeders	LU	1.00000	0.00000	0.00000	0.00000
6	Jordan Hydroelectric LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Joseph Callahan	LU	1.00000	0.00000	0.00000	0.00000
8	Joseph Ponzi	LU	1.00000	0.00000	0.00000	0.00000
9	JT Hobby & Sons Inc.	LU	1.00000	0.00000	0.00000	0.00000
10	K & HB Enterprises LLC - Waynesville	LU	1.00000	0.00000	0.00000	0.00000
11	K & HB Enterprises LLC - Asheville	LU	1.00000	0.00000	0.00000	0.00000
12	Karen Mallam	LU	1.00000	0.00000	0.00000	0.00000
13	Kathy Hansinger	LU	1.00000	0.00000	0.00000	0.00000
14	Keen Farm	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Kelly Daiker	LU	1.00000	0.00000	0.00000	0.00000
2	Kenansville Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Kenansville Solar Farm LLC (Heelstone	LU	1.00000	0.00000	0.00000	0.00000
4	Kenansville Solar LLC (FLS Energy)	LU	1.00000	0.00000	0.00000	0.00000
5	Kennedy Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Kenneth Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Kinston Davis Farm	LU	1.00000	0.00000	0.00000	0.00000
8	Kinston Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Kirkwall Holdings LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Kojak farm	LU	1.00000	0.00000	0.00000	0.00000
11	Kristen Blackley	LU	1.00000	0.00000	0.00000	0.00000
12	L&D Incorporated	LU	1.00000	0.00000	0.00000	0.00000
13	L&S Waterpower	LU	1.00000	0.00000	0.00000	0.00000
14	Lake Upchurch Power Inc.	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Land of the Sky MT (Eden Solar/Innovat	LU	1.00000	0.00000	0.00000	0.00000
2	Laney Development Inc	LU	1.00000	0.00000	0.00000	0.00000
3	Lang Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Langdon Solar	LU	1.00000	0.00000	0.00000	0.00000
5	Lanier Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Laurinburg Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Lea Romano	LU	1.00000	0.00000	0.00000	0.00000
8	Lenior Farm 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Lenior Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Leonard Bernstein	LU	1.00000	0.00000	0.00000	0.00000
11	Lewis Rothlein	LU	1.00000	0.00000	0.00000	0.00000
12	Lillington Solar	LU	1.00000	0.00000	0.00000	0.00000
13	Linda Sweeney	LU	1.00000	0.00000	0.00000	0.00000
14	Logan Trading Co Inc.	LU	1.00000	0.00000	0.00000	0.00000
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1	Lumberton Power	LU	1.00000	0.00000	0.00000	0.00000
2	M B Haynes Corporation 12KW	LU	1.00000	0.00000	0.00000	0.00000
3	M B Haynes Corporation 24KW	LU	1.00000	0.00000	0.00000	0.00000
4	M Stone (Mike)	LU	1.00000	0.00000	0.00000	0.00000
5	Madison Hydro Partners	LU	1.00000	0.00000	0.00000	0.00000
6	Mahadev Enterprises LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Manway Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Margaret Hayes	LU	1.00000	0.00000	0.00000	0.00000
9	Mark Parker	LU	1.00000	0.00000	0.00000	0.00000
10	Marshall's Locksmith Services Inc	LU	1.00000	0.00000	0.00000	0.00000
11	Martin Creek Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Maxton Solar 1	LU	1.00000	0.00000	0.00000	0.00000
13	McCallum Farm	LU	1.00000	0.00000	0.00000	0.00000
14	McGoogan Farm	LU	1.00000	0.00000	0.00000	0.00000
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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	McKenzie Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
2	MDK Cornerstone LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Melinda Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Meriwether Farm	LU	1.00000	0.00000	0.00000	0.00000
5	Metropolitan Sewerage	LU	1.00000	0.00000	0.00000	0.00000
6	Mile Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Mill Pond Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
8	Mills Anson Farm	LU	1.00000	0.00000	0.00000	0.00000
9	Moncure Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Montgomery Solar	LU	1.00000	0.00000	0.00000	0.00000
11	Moorings Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Moorings Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Morgan Farm	LU	1.00000	0.00000	0.00000	0.00000
14	Mount Olive 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	04/14/2020	End of 2019/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	MP Wayne County Landfill	LU	1.00000	0.00000	0.00000	0.00000
2	Mt Olive Farm	LU	1.00000	0.00000	0.00000	0.00000
3	Mt Olive Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Mt Olive Solar 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Munich Motors INC	LU	1.00000	0.00000	0.00000	0.00000
6	Murdock Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Nash 58 Farm	LU	1.00000	0.00000	0.00000	0.00000
8	Nash 64 Farm	LU	1.00000	0.00000	0.00000	0.00000
9	Nash 97 Solar	LU	1.00000	0.00000	0.00000	0.00000
10	Nashville Farms LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Nathan Conroy	LU	1.00000	0.00000	0.00000	0.00000
12	NC State Museum of Nat Science	LU	1.00000	0.00000	0.00000	0.00000
13	NCEMC - Ajax	LU	1.00000	0.00000	0.00000	0.00000
14	NCEMC - Bear Creek Solar	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	NCEMC - Flint Solar	LU	1.00000	0.00000	0.00000	0.00000
2	NCEMC - Jersey Holdings Solar	LU	1.00000	0.00000	0.00000	0.00000
3	NCEMC - Long Henry Solar	LU	1.00000	0.00000	0.00000	0.00000
4	NCEMC - Revolution Dial Road	LU	1.00000	0.00000	0.00000	0.00000
5	NCEMC - Revolution Ezzel Road	LU	1.00000	0.00000	0.00000	0.00000
6	NCEMC - Robeson Landfill (Phase 1)	LU	1.00000	0.00000	0.00000	0.00000
7	NCEMC - Robeson Landfill (Phase 2)	LU	1.00000	0.00000	0.00000	0.00000
8	NCEMC - Rosewood Solar	LU	1.00000	0.00000	0.00000	0.00000
9	NCEMC - Ruskin Solar	LU	1.00000	0.00000	0.00000	0.00000
10	NCEMC - Scarlett Solar	LU	1.00000	0.00000	0.00000	0.00000
11	NCEMC - Snow Camp Solar	LU	1.00000	0.00000	0.00000	0.00000
12	NCEMC - Storm Hog Partners	LU	1.00000	0.00000	0.00000	0.00000
13	NCEMC - Storm Hog Partners 2	LU	1.00000	0.00000	0.00000	0.00000
14	NCEMC - Sunny Point	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	NCEMC - Viper Solar	LU	1.00000	0.00000	0.00000	0.00000
2	NCEMPA	LU	1.00000	0.00000	0.00000	0.00000
3	Neuse River Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
4	New Bern Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Nitro Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
6	North Carolina Solar I LLC	LU	1.00000	0.00000	0.00000	0.00000
7	North Carolina Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
8	North Carolina Solar III Lessee LLC	LU	1.00000	0.00000	0.00000	0.00000
9	North Nash Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Oakboro Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Old Webbs Mill Hydro LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Old Wire Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Onslow Power Producers LLC	LU	1.00000	0.00000	0.00000	0.00000
14	P K Ventures Inc	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Pate Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
2	PCIP Solar Lessee LLC	LU	1.00000	0.00000	0.00000	0.00000
3	PCSP3 Airport LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Perkins Solar	LU	1.00000	0.00000	0.00000	0.00000
5	Pikeville Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Pinedale Springs	LU	1.00000	0.00000	0.00000	0.00000
7	Pohoja Corporation (Kenneth Sheffield)	LU	1.00000	0.00000	0.00000	0.00000
8	Pollocksville Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Porter Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Prestage Agenergy NC	LU	1.00000	0.00000	0.00000	0.00000
11	Prestage Farms Inc.	LU	1.00000	0.00000	0.00000	0.00000
12	Progress Solar I LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Progress Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Progress Solar III LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Quarters LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Quincy Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Raeford Farm	LU	1.00000	0.00000	0.00000	0.00000
4	Railroad Farm	LU	1.00000	0.00000	0.00000	0.00000
5	Railroad Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Railroad Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Red Hill Solar	LU	1.00000	0.00000	0.00000	0.00000
8	Red Oak Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Red Toad A Powatan Road LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Red Toad II LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Renewable Power LLC (Foodlion)	LU	1.00000	0.00000	0.00000	0.00000
12	RES AG DM 2-1 LLC (RES Agriculture NC	LU	1.00000	0.00000	0.00000	0.00000
13	RES AG DM 4-3 LLC (RES Agriculture NC	LU	1.00000	0.00000	0.00000	0.00000
14	Riding Partners Bio	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Riding Partners INC	LU	1.00000	0.00000	0.00000	0.00000
2	Riding Partners INC #2	LU	1.00000	0.00000	0.00000	0.00000
3	Riding Partners INC #3	LU	1.00000	0.00000	0.00000	0.00000
4	Robert & Phyllis Wooten	LU	1.00000	0.00000	0.00000	0.00000
5	Robert Beatty	LU	1.00000	0.00000	0.00000	0.00000
6	Robert Dick	LU	1.00000	0.00000	0.00000	0.00000
7	Robert Harris	LU	1.00000	0.00000	0.00000	0.00000
8	Robert Hicks	LU	1.00000	0.00000	0.00000	0.00000
9	Robert Wooten	LU	1.00000	0.00000	0.00000	0.00000
10	Rock Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Rockingham Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Rocky Mount Mills	LU	1.00000	0.00000	0.00000	0.00000
13	Rocky River Hydro LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Rose Hill Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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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	Roxboro Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Roxboro Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
3	Royal Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Sam Rogers	LU	1.00000	0.00000	0.00000	0.00000
5	Samarcand Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
6	Sampson Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Sandy Cross Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Sarah Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	SAS - 1200KW	LU	1.00000	0.00000	0.00000	0.00000
10	SAS Institute - Building G	LU	1.00000	0.00000	0.00000	0.00000
11	SAS Institute - Building T	LU	1.00000	0.00000	0.00000	0.00000
12	Scott Shackleton	LU	1.00000	0.00000	0.00000	0.00000
13	Sedberry Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
14	SEGY 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	04/14/2020	End of 2019/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	Selma Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
2	Shannon Farm	LU	1.00000	0.00000	0.00000	0.00000
3	Siler 421 Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
4	SMB Holding 10 LLC	LU	1.00000	0.00000	0.00000	0.00000
5	SMB Holdings 5 LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Snow Hill Solar 2	LU	1.00000	0.00000	0.00000	0.00000
7	Sol Sencia Ventures LLC (Paul Kazmer)	LU	1.00000	0.00000	0.00000	0.00000
8	Solar 55 LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Solarworks RCC LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Soluga Farm I LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Soluga Farm II LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Soluga Farm III LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Sonne One LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Soul City Solar	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	South Atlantic Services	LU	1.00000	0.00000	0.00000	0.00000
2	South Louisburg Solar	LU	1.00000	0.00000	0.00000	0.00000
3	South Robeson Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Southeastern Freight Lines	LU	1.00000	0.00000	0.00000	0.00000
5	Southerland Farms	LU	1.00000	0.00000	0.00000	0.00000
6	Spicewood Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
7	Spring Valley Solar 2	LU	1.00000	0.00000	0.00000	0.00000
8	St. Pauls Solar 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
9	St. Pauls Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Stagecoach Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Stainback Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
12	Steve Zarnowski (FLAT CREEK)	LU	1.00000	0.00000	0.00000	0.00000
13	Stone Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Strata Fund 11 Lessee LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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PURCHASED POWER (Account 555)
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1	Sumter Heat & Power LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Sun Devil Solar	LU	1.00000	0.00000	0.00000	0.00000
3	SunE Bearpond Lessee	LU	1.00000	0.00000	0.00000	0.00000
4	SunE Graham Lessee	LU	1.00000	0.00000	0.00000	0.00000
5	SunE NC Progress LLC	LU	1.00000	0.00000	0.00000	0.00000
6	SunE Shankle Lessee	LU	1.00000	0.00000	0.00000	0.00000
7	Sunenergy1-Asheville LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Sunfish Solar	LU	1.00000	0.00000	0.00000	0.00000
9	Sunstruck Energy LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Sweetgum Solar	LU	1.00000	0.00000	0.00000	0.00000
11	Tart Farm	LU	1.00000	0.00000	0.00000	0.00000
12	Thaddeus Burgess Trust	LU	1.00000	0.00000	0.00000	0.00000
13	The Big Chicken LLC	LU	1.00000	0.00000	0.00000	0.00000
14	The N C Growers Assoc Inc	LU	1.00000	0.00000	0.00000	0.00000
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1	The Rock Solar Energy Plant LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Tony Gaddis	LU	1.00000	0.00000	0.00000	0.00000
3	Town of Warsaw Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Tracy Solar	LU	1.00000	0.00000	0.00000	0.00000
5	Tria Cline	LU	1.00000	0.00000	0.00000	0.00000
6	Tryon Road INC	LU	1.00000	0.00000	0.00000	0.00000
7	Turkey Branch Solar (FLS 2014 SOLAR A)	LU	1.00000	0.00000	0.00000	0.00000
8	TWE Chocowinity	LU	1.00000	0.00000	0.00000	0.00000
9	TWE Kinston Solar	LU	1.00000	0.00000	0.00000	0.00000
10	TWE Laurinburg	LU	1.00000	0.00000	0.00000	0.00000
11	TWE New Bern Solar	LU	1.00000	0.00000	0.00000	0.00000
12	US Dept of Commerce NOAA (Randy Grady)	LU	1.00000	0.00000	0.00000	0.00000
13	Uwharrie Mountain Renewables	LU	1.00000	0.00000	0.00000	0.00000
14	Vance Solar 1	LU	1.00000	0.00000	0.00000	0.00000
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1	Vandy LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Vickers Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
3	Vicksburg Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	W.E. Partners IV LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Wadesboro Farm	LU	1.00000	0.00000	0.00000	0.00000
6	Wadesboro Farm 2	LU	1.00000	0.00000	0.00000	0.00000
7	Wadesboro Farm 3	LU	1.00000	0.00000	0.00000	0.00000
8	Wagstaff Farm 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Wake Tech Innovations Inc	LU	1.00000	0.00000	0.00000	0.00000
10	Wallace Solar	LU	1.00000	0.00000	0.00000	0.00000
11	Warren Wilson College	LU	1.00000	0.00000	0.00000	0.00000
12	Warrenton Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Warsaw Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Warsaw Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
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1	Watts Farm	LU	1.00000	0.00000	0.00000	0.00000
2	Wayne County Public Schools	LU	1.00000	0.00000	0.00000	0.00000
3	Wayne Hilbert	LU	1.00000	0.00000	0.00000	0.00000
4	Wayne Solar I LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Wayne Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
6	Wayne Solar III LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Wellons Farm	LU	1.00000	0.00000	0.00000	0.00000
8	West Siler Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Westgate Auto Group LLC	LU	1.00000	0.00000	0.00000	0.00000
10	William Kelly	LU	1.00000	0.00000	0.00000	0.00000
11	Wilson Farm 1 LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Woodland Church Farm	LU	1.00000	0.00000	0.00000	0.00000
13	Wortham Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Yanceyville Farm 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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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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	Yanceyville Farm 3	LU	1.00000	0.00000	0.00000	0.00000
2	Yanceyville Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	ZV Solar 1	LU	1.00000	0.00000	0.00000	0.00000
4	ZV Solar 2	LU	1.00000	0.00000	0.00000	0.00000
5	ZV Solar 3	LU	1.00000	0.00000	0.00000	0.00000
6	Barker Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Bladen Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Broadridge Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Bullock Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Freedom Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Henry Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Innovative Solar 55 LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Shoe Creek Solar	LU	1.00000	0.00000	0.00000	0.00000
14	Wakefield 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	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	MDK Cornerstone LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Warren Wilson College	LU	1.00000	0.00000	0.00000	0.00000
3	ABD Farm Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Wadesboro Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	NCEMC - Bondi Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Bearford Solar II LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Bayboro Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
8	Sneads Grove Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Wadford Storage	LU	1.00000	0.00000	0.00000	0.00000
10	NCEMC - Strider Solar	LU	1.00000	0.00000	0.00000	0.00000
11	DSM Nutritional	LU	1.00000	0.00000	0.00000	0.00000
12	Cougar Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Hanover Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Kalish Farm 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
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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Kelly Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Mustang Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Sadiebrook Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Heedeh Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Bladenboro Farm 2	LU	1.00000	0.00000	0.00000	0.00000
6	County Home	LU	1.00000	0.00000	0.00000	0.00000
7	ESA Church Road	LU	1.00000	0.00000	0.00000	0.00000
8	Soluga Farms IV LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Trent River Farm	LU	1.00000	0.00000	0.00000	0.00000
10	Lane Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	A&G/Kitty hawk Solar	LU	1.00000	0.00000	0.00000	0.00000
12	Arthur Solar	LU	1.00000	0.00000	0.00000	0.00000
13	NCEMC - Copperfield Solar	LU	1.00000	0.00000	0.00000	0.00000
14	NCEMC - Hopewell Friends 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	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	NCEMC - Morning View Solar	LU	1.00000	0.00000	0.00000	0.00000
2	Brantley Farm Solar	LU	1.00000	0.00000	0.00000	0.00000
3	Buckleberry Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Fox Creek Farm	LU	1.00000	0.00000	0.00000	0.00000
5	UP Property 2 LLC(Hydrodyne-High Fall	LU	1.00000	0.00000	0.00000	0.00000
6	Tinker Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
7	Atkinson Solar II	LU	1.00000	0.00000	0.00000	0.00000
8	Bond Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Boston Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
10	Farrington Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Flatwood Farm	LU	1.00000	0.00000	0.00000	0.00000
12	Gary Solar	LU	1.00000	0.00000	0.00000	0.00000
13	Innovative Solar 54	LU	1.00000	0.00000	0.00000	0.00000
14	Innovative Solar 67	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	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
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1	Kathleen Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Red Toad 4451	LU	1.00000	0.00000	0.00000	0.00000
3	Red Toad 5840	LU	1.00000	0.00000	0.00000	0.00000
4	Page Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Quarter Horse Farm	LU	1.00000	0.00000	0.00000	0.00000
6	Sapphire Solar	LU	1.00000	0.00000	0.00000	0.00000
7	Shelter Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
8	Siler Solar	LU	1.00000	0.00000	0.00000	0.00000
9	South Solar	LU	1.00000	0.00000	0.00000	0.00000
10	Willis Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Achilles Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Bay Branch Solar	LU	1.00000	0.00000	0.00000	0.00000
13	Belafonte Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Cookstown Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Nickelson Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Pinesage Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
3	Blacktip Solar	LU	1.00000	0.00000	0.00000	0.00000
4	Bo Biggs Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Meadowlark Solar	LU	1.00000	0.00000	0.00000	0.00000
6	Michael Ian McGregor	LU	1.00000	0.00000	0.00000	0.00000
7	Nash 97 Solar 2 LLC	LU	1.00000	0.00000	0.00000	0.00000
8	River Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
9	Siler City Solar 2	LU	1.00000	0.00000	0.00000	0.00000
10	Starr Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
11	Three Bridge Farm	LU	1.00000	0.00000	0.00000	0.00000
12	Warrenton Solar I	LU	1.00000	0.00000	0.00000	0.00000
13	Abbot Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Arborgate Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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1	Badger Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Cube Yadkin Generation LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Flowers Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
4	HCE Moore I LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Innovative Solar 31	LU	1.00000	0.00000	0.00000	0.00000
6	Neal Hydro (formerly L&S Waterpower)	LU	1.00000	0.00000	0.00000	0.00000
7	Nickelson Solar 2	LU	1.00000	0.00000	0.00000	0.00000
8	Wadesboro Farm 4	LU	1.00000	0.00000	0.00000	0.00000
9	NCEMC - Leggett Solar	LU	1.00000	0.00000	0.00000	0.00000
10	NCEMC - Tobacco Rd Solar	LU	1.00000	0.00000	0.00000	0.00000
11	Bloom Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
12	Goldenrod Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Hydrodyne Energy	LU	1.00000	0.00000	0.00000	0.00000
14	Marguerite Rogers	LU	1.00000	0.00000	0.00000	0.00000
	Total					

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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	Redwing Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Vincent Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
3	NCEMC - Panda NC 1	LU	1.00000	0.00000	0.00000	0.00000
4	NCEMC - Panda NC 2	LU	1.00000	0.00000	0.00000	0.00000
5	NCEMC - Panda NC 3	LU	1.00000	0.00000	0.00000	0.00000
6	NCEMC - Panda NC 4	LU	1.00000	0.00000	0.00000	0.00000
7	NCEMC - Panda NC 5	LU	1.00000	0.00000	0.00000	0.00000
8	NCEMC - Panda NC 6	LU	1.00000	0.00000	0.00000	0.00000
9	NCEMC - Panda NC 9	LU	1.00000	0.00000	0.00000	0.00000
10	NCEMC - Panda NC 10	LU	1.00000	0.00000	0.00000	0.00000
11	NCEMC - Panda NC 11	LU	1.00000	0.00000	0.00000	0.00000
12	200 Cornerstone LLC	LU	1.00000	0.00000	0.00000	0.00000
13	Changeup Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
14	Jessamine 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	04/14/2020	End of 2019/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	Kendall Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
2	Peake Road Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
3	Rocky Mount Mill	LU	1.00000	0.00000	0.00000	0.00000
4	Watauga Solar LLC	LU	1.00000	0.00000	0.00000	0.00000
5	Woodsdale Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
6	NCEMC - Panda NC 7	LU	1.00000	0.00000	0.00000	0.00000
7	Smith Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
8	Ann Willard	LU	1.00000	0.00000	0.00000	0.00000
9	Jason Sprouse	LU	1.00000	0.00000	0.00000	0.00000
10	Mildred Long	LU	1.00000	0.00000	0.00000	0.00000
11	Peter Brezny	LU	1.00000	0.00000	0.00000	0.00000
12	Ron Hess	LU	1.00000	0.00000	0.00000	0.00000
13	Warren Solar Farm	LU	1.00000	0.00000	0.00000	0.00000
14	NCEMC - Panda NC 8	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	04/14/2020	End of 2019/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	NCEMC - Country Poultry	LU	1.00000	0.00000	0.00000	0.00000
2	Legacy Biogas	LU	1.00000	0.00000	0.00000	0.00000
3	Wendell Solar Farm LLC	LU	1.00000	0.00000	0.00000	0.00000
4	Innovative Solar 43	LU	1.00000	0.00000	0.00000	0.00000
5	Broad River Energy, LLC	LU	1			
6	Broad River Energy, LLC	AD	1			
7	City of Fayetteville (Butler Warner)	OS				
8	City of Fayetteville (Butler Warner)	AD				
9	Southern Power Co	LU	7			
10	Southern Power Co	AD	7			
11	Hamlet (NCEMC)	LU				
12	Hamlet (NCEMC)	AD				
13	PJM Settlements, Inc	OS	188			
14	PJM Settlements, Inc	AD	188			
	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	04/14/2020	End of 2019/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	Haywood Electric Membership Corp	LF	180			
2	Haywood Electric Membership Corp	AD	180			
3	NC Electric Membership Corp	LF	182			
4	NC Electric Membership Corp	AD	182			
5	Duke Energy Carolinas, LLC	OS	341			
6	Duke Energy Carolinas, LLC	AD	341			
7	Duke Energy Carolinas, LLC	OS	10			
8	Duke Energy Carolinas, LLC	OS	4			
9	Duke Energy Carolinas, LLC	AD	4			
10	Virginia Electric and Power Company	OS	196			
11	NC Electric Membership Corp	EX				
12	Town of Black Creek	EX				
13	Town of Lucama	EX				
14	Town of Sharpsburg	EX				
	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	04/14/2020	End of 2019/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.

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IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

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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	Town of Stantonsburg	EX				
2	Town of Waynesville	EX				
3	Town of Winterville	EX				
4	Net Metering					
5	Smurfit Stone Container					
6						
7						
8						
9						
10						
11						
12						
13						
14						
	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 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
556				42,542		42,542	2
560				35,087		35,087	3
				5		5	4
40				3,079		3,079	5
10,619				716,746		716,746	6
15				1,056		1,056	7
15				1,181		1,181	8
8,511				717,305		717,305	9
5				186		186	10
				10		10	11
3,921				328,231		328,231	12
9,439				639,573		639,573	13
7,527				632,128		632,128	14
9,989,520			107,777,742	528,615,577		636,393,319	

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.
3,160				265,469		265,469	1
				2		2	2
268				9,599		9,599	3
656				50,230		50,230	4
287				21,936		21,936	5
763				58,430		58,430	6
279				17,440		17,440	7
9,241				625,956		625,956	8
9,032				610,800		610,800	9
7				462		462	10
14				1,054		1,054	11
16				1,200		1,200	12
9,087				615,405		615,405	13
8,005				507,494		507,494	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
-2				-137		-137	1
7				252		252	2
33				2,058		2,058	3
31				1,904		1,904	4
9,231				617,659		617,659	5
29,317				1,953,934		1,953,934	6
7				628		628	7
3,298				277,012		277,012	8
587				44,916		44,916	9
3				121		121	10
2,045				74,416		74,416	11
9,102				534,737		534,737	12
9,506				645,110		645,110	13
9,549				647,322		647,322	14
9,989,520			107,777,742	528,615,577		636,393,319	

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 ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
63,863				3,866,258		3,866,258	1
8,241				692,121		692,121	2
9,468				639,870		639,870	3
9,412				638,302		638,302	4
9,107				615,681		615,681	5
8,882				742,618		742,618	6
				14		14	7
20				1,510		1,510	8
8,606				579,290		579,290	9
				27		27	10
9,027				758,310		758,310	11
1,908				150,710		150,710	12
6				209		209	13
8				307		307	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,187				556,377		556,377	1
9,521				798,148		798,148	2
9,840				716,942		716,942	3
7				241		241	4
8,932				605,332		605,332	5
74				4,751		4,751	6
739				46,290		46,290	7
341				21,349		21,349	8
307				19,221		19,221	9
3,613				301,562		301,562	10
13				477		477	11
9,365				634,163		634,163	12
2,934				245,244		245,244	13
1,061				81,271		81,271	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
9,357				634,556		634,556	1
9,303				778,217		778,217	2
				19		19	3
8,412				556,940		556,940	4
8,858				598,507		598,507	5
10,729				722,639		722,639	6
8,567				579,638		579,638	7
512				30,952		30,952	8
8,930				602,389		602,389	9
37				2,294		2,294	10
7				256		256	11
9,892				665,569		665,569	12
9,811				663,262		663,262	13
9,487				641,861		641,861	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
-10				-711		-711	1
9,299				780,013		780,013	2
9,678				613,028		613,028	3
11				445		445	4
1,305				104,375		104,375	5
							6
							7
324,478				25,169,879		25,169,879	8
459,585				37,432,762		37,432,762	9
5				201		201	10
326,644				16,286,492		16,286,492	11
9,014				606,392		606,392	12
9,060				614,147		614,147	13
9,177				607,302		607,302	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
8,912				564,975		564,975	1
-2				-184		-184	2
19,503				1,045,705		1,045,705	3
				6		6	4
9,735				611,233		611,233	5
3				144		144	6
9,423				594,850		594,850	7
1,288				103,910		103,910	8
8,671				584,872		584,872	9
58				2,076		2,076	10
8,858				742,562		742,562	11
8,699				730,928		730,928	12
24				1,517		1,517	13
3,571				298,809		298,809	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
8,086				677,265		677,265	1
8,881				744,943		744,943	2
3,788				316,962		316,962	3
13				802		802	4
8,929				749,490		749,490	5
8,749				592,140		592,140	6
2				95		95	7
1				52		52	8
7,326				485,430		485,430	9
8,697				569,797		569,797	10
586				44,895		44,895	11
2,904				243,150		243,150	12
8,946				591,417		591,417	13
1,562				97,797		97,797	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
11				685		685	1
5				308		308	2
1,514				97,459		97,459	3
542				45,272		45,272	4
9,442				640,259		640,259	5
33				2,096		2,096	6
3,230				213,485		213,485	7
-18				-1,397		-1,397	8
188				6,791		6,791	9
15				852		852	10
-34				-1,106		-1,106	11
-13				-429		-429	12
9,416				638,541		638,541	13
2,364				185,631		185,631	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
110				9,308		9,308	1
613				38,384		38,384	2
6,494				548,669		548,669	3
3,137				263,688		263,688	4
3,596				243,579		243,579	5
85				6,497		6,497	6
352				26,930		26,930	7
							8
6,247				422,228		422,228	9
8,672				587,498		587,498	10
8,647				585,982		585,982	11
67				4,225		4,225	12
9,599				648,718		648,718	13
3,713				312,534		312,534	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
3,184				266,625		266,625	1
9,457				635,851		635,851	2
9,693				613,746		613,746	3
9,543				647,280		647,280	4
9,708				655,939		655,939	5
9,281				625,957		625,957	6
8,860				597,825		597,825	7
8,460				576,986		576,986	8
8,245				687,871		687,871	9
3,652				246,314		246,314	10
6,811				571,950		571,950	11
13				482		482	12
3				109		109	13
1				57		57	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
				13		13	1
499				33,652		33,652	2
7				465		465	3
4,807				368,087		368,087	4
315				19,747		19,747	5
250				15,678		15,678	6
6,931				469,824		469,824	7
9,174				769,232		769,232	8
3,597				227,956		227,956	9
9,156				614,843		614,843	10
3,550				240,197		240,197	11
9,480				599,279		599,279	12
133				8,326		8,326	13
142				10,888		10,888	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
8,971				608,418		608,418	1
2				95		95	2
				9		9	3
9,275				630,123		630,123	4
9,742				659,852		659,852	5
34,143				1,987,109		1,987,109	6
9,374				635,807		635,807	7
10				366		366	8
45				4,834		4,834	9
181				13,805		13,805	10
256				19,571		19,571	11
49,089				3,345,921		3,345,921	12
18,950				652,536		652,536	13
2,552				170,798		170,798	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
51,720				3,253,036		3,253,036	1
3,355				208,495		208,495	2
147,873				8,572,157		8,572,157	3
133,071				7,266,399		7,266,399	4
60,780				3,713,217		3,713,217	5
8,030				545,045		545,045	6
153,803				8,846,836		8,846,836	7
70,775				4,117,278		4,117,278	8
8,531				578,026		578,026	9
3,857				242,773		242,773	10
1,239				81,984		81,984	11
3,813				238,435		238,435	12
8,782				597,649		597,649	13
8,848				598,766		598,766	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
8,881				565,872		565,872	1
1,526				101,544		101,544	2
3,367				224,254		224,254	3
1,038				31,253		31,253	4
13				476		476	5
3				111		111	6
29				1,794		1,794	7
6				210		210	8
2				151		151	9
51				1,841		1,841	10
51				1,888		1,888	11
4				147		147	12
6				223		223	13
				-5		-5	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
2				100		100	1
				10		10	2
				16		16	3
6				210		210	4
121				3,681		3,681	5
6,197				420,500		420,500	6
1				29		29	7
7				244		244	8
1,672				140,250		140,250	9
34				2,100		2,100	10
30				1,864		1,864	11
1				40		40	12
				4		4	13
8,988				609,359		609,359	14
9,989,520			107,777,742	528,615,577		636,393,319	

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				37		37	1
3,444				232,728		232,728	2
7,518				629,747		629,747	3
3,330				277,191		277,191	4
8,982				606,947		606,947	5
4,925				332,884		332,884	6
8,855				586,415		586,415	7
3,821				318,256		318,256	8
9,328				632,113		632,113	9
8,851				598,013		598,013	10
5				172		172	11
9				540		540	12
673				53,458		53,458	13
							14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
85,937				5,496,189		5,496,189	1
10				768		768	2
9,174				619,924		619,924	3
8,806				595,790		595,790	4
9,429				637,930		637,930	5
3,878				262,461		262,461	6
				12		12	7
8,245				694,571		694,571	8
8,037				673,894		673,894	9
				7		7	10
				17		17	11
9,924				630,612		630,612	12
3				200		200	13
72				4,486		4,486	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
135,035				10,353,719		10,353,719	1
13				982		982	2
31				2,356		2,356	3
				1		1	4
3,748				242,589		242,589	5
13				973		973	6
9,400				635,449		635,449	7
6				219		219	8
4				146		146	9
16				1,216		1,216	10
4,911				411,528		411,528	11
9,500				644,117		644,117	12
8,548				718,176		718,176	13
9,430				635,283		635,283	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
9,228				609,712		609,712	1
-1				-67		-67	2
8,300				558,755		558,755	3
9,517				601,931		601,931	4
10				445		445	5
7,968				662,556		662,556	6
10,164				640,566		640,566	7
8,703				587,226		587,226	8
5,998				504,489		504,489	9
38,544				2,407,890		2,407,890	10
9,277				585,733		585,733	11
7,935				667,542		667,542	12
9,291				628,396		628,396	13
3,857				261,028		261,028	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
8,914				542,041		542,041	1
9,521				799,794		799,794	2
8,944				749,848		749,848	3
8,599				581,631		581,631	4
4				136		136	5
7,015				474,407		474,407	6
9,017				755,119		755,119	7
7,317				614,515		614,515	8
9,349				632,411		632,411	9
3,677				308,139		308,139	10
				10		10	11
2				108		108	12
4,082				233,261		233,261	13
4,068				232,929		232,929	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
9,027				460,302		460,302	1
2,203				87,472		87,472	2
4,043				230,495		230,495	3
869				43,372		43,372	4
773				52,933		52,933	5
14				1,145		1,145	6
							7
3,994				228,816		228,816	8
4,014				229,103		229,103	9
3,902				222,915		222,915	10
11,129				614,708		614,708	11
							12
801				56,992		56,992	13
1,481				86,573		86,573	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	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.
3,955				226,102		226,102	1
257,961				16,389,603		16,389,603	2
1,641				102,730		102,730	3
8,713				730,261		730,261	4
7,204				487,483		487,483	5
3,128				239,542		239,542	6
3,237				271,724		271,724	7
8,811				740,216		740,216	8
9,661				652,885		652,885	9
8,663				574,719		574,719	10
							11
10,161				640,597		640,597	12
8,016				575,461		575,461	13
							14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,506				715,989		715,989	1
1,781				111,514		111,514	2
3,724				285,116		285,116	3
3,792				241,395		241,395	4
10,251				648,732		648,732	5
101				6,376		6,376	6
16				607		607	7
9,777				659,485		659,485	8
8,618				540,495		540,495	9
381				20,056		20,056	10
362				28,965		28,965	11
5,809				483,942		483,942	12
5,881				493,603		493,603	13
6,098				512,599		512,599	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
554				42,414		42,414	1
5,654				386,441		386,441	2
8,928				749,035		749,035	3
8,427				707,793		707,793	4
9,542				802,465		802,465	5
6,568				446,644		446,644	6
8,468				710,423		710,423	7
9,797				619,821		619,821	8
4,055				267,600		267,600	9
718				54,954		54,954	10
188				11,755		11,755	11
							12
							13
				-6		-6	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
7				248		248	1
6				244		244	2
3				125		125	3
				-2		-2	4
16				572		572	5
				11		11	6
2				69		69	7
				6		6	8
							9
9,096				764,486		764,486	10
9,379				630,846		630,846	11
							12
							13
3,341				277,188		277,188	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES 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.
7,889				652,788		652,788	1
9,165				581,727		581,727	2
8,653				586,010		586,010	3
7				242		242	4
8,428				709,175		709,175	5
3,933				264,372		264,372	6
2,088				159,878		159,878	7
8,464				572,877		572,877	8
1,830				114,580		114,580	9
							10
							11
				25		25	12
8,981				606,319		606,319	13
3				136		136	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
9,065				761,639		761,639	1
8,299				696,091		696,091	2
9,943				670,563		670,563	3
15				1,025		1,025	4
12				426		426	5
3,686				309,267		309,267	6
97				3,517		3,517	7
2,526				211,088		211,088	8
486				37,243		37,243	9
8,973				593,561		593,561	10
8,638				569,806		569,806	11
9,641				653,885		653,885	12
9,534				645,507		645,507	13
5,260				354,991		354,991	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
2,908				192,857		192,857	1
9,675				653,385		653,385	2
8,546				716,906		716,906	3
1,649				60,420		60,420	4
9,658				610,328		610,328	5
8,435				558,739		558,739	6
9,411				592,027		592,027	7
9,119				578,374		578,374	8
9,547				648,239		648,239	9
8,848				596,874		596,874	10
9,676				562,290		562,290	11
30				1,077		1,077	12
9,465				641,128		641,128	13
9,047				759,952		759,952	14
9,989,520			107,777,742	528,615,577		636,393,319	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,321				404,875		404,875	1
8,718				588,033		588,033	2
8,923				747,725		747,725	3
9,243				778,314		778,314	4
1,728				108,218		108,218	5
7,922				660,087		660,087	6
281				17,625		17,625	7
9,188				618,259		618,259	8
71				5,337		5,337	9
9,386				634,117		634,117	10
8,927				605,741		605,741	11
30				1,865		1,865	12
13				471		471	13
17				1,083		1,083	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
554				42,444		42,444	1
				7		7	2
1,096				73,597		73,597	3
18,514				1,196,416		1,196,416	4
5				204		204	5
5				177		177	6
8,818				518,057		518,057	7
6,796				460,510		460,510	8
8,689				590,777		590,777	9
9,030				611,890		611,890	10
6,109				414,565		414,565	11
				11		11	12
60,914				3,472,089		3,472,089	13
8,821				596,989		596,989	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
12				419		419	1
3,868				255,414		255,414	2
8,492				573,022		573,022	3
17				649		649	4
8,808				583,868		583,868	5
9,506				642,193		642,193	6
9,614				647,909		647,909	7
8,104				674,795		674,795	8
515				39,433		39,433	9
3,322				277,104		277,104	10
-1				-73		-73	11
7,734				641,357		641,357	12
3,487				291,385		291,385	13
3,494				292,420		292,420	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,047				673,322		673,322	1
340				21,449		21,449	2
				27		27	3
6,330				540,141		540,141	4
8,735				732,041		732,041	5
8,502				711,572		711,572	6
9,506				645,019		645,019	7
9,139				616,951		616,951	8
102				7,841		7,841	9
				4		4	10
7,833				656,676		656,676	11
8,810				597,515		597,515	12
9,043				571,427		571,427	13
6,540				426,931		426,931	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
8,686				586,749		586,749	1
7,860				654,554		654,554	2
9,841				666,266		666,266	3
9,589				648,553		648,553	4
9,384				634,384		634,384	5
9,319				590,371		590,371	6
101,776				5,586,250		5,586,250	7
10,057				678,814		678,814	8
101,741				5,669,763		5,669,763	9
10,146				539,950		539,950	10
9,584				607,023		607,023	11
8,910				561,508		561,508	12
142,288				7,956,710		7,956,710	13
10,062				637,499		637,499	14
9,989,520			107,777,742	528,615,577		636,393,319	

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				363		363	1
6				258		258	2
9,601				612,116		612,116	3
10,142				638,015		638,015	4
10,276				532,762		532,762	5
9,563				645,332		645,332	6
9,298				585,584		585,584	7
9,740				614,539		614,539	8
440				26,467		26,467	9
9,541				496,822		496,822	10
1,879				109,026		109,026	11
3,718				236,331		236,331	12
9,475				599,057		599,057	13
9,307				625,037		625,037	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
9,696				653,881		653,881	1
10,285				652,776		652,776	2
8,656				546,683		546,683	3
7,338				465,611		465,611	4
9,077				574,067		574,067	5
10,221				645,060		645,060	6
7,692				488,005		488,005	7
6,244				395,284		395,284	8
9,348				585,329		585,329	9
9,639				608,514		608,514	10
188				15,844		15,844	11
9,557				597,354		597,354	12
3,753				146,568		146,568	13
8,823				479,731		479,731	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,916				155,972		155,972	1
119,409				6,787,697		6,787,697	2
110,042				6,316,006		6,316,006	3
99,205				5,695,810		5,695,810	4
							5
10,304				648,890		648,890	6
4,415				274,190		274,190	7
3,922				227,823		227,823	8
10,546				662,576		662,576	9
1,530				117,152		117,152	10
9,507				599,862		599,862	11
4,232				246,638		246,638	12
101,642				5,658,410		5,658,410	13
74,331				4,117,289		4,117,289	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,262				647,071		647,071	1
4,562				284,911		284,911	2
4,744				297,220		297,220	3
2,584				163,715		163,715	4
10,607				661,012		661,012	5
4,395				256,100		256,100	6
9,532				603,749		603,749	7
9,874				623,164		623,164	8
4,214				243,721		243,721	9
4,150				240,351		240,351	10
9,805				658,259		658,259	11
8,703				549,994		549,994	12
7,204				455,028		455,028	13
10,552				664,401		664,401	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,408				588,019		588,019	1
8,158				513,146		513,146	2
4,126				240,203		240,203	3
9,677				608,090		608,090	4
10,901				683,690		683,690	5
13				368		368	6
9,088				608,643		608,643	7
4,028				236,032		236,032	8
8,619				552,949		552,949	9
10,578				667,274		667,274	10
3,653				231,411		231,411	11
7,890				505,829		505,829	12
4,212				242,566		242,566	13
7,548				511,568		511,568	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,549				593,213		593,213	1
140,948				4,416,713		4,416,713	2
6,496				415,203		415,203	3
2,923				185,454		185,454	4
906				50,649		50,649	5
820				65,352		65,352	6
9,933				620,562		620,562	7
3,845				242,318		242,318	8
385				12,325		12,325	9
							10
3,499				205,317		205,317	11
3,349				197,121		197,121	12
23				1,890		1,890	13
1				35		35	14
9,989,520			107,777,742	528,615,577		636,393,319	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,412				201,705		201,705	1
3,262				192,526		192,526	2
1,039				33,237		33,237	3
1,910				61,070		61,070	4
1,679				53,733		53,733	5
1,622				51,916		51,916	6
1,074				34,378		34,378	7
1,136				36,336		36,336	8
1,912				61,167		61,167	9
1,670				53,431		53,431	10
1,630				52,141		52,141	11
3				110		110	12
3,634				229,410		229,410	13
2,558				155,375		155,375	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
6,600				437,211		437,211	1
5,673				376,285		376,285	2
							3
3,123				184,059		184,059	4
2,888				187,339		187,339	5
881				28,200		28,200	6
4,898				334,205		334,205	7
				15		15	8
							9
							10
				11		11	11
1				40		40	12
7,551				486,658		486,658	13
634				20,288		20,288	14
9,989,520			107,777,742	528,615,577		636,393,319	

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 ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
351				16,257		16,257	1
1,753				103,416		103,416	2
1,726				104,677		104,677	3
9,125				477,148		477,148	4
416,022			44,655,023	22,352,999		67,008,022	5
				20,194		20,194	6
11,065			12,516,750	1,020,067		13,536,817	7
				-47,248		-47,248	8
1,130,569			13,759,200	33,626,406		47,385,606	9
				-751		-751	10
61,721			3,244,080	2,488,837		5,732,917	11
							12
90,402				2,775,949		2,775,949	13
				22,486		22,486	14
9,989,520			107,777,742	528,615,577		636,393,319	

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.
168			339,600	5,836		345,436	1
			16,033			16,033	2
131,285			33,247,056	5,401,618		38,648,674	3
				1,064		1,064	4
1,940,148				58,599,427		58,599,427	5
6,446				823,017		823,017	6
25,849				1,429,935		1,429,935	7
				235,331		235,331	8
				-521		-521	9
1,415				43,433		43,433	10
914				16,241		16,241	11
579				16,039		16,039	12
754				18,973		18,973	13
1,508				46,100		46,100	14
9,989,520			107,777,742	528,615,577		636,393,319	

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)	
1,372				39,071		39,071	1
-39				-1,522		-1,522	2
1,638				44,423		44,423	3
395				16,951		16,951	4
7,277				225,100		225,100	5
							6
							7
							8
							9
							10
							11
							12
							13
							14
9,989,520			107,777,742	528,615,577		636,393,319	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	various	various	OLF
2	Southeastern Power Administration	various	various	AD
3	Brookfield Energy Marketing LP	various	various	OS
4	Brookfield Energy Marketing LP	various	various	AD
5	Duke Power Company	various	various	OS
6	Cargill Power and Gas	various	various	AD
7	EDF Trading North America	various	various	OS
8	Exelon Power Team	various	various	OS
9	Exelon Power Team	various	various	AD
10	Florida Power Corp	various	various	OS
11	Industrial Power Generating Company LLC	various	various	LFP
12	Industrial Power Generating Company LLC	various	various	AD
13	Macquarie Energy LLC	various	various	SF
14	Macquarie Energy LLC	various	various	OS
15	Morgan Stanley Capital Group Inc	various	various	OS
16	NTE Carolinas LLC	various	various	SF
17	NTE Carolinas LLC	various	various	AD
18	North Carolina EMC	various	various	LFP
19	North Carolina EMC	various	various	SFP
20	North Carolina EMC	various	various	NF
21	North Carolina Municipal Power Agency 1	various	various	SF
22	North Carolina Municipal Power Agency 1	various	various	AD
23	Southern Wholesale	various	various	SF
24	Southern Wholesale	various	various	OS
25	The Energy Authority	various	various	OS
26	The Energy Authority	various	various	AD
27	MWH Received and Delivered	various	various	
28	City of Camden	various	various	FNO
29	French Broad EMC	various	various	FNO
30	Haywood EMC	various	various	FNO
31	North Carolina EMC	various	various	FNO
32	North Carolina Eastern Municipal Power	various	various	FNO
33	Piedmont EMC	various	various	FNO
34	Public Works Commission of the City of	various	various	FNO
	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	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Town of Black Creek	various	various	FNO
2	Town of Lucama	various	various	FNO
3	Town of Sharpsburg	various	various	FNO
4	Town of Stantonsburg			FNO
5	Town of Waynesville			FNO
6	Town of Winterville			FNO
7	Craven County Wood Energy			OS
8	Lumberton Energy LLC			OS
9	Uwharrie Mountain Renewable En			OS
10	Accrue for Mutually Agreed Upon Items			
11	Accrue CTA Asset Adjustment			
12	Accrue for Page 227 M&S Inventory Refund			
13	Accrue for Federal Tax Change			
14	Miscellaneous GO Collection			
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
RS127	PJM	CPLE	282			1
	YAD	PJM				2
						3
						4
						5
						6
						7
						8
						9
	CPLE	CPLE				10
	CPLE	CPLE	16			11
						12
	various	various				13
	various	various				14
						15
						16
						17
						18
						19
	CPLE	PJM				20
	CPLE	CPLE				21
JointOATT/309	CPLE	CPLE				22
	CPLE	CPLE				23
						24
	CPLW	CPLW				25
	CPLE	CPLE				26
				1,974,975	1,948,460	27
						28
						29
						30
						31
						32
						33
						34
			298	**1,974,975**	**1,948,460**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
JointOATT/271						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			298	**1,974,975**	**1,948,460**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.
1,268,207			1,268,207	1
		88,451	88,451	2
1,236			1,236	3
		-187	-187	4
2,940,515			2,940,515	5
		-1,047	-1,047	6
57		-3	54	7
		4,664	4,664	8
		-3,108	-3,108	9
1,751		-19	1,732	10
76,117			76,117	11
		-2,253	-2,253	12
		1,138,814	1,138,814	13
		-32,338	-32,338	14
		899	899	15
		598,756	598,756	16
		-23,348	-23,348	17
		3,143,863	3,143,863	18
18,569		1,586	20,155	19
93,886		8,112	101,998	20
		1,734,465	1,734,465	21
		-57,551	-57,551	22
		634	634	23
		-93	-93	24
		472,409	472,409	25
		-12,932	-12,932	26
				27
768,469		4,500	772,969	28
1,453,650		70,200	1,523,850	29
600,393		21,000	621,393	30
35,593,344		72,000	35,665,344	31
20,361,198			20,361,198	32
463,673		30,000	493,673	33
6,851,038		36,000	6,887,038	34
76,845,833	**0**	**7,342,626**	**84,188,459**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.
56,894		4,800	61,694	1
91,892		4,800	96,692	2
80,409		4,800	85,209	3
94,159		5,100	99,259	4
251,436			251,436	5
248,499		8,400	256,899	6
		10,500	10,500	7
		4,800	4,800	8
		5,052	5,052	9
-1,076,732			-1,076,732	10
158,950			158,950	11
326,669			326,669	12
6,121,554			6,121,554	13
		900	900	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
76,845,833	**0**	**7,342,626**	**84,188,459**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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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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	04/14/2020	End of 2019/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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Progress	LFP	1,974,982	1,948,350				
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,974,982	1,948,350				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	717,551
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,400,373
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Service Company Support	-26,701,295
7	Allocated Incentives	17,049
8	Suspense Clearing	-602,664
9	Environmental Accrual Adjustment	2,404,046
10	Consultants and Contract Services	1,016,482
11	Labor Accrual	1,114,145
12	Restricted Stock Units	540,440
13	Other Contracts	436,545
14	Allocated Labor	131,304
15	Travel	136,266
16	Direct Purchase Allocations	177,747
17	Personal Vehicle Mileage Reimbursement	2,344
18	Postage and Freight	24,327
19	Rent	1,234
20	Sponsorships	
21	Miscellaneous < $5k	20,268
22	Miscellaneous > $5k	41,059
23	Moving Expenses	1,669,956
24	Dues and Subscriptions to Various Organizations	313,387
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
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36		
37		
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43		
44		
45		
46	TOTAL	-17,139,436

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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			52,681,881		52,681,881
2	Steam Production Plant	147,218,111				147,218,111
3	Nuclear Production Plant	262,079,794				262,079,794
4	Hydraulic Production Plant-Conventional	4,980,423				4,980,423
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	145,443,909				145,443,909
7	Transmission Plant	51,597,519				51,597,519
8	Distribution Plant	176,399,571				176,399,571
9	Regional Transmission and Market Operation					
10	General Plant	37,382,579				37,382,579
11	Common Plant-Electric					
12	TOTAL	825,101,906		52,681,881		877,783,787

B. Basis for Amortization Charges

Account 404 is the amortization of capitalized software and generating plant relicensing. Intangible plant is amortized over 3, 5, and 10 years. The generating plant relicensing is amortized over the remaining life of the license.

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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46							
47							
48							
49							
50							

FOOTNOTE DATA

Schedule Page: 336 Line No.: 3 Column: b

Depreciation rates do not include nuclear decommissioning amortization. The portion for nuclear decommissioning amortization accrued in the current year to Account 403 (Depreciation Expense) was $24,397,613

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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)	1,121,122		1,121,122	2,609,079
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	2,470,218		2,470,218	
13					
14	Annual Charges Assessed by the NC Utilities				
15	Commission as required by Senate Bill 1320	5,250,365		5,250,365	
16					
17	Annual Charges Assessed by the SC Public				
18	Service Commission	1,775,183		1,775,183	
19					
20					
21	SC Rate Case Amortization (5 years)	110,421		110,421	
22					
23					
24	Other				
25					
26					
27	NC Regulatory Fee Amortization	375,831		375,831	1,497,978
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	11,103,140		11,103,140	4,107,057

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
							3
							4
							5
							6
				182.3	1,121,122	2,609,079	7
							8
							9
							10
							11
Electric	928	2,470,218					12
							13
							14
Electric	928	5,250,365					15
							16
							17
Electric	928	1,775,183					18
							19
							20
Electric	928	110,421					21
							22
							23
Electric	928						24
							25
							26
				182.3	375,831	1,122,147	27
							28
							29
							30
							31
							32
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							44
							45
		9,606,187			1,496,953	3,731,226	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	04/14/2020	End of 2019/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	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		Other (Less than $50K each)
12		
13	(4) Research Support to Others	Alternative Energy (Advanced Energy Research)
14		Electric Power Research Institute
15		
16	(5) TOTAL ELECTRIC R, D&D PERFORMED EXTERNALLY	
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	04/14/2020	End of 2019/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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
45,259		930.7	45,259		3
					4
45,259			45,259		5
					6
					7
					8
4,092,711		Various	4,092,711		9
697,489		524.0	697,489		10
67,559		Various	67,559		11
					12
1,353,248		930.8	1,353,248		13
1,865		930.7	1,865		14
					15
6,212,872			6,212,872		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	04/14/2020	End of 2019/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	202,651,235		
4	Transmission	8,382,744		
5	Regional Market			
6	Distribution	20,242,796		
7	Customer Accounts	21,381,351		
8	Customer Service and Informational	2,161,051		
9	Sales	4,980,678		
10	Administrative and General	110,840,170		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	370,640,025		
12	Maintenance			
13	Production	135,158,534		
14	Transmission	7,328,810		
15	Regional Market			
16	Distribution	28,622,082		
17	Administrative and General	19,786		
18	TOTAL Maintenance (Total of lines 13 thru 17)	171,129,212		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	337,809,769		
21	Transmission (Enter Total of lines 4 and 14)	15,711,554		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	48,864,878		
24	Customer Accounts (Transcribe from line 7)	21,381,351		
25	Customer Service and Informational (Transcribe from line 8)	2,161,051		
26	Sales (Transcribe from line 9)	4,980,678		
27	Administrative and General (Enter Total of lines 10 and 17)	110,859,956		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	541,769,237		541,769,237
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	541,769,237		541,769,237
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	187,368,490		187,368,490
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	187,368,490		187,368,490
72	Plant Removal (By Utility Departments)			
73	Electric Plant	31,536,559		31,536,559
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	31,536,559		31,536,559
77	Other Accounts (Specify, provide details in footnote):			
78	Non-Regulated Products and Services	4,745,776		4,745,776
79	Other Work in Progress	4,445,632		4,445,632
80	Other Accounts	5,001,262		5,001,262
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	14,192,670		14,192,670
96	TOTAL SALARIES AND WAGES	774,866,956		774,866,956

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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 the year ending 2019.

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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)	1,892,400	2,092,093	2,163,281	2,798,435
3	Net Sales (Account 447)	39,106	228,563	442,350	753,418
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
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36					
37					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL	1,931,506	2,320,656	2,605,631	3,551,853

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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				47,158,156	MWH	1,792,120
2	Reactive Supply and Voltage				47,158,156	MWH	4,358,304
3	Regulation and Frequency Response						22,948
4	Energy Imbalance	6,727	MWH	163,080	-907	MWH	-23,456
5	Operating Reserve - Spinning				483	MWH	33,847
6	Operating Reserve - Supplement				345	MWH	24,189
7	Other						
8	Total (Lines 1 thru 7)	6,727		163,080	94,316,233		6,207,952

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MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	13,986	22	8	9,360	4,307	319			
2	February	12,231	1	8	8,241	3,671	319			
3	March	12,032	7	7	8,023	3,690	319			
4	Total for Quarter 1				25,624	11,668	957			
5	April	10,204	3	8	6,971	2,914	319			
6	May	12,883	29	17	8,790	3,774	319			
7	June	12,585	24	18	8,393	3,708	484			
8	Total for Quarter 2				24,154	10,396	1,122			
9	July	13,409	17	16	8,984	3,941	484			
10	August	13,197	13	16	8,953	3,760	484			
11	September	12,520	12	16	8,576	3,625	319			
12	Total for Quarter 3				26,513	11,326	1,287			
13	October	12,608	3	16	8,607	3,682	319			
14	November	11,403	14	7	7,704	3,380	319			
15	December	12,539	20	8	8,395	3,824	319			
16	Total for Quarter 4				24,706	10,886	957			
17	Total Year to Date/Year				100,997	44,276	4,323			

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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									

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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)	44,190,984
3	Steam	9,596,535	23	Requirements Sales for Resale (See instruction 4, page 311.)	18,641,160
4	Nuclear	28,703,669	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,524,681
5	Hydro-Conventional	673,441	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	94,234
7	Other	21,575,333	27	Total Energy Losses	2,070,973
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	70,522,032
9	Net Generation (Enter Total of lines 3 through 8)	60,548,978			
10	Purchases	9,989,520			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	1,974,975			
17	Delivered	1,948,460			
18	Net Transmission for Other (Line 16 minus line 17)	26,515			
19	Transmission By Others Losses	-42,981			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	70,522,032			

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MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	6,348,747	375,335	13,434	22	800
30	February	5,319,944	613,622	11,731	1	800
31	March	5,172,418	372,873	11,527	7	700
32	April	4,875,290	402,150	9,683	3	800
33	May	5,734,377	218,666	12,350	29	1700
34	June	6,118,760	356,939	11,897	24	1800
35	July	6,992,159	370,771	12,694	17	1600
36	August	6,639,015	281,821	12,492	13	1600
37	September	6,407,421	711,351	12,011	12	1700
38	October	5,475,754	616,228	12,084	3	1600
39	November	5,426,423	517,448	10,884	14	700
40	December	6,011,724	687,477	12,038	20	800
41	TOTAL	70,522,032	5,524,681			

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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)	413.60			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	374			0		
7	Plant Hours Connected to Load	8715			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	71			3		
12	Net Generation, Exclusive of Plant Use - KWh	1118635000			0		
13	Cost of Plant: Land and Land Rights	4325516			0		
14	Structures and Improvements	87594941			0		
15	Equipment Costs	381509449			0		
16	Asset Retirement Costs	414869495			0		
17	Total Cost	888299401			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	2147.7258			0		
19	Production Expenses: Oper, Supv, & Engr	766956			4		
20	Fuel	45291235			1482		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	7268619			5		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1312			0		
26	Misc Steam (or Nuclear) Power Expenses	1212158			-7774		
27	Rents	0			0		
28	Allowances	9655541			-8102		
29	Maintenance Supervision and Engineering	703295			79		
30	Maintenance of Structures	1792964			-175826		
31	Maintenance of Boiler (or reactor) Plant	2808807			0		
32	Maintenance of Electric Plant	389569			-58		
33	Maintenance of Misc Steam (or Nuclear) Plant	1126570			24151		
34	Total Production Expenses	71017026			-166039		
35	Expenses per Net KWh	0.0635			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	9020	552751	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138135	12407	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	87.910	87.750	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	88.978	79.860	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	15.336	3.218	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	12308.000	12308.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *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)	2450			0		
7	Plant Hours Connected to Load	7761			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	213			0		
12	Net Generation, Exclusive of Plant Use - KWh	6952370000			0		
13	Cost of Plant: Land and Land Rights	8105075			0		
14	Structures and Improvements	324051684			0		
15	Equipment Costs	2198596194			0		
16	Asset Retirement Costs	868946850			0		
17	Total Cost	3399699803			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1328.9421			0		
19	Production Expenses: Oper, Supv, & Engr	3476126			18412		
20	Fuel	261874801			-177189		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	11975519			6250		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	-367			0		
26	Misc Steam (or Nuclear) Power Expenses	4875425			74702		
27	Rents	0			0		
28	Allowances	21236987			103681		
29	Maintenance Supervision and Engineering	3179752			16224		
30	Maintenance of Structures	1978270			1920267		
31	Maintenance of Boiler (or reactor) Plant	16604080			-5708		
32	Maintenance of Electric Plant	2402110			4071		
33	Maintenance of Misc Steam (or Nuclear) Plant	5227501			154		
34	Total Production Expenses	332830204			1960864		
35	Expenses per Net KWh	0.0479			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	47089	2900996	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138172	12550	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	86.440	84.300	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	87.677	88.273	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	12.651	3.517	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.037	0.037	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10520.000	10520.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *H.B. Robinson* (b)			Plant Name: *Asheville* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1971			1999		
4	Year Last Unit was Installed	1971			2000		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	768.60			423.50		
6	Net Peak Demand on Plant - MW (60 minutes)	794			374		
7	Plant Hours Connected to Load	8208			2692		
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	606			0		
12	Net Generation, Exclusive of Plant Use - KWh	6376319000			329867000		
13	Cost of Plant: Land and Land Rights	1992003			565402		
14	Structures and Improvements	385856308			31820362		
15	Equipment Costs	1295568450			82805946		
16	Asset Retirement Costs	319043047			0		
17	Total Cost	2002459808			115191710		
18	Cost per KW of Installed Capacity (line 17/5) Including	2605.3341			271.9993		
19	Production Expenses: Oper, Supv, & Engr	10807301			218382		
20	Fuel	37658659			23270061		
21	Coolants and Water (Nuclear Plants Only)	3015448			0		
22	Steam Expenses	9302381			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1678902			43998		
26	Misc Steam (or Nuclear) Power Expenses	47649987			1034339		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	14557635			231651		
30	Maintenance of Structures	3138559			259714		
31	Maintenance of Boiler (or reactor) Plant	8525207			0		
32	Maintenance of Electric Plant	4809434			548978		
33	Maintenance of Misc Steam (or Nuclear) Plant	9041804			135288		
34	Total Production Expenses	150185317			25742411		
35	Expenses per Net KWh	0.0236			0.0780		
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	65416809	0	798623	31383	3370646	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	137469	1031253	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	87.910	6.061	0.000
41	Average Cost of Fuel per Unit Burned	0.000	45.602	0.000	89.481	6.061	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.557	0.000	15.498	5.877	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.006	0.000	0.070	0.070	0.000
44	Average BTU per KWh Net Generation	0.000	10259.000	0.000	11087.000	11087.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Morehead* (b)			Plant Name: *Cape Fear* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed	1968			1969		
4	Year Last Unit was Installed	1968			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	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			-5		
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			21		
26	Misc Steam (or Nuclear) Power Expenses	0			1363		
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			1379		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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)	828			2148		
7	Plant Hours Connected to Load	697			12326		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	963			2184		
10	When Limited by Condenser Water	857			1845		
11	Average Number of Employees	4			60		
12	Net Generation, Exclusive of Plant Use - KWh	140236000			9392249000		
13	Cost of Plant: Land and Land Rights	4581022			2839730		
14	Structures and Improvements	10373406			107461284		
15	Equipment Costs	258849117			966031342		
16	Asset Retirement Costs	0			0		
17	Total Cost	273803545			1076332356		
18	Cost per KW of Installed Capacity (line 17/5) Including	279.4769			479.4781		
19	Production Expenses: Oper, Supv, & Engr	281100			3788430		
20	Fuel	7175735			258564836		
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	311965			713824		
26	Misc Steam (or Nuclear) Power Expenses	856925			3013947		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	760119			2218323		
30	Maintenance of Structures	302017			2636592		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	560998			23859514		
33	Maintenance of Misc Steam (or Nuclear) Plant	2223140			3484534		
34	Total Production Expenses	12471999			298280000		
35	Expenses per Net KWh	0.0889			0.0318		
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	15781	1484703	0	5781	70803430	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	137654	1032878	0	140000	1030339	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	3.711	0.000	0.000	3.658	0.000
41	Average Cost of Fuel per Unit Burned	100.824	3.711	0.000	97.760	3.658	0.000
42	Average Cost of Fuel Burned per Million BTU	17.440	3.551	0.000	16.626	3.550	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.051	0.051	0.000	0.028	0.028	0.000
44	Average BTU per KWh Net Generation	11715.000	11715.000	0.000	7771.000	7771.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *H.F. Lee* (d)			Plant Name: *Mayo* (e)			Plant Name: *H.B. Robinson* (f)			Line No.
Steam			Steam			Steam			1
Full Outdoor			Full Outdoor			Full Outdoor			2
1951			1983			1960			3
1962			1983			1960			4
0.00			763.20			0.00			5
0			691			0			6
0			4407			0			7
0			0			0			8
0			746			0			9
0			727			0			10
0			67			0			11
0			1525530000			0			12
0			14994716			0			13
0			270025395			0			14
0			1015166764			0			15
0			339022175			0			16
0			1639209050			0			17
0			2147.8106			0			18
25738			1334135			1139			19
2106			62488265			0			20
0			0			0			21
8253			4718036			1			22
0			0			0			23
0			0			0			24
0			-560			0			25
28351			1447267			-2609			26
0			0			0			27
65095			7832569			-1533			28
22247			825341			442			29
232545			4849060			55658			30
0			4389202			5927			31
4467			743484			4801			32
58			4189092			3988			33
388860			92815891			67814			34
0.0000			0.0608			0.0000			35
			Oil	Coal					36
			Barrels	Tons					37
0	0	0	34072	710092	0	0	0	0	38
0	0	0	137888	12602	0	0	0	0	39
0.000	0.000	0.000	86.730	82.220	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	88.096	82.470	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	15.212	3.272	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.040	0.040	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	11861.000	11861.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *W.H. Weatherspoon* (d)			Plant Name: *Brunswick* (e)			Plant Name: *Harris* (f)			Line No.
Steam			Nuclear			Nuclear			1
Outdoor Boiler			Conventional			Conventional			2
1949			1975			1987			3
1952			1977			1987			4
0.00			2003.20			950.90			5
0			1922			1018			6
0			8382			7859			7
0			0			0			8
0			1928			1009			9
0			1870			964			10
0			779			637			11
0			14716756000			7610594000			12
0			4060633			62470413			13
0			850585843			1922379323			14
0			2447272084			2327692183			15
0			773460895			482486408			16
0			4075379455			4795028327			17
0			2034.4346			5042.6210			18
14923			17828806			11549226			19
203			91336061			51097326			20
0			9632236			7691805			21
1251			22541122			12950035			22
0			0			0			23
0			0			0			24
0			2491329			1736931			25
4543			68846965			53834697			26
0			0			0			27
21617			0			0			28
3425			25922734			14772086			29
-21731			4159656			4176323			30
0			23101488			18627414			31
659			14985152			13180946			32
8			22591837			12739274			33
24898			303437386			202356063			34
0.0000			0.0206			0.0266			35
				Nuclear			Nuclear		36
			MBTUs		MW Days	MBTUs		MW Days	37
0	0	0	155615243	0	1899674	78361027	0	956649	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	47.703	0.000	0.000	53.161	0.000	41
0.000	0.000	0.000	0.000	0.582	0.000	0.000	0.649	0.000	42
0.000	0.000	0.000	0.000	0.006	0.000	0.000	0.007	0.000	43
0.000	0.000	0.000	0.000	10563.000	0.000	0.000	10296.000	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
50			0			2550			6
25			0			10464			7
0			0			0			8
68			0			719			9
52			0			685			10
4			0			49			11
-535250			0			4620495000			12
0			0			1208226			13
926386			0			41382080			14
12600160			0			617809455			15
0			0			0			16
13526546			0			660399761			17
193.2364			0			776.0279			18
11463			67			802018			19
89090			0			153282583			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
2892			5			348612			25
52138			286			1639870			26
0			0			0			27
0			0			0			28
28175			0			1091678			29
29221			0			1387171			30
0			0			0			31
124847			23			1969623			32
142009			0			2771686			33
479835			381			163293241			34
-0.8965			0.0000			0.0353			35
Oil						Oil	Gas		36
Barrels						Barrels	MCF		37
843	0	0	0	0	0	86	32717280	0	38
140492	0	0	0	0	0	144000	1030305	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	4.683	0.000	40
99.308	0.000	0.000	0.000	0.000	0.000	117.821	4.683	0.000	41
16.840	0.000	0.000	0.000	0.000	0.000	19.476	4.545	0.000	42
-0.156	0.000	0.000	0.000	0.000	0.000	0.033	0.033	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	7296.000	7296.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Darlington* (d)			Plant Name: *H.F. Lee* (e)			Plant Name: *W.H. Weatherspoon* (f)			Line No.
Gas Turbine			Gas Turbine			Gas Turbine			1
Conventional			Conventional			Conventional			2
1974			1968			1970			3
1997			2012			1971			4
845.40			1068.00			163.00			5
325			1018			117			6
265			7858			29			7
0			0			0			8
763			1059			164			9
613			888			124			10
0			58			4			11
21079990			6648487000			-118000			12
50044			673304			84323			13
10242386			25539350			4099667			14
118932899			666781567			20110748			15
0			0			0			16
129225329			692994221			24294738			17
152.8570			648.8710			149.0475			18
724889			448902			191061			19
1770134			191731629			252308			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
139993			544818			10838			25
4704225			2159819			223806			26
0			0			0			27
0			0			0			28
562665			1073073			65842			29
118930			1650974			43102			30
0			0			0			31
1512917			2213041			95897			32
458622			753102			203130			33
9992375			200575358			1085984			34
0.4740			0.0302			-9.2033			35
Oil	Gas		Oil	Gas		Oil			36
Barrels	MCF		Barrels	MCF		Barrels			37
6648	288937	0	0	47515571	0	2557	0	0	38
138672	1027528	0	0	1032683	0	139974	0	0	39
89.340	3.553	0.000	0.000	4.033	0.000	86.700	0.000	0.000	40
100.510	3.553	0.000	0.000	4.033	0.000	93.643	0.000	0.000	41
17.256	3.458	0.000	0.000	3.906	0.000	15.929	0.000	0.000	42
0.080	0.080	0.000	0.000	0.029	0.000	-2.032	0.000	0.000	43
15921.000	15921.000	0.000	0.000	7380.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Asheville* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Gas			1
Combined Cycle			2
2019			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
101993600	0	0	14
664422512	0	0	15
0	0	0	16
766416112	0	0	17
0	0	0	18
18300	0	0	19
12449516	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
19650	0	0	25
306954	0	0	26
0	0	0	27
0	0	0	28
3544	0	0	29
0	0	0	30
0	0	0	31
9794	0	0	32
126859	0	0	33
12934617	0	0	34
0.0000	0.0000	0.0000	35

Oil	Gas								
Barrels	MCF								37
2870	1045271	0	0	0	0	0	0	0	38
137710	1031083	0	0	0	0	0	0	0	39
88.870	11.666	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
88.874	11.666	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
15.381	11.308	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.091	0.091	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
7970.000	7970.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

FOOTNOTE DATA

Schedule Page: 402 Line No.: 1 Column: c

Cape Fear coal units 3,4,5 & 6 were retired on October 1, 2012.

Schedule Page: 403 Line No.: 1 Column: d

Lee coal units 1,2 & 3 were retired on September, 15 2012.

Schedule Page: 403 Line No.: 1 Column: f

Robinson coal unit 1 was retired on October 1, 2012.

Schedule Page: 402 Line No.: 20 Column: b

Asheville Steam Total fuel costs include Fuel Handling, Coal Sampling and Sale of Fly Ash.

Schedule Page: 402 Line No.: 20 Column: c

Cape Fear Steam Total fuel costs reflect Sale of Fly Ash.

Schedule Page: 403 Line No.: 20 Column: d

HF Lee Steam Total fuel costs 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.

Schedule Page: 403.1 Line No.: 20 Column: d

Weatherspoon Steam Total fuel costs include Sale of Fly Ash. Accounts 501007, 501008, and 501009 for Coal Ash Beneficial Reuse in the amount of $8,786,094 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: 402.3 Line No.: 1 Column: b

Morehead CT was retired on October 1, 2012.

Schedule Page: 402.3 Line No.: 1 Column: c

FOOTNOTE DATA

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 $416,530.

Schedule Page: 403.4 Line No.: 20 Column: d

Asheville Combined Cycle total fuel costs do not include pre-commercial generation for Unit 7 in the amount of $4,867,107.

Schedule Page: 402 Line No.: 41 Column: b2

Asheville Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling and Sale of Fly Ash.

Schedule Page: 402 Line No.: 41 Column: e2

Mayo Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling 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

FOOTNOTE DATA

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.: 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: 402.4 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.: 43 Column: d1

Asheville Combined Cycle Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 43 Column: d2

Asheville Combined Cycle 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.

Schedule Page: 402.4 Line No.: 44 Column: d1

Asheville Combined Cycle Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 44 Column: d2

Asheville Combined Cycle 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	04/14/2020	End of 2019/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)	0	85
7	Plant Hours Connect to Load	0	4,770
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	4	6
12	Net Generation, Exclusive of Plant Use - Kwh	-421,000	232,720,000
13	Cost of Plant		
14	Land and Land Rights	500,333	1,151,690
15	Structures and Improvements	6,616,952	7,751,682
16	Reservoirs, Dams, and Waterways	7,962,615	6,831,147
17	Equipment Costs	23,773,635	20,652,240
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	706,699	440,012
20	TOTAL cost (Total of 14 thru 19)	39,560,234	36,826,771
21	Cost per KW of Installed Capacity (line 20 / 5)	1,608.1396	438.4139
22	Production Expenses		
23	Operation Supervision and Engineering	573,804	787,395
24	Water for Power	-241	62,741
25	Hydraulic Expenses	3,190	-305,882
26	Electric Expenses	17,650	60,270
27	Misc Hydraulic Power Generation Expenses	206,798	262,828
28	Rents	0	0
29	Maintenance Supervision and Engineering	54,078	102,516
30	Maintenance of Structures	63,887	85,730
31	Maintenance of Reservoirs, Dams, and Waterways	77,657	956,707
32	Maintenance of Electric Plant	-63,112	252,747
33	Maintenance of Misc Hydraulic Plant	421,418	784,172
34	Total Production Expenses (total 23 thru 33)	1,355,129	3,049,224
35	Expenses per net KWh	0.0000	0.0131

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
109	0	0	6
8,753	0	0	7
			8
113	0	0	9
113	0	0	10
7	0	0	11
441,426,000	0	0	12
			13
712,606	0	0	14
3,695,666	0	0	15
34,772,961	0	0	16
25,034,998	0	0	17
8,258	0	0	18
587,409	0	0	19
64,811,898	0	0	20
600.1102	0.0000	0.0000	21
			22
936,199	0	0	23
0	0	0	24
-4,108	0	0	25
31,692	0	0	26
376,339	0	0	27
0	0	0	28
143,559	0	0	29
77,002	0	0	30
201,520	0	0	31
145,187	0	0	32
354,540	0	0	33
2,261,930	0	0	34
0.0051	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	04/14/2020	End of 2019/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	04/14/2020	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	1.0	-284,000	13,819,245
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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	04/14/2020	End of 2019/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		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
2,763,849	53,332		45,977			1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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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	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Cumberland	Richmond	500.00	500.00	T	56.62		1
2	Cumberland	Wake	500.00	500.00	T	67.26		1
3	Durham	Wake	500.00	500.00	T	27.90		1
4	Mayo	Durham	500.00	500.00	T	45.41		1
5	Mayo	Person	500.00	500.00	T	9.94		1
6	Richmond	Newport (DPC)	500.00	500.00	T	32.69		1
7	Wake	Heritage (VEPCO)	500.00	500.00	T	52.60		1
8	Tot. 500KV Lines							
9	Asheboro	Biscoe	230.00	230.00	S-HFR	0.88		1
10	Asheboro	Biscoe	230.00	230.00	W-HFR	24.97		1
11	Asheboro	DPC Pleasant Garden	230.00	230.00	S-HFR	18.48		1
12	Asheboro	Siler City	230.00	230.00	W-HFR	8.24		1
13	Asheboro	Siler City	230.00	230.00	S-HFR	1.68		1
14	Asheboro	Siler City	230.00	230.00	C-HFR	15.69		1
15	Asheville CC Plant	Asheville Plant	230.00	230.00	S-SP	0.54		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	6,264.95		2,277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	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	Cane River SVC	230.00	230.00	S-SP	0.08		1
29	Cane River	Nagel East & West(APCO)	230.00	230.00	DC T	15.01		2
30	Cane River	Craggy	230.00	230.00	S-HFR	26.39		1
31	Cape Fear Plant	Cape Fear Plant Cap Bank	230.00	230.00	W-HFR	0.10		1
32	Cape Fear Plant	Harris Plant (North)	230.00	230.00	W-HFR	7.12		1
33	Cape Fear Plant	Harris Plant (North)	230.00	230.00	S-HFR	0.25		1
34	Cape Fear Plant	Harris Plant (South)	230.00	230.00	W-HFR	6.14		1
35	Cape Fear Plant	Harris Plant (South)	230.00	230.00	S-HFR	0.38		1
36					TOTAL	6,264.95		2,277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Jonesboro	230.00	230.00	W-HFR	10.10		1
2	Cape Fear Plant	West End	230.00	230.00	DC T	0.24		2
3	Cape Fear Plant	West End	230.00	230.00	W-HFR	37.30		1
4	Cary Regency Park	Method	230.00	230.00	DC S-SP	0.26		2
5	Cary Regency Park	Method	230.00	230.00	S-SP	4.49		1
6	Cary Regency Park	Method	230.00	230.00	W-HFR	4.00		1
7	Cary Regency Park	RTP	230.00	230.00	S-HFR	11.03		1
8	Castle Hayne	Folkstone	230.00	230.00	S-HFR	0.24		1
9	Castle Hayne	Folkstone	230.00	230.00	W-HFR	24.77		1
10	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	S-SP	0.45		1
11	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	W-HFR	5.12		1
12	Clinton	Erwin	230.00	230.00	S-SP	1.76		1
13	Clinton	Erwin	230.00	230.00	W-HFR	32.03		1
14	Clinton	Erwin	230.00	230.00	S-HFR	0.52		1
15	Clinton	Mt Olive	230.00	230.00	S-HFR	0.27		1
16	Clinton	Mt. Olive	230.00	230.00	S-SP	14.22		1
17	Clinton	Wallace	230.00	230.00	W-HFR	36.68		1
18	Concord	East Danville (AEP)	230.00	230.00	S-HFR	1.21		1
19	Concord	East Danville (AEP)	230.00	230.00	DC S-HFR	7.26		2
20	Concord	East Danville (AEP)	230.00	230.00	DC S-SP	1.74		2
21	Cumberland	Delco	230.00	230.00	W-HFR	54.40		1
22	Cumberland	Fayetteville (North)	230.00	230.00	DC S-SP	5.16		2
23	Cumberland	Fayetteville (North)	230.00	230.00	W-HFR	8.58		1
24	Cumberland	Fayetteville (South)	230.00	230.00	W-HFR	8.57		1
25	Cumberland	Fayetteville (South)	230.00	230.00	DC S-SP	5.16		2
26	Cumberland	Whiteville	230.00	230.00	W-HFR	40.93		1
27	Durham	East Durham (DPC)	230.00	230.00	DC S-HFR	0.75		2
28	Durham	East Durham (DPC)	230.00	230.00	C-HFR	0.60		1
29	Durham	East Durham (DPC)	230.00	230.00	W-HFR	8.31		1
30	Durham	Falls	230.00	230.00	S-HFR	4.28		1
31	Durham	Falls	230.00	230.00	DC S-HFR	3.35		2
32	Durham	Falls	230.00	230.00	S-SP	2.79		1
33	Durham	Falls	230.00	230.00	W-HFR	4.12		1
34	Durham	Method	230.00	230.00	DC S-SP	1.52		2
35	Durham	Method	230.00	230.00	S-SP	1.56		1
36					TOTAL	6,264.95		2,277

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Durham	Method	230.00	230.00	W-HFR	13.12		1
2	Durham	RTP	230.00	230.00	S-HFR	0.46		1
3	Durham	RTP	230.00	230.00	W-HFR	7.41		1
4	Durham	RTP	230.00	230.00	S-SP	2.23		1
5	Erwin	Fayetteville East	230.00	230.00	W-HFR	23.09		1
6	Erwin	Milburnie	230.00	230.00	S-HFR	0.50		1
7	Erwin	Milburnie	230.00	230.00	S-SP	0.71		1
8	Erwin	Milburnie	230.00	230.00	DC T	1.33		2
9	Erwin	Milburnie	230.00	230.00	W-HFR	34.08		1
10	Erwin	Selma	230.00	230.00	S-SP	1.08		1
11	Erwin	Selma	230.00	230.00	W-HFR	24.12		1
12	Falls	Milburnie	230.00	230.00	DC T	10.92		2
13	Falls	Milburnie	230.00	230.00	S-HFR	0.32		1
14	Fayetteville	Fayetteville East	230.00	230.00	DC T	0.97		2
15	Fayetteville	Fayetteville East	230.00	230.00	W-HFR	9.82		1
16	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	0.21		2
17	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.00		1
18	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	W-HFR	17.70		1
19	Fayetteville	Raeford	230.00	230.00	DC S-SP	2.08		2
20	Fayetteville	Raeford	230.00	230.00	W-HFR	14.78		1
21	Fayetteville	Raeford	230.00	230.00	S-HFR	0.16		1
22	Fayetteville	Rockingham	230.00	230.00	W-HFR	49.09		1
23	Fayetteville	Rockingham	230.00	230.00	DC S-HFR	2.30		2
24	Fayetteville	Rockingham	230.00	230.00	DC S-SP	2.08		2
25	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC S-HFR	6.58		2
26	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.60		1
27	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	0.27		2
28	Folkstone	Jacksonville	230.00	230.00	W-HFR	20.00		1
29	Folkstone	Jacksonville	230.00	230.00	S-HFR	0.10		1
30	Fort Bragg Woodruff St.	Raeford	230.00	230.00	S-SP	7.20		1
31	Fort Bragg Woodruff St.	Raeford	230.00	230.00	DC S-HFR	2.77		2
32	Fort Bragg Woodruff St.	Raeford	230.00	230.00	S-HFR	19.88		1
33	Greenville	Everetts (VP)	230.00	230.00	DC T	1.83		2
34	Greenville	Kinston Dupont	230.00	230.00	S-HFR	24.82		1
35	Greenville	Kinston Dupont	230.00	230.00	S-SP	0.17		1
36					TOTAL	6,264.95		2,277

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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	Greenville	Kinston Dupont	230.00	230.00	DC S-SP	0.33		2
2	Greenville	Wilson	230.00	230.00	W-HFR	33.69		1
3	Greenville	Wilson	230.00	230.00	S-HFR	0.30		1
4	Harris Plant	Siler City	230.00	230.00	S-HFR	1.44		1
5	Harris Plant	Siler City	230.00	230.00	W-HFR	30.04		1
6	Harris Plant	Cary Regency Park	230.00	230.00	W-HFR	10.01		1
7	Harris Plant	Cary Regency Park	230.00	230.00	S-HFR	0.87		1
8	Harris Plant	Erwin	230.00	230.00	S-HFR	0.27		1
9	Harris Plant	Erwin	230.00	230.00	W-HFR	29.50		1
10	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	1.15		2
11	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	S-HFR	0.20		1
12	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	W-HFR	34.30		1
13	Harris Plant	RTP	230.00	230.00	S-SP	16.96		1
14	Harris Plant	RTP	230.00	230.00	S-HFR	3.71		1
15	Harris Plant	Wake	230.00	230.00	S-SP	5.39		1
16	Harris Plant	Wake	230.00	230.00	S-HFR	32.43		1
17	Harris Plant	Harris Plt Start-Up Tran 1A	230.00	230.00	S-SP	0.17		1
18	Harris Plant	Harris Plt Start-Up Tran 1B	230.00	230.00	S-HFR	0.28		1
19	Havelock	Jacksonville	230.00	230.00	DC T	5.61		2
20	Havelock	Jacksonville	230.00	230.00	W-HFR	32.64		1
21	Havelock	Morehead Wildwood	230.00	230.00	DC S-SP	0.27		2
22	Havelock	Morehead Wildwood	230.00	230.00	W-HFR	14.82		1
23	Havelock	Morehead Wildwood	230.00	230.00	S-SP	0.23		1
24	Havelock	New Bern	230.00	230.00	DC T	0.13		2
25	Havelock	New Bern	230.00	230.00	W-HFR	23.34		1
26	Havelock Sub	Havelock Cap Bank	230.00	230.00	S-HFR	0.07		1
27	Henderson	Person	230.00	230.00	DC T	2.46		2
28	Henderson	Person	230.00	230.00	W-HFR	37.47		1
29	Jacksonville	Jacksonville SVC	230.00	230.00	S-HFR	0.10		1
30	Jacksonville	New Bern	230.00	230.00	W-HFR	29.92		1
31	Jacksonville	New Bern	230.00	230.00	S-HFR	0.61		1
32	Jacksonville	Wallace	230.00	230.00	W-HFR	30.82		1
33	Kinston Dupont	Wommack	230.00	230.00	S-SP	0.14		1
34	Kinston Dupont	Wommack	230.00	230.00	S-HFR	19.06		1
35	Laurinburg	Richmond Sub	230.00	230.00	C-SP	3.32		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	Laurinburg	Richmond Sub	230.00	230.00	W-HFR	17.12		1
2	Lee CC Plant	Lee Sub	230.00	230.00	S-HFR	0.87		1
3	Lee Sub	Milburnie	230.00	230.00	S-SP	0.43		1
4	Lee Sub	Milburnie	230.00	230.00	W-HFR	38.24		1
5	Lee Sub	Milburnie	230.00	230.00	DC T	1.36		2
6	Lee Sub	Milburnie	230.00	230.00	S-HFR	0.23		1
7	Lee Sub	Mt. Olive	230.00	230.00	S-HFR	0.23		1
8	Lee Sub	Mt. Olive	230.00	230.00	S-SP	10.39		1
9	Lee Sub	Mt. Olive	230.00	230.00	DC S-HFR	3.21		2
10	Lee Sub	Selma	230.00	230.00	S-SP	0.24		1
11	Lee Sub	Selma	230.00	230.00	W-HFR	16.54		1
12	Lee Sub	Wommack (North)	230.00	230.00	W-HFR	30.37		1
13	Lee Sub	Wommack (South)	230.00	230.00	S-HFR	29.45		1
14	Lilesville	DPC Oakboro (Black)	230.00	230.00	S-HFR	0.30		1
15	Lilesville	DPC Oakboro (Black)	230.00	230.00	DC T	24.40		2
16	Lilesville	DPC Oakboro (White)	230.00	230.00	S-HFR	0.32		1
17	Lilesville	DPC Oakboro (Whilte)	230.00	230.00	DC T	24.38		2
18	LIlesville	Rockingham (Black)	230.00	230.00	S-HFR	10.36		1
19	Lilesville	Rockingham (White)	230.00	230.00	S-HFR	10.35		1
20	Lilesville	Rockingham (South)	230.00	230.00	S-HFR	12.70		1
21	Marion	Whiteville	230.00	230.00	S-SP	14.49		1
22	Marion	Whiteville	230.00	230.00	S-HFR	2.38		1
23	Marion	Whiteville	230.00	230.00	DC S-HFR	5.04		2
24	Method	East Durham (DPC)	230.00	230.00	DC S-HFR	0.77		2
25	Method	East Durham (DPC)	230.00	230.00	S-SP	4.36		1
26	Method	East Durham (DPC)	230.00	230.00	C-HFR	0.55		1
27	Method	East Durham (DPC)	230.00	230.00	W-HFR	14.17		1
28	Method	East Durham (DPC)	230.00	230.00	S-HFR	0.55		1
29	Method	East Durham (DPC)	230.00	230.00	DC S-SP	1.53		2
30	Method	Milburnie	230.00	230.00	DC S-SP	3.64		2
31	Method	Milburnie	230.00	230.00	S-SP	3.79		1
32	Method	Milburnie	230.00	230.00	W-SP	5.31		1
33	Milburnie	Person	230.00	230.00	DC T	58.66		2
34	Milburnie	Person	230.00	230.00	S-HFR	0.49		1
35	Milburnie	Person	230.00	230.00	W-HFR	0.49		1
36					TOTAL	6,264.95		2,277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Milburnie	Wake	230.00	230.00	W-HFR	7.19		1
2	New Bern	Wommack (North)	230.00	230.00	S-HFR	2.57		1
3	New Bern	Wommack (North)	230.00	230.00	S-SP	0.14		1
4	New Bern	Wommack (North)	230.00	230.00	W-HFR	29.32		1
5	New Bern	Wommack (South)	230.00	230.00	W-HFR	33.33		1
6	New Bern	Wommack (South)	230.00	230.00	S-HFR	0.54		1
7	Person	Rocky Mount	230.00	230.00	S-HFR	0.13		1
8	Person	Rocky Mount	230.00	230.00	DC S-SP	0.18		2
9	Person	Rocky Mount	230.00	230.00	T	8.59		1
10	Person	Rocky Mount	230.00	230.00	W-HFR	69.41		1
11	Person	Rocky Mount	230.00	230.00	DC T	2.47		2
12	Person	Sedge Hill (VP)	230.00	230.00	W-HFR	4.85		1
13	Raeford	Richmond Substation 230KV	230.00	230.00	W-HFR	33.74		1
14	Raeford	Richmond Substation 230KV	230.00	230.00	S-HFR	1.40		1
15	Raeford	Richmond Substation 230KV	230.00	230.00	S-SP	2.48		1
16	Raeford	Richmond Substation 230KV	230.00	230.00	S-HFR	37.81		1
17	Richmond Sub	Rockingham (East)	230.00	230.00	S-HFR	0.39		1
18	Richmond Sub	Rockingham (East)	230.00	230.00	W-HFR	5.57		1
19	Richmond Sub	Rockingham (West)	230.00	230.00	DC S-HFR	1.21		1
20	Richmond Sub	Rockingham (West)	230.00	230.00	S-HFR	6.63		1
21	Richmond County Plant	Richmond Sub (Black)	230.00	230.00	S-HFR	1.13		1
22	Richmond County Plant	Richmond Sub (White)	230.00	230.00	S-HFR	0.88		1
23	Richmond County Plant	Richmond Sub (Orange	230.00	230.00	S-HFR	1.56		1
24	Robinson Plant	Rockingham	230.00	230.00	DC S-HFR	1.21		2
25	Robinson Plant	Rockingham	230.00	230.00	S-HFR	0.20		1
26	Robinson Plant	Rockingham	230.00	230.00	W-HFR	7.53		1
27	Rockingham	West End (West)	230.00	230.00	DC T	5.73		2
28	Rockingham	West End (West)	230.00	230.00	W-HFR	28.26		1
29	Rockingham	West End (East)	230.00	230.00	DC S-HFR	2.30		2
30	Rockingham	West End (East)	230.00	230.00	S-HFR	29.81		1
31	Rocky Mount	Hathaway (VP) (East)	230.00	230.00	DC T	4.74		2
32	Rocky Mount	Hathaway (VP) (East)	230.00	230.00	DC S-SP	0.30		2
33	Rocky Mount	Hathaway (VP) (West)	230.00	230.00	DC T	4.74		2
34	Rocky Mount	Hathaway (VP) (West)	230.00	230.00	DC S-SP	0.30		2
35	Rocky Mount	Wilson	230.00	230.00	S-SP	0.85		1
36					TOTAL	6,264.95		2,277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		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	Rocky Mount	Wilson	230.00	230.00	DC S-SP	8.26		2
2	Rocky Mount	Wilson	230.00	230.00	DC S-HFR	3.68		2
3	Roxboro Plant	East Danville (AEP)	230.00	230.00	S-HFR	1.79		1
4	Roxboro Plant	East Danville (AEP)	230.00	230.00	DC S-HFR	7.26		2
5	Roxboro Plant	East Danville (AEP)	230.00	230.00	DC S-SP	1.74		2
6	Roxboro Plant	Concord	230.00	230.00	S-HFR	0.61		1
7	Roxboro Plant	Falls	230.00	230.00	DC T	47.89		2
8	Roxboro Plant	Falls	230.00	230.00	C-SP	0.21		1
9	Roxboro Plant	Falls	230.00	230.00	S-HFR	0.17		1
10	Roxboro Plant	Falls	230.00	230.00	W-HFR	1.55		1
11	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	C-HFR	1.65		1
12	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	W-HFR	31.99		1
13	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	DC S-HFR	0.76		2
14	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	C-HFR	1.71		1
15	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	W-HFR	31.98		1
16	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	DC S-HFR	0.77		2
17	Roxboro Plant	Eno (DPC) (Black)	230.00	230.00	DC T	16.66		2
18	Roxboro Plant	Eno (DPC) (Black)	230.00	230.00	C-SP	0.22		1
19	Roxboro Plant	Eno (DPC) (White)	230.00	230.00	DC T	16.66		2
20	Roxboro Plant	Eno (DPC) (White)	230.00	230.00	C-SP	0.22		1
21	Roxboro Plant	Person (Middle)	230.00	230.00	C-HFR	0.10		1
22	Roxboro Plant	Person (Middle)	230.00	230.00	T	0.14		1
23	Roxboro Plant	Person (Middle)	230.00	230.00	S-HFR	1.83		1
24	Roxboro Plant	Person (Ceffo)	230.00	230.00	C-SP	0.21		1
25	Roxboro Palnt	Person (Ceffo)	230.00	230.00	DC T	0.15		2
26	Roxboro Plant	Person (Ceffo)	230.00	230.00	W-HFR	1.90		1
27	Roxboro Plant	Person (Hyco)	230.00	230.00	T	0.08		1
28	Roxboro Plant	Person (Hyco)	230.00	230.00	W-HFR	1.18		1
29	Selma	Wake	230.00	230.00	W-HFR	21.00		1
30	Sutton CC Plant	Sutton Plant	230.00	230.00	S-HFR	0.16		1
31	Sutton Plant	Castle Hayne	230.00	230.00	W-HFR	12.97		1
32	Sutton Plant	Castle Hayne	230.00	230.00	DC T	0.11		2
33	Sutton Plant	Castle Hayne	230.00	230.00	S-HFR	0.93		2
34	Sutton Plant	Delco	230.00	230.00	W-HFR	14.57		1
35	Sutton Plant	Delco	230.00	230.00	S-HFR	0.44		1
36					TOTAL	6,264.95		2,277

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Sutton Plant	Delco	230.00	230.00	DC T	0.28		2
2	Sutton Plant	Wallace	230.00	230.00	T	0.45		1
3	Sutton Plant	Wallace	230.00	230.00	W-HFR	31.89		1
4	Wake	Zebulon	230.00	230.00	W-HFR	10.74		1
5	Wake	Zebulon	230.00	230.00	S-HFR	0.49		1
6	Wayne County Plant	Lee Sub	230.00	230.00	S-HFR	0.35		1
7	Weatherspoon Plant	Fayetteville	230.00	230.00	W-HFR	32.55		1
8	Weatherspoon Plant	Fayetteville	230.00	230.00	DC T	0.97		2
9	Weatherspoon Plant	Latta	230.00	230.00	T	0.37		1
10	Weatherspoon Plant	Latta	230.00	230.00	W-HFR	18.29		1
11	Weatherspoon Plant	Latta	230.00	230.00	DC T	0.28		2
12	Weatherspoon Plant	Laurinburg	230.00	230.00	W-HFR	31.46		1
13	Weatherspoon Plant	Laurinburg	230.00	230.00	S-HFR	0.99		1
14	Wayne County Plant	Lee Substation	230.00	230.00	S-HFR	0.31		1
15	Wilmington Corning SW Sta.	Wilmington Corning Sub. (N)	230.00	230.00	S-SP	0.48		1
16	Wilmington Corning SW Sta.	Wilmington Corning Sub (S)	230.00	230.00	S-SP	0.43		1
17	Wilson	Zebulon	230.00	230.00	W-HFR	25.92		1
18	Wilson	Zebulon	230.00	230.00	S-HFR	0.46		1
19	Tap Point	Angier	230.00	230.00	W-HFR	0.11		1
20	Tap Point	Ansonville	230.00	230.00	S-SP	0.03		1
21	Tap Point	Apex (Bank #1)	230.00	230.00	W-HFR	0.01		1
22	Tap Point	Apex (Bank #2)	230.00	230.00	S-HFR	0.01		1
23	Tap Point	Auburn	230.00	230.00	W-HFR	0.10		1
24	Tap Point	Aurora PCS Mine POD	230.00	230.00	S-HFR	0.02		1
25	Tap Point	Bahama	230.00	230.00	W-HFR	0.06		1
26	Tap Point	Bailey	230.00	230.00	W-HFR	1.38		1
27	Tap Point	Bayboro	230.00	230.00	W-HFR	2.12		1
28	Tap Point	Benson	230.00	230.00	W-HFR	0.01		1
29	Tap Point	Benson PGI	230.00	230.00	W-HFR	1.98		1
30	Tap Point	Bladenboro Solar	230.00	230.00	S-HFR	0.09		1
31	Tap Point	Brunswick EMC Bolivia	230.00	230.00	S-HFR	0.02		1
32	Tap Point	Brunswick EMC Daws Crk	230.00	230.00	S-HFR	0.02		1
33	Tap Point	Buies Creek	230.00	230.00	W-HFR	0.06		1
34	Tap Point	Bynum	230.00	230.00	S-HFR	0.06		1
35	Tap Point	Bynum	230.00	230.00	W-HFR	9.26		1
36					TOTAL	6,264.95		2,277

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Tap Point	Camp Geiger	230.00	230.00	S-SP	1.94		1
2	Tap Point	Camp LeJeune Sub #1	230.00	230.00	W-HFR	4.65		1
3	Tap Point	Camp LeJeune Sub #2	230.00	230.00	W-HFR	0.04		1
4	Tap Point	Camp LeJeune French Creek	230.00	230.00	S-SP/S-HFR	2.92		1
5	Tap Point	Cary	230.00	230.00	W-HFR	0.93		1
6	Tap Point	Cary Evans Road (East)	230.00	230.00	W-HFR	0.04		1
7	Tap Point	Cary Evans Road (West)	230.00	230.00	S-HFR	0.04		1
8	Tap Point	Cary Trenton Road	230.00	230.00	S-SP-11	4.34		1
9	Tap Point	Cary Triangle Forest	230.00	230.00	W-HFR	0.04		1
10	Tap Point	Catherine Lake	230.00	230.00	W-HFR	0.08		1
11	Tap Point	Chocowinity	230.00	230.00	W-HFR	0.05		1
12	Tap Point	City of Lumberton POD #3	230.00	230.00	S-SP	0.70		1
13	Tap Point	Clifdale	230.00	230.00	W-HFR	0.54		1
14	Tap Point	Concord	230.00	230.00	S-HFR	0.13		1
15	Tap Point	County Line Solar	230.00	230.00	S-HFR	0.08		1
16	Tap Point	Craven County Wood Energy	230.00	230.00	W-HFR	1.87		1
17	Tap Point	Dover	230.00	230.00	S-HFR	0.04		1
18	Tap Point	Dudley Georgia Pacific	230.00	230.00	W-HFR	2.64		1
19	Tap Point	Eden Solar	230.00	230.00	S-HFR	0.06		1
20	Tap Point	Ellerbe	230.00	230.00	W-HFR	0.04		1
21	Tap Point	Fort Bragg Knox St.	230.00	230.00	W-HFR	0.08		1
22	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	S-SP	0.47		1
23	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	DC S-HFR	2.75		2
24	Tap Point	Fort Bragg Main	230.00	230.00	S-SP	0.04		1
25	Tap Point	Fort Bragg Woodruff St.	230.00	230.00	S-HFR	0.07		1
26	Tap Point	Four Oaks (East)	230.00	230.00	S-HFR	0.05		1
27	Tap Point	Four Oaks (West)	230.00	230.00	W-HFR	0.07		1
28	Tap Point	Fuquay	230.00	230.00	W-HFR	0.48		1
29	Tap Point	Fuquay Bells Lake	230.00	230.00	W-HFR	0.15		1
30	Tap Point	Garland	230.00	230.00	W-HFR	0.06		1
31	Tap Point	Garner Panther Branch(East)	230.00	230.00	W-HFR	0.15		1
32	Tap Point	Garner Panther Branch(West)	230.00	230.00	S-HFR	0.07		1
33	Tap Point	Grantham	230.00	230.00	W-HFR	0.10		1
34	Tap Point	Hamlet (North)	230.00	230.00	W-HFR	0.02		1
35	Tap Point	Hamlet (South)	230.00	230.00	S-HFR	0.02		1
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1	Tap Point	Henderson East	230.00	230.00	W-HFR	0.06		1
2	Tap Point	Holly Springs (East)	230.00	230.00	S-HFR	0.11		1
3	Tap Point	Holly Springs (West)	230.00	230.00	S-HFR	0.11		1
4	Tap Point	Holly Springs Industrial	230.00	230.00	S-HFR	0.83		1
5	Tap Point	Hope Mills Rockfish Road	230.00	230.00	W-HFR	0.07		1
6	Tap Point	Jacksonville Tarawa	230.00	230.00	W-HFR	0.04		1
7	Tap Point	Knightdale Square D	230.00	230.00	W-HFR	0.95		1
8	Tap Point	Laurel Hills	230.00	230.00	W-HFR	0.03		1
9	Tap Point	Laurinburg City	230.00	230.00	W-HFR	0.03		1
10	Tap Point	Leesville Wood Valley	230.00	230.00	W-HFR	0.15		1
11	Tap Point	Masonboro	230.00	230.00	S-SP	0.03		1
12	Tap Point	Mayo Plant	230.00	230.00	W-HFR	3.06		1
13	Tap Point	Morrisville	230.00	230.00	W-HFR	0.11		1
14	Tap Point	NCSU CBC	230.00	230.00	S-HFR	0.20		1
15	Tap Point	New Bern West	230.00	230.00	W-HFR	0.04		1
16	Tap Point	New Hill	230.00	230.00	W-HFR	0.20		1
17	Tap Point	Newton Grove	230.00	230.00	W-HFR	2.13		1
18	Tap Point	Oxford North	230.00	230.00	W-HFR	0.92		1
19	Tap Point	Oxford South	230.00	230.00	W-HFR	6.30		1
20	Tap Point	Person Sub 230/24kV Bank	230.00	230.00	S-HFR	0.11		1
21	Tap Point	Pitt Greene EMC Farmville	230.00	230.00	S-HFR	0.04		1
22	Tap Point	Pittsboro	230.00	230.00	W-HFR	0.03		1
23	Tap Point	Prospect	230.00	230.00	W-HFR	0.03		1
24	Tap Point	Raleigh Blue Ridge Road	230.00	230.00	S-SP	0.03		1
25	Tap Point	Raleigh Durham Airport	230.00	230.00	W-HFR	0.09		1
26	Tap Point	Raleigh Foxcroft	230.00	230.00	W-HFR	0.03		1
27	Tap Point	Raleigh Homestead (North)	230.00	230.00	S-HFR	0.07		1
28	Tap Point	Raleigh Homestead (South)	230.00	230.00	S-HFR	0.07		1
29	Tap Point	Raleigh Leesville Road	230.00	230.00	W-HFR	0.04		1
30	Tap Point	Raleigh NCSU Centennial	230.00	230.00	S-SP	0.05		1
31	Tap Point	Raleigh Oakdale	230.00	230.00	S-SP	1.26		1
32	Tap Point	Raleigh Six Forks	230.00	230.00	S-HFR	0.07		1
33	Tap Point	Rockingham Aberdeen Road	230.00	230.00	W-HFR	0.60		1
34	Tap Point	Rolesville	230.00	230.00	W-HFR	5.67		1
35	Tap Point	Rose Hill	230.00	230.00	W-HFR	0.16		1
36					TOTAL	6,264.95		2,277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Tap Point	Rowan Creek Solar	230.00	230.00	S-HFR	0.07		1
2	Tap Point	Rowland	230.00	230.00	W-HFR	6.86		1
3	Tap Point	Roxboro Bowmantown Road	230.00	230.00	S-HFR	0.04		1
4	Tap Point	Roxboro Cogentrix	230.00	230.00	W-HFR	0.60		1
5	Tap Point	Rox. Plt Unit #3 C. Tower	230.00	230.00	W-HFR	0.24		1
6	Tap Point	Roxboro South	230.00	230.00	W-HFR	0.79		1
7	Tap Point	Sanford Deep River	230.00	230.00	W-HFR	2.63		1
8	Tap Point	Sanford Deep River	230.00	230.00	S-HFR	0.09		1
9	Tap Point	Sanford Garden Street	230.00	230.00	W-HFR	3.25		1
10	Tap Point	Sanford Horner Blvd.	230.00	230.00	W-HFR	0.04		1
11	Tap Point	Sandhills Util. Ft. Brg 3rd	230.00	230.00	S-HFR	0.35		1
12	Tap Point	Scotts Hill	230.00	230.00	S-SP	3.37		1
13	Tap Point	Shoe Heel Creek Solar	230.00	230.00	S-HFR	0.08		1
14	Tap Point	Siler City Hwy. 64	230.00	230.00	S-HFR	0.53		1
15	Tap Point	Southport	230.00	230.00	W-HFR	1.88		1
16	Tap Point	Southport ADM (West)	230.00	230.00	W-HFR	0.48		1
17	Tap Point	Southport Cogentrix	230.00	230.00	W-HFR	0.30		1
18	Tap Point	Swansbsoro	230.00	230.00	W-HFR	0.07		1
19	Tap Point	Tideland EMC Edwards	230.00	230.00	S-SP	0.61		1
20	Tap Point	Topsail	230.00	230.00	W-HFR	1.55		1
21	Tap Point	Town of Apex POD #4	230.00	230.00	S-HFR	0.12		1
22	Tap Point	Town of Farmville	230.00	230.00	S-HFR	0.03		1
23	Tap Point	Turnbull Solar	230.00	230.00	S-HFR	0.07		1
24	Tap Point	Wadesboro	230.00	230.00	S-HFR	0.02		1
25	Tap Point	Wadesboro Bowman School	230.00	230.00	S-HFR	12.98		1
26	Tap Point	Wake Tech	230.00	230.00	S-HFR	0.06		1
27	Tap Point	Warsaw	230.00	230.00	S-SP	0.61		1
28	Tap Point	Warsaw	230.00	230.00	W-HFR	2.46		1
29	Tap Point	Warsaw Solar	230.00	230.00	S-HFR	0.06		1
30	Tap Point	Weatherspoon Sub	230.00	230.00	W-HFR	0.09		1
31	Tap Point	Wendell	230.00	230.00	W-HFR	0.07		1
32	Tap Point	Wilmington Invista	230.00	230.00	W-HFR	0.58		1
33	Tap Point	Wilmington Cedar Avenue	230.00	230.00	S-SP	0.21		1
34	Tap Point	Wilmington East	230.00	230.00	W-HFR	0.01		1
35	Tap Point	Wilmington Ninth & Orange	230.00	230.00	S-SP	2.01		1
36					TOTAL	6,264.95		2,277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Tap Point	Wilmington Ogden (East)	230.00	230.00	W-HFR	0.06		1
2	Tap Point	Wilmington Ogden (West)	230.00	230.00	S-HFR	0.06		1
3	Tap Point	Wilmington Praxair	230.00	230.00	W-HFR	0.58		1
4	Tap Point	Wilmington BASF	230.00	230.00	W-HFR	0.22		1
5	Tap Point	Wilmington Winter Park	230.00	230.00	S-HFR	0.02		1
6	Tap Point	Yanceyville	230.00	230.00	S-SP	10.36		1
7	Barnard Creek	Town Creek	230.00	230.00	UNDERGROU	1.42		1
8	Bennettsville Sw Sta	Laurinburg	230.00	230.00	S-HFR	0.12		1
9	Bennettsville Sw Sta	Laurinburg	230.00	230.00	W-HFR	9.90		1
10	Camden	Lugoff(SCPSA)	230.00	230.00	W-HFR	5.37		1
11	Darlington County Plant	Bennettsville Sw Sta	230.00	230.00	S-HFR	0.13		1
12	Darlington County Plant	Bennetsville Sw Sta	230.00	230.00	W-HFR	34.06		1
13	Darlington County Plant	Darlington IC Turbine Yard	230.00	230.00	S-HFR	0.20		1
14	Darlington County Plant	Florence	230.00	230.00	S-SP	37.28		1
15	Darlington County Plant	Robinson Plant (South)	230.00	230.00	W-HFR	1.71		1
16	Darlington County Plant	Robinson Plant (North)	230.00	230.00	S-HFR	1.67		1
17	Darlington County Plant	South Bethune (SCPSA)	230.00	230.00	W-HFR	0.06		1
18	Darlington County Plant	Sumter	230.00	230.00	DC S-SP	5.33		2
19	Darlington County Plant	Sumter	230.00	230.00	W-HFR	48.36		1
20	Florence	Kingstree	230.00	230.00	W-HFR	49.46		1
21	Florence	Latta	230.00	230.00	W-HFR	23.42		1
22	Florence	Latta	230.00	230.00	S-SP	0.17		1
23	Florence	Darlington (SCPSA)	230.00	230.00	W-HFR	11.05		1
24	Latta	Marion	230.00	230.00	W-HFR	8.43		1
25	Marion	Marion (SCPSA) (North)	230.00	230.00	S-HFR	0.07		1
26	Marion	Marion (SCPSA) (South)	230.00	230.00	S-HFR	0.06		1
27	Marion	Whiteville	230.00	230.00	S-SP	6.60		1
28	Marion	Whiteville	230.00	230.00	W-HFR	14.81		1
29	Robinson Plant	Florence	230.00	230.00	DC T	1.40		2
30	Robinson Plant	Florence	230.00	230.00	W-HFR	38.41		1
31	Robinson Plant	Rockingham	230.00	230.00	S-SP	0.23		1
32	Robinson Plant	Rockingham	230.00	230.00	W-HFR	38.95		1
33	Robinson Plant	Rockingham	230.00	230.00	DC T	1.40		2
34	Robinson Plant	Darlington (SCPSA)	230.00	230.00	DC T	0.60		2
35	Robinson Plant	Darlington (SCPSA)	230.00	230.00	W-HFR	17.95		1
36					TOTAL	6,264.95		2,277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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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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	Robinson Plant	Sumter	230.00	230.00	W-HFR	40.56		1
2	Robinson Plant	Sumter	230.00	230.00	DC T	0.60		2
3	Sumter	St. Geroge (SCE&G)	230.00	230.00	DC T	7.26		2
4	Sumter	St. George (SCE&G)	230.00	230.00	W-HFR	22.90		1
5	Sumter	Wateree Plant (SCE&G)	230.00	230.00	W-HFR	16.58		1
6	Sumter	Wateree Plant (SCE&G)	230.00	230.00	DC T	7.26		2
7	Weatherspoon	Latta	230.00	230.00	W-HFR	13.45		1
8	Tap Point	Bishopville	230.00	230.00	W-HFR	0.16		1
9	Tap Point	Camden 230/23kv Yard	230.00	230.00	W-HFR	0.18		1
10	Tap Point	Cheraw Cash Rd.	230.00	230.00	S-SP	1.08		1
11	Tap Point	Cheraw Reid Park	230.00	230.00	W-HFR	5.30		1
12	Tap Point	Dillon North	230.00	230.00	S-SP	3.51		1
13	Tap Point	Dillon Maple	230.00	230.00	W-HFR	4.39		1
14	Tap Point	Dovesville Nucor	230.00	230.00	W-HFR	6.81		1
15	Tap Point	Elliott	230.00	230.00	W-HFR	2.15		1
16	Tap Point	Florence Cashua	230.00	230.00	C-SP	1.30		1
17	Tap Point	Florence Ebenezer	230.00	230.00	W-HFR	0.08		1
18	Tap Point	Florence West	230.00	230.00	W-HFR	0.03		1
19	Tap Point	Hartsville Segars Mill	230.00	230.00	W-HFR	0.06		1
20	Tap Point	Hartsville Talley Metals	230.00	230.00	W-HFR	0.31		1
21	Tap Point	Hartsville Talley Metals	230.00	230.00	S-SP	0.74		1
22	Tap Point	Kingstree North	230.00	230.00	W-HFR	0.14		1
23	Tap Point	Lake City	230.00	230.00	W-HFR	0.08		1
24	Tap Point	McColl	230.00	230.00	W-HFR	0.90		1
25	Tap Point	Olanta	230.00	230.00	W-HFR	0.05		1
26	Tap Point	Society Hill	230.00	230.00	W-SP	1.13		1
27	Tap Point	Summerton	230.00	230.00	W-HFR	2.70		1
28	Tap Point	Sumter Alice Drive	230.00	230.00	W-HFR	0.30		1
29	Tap Point	Sumter Continental Tire	230.00	230.00	S-HFR	0.31		1
30	Tap Point	Sumter North	230.00	230.00	S-SP	0.73		1
31	Tap Point	Sumter Wedgefield Rd.	230.00	230.00	W-HFR	0.05		1
32	Tap Point	Bayboro	230.00	230.00	S-HFR	0.06		1
33	Tap Point	Powhatan Industrial	230.00	230.00	S-HFR	1.62		1
34	Tap Point	Buckleberry Canal Solar	230.00	230.00	S-HFR	0.10		1
35	Tap Point	Sandy Bottom Solar	230.00	230.00	S-HFR	0.22		1
36					TOTAL	6,264.95		2,277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Tap Point	Willard Solar	230.00	230.00	S-HFR	0.04		1
2	Tap Point	Crooked Run Solar	230.00	230.00	S-HFR	0.04		1
3	Tap Point	Green Level (East)	230.00	230.00	S-HFR	0.07		1
4	Tap Point	Green Level (West)	230.00	230.00	S-HFR	0.06		1
5	Tap Point	Hope Mills Rockfish Rd Bk 2	230.00	230.00	S-HFR	0.07		1
6	Tap Point	Roxboro Plant Waste Water	230.00	230.00	S-HFR	0.19		1
7								
8								
9	Tot. 230kV Lines							
10								
11	Tot. 115kV Lines				Tower and	2,563.12		568
12								
13	Tot. 66kV - 69kV Lines				Tower and	11.92		1,136
14								
15	Expenses (Columns M & N)							
16								
17	Total KV Lines					6,264.95		2,277
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	6,264.95		2,277

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1590MCMA(B)								1
1590MCMA(B)								2
3-1590MCMA								3
3-1590MCMA								4
1590MCMA(B)								5
2515MCMA(B)								6
2515MCMA(B)								7
	23,522,235	77,290,943	100,813,178					8
1272MCMA								9
1272MCMA								10
2-1590MCMA								11
1272MCMA(B)								12
1272MCMA(B)								13
1272MCMA(B)								14
1272MCMA								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
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	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	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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
795MCMA								28
1590MCMA								29
1590MCMA								30
795MCMA								31
2515&1272MCMA(								32
1272MCMA(B)								33
1272MCMA(B)								34
1272MCMA(B)								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	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	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795&1272MCMA(B)								1
1272MCMA								2
1272&2515MCMA								3
2515MCMA								4
2515&1272MCMA								5
1272MCMA(B)								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272MCMA								12
1272MCMA								13
1272MCMA								14
1590MCMA								15
1590MCMA								16
1272&556MCMA(B)								17
1590MCMA								18
1590MCMA								19
1590MCMA								20
1272MCMA								21
2515MCMA								22
2515MCMA								23
2515MCMA								24
2515MCMA								25
1272&2515MCMA								26
1272MCMA(B)								27
1272MCMA(B)								28
1272MCMA(B)								29
1590MCMA(B)								30
1590MCMA(B)								31
1590MCMA(B)								32
1272MCMA								33
2515MCMA								34
2515MCMA								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	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	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2515&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								15
1272MCMA(B)								16
2515&1272MCMA(								17
1272MCMA(B)								18
1272MCMA(B)								19
1272MCMA(B)								20
1272MCMA(B)								21
1272MCMA								22
1272MCMA								23
1272MCMA								24
1590MCMA								25
1590MCMA								26
1590MCMA								27
1272MCMA								28
1272MCMA								29
1590MCMA(B)								30
1590MCMA(B)								31
1590MCMA(B)								32
1109MCMA								33
795MCMA(B)								34
795MCMA(B)								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	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	04/14/2020	End of 2019/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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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(B)								1
1272&546MCMA(B)								2
1272MCMA								3
1272MCMA(B)								4
2515&1272MCMA(								5
1272MCMA(B)								6
1590MCMA(B)								7
1272MCMA(B)								8
1272MCMA(B)								9
1272MCMA(B)								10
1272MCMA(B)								11
1272MCMA(B)								12
1590MCMA(B)								13
1590MCMA(B)								14
1590MCMA(B)								15
1590MCMA(B)								16
795MCMA								17
2515MCMA(B)								18
1272MCMA								19
1272&556MCMA(B)								20
1590MCMA								21
1590MCMA								22
1590MCMA								23
1272MCMA								24
1272MCMA								25
795MCMA								26
1272MCMA								27
1272MCMA								28
795MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
795MCMA(B)								33
795MCMA(B)								34
2515MCMA								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	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	04/14/2020	End of 2019/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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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)	
2515&1272MCMA(								1
1590MCMA(B)								2
1272MCMA								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
1590MCMA								7
1590MCMA								8
1590MCMA								9
2515&1272MCMA(								10
1272MCMA(B)								11
1272MCMA(B)								12
1272MCMA(B)								13
1272 MCMA								14
1272MCMA								15
1272 MCMA								16
1272MCMA								17
1272 MCMA								18
1272 MCMA								19
2515 MCMA								20
1590MCMA								21
1590MCMA								22
1590MCMA								23
1272MCMA(B)								24
2515MCMA								25
1272MCMA(B)								26
2515&1272MCMA(								27
1272MCMA(B)								28
1272MCMA(B)								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	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	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMA(B)								1
1272MCMA								2
1272MCMA								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272MCMA								12
1272MCMA(B)								13
1272MCMA(B)								14
1590MCMA(B)								15
1590MCMA(B)								16
1272MCMA(B)								17
1272MCMA(B)								18
1590MCMA(B)								19
1590MCMA(B)								20
21590MCMA(B)								21
21590MCMA(B)								22
21590MCMA								23
1590MCMA(B)								24
1590MCMA(B)								25
1272&1590MCMA(								26
1272MCMA								27
1272MCMA								28
2-1590MCMA								29
2-1590MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1590MCMA								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	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	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1590MCMA								1
1590MCMA								2
1590MCMA								3
1590MCMA								4
1590MCMA								5
1590MCMA								6
1272MCMA								7
1590MCMA								8
1272MCMA								9
1272&1590MCMA								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
1272MCMA(B)								22
1590MCMA(B)								23
1590MCMA(B)								24
1590MCMA(B)								25
1590MCMA(B)								26
2515MCMA								27
1272&2515MCMA(								28
2515&1272MCMA(								29
1590MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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1272MCMA								1
1272MCMA								2
1272MCMA								3
1272MCMA(B)								4
1272MCMA(B)								5
1590MCMA(B)								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272&2515MCMA								12
1272MCMA								13
1590MCMA(B)								14
795MCMA								15
795MCMA								16
1272MCMA(B)&251								17
1272MCMA(B)								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
1272MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
1272MCMA								27
795MCMA								28
795MCMA								29
795MCMA								30
1272MCMA								31
1272MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	36

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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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1272MCMA								1
795MCMA								2
795MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
795MCMA								7
795MCMA								8
795MCMA								9
795MCMA								10
1272MCMA								11
795MCMA								12
795MCMA								13
795MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
1272MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
795MCMA								30
795MCMA								31
795MCMA								32
795MCMA								33
1272MCMA								34
1272MCMA								35
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMA								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
795MCMA								17
1272MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
1272MCMA								27
1272MCMA								28
795MCMA								29
1272MCMA								30
795MCMA								31
1272MCMA								32
795MCMA								33
1590MCMA								34
795MCMA								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	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	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795MCMA								1
795MCMA								2
1272MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
795MCMA								7
795MCMA								8
1590MCMA								9
795MCMA								10
795MCMA								11
795MCMA								12
795MCMA								13
795MCMA								14
1272MCMA								15
1272MCMA								16
795MCMA								17
795MCMA								18
1590MCMA								19
795MCMA								20
795 MCMA								21
795 MCMA								22
795MCMA								23
795MCMA								24
1590MCMA								25
795MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
795MCMA								30
795MCMA								31
1272MCMA								32
795MCMA								33
1272MCMA								34
1272MCMA								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	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	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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795MCMA								1
795MCMA								2
795MCMA								3
795MCMA								4
1272MCMA								5
795MCMA								6
2-2500MCMA								7
2515MCMA								8
2515MCMA								9
1272MCMA								10
2515MCMA								11
2515MCMA								12
1590MCMA								13
1590MCMA								14
2515MCMA								15
2515MCMA								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
1272MCMA								22
1272MCMA								23
1590MCMA								24
1272MCMA(B)								25
1272MCMA(B)								26
1590MCMA								27
1590MCMA								28
1272MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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1272MCMA								1
1272MCMA								2
795MCMA								3
795MCMA								4
1272MCMA								5
1272MCMA								6
1272MCMA								7
795MCMA								8
1272MCMA								9
795MCMA								10
1272MCMA								11
795MCMA								12
795MCMA								13
1272MCMA								14
795MCMA								15
795MCMA								16
1590MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
1590MCMA								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
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795MCMA								1
795MCMA								2
795MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
								7
								8
	128,608,778	888,287,312	1,016,896,090					9
								10
	34,813,299	505,275,205	540,088,504					11
								12
	57,228	4,355,001	4,412,229					13
								14
				789,800	14,579,117		15,368,917	15
								16
	187,001,540	1,475,208,461	1,662,210,001	789,800	14,579,117		15,368,917	17
								18
								19
								20
								21
								22
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								26
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								28
								29
								30
								31
								32
								33
								34
								35
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TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Tap Point	Crooked Run Solar	0.04	S-HFR		1	1
2	Tap Point	Green Level (East Tap)	0.07	S-HFR		1	1
3	Tap Point	Green Level (West Tap)	0.06	S-HFR		1	1
4	Tap Point (Bank #2)	Hope Mills Rockfish Road	0.07	S-HFR		1	1
5	Tap Point	Roxboro Plant Waste Water	0.19	S-HFR		1	1
6							
7							
8							
9	Cane River	Cane River SVC	0.08	S-SP		1	1
10	Asheville CC Plant	Asheville Plant	0.54	S-SP		1	1
11							
12							
13	Tap Point	Vanceboro West Craven	0.39	S-HFR		1	1
14	Tap Point	Fuquay Wade Nash Road	0.13	S-SP		1	1
15	Tap Point	Fuquay Guilford Mills	-1.07	S-SP	10.00	1	1
16							
17	Asheville CC Plant	Asheville Plant (West Line)	0.69	DC S-SP		2	2
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		1.19		10.00	12	12

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		152,083	291,796	31,396	475,275	1
795	MCMA	FLAT	230		215,587	57,108		272,695	2
795	MCMA	FLAT	230		215,586	57,107		272,693	3
795	MCMA	FLAT	230		59,945	110,509		170,454	4
795	MCMA	FLAT	230		221,626	625,476		847,102	5
									6
									7
									8
795	MCMA	VERT	230		745,663	2,656,551		3,402,214	9
1272	MCMA	VERT	230		2,430,575	657,503		3,088,078	10
									11
									12
336.4	MCMA	FLAT	115		996,996			996,996	13
795	MCMA	VERT	115		136,000	38,825	397,866	572,691	14
795	MCMA	VERT	115				128,818	128,818	15
									16
1590	MCMA	VERT	115		309,357	908,825		1,218,182	17
									18
									19
									20
									21
									22
									23
									24
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									30
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									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					5,483,418	5,403,700	558,080	11,445,198	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	04/14/2020	End of 2019/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	24.00	
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	23.00	
21	Asheville S.E. Plant Asheville	T-A Gen Set-Up 3,4	115.00	23.00	
22	Atlantic Beach 115kV Morehead	D-U	115.00	12.00	
23	Avery Creek 115 kV Arden	D-U	115.00	24.00	
24	Auburn 230kV Auburn	D-U	230.00	24.00	
25	Bahama 230kV Durham Co.	D-U	230.00	24.00	
26	Bailey 230kV Bailey	D-U	230.00	24.00	
27	Baldwin 115kV Arden	D-U	115.00	24.00	
28	Barnard Creek 230kV Wilmington	T-U	230.00	115.00	
29	Barnardsville 115kV Barnardsville	D-U	115.00	12.00	
30	Bayboro 230kV Bayboro	D-U	230.00	24.00	
31	Bear Branch, Broadway	D-U	230.00	24.00	
32	Beard 115kV Beard	D-U	115.00	13.00	
33	Beaufort 115kV Beaufort	D-U	115.00	12.00	
34	Beaverdam 115kV Asheville	D-U	115.00	24.00	
35	Belfast 115kV Goldsbsoro	D-U	115.00	23.00	
36	Benson 230kV Benson	D-U	230.00	24.00	
37	Beulaville 115kV Beulaville	D-U	115.00	23.00	
38	Biltmore 115kV Asheville	D-U	115.00	12.00	
39	Biscoe 115kV Biscoe	D-U	115.00	24.00	
40	Biscoe 230kV Bisco	T-U	230.00	115.00	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	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	13.00	
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	13.00	
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	25.00	
25	Cary Triangle Forest 230kV Cary	D-U	230.00	23.00	
26	Castalia 230 kV Castalia	D-U	230.00	24.00	
27	Castle Hayne 115kV Wilmington	D-U	115.00	24.00	
28	Castle Hayne 230kV Wilmington	T-U	230.00	115.00	13.80
29	Catherine Lake 230kV Jacksonville	D-U	230.00	24.00	
30	Chadbourn 115kV Chadbourn	D-U	115.00	24.00	
31	Cherry Point #1 115kV Havelock	D-U	115.00	12.00	
32	Cherry Point #2 115kV Havelock	D-U	115.00	12.00	
33	Chestnut Hills 115kV Raleigh	D-U	115.00	24.00	
34	Chocowinity 230kV Chocowinity	D-U	230.00	23.00	
35	Clarkton 115kV Clarkton	D-U	115.00	24.00	
36	Clayton 115kV Clayton	D-U	115.00	24.00	
37	Clayton Industrial 115kV Clayton	D-U	115.00	24.00	
38	Clifdale 230kV Clifdale	D-U	230.00	24.00	
39	Clinton 230kV Clinton	T-U	230.00	115.00	13.80
40	Clinton Ferrell St. 115kV Clinton	D-U	115.00	23.00	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Clinton (N) 115kV Clinton	D-U	115.00	23.00	
2	Concord 230kV Concord	T-U	230.00	115.00	
3	Craggy 230kV Craggy	T-U	230.00	115.00	
4	Cumberland 500kV Fayetteville	T-U	500.00	230.00	13.80
5	Delco 115kV Delco	D-U	115.00	24.00	
6	Delco 230kV Delco	T-U	230.00	115.00	13.80
7	Dover 230kV Kinston	D-U	230.00	24.00	
8	Duncan 230kV Garner	D-U	230.00	24.00	
9	Dunn 230kV Dunn	D-U	230.00	23.00	
10	Durham 500kV Leesville	T-U	500.00	230.00	13.80
11	Eagle Island 115kV Wilmington	D-U	115.00	24.00	
12	Edmondson 230kV Raleigh	D-U	230.00	24.00	
13	Elizabethtown 115kV Elizabethtown	D-U	115.00	24.00	
14	Elk Mountain 115kV Asheville	D-U	115.00	24.00	
15	Ellerbe 230kV Ellerbe	D-U	230.00	23.00	
16	Elm City 115kV Elm City	D-U	115.00	24.00	
17	Emma 115kV Asheville	D-U	115.00	12.00	
18	Enka 230kV Enka	T-U	230.00	115.00	
19	Enka Sardis Rd. 115kV Enka	D-U	115.00	24.00	
20	Erwin 230kV Erwin	T-U	230.00	115.00	13.80
21	Erwin 230kV Erwin	D-U	115.00	24.00	12.00
22	Erwin 230kV Erwin	D-U	115.00	24.00	
23	Erwin Mills 115kv Erwin	D-U	115.00	12.00	
24	Fair Bluff 115kV Fair Bluff	D-U	115.00	24.00	
25	Fairmont 115kV Fairmont	D-U	115.00	23.00	
26	Fairview 115kV Fairview	D-U	115.00	12.00	
27	Falls 230kV Raleigh	D-U	230.00	24.00	
28	Falls 230kV Raleigh	T-U	230.00	115.00	
29	Farmville 230kV Farmville	D-U	230.00	12.00	
30	Fayetteville 230kV Fayetteville	D-U	115.00	24.00	13.20
31	Fayetteville 230kV Fayetteville	T-U	230.00	115.00	
32	Fayetteville Slocomb 115kV Slocomb	D-U	115.00	12.00	
33	Folkstone 230kV Holly Ridge	T-U	230.00	115.00	
34	Four Oaks 230kV Four Oaks	D-U	230.00	24.00	
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	Fuquay Wade Nash Road	D-U	115.00	24.00	
6	Garland 230kV Garland	D-U	230.00	23.00	
7	Garner 115kV Garner	D-U	115.00	24.00	
8	Garner I-40 230kV Garner	D-U	230.00	24.00	
9	Garner Panther Branch 230kV Wake Co.	D-U	230.00	23.00	
10	Garner Tryon Hills 115kV Garner	D-U	115.00	24.00	
11	Garner White Oak 230kV Garner	D-U	230.00	24.00	
12	Global Trans Park 115kV Kinston	D-U	115.00	23.00	
13	Godwin 115kV Godwin	D-U	115.00	23.00	
14	Goldsboro City 115kV Goldsboro	D-U	115.00	12.00	
15	Goldsboro Hemlock 115kV Goldsboro	D-U	115.00	12.00	
16	Goldsboro Langston 115kV Goldsboro	D-U	115.00	24.00	
17	Goldsboro-Weil 115kV Goldsboro	D-U	115.00	24.00	
18	Grantham 230kV Grantham	D-U	230.00	24.00	
19	Grants Creek 230 KV Jacksonville	D-U	230.00	115.00	
20	Green Level 230kV Green Level	D-U	230.00	24.00	
21	Grifton 115kV Grifton	D-U	115.00	23.00	
22	Hamlet 230kV Hamlet	D-U	230.00	24.00	
23	Harlowe 230 KV Newport	D-U	230.00	115.00	
24	Havelock 230kV Havelock	D-U	115.00	23.00	
25	Havelock 230kV Havelock	T-U	230.00	115.00	13.80
26	Hazelwood 115kV Hazelwood	D-U	115.00	24.00	
27	Henderson 230kV Henderson	T-U	230.00	115.00	13.20
28	Henderson 230kV Henderson	D-U	115.00	24.00	
29	Henderson East 230kV Henderson	D-U	230.00	24.00	
30	Henderson North 115kV Henderson	D-U	115.00	24.00	
31	Holly Ridge 115kV Holly Ridge	D-U	115.00	23.00	
32	Holly Springs 230kV Holly Springs	D-U	230.00	24.00	
33	Holly Springs Industrial 230kV Holly Springs	D-U	230.00	24.00	
34	Hope Mills Church St. 115kV Hope Mills	D-U	115.00	23.00	
35	Hope Mills Rockfish Rd. 230kV Hope Mills	D-U	230.00	24.00	
36	Jacksonville 230kV Jacksonville	T-U	230.00	115.00	
37	Jacksonville Blue Creek, Jacksonville	D-U	115.00	24.00	
38	Jacksonville City 115kV Jacksonville	D-U	115.00	24.00	
39	Jacksonville Northwoods 115kV Jacksonville	D-U	115.00	23.00	
40	Jacksonville Tarawa 230kV Jacksonville	D-U	230.00	24.00	

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1	Jonesboro 230kV Sanford	D-U	230.00	24.00	
2	Kings Bluff 115kV Wilmington	D-U	115.00	12.00	
3	Kinston 115kV Kinston	D-U	115.00	24.00	
4	Kinston DuPont 115kV Kinston	D-U	115.00	12.00	
5	Kinston DuPont 230kV Kinston	T-U	230.00	115.00	
6	Knightdale Hodge Road 230 KV	D-U	230.00	24.00	
7	Knightdale Square D 230kV Knightdale	D-U	230.00	24.00	
8	Knightdale 115kV Knightdale	D-U	115.00	23.00	
9	Kornegay 115kV Kornegay	D-U	115.00	23.00	
10	LaGrange 115kV LaGrange	D-U	115.00	12.00	
11	Lake Junaluska 115kV Lake Junaluska	D-U	115.00	24.00	
12	Lake Wacamaw 115kV Lake Waccamaw	D-U	115.00	24.00	
13	Lakestone 115kV Raleigh	D-U	115.00	12.00	
14	Lakeview 115kv Carthage	D-U	115.00	24.00	
15	Laurel Hill 230kV Laurel Hill	D-U	230.00	23.00	
16	Laurinburg 230kV Laurinburg	T-U	230.00	115.00	13.80
17	Laurinburg 230kV Laurinburg	D-U	115.00	24.00	
18	Laurinburg City 230kV Laurinburg	D-U	230.00	23.00	
19	Lee Combined Cycle Plant	T-A	230.00	115.00	
20	Lee 230kV Goldsboro	T-U	230.00	115.00	
21	Lee 230kV Goldsboro	T-U	115.00	13.80	
22	Leesville Wood Valley 230kV Raleigh	D-U	230.00	24.00	
23	Leicester 115kV Leicester	D-U	115.00	24.00	
24	Leland 115kV Wilmington	D-U	115.00	24.00	
25	Leland Industrial 115kV Leland	D-U	115.00	24.00	
26	Liberty 115kV Liberty	D-U	115.00	23.00	
27	Lillington 115kV Lillington	D-U	115.00	24.00	
28	Littleton 115kV Littleton	D-U	115.00	24.00	
29	Louisburg 115kV Louisburg	D-U	115.00	23.00	
30	Lumberton 115kV Lumberton	D-U	115.00	24.00	
31	Maggie Valley 115kV Maggie Valley	D-U	115.00	24.00	
32	Marshall H.E. Plant Marshall	D-U	115.00	23.00	
33	Marshall H.E. Plant Marshall	T-U Gen Step-Up	23.00	4.00	
34	Masonboro 230kV Wilmington	D-U	230.00	23.00	
35	Maxton 115kV Maxton	D-U	115.00	24.00	
36	Maxton Airport 115kV Maxton	D-U	115.00	23.00	
37	Mayo S.E. Plant Roxboro	T-A Gen Step-Up	500.00	19.90	
38	Method 230kV Raleigh	D-U	115.00	12.00	
39	Method 230kV Raleigh	T-U	230.00	115.00	13.80
40	Micaville 115kV Micaville	D-U	115.00	12.00	

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1	Milburnie 230kV Raleigh	D-U	115.00	23.00	
2	Milburnie 230kV Raleigh	T-U	230.00	115.00	13.80
3	Moncure 115kV Moncure	D-U	115.00	24.00	
4	Monte Vista 115kV Asheville	D-U	115.00	23.00	
5	Mordecai 115kV Raleigh	D-U	115.00	12.00	
6	Morehead 115kV Morehead	D-U	115.00	12.00	
7	Morehead Wildwood 230kV	D-U	115.00	24.00	
8	Morehead Wildwood 230kV Morehead	T-U	230.00	115.00	
9	Morrisville 230kV Morrisville	D-U	230.00	23.00	
10	Mount Gilead 115kV Mount Gilead	D-U	115.00	12.00	
11	Mount Gilead Industrial 115kV Mount Gilead	D-U	115.00	13.00	
12	Mount Olive 115kV Mount Olive	D-U	115.00	12.00	
13	Mount Olive 230kV Mount Olive	T-U	230.00	115.00	
14	Mount Olive West 115kV Mount Olive	D-U	115.00	24.00	
15	Murrayville 230kV New Hanover	D-U	230.00	23.00	
16	Nagel (APCO) 500kV Hawkins, Tn.	T-U	500.00	230.00	13.80
17	Nashville 115kV Nashville	D-U	115.00	25.00	
18	Neuse 115kV Neuse	D-U	115.00	23.00	
19	New Bern 230kV New Bern	T-U	230.00	115.00	13.20
20	New Bern Amital 115kV New Bern	D-U	115.00	12.00	
21	New Bern West 230kV New Bern	D-U	230.00	23.00	
22	New Hill 230kV New Hill	D-U	230.00	23.00	
23	New Hope 115kV Goldsboro	D-U	115.00	23.00	
24	New Salem 115kV Swannanoa	D-U	115.00	12.00	
25	Newport 115kV Newport	D-U	115.00	23.00	
26	Newton Grove 230kV Newton Grove	D-U	230.00	23.00	
27	North River 115kV Beaufort	D-U	115.00	34.50	
28	Oteen 115kV Asheville	D-U	115.00	12.00	
29	Oxford North 230kV Oxford	D-U	230.00	23.00	
30	Oxford South 230kV Oxford	D-U	230.00	23.00	
31	Pembroke 115kV Pembroke	D-U	115.00	23.00	
32	Person 500kV Roxboro	T-U	500.00	230.00	13.80
33	Person 500kV Roxboro	D-U	230.00	24.00	
34	Pine Lake 230kV Raleigh	D-U	230.00	24.00	
35	Pinehurst 115kV Pinehurst	D-U	115.00	24.00	
36	Pisgah Forest (Duke) 230kV Brevard	T-U	115.00	100.00	13.00
37	Pittsboro 230kV Pittsboro	D-U	230.00	23.00	
38	Powhatan Industrial 230	D-U	230.00	24.00	
39	Princeton 115kV Princeton	D-U	115.00	24.00	
40	Raeford 115kV Raeford	D-U	115.00	12.00	

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1	Raeford 230kV Raeford	T-U	230.00	115.00	
2	Raeford South 115kV Raeford	D-U	115.00	12.00	
3	Raleigh 115kV Raleigh	D-U	115.00	12.00	
4	Raleigh Atlantic Avenue 115kV Raleigh	D-U	115.00	23.00	
5	Raleigh Blue Ridge 230kV Raleigh	D-U	230.00	23.00	
6	Raleigh Brier Creek 230kV Raleigh	D-U	230.00	24.00	
7	Raleigh Durham Airport 230-23kV Raleigh	D-U	230.00	23.00	
8	Raleigh East St. 230kV Raleigh	D-U	230.00	12.00	
9	Raleigh Foxcroft 230kV Raleigh	D-U	230.00	24.00	
10	Raleigh Harrington Street 115kV Raleigh	D-U	115.00	13.20	
11	Raleigh Homestead 230kV Raleigh	D-U	230.00	24.00	
12	Raleigh Honeycutt 230kV Raleigh	D-U	230.00	24.00	
13	Raleigh Leesville Road 230kV Raleigh	D-U	230.00	24.00	
14	Raleigh Northside 115kV Raleigh	D-U	115.00	12.00	
15	Raleigh Oakdale 230kV Raleigh	D-U	230.00	23.00	
16	Raleigh Prison Farm 230kV Raleigh	D-U	230.00	24.00	
17	Raleigh Six Forks 230kV Raleigh	D-U	230.00	24.00	
18	Raleigh South 115kV Raleigh	D-U	115.00	23.00	
19	Raleigh Timberlake 115kV Raleigh	D-U	115.00	23.00	
20	Raleigh Worthdale 230kV Raleigh	D-U	230.00	23.00	
21	Raleigh Yonkers Rd 115kV Raleigh	D-U	115.00	23.00	
22	Ramseur 115kV Ramseur	T-U	115.00	69.00	12.00
23	Ramseur 115kV Ramseur	D-U	115.00	24.00	
24	Red Springs 115kV Red Springs	D-U	115.00	23.00	
25	Reynolds 115kV Asheville	D-U	115.00	12.00	
26	Rhems 230kV New Bern	D-U	230.00	24.00	
27	Rhems 115kV New Bern	D-U	115.00	24.00	
28	Richmond 500kV Rockingham	T-U	500.00	230.00	13.80
29	Richmond County Plant Hamlet	T-A Gen Step-Up	230.00	18.00	13.80
30	Robbins 115kV Robbins	D-U	115.00	24.00	
31	Rockingham 230kV Rockingham	T-U	230.00	115.00	13.80
32	Rockingham 230kV Rockingham	D-U	115.00	23.00	
33	Rockingham Aberdeen Rd. 230kV Rockingham	D-U	230.00	23.00	
34	Rockingham West 115kV Rockingham	D-U	115.00	24.00	
35	Rocky Mount 230kV Rocky Mount	D-U	115.00	24.00	
36	Rocky Mount 230kV Rocky Mount	T-U	230.00	69.00	13.20
37	Rocky Mount 230kV Rocky Mount	T-U	230.00	115.00	13.80
38	Rocky Point 230KV Rocky Point	D-U	230.00	24.00	
39	Rolesville 230kV Rolesville	D-U	230.00	24.00	
40	Rose Hill 230kV Rose Hill	D-U	230.00	24.00	

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1	Roseboro 115kV Roseboro	D-U	115.00	23.00	
2	Rowland 230kV Rowland	D-U	230.00	24.00	
3	Rosewood 115KV Goldsboro	D-U	115.00	24.00	
4	Roxboro 115kV Roxboro	D-U	115.00	24.00	
5	Roxboro 115kV Roxboro	T-U	115.00	24.00	
6	Roxboro Bowmantown Rd. 230kV Roxboro	D-U	230.00	23.00	
7	Roxboro South 230kV Roxboro	D-U	230.00	24.00	
8	Roxboro S.E. Plant Roxboro	T-A Gen Step-Up 1	230.00	25.00	
9	Roxboro S.E. Plant Roxboro	TA Gen St-Dwn ICTG	115.00	4.00	
10	Roxboro S.E. Plant (Cooling Tower) Roxboro	T-A	230.00	4.00	
11	RTP 230KV Morrisville	D-U	230.00	24.00	
12	Samaria 115kV Samaria	D-U	115.00	24.00	
13	Sanford Deep River 230kV Sanford	D-U	230.00	24.00	
14	Sanford Garden St. 230kV Sanford	D-U	230.00	23.00	
15	Sanford Horner Blvd 230kV Sanford	D-U	230.00	24.00	
16	Sanford US #1 230-23kV Sanford	D-U	230.00	24.00	
17	Scotts Hill 230kV Scotts Hill	D-U	230.00	24.00	
18	Seagrove 115kV Seagrove	D-U	115.00	12.00	
19	Selma 230kV Selma	D-U	115.00	12.00	
20	Selma 230kV Selma	D-U	115.00	24.00	13.20
21	Selma 230kV Selma	T-U	230.00	115.00	
22	Seymour Johnson 115kV Goldsboro	D-U	115.00	12.00	
23	Shannon 115kV Shannon	D-U	115.00	23.00	
24	Shearon Harris S.E. Plant New Hill	T-A Gen Step-Up	230.00	21.50	
25	Siler City 115kV Siler City	D-U	115.00	24.00	
26	Siler City 230kV Siler City	T-U	230.00	115.00	13.80
27	Siler City Hwy 64E 230kV Siler City	D-U	230.00	24.00	
28	Skyland 115-23kV Skyland	D-U	115.00	24.00	
29	Smithfield 115kV Smithfield	D-U	115.00	12.00	
30	Snow Hill 115kV Snow Hill	D-U	115.00	23.00	
31	Southern Pines 115kV Southern Pines	D-U	115.00	23.00	
32	Southport 230kV Southport	D-U	230.00	23.00	
33	So. Pines Center Pk. 115kV Southern Pines	D-U	115.00	23.00	
34	Spring Hope 115kV Spring Hope	D-U	115.00	23.00	
35	Spring Lake 115kV Spring Lake	D-U	230.00	24.00	
36	Spruce Pine 115kV Spruce Pine	D-U	115.00	23.00	
37	Stallings Crossroads 115kV Stallings X-Road	D-U	115.00	23.00	
38	St. Pauls 115kV St. Pauls	D-U	115.00	23.00	
39	Sutton CC Plant Wilmington	T-A Gen St-Up SCC01A	115.00	16.50	
40	Sutton S.E. Plant Wilmington	TAGenSt-Up 2A,2B	115.00	13.20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Sutton S.E. Plant Wilmington	TA Gen Step-Up ICTG1	115.00	13.80	
2	Suton CC Plant Wilmington	TA G St-Up STI SCC01	230.00	23.50	
3	Swannanoa 115kV Swannanoa	D-U	115.00	12.00	
4	Swansboro 230kV Swansboro	D-U	230.00	23.00	
5	Tillery H.E. Plant Mt. Gilead	T-A Gen Step-Up	115.00	13.20	
6	Topsail 230kV Hampstead	D-U	230.00	23.00	
7	Troy 115kV Troy	D-U	115.00	12.00	
8	Troy Burnette St 115kV Troy	D-U	115.00	12.00	
9	Vanceboro West Cravem	D-U	115.00	24.00	
10	Vander 115kV Vander	T-U	115.00	24.00	
11	Vanderbilt 115kV Asheville	D-U	115.00	12.00	
12	Vander Dak 115kV	D-U	115.00	12.00	
13	Vander Dak/DuPont/Praxair	D-U	115.00	12.00	
14	VIsta 115kV	D-U	115.00	24.00	
15	Wadesboro 230V Wadesboro	D-U	230.00	24.00	
16	Wadesboro-Bowman Sch 230kV Wadesboro	D-U	230.00	24.00	
17	Wake 500kV Knigthdale	T-U	115.00	230.00	
18	Wake Forest 115kV Wake Forest	T-U	115.00	69.00	13.20
19	Wake Tech 230kV Raleigh	D-U	230.00	24.00	
20	Wallace 115kV Wallace	T-U	115.00	69.00	13.20
21	Wallace 115kV Wallace	D-U	115.00	24.00	
22	Wallace 230kV Wallace	T-U	230.00	115.00	13.80
23	Walters H.E.P. Waterville	T-A	161.00	115.00	13.80
24	Walters H.E.P. Waterville	D-A	115.00	12.00	
25	Walters H.E.P. Waterville	T-A Gen Step-Up	115.00	12.00	
26	Walters H.E.P. Waterville	T-A	138.00	115.00	8.60
27	Warrenton 115kV Warrenton	D-U	115.00	24.00	
28	Warsaw 230kV Warsaw	D-U	230.00	24.00	
29	Wayne County Plant	T-A	230.00	18.00	
30	Waynesville 115kV Waynesville	D-U	115.00	12.00	
31	Weatherspoon 230kV Lumberton	D-U	230.00	24.00	
32	Weatherspoon Plant Lumberton	T-A	230.00	115.00	
33	Weatherspoon Plant Lumberton	T-A Gen Step-Up	115.00	13.20	
34	Weaverville 115kV Weaverville	D-U	115.00	12.00	
35	Wendell 230kV Wendell	D-U	230.00	23.00	
36	West Asheville 115kV Asheville	D-U	115.00	12.00	
37	West End 230kV West End	D-U	230.00	24.00	
38	West End 230kV West End	T-U	230.00	115.00	13.80
39	Whiteville 115kV Whiteville	D-U	115.00	23.00	
40	Whiteville 230kV Whiteville	T-U	230.00	115.00	13.80

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Whiteville SE Regional Park 115kV Whiteville	D-U	115.00	24.00	
2	Wilmington Cedar Ave. 230kV Wilmington	D-U	230.00	23.00	
3	Wilmington East 230kV Wilmington	D-U	230.00	24.00	
4	Wilmington Invista 230 KV Willmington	D-U	230.00	12.00	
5	Wilmington Ogden 230kV Wilmington	D-U	230.00	23.00	
6	Wilm. 9th & Orange 230kV Wilmington	D-U	230.00	24.00	
7	Wilmington River Road 115KV Wilmington	D-U	115.00	24.00	
8	Wilm. Sunset Pk. 115kV Wilmington	D-U	115.00	24.00	
9	Wilm. Winter Pk. 230kV Wilmington	D-U	230.00	23.00	
10	Wilson 230kV Wilson	T-U	230.00	115.00	13.80
11	Wilson's Mills 230kV Wilson's Mills	D-U	230.00	24.00	
12	Wommack 230kV Kinston	T-U	230.00	115.00	13.80
13	Wrightsville Beach 230kV Wrightsville Beach	D-U	230.00	24.00	
14	Yanceyville 230kV Yanceyville	D-U	230.00	12.00	
15	Youngsville 115kV Youngsville	D-U	115.00	24.00	
16	Zebulon 115kV Zebulon	T-U	115.00	69.00	
17	Zebulon 115kV Zebulon	D-U	115.00	24.00	
18	Zebulon 230kV Zebulon	T-U	115.00	69.00	
19					
20					
21	South Carolina Substations				
22	----------				
23	Andrews 115kV Andrews	D-U	115.00	24.00	
24	Bennettsville 230kV Bennettsville	D-U	230.00	24.00	
25	Bethune 115kV Bethune	D-U	115.00	12.00	
26	Bishopville 230kV Bishopville	D-U	230.00	24.00	
27	Camden 230kV Camden	D-U	230.00	24.00	
28	Camden 230kV Camden	T-U	230.00	115.00	
29	Camden Steeplechase 115kV Camden	D-U	115.00	24.00	
30	Cheraw 115kV Cheraw	D-U	115.00	24.00	
31	Cheraw Cash Road 230kV Cheraw	D-U	230.00	23.00	
32	Cheraw-Reid Park 230kV Cheraw	D-U	230.00	24.00	
33	Chesterfield 115kV Chesterfield	D-U	115.00	24.00	
34	Darlington 115kV Darlington	D-U	115.00	24.00	
35	Darlington I.C. Plant Darlington	T-A Gen Step-Up	230.00	14.00	
36	Darlington Pineville Rd 115kV Darlington	D-U	115.00	24.00	
37	Dillon 115kV Dillon	D-U	115.00	24.00	
38	Dillon-Maple 230kV Dillon	D-U	230.00	24.00	
39	Dillon North 230kV Dillon	D-U	230.00	24.00	
40	Elgin 115kV Elgin	D-U	115.00	24.00	

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1	Elliott 230kV Elliott	D-U	230.00	24.00	
2	Florence 230kV Florence	D-U	115.00	24.00	
3	Florence 230kV Florence	T-U	230.00	115.00	
4	Florence Burchs Crossroads 115kV Florence	D-U	115.00	23.00	
5	Florence Cashua 230kV Florence	D-U	230.00	23.00	
6	Florence-Ebenezer 230kV Florence	D-U	230.00	24.00	
7	Florence-Mars Bluff 115kV Florence	D-U	115.00	24.00	
8	Florence-Mount Hope 115kV Florence	D-U	115.00	23.00	
9	Florence-Sardis 230kV Sardis	D-U	230.00	24.00	
10	Florence South 115kV Florence	D-U	115.00	24.00	
11	Florence West 230kV Florence	D-U	230.00	24.00	
12	Hartsville 115kV Hartsville	D-U	115.00	24.00	
13	Hartsville-Segars Mill 230kV Hartsville	D-U	230.00	24.00	
14	Hartsville Sonoco 115kV Hartsville	D-U	115.00	14.00	
15	Hemingway 115kV Hemingway	D-U	115.00	24.00	
16	Jefferson 115kV Jefferson	D-U	115.00	23.00	
17	Kingstree 230kV Kingstree	T-U	230.00	115.00	13.80
18	Kingstree 230kV Kingstree	D-U	115.00	24.00	
19	Kingstree North 230kV Kingstree	D-U	230.00	24.00	
20	Lake City 230kV Lake City	D-U	230.00	24.00	
21	Manning 115kV Manning	D-U	115.00	24.00	
22	Marion 230kV Marion	D-U	115.00	24.00	12.00
23	Marion 230kV Marion	T-U	230.00	115.00	13.80
24	Marion-Bypass 115kV Marion	D-U	115.00	23.00	
25	McColl 230kV McColl	D-U	230.00	24.00	
26	Mullins 115kV Mullins	D-U	115.00	24.00	
27	Nichols 115kV Nichols	D-U	115.00	24.00	
28	Olanta 230kV Olanta	D-U	230.00	24.00	
29	Pageland 115kV Pageland	D-U	115.00	24.00	
30	Pamplico 115kV Pamplico	D-U	115.00	24.00	
31	Robinson S.E. Plant Hartsville	T-A Gen Step-Up	230.00	23.00	
32	Robinson S.E. Plant Hartsville	T-A Gen Step-Up	230.00	115.00	
33	Shaw Field 115kV Sumter	D-U	115.00	12.00	
34	Society Hill 230kV Society Hill	D-U	230.00	24.00	
35	Summerton 230kV Summerton	D-U	230.00	24.00	
36	Sumter 230kV Sumter	D-U	115.00	23.00	
37	Sumter 230kV Sumter	T-U	230.00	115.00	13.80
38	Sumter Alice Drive 230kV Sumter	D-U	230.00	23.00	
39	Sumter Industrial 115-23kV Sumter	D-U	115.00	23.00	
40	Sumter North 230kV Sumter	D-U	230.00	24.00	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Sumter-Wedgefield Rd. 230kV Sumter	D-U	230.00	24.00	
2	Wateree HE.P. (Duke) Sumter	T-A	115.00	100.00	7.00
3					
4					
5					
6		Total T-A			
7		Total T-U			
8		Total D-A			
9		Total D-U			
10					
11					
12					
13					
14					
15					
16					
17					
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40					

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
30	2					3
80	2					4
40	2					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
540	3					18
210	1	1				19
235	1	1				20
440	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
34	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

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
19	3	1				1
19	3					2
	1					3
33	1					4
19	3					5
2400	6	2				6
25	1					7
25	1					8
10	3					9
50	2					10
40	1					11
25	1					12
25	1					13
336	3	1				14
80	2					15
650	2					16
70	3					17
50	2					18
40	1					19
50	2					20
90	3					21
90	3					22
50	2					23
80	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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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.
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
73	2					34
50	2					35
25	1					36
50	2					37
25	1					38
600	2					39
25	1					40

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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.
25	1					1
25	1					2
50	2					3
50	2					4
40	2					5
15	3	1				6
50	2					7
40	1					8
90	3					9
40	1					10
40	1					11
13	3					12
23	1					13
50	2					14
25	1					15
90	2					16
25	1					17
25	1					18
336	1					19
80	2					20
25	1					21
65	3					22
336	1					23
50	2					24
400	2					25
65	2					26
600	2					27
50	2					28
50	3					29
50	2					30
9	1					31
80	2					32
40	1					33
25	1					34
73	2					35
600	2					36
40	1					37
50	3	1				38
50	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.
75	3					1
6	3	1				2
50	2					3
100	4					4
300	1					5
24	1					6
25	1					7
50	3	1				8
19	3					9
25	1					10
65	2					11
25	1					12
50	2					13
40	1					14
50	2					15
400	2					16
50	2					17
50	2					18
						19
600	2					20
13	3					21
90	3					22
50	2					23
25	1					24
50	2					25
25	1					26
50	2					27
25	1					28
31	3	1				29
25	1					30
40	1					31
6	1					32
6	1					33
75	3					34
25	1					35
25	1					36
765	3	1				37
50	2					38
600	2					39
13	1	1				40

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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.
50	3	1				1
600	2					2
50	2					3
80	2					4
50	2					5
50	2					6
25	1					7
300	1					8
50	2					9
19	3					10
25	1					11
25	1					12
200	1					13
25	1					14
40	1					15
75		1				16
56	3	1				17
50	2					18
400	2					19
25	1					20
50	2					21
25	1					22
50	3	1				23
30	1					24
25	1					25
25	1					26
50	2			3	1	27
50	3	1				28
50	2					29
50	2					30
40	1					31
1000	3	1				32
25	1					33
73	3					34
80	2					35
100	1					36
25	1					37
24	1					38
24	1					39
55	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	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
420	3					1
15	3					2
50	2					3
25	1					4
50	2					5
80	2					6
50	2					7
80	2					8
40	1					9
60	2					10
80	2					11
40	1					12
90	3					13
50	2					14
50	2					15
50	2					16
50	2					17
50	2					18
50	2					19
50	2					20
40	1					21
53	3	2		1	2	22
40	1					23
25	1					24
30	1					25
40	1					26
40	1					27
1500	6	1				28
2596	11	4				29
25	1					30
550	2		230kV Phase Angle	2	1,080	31
50	3	1				32
25	1					33
75	4	1				34
25	1					35
300	2					36
400	2					37
25	1					38
80	2					39
25	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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25	1					1
13	1					2
40	1					3
50	3	1				4
60	1					5
25	1					6
50	2					7
795	3	2				8
45	1					9
45	2					10
40	1					11
40	1					12
65	2					13
50	2					14
50	2					15
50	2		23/12Kv Step-Down	4	5	16
65	2					17
13	1					18
19	3	1				19
50	2					20
200	1					21
31	3	1				22
25	1					23
1008	3					24
50	3	1				25
200	1					26
25	1					27
50	2					28
50	3	1				29
28	1					30
50	2					31
50	2					32
50	2					33
25	1					34
40	1					35
50	3	1				36
25	1					37
25	1					38
290	1					39
80	2					40

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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.
20	1					1
740	2					2
56	2					3
50	2					4
110	4					5
40	1					6
25	2					7
30	1					8
28	1					9
25	1					10
50	2					11
50	2					12
48	2					13
40	1					14
50	2					15
25	1					16
	2		MbSp230-115/24/13/12	4	83	17
50	3	2				18
40	1					19
80	3	1				20
50	2	1				21
150	1					22
336	1					23
5	3					24
150	3	1				25
100	1					26
50	2					27
50	2					28
1186	7					29
20	3	1				30
50	2					31
400	2					32
180	2					33
30	1					34
50	2					35
50	3	1				36
50	2					37
600	2		Mb.Sp.(230/23kV)	1	25	38
50	3	1				39
300	1					40

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SUBSTATIONS (Continued)

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25	1					1
50	2					2
50	2					3
50	2					4
100	4					5
50	2					6
40	1					7
90	2					8
90	3					9
600	2					10
40	1					11
400	2					12
100	4					13
25	1					14
40	1					15
50	3	1				16
50	2					17
56	2	1				18
						19
						20
						21
						22
25	1					23
50	2					24
25	1					25
50	2					26
25	1					27
200	1					28
25	1					29
25	1					30
25	1					31
50	2					32
25	1					33
50	3	1				34
1084	8					35
40	1					36
50	3	1				37
25	1					38
25	1					39
23	2					40

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SUBSTATIONS (Continued)

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25	1					1
75	3					2
600	2					3
40	1	1				4
25	1					5
25	1					6
25	1					7
50	2					8
40	1					9
50	3	1				10
50	2					11
50	3	1				12
50	2					13
50	2					14
20	3					15
6	1					16
150	1					17
25	1					18
65	2					19
30	3	1				20
25	1					21
25	1					22
400	2					23
50	3	1				24
25	1					25
50	2					26
15	3					27
25	1					28
25	1					29
25	1					30
1320	4	1				31
360	4	1				32
50	3	1	12/23kV Step-Up	1	25	33
25	1					34
25	1					35
75	3					36
600	2					37
25	1					38
50	3	1				39
50	2					40

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SUBSTATIONS (Continued)

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50	2					1
154	2					2
						3
						4
						5
16272						6
22594						7
5						8
15053						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
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						32
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						35
						36
						37
						38
						39
						40

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Duke Energy Progress, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	646,026,446
3				
4	Customer & Market services	Duke Energy Carolinas, LLC	Various	56,132,884
5	Generation services	Duke Energy Carolinas, LLC	Various	561,488,566
6	Other goods and services	Duke Energy Carolinas, LLC	Various	40,230,113
7	Transmission and Distribution services	Duke Energy Carolinas, LLC	Various	49,643,306
8				
9	Customer & Market services	Duke Energy Florida, LLC	Various	1,660,090
10	Generation services	Duke Energy Florida, LLC	Various	537,463
11	Other goods and services	Duke Energy Florida, LLC	Various	128,438
12	Transmission and Distribution services	Duke Energy Florida, LLC	Various	4,895,660
13				
14	Customer & Market services	Duke Energy Indiana, LLC	Various	61,748
15	Generation services	Duke Energy Indiana, LLC	Various	30,275
16	Other goods and services	Duke Energy Indiana, LLC	Various	51,635
17	Transmission and Distribution services	Duke Energy Indiana, LLC	Various	1,184,449
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Services provided to DE Business Services, LLC	Duke Energy Business Services	Various	1,589,774
22				
23	Customer & Market services	Duke Energy Carolinas, LLC	Various	8,501,075
24	Generation services	Duke Energy Carolinas, LLC	Various	31,285,789
25	Other goods and services	Duke Energy Carolinas, LLC	Various	5,004,338
26	Transmission and Distribution services	Duke Energy Carolinas, LLC	Various	27,580,077
27				
28	Customer & Market services	Duke Energy Florida, LLC	Various	2,117,794
29	Generation services	Duke Energy Florida, LLC	Various	1,984,499
30	Other goods and services	Duke Energy Florida, LLC	Various	4,705,852
31	Transmission and Distribution services	Duke Energy Florida, LLC	Various	3,508,044
32				
33	Customer & Market services	Duke Energy Indiana, LLC	Various	1,087,193
34	Generation services	Duke Energy Indiana, LLC	Various	755,823
35	Other goods and services	Duke Energy Indiana, LLC	Various	1,045,155
36	Transmission and Distribution services	Duke Energy Indiana, LLC	Various	1,920,503
37				
38	Customer & Market services	Duke Energy Kentucky, Inc.	Various	213,406
39	Generation services	Duke Energy Kentucky, Inc.	Various	191,693
40	Other goods and services	Duke Energy Kentucky, Inc.	Various	394,481
41	Transmission and Distribution services	Duke Energy Kentucky, Inc.	Various	153,493
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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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	81,533
4	Gas Distribution services	Duke Energy Ohio, Inc.	Various	578
5	Other goods and services	Duke Energy Ohio, Inc.	Various	371
6	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	996,183
7				
8	Customer & Market services	Duke Energy Kentucky, Inc.	Various	
9	Gas Distribution services	Duke Energy Kentucky, Inc.	Various	
10	Generation services	Duke Energy Kentucky, Inc.	Various	
11	Other goods and services	Duke Energy Kentucky, Inc.	Various	
12	Transmission and Distribution services	Duke Energy Kentucky, Inc.	Various	
13				
14	Gas Distribution services	Piedmont Natural Gas Company, Inc.	Various	75,697,456
15				
16	Other goods and services	Duke Energy Commercial Enterprises	Various	1,376,066
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Customer & Market services	Duke Energy Ohio, Inc.	Various	1,260,322
22	Generation services	Duke Energy Ohio, Inc.	Various	41,054
23	Other goods and services	Duke Energy Ohio, Inc.	Various	88,026
24	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	1,203,470
25				
26	Customer & Market services	Piedmont Natural Gas Company, Inc.	Various	
27	Generation services	Piedmont Natural Gas Company, Inc.	Various	
28	Other goods and services	Piedmont Natural Gas Company, Inc.	Various	
29	Transmission and Distribution services	Piedmont Natural Gas Company, Inc.	Various	
30				
31	Other goods and services	Cinergy Solutions	Various	12,347,601
32				
33				
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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

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Transactions on this page do not include transactions between Duke Energy Progress and Duke Energy Progress Receivables.

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