THIS FILING IS
Item 1: ☐ An Initial (Original) Submission OR ☑ Resubmission No.

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: 2023/ Q4

Deloitte.

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Charlotte, NC 28202
USA

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www.deloitte.com

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of
Duke Energy Progress, LLC
Charlotte, North Carolina

Opinion

We have audited the financial statements of Duke Energy Progress, LLC (the "Company"), which comprise the balance sheet — regulatory basis as of December 31, 2023, and the related statements of income — regulatory basis, retained earnings — regulatory basis, and cash flows — regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements (the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2023, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company, and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Emphasis of Matter — Basis of Accounting

As discussed in the opening paragraph of the notes to the financial statements, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. As a result, the financial statements may not be suitable for another purpose. Our opinion is not modified with respect to this matter.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Management is also responsible for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are available to be issued.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Restriction on Use

This report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

April 15, 2024

GENERAL INFORMATION

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.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others 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:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

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

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

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:

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

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.)

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

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 [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF 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.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

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 https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

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

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

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

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.

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.

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).

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.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

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

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.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

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

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.

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:

'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;

'Person' means an individual or a corporation;

'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;

'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; ......

"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

'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."

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

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.

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.

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special" reports as the Commission may by 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 shall 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
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: 2023/ 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) 411 Fayetteville Street, Raleigh, North Carolina 27601	
05 Name of Contact Person David Raiford	06 Title of Contact Person Manager Accounting II
07 Address of Contact Person (Street, City, State, Zip Code) 525 South Tryon Street, Charlotte, North Carolina 28202	

08 Telephone of Contact Person, Including Area Code (980) 373-2402	09 This Report Is An Original / A Resubmission (1) ☐ An Original (2) ☑ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/15/2024

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 Cynthia S. Lee	03 Signature Cynthia S. Lee	04 Date Signed (Mo, Da, Yr) 04/15/2024
02 Title VP, CAO, and Controller		

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

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	N/A
25	Unrecovered Plant and Regulatory Study Costs	230b	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	N/A

31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	N/A
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	N/A
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	Resubmission 1: Duke Energy Progress (DEP) discovered that Maintenance of Energy Storage Equipment (592.2) and Maintenance of Overhead Lines (593) were incorrect due to an upload issue into the software used to file the FERC Form 1.
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	N/A
57	Amounts Included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	N/A
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	
66.2	Energy Storage Operations (Small Plants)	419	

67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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.

Vice President, Chief Accounting Officer and Controller

525 South Tryon Street, Charlotte, North Carolina 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.

State of Incorporation: NC

Date of Incorporation: 1926-04-06

Incorporated Under Special Law:

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.

(a) Name of Receiver or Trustee Holding Property of the Respondent: N/A

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created: N/A

(d) Date when possession by receiver or trustee ceased:

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

Per the 2023 10-K: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' service area covers approximately 28,000 square miles and supplies electric service to approximately 1.7 million residential, commercial and industrial customers.For information about Duke Energy Progress' generating facilities, see Item 2, "Properties." Duke Energy Progress is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC. Substantially all of Duke Energy Progress' operations are regulated and qualify for regulatory accounting. Duke Energy Progress operates one reportable business segment, EU&I. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, "Business Segments."

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

(2) ☑ No

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries for whom trust was maintained, and purpose of the trust.

Manner/Extent of Control: Membership Interest in respondent, Duke Energy Progress, LLC is a wholly-owned subsidiary of Progress Energy, Inc., which is a wholly-owned subsidiary of Duke Energy Corporation.

Chain of Ownership/Control to Main Parent company: 100% of the membership interest in respondent, Duke Energy Progress, LLC, is owned and controlled by Duke Energy Corporation, which is the publicly held parent company.

See also 2023 Duke Energy Corporation Form 10-K filed with the SEC in February, 2024.

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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	CaroFund, Inc	Investment	100	
2	CaroHome, LLC	Affordable Housing Investment	99	(a) A
3	Duke Energy Progress NC Storm Funding LLC	Storm Securitization Recovery	100	
4	Duke Energy Progress Receivables, LLC	Receivables Finance	100	
5	Powerhouse Square, LLC	Real Estate	100	

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: FootnoteReferences

The remaining 1.0 % is owned by CaroFund

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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)	Date Started in Period (d)	Date Ended in Period (e)
1	Chief Executive Officer	Lynn Good	1,500,000	2023-01-01	2023-12-31
2	Executive Vice President & Chief Financial Officer	Brian Savoy	651,040	2023-01-01	2023-12-31
3	Executive Vice President & Chief Operating Officer	Dhiaa Jamil	903,611	2023-01-01	2023-06-30
4	Executive Vice President, Chief Human Resources Officer	Ron Reising	518,771	2023-01-01	2023-12-31
5	Executive Vice President and CEO, Duke Energy Carolinas	Julie Janson	800,337	2023-01-01	2023-12-31
6	State President, NC	Kendal Bowman	360,706	2023-01-01	2023-12-31
7	State President, SC	Michael Callahan	340,787	2023-01-01	2023-12-31
8	Senior Vice President, Corporate Development and Treasurer	Karl Newlin	553,045	2023-01-01	2023-12-31
9	Vice President, Chief Accounting Officer and Controller	Cynthia Lee	337,629	2023-01-01	2023-12-31
10	Executive Vice President, Customer Experience, Solutions, and Services	Harry Sideris	637,620	2023-01-01	2023-12-31
11	Executive Vice President, Chief Commercial Officer	Steven Keith Young	826,908	2023-01-01	2023-12-31
12	Executive Vice President, Chief Legal Officer and Secretary	Kodwo Ghartey-Tagoe	700,000	2023-01-01	2023-12-31
13	Executive Vice President, External Affairs & Communications	Louis Renjel	541,800	2023-01-01	2023-12-31
14	Executive Vice President and CEO, Duke Energy Florida and Midwest	Alex Glenn	541,263	2023-01-01	2023-12-31
15	Executive Vice President, Chief Generation Officer and Enterprise Operational Excellence	T Preston Gillespie	736,159	2023-01-01	2023-12-31

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Kodwo Ghartey-Tagoe, Executive Vice President, Chief Legal Officer and Secretary	525 South Tryon St, Charlotte, NC 28202	true	false
2	R. Alexander Glenn, Executive Vice President	525 South Tryon St, Charlotte, NC 28202	true	false
3	Lynn J. Good, Chief Executive Officer	525 South Tryon St, Charlotte, NC 28202	true	true
4	T. Preston Gillespie Jr, Executive Vice President, Chief Generation Officer and Enterprise Operational Excellence	525 South Tryon St, Charlotte, NC 28202	true	false
5	Julia S. Janson, Executive Vice President	525 South Tryon St, Charlotte, NC 28202	true	false

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ 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 (a)	FERC Proceeding (b)
1	Rate Schedule 134	ER23-908
2	Rate Schedule 200	ER22-682-005, ER22-682-004
3	Rate Schedule 375	ER23-2921
4	Rate Schedule 199	ER24-768
5	Joint Open Access Transmission Tariff (10.A-2)	ER22-2844
6	Joint Open Access Transmission Tariff (10.A-2, 10-B Exhibit B and Attachment H.1)	ER23-1206
7	Joint Open Access Transmission Tariff (Sections 15 and 28)	ER23-1610
8	Joint Open Access Transmission Tariff (Sec 4)	ER22-1166-001
9	Joint Open Access Transmission Tariff (Attachment J)	ER24-679-000
10	Joint Open Access Transmission Tariff (Attachment M)	ER24-683-000

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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)?	☑ Yes ☐ No

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20230515-5335	05/15/2023	ER09-1165	2023 Annual Transmission Update for OATT Formula Transmission Rate of Duke Energy Progress, LLC	Tariff Volume No. 4, Open Access Transmission Tariff

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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). (a)	Schedule (b)	Column (c)	Line No. (d)
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 and Personal Property	i	10 & 19
13	311	Energy Charges - Non-RQ	i	NonRQ
14	321	Total Production Expenses	b	80
15	321	Total Transmission OM	b	112
16	323	Property Insurance	b	185
17	323	Total Administration and General Expenses	b	197
18	335	Industry Dues, R&D, C-V Nuclear Power Association	b	1-3
19	336	Intangible Amortization	f	1
20	336	Production Depreciation Expenses	b	2-6
21	336	General Depreciation Expenses	b	10

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Pages 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.

1. None

2. None

3. None

4. None

5. None

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

7. None

8. None

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

10. None

12. None

13. There are no changes to major security holders and voting powers of Duke Energy Progress, LLC that occurred during 2023. The changes in officer and director appointments and resignations for Duke Energy Progress, LLC that occurred during 2023 are as follows:

Appointments Effective January 2023	
Basta, Laura A.	Vice President, Customer Care
Bowman, Kendal C.	President, North Carolina
Flippin, Nicole L.	Site Vice President, Catawba
Gillespie Jr., T. Preston	Executive Vice President, Chief Generation Officer and Enterprise Operational Excellence
Hall, Zachary S.	Vice President, Environmental, Health and Safety Programs
Ray, Thomas D.	Senior Vice President, Nuclear Corporate
Simril Jr., Robert T.	Senior Vice President, Nuclear Operations - NC
Wells, James	Vice President, New Nuclear Generation
Williams, Jason S.	Senior Vice President, Transmission Maintenance and Construction
Appointments Effective March 2023	
Council, Donna T.	Senior Vice President, Corporate Real Estate, Aviation and Business Services
Glenn, R. Alexander	Executive Vice President
Renjel, Louis E.	Executive Vice President, External Affairs and Communications
Reising, Ronald R.	Executive Vice President and Chief Human Resources Officer
Appointments Effective April 2023	
Grammatico, Reem	Director of Electric Utilities and Infrastructure
Appointments Effective May 2023	
Metzler, Renee H.	Vice President, Total Rewards and Human Resources Operations
Suris, Oscar	Senior Vice President and Chief Communications Officer
Appointments Effective June 2023	
Gillespie Jr., T. Preston	Director
Appointments Effective September 2023	
Nader, Rounette K.	Vice President, New Nuclear Generation and License Renewal
Appointments Effective October 2023	
Johns, Melisa B.	Vice President, Renewables Development
Turner, Julie K.	Vice President, Carolinas Dispatchable Generation
Resignations Effective January 2023	
Flippin, Nicole L.	Site Vice President, Robinson
Gillespie Jr., T. Preston	Senior Vice President and Chief Generation Officer
Ray, Thomas D.	Senior Vice President, Nuclear Operations - NC
Wells, James	Vice President, Environmental, Health and Safety Programs and Environmental Sciences
Resignations Effective March 2023	
Bingol, M. Selim	Senior Vice President and Chief Communications Officer
Council, Donna T.	Senior Vice President, Administrative Services
Glenn, R. Alexander	Senior Vice President
Reising, Ronald R.	Senior Vice President and Chief Human Resources Officer
Renjel, Louis E.	Senior Vice President, External Affairs and Communications
Resignations Effective April 2023	
David L.Doss Jr.	Vice President, Accounting
Michael O'Keeffe	Director of Electric Utilities and Infrastructure
Catherine B. Stancombe	Senior Vice President, Enterprise Operational Excellence
Resignations Effective May 2023	
Renee H. Metzler	Managing Director, Total Rewards
Resignations Effective June 2023	
Jamil, Dhiaa M.	Director
Jamil, Dhiaa M.	Executive Vice President and Chief Operating Officer
Resignations Effective July 2023	
Silinski, Thomas	Vice President, Human Resources, Total Rewards & HR Operations
Wells, James	Vice President, New Nuclear Generation
Resignations Effective October 2023	
Fallon, Christopher M.	Senior Vice President and President, Duke Energy Sustainable Solutions
Johns, Melisa B.	Vice President, Distributed Energy Solutions and Regulated Renewables
Turner, Julie K.	Vice President, Carolinas Generation
Resignations Effective December 2023	
Hatcher, Larry E.	Senior Vice President, Customer Experience and Services
Reising, Ronald R.	Executive Vice President and Chief Human Resources Officer

14. N/A

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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	36,465,819,185	36,535,274,778
3	Construction Work in Progress (107)	200	1,660,121,830	1,316,025,326
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		38,125,941,015	37,851,300,104
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	15,283,946,602	14,417,069,205
6	Net Utility Plant (Enter Total of line 4 less 5)		22,841,994,413	23,434,230,899
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	347,848,358	231,666,655
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)		791,381,658	783,079,291
10	Spent Nuclear Fuel (120.4)		297,647,656	342,972,447
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	802,158,432	749,081,141
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		634,719,240	608,637,252
14	Net Utility Plant (Enter Total of lines 6 and 13)		23,476,713,653	24,042,868,151
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		37,660,721	37,536,477
19	(Less) Accum. Prov. for Depr. and Amort. (122)		13,377,132	13,038,888
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	28,935,656	27,386,435
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		50,263,198	41,902,157
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		4,412,841,915	3,736,840,150
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)		8,986,723	51,549,315
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,525,311,081	3,882,175,646
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		(7,367,447)	22,912,279

36	Special Deposits (132-134)			
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		590,185,019	629,291,721
41	Other Accounts Receivable (143)		243,633,703	167,401,161
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		43,765,832	44,494,583
43	Notes Receivable from Associated Companies (145)		3,848,135	3,848,135
44	Accounts Receivable from Assoc. Companies (146)		18,671,338	54,532,440
45	Fuel Stock (151)	227	263,768,961	186,850,138
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	914,494,663	778,926,680
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227	3,696	(14,813)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	135,341,753	125,987,224
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	[a]48,634,307	[a]40,273,508
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		96,306,708	69,526,919
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		172,192	122,817
61	Accrued Utility Revenues (173)		193,195,458	200,759,072
62	Miscellaneous Current and Accrued Assets (174)		10,634,958	
63	Derivative Instrument Assets (175)			23,487,475
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)		9,010,467	119,659,790
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		8,986,723	51,549,315
67	Total Current and Accrued Assets (Lines 34 through 66)		2,467,781,356	2,327,520,649
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		57,151,395	54,640,965
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	149,897,812	177,781,050
72	Other Regulatory Assets (182.3)	232	4,713,389,862	4,520,315,051
73	Prelim. Survey and Investigation Charges (Electric) (183)		15,486,197	8,942,807
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			

75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		(7,086)	(2,339,201)
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	131,935,342	237,138,897
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		352,603	670,388
82	Accumulated Deferred Income Taxes (190)	234	1,912,828,231	2,192,293,660
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		6,981,034,356	7,189,443,617
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		37,450,840,446	37,442,008,063

FOOTNOTE DATA

(a) Concept: StoresExpenseUndistributed

Stores Expense: Production 33,602,200 Transmission 2,455,532 Distribution 12,576,575

(b) Concept: StoresExpenseUndistributed

Stores Expense: Production 31,005,998 Transmission 1,942,860 Distribution 7,324,650

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		
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	2,784,302,138	2,784,376,969
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	8,300,580,591	7,807,019,922
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(275,988,300)	(277,537,521)
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(42,612)	(74,166)
16	Total Proprietary Capital (lines 2 through 15)		10,808,851,817	10,313,785,204
17	LONG-TERM DEBT			
18	Bonds (221)	256	9,975,185,000	9,275,185,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256	150,000,000	150,000,000
21	Other Long-Term Debt (224)	256	400,000,000	400,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		24,107,655	22,606,887
24	Total Long-Term Debt (lines 18 through 23)		10,501,077,345	9,802,578,113
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		808,014,842	887,567,827
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		1,402,864	14,380,350
29	Accumulated Provision for Pensions and Benefits (228.3)		133,362,726	145,577,752
30	Accumulated Miscellaneous Operating Provisions (228.4)		14,458,815	15,363,111
31	Accumulated Provision for Rate Refunds (229)			4,319,350
32	Long-Term Portion of Derivative Instrument Liabilities		9,003,008	
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		10,180,785	332,244
34	Asset Retirement Obligations (230)		3,870,405,622	5,823,180,157

35	Total Other Noncurrent Liabilities (lines 26 through 34)		4,846,828,662	6,890,720,791
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			
38	Accounts Payable (232)		669,136,641	612,233,801
39	Notes Payable to Associated Companies (233)		890,707,000	238,562,000
40	Accounts Payable to Associated Companies (234)		331,281,621	506,161,702
41	Customer Deposits (235)		94,253,374	105,561,956
42	Taxes Accrued (236)	262	157,825,140	64,272,199
43	Interest Accrued (237)		113,043,866	100,840,586
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		18,943,407	12,984,511
48	Miscellaneous Current and Accrued Liabilities (242)		221,530,274	244,771,115
49	Obligations Under Capital Leases-Current (243)		82,017,718	85,981,004
50	Derivative Instrument Liabilities (244)		20,334,758	
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		9,003,008	
52	Derivative Instrument Liabilities - Hedges (245)		116,823,234	475,107
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		10,180,785	332,244
54	Total Current and Accrued Liabilities (lines 37 through 53)		2,696,713,239	1,971,511,737
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,616,243	(1,591,009)
57	Accumulated Deferred Investment Tax Credits (255)	266	128,762,814	124,201,915
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	48,812,776	91,995,889
60	Other Regulatory Liabilities (254)	278	3,947,411,260	3,580,018,852
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		2,761,957,524	3,066,937,436
64	Accum. Deferred Income Taxes-Other (283)		1,708,808,766	1,601,849,135
65	Total Deferred Credits (lines 56 through 64)		8,597,369,383	8,463,412,218
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		37,450,840,446	37,442,008,063

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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

Do not report fourth quarter data in columns (e) and (f)
Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in 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.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
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.
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 purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
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.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

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)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	6,386,484,391	6,667,955,304			6,386,484,391	6,667,955,304				
3	Operating Expenses											
4	Operation Expenses (401)	320	3,065,485,484	3,385,959,179			3,065,485,484	3,385,959,179				
5	Maintenance Expenses (402)	320	370,925,707	438,233,825			370,925,707	438,233,825				
6	Depreciation Expense (403)	336	938,737,716	883,748,837			938,737,716	883,748,837				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	54,521,478	53,628,736			54,521,478	53,628,736				
9	Amort. of Utility Plant Acq. Adj. (406)	336	12,758,733	12,758,733			12,758,733	12,758,733				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		35,941,485	45,366,039			35,941,485	45,366,039				
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		375,709,635	384,340,376			375,709,635	384,340,376				
13	(Less) Regulatory Credits (407.4)		153,707,501	144,731,264			153,707,501	144,731,264				
14	Taxes Other Than Income Taxes (408.1)	262	165,183,386	190,865,557			165,183,386	190,865,557				
15	Income Taxes - Federal (409.1)	262	208,643,419	36,773,502			208,643,419	36,773,502				
16	Income Taxes - Other (409.1)	262	5,209,993	4,854			5,209,993	4,854				
17	Provision for Deferred Income Taxes (410.1)	234, 272	1,362,997,715	1,105,992,243			1,362,997,715	1,105,992,243				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	1,420,387,094	986,711,346			1,420,387,094	986,711,346				
19	Investment Tax Credit Adj. - Net (411.4)	266	(3,310,248)	(4,268,292)			(3,310,248)	(4,268,292)				

20	(Less) Gains from Disp. of Utility Plant (411.6)		1,542,778	351,015			1,542,778	351,015				
21	Losses from Disp. of Utility Plant (411.7)		45,912				45,912					
22	(Less) Gains from Disposition of Allowances (411.8)											
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		787,492	810,225			787,492	810,225				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		5,018,000,534	5,402,420,189			5,018,000,534	5,402,420,189				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		1,368,483,857	1,265,535,115			1,368,483,857	1,265,535,115				
28	Other Income and Deductions											
29	Other Income											
30	Nonutility Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		744,544	124,059								
33	Revenues From Nonutility Operations (417)		68,859,624	74,731,031								
34	(Less) Expenses of Nonutility Operations (417.1)		46,044,175	51,242,005								
35	Nonoperating Rental Income (418)		(694,036)	(729,245)								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,549,221	(136,292)								
37	Interest and Dividend Income (419)		8,749,820	7,605,252								
38	Allowance for Other Funds Used During Construction (419 1)		51,915,773	51,792,412								
39	Miscellaneous Nonoperating Income (421)		24,369,535	19,480,676								
40	Gain on Disposition of Property (421.1)		1,895,020	3,946,946								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		109,856,238	105,324,716								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		673,926	(118,467)								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		11,040,274	3,891,528								
46	Life Insurance (426.2)		1,090,375	94,581								
47	Penalties (426.3)		12,531	52,558								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		5,241,917	5,392,959								
49	Other Deductions (426.5)		60,952,957	8,593,163								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		79,011,980	17,906,322								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	(816,074)	(1,268,918)								
53	Income Taxes-Federal (409.2)	262	(9,683,382)	851,266								
54	Income Taxes-Other (409.2)	262	(1,244,576)	103,838								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	25,949,503	7,642,774								

56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	19,893,872	1,313,219								
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)		(5,688,401)	6,015,741								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		36,532,659	81,402,653								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		405,898,066	343,020,006								
63	Amort. of Debt Disc. and Expense (428)		6,779,865	6,411,221								
64	Amortization of Loss on Reaquired Debt (428.1)		290,425	815,363								
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)		25,378,732	3,489,644								
68	Other Interest Expense (431)		6,356,968	2,537,976								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		34,797,430	19,591,692								
70	Net Interest Charges (Total of lines 62 thru 69)		409,906,626	336,682,518								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		995,109,890	1,010,255,250								
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										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		995,109,890	1,010,255,250								

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, 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 for 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 for 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, attach them at page 122.

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		7,797,921,064	7,038,523,336
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Current Expected Credit Losses (CECL) adjustments			
4.2	Current Expected Credit Losses (CECL) adjustments	216		
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Current Expected Credit Losses (CECL) adjustments	144		
10.2				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		993,560,669	1,010,391,542
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Hydro Project Reserve Amort		[(a)](1,178,041)	[(a)](993,814)
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(1,178,041)	(993,814)
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Cash Distribution to Parent		(500,000,000)	(250,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(500,000,000)	(250,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		8,290,303,692	7,797,921,064
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
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)		10,276,899	9,098,858
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		10,276,899	9,098,858
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		8,300,580,591	7,807,019,922

	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(277,537,521)	(277,396,307)
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,549,221	(136,292)
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1	Transfers from Unappropriated Retained Earnings (Account 216)			(4,922)
53	Balance-End of Year (Total lines 49 thru 52)		(275,988,300)	(277,537,521)

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

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

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Instructions 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)	995,109,890	1,010,255,250
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	938,737,716	883,748,837
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Primary Nuclear Fuel	544,050,698	537,284,792
5.2	Net Increase (Decrease) to MTM and Hedging Transactions	270,819,682	(35,387,357)
5.3	Contributions to Company Sponsored Pension Plans	(13,000,991)	(8,087,542)
8	Deferred Income Taxes (Net)	(51,333,748)	125,610,452
9	Investment Tax Credit Adjustment (Net)	(3,310,248)	(4,268,292)
10	Net (Increase) Decrease in Receivables	12,359,955	(145,565,541)
11	Net (Increase) Decrease in Inventory	(220,866,115)	(84,702,960)
12	Net (Increase) Decrease in Allowances Inventory	(9,354,529)	6,852,159
13	Net Increase (Decrease) in Payables and Accrued Expenses	(83,729,110)	(877,915)
14	Net (Increase) Decrease in Other Regulatory Assets	(283,600,636)	(432,559,713)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(139,718,863)	126,418,523
16	(Less) Allowance for Other Funds Used During Construction	51,915,773	51,792,412
17	(Less) Undistributed Earnings from Subsidiary Companies	1,549,221	(141,214)
18	Other (provide details in footnote):		
18.1	Changes in Other Non Current Assets	121,042,957	(129,025,802)
18.2	Asset retirement obligations liabilities settled	(248,565,004)	(193,374,811)
18.3	Change in prepaid and other current assets	(28,876,491)	6,861,071
18.4	Changes in deferred credit and other long-term liabilities	(39,636,143)	(46,773,883)
18.5	Gain on sale of assets	(2,388,983)	(4,065,413)
18.6	Impairment	29,296,702	7,491,922
18.7	Accrued Pension and Other Post-Retirement Benefit Costs adj to NI	(17,929,761)	(13,970,548)
18.8	Provision for Rate Refund	(24,000,000)	(58,000,000)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,691,641,984	1,496,212,031
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		

26	Gross Additions to Utility Plant (less nuclear fuel)	(2,226,939,168)	(1,883,910,420)
27	Gross Additions to Nuclear Fuel	(212,332,109)	(237,310,900)
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(124,244)	(130,229)
30	(Less) Allowance for Other Funds Used During Construction	(51,915,773)	(51,792,412)
31	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(2,387,479,748)	(2,069,559,137)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)	(1,406,215,747)	(1,148,126,721)
45	Proceeds from Sales of Investment Securities (a)	1,402,063,437	1,138,483,407
46	Loans Made or Purchased		
47	Collections on Loans		
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):		
53.1	Cost of Removal, of net of salvage	(154,440,295)	(107,237,876)
53.2	Property Insurance Claims Proceeds	1,499,553	33,827,075
53.3	Death Proceeds from COLI		3,074,669
53.4	Proceeds from sale of Office Building	14,855,637	4,683,800
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(2,529,717,163)	(2,144,854,783)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	997,432,696	1,485,897,155
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Unamortized Debt Expenses Associated with Master Credit Facility Fees	(558,500)	(1,167,320)
67.2	Issuance Costs	(6,443,624)	(8,797,054)
70	Cash Provided by Outside Sources (Total 61 thru 69)	990,430,572	1,475,932,781
72	Payments for Retirement of:		

73	Long-term Debt (b)	(334,780,119)	(630,116,902)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Net Increase (Decrease) in Intercompany Notes	652,145,000	66,433,000
76.2	Cash Distribution to Parent	(500,000,000)	(250,000,000)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	807,795,453	662,248,879
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(30,279,726)	13,606,127
88	Cash and Cash Equivalents at Beginning of Period	22,912,279	9,306,152
90	Cash and Cash Equivalents at End of Period	(7,367,447)	22,912,279

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: CashFlowsProvidedFromUsedInFinancingActivities

Accrued Capital Expenditures $313,424,689Supplemental Disclosures:Cash Paid for Interest, Net of Amount Capitalized $447,290,255Cash Paid for Income Taxes, Net ($72,987,516)

(b) Concept: CashAndCashEquivalents

Cash and working funds (131 & 135) $22,912,279Special deposits (132 - 134) 0Temporary cash investments 0Total $22,912,279

(c) Concept: CashAndCashEquivalents

Cash and working funds (131 & 135) $22,912,279Special deposits (132 - 134) 0Temporary cash investments 0Total $22,912,279

(d) Concept: CashAndCashEquivalents

Cash and working funds (131 & 135) ($7,367,447)Special deposits (132 - 134) 0Temporary cash investments 0Total ($7,367,447)

(e) Concept: CashFlowsProvidedFromUsedInFinancingActivities

Accrued Capital Expenditures $268,843,056Supplemental Disclosures:Cash Paid for Interest, Net of Amount Capitalized $385,591,003Cash Paid for Income Taxes, Net $158,025,444

(f) Concept: CashAndCashEquivalents

Cash and working funds (131 & 135) $9,306,152Special deposits (132 - 134) 0Temporary cash investments 0Total $9,306,152

(g) Concept: CashAndCashEquivalents

Cash and working funds (131 & 135) $22,912,279Special deposits (132 - 134) 0Temporary cash investments 0Total $22,912,279

(h) Concept: CashAndCashEquivalents

Cash and working funds (131 & 135) $22,912,279Special deposits (132 - 134) 0Temporary cash investments 0Total $22,912,279

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Commission 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.

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:

- 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.
- 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.
- FERC requires that income or losses of an unusual nature and infrequent occurrence, which would significantly distort the current year's income, be recorded as extraordinary income or deductions, respectively.
- GAAP requires that removal and nuclear decommissioning costs for property that does 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.
- 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.
- 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.
- 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.
- GAAP requires that any deferred costs associated with a specific debt issuance be presented as a reduction to debt on the Balance Sheet. FERC requires any Unamortized Debt Expense to be separately stated as a Deferred Debit on the Balance Sheet.
- 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.
- GAAP requires that the current portion of the provision for injuries and damages be reported as a current liability on the Balance Sheet. GAAP also requires that the current portion of the expected insurance proceeds receivable related to the provision for injuries and damages be reported as a current asset on the Balance Sheet. FERC requires that the current portion of the provision for injuries and damages be reported as 'Accumulated Provision for Injuries and Damages' and that the current portion of the related insurance receivable be reported as 'Deferred Debits'.
- 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.
- 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.
- 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 in the fourth quarter ended December 31, 2023 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 23, 2024. 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, 2023 up to February 23, 2024 (March 12, 2024 for DE Kentucky), the date that the Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 15, 2024. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

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, 2023, or 2022.

		December 31,	
(in millions)	Location	2023	2022
Duke Energy Carolinas			
Accrued compensation	Current Liabilities	$ 224	$ 247
Duke Energy Florida			
Customer deposits/Collateral liabilities	Current Liabilities	$ 168	$ 200
Duke Energy Ohio			
Gas Storage	Current Assets	$ 23	$ 57
Tax receivables	Current Assets	95	4
Duke Energy Indiana			
Mark-to-market transactions	Current Assets	$ 15	$ 110
Customer advances	Current Liabilities	$ 57	$ 51

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. For the years ended December 31, 2023, 2022 and 2021, the Loss From Discontinued Operations, net of tax on Duke Energy's Consolidated Statements of Operations includes amounts related to noncontrolling interests. A portion of Noncontrolling Interests on Duke Energy's Consolidated Balance Sheets relates to discontinued operations for the periods presented. See Note 2 for discussion of discontinued operations related to the Commercial Renewables Disposal Groups.

Noncontrolling Interest

Duke Energy maintains a controlling financial interest in certain less than wholly owned 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 Sheets. 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.

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. Regulatory assets are reviewed for recoverability each reporting period. If a regulatory asset is no longer deemed probable of recovery, the deferred cost is charged to earnings. 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. Duke Energy Carolinas and Duke Energy Progress have restricted cash balances related to VIEs from storm recovery bonds issued. 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, 2023				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Current Assets					
Cash and cash equivalents	$ 253	$ 8	$ 69	$ 18	$ 24
Other	76	9	57	31	36
Other Noncurrent Assets					
Other	16	1	9	2	7
Total cash, cash equivalents and restricted cash	$ 345	$ 18	$ 135	$ 51	$ 67

	December 31, 2022				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Current Assets					
Cash and cash equivalents	$ 409	$ 44	$ 108	$ 49	$ 45
Other	82	8	74	28	41
Other Noncurrent Assets					
Other	11	1	2	2	—
Total cash, cash equivalents and restricted cash	$ 502	$ 53	$ 184	$ 79	$ 86

Inventory

Inventory related to regulated operations is valued at historical cost. 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, 2023, and 2022, respectively. The components of inventory are presented in the tables below.

	December 31, 2023							
(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	$ 3,086	$ 1,076	$ 1,465	$ 963	$ 502	$ 139	$ 461	$ 12
Coal	842	364	231	154	77	28	219	—
Natural gas, oil and other	364	46	205	110	95	12	2	100
Total inventory	$ 4,292	$ 1,484	$ 1,901	$ 1,227	$ 674	$ 179	$ 682	$ 112

	December 31, 2022							
(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	$ 2,604	$ 876	$ 1,232	$ 819	$ 413	$ 105	$ 342	$ 12
Coal	620	253	190	99	91	34	144	—
Natural gas, oil and other	360	35	157	88	69	5	3	160
Total inventory	$ 3,584	$ 1,164	$ 1,579	$ 1,006	$ 573	$ 144	$ 489	$ 172

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, unless it is determined the carrying value of an investment has a credit loss. For certain investments of regulated operations, such as substantially all of the NDTF, realized and unrealized gains and losses (including any credit losses) 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.

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 that are held and used, 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 that are held and used using various methods, including recent comparable third-party sales, internally developed discounted cash flow analysis and analysis from outside advisors. Triggering events to reassess cash flows may include, but are not limited to, significant changes in commodity prices, the condition of an asset or management's interest in selling the asset.

Property, Plant and Equipment

Property, plant and equipment are stated at the lower of depreciated historical cost net of any disallowances or fair value, if impaired. The Duke Energy Registrants capitalize all construction-related direct labor and material costs, as well as indirect construction costs such as general engineering, taxes and financing costs. See "Allowance for Funds Used During Construction and Interest Capitalized" section below 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,		
	2023	2022	2021
Duke Energy	2.9 %	3.0 %	2.8 %
Duke Energy Carolinas	2.7 %	2.7 %	2.7 %
Progress Energy	3.3 %	3.2 %	3.1 %
Duke Energy Progress	3.1 %	3.0 %	3.0 %
Duke Energy Florida	3.5 %	3.5 %	3.3 %
Duke Energy Ohio	2.8 %	2.9 %	2.9 %
Duke Energy Indiana	3.6 %	3.8 %	3.6 %
Piedmont	2.1 %	2.1 %	2.1 %

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 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, 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.

Other Noncurrent Assets

Duke Energy, through a nonregulated subsidiary, was the winner of the Carolina Long Bay offshore wind auction in May 2022 and recorded an asset of $150 million related to the contract in Other within Other noncurrent assets on the Consolidated Balance Sheets as of December 31, 2023 and 2022. The asset is recorded at historical cost and is subject to impairment testing should circumstances indicate the carrying value may not be recoverable. In November 2022, Duke Energy committed to a plan to sell the Commercial Renewables business segment, excluding the offshore wind contract for Carolina Long Bay, which was moved to the EU&I segment. See Notes 2 and 3 for further information.

Leases

Duke Energy determines if an arrangement is a lease at contract inception based on whether the arrangement involves the use of a physically distinct identified asset and whether Duke Energy has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period as well as the right to direct the use of the asset. As a policy election, Duke Energy does not evaluate arrangements with initial contract terms of less than one year as leases.

Operating leases are included in Operating lease ROU assets, net, Other current liabilities and Operating lease liabilities on the Consolidated Balance Sheets. Finance leases are included in Property, Plant and Equipment, Current maturities of long-term debt and Long-Term Debt on the Consolidated Balance Sheets.

For lessee and lessor arrangements, Duke Energy has elected a policy to not separate lease and non-lease components for all asset classes. For lessor arrangements, lease and non-lease components are only combined under one arrangement and accounted for under the lease accounting framework if the non-lease components are not the predominant component of the arrangement and the lease component would be classified as an operating lease.

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.

Asset Retirement Obligations

AROs are recognized for legal obligations associated with the retirement of property, plant and equipment. 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.

Accounts Payable

Duke Energy has a voluntary supply chain finance program (the "program") that allows Duke Energy suppliers, at their sole discretion, to sell their receivables from Duke Energy to a global financial institution at a rate that leverages Duke Energy's credit rating and, which may result in favorable terms compared to the rate available to the supplier on their own credit rating. Suppliers participating in the program, determine at their sole discretion which invoices they will sell to the financial institution. Suppliers' decisions on which invoices are sold do not impact Duke Energy's payment terms, which are based on commercial terms negotiated between Duke Energy and the supplier regardless of program participation. The commercial terms negotiated between Duke Energy and its suppliers are consistent regardless of whether the supplier elects to participate in the program. Duke Energy does not issue any guarantees with respect to the program and does not participate in negotiations between suppliers and the financial institution. Duke Energy does not have an economic interest in the supplier's decision to participate in the program and receives no interest, fees or other benefit from the financial institution based on supplier participation in the program.

The following table presents the outstanding accounts payable balance sold to the financial institution by our suppliers and the supplier invoices sold to the financial institution under the program included within Net cash provided by operating activities on the Consolidated Statements of Cash Flows as of December 31, 2023, and December 31, 2022.

	For the Years Ended December 31, 2022 and 2023							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Confirmed obligations outstanding at December 31, 2021	$ 19	$ —	$ 9	$ —	$ 9	$ 6	$ —	$ 4
Invoices confirmed during the period	283	29	76	26	50	32	2	145
Confirmed invoices paid during the period	(215)	(23)	(66)	(18)	(48)	(33)	(2)	(92)
Confirmed obligations outstanding at December 31, 2022	$ 87	$ 6	$ 19	$ 8	$ 11	$ 5	$ —	$ 57
Invoices confirmed during the period	228	24	58	22	36	7	—	139
Confirmed invoices paid during the period	(265)	(30)	(74)	(30)	(44)	(12)	—	(149)
Confirmed obligations outstanding at December 31, 2023	$ 50	$ —	$ 3	$ —	$ 3	$ —	$ —	$ 47

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.

Alternative Revenue Programs

Duke Energy accounts for certain types of programs established by the regulators in the states in which it operates, including decoupling mechanisms, as alternative revenue programs. Alternative revenue programs are contracts between an entity and its regulator, not a contract between an entity and a customer. Revenue arising from alternative revenue programs is presented as Regulated electric revenues and Regulated natural gas revenues on the Consolidated Statements of Operations. Revenue from alternative revenue programs is recognized in

the period they are earned (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage or when specific targets are met resulting in the achievement of performance incentives or penalties) and a regulatory asset or liability on the Consolidated Balance Sheets is established which is subsequently billed or refunded to customers. Duke Energy recognizes revenue as alternative revenue programs for programs that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. See Note 19 for disaggregated revenue information including revenue from contracts with customers and revenues recognized as alternative revenue programs.

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.

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 are 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 the loss 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.

Severance and Special Termination Benefits

Duke Energy maintains severance plans for the general employee population under which, in general, the longer a terminated employee worked prior to termination the greater the amount of severance benefits provided. 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. Duke Energy recognizes a liability for the best estimate of its loss due to the nonperformance of the guaranteed party. This liability is recognized at the inception of a guarantee and is updated periodically. See Note 8 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. Duke Energy's results of operations could be impacted if the 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 a reversal.

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.

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 Energy 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)	**2023**	**2022**	**2021**
Duke Energy	$ 458	$ 448	$ 420
Duke Energy Carolinas	27	47	44
Progress Energy	322	290	250
Duke Energy Progress	5	25	22
Duke Energy Florida	317	265	228
Duke Energy Ohio	106	104	102
Duke Energy Indiana	1	7	23
Piedmont	2	1	1

Dividend Restrictions and Unappropriated Retained Earnings

Duke Energy does not have any current legal, regulatory or other restrictions on paying common stock dividends to shareholders. However, if Duke Energy were to defer dividend payments on the preferred stock, the declaration of common stock dividends would be prohibited. See Note 20 for more information. Additionally, 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, 2023, and 2022, an insignificant amount of Duke Energy's consolidated Retained earnings balance represents undistributed earnings of equity method investments.

New Accounting Standards

The following accounting standard was adopted by the Duke Energy Registrants in 2021.

Leases with Variable Lease Payments. In July 2021, the Financial Accounting Standards Board issued new accounting guidance requiring lessors to classify a lease with variable lease payments that do not depend on a reference index or rate as an operating lease if both of the following are met: (1) the lease would have to be classified as a sales-type or direct financing lease under prior guidance, and (2) the lessor would have recognized a day-one loss. Duke Energy elected to adopt the guidance immediately upon issuance of the new standard and will be applying the new standard prospectively to new lease arrangements meeting the criteria. Duke Energy did not have any lease arrangements that this new accounting guidance materially impacted.

2. DISPOSITIONS

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

	Years Ended December 31,		
(in millions)	**2023**	**2022**	**2021**
Commercial Renewables Disposal Groups	$(1,457)	$(1,349)	$(151)
Other[(a)]	2	26	7
Loss from Discontinued Operations, net of tax	$(1,455)	$(1,323)	$(144)

(a) Amounts primarily represent income tax adjustments for previously sold businesses not related to the Commercial Renewables Disposal Groups.

Sale of Commercial Renewables Segment

In November 2022, Duke Energy committed to a plan to sell the Commercial Renewables business segment, excluding the offshore wind contract for Carolina Long Bay, which was moved to the EU&I segment. In June 2023, Duke Energy announced that it had entered into a purchase and sale agreement with affiliates of Brookfield for the sale of the utility-scale solar and wind group. Duke Energy closed on this transaction on October 25, 2023, for proceeds of $1.1 billion, with approximately half of the proceeds received at closing and the remainder due 18 months after closing. The balance of the proceeds to be received is classified in Other, within Other Noncurrent Asset on Duke Energy's Consolidated Balance Sheets. In July 2023, Duke Energy announced that it had entered into a purchase and sale agreement with affiliates of ArcLight for the distributed generation group. Duke Energy closed on this transaction on October 4, 2023, and received proceeds of $243 million. These proceeds amounts are gross of cash divested as part of the sales of the utility-scale wind and solar group and the distributed generation group, which totaled approximately $75 million. In March 2023, assets for certain projects were removed from the utility-scale solar and wind group and placed in a separate disposal group. The disposal process for the remaining assets is expected to be completed in the first half of 2024, with net proceeds from the dispositions not anticipated to be material.

Assets Held For Sale and Discontinued Operations

The Commercial Renewables Disposal Groups were classified as held for sale and as discontinued operations in the fourth quarter of 2022. No interest from corporate level debt was allocated to discontinued operations and no adjustments were made to the historical activity within the Consolidated Statements of Comprehensive Income, Consolidated Statements of Cash Flows or the Consolidated Statements of Changes in Equity. Unless otherwise noted, the notes to these consolidated financial statements exclude amounts related to discontinued operations for all periods presented.

The following table presents the carrying values of the major classes of Assets held for sale and Liabilities associated with assets held for sale included in Duke Energy's Consolidated Balance Sheets.

(in millions)		December 31, 2023		2022
Current Assets Held for Sale				
Cash and cash equivalents	$	—	$	10
Receivables, net		—		107
Inventory		—		88
Other		14		151
Total current assets held for sale		14		356
Noncurrent Assets Held for Sale				
Property, Plant and Equipment				
Cost		247		6,444
Accumulated depreciation and amortization		(57)		(1,651)
Net property, plant and equipment		190		4,793
Operating lease right-of-use assets, net		4		140
Investments in equity method unconsolidated affiliates		—		522
Other		3		179
Total other noncurrent assets held for sale		7		841
Total Assets Held for Sale	$	211	$	5,990
Current Liabilities Associated with Assets Held for Sale				
Accounts payable	$	9	$	122
Taxes accrued		3		17
Current maturities of long-term debt		5		276
Unrealized losses on commodity hedges		68		37
Other		37		83
Total current liabilities associated with assets held for sale		122		535
Noncurrent Liabilities Associated with Assets Held for Sale				
Long-Term debt		39		1,188
Operating lease liabilities		5		150
Asset retirement obligations		8		190
Unrealized losses on commodity hedges		94		187
Other		11		212
Total other noncurrent liabilities associated with assets held for sale		157		1,927
Total Liabilities Associated with Assets Held for Sale	$	279	$	2,462

As of December 31, 2023, and 2022, the noncontrolling interest balance is $66.3 million and $1.6 billion, respectively.

The following table presents the results of the Commercial Renewables Disposal Groups, which are included in Loss from Discontinued Operations, net of tax in Duke Energy's Consolidated Statements of Operations.

(in millions)		Years Ended December 31, 2023		2022		2021
Operating revenues	$	338	$	465	$	478
Operation, maintenance and other		302		337		343
Depreciation and amortization[(a)]		—		201		227
Property and other taxes		45		36		34
Other income and expenses, net		(8)		2		(27)
Interest expense		66		10		72
Loss on disposal		1,725		1,748		—
Loss before income taxes		(1,815)		(1,865)		(227)
Income tax benefit		(358)		(516)		(76)
Loss from discontinued operations	$	(1,457)	$	(1,349)	$	(151)
Add: Net loss attributable to noncontrolling interest included in discontinued operations		64		108		344
Net (loss) income from discontinued operations attributable to Duke Energy Corporation	$	(1,393)	$	(1,241)	$	193

(a) Upon meeting the criteria for assets held for sale, beginning in November 2022 depreciation and amortization expense were ceased.

The Commercial Renewables Disposal Groups' assets held for sale amounts presented above reflect pretax impairments recorded against property, plant and equipment of approximately $278 million and $1.7 billion as of December 31, 2023, and 2022, respectively. In connection with the sales of the utility-scale solar and wind group and the distributed generation group, impairments were recorded based upon the purchase and sale agreements and the net assets were derecognized following the closing of the sales. For the remainder of the assets, impairments were recorded based upon fair value determined from a discounted cash flow analysis. The impairments were included in Loss from Discontinued Operations, net of tax in Duke Energy's Consolidated Statements of Operations and Comprehensive Income for the periods presented. The discounted cash flow model utilized Level 2 and Level 3 inputs. The fair value hierarchy levels are further discussed in Note 17. The impairments for the utility-scale and distributed generation assets were updated based on customary adjustments at closing, and will be updated, if necessary, for any post-closing adjustments. The carrying amounts for the remaining assets will be updated, if necessary, based on final disposition amounts.

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

(in millions)		Years Ended December 31, 2023		2022		2021
Cash flows provided by (used in):						
Operating activities	$	607	$	213	$	62
Investing activities		122		(802)		(542)

Other Sale Related Matters

Duke Energy (Parent) and several Duke Energy renewables project companies, located in the Electric Reliability Council of Texas (ERCOT) market, were named in several lawsuits arising out of Texas Storm Uri, which occurred in February 2021. The legal actions related to all but one of the project companies in this matter transferred to affiliates of Brookfield in conjunction with the transaction closing in October 2023. See Note 5 for more information.

As part of the purchase and sale agreement for the distributed generation group, Duke Energy has agreed to retain certain guarantees, with expiration dates between 2029 through 2034, related to tax equity partners' assets and operations that will be disposed of via sale. Duke Energy has obtained certain guarantees from the buyers in regard to future performance obligations to assist in limiting Duke Energy's exposure under the retained guarantees. The fair value of the guarantees is immaterial as Duke Energy does not believe conditions are likely for performance under these guarantees.

Sale of Minority Interest in Duke Energy Indiana Holdco, LLC

On January 28, 2021, Duke Energy executed an agreement providing for an investment by an affiliate of GIC in Duke Energy Indiana in exchange for a 19.9% minority interest issued by Duke Energy Indiana Holdco, LLC, the holding company for Duke Energy Indiana. The transaction was completed following two closings for an aggregate purchase price of approximately $2.05 billion. The first closing, which occurred on September 8, 2021, resulted in Duke Energy Indiana Holdco, LLC issuing 11.05% of its membership interests in exchange for approximately $1.03 billion or 50% of the purchase price. The difference between the cash consideration received, net of transaction costs of approximately $27 million, and the carrying value of the noncontrolling interest is $545 million and was recorded as an increase to equity. The second closing was completed in December 2022 and resulted in Duke Energy Indiana Holdco, LLC issuing an additional 8.85% of its membership interests in exchange for approximately $1.03 billion. The difference between the cash consideration received, net of transaction costs of approximately $8 million, and the carrying value of the noncontrolling interest is $492 million and was recorded as an increase to equity. Duke Energy retained indirect control of these assets, and, therefore, no gain or loss was recognized on the Consolidated Statements of Operations for either transaction.

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 and preferred stock dividends. 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

Due to Duke Energy's commitment in the fourth quarter of 2022 to sell the Commercial Renewables business segment, Duke Energy's segment structure now includes the following two segments: EU&I and GU&I. Prior period information has been recast to conform to the current segment structure. See Note 2 for further information on the Commercial Renewables Disposal Groups.

The EU&I 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. EU&I also includes Duke Energy's electric transmission infrastructure investments and the offshore wind contract for Carolina Long Bay. Refer to Note 2 for further information.

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

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.

(in millions)	Year Ended December 31, 2023										
		Electric Utilities and Infrastructure		Gas Utilities and Infrastructure		Total Reportable Segments		Other		Eliminations		Total
Unaffiliated Revenues	$	26,846	$	2,177	$	29,023	$	37	$	—	$	29,060
Intersegment Revenues		75		89		164		97		(261)		—
Total Revenues	$	26,921	$	2,266	$	29,187	$	134	$	(261)	$	29,060
Interest Expense	$	1,850	$	217	$	2,067	$	1,097	$	(150)	$	3,014
Depreciation and amortization		4,684		349		5,033		248		(28)		5,253
Equity in earnings of unconsolidated affiliates		7		40		47		66		—		113
Income tax expense (benefit)		742		116		858		(420)		—		438
Segment income (loss)[a][b]		4,223		519		4,742		(616)		—		4,126
Less noncontrolling interest												(33)
Add back preferred stock dividend												106
Discontinued operations												(1,391)
Net Income											$	2,874
Capital investments expenditures and acquisitions[c]	$	10,135	$	1,492	$	11,627	$	995	$	—	$	12,622
Segment assets[d]		155,449		17,349		172,798		4,095		—		176,893

(a) EU&I includes $35 million recorded with Impairment of assets and other charges and $8 million within Operations, maintenance and other primarily related to the North Carolina rate case order on Duke Energy Carolinas' Consolidated Statements of Operations; it also includes $33 million within Impairment of assets and other charges and $8 million within Operations, maintenance and other primarily related to the North Carolina rate case order on Duke Energy Progress' Consolidated Statements of Operations. See Note 4 for additional information.
(b) Other includes $110 million recorded within Operations, maintenance and other and $14 million within Impairments of assets and other charges primarily related to strategic repositioning as the Company transitions to a fully regulated utility on the Consolidated Statements of Operations. See Note 21 for additional information.
(c) Other includes capital investments expenditures and acquisitions related to the Commercial Renewables Disposal Groups.
(d) Other includes Assets Held for Sale balances related to the Commercial Renewables Disposal Groups. Refer to Note 2 for further information.

(in millions)	Year Ended December 31, 2022										
		Electric Utilities and Infrastructure		Gas Utilities and Infrastructure		Total Reportable Segments		Other		Eliminations		Total
Unaffiliated Revenues	$	25,990	$	2,748	$	28,738	$	30	$	—	$	28,768
Intersegment Revenues		34		92		126		92		(218)		—
Total Revenues	$	26,024	$	2,840	$	28,864	$	122	$	(218)	$	28,768
Interest Expense	$	1,565	$	182	$	1,747	$	778	$	(86)	$	2,439
Depreciation and amortization		4,550		327		4,877		236		(27)		5,086
Equity in earnings of unconsolidated affiliates		7		20		27		86		—		113
Income tax expense (benefit)		536		8		544		(244)		—		300
Segment income (loss)[a][b]		3,929		468		4,397		(737)		(1)		3,659
Less noncontrolling interest												95
Add back preferred stock dividend												106
Discontinued operations												(1,215)
Net Income											$	2,455
Capital investments expenditures and acquisitions[c]	$	8,985	$	1,295	$	10,280	$	1,139	$	—	$	11,419
Segment assets[d]		152,104		16,411		168,515		9,571		—		178,086

(a) EU&I includes $386 million recorded within Impairment of assets and other charges, $46 million within Regulated electric revenues and $34 million within Noncontrolling interests related to the Duke Energy Indiana court rulings on coal ash on the Consolidated Statements of Operations. See Note 4 for additional information.
(b) Other includes $72 million recorded within Impairment of assets and other charges, $71 million within Operations, maintenance and other and a $7 million gain within Gains on sales of other assets related to costs attributable to business transformation, including long-term real estate strategy changes and workforce realignment on the Consolidated Statements of Operations; it also includes $25 million recorded within Operations, maintenance and other related to litigation on the Consolidated Statements of Operations.
(c) Other includes capital investments expenditures and acquisitions related to the Commercial Renewables Disposal Groups.
(d) Other includes Assets Held for Sale balances related to the Commercial Renewables Disposal Groups. Refer to Note 2 for further information.

(in millions)	Year Ended December 31, 2021										
		Electric Utilities and Infrastructure		Gas Utilities and Infrastructure		Total Reportable Segments		Other		Eliminations		Total
Unaffiliated Revenues	$	22,570	$	2,022	$	24,592	$	29	$	—	$	24,621
Intersegment Revenues		33		90		123		84		(207)		—
Total Revenues	$	22,603	$	2,112	$	24,715	$	113	$	(207)	$	24,621
Interest Expense	$	1,432	$	142	$	1,574	$	643	$	(10)	$	2,207
Depreciation and amortization		4,251		303		4,554		236		(28)		4,762
Equity in earnings of unconsolidated affiliates		7		8		15		47		—		62
Income tax expense (benefit)		494		55		549		(281)		—		268
Segment income (loss)[a][b][c]		3,850		396		4,246		(641)		(3)		3,602
Less noncontrolling interest												329
Add back preferred stock dividend												106
Discontinued operations												200
Net Income											$	3,579
Capital investments expenditures and acquisitions[d]	$	7,653	$	1,271	$	8,924	$	828	$	—	$	9,752
Segment assets[e]		143,841		15,179		159,020		10,567		—		169,587

(a) EU&I includes $160 million of expense recorded within Impairment of assets and other charges, $77 million of income within Other income and expenses, $5 million of expense within Operations, maintenance and other, $13 million of income within regulated operating revenues, $3 million of expense within Interest expense and $8 million of expense within Depreciation and amortization on the Duke Energy Carolinas' Consolidated Statement of Operations related to the South Carolina Supreme Court decision on coal ash and insurance proceeds; it also includes $42 million of expense recorded within Impairment of assets and other charges, $34 million of income within Other income and expenses, $7 million of expense within Operations, maintenance, and other, $15 million of income within Regulated electric operating revenues, $5 million of expense within Interest expense and $1 million of expense within Depreciation and amortization on the Duke Energy Progress' Consolidated Statement of Operations.
(b) GU&I includes $20 million, recorded within Equity in earnings (losses) of unconsolidated affiliates on the Consolidated Statements of Operations, related to natural gas pipeline investments.
(c) Other includes $133 million recorded within Impairment of assets and other charges, $42 million within Operations, maintenance and other, and $17 million within Depreciation and amortization on the Consolidated Statements of Operations, related to the workplace and workforce realignment. See Note 11 for additional information.
(d) Other includes capital investments expenditures and acquisitions related to the Commercial Renewables Disposal Groups.
(e) Other includes Assets Held for Sale balances related to the Commercial Renewables Disposal Groups. Refer to Note 2 for further information.

Geographical Information

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

Major Customers

No Subsidiary Registrant has an individual customer representing more than 10% of its revenues for the year ended December 31, 2023.

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
2023										
Electric Utilities and Infrastructure	$	23,484	$	2,193	$	—	$	1,244	$	26,921
Gas Utilities and Infrastructure		—		—		2,199		67		2,266
Total Reportable Segments	$	23,484	$	2,193	$	2,199	$	1,311	$	29,187
2022										
Electric Utilities and Infrastructure	$	22,036	$	2,882	$	—	$	1,106	$	26,024
Gas Utilities and Infrastructure		—		—		2,535		305		2,840
Total Reportable Segments	$	22,036	$	2,882	$	2,535	$	1,411	$	28,864
2021										
Electric Utilities and Infrastructure	$	19,410	$	2,216	$	—	$	977	$	22,603
Gas Utilities and Infrastructure		—		—		2,025		87		2,112
Total Reportable Segments	$	19,410	$	2,216	$	2,025	$	1,064	$	24,715

Duke Energy Ohio

Duke Energy Ohio has two reportable segments, EU&I and GU&I.

EU&I transmits and distributes electricity in portions of Ohio and generates, distributes and sells electricity in portions of Northern Kentucky. GU&I 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.

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

	Year Ended December 31, 2023										
(in millions)		Electric Utilities and Infrastructure		Gas Utilities and Infrastructure		Total Reportable Segments		Other		Eliminations	Total
Total revenues	$	1,868	$	639	$	2,507	$	—	$	— $	2,507
Interest expense	$	116	$	53	$	169	$	—	$	— $	169
Depreciation and amortization		257		110		367		—		—	367
Income tax expense (benefit)		42		23		65		(2)		—	63
Segment income (loss)/Net income		227		116		343		(9)		—	334
Capital expenditures	$	520	$	419	$	939	$	—	$	— $	939
Segment assets		7,978		4,346		12,324		13		(121)	12,216

	Year Ended December 31, 2022										
(in millions)		Electric Utilities and Infrastructure		Gas Utilities and Infrastructure		Total Reportable Segments		Other		Eliminations	Total
Total revenues	$	1,798	$	716	$	2,514	$	—	$	— $	2,514
Interest expense	$	86	$	43	$	129	$	—	$	— $	129
Depreciation and amortization		221		103		324		—		—	324
Income tax expense (benefit)		24		(43)		(19)		(2)		—	(21)
Segment income (loss)/Net income		189		121		310		(8)		—	302
Capital expenditures	$	488	$	362	$	850	$	—	$	— $	850
Segment assets		7,504		4,164		11,668		14		(176)	11,506

	Year Ended December 31, 2021										
(in millions)		Electric Utilities and Infrastructure		Gas Utilities and Infrastructure		Total Reportable Segments		Other		Eliminations	Total
Total revenues	$	1,493	$	544	$	2,037	$	—	$	— $	2,037
Interest expense	$	87	$	24	$	111	$	—	$	— $	111
Depreciation and amortization		217		90		307		—		—	307
Income tax expense (benefit)		15		19		34		(4)		—	30
Segment income (loss)/Net income		141		78		219		(15)		—	204
Capital expenditures	$	486	$	362	$	848	$	—	$	— $	848
Segment assets		6,882		3,892		10,774		29		(29)	10,774

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)		2023		2022		2023		2022
Regulatory Assets								
AROs – coal ash	$	3,214	$	3,205	$	1,230	$	1,429
AROs – nuclear and other		1,179		945		1,127		884
Deferred fuel and purchased power		2,486		3,866		1,173		2,060
Accrued pension and OPEB		2,389		2,336		767		759
Storm cost securitized balance, net		890		940		682		720
Nuclear asset securitized balance, net		830		881		830		881
Debt fair value adjustment		774		829		—		—
Hedge costs deferrals		749		378		323		128
Storm cost deferrals		497		687		298		659
COR regulatory asset		371		221		337		221
Post-in-service carrying costs (PISCC) and deferred operating expenses		357		359		42		42
Retired generation facilities		275		316		220		243
Deferred asset – Lee and Harris COLA		252		288		15		21
Customer connect project		251		271		125		136
Advanced metering infrastructure (AMI)		243		283		92		111
Incremental COVID-19 expenses		237		210		80		78
Vacation accrual		228		222		43		43
Grid Deferral		210		136		81		40
Demand side management (DSM)/Energy efficiency (EE)		201		189		191		188
CEP deferral		183		190		—		—
NCEMPA deferrals		172		157		172		157
Derivatives – natural gas supply contracts		147		168		—		—
Deferred pipeline integrity costs		133		121		—		—
Nuclear deferral		131		154		42		64
COR settlement		115		120		30		32
Decoupling		115		42		15		—
Deferred coal ash handling system costs		86		92		21		25
Qualifying facility contract buyouts		68		81		68		81
Network Integration Transmission Services deferral		31		23		—		—
Transmission expansion obligation		30		31		—		—
East Bend deferrals		28		33		—		—
Propane caverns		26		26		—		—
Tennessee ARM Deferral		20		3		—		—
Other		428		327		127		77
Total regulatory assets		17,266		18,130		8,091		8,979
Less: Current portion		3,648		3,485		1,661		1,833
Total noncurrent regulatory assets	$	13,618	$	14,645	$	6,430	$	7,146
Regulatory Liabilities								
Net regulatory liability related to income taxes	$	5,901	$	6,462	$	2,908	$	2,192
COR regulatory liability		5,497		5,151		2,806		2,269
AROs – nuclear and other		1,673		1,038		—		—
Hedge cost deferrals		443		683		208		252
Accrued pension and OPEB		266		211		—		—
Deferred fuel and purchased power		137		35		14		—
DSM/EE		59		88		—		—
DOE Settlement		32		154		32		154
Provision for rate refunds		15		78		4		28
Other		1,355		1,148		430		434
Total regulatory liabilities		15,408		15,048		6,501		5,329
Less: Current portion		1,369		1,466		418		576
Total noncurrent regulatory liabilities	$	14,039	$	13,582	$	6,083	$	4,753

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.

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

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 securitized balance, net. Represents the North Carolina portion of storm restoration expenditures related to Hurricane Florence, Hurricane Michael, Hurricane Dorian and Winter Storm Diego (2018 and 2019 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.

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

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

COR regulatory asset. Represents the excess of spend over funds received from customers to cover the future removal of property, plant and equipment from retired or abandoned sites as property is retired, net of certain deferred gains on NDTF investments.

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.

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

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

Customer connect project. Represents incremental operating expenses and carrying costs on deferred amounts related to the deployment of the new customer information system.

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 future recovery of net book value of electromechanical meters that have been replaced with AMI meters at Duke Energy Indiana.

Incremental COVID-19 expenses. Represents incremental costs related to ensuring continuity and quality of service in a safe manner during the COVID-19 pandemic.

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

Grid deferral. Represents deferred incremental operation and maintenance expense, depreciation and property taxes associated with grid improvement plans.

DSM/EE. Deferred costs related to various DSM and EE programs recoverable or refundable as approved by the applicable regulatory body.

CEP deferral. Represents deferred depreciation, PISCC and deferred property tax for Duke Energy Ohio Gas capital assets for the CEP.

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

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

Deferred pipeline integrity costs. Represents pipeline integrity management costs in compliance with federal regulations.

Nuclear deferral. Includes amounts related to nuclear plant outage and refueling costs, which are deferred and recovered over the nuclear fuel cycle.

COR settlement. Represents approved COR settlements that are being amortized over the average remaining lives, at the time of approval, of the associated assets.

Decoupling. Relates primarily to margin and revenue decoupling.

Deferred coal ash handling system costs. Represents deferred depreciation and returns associated with capital assets related to converting the ash handling system from wet to dry.

Qualifying facility contract buyouts. Represents termination payments for regulatory recovery through the capacity clause.

Network Integration Transmission Services deferral. Represents a deferral of costs and return related transmission costs.

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

East Bend deferrals. Represents amounts to be recovered for deferred costs and depreciation related to the East Bend station.

Propane Caverns. Represents amounts for costs related to propane inventory, the net book value of remaining assets and decommissioning costs at Duke Energy Ohio.

TN ARM Deferral. Represents amounts to be recovered for uncollected revenue for 2022 and deferred depreciation and carrying costs on the portion of capital expenditures placed in service but not yet reflected in rates.

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.

COR regulatory liability. 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.

DOE Settlement. Represents litigation settlement funds received resulting from the DOE's failure to accept spent nuclear fuel and other radioactive waste from the Crystal River Unit 3 during 2014-2018 as required under the Nuclear Waste Policy Act.

Provision for rate refunds. Represents estimated amounts due to customers based on recording interim rates subject to refund.

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, 2023.

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, 2023.

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 Ian

In late September and early October 2022, Hurricane Ian inflicted severe damage to the Duke Energy Carolinas and Duke Energy Progress territories in North Carolina and South Carolina. Approximately 950,000 customers were impacted. As of December 31, 2023, total estimated operation and maintenance expenses incurred for restoration efforts were approximately $95 million, with an additional $8 million in capital investments. Approximately $87 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, 2023 ($32 million and $55 million for Duke Energy Carolinas and Duke Energy Progress, respectively), Duke Energy Carolinas and Duke Energy Progress have regulatory tools to recover storm costs including deferral and securitization. These estimates could change as Duke Energy Carolinas and Duke Energy Progress receive additional information on actual costs.

Nuclear Station Subsequent License Renewal

On June 7, 2021, Duke Energy Carolinas filed a subsequent license renewal (SLR) application for the Oconee Nuclear Station (ONS) with the U.S. Nuclear Regulatory Commission (NRC) to renew ONS's operating license for an additional 20 years. The SLR would extend operations of the facility from 60 to 80 years. The current licenses for units 1 and 2 expire in 2033 and the license for unit 3 expires in 2034. By a Federal Register Notice dated July 28, 2021, the NRC provided a 60-day comment period for persons whose interest may be affected by the issuance of a subsequent renewed license for ONS to file a request for a hearing and a petition for leave to intervene. On September 27, 2021, Beyond Nuclear and Sierra Club (Petitioners) filed a Hearing Request and Petition to Intervene (Hearing Request) and a Petition for Waiver. The Hearing Request proposed three contentions and claimed that Duke Energy Carolinas did not satisfy the National Environmental Policy Act (NEPA) of 1969, as amended, or the NRC's NEPA-implementing regulations. Following Duke Energy Carolinas' answer and the Petitioners' reply, on February 11, 2022, the Atomic Safety and Licensing Board (ASLB) issued its decision on the Hearing Request and found that the Petitioners failed to establish that the proposed contentions are litigable. The ASLB also denied the Petitioners' Petition for Waiver and terminated the proceeding.

On February 24, 2022, the NRC issued a decision in the SLR appeal related to Florida Power and Light's Turkey Point nuclear generating station in Florida. The NRC ruled that the NRC's license renewal Generic Environmental Impact Statement (GEIS) does not apply to SLR because the GEIS does not address SLR. The decision overturned a 2020 NRC decision that found the GEIS applies to SLR. Although Turkey Point is not owned or operated by a Duke Energy Registrant, the NRC's order applies to all SLR applicants, including Oconee. The NRC order also indicated no subsequent renewed licenses will be issued until the NRC staff has completed an adequate NEPA review for each application. On April 5, 2022, the NRC approved a 24-month rulemaking plan that will enable the NRC staff to complete an adequate NEPA review. Although an SLR applicant may wait until the rulemaking is completed, the NRC also noted that an applicant may submit a supplement to its environmental report providing information on environmental impacts during the SLR period prior to the rulemaking being completed. On November 7, 2022, Duke Energy Carolinas submitted a supplement to its environmental report addressing environmental impacts during the SLR period. On September 14, 2023, the NRC posted on its website that the issuance of the GEIS will now be issued in August 2024 instead of May 2024 due to the volume and technical complexity of the comments received.

On December 19, 2022, the NRC published a notice in the Federal Register that the NRC will conduct a limited scoping process to gather additional information necessary to prepare an environmental impact statement (EIS) to evaluate the environmental impacts at Oconee during the SLR period. The NRC received comments from the EPA and the Petitioners and these comments identify 18 potential impacts that should be considered by the NRC in the EIS, which include, but are not limited to, climate change and flooding, environmental justice, severe accidents, and external events. On February 8, 2024, the NRC issued the Oconee site-specific draft EIS.

On December 19, 2022, the NRC issued the Safety Evaluation Report (SER) for the safety portion of the SLR application. The NRC determined Duke Energy Carolinas met the requirements of the applicable regulations and identified actions that have been taken or will be taken to manage the effects of aging and address time-limited analyses. Duke Energy Carolinas and the NRC met with the Advisory Committee on Reactor Safeguards (ACRS) on February 2, 2023, to discuss issues regarding the SER and SLR application. On February 25, 2023, the ACRS issued a report to the NRC on the safety aspects of the Oconee SLR application, which concluded that the established programs and commitments made by Duke Energy Carolinas to manage age-related degradation provide confidence that Oconee can be operated in accordance with its current licensing basis for the subsequent period of extended operation without undue risk to the health and safety of the public and the SLR application for Oconee should be approved.

Although the NRC's GEIS applicability decision has delayed completion of the SLR proceeding, Duke Energy Carolinas does not believe it changes the probability that the Oconee subsequent renewed licenses will ultimately be issued, although Duke Energy Carolinas cannot guarantee the outcome of the license application process.

Duke Energy Carolinas and Duke Energy Progress intend to seek renewal of operating licenses and 20-year license extensions for all of their nuclear stations. Accordingly, new depreciation rates were implemented for all of the nuclear facilities during the second quarter of 2021. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of these additional relicensing proceedings.

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, 2023		2022	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[(a)]						
AROs – coal ash	$	1,659	$	1,391	(g)	(b)
Deferred fuel and purchased power[(i)]		1,293		1,614	(e)	2025
Accrued pension and OPEB		671		614		(h)
Storm cost securitized balance, net		208		220	Yes	2041
Hedge costs deferrals		405		228		(b)
Storm cost deferrals		97		114	Yes	(b)
PISCC and deferred operating expenses		48		47	Yes	(b)
Retired generation facilities[(c)]		26		39	Yes	(b)
Deferred asset – Lee COLA		237		267		(b)
Customer connect project[(c)]		58		82	Yes	(b)
AMI[(c)]		125		139	Yes	(b)
Incremental COVID-19 expenses		152		127	Yes	(b)
Vacation accrual		87		84		2024
Grid Deferral[(c)]		159		96	Yes	(b)
Nuclear deferral		89		90		2025
COR settlement[(c)]		85		88	Yes	(b)
Deferred coal ash handling system costs[(c)]		65		67	Yes	(b)
Other		118		101		(b)
Total regulatory assets		5,580		5,388		
Less: Current portion		1,664		1,095		
Total noncurrent regulatory assets	$	3,916	$	4,293		
Regulatory Liabilities[(a)]						
Net regulatory liability related to income taxes[(d)]	$	2,200	$	2,475	Yes	(b)
COR regulatory liability[(c)]		1,641		1,769	Yes	(f)
AROs – nuclear and other		1,673		1,038		(b)
Hedge cost deferrals		158		350		(b)
Accrued pension and OPEB		106		44		(h)
Deferred fuel and purchased power[(i)]		85		—	(e)	2025
DSM/EE[(j)]		87		86	Yes	(j)
Provision for rate refunds[(c)]		11		50	Yes	(b)
Other		616		501		(b)
Total regulatory liabilities		6,577		6,313		
Less: Current portion		587		530		
Total noncurrent regulatory liabilities	$	5,990	$	5,783		

(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. Portions are included in rate base.
(e) 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. The asset balance principally relates to North Carolina costs while the liability balance relates to South Carolina.
(f) Recovered over the life of the associated assets.
(g) Earns a debt and equity return on coal ash expenditures for North Carolina and South Carolina retail customers as permitted by various regulatory orders.
(h) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.
(i) Duke Energy Carolinas submitted a fuel filing to the NCUC in February 2023 for recovery of $998 million, which included deferrals through December 2022. The NCUC approved recovery of this balance through December 2024. The next filing will be made in the first quarter of 2024. Duke Energy Carolinas submitted a fuel filing to the PSCSC in August 2023 for recovery of $310 million, which included deferrals through May 2023. The PSCSC approved recovery of this balance through October 2024. The next filing will be made in the third quarter of 2024.
(j) Includes incentives on DSM/EE investments and is recovered or refunded through an annual rider mechanism.

2023 North Carolina Rate Case

On January 19, 2023, Duke Energy Carolinas filed a PBR application with the NCUC to request an increase in base rate retail revenues. The PBR Application included an MYRP to recover projected capital investments during the three-year MYRP period. In addition to the MYRP, the PBR Application included an Earnings Sharing Mechanism, Residential Decoupling Mechanism and Performance Incentive Mechanisms (PIMS) as required by HB 951. The application as originally filed requested an overall retail revenue increase of $501 million in Year 1, $172 million in Year 2 and $150 million in Year 3, for a combined total of $823 million or 15.7% by early 2026. The rate increase is driven primarily by transmission and distribution investments since the last rate case and projected in the MYRP, as well as investments in energy storage and solar assets included in the MYRP consistent with the Carbon Plan.

On August 22, 2023, Duke Energy Carolinas filed with the NCUC a partial settlement with the Public Staff in connection with its PBR application. The partial settlement included, among other things, agreement on a substantial portion of the North Carolina retail rate base for the historic base case of approximately $19.5 billion and all of the capital projects and related costs to be included in the three-year MYRP, including $4.6 billion (North Carolina retail allocation) projected to go in service over the MYRP period. Additionally, the partial settlement included agreement, with certain adjustments, on depreciation rates, the recovery of grid improvement plan costs and PIMs, Tracking Metrics and the Residential Decoupling Mechanism under the PBR application. On August 28, 2023, Duke Energy Carolinas filed with the NCUC a second partial settlement with the Public Staff resolving additional issues, including the future treatment of nuclear production tax credits related to the Inflation Reduction Act, through a stand-alone rider that will provide the benefits to customers beginning January 1, 2025.

On December 15, 2023, the NCUC issued an order approving Duke Energy Carolinas' PBR Application, as modified by the partial settlements and the order, including an overall retail revenue increase of $436 million in Year 1, $174 million in Year 2 and $158 million in Year 3, for a combined total of $768 million. The order established an ROE of 10 1% based upon a capital structure of 53% equity and 47% debt and approved, with certain adjustments, depreciation rates and the recovery of grid improvement plan costs and certain deferred COVID-related costs. Additionally, the Residential Decoupling Mechanism and PIMs were approved as requested under the PBR Application and revised by the partial settlements. As a result of the partial settlements and the order, Duke Energy Carolinas recognized pretax charges of $29 million within Impairment of assets and other charges, and $8 million within Operations, maintenance and other, for the year ended December 31, 2023, on the Consolidated Statements of Operations. Duke Energy Carolinas implemented interim rates, subject to refund, on September 1, 2023. New revised Year 1 rates and the residential decoupling were implemented on January 15, 2024. On February 13, 2024, a number of parties filed Notices of Appeal of the December 15, 2023 NCUC order. Appeals were filed by the Carolina Industrial Group for Fair Utility Rates (CIGFUR) III, a collection of various electric membership corporations (collectively, the EMCs), and the North Carolina Attorney General's Office (the AGO). CIGFUR III and the EMCs appealed the interclass subsidy reduction percentage and the Transmission Cost Allocation stipulation. In addition, CIGFUR III appealed the NCUC's elimination of the equal percentage fuel cost allocation methodology. The AGO appealed several issues including the authorized ROE and certain rate design and accounting matters. Duke Energy Carolinas cannot predict the outcome of this matter.

2024 South Carolina Rate Case

On January 4, 2024, Duke Energy Carolinas filed a rate case with the PSCSC to request an average effective net increase in annual retail revenues of 11.4%, or approximately $239 million, in the first two years, and an additional overall effective increase of about 4.1%, or approximately $84 million additional revenue, after the first two years. The requested increases, if approved, would result in an overall average 15.5% increase in annual retail revenues, or approximately $323 million, prior to mitigation efforts. To mitigate the rate increase, Duke Energy Carolinas has proposed to accelerate the return of remaining federal unprotected EDIT balances to customers over two years. This offset reduces the impact to customers in the first two years to the effective net increase of 11.4%, after which the credit for EDIT balances expire. Duke Energy Carolinas has requested the revised rates to be effective no later than August 1, 2024. The evidentiary hearing is scheduled to commence on May 20, 2024. Duke Energy Carolinas cannot predict the outcome of this matter.

Duke Energy Progress

Regulatory Assets and Liabilities

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

(in millions)		December 31, 2023	2022	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[(a)]					
AROs – coal ash	$	1,218 $	1,418	(g)	(b)
AROs – nuclear and other		1,110	889		(c)
Deferred fuel and purchased power[(l)]		579	705	(e)	2025
Accrued pension and OPEB		408	417		(j)
Storm cost securitized balance, net		682	720	Yes	2041
Hedge costs deferrals		260	55		(b)
Storm cost deferrals		228	234	Yes	(b)
PISCC and deferred operating expenses		42	42	Yes	2054
Retired generation facilities[(d)]		126	149	Yes	(b)
Deferred asset – Harris COLA		15	21		(b)
Customer connect project[(d)]		49	54	Yes	(b)
AMI[(d)]		68	81	Yes	(b)
Incremental COVID-19 expenses		80	78		(b)
Vacation accrual		43	43 -		2024
Grid Deferral[(d)]		51	40	Yes	(b)
DSM/EE[(d)]		182	180	Yes	(h)
NCEMPA deferrals[(d)]		172	157	(f)	2042
Nuclear deferral		42	64		2025
COR settlement[(d)]		38	32	Yes	(b)
Decoupling		15	—	Yes	(b)
Deferred coal ash handling system costs[(d)]		21	25	Yes	(b)
Other		67	30		(b)
Total regulatory assets		5,488	5,414		
Less: Current portion		942	690		
Total noncurrent regulatory assets	$	4,546 $	4,724		
Regulatory Liabilities[(a)]					
Net regulatory liability related to income taxes[(k)]	$	1,420 $	1,559	Yes	(b)
COR regulatory liability		2,805	2,269		(i)
Hedge cost deferrals		87	252		(b)
Deferred fuel and purchased power[(l)]		14	—	(e)	2025
Provision for rate refunds[(d)]		4	28	Yes	(b)
Other		345	344		(b)
Total regulatory liabilities		4,675	4,452		
Less: Current portion		300	332		
Total noncurrent regulatory liabilities	$	4,375 $	4,120		

(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) Included in rate base.
(e) 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. The asset balance principally relates to North Carolina costs while the liability balance relates to South Carolina.
(f) South Carolina retail allocated costs are earning a return.
(g) Earns a debt and equity return on coal ash expenditures for North Carolina and South Carolina retail customers as permitted by various regulatory orders.
(h) Includes incentives on DSM/EE investments and is recovered through an annual rider mechanism.
(i) Recovered over the life of the associated assets.
(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.
(k) 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. Portions are included in rate base.
(l) Duke Energy Progress submitted a fuel filing to the NCUC in June 2023 for recovery of $445 million, which included deferrals through March 2023. The NCUC approved recovery of this balance through November 2024. The next filing will be made in the second quarter of 2024. Duke Energy Progress submitted a fuel filing to the PSCSC in May 2023 for recovery of $79 million, which included deferrals through February 2023. The PSCSC approved recovery of this balance through July 2024. The next filing will be made in the second quarter of 2024.

2022 North Carolina Rate Case

On October 6, 2022, Duke Energy Progress filed a PBR application with the NCUC to request an increase in base rate retail revenues. The rate request before the NCUC included an MYRP to recover projected capital investments during the three-year MYRP period. In addition to the MYRP, the PBR Application included an Earnings Sharing Mechanism, Residential Decoupling Mechanism and PIMS as required by HB 951. The overall retail revenue increase as originally filed would have been $326 million in Year 1, $151 million in Year 2 and $138 million in Year 3, for a combined total of $615 million, by late 2025. The rate increase is driven primarily by transmission and distribution investments since the last rate case and projected in the MYRP, as well as investments in energy storage and solar assets included in the MYRP consistent with the Carbon Plan.

On April 28, 2023, Duke Energy Progress filed with the NCUC a partial settlement with Public Staff, which included agreement on many aspects of Duke Energy Progress' three-year MYRP proposal. In May 2023, CIGFUR II joined this partial settlement and Public Staff and CIGFUR II filed a separate settlement reaching agreement on PIMs, Tracking Metrics and the Residential Decoupling Mechanism under the PBR application.

On August 18, 2023, the NCUC issued an order approving Duke Energy Progress' PBR Application, as modified by the partial settlements and the order, including an overall retail revenue increase of $233 million in Year 1, $126 million in Year 2 and $135 million in Year 3, for a combined total of $494 million. Key aspects of the order include the approval of North Carolina retail rate base for the historic base case of approximately $12.2 billion and capital projects and related costs to be included in the three-year MYRP, including $3.5 billion (North Carolina retail allocation) projected to go in service over the MYRP period. The order established an ROE of 9.8% based upon a capital structure of 53% equity and 47% debt and approved, with certain adjustments, depreciation rates and the recovery of grid improvement plan costs and certain deferred COVID-related costs. Additionally, the Residential Decoupling Mechanism and PIMs were approved as requested under the PBR Application and revised by the partial settlements. As a result of the order, Duke Energy Progress recognized pretax charges of $28 million within Impairment of assets and other charges, which primarily related to certain COVID-19 deferred costs, and $8 million within Operations, maintenance and other, for the year ended December 31, 2023, on the Consolidated Statements of Operations. Duke Energy Progress implemented interim rates, subject to refund, on June 1, 2023, and implemented revised Year 1 rates and the residential decoupling on October 1, 2023.

On October 17, 2023, CIGFUR II and Haywood Electric Membership Corporation each filed a Notice of Appeal and Exceptions to the Supreme Court of North Carolina. Both parties were appealing certain matters that do not impact the overall revenue requirement in the rate case. Specifically, they appealed the interclass subsidy reduction percentage, and CIGFUR II also appealed the Customer Assistance Program and the equal percentage fuel cost allocation methodology. On November 6, 2023, the AGO filed a Notice of Cross Appeal of the NCUC's determination regarding the exclusion of electric vehicle revenue from the residential decoupling mechanism. On November 9, 2023, Duke Energy Progress, the Public Staff, CIGFUR II, and a number of other parties reached a settlement pursuant to which CIGFUR II agreed not to pursue its appeal of the Customer Assistance Program. Duke Energy Progress cannot predict the outcome of this matter.

2023 South Carolina Storm Securitization

On May 31, 2023, Duke Energy Progress filed a petition with the PSCSC requesting authorization for the financing of Duke Energy Progress' storm recovery costs in the amount of approximately $171 million, through securitization, due to storm recovery activities required as a result of the following storms: Pax, Ulysses, Matthew, Florence, Michael, Dorian, Izzy and Jasper. On September 8, 2023, Duke Energy Progress filed a comprehensive settlement agreement with all parties on all cost recovery issues raised in the storm securitization proceeding.

The evidentiary hearing occurred in early September 2023. On September 20, 2023, the PSCSC approved the comprehensive settlement agreement and on October 13, 2023, the PSCSC issued its financing order. Duke Energy Progress will proceed with structuring, marketing and pricing the storm recovery bonds and then seek PSCSC authorization to issue the bonds in the first half of 2024. Duke Energy Progress cannot predict the outcome of this matter.

2022 South Carolina Rate Case

On September 1, 2022, Duke Energy Progress filed an application with the PSCSC to request an increase in base rate retail revenues. On January 12, 2023, Duke Energy Progress and the ORS, as well as other consumer, environmental, and industrial intervening parties, filed a comprehensive Agreement and Stipulation of Settlement resolving all issues in the base rate proceeding. The major components of the stipulation include:

- A $52 million annual customer rate increase prior to the reduction from the accelerated return to customers of federal unprotected Property, Plant and Equipment related EDIT. After extending the remaining EDIT giveback to customers to 33 months, the net annual retail rate increase is approximately $36 million.
- ROE of 9.6% based upon a capital structure of 52.43% equity and 47.57% debt.
- Continuation of deferral treatment of coal ash basin closure costs. Supports an amortization period for remaining coal ash closure costs in this rate case of seven years. Duke Energy Progress agreed not to seek recovery of approximately $50 million of deferred coal ash expenditures related to retired sites in this rate case (South Carolina retail allocation).
- Accepts the 2021 Depreciation Study as proposed in this case, as adjusted for certain recommendations from ORS and includes accelerated retirement dates for certain coal units as originally proposed.
- Establishment of a storm reserve to help offset the costs of major storms.

The PSCSC held a hearing on January 17, 2023, to consider evidence supporting the stipulation and unanimously voted to approve the comprehensive agreement on February 9, 2023. A final written order was issued on March 8, 2023. New rates went into effect April 1, 2023.

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.

(in millions)	December 31, 2023	December 31, 2022	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash	$ 12	$ 11		(b)
AROs – nuclear and other	17	15		(b)
Deferred fuel and purchased power[g]	594	1,355	(e)	2024
Accrued pension and OPEB[c]	349	342	Yes	(f)
Nuclear asset securitized balance, net	830	881		2036
Hedge costs deferrals[c]	63	73	Yes	2038
Storm cost deferrals[c]	70	325	(e)	(b)
COR regulatory asset	337	221	(d)	(b)
Retired generation facilities[c]	94	94	Yes	2044
Customer connect project[c]	76	82	Yes	2037
AMI[c]	24	30	Yes	2032
Qualifying facility contract buyouts[c]	68	81	Yes	2034
Other	69	55	(d)	(b)
Total regulatory assets	2,603	3,565		
Less: Current portion	720	1,143		
Total noncurrent regulatory assets	$ 1,883	$ 2,422		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes[c]	$ 588	$ 633		(b)
Hedge cost deferrals	121	—		(b)
DOE Settlement	32	154		2024
Other	85	90	(d)	(b)
Total regulatory liabilities	826	877		
Less: Current portion	118	244		
Total noncurrent regulatory liabilities	$ 708	$ 633		

(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 commercial paper rate.
(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.
(g) On March 6, 2023, the FPSC approved Duke Energy Florida's amended February 2023 fuel filing recovery of $489 million, which included the 2022 actual under-recovery of $1.2 billion, offset by projected declining fuel costs in 2023 due to lower natural gas prices. The approved 21-month recovery period for the actual 2022 under-recovery is April 2023 through December 2024; the reduction in 2023 fuel costs were approved to be returned over 9-months from April 2023 through December 2023. Duke Energy Florida made its most recent fuel filing in September 2023. On November 1, 2023, the FPSC approved Duke Energy Florida's September 2023 fuel filing, which included the proposed fuel factors for 2024. In addition to the under-recoveries approved above, that filing also included a re-projected 2023 over-recovery of approximately $120 million that will be returned to customers January 2024 through December 2024.

2021 Settlement Agreement

On January 14, 2021, Duke Energy Florida filed the 2021 Settlement with the FPSC. The parties to the 2021 Settlement include Duke Energy Florida, the Office of Public Counsel (OPC), the Florida Industrial Power Users Group, White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate and NUCOR Steel Florida, Inc. (collectively, the Parties).

Pursuant to the 2021 Settlement, the Parties agreed to a base rate stay-out provision that expires year-end 2024; however, Duke Energy Florida is allowed an increase to its base rates of an incremental $67 million in 2022, $49 million in 2023 and $79 million in 2024, subject to adjustment in the event of tax reform during the years 2021, 2022 and 2023. The Parties also agreed to an ROE band of 8.85% to 10.85% with a midpoint of 9.85% based on a capital structure of 53% equity and 47% debt. The ROE band can be increased by 25 basis points if the average 30-year U.S. Treasury rate increases 50 basis points or more over a six-month period in which case the midpoint ROE would rise from 9.85% to 10.10%. On July 25, 2022, this provision was triggered. Duke Energy Florida filed a petition with the FPSC on August 12, 2022, to increase the ROE effective August 2022 with a base rate increase effective January 1, 2023. The FPSC approved this request on October 4, 2022. The 2021 Settlement also provided that Duke Energy Florida will be able to retain $173 million of the expected DOE award from its lawsuit to recover spent nuclear fuel to mitigate customer rates over the term of the 2021 Settlement. In return, Duke Energy Florida is permitted to recognize the $173 million into earnings through the approved settlement period. Duke Energy Florida settled the DOE lawsuit and received payment of approximately $180 million on June 15, 2022, of which the retail portion was approximately $154 million. The 2021 Settlement authorizes Duke Energy Florida to collect the difference between $173 million and the $154 million retail portion of the amount received through the capacity cost recovery clause. As of December 31, 2023, Duke Energy Florida has recognized $141 million into earnings. The remaining $32 million is expected to be recognized in 2024, while also remaining within the approved return on equity band.

The 2021 Settlement also contained a provision to recover or flow-back the effects of tax law changes. As a result of the IRA enacted on August 16, 2022, Duke Energy Florida is eligible for PTCs associated with solar facilities placed in service beginning in January 2022. Duke Energy Florida filed a petition with the FPSC on October 17, 2022, to reduce base rates effective January 1, 2023, by $56 million to flow back the expected 2023 PTCs and to flow back the expected 2022 PTCs via an adjustment to the capacity cost recovery clause. On December 14, 2022, the FPSC issued an order approving Duke Energy Florida's petition. See Note 24 for additional information on the IRA.

In addition to these terms, the 2021 Settlement contained provisions related to the accelerated depreciation of Crystal River Units 4-5, the approval of approximately $1 billion in future investments in new cost-effective solar power, the implementation of a new Electric Vehicle Charging Station Program and the deferral and recovery of costs in connection with the implementation of Duke Energy Florida's Vision Florida program, which explores various emerging non-carbon emitting generation technology, distributed technologies and resiliency projects, among other things. The 2021 Settlement also resolved remaining unrecovered storm costs for Hurricane Michael and Hurricane Dorian.

The FPSC approved the 2021 Settlement on May 4, 2021, issuing an order on June 4, 2021. Revised customer rates became effective January 1, 2022, with subsequent base rate increases effective January 1, 2023, and January 1, 2024.

Clean Energy Connection

On July 1, 2020, Duke Energy Florida petitioned the FPSC for approval of a voluntary solar program consisting of 10 new solar generating facilities with combined capacity of approximately 750 MW. The program allows participants to support cost-effective solar development in Florida by paying a subscription fee based on per kilowatt subscriptions and receiving a credit on their bill based on the actual generation associated with their portion of the solar portfolio. The estimated cost of the 10 new solar generation facilities is approximately $1 billion and the projects are expected to be completed by the end of 2024. This investment will be included in base rates offset by the revenue from the subscription fees and the credits will be included for recovery in the fuel cost recovery clause. The FPSC approved the program in January 2021.

On February 24, 2021, the League of United Latin American Citizens (LULAC) filed a notice of appeal of the FPSC's order approving the Clean Energy Connection to the Supreme Court of Florida. The Supreme Court of Florida heard oral arguments in the appeal on February 9, 2022. On May 27, 2022, the Supreme Court of Florida issued an order remanding the case back to the FPSC so that the FPSC can amend its order to better address some of the arguments raised by LULAC. On September 23, 2022, the FPSC issued a revised order and submitted it on September 26, 2022, to the Supreme Court of Florida. The Supreme Court of Florida requested that the parties file supplemental briefs regarding the revised order, which were filed February 6, 2023. LULAC has filed a request for Oral Argument on the issues discussed in the supplemental briefs, but the Court has yet to rule on that request. The FPSC approval order remains in effect pending the outcome of the appeal. Duke Energy Florida cannot predict the outcome of this matter.

Storm Protection Plan

On April 11, 2022, Duke Energy Florida filed a Storm Protection Plan for approval with the FPSC. The plan, which covers investments for the 2023-2032 time frame, reflects approximately $7 billion of capital investment in transmission and distribution meant to strengthen its infrastructure, reduce outage times associated with extreme weather events, reduce restoration costs and improve overall service reliability. The evidentiary hearing began on August 2, 2022. On October 4, 2022, the FPSC voted to approve Duke Energy Florida's plan with one modification to remove the transmission loop radially fed program, representing a reduction of approximately $80 million over the 10-year period starting in 2025. On December 9, 2022, the OPC filed a notice of appeal of this order to the Florida Supreme Court. The OPC's initial brief was filed on April 18, 2023. Duke Energy Florida filed its answer brief on July 17, 2023. The OPC's reply brief was filed on October 16, 2023. The Florida Supreme Court heard oral arguments on February 7, 2024. Duke Energy Florida cannot predict the outcome of this matter.

Hurricanes Ian and Idalia

On September 28, 2022, much of Duke Energy Florida's service territory was impacted by Hurricane Ian, which caused significant damage resulting in more than 1.1 million outages. Duke Energy Florida's Consolidated Balance Sheets included an estimate of approximately $353 million as of December 31, 2022, related to deferred Hurricane Ian storm costs, consistent with the FPSC's storm rule, in Regulatory assets within Other Noncurrent Assets. After depleting any existing storm reserves, which were approximately $107 million before Hurricane Ian, Duke Energy Florida is permitted to petition the FPSC for recovery of additional incremental operation and maintenance costs resulting from the storm and to replenish the retail customer storm reserve to approximately $132 million. Duke Energy Florida filed its petition for cost recovery of various storms, including Hurricane Ian, and replenishment of the storm reserve on January 23, 2023, seeking recovery of $442 million, for recovery over 12 months beginning with the first billing cycle in April 2023. On March 7, 2023, the FPSC approved this request for interim recovery, subject to refund, and ordered Duke Energy Florida to file documentation of the total actual storm costs, once known. Duke Energy Florida filed documentation evidencing its total actual storm costs of $431 million on September 29, 2023. The FPSC will hold a final hearing to determine the prudence of these costs in May of 2024.

On August 30, 2023, Hurricane Idalia made landfall on Florida's gulf coast, causing damage and impacting more than 200,000 customers across Duke Energy Florida's service territory. Duke Energy Florida's December 31, 2023, Consolidated Balance Sheets includes an estimate of approximately $102 million in Regulatory Assets within Current Assets related to deferred Hurricane Idalia storm costs consistent with the FPSC's storm rule. On October 16, 2023, Duke Energy Florida requested to combine the $92 million retail portion of the deferred estimated Hurricane Idalia costs with $74 million of costs projected to be collected after December 31, 2023, under the existing approved storm cost recovery and storm surcharge. This $74 million of costs relates primarily to the approved ongoing replenishment of the storm reserves. At its December 5, 2023 Agenda Conference, the FPSC approved recovery of the total $166 million over 12 months beginning with its first billing cycle in January 2024, replacing the previously approved storm cost recovery and storm surcharge, and ordered Duke Energy Florida to file documentation of the total actual Idalia related storm costs, once known. Revised rates were effective January 1, 2024. Duke Energy Florida cannot predict the outcome of these matters.

2024 Florida Rate Case

In January 2024, Duke Energy Florida notified the FPSC that it expects to file a formal request for new base rates in April 2024. Duke Energy Florida intends to propose a three-year rate plan that would begin in January 2025, once its current base rate settlement agreement concludes at the end of 2024. Duke Energy Florida will propose multiyear rate increases that use the projected 12-month periods ending December 31, 2025, 2026, and 2027 as the test years, with adjusted rates to be effective with the first billing period of January 2025, 2026, and 2027, respectively. Duke Energy Florida expects to request additional base rate revenue requirements of approximately $598 million in 2025, $95 million in 2026 and $127 million in 2027, representing an average annual increase in revenue requirements of approximately 4% over 2025 through 2027.

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, 2023	2022	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash	$ 17	$ —	Yes	(b)
Deferred fuel and purchased gas costs	28	54		2024
Accrued pension and OPEB	123	129		(e)
Storm cost deferrals	12	14		2024
COR regulatory asset	34	—		(b)
PISCC and deferred operating expenses[c]	15	15	Yes	2083
Customer connect project	49	54		(b)
AMI	13	18		(b)
CEP deferral	183	190	Yes	(b)
Deferred pipeline integrity costs	30	28	Yes	(b)
Decoupling	25	—		(b)
Network Integration Transmission Services deferral	31	23	Yes	(b)
Transmission expansion obligation	30	31		(b)
East Bend deferrals[c]	28	33	Yes	(b)
Propane caverns	28	26		(b)
Other	103	69		(b)
Total regulatory assets	749	684		
Less: Current portion	73	103		
Total noncurrent regulatory assets	$ 676	$ 581		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes	$ 466	$ 496		(b)
COR regulatory liability	—	9		(d)
Accrued pension and OPEB	17	21		(e)
Deferred fuel and purchased gas costs	15	35		2024
Other	55	72		(b)
Total regulatory liabilities	553	633		
Less: Current portion	56	99		
Total noncurrent regulatory liabilities	$ 497	$ 534		

(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 primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.

Duke Energy Ohio Electric Base Rate Case

Duke Energy Ohio filed with the PUCO an electric distribution base rate case application on October 1, 2021, with supporting testimony filed on October 15, 2021, requesting an increase in electric distribution base rates of approximately $55 million. On September 19, 2022, Duke Energy Ohio filed a Stipulation and Recommendation with the PUCO, which included an increase in overall electric distribution base rates of approximately $23 million with an equity ratio of 50.5% and an ROE of 9.5%. The stipulation was among all but one party to the proceeding. The PUCO issued an order on December 14, 2022, approving the Stipulation without modification. Rates went into effect on January 3, 2023. The Ohio Consumers' Counsel (OCC) filed an application for rehearing on January 13, 2023, arguing the Stipulation was unreasonable, discriminatory and denied OCC due process. On February 8, 2023, the Commission granted the OCC's application for rehearing for further consideration. Duke Energy Ohio cannot predict the outcome of this matter.

Energy Efficiency Cost Recovery

In response to changes in Ohio law that eliminated Ohio's energy efficiency mandates, the PUCO issued an order on February 26, 2020, directing utilities to wind down their demand-side management programs by September 30, 2020, and to terminate the programs by December 31, 2020.

- On March 27, 2020, Duke Energy Ohio filed an application for rehearing seeking clarification on the final true up and reconciliation process after 2020.
- Effective January 1, 2021, Duke Energy Ohio suspended its energy efficiency programs.

On August 9, 2023, the PUCO issued its decision approving the Company's request for recovery and final true up of energy efficiency program costs, lost distribution revenues and performance incentives from calendar years 2018 through 2020, resulting in $14 million of Regulated electric revenue on the Consolidated Statements of Operations for the year ended December 31, 2023, and resolving all outstanding issues in these proceedings. Revised rates were effective September 1, 2023.

Duke Energy Ohio Natural Gas Base Rate Case

Duke Energy Ohio filed with the PUCO a natural gas base rate case application on June 30, 2022, with supporting testimony filed on July 14, 2022, requesting an increase in natural gas base rates of approximately $49 million. The drivers for this case are capital invested since Duke Energy Ohio's last natural gas base rate case in 2012. Duke Energy Ohio also sought to adjust the caps on its CEP Rider. On April 28, 2023, Duke Energy Ohio filed a stipulation with all parties to the case except the OCC. In the stipulation, the parties agreed to approximately $32 million in revenue increases with an equity ratio of 52.32% and an ROE of 9.6%, and adjustments to the CEP Rider caps. The stipulation was opposed by the OCC at an evidentiary hearing that concluded on May 24, 2023. On November 1, 2023, PUCO issued an order approving the stipulation as filed. New rates went into effect November 1, 2023. On December 1, 2023, the OCC filed an application for rehearing. On December 13, 2023, the PUCO granted OCC's application for rehearing for further consideration of issues raised. Duke Energy Ohio cannot predict the outcome of this matter.

MGP Cost Recovery

In an order issued in 2013, the PUCO approved Duke Energy Ohio's deferral and recovery of costs related to environmental remediation at two sites (East End and West End) that housed former MGP operations. Duke Energy Ohio 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 base rate case.

A Stipulation and Recommendation was filed jointly by Duke Energy Ohio, the Staff, the Office of the Ohio Consumers' Counsel and the Ohio Energy Group on August 31, 2021, which was approved without modification by the PUCO on April 20, 2022. The Stipulation and Recommendation resolved all open issues regarding MGP remediation costs incurred between 2013 and 2019, Duke Energy Ohio's request for additional deferral authority beyond 2019 and the pending issues related to the Tax Act described below as it related to Duke Energy Ohio's natural gas operations. As a result of the approval of the Stipulation and Recommendation, Duke Energy Ohio recognized pretax charges of approximately $15 million to Operating revenues, regulated natural gas and $58 million to Operation, maintenance and other and a tax benefit of $72 million to Income Tax (Benefit) Expense in the Consolidated Statements of Operations for the year ended December 31, 2022. The Stipulation and Recommendation further acknowledged Duke Energy Ohio's ability to file a request for additional deferral authority in the future related to environmental remediation of any MGP impacts in the Ohio River, if necessary, subject to specific conditions. On June 15, 2022, the PUCO granted the rehearing requests of Interstate Gas Supply, Inc. (IGS) and The Retail Energy Supply Association (RESA), which were filed on May 20, 2022, for further consideration. Duke Energy Ohio cannot predict the outcome of this matter.

Tax Act – Ohio

On December 21, 2018, Duke Energy Ohio filed an application to change its base rate tariffs and establish a rider to implement the benefits of the Tax Act for natural gas customers. The rider would flow through to customers the benefit of the reduction in the 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 would be refunded consistent with federal law and deferred income taxes not subject to normalization rules will be refunded over a 10-year period. An evidentiary hearing occurred on August 7, 2019. The Stipulation and Recommendation filed on August 31, 2021, and approved on April 20, 2022, disclosed in the MGP Cost Recovery matter above, resolved the outstanding issues in this proceeding by providing customers a one-time bill credit for the reduction in the statutory federal tax rate from 35% to 21% since January 1, 2018, through June 1, 2022, and reducing base rates going forward. Deferred income taxes not subject to normalization rules were written off. Deferred income taxes subject to normalization rules are refunded consistent with federal law through a rider. The commission granted the rehearing requests of IGS and RESA for further consideration. Duke Energy Ohio cannot predict the outcome of this matter.

Midwest Propane Caverns

Duke Energy Ohio used propane stored in caverns to meet peak demand during winter for several decades. Once the Central Corridor Project was complete and placed in service, the propane peaking facilities were no longer necessary and were retired. On October 7, 2021, Duke Energy Ohio requested deferral treatment of the property, plant and equipment as well as costs related to propane inventory and decommissioning costs. On January 6, 2022, the Staff issued a report recommending deferral authority for costs related to propane inventory and decommissioning costs, but not for the net book value of the remaining plant assets. As a result of the Staff's report, Duke Energy Ohio recorded a $19 million charge to Impairment of assets and other charges on the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2021. A Stipulation and Recommendation was filed jointly by Duke Energy Ohio and the Staff on April 27, 2022, recommending, among other things, approval of deferral treatment of a portion of the net book value of the property, plant and equipment prior to the 2021 impairment at the time of the next natural gas base rate case, excluding operations and maintenance savings, decommissioning costs not to exceed $7 million and costs related to propane inventory. The Stipulation and Recommendation states that Duke Energy Ohio will seek recovery of the deferral through its next natural gas base rate case proceeding with a proposed amortization period of at least 10 years and include an independent engineering study analyzing the necessity and prudency of the incremental investments made at the facilities since March 31, 2012. Duke Energy Ohio will not seek a return on the deferred amounts. An evidentiary hearing was held on September 8, 2022. On October 5, 2022, the PUCO issued an order approving the Stipulation and Recommendation as filed. As a result of the order, Duke Energy Ohio recorded a reversal of $12 million to Impairment of assets and other charges on the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2022.

Duke Energy Kentucky Electric Base Rate Case

On December 1, 2022, Duke Energy Kentucky filed a rate case with the KPSC requesting an annualized increase in electric base rates of approximately $75 million. The request for rate increase was driven by capital investments to strengthen the electricity generation and delivery systems along with adjusted depreciation rates for the East Bend and Woodsdale generation stations to support the energy transition. Duke Energy Kentucky also requested new programs and tariff updates, including a voluntary community-based renewable subscription program and two electric vehicle charging programs. The KPSC issued an order on October 12, 2023, including a $48 million increase in base revenues, an ROE of 9.75% for electric base rates and 9.65% for electric riders and an equity ratio of 52.145%. New rates went into effect October 13, 2023. The Company's request to align the depreciation rates of East Bend with a 2035 retirement date was denied and the KPSC ordered depreciation rates with a 2041 retirement date for the unit. The KPSC did approve the request to align the depreciation rates of Woodsdale CT with a 2040 retirement date and denied the voluntary community-based renewable subscription program and the two electric vehicle charging programs.

On November 1, 2023, Duke Energy Kentucky filed for rehearing requesting certain matters be reconsidered by the KPSC. On November 21, 2023, KPSC granted in part and denied in part the Company's request for rehearing. On February 15, 2024, the KPSC issued a briefing schedule for the rehearing process. Simultaneous briefs are due on March 18, 2024, simultaneous reply briefs are due on April 1, 2024 and the matter shall stand submitted on April 2, 2024. On December 14, 2023, Duke Energy Kentucky filed an appeal with the Franklin County Circuit Court on certain matters for which the KPSC denied rehearing, specifically as it relates to including decommissioning costs in depreciation rates for East Bend and Woodsdale. On January 8, 2024, answers to the appeal were filed by the KPSC, Kentucky Attorney General, and the Kentucky Broadband & Cable Association. Duke Energy Kentucky cannot predict the outcome of this matter.

Duke Energy Indiana

Regulatory Assets and Liabilities

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

(in millions)	December 31, 2023	2022	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[(a)]				
AROs – coal ash	$ 408	$ 385	Yes	(b)
Deferred fuel and purchased power	—	138		2024
Accrued pension and OPEB	208	214		(e)
Hedge costs deferrals	19	20		(b)
PISCC and deferred operating expenses[(c)]	252	255	Yes	(b)
Retired generation facilities[(c)]	29	34	Yes	2030
Customer connect project	19	19		(b)
AMI	13	15		2031
Other	48	44		(b)
Total regulatory assets	996	1,124		
Less: Current portion	102	249		
Total noncurrent regulatory assets	$ 894	$ 875		
Regulatory Liabilities[(a)]				
Net regulatory liability related to income taxes	$ 794	$ 840		(b)
COR regulatory liability	496	531		(d)
Hedge cost deferrals	77	81		(b)
Accrued pension and OPEB	109	104		(e)
Deferred fuel and purchased power	23	—		2024
Other	169	85		(b)
Total regulatory liabilities	1,668	1,641		
Less: Current portion	209	187		
Total noncurrent regulatory liabilities	$ 1,459	$ 1,454		

(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) 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 for a rate increase for retail customers of approximately $395 million. 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. On June 29, 2020, the IURC issued an order in the rate case approving a revenue increase of $146 million before certain adjustments and ratemaking refinements. The order approved Duke Energy Indiana's requested forecasted rate base of $10.2 billion as of December 31, 2020, including the Edwardsport Integrated Gasification Combined Cycle (IGCC) Plant. The IURC reduced Duke Energy Indiana's request by slightly more than $200 million, when accounting for the utility receipts tax and other adjustments. Step one rates were estimated to be approximately 75% of the total rate increase and became effective on July 30, 2020. Step two rates estimated to be the remaining 25% of the total rate increase were approved on July 28, 2021, and implemented in August 2021.

Several groups appealed the IURC order to the Indiana Court of Appeals. The Indiana Court of Appeals affirmed the IURC decision on May 13, 2021. However, upon appeal by the Indiana Office of Utility Consumer Counselor (OUCC) and the Duke Industrial Group on March 10, 2022, the Indiana Supreme Court found that the IURC erred in allowing Duke Energy Indiana to recover coal ash costs incurred before the IURC's rate case order in June 2020. The Indiana Supreme Court found that allowing Duke Energy Indiana to recover coal ash costs incurred between rate cases that exceeded the amount built into base rates violated the prohibition against retroactive ratemaking. The IURC's order was remanded to the IURC for additional proceedings consistent with the Indiana Supreme Court's opinion. As a result of the court's opinion, Duke Energy Indiana recognized pretax charges of approximately $211 million to Impairment of assets and other charges and $46 million to Operating revenues in the Consolidated Statements of Operations for the year ended December 31, 2022. Duke Energy Indiana filed a request for rehearing with the Supreme Court on April 11, 2022, which the court denied on May 26, 2022. Duke Energy Indiana filed its testimony in the remand proceeding on August 18, 2022. On February 3, 2023, Duke Energy Indiana filed a settlement agreement reached with the OUCC and Duke Industrial Group, which includes an agreed amount of approximately $70 million of refunds to be paid to customers. The IURC approved this settlement agreement in its entirety on April 12, 2023. In June of 2023, Duke Energy Indiana commenced refunding the approximate $70 million to customers in accordance with the settlement agreement.

Indiana Coal Ash Recovery

In Duke Energy Indiana's 2019 rate case, the IURC also opened a subdocket for post-2018 coal ash related expenditures. Duke Energy Indiana filed testimony on April 15, 2020, in the coal ash subdocket requesting recovery for the post-2018 coal ash basin closure costs for plans that have been approved by IDEM as well as continuing deferral, with carrying costs, on the balance. On November 3, 2021, the IURC issued an order allowing recovery for post-2018 coal ash basin closure costs for the plans that have been approved by IDEM, as well as continuing deferral, with carrying costs, on the balance. The OUCC and the Duke Industrial Group appealed. The Indiana Court of Appeals issued its opinion on February 21, 2023, reversing the IURC's order to the extent that it allowed Duke Energy Indiana to recover federally mandated costs incurred prior to the IURC's November 3, 2021, order. In addition, the court found that any costs incurred pre-petition to determine federally mandated compliance options were not specifically authorized by the statute and should also be disallowed. As a result of the Indiana Court of Appeals' opinion, Duke Energy Indiana recognized a pretax charge of approximately $175 million to Impairment of assets and other charges for the year ended December 31, 2022.

In the second quarter of 2023, Duke Energy Indiana filed its proposal to remove from rates certain costs incurred prior to the IURC's November 3, 2021, order date. On September 20, 2023, the commission approved the Company's proposal to remove the costs from its rates and assessed simple interest of the refunds of 4.71%, beginning from when the costs were initially recovered from customers. Duke Energy Indiana filed a new petition under the amended version of the federal mandate statute for post-2018 coal ash closure costs for the remaining basins not included in the 2020 Indiana Coal Ash Recovery Case. An evidentiary hearing was held on January 25, 2024. Duke Energy Indiana cannot predict the outcome of this matter.

TDSIC 2.0

On November 23, 2021, Duke Energy Indiana filed for approval of the Transmission, Distribution, Storage Improvement Charge 2.0 investment plan for 2023-2028 (TDSIC 2.0). On June 15, 2022, the IURC approved, without modification, TDSIC 2.0, which includes approximately $2 billion in transmission and distribution investments selected to improve customer reliability, harden and improve resiliency of the grid, enable expansion of renewable and distributed energy projects and encourage economic development. In addition, the IURC set up a subdocket to consider a targeted economic development project, which the IURC approved on March 2, 2022. On July 15, 2022, the OUCC filed a notice of appeal to the Indiana Court of Appeals in Duke Energy Indiana's TDSIC 2.0 proceeding. An appellant brief was filed on October 28, 2022, and Duke Energy Indiana filed its responsive brief on December 28, 2022. The Indiana Court of Appeals issued its opinion on March 9, 2023, affirming the IURC's order in its entirety. The Duke Industrial Group filed a petition to transfer to the Indiana Supreme Court. The Indiana Supreme Court granted transfer and held an oral argument on September 28, 2023. Duke Energy Indiana cannot predict the outcome of this matter.

Piedmont

Regulatory Assets and Liabilities

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

(in millions)	December 31, 2023	2022	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[(a)]				
AROs – nuclear and other	$ 26	$ 27		(d)
Accrued pension and OPEB[(g)]	129	119		(g)
Vacation accrual	13	12		2024
Derivatives – natural gas supply contracts[(f)]	147	168		
Deferred pipeline integrity costs[(c)]	103	93		2025
Decoupling	75	42	(e)	(b)
Tennessee ARM Deferral	20	3	(e)	(b)
Other	58	47	(e)	(b)
Total regulatory assets	571	511		
Less: Current portion	161	119		
Total noncurrent regulatory assets	$ 410	$ 392		
Regulatory Liabilities[(a)]				
Net regulatory liability related to income taxes	$ 433	$ 459		(b)
COR regulatory liability[(d)]	556	573		(d)
Other	58	66	(e)	(b)
Total regulatory liabilities	1,046	1,098		
Less: Current portion	88	74		
Total noncurrent regulatory liabilities	$ 958	$ 1,024		

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

Tennessee Annual Review Mechanism

On October 10, 2022, the TPUC approved Piedmont's petition to adopt an ARM as allowed by Tennessee law. Under the ARM, Piedmont will adjust rates annually to achieve its allowed 9.80% ROE over the upcoming year and to true up any variance between its allowed ROE and actual ROE from the prior calendar year. The initial year subject to the true up was 2022, and Piedmont filed the initial rate adjustments request on May 19, 2023, for a total increase of approximately $42 million. On September 11, 2023, the TPUC approved a settlement between Piedmont and the Consumer Advocate Division of the Tennessee Attorney General's Office, which provided for recovery of the Historic Base Period Reconciliation cost of service of $11 million through rider rates and an increase in Piedmont's base rates of $29 million for the Annual Base Rate Reset component of the ARM. These amounts result in a total increase of $40 million with adjusted rates effective October 1, 2023.

OTHER REGULATORY MATTERS

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 resources proposed to meet those needs.

IRPs filed by certain Subsidiary Registrants included planning assumptions around future retirement dates of aging coal-fired generating facilities in North Carolina (Duke Energy Carolinas and Duke Energy Progress) and Indiana (Duke Energy Indiana). In North Carolina, the NCUC concluded in its December 2022 Carbon Plan order that the projected retirement dates presented by Duke Energy Carolinas and Duke Energy Progress in their Carbon Plan for coal-fired generating facilities were reasonable for planning purposes and further directed that appropriate steps be taken to optimally retire the coal fleet according to such schedule. Duke Energy Carolinas and Duke Energy Progress filed updated Resource Plans (Carbon Plan and IRP) in August 2023, and a supplemental filing in January 2024. See the "Other Matters" section of Item 7 Management's Discussion and Analysis for further details on IRPs.

Duke Energy continues to evaluate the retirement date assumptions for coal-fired generating facilities as changes in energy usage and/or growth and availability of replacement generation could result in different retirement dates of units than their current estimated useful lives. Except as discussed above related to Duke Energy Kentucky's East Bend plant, rate cases recently filed or approved across all jurisdictions included proposed depreciation rates reflecting the earlier retirement dates as outlined in recent IRPs. Duke Energy plans to seek regulatory recovery for amounts that would not be otherwise recovered when any of these assets are retired.

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 achieved a SAFSTOR condition in July 2019. On October 1, 2020, Crystal River Unit 3 changed decommissioning strategies from SAFSTOR to DECON.

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 $16.2 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 for Crystal River in compliance with the law.

Excess Liability Program

This program provides $16.2 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 $166 million times the current 95 licensed commercial nuclear reactors in the U.S. Under this program, operating unit 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 $24.7 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 Catawba, McGuire and Harris, $462 million for Brunswick and Oconee and $378 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 $147 million, $90 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 regulations regarding air and water quality, hazardous and solid waste disposal, coal ash and other environmental matters. These regulations can be changed from time to time, imposing new obligations on the Duke Energy Registrants. The following environmental matters impact all of the Duke Energy Registrants.

Remediation Activities

In addition to AROs 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 table contains information regarding reserves for probable and estimable costs related to the various environmental sites. These reserves are recorded in Accounts Payable within Other Current Liabilities and Other within Other Noncurrent Liabilities on the Consolidated Balance Sheets.

(in millions)	December 31, 2023	December 31, 2022
Reserves for Environmental Remediation		
Duke Energy	$ 88	$ 84
Duke Energy Carolinas	23	22
Progress Energy	19	19
Duke Energy Progress	9	8
Duke Energy Florida	10	11
Duke Energy Ohio	36	33
Duke Energy Indiana	2	3
Piedmont	7	7

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.

LITIGATION

Duke Energy

Texas Storm Uri Tort Litigation

Duke Energy (Parent), several Duke Energy renewables project companies, and others in the ERCOT market were named in multiple lawsuits arising out of Texas Storm Uri, which occurred in February 2021. These lawsuits seek recovery for property damage, personal injury and wrongful death allegedly caused by the power outages that plaintiffs claim were the collective failure of generators including Duke Energy entities, transmission and distribution operators (TDUs), retail energy providers, and all others, including ERCOT. The cases were consolidated into a Texas state court multidistrict litigation (MDL) proceeding for discovery and pre-trial motions. Five MDL cases were designated as lead cases in which motions to dismiss were filed and all other cases were stayed. On January 28, 2023, the Court denied certain motions including those by the generator defendants and TDUs and granted others. The generators and TDUs filed separate petitions for Writ of Mandamus to the Texas Court of Appeals seeking to overturn the denials. The TDUs' petition, filed first, was accepted and oral argument was held on October 23, 2023. In the cases against the generators, Plaintiffs have dismissed the claims against Duke Energy (Parent). However, before Duke Energy (Parent) was dismissed from all cases, on December 14, 2023, without argument, the Court of Appeals accepted mandamus of the generator defendants' appeal, which includes all Duke Energy entities, and directed the MDL court to dismiss all claims. Plaintiffs filed their Petition for Reconsideration on January 29, 2024. Regardless of the outcome of any motion for reconsideration or appeal, claims against Duke Energy (Parent) will remain dismissed. In October 2023, in conjunction with the closing of the sale of the utility-scale solar and wind group, all but one of the project company lawsuits transferred to Brookfield. Based on legal proceedings to date and applicable insurance and reinsurance coverage, Duke Energy (Parent) does not anticipate any material financial impacts with this remaining case. Duke Energy cannot predict the ultimate outcome of this matter. See Note 2 for more information related to the sale of the Commercial Renewables Disposal Groups.

Duke Energy Carolinas

Ruben Villano, et al. v. Duke Energy Carolinas, LLC

On June 18, 2021, a group of nine individuals went over a low-head dam adjacent to the Dan River Steam Station in Eden, North Carolina, while water tubing. Emergency personnel rescued four people and five others were confirmed deceased. On August 11, 2021, Duke Energy Carolinas was served with the complaint filed in Durham County Superior Court on behalf of four survivors, which was later amended to include all the decedents along with the survivors. The lawsuit alleges that Duke Energy Carolinas knew that the river was used for recreational purposes, did not adequately warn about the dam, and created a dangerous and hidden hazard on the Dan River in building and maintaining the low-head dam. In 2023, Duke Energy Carolinas reached an agreement that resolved this matter. The resolution, which did not have a material financial impact, was approved by the Durham County Superior Court. The case was dismissed on June 6, 2023.

NTE Carolinas II, LLC Litigation

In November 2017, Duke Energy Carolinas entered into a standard FERC large generator interconnection agreement (LGIA) with NTE Carolinas II, LLC (NTE), a company that proposed to build a combined-cycle natural gas plant in Rockingham County, North Carolina. On September 6, 2019, Duke Energy Carolinas filed a lawsuit in Mecklenburg County Superior Court against NTE for breach of contract, alleging that NTE's failure to pay benchmark payments for Duke Energy Carolinas' transmission system upgrades required under the interconnection agreement constituted a termination of the interconnection agreement. Duke Energy Carolinas sought a monetary judgment against NTE because NTE failed to make multiple milestone payments. The lawsuit was moved to federal court in North Carolina. NTE filed a motion to dismiss Duke Energy Carolinas' complaint and brought counterclaims alleging anti-competitive conduct and violations of state and federal statutes. Duke Energy Carolinas filed a motion to dismiss NTE's counterclaims. Both NTE's and Duke Energy Carolinas' motions to dismiss were subsequently denied by the court.

On May 21, 2020, in response to a NTE petition challenging Duke Energy Carolinas' termination of the LGIA, FERC issued a ruling that 1) it has exclusive jurisdiction to determine whether a transmission provider may terminate a LGIA; 2) FERC approval is required to terminate a conforming LGIA if objected to by the interconnection customer; and 3) Duke Energy may not announce the termination of a conforming LGIA unless FERC has approved the termination. FERC's Office of Enforcement also initiated an investigation of Duke Energy Carolinas into matters pertaining to the LGIA. On April 6, 2023, Duke Energy Carolinas received notice from the FERC Office of Enforcement that they have closed their non-public investigation with no further action recommended.

Following completion of discovery, Duke Energy Carolinas filed a motion for summary judgment seeking a ruling in its favor as to some of its affirmative claims against NTE and to all of NTE's counterclaims. On June 24, 2022, the court issued an order partially granting Duke Energy Carolinas' motion by dismissing NTE's counterclaims that Duke Energy Carolinas engaged in anti-competitive behavior in violation of state and federal statutes. On October 12, 2022, the parties executed a settlement agreement with respect to the remaining breach of contract claims in the litigation and a Stipulation of Dismissal was filed with the court on October 13, 2022. On November 11, 2022, NTE filed its Notice of Appeal to the U.S. Court of Appeals for the Fourth Circuit as to the District Court's summary judgment ruling in Duke Energy Carolinas' favor on NTE's antitrust and unfair competition claims. Briefing on NTE's appeal was completed on June 30, 2023. Oral Argument has been tentatively set for May 7-10, 2024. Duke Energy Carolinas cannot predict the outcome of this matter.

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.

Duke Energy Carolinas has recognized asbestos-related reserves of $423 million and $457 million at December 31, 2023, and 2022, 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 2043 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 2043 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. Receivables for insurance recoveries were $572 million and $595 million at December 31, 2023, and 2022, respectively. These amounts are classified in Other within Other Noncurrent Assets and Receivables within Current Assets on the Consolidated Balance Sheets. Any future payments up to the policy limit will be reimbursed by the third-party insurance carrier. 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.

The reserve for credit losses for insurance receivables for the asbestos-related injuries and damages is $9 million as of December 31, 2023, and $12 million as of December 31, 2022, for both Duke Energy and Duke Energy Carolinas. The insurance receivable is evaluated based on the risk of default and the historical losses, current conditions and expected conditions around collectability. Management evaluates the risk of default annually based on payment history, credit rating and changes in the risk of default from credit agencies.

Duke Energy Indiana

Coal Ash Insurance Coverage Litigation

In June 2022, Duke Energy Indiana filed a civil action in Indiana Superior Court against various insurance companies seeking declaratory relief with respect to insurance coverage for CCR-related expenses and liabilities covered by third-party liability insurance policies. The insurance policies cover the 1969-1972 and 1984-1985 periods and provide third-party liability insurance for claims and suits alleging property damage, bodily injury and personal injury (or a combination thereof). A trial date has not yet been set. On June 30, 2023, Duke Energy Indiana and Associated Electric and Gas Insurance Services (AEGIS) reached a confidential settlement, the results of which were not material to Duke Energy, and as a result, AEGIS was dismissed from the litigation on July 13, 2023. On December 11, 2023, Duke Energy Indiana and Munich Reinsurance America, Inc. (formerly known as American Re-Insurance Company) (AmRe) reached a confidential settlement, the results of which were not material, and AmRe was dismissed from the litigation on January 18, 2024. The lawsuit remains pending as to the other insurers, but is stayed until March 31, 2024, to allow for further settlement negotiations with other defendants. Duke Energy Indiana cannot predict the outcome of this matter.

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 for the years presented. Reserves are classified on the Consolidated Balance Sheets in Other within Other Noncurrent Liabilities and Other within Current Liabilities.

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. However, the Duke Energy Registrants do not believe these guarantees will have a material effect on their results of operations, cash flows or financial position. See Note 8 for more information.

Purchase Obligations

Purchased Power

Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana 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, 2023						
(in millions)	Contract Expiration	2024	2025	2026	2027	2028	Thereafter	Total
Duke Energy Progress[a]	2026-2032	$ 21	$ 22	$ 18	$ 19	$ 19	$ 7	$ 106
Duke Energy Florida[b]	2025	86	91	—	—	—	—	177
Duke Energy Ohio[c]	2025	153	98	—	—	—	—	251
Duke Energy Indiana[c]	2026	12	20	8	—	—	—	40

(a) Contracts represent between 18% and 100% of net plant output.
(b) Contracts represent 100% of net plant output.
(c) Share of net plant output varies. Duke Energy Ohio excludes PPA with OVEC.

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 specific fuel rate components operating in conjunction with PGA procedures, and subject to periodic prudence reviews in North Carolina and South Carolina and the Performance Incentive Plan in Tennessee. In the Midwest, these costs are recovered via the Gas Cost Recovery Rate in Ohio or the Gas Cost Adjustment Clause in Kentucky. The time periods for fixed payments under pipeline and storage capacity contracts are up to 19 years. The time periods for fixed payments under natural gas supply contracts is up to two years. The time period for the natural gas supply purchase commitments is up to seven 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, 2023.

(in millions)	2024	2025	2026	2027	2028	Thereafter	Total
Duke Energy Ohio	$ 103	$ 87	$ 57	$ 53	$ 51	$ 574	$ 925
Piedmont	295	287	268	209	186	373	1,618

6. LEASES

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, the failed sale-leaseback obligation is reported 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.

Piedmont has certain agreements with Duke Energy Carolinas for the construction and transportation of natural gas pipelines to supply its natural gas plant needs. Piedmont accounts for these pipeline lateral contracts as sales-type leases since the present value of the sum of the lease payments equals the fair value of the assets. These pipeline lateral assets owned by Piedmont had a current net investment basis of $2 million as of December 31, 2023, and 2022, and a long-term net investment basis of $199 million and $201 million as of December 31, 2023, and 2022, respectively. 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 contracts as finance leases. The activity for these contracts is eliminated in consolidation at Duke Energy.

The following tables present the components of lease expense.

	Year Ended December 31, 2023							
(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]	$ 236	$ 41	$ 157	$ 80	$ 77	$ 11	$ 17	$ 2
Short-term lease expense[a]	5	—	2	1	1	—	1	—
Variable lease expense[a]	27	2	22	11	11	—	—	1
Finance lease expense								
Amortization of leased assets[b]	160	7	57	35	22	—	—	—
Interest on lease liabilities[b]	46	31	45	43	2	—	1	—
Total finance lease expense	206	38	102	78	24	—	1	—
Total lease expense	$ 474	$ 81	$ 283	$ 170	$ 113	$ 11	$ 19	$ 3

(in millions)		Year Ended December 31, 2022						
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Operating lease expense[(a)]	$ 229	$ 39	$ 153	$ 83	$ 70	$ 10	$ 19	$ 6
Short-term lease expense[(a)]	4	—	1	—	1	—	2	—
Variable lease expense[(a)]	61	(1)	60	37	23	—	—	1
Finance lease expense								
Amortization of leased assets[(b)]	151	6	61	41	20	—	—	—
Interest on lease liabilities[(c)]	50	32	49	45	4	—	1	—
Total finance lease expense	201	38	110	86	24	—	1	—
Total lease expense	$ 495	$ 76	$ 324	$ 206	$ 118	$ 10	$ 22	$ 7

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

(in millions)	December 31, 2023							
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
2024	$ 244	$ 21	$ 116	$ 66	$ 60	$ 2	$ 7	$ 5
2025	214	18	102	42	60	2	7	4
2026	201	15	105	46	59	2	6	1
2027	170	9	79	47	32	2	5	—
2028	136	8	67	47	20	1	4	—
Thereafter	388	41	315	153	152	13	39	—
Total operating lease payments	1,353	110	784	401	383	22	68	10
Less: Present value discount	(248)	(20)	(146)	(63)	(83)	(5)	(16)	—
Total operating lease liabilities[(a)]	$ 1,105	$ 90	$ 638	$ 338	$ 300	$ 17	$ 52	$ 10

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

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

(in millions)	December 31, 2023					
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana
2024	$ 157	$ 38	$ 88	$ 79	$ 8	$ 1
2025	88	38	85	80	5	1
2026	83	38	86	81	6	1
2027	76	38	83	81	2	1
2028	74	38	81	81	—	1
Thereafter	511	389	474	474	—	21
Total finance lease payments	989	579	897	876	21	26
Less: Amounts representing interest	(350)	(302)	(326)	(324)	(2)	(17)
Total finance lease liabilities	$ 639	$ 277	$ 571	$ 552	$ 19	$ 9

The following tables contain additional information related to leases.

(in millions)	Classification	December 31, 2023							
		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	$ 1,092	$ 78	$ 617	$ 318	$ 299	$ 16	$ 50	$ 4
Finance	Net property, plant and equipment	687	268	615	552	63	—	6	—
Total lease assets		$ 1,779	$ 346	$ 1,232	$ 870	$ 362	$ 16	$ 56	$ 4
Liabilities									
Current									
Operating	Other current liabilities	$ 188	$ 15	$ 94	$ 45	$ 49	$ 1	$ 6	$ —
Finance	Current maturities of long-term debt	115	8	46	38	8	—	—	—
Noncurrent									
Operating	Operating lease liabilities	917	75	544	293	251	16	46	10
Finance	Long-Term Debt	524	269	525	514	11	—	9	—
Total lease liabilities		$ 1,744	$ 367	$ 1,209	$ 890	$ 319	$ 17	$ 61	$ 10

(in millions)	Classification	December 31, 2022							
		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	$ 1,042	$ 78	$ 628	$ 370	$ 258	$ 18	$ 49	$ 4
Finance	Net property, plant and equipment	810	284	674	590	84	—	6	—
Total lease assets		$ 1,852	$ 362	$ 1,302	$ 960	$ 342	$ 18	$ 55	$ 4
Liabilities									
Current									
Operating	Other current liabilities	$ 179	$ 14	$ 96	$ 61	$ 45	$ 1	$ 4	$ —
Finance	Current maturities of long-term debt	153	7	57	35	22	—	—	—
Noncurrent									
Operating	Operating lease liabilities	876	83	546	335	211	17	47	13
Finance	Long-Term Debt	611	277	571	552	19	—	9	—
Total lease liabilities		$ 1,819	$ 381	$ 1,270	$ 973	$ 297	$ 18	$ 60	$ 13

(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, 2023							
Cash paid for amounts included in the measurement of lease liabilities[(a)]								
Operating cash flows from operating leases	$ 228	$ 18	$ 123	$ 64	$ 59	$ 2	$ 7	$ —
Operating cash flows from finance leases	48	31	48	43	2	—	1	—
Financing cash flows from finance leases	169	7	57	35	22	—	—	—
Lease assets obtained in exchange for new lease liabilities (non-cash)								
Operating	$ 296	$ 14	$ 92	$ 1	$ 91	$ 2	$ 6	$ 2
Finance	38	—	—	—	—	—	—	—

(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, 2022							
Cash paid for amounts included in the measurement of lease liabilities[(a)]								
Operating cash flows from operating leases	$ 230	$ 24	$ 118	$ 63	$ 55	$ 2	$ 6	$ 4
Operating cash flows from finance leases	50	32	49	45	4	—	1	—
Financing cash flows from finance leases	151	6	61	41	20	—	—	—
Lease assets obtained in exchange for new lease liabilities (non-cash)								
Operating	$ 111	$ 10	$ —	$ —	$ —	$ —	$ —	—
Finance	—	—	—	—	—	—	—	—

(a) No amounts were classified as investing cash flows from operating leases.

	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2023							
Weighted average remaining lease term (years)								
Operating leases	9	10	10	9	11	13	13	4
Finance leases	11	18	11	11	18	—	22	3
Weighted average discount rate[(a)]								
Operating leases	3.1 %	4.8 %	3.8 %	3.5 %	4.0 %	4.2 %	3.9 %	2.4 %
Finance leases	8.5 %	11.5 %	9.1 %	9.2 %	7.8 %	— %	11.9 %	5.4 %

	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2022							
Weighted average remaining lease term (years)								
Operating leases	8	10	8	9	8	15	15	1
Finance leases	10	17	12	12	12	—	23	—
Weighted average discount rate[(a)]								
Operating leases	3.4 %	3.8 %	3.6 %	3.5 %	3.8 %	4.2 %	4.0 %	3.3 %
Finance leases	7.7 %	11.5 %	9.1 %	9.1 %	8.0 %	— %	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.

(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
	December 31, 2023								
Unsecured debt, maturing 2024-2082	4.36 %	$ 39,436	$ 1,156	$ 1,800	$ —	$ 150	$ 1,155	$ 393	$ 3,695
Secured debt, maturing 2024-2052	4.23 %	4,292	1,441	2,379	1,121	1,258	—	—	—
First mortgage bonds, maturing 2025-2073[(a)]	4.18 %	37,443	12,955	18,550	9,475	9,076	2,300	3,638	—
Finance leases, maturing 2024-2051[(b)]		639	277	671	652	19	—	9	—
Tax-exempt bonds, maturing 2027-2046[(c)]	3.89 %	1,331	—	500	500	—	77	352	—
Notes payable and commercial paper[(d)]	5.58 %	4,925	—	—	—	—	—	—	—
Money pool/intercompany borrowings		—	968	1,193	1,041	152	638	487	538
Fair value hedge carrying value adjustment		32	—	—	—	—	—	—	—
Unamortized debt discount and premium, net[(e)]		916	(29)	(46)	(24)	(20)	(24)	(18)	(8)
Unamortized debt issuance costs[(f)]		(383)	(82)	(145)	(68)	(81)	(15)	(25)	(19)
Total debt	4.35 %	$ 79,549	$ 16,650	$ 24,802	$ 12,605	$ 10,653	$ 4,131	$ 4,758	$ 4,206
Short-term notes payable and commercial paper		(4,298)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	(868)	(1,043)	(891)	(152)	(613)	(256)	(538)
Current maturities of long-term debt[(g)]		(2,800)	(19)	(661)	(72)	(689)	—	(4)	(40)
Total long-term debt[(g)]		$ 72,452	$ 15,993	$ 23,098	$ 11,642	$ 9,812	$ 3,518	$ 4,498	$ 3,628

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $63 million of finance lease purchase accounting adjustments related to Duke Energy Florida 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 23 days.
(e) Duke Energy includes $992 million and $69 million in purchase accounting adjustments related to Progress Energy and Piedmont, respectively.
(f) Duke Energy includes $25 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.

(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
	December 31, 2022								
Unsecured debt, maturing 2023-2082	4.20 %	$ 29,585	$ 1,150	$ 2,600	$ —	$ 950	$ 1,330	$ 697	$ 3,390
Secured debt, maturing 2023-2052	3.70 %	4,118	1,317	2,383	1,155	1,228	—	—	—
First mortgage bonds, maturing 2023-2052[(a)]	3.89 %	32,645	11,308	18,350	8,776	7,576	1,850	3,138	—
Finance leases, maturing 2024-2051[(b)]		764	284	628	587	41	—	9	—
Tax-exempt bonds, maturing 2027-2046[(c)]	3.84 %	1,331	—	500	500	—	77	352	—
Notes payable and commercial paper[(d)]	4.50 %	4,582	—	—	—	—	—	—	—
Money pool/intercompany borrowings		—	1,533	993	389	605	522	585	514
Fair value hedge carrying value adjustment		(5)	—	—	—	—	—	—	—
Unamortized debt discount and premium, net[(e)]		1,016	(21)	(40)	(23)	(16)	(25)	(17)	(9)
Unamortized debt issuance costs[(f)]		(331)	(70)	(132)	(59)	(70)	(12)	(22)	(18)
Total debt	4.07 %	$ 73,703	$ 15,499	$ 23,282	$ 11,325	$ 10,314	$ 3,742	$ 4,742	$ 3,877
Short-term notes payable and commercial paper		(3,852)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	(1,233)	(843)	(238)	(605)	(497)	(435)	(514)
Current maturities of long-term debt[(g)]		(3,878)	(1,018)	(697)	(369)	(328)	(475)	(303)	(45)
Total long-term debt[(g)]		$ 65,873	$ 13,248	$ 21,742	$ 10,718	$ 9,381	$ 2,770	$ 4,004	$ 3,318

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $164 million of finance lease purchase accounting adjustments related to Duke Energy Florida 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 15 days.
(e) Duke Energy includes $1,057 million and $85 million in purchase accounting adjustments related to Progress Energy and Piedmont, respectively.
(f) Duke Energy includes $27 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, 2023
Unsecured Debt			
Duke Energy (Parent) Term Loan Facility[(a)]	March 2024	6.157 %	1,000
Duke Energy (Parent)	April 2024	3.750 %	1,000
First Mortgage Bonds			
Duke Energy Florida[(b)]	October 2073	4.960 %	200
Other[(c)]			600
Current maturities of long-term debt			$ 2,800

(a) Debt has a floating interest rate. In January 2024, Duke Energy (Parent) repaid the Term Loan Facility due March 2024.
(b) While final maturity is October 2073, these first mortgage bonds are classified as Current maturities of long-term debt on the Consolidated Balance Sheets beginning December 31, 2023, based on terms of the indenture, which could require repayment in less than 12 months if exercised by the bondholders.
(c) Includes finance lease obligations, amortizing debt, tax-exempt bonds with mandatory put options 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.

(in millions)	Duke Energy[(a)]	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2023							
2024	$ 2,800	$ 19	$ 664	$ 72	$ 592	$ —	$ 4	$ 40
2025	4,177	521	1,040	975	65	245	4	206
2026	4,289	623	345	279	66	45	4	40
2027	2,472	25	797	83	714	77	27	300
2028	4,583	1,276	1,551	737	815	65	157	—
Thereafter	56,376	13,659	19,543	9,652	8,239	3,125	4,347	3,110
Total long-term debt, including current maturities	$ 74,697	$ 16,123	$ 23,940	$ 11,798	$ 10,491	$ 3,657	$ 4,543	$ 3,696

(a) Excludes $1,086 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.

(in millions)	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Ohio	Duke Energy Indiana
	December 31, 2023 and 2022				
Tax-exempt bonds	$ 312	$ —	$ —	$ 27	$ 285
Commercial paper[(a)]	625	300	150	25	150
Total	$ 937	$ 300	$ 150	$ 52	$ 435

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

Summary of Significant Debt Issuances

In January 2024, Duke Energy Corporation issued $1.25 billion of senior unsecured notes. The issuance was split between a $600 million, three-year tranche and a $650 million, five-year tranche, both at a fixed rate of 4.85%. The net proceeds were used to repay Duke Energy (Parent)'s $1 billion Term Loan Facility due March 2024, pay off short-term debt and for general corporate purposes.

In January 2024, Duke Energy Carolinas issued $1 billion of first mortgage bonds. The issuance consisted of a $575 million, 10-year tranche at 4.85% and a $425 million, 30-year tranche at 5.40%. The net proceeds were used to pay off short-term debt and for general company purposes.

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

Issuance Date	Maturity Date	Interest Rate	Year Ended December 31, 2023 Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unsecured Debt										
April 2023(a)	April 2026	4.125 %	$ 1,725	$ 1,725	$ —	$ —	$ —	$ —	$ —	$ —
June 2023(b)	June 2033	5.400 %	350	—	—	—	—	—	—	350
September 2023(c)	September 2033	5.750 %	600	600	—	—	—	—	—	—
September 2023(c)	September 2053	6.100 %	750	750	—	—	—	—	—	—
First Mortgage Bonds										
January 2023(d)	January 2033	4.950 %	900	—	900	—	—	—	—	—
January 2023(d)	January 2053	5.350 %	900	—	900	—	—	—	—	—
March 2023(e)	March 2033	5.250 %	500	—	—	500	—	—	—	—
March 2023(e)	March 2053	5.350 %	500	—	—	500	—	—	—	—
March 2023(f)	April 2033	5.250 %	375	—	—	—	—	375	—	—
March 2023(f)	April 2053	5.650 %	375	—	—	—	—	375	—	—
March 2023(g)	April 2053	5.400 %	500	—	—	—	—	—	500	—
June 2023(h)	January 2033	4.950 %	350	—	350	—	—	—	—	—
June 2023(h)	January 2054	5.400 %	500	—	500	—	—	—	—	—
September 2023(i)	October 2073	4.960 %	200	—	—	—	200	—	—	—
November 2023(i)	November 2033	5.875 %	600	—	—	—	600	—	—	—
November 2023(i)	November 2053	6.200 %	700	—	—	—	700	—	—	—
Total issuances			$ 9,825	$ 3,075	$ 2,650	$ 1,000	$ 1,500	$ 750	$ 500	$ 350

(a) See "Duke Energy (Parent) Convertible Senior Notes" below for additional information.
(b) Debt issued to repay $45 million of maturities due October 2023, to pay down a portion of short-term debt and for general corporate purposes.
(c) Debt issued to repay $400 million of maturities due October 2023, to pay down a portion of short-term debt and for general corporate purposes.
(d) Debt issued to repay $1 billion of maturities due March 2023, to pay down a portion of short-term debt and for general company purposes.
(e) Debt issued to repay $300 million of maturities due September 2023, to pay down a portion of short-term debt and for general company purposes.
(f) Debt issued to repay $300 million of maturities due September 2023, to pay down a portion of the $100 million Duke Energy Ohio Term Loan due October 2023, to repay a portion of short-term debt and for general corporate purposes.
(g) Debt issued to repay the $300 million Duke Energy Indiana Term Loan due October 2023, to pay down a portion of short-term debt and for general company purposes.
(h) Debt issued to pay down a portion of short-term debt and for general company purposes.
(i) Debt issued to repay the $800 million Duke Energy Florida Term Loan due April 2024, to pay down a portion of short-term debt and for general company purposes.

Issuance Date	Maturity Date	Interest Rate	Year Ended December 31, 2022 Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Piedmont
Unsecured Debt								
May 2022(a)	May 2052	5.050 %	$ 400	$ —	$ —	$ —	$ —	$ 400
June 2022(b)	June 2028	4.750 %	645	645	—	—	—	—
June 2022(b)	June 2034	5.306 %	537	537	—	—	—	—
August 2022(c)	March 2028	4.300 %	900	900	—	—	—	—
August 2022(c)	August 2032	4.500 %	1,150	1,150	—	—	—	—
August 2022(c)	August 2052	5.000 %	1,150	1,150	—	—		—
December 2022(d)	December 2025	5.000 %	500	500	—	—		—
December 2022(c)	December 2027	5.000 %	500	500	—	—	—	—
First Mortgage Bonds								
March 2022(d)	March 2032	2.850 %	500	—	500	—	—	—
March 2022(d)	March 2052	3.550 %	650	—	650	—	—	—
March 2022(a)	April 2032	3.400 %	500	—	—	500	—	—
March 2022(d)	April 2052	4.000 %	400	—	—	400	—	—
November 2022(e)	November 2052	5.950 %	500	—	—	—	500	—
Tax-exempt Bonds			—	—	—	—		—
June 2022(f)	September 2030	4.000 %	168	168	—	—	—	—
June 2022(f)	November 2039	4.250 %	234	234	—	—	—	—
September 2022(g)	October 2046	3.300 %	200	—	—	200		—
September 2022(h)	October 2046	3.700 %	210	—	—	210		—
September 2022(h)	October 2046	4.000 %	42	—	—	42		—
Total issuances			$ 9,186	$ 5,784	$ 1,150	$ 1,352	$ 500	$ 400

(a) Debt issued to repay a portion of short-term debt and for general corporate purposes.
(b) Duke Energy (Parent) issued 600 million euros aggregate principal amount of 3.10% senior notes due June 2028 and 500 million euros aggregate principal amount of 3.85% senior notes due June 2034. Debt issued to repay a $500 million debt maturity, pay down a portion of short-term debt and for general corporate purposes. Duke Energy's obligations under its euro-denominated fixed-rate notes were effectively converted to fixed-rate U.S. dollars at issuance through cross-currency swaps, mitigating foreign currency exchange risk associated with the interest and principal payments. See Note 15 for additional information.
(c) Debt issued to repay a portion of short-term debt and for general corporate purposes.
(d) Debt issued to finance or refinance, in whole or in part, existing or new eligible projects under the sustainable financing framework.
(e) Debt issued to repay a portion of short-term debt and for general company purposes.
(f) Debt issued to refund the Ohio Air Quality Development Revenue Refunding bonds, previously held in treasury, which were used to finance or refinance portions of certain solid waste disposal facilities. The mandatory purchase date of these bonds is June 1, 2027.
(g) Debt issued to provide funds to refund the prior bonds, which were used to finance or refinance portions of certain air and water pollution control equipment and solid waste disposal equipment. The mandatory purchase date of these bonds is October 1, 2026.
(h) Debt issued to provide funds to refund the prior bonds, which were used to finance or refinance portions of certain air and water pollution control equipment and solid waste disposal equipment. The mandatory purchase date of these bonds is October 1, 2030.

Duke Energy (Parent) Convertible Senior Notes

In April 2023, Duke Energy (Parent) completed the sale of $1.7 billion 4.125% Convertible Senior Notes due April 2026 (convertible notes). The convertible notes are senior unsecured obligations of Duke Energy, and will mature on April 15, 2026, unless earlier converted or repurchased in accordance with their terms. The convertible notes bear interest at a fixed rate of 4.125% per year, payable semiannually in arrears on April 15 and October 15 of each year, beginning on October 15, 2023. Proceeds were used to repay a portion of outstanding commercial paper and for general corporate purposes.

Prior to the close of business on the business day immediately preceding January 15, 2026, the convertible notes will be convertible at the option of the holders when the following conditions are met:

- during any calendar quarter commencing after the calendar quarter ending on June 30, 2023, (and only during such calendar quarter) if the last reported sale price of Duke Energy common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day;
- during the five consecutive business day period after any 10 consecutive trading day period (the measurement period) in which the trading price, as defined, per $1,000 principal amount of notes for each trading day of the measurement period was less than 98% of the product of the last reported sale price of Duke Energy common stock and the conversion rate on each such trading day; or
- upon the occurrence of specified corporate events described in the indenture agreement.

On or after January 15, 2026, until the close of business on the second scheduled trading day immediately preceding the maturity date, holders of the convertible notes may convert all or any portion of their convertible notes at their option at any time at the conversion rate then in effect, irrespective of these conditions. Duke Energy will settle conversions of the convertible notes by paying cash up to the aggregate principal amount of the convertible notes to be converted and paying or delivering, as the case may be, cash, shares of Duke Energy's common stock, $0.001 par value per share, or a combination of cash and shares of its common stock, at its election, in respect of the remainder, if any, of its conversion obligation in excess of the aggregate principal amount of the convertible notes being converted.

The conversion rate for the convertible notes is initially 8.4131 shares of Duke Energy's common stock per $1,000 principal amount of convertible notes. The initial conversion price of the convertible notes represents a premium of approximately 25% over the last reported sale price of Duke Energy's common stock on the NYSE on April 3, 2023. The conversion rate and the corresponding conversion price will not be adjusted for any accrued and unpaid interest but will be subject to adjustment in some instances, such as stock splits or share combinations, certain distributions to common stockholders, or tender offers at off-market rates. The changes in the conversion rates are intended to make convertible note holders whole for changes in the fair value of Duke Energy common stock resulting from such events. Duke Energy may not redeem the convertible notes prior to the maturity date.

Duke Energy issued the convertible notes pursuant to an indenture, dated as of April 6, 2023, by and between Duke Energy and The Bank of New York Mellon Trust Company, N.A., as trustee. The terms of the convertible notes include customary fundamental change provisions that require repayment of the notes with interest upon certain events, such as a stockholder approved plan of liquidation or if Duke Energy's common stock ceases to be listed on the NYSE.

AVAILABLE CREDIT FACILITIES

Master Credit Facility

In March 2023, Duke Energy amended its existing Master Credit Facility of $9 billion to extend the termination date to March 2028. 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. An amendment in conjunction with the issuance of the Convertible Senior Notes due April 2026 clarifies that payments due as a result of a conversion of a convertible note would not constitute an event of default.

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

(in millions)	Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2023							
Facility size[(a)]	$ 9,000	$ 2,275	$ 1,575	$ 1,400	$ 950	$ 1,050	$ 950	$ 800
Reduction to backstop issuances								
Commercial paper[(b)]	(3,941)	(198)	(968)	(1,041)	(152)	(638)	(406)	(538)
Outstanding letters of credit	(39)	(27)	(4)	(1)	(7)	—	—	—
Tax-exempt bonds	(81)	—	—	—	—	—	(81)	—
Available capacity	$ 4,939	$ 2,050	$ 603	$ 358	$ 791	$ 412	$ 463	$ 262

(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.

Duke Energy (Parent) Term Loan Facility

In March 2022, Duke Energy (Parent) entered into a Term Loan Credit Facility (facility) with commitments totaling $1.4 billion maturing March 2024. Borrowings under the facility were used to repay amounts drawn under the Three-Year Revolving Credit Facility and for general corporate purposes, including repayment of a portion of Duke Energy's outstanding commercial paper. The Three-Year Revolving Credit Facility was terminated in March 2022. In December 2022, Duke Energy (Parent) repaid $400 million of the facility. In January 2024, Duke Energy (Parent) repaid the remaining $1 billion outstanding on the facility, which was classified as Current maturities of long-term debt on Duke Energy's Consolidated Balance Sheets as of December 31, 2023.

Other Debt Matters

In September 2022, 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, including preferred stock, 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.

Also in September 2022, to replace another similar prior filing, Duke Energy filed an effective Form S-3 with the SEC to sell up to $4 billion of variable denomination floating-rate demand notes, called PremierNotes. The Form S-3 states that no more than $2 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, 2023, and 2022, was $965 million and $897 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 and Intercompany Credit Agreements

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 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.

In March 2022, Progress Energy closed a revolving credit agreement with Duke Energy (Parent), which allowed up to $2.5 billion in intercompany borrowings.

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, 2023, each of the Duke Energy Registrants were in compliance with all covenants related to their debt agreements. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

Other Loans

As of December 31, 2023, and 2022, Duke Energy had loans outstanding of $873 million, including $32 million at Duke Energy Progress and $852 million, including $33 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 and include guarantees and indemnifications related to Commercial Renewables Disposal Groups as described in Note 2. 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, 2023, 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 Energy Capital, LLC (Spectra Capital) or its affiliates prior to the spin-off remained with Spectra Capital subsequent to the spin-off, except for guarantees that were later assigned to Duke Energy. Duke Energy has indemnified Spectra Capital against any losses incurred under certain of the guarantee obligations that remain with Spectra Capital. At December 31, 2023, the maximum potential amount of future payments associated with these guarantees were $33 million, the majority of which expire 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. In July 2020, ACP reduced the size of the credit facility to $1.9 billion. Duke Energy's maximum exposure to loss under the terms of the guarantee was $860 million as of December 31, 2020. This amount represented 47% of the outstanding borrowings under the credit facility and was recognized within Other Current Liabilities on the Consolidated Balance Sheets at December 31, 2020, of which $95 million was previously recognized due the adoption of new guidance for credit losses effective January 1, 2020. In February 2021, Duke Energy paid approximately $855 million to fund ACP's outstanding debt, relieving Duke Energy of its guarantee.

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, 2023, was $28 million of which all expire between 2024 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, 2023, Duke Energy had issued a total of $411 million in letters of credit, which expire between 2024 and 2026. There are no unused amounts under these letters of credit.

Duke Energy recognized $2 million as of both December 31, 2023, and 2022, 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 and 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 EU&I segment.

(in millions except for ownership interest)	Ownership Interest	Property, Plant and Equipment	Accumulated Depreciation	Construction Work in Progress
	December 31, 2023			
Duke Energy Carolinas				
Catawba (units 1 and 2)[(a)]	19.25 %	$ 976	$ 559	$ 42
W.S. Lee CC[(b)]	87.27 %	654	88	2
Duke Energy Indiana				
Gibson (unit 5)[(c)]	50.05 %	468	263	4
Vermillion[(d)]	62.50 %	183	119	—
Transmission and local facilities[(c)]	Various	7,252	1,578	189

(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 amount spent may be higher than the amount accrued and result in a net asset. 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.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2023							
Decommissioning of nuclear power facilities	$ 4,576	$ 1,949	$ 2,601	$ 2,410	$ 191	$ —	$ —	$ —
Closure of ash impoundments	4,313	2,810	1,449	1,427	21	73	781	—
Other	267	54	95	33	63	63	28	26
Total asset retirement obligation	$ 9,156	$ 4,813	$ 4,146	$ 3,870	$ 275	$ 136	$ 809	$ 26
Less: Current portion	596	224	246	244	1	6	120	—
Total noncurrent asset retirement obligation	$ 8,560	$ 3,789	$ 3,900	$ 3,626	$ 274	$ 130	$ 689	$ 26

Nuclear Decommissioning Liability

AROs related to nuclear decommissioning are based on site-specific cost studies. The NCUC and the PSCSC require Duke Energy Carolinas and Duke Energy Progress update cost estimates for decommissioning their nuclear plants every five years. The nuclear decommissioning liabilities are assessed and updated based on changes in cash flows provided in new studies as well as annual assessments to evaluate whether any indicators suggest a change in the estimate of the ARO is necessary.

The following table summarizes information about the most recent site-specific nuclear decommissioning cost studies. Decommissioning costs are stated in 2023 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[b]	Year of Cost Study
Duke Energy	$ 4	$ 8,814	2023 or 2019
Duke Energy Carolinas[b][c]	—	4,439	2023
Duke Energy Progress[d]	4	4,181	2019
Duke Energy Florida[e]	—	194	N/A

(a) Amount represents annual funding requirement for the current fiscal year. Amounts for Progress Energy equal the sum of Duke Energy Progress and Duke Energy Florida.
(b) Decommissioning costs 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 2023 was filed with the NCUC and PSCSC in 2024. A funding study was last completed and filed in 2019. An updated funding study will be completed and filed with the NCUC and PSCSC in 2024.
(d) Duke Energy Progress' site-specific nuclear decommissioning cost study completed in 2019 was filed with the NCUC and PSCSC in March 2020. Duke Energy Progress also completed a funding study, which was filed with the NCUC and PSCSC in July 2020. In October 2021, Duke Energy Progress filed the 2019 nuclear decommissioning cost study with the FERC, as well as a revised rate schedule for decommissioning expense to be collected from wholesale customers. The FERC accepted the filing, as filed on December 9, 2021
(e) During 2019, Duke Energy Florida reached an agreement to transfer decommissioning work for Crystal River Unit 3 to a third party and decommissioning costs are based on the agreement with this third party rather than a cost study. Regulatory approval was received from the NRC and the FPSC in April 2020 and August 2020, respectively. Duke Energy Florida provides the FPSC periodic reports on the status and progress of decommissioning activities.

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 entered into an agreement with a third party to decommission 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)	2023	2022
Duke Energy	$ 8,851	$ 7,466
Duke Energy Carolinas	5,002	4,208
Duke Energy Progress	3,849	3,258

Nuclear Operating Licenses

As described in Note 4, Duke Energy Carolinas and Duke Energy Progress intend to seek renewal of operating licenses and 20-year license extensions for all of their nuclear stations. 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. During 2019, Duke Energy Florida entered into an agreement for the accelerated decommissioning of Crystal River Unit 3. Regulatory approval was received from the NRC and the FPSC in April 2020 and August 2020, respectively 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 2023 and 2022.

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 and Note 5 for additional information on commitments and contingencies.

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, 2021	$ 12,600	$ 5,301	$ 6,112	$ 5,675	$ 437	$ 136	$ 987	$ 22
Accretion expense[a]	501	242	229	215	14	6	30	1
Liabilities settled[b]	(680)	(234)	(334)	(228)	(106)	(13)	(98)	—
Liabilities incurred in the current year	22	—	18	—	18	—	5	—
Revisions in estimates of cash flows[c]	285	73	156	161	(5)	25	27	3
Balance at December 31, 2022	12,728	5,382	6,181	5,823	358	154	951	26
Accretion expense[a]	523	254	237	225	12	7	33	1
Liabilities settled[b]	(758)	(256)	(379)	(292)	(87)	(15)	(108)	—
Liabilities incurred in the current year	29	3	21	6	15	1	4	—
Revisions in estimates of cash flows[c]	(3,366)	(1,370)	(1,915)	(1,882)	(23)	(11)	(71)	(1)
Balance at December 31, 2023	$ 9,156	$ 4,013	$ 4,145	$ 3,870	$ 275	$ 136	$ 809	$ 26

(a) Substantially all accretion expense for the years ended December 31, 2023, and 2022, 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.
(c) The amounts recorded represent the discounted cash flows for estimated closure costs as evaluated on a site-by-site basis. The increases in 2022 primarily relate to higher unit costs associated with basin closure and routine maintenance. The decreases in 2023 primarily relate to lower discounted cash flows for decommissioning the nuclear power facilities due to changes in estimates and economic assumptions including discount rates, cost escalation rates and cash flow timing, as well as lower unit costs associated with basin closure, routine maintenance and beneficiation activities, as well as reduction in monitoring wells needed.

11. PROPERTY, PLANT AND EQUIPMENT

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

		December 31, 2023							
(in millions)	Average Remaining Useful Life (Years)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Land		$ 2,345	$ 581	$ 1,012	$ 502	$ 510	$ 242	$ 133	$ 352
Plant – Regulated									
Electric generation, distribution and transmission	40	129,985	48,107	57,436	33,171	24,265	7,243	17,199	—
Natural gas transmission and distribution	67	14,139	—	—	—	—	3,993	—	10,137
Other buildings and improvements	42	2,887	1,213	677	377	300	421	356	221
Nuclear fuel		3,303	1,866	1,437	1,437	—	—	—	—
Equipment	14	3,409	879	1,104	654	450	474	442	143
Construction in process		8,372	2,578	3,941	1,661	2,280	427	427	690
Other	12	6,920	1,455	2,037	1,481	556	419	344	363
Total property, plant and equipment[(a)]		171,351	56,670	67,644	39,283	28,353	13,210	18,900	11,906
Total accumulated depreciation – regulated[(b)(c)]		(54,323)	(19,896)	(22,300)	(15,227)	(7,067)	(3,451)	(6,501)	(2,259)
Total accumulated depreciation – other[(d)]		(1,715)	—	—	—	—	—	—	—
Facilities to be retired, net		2	—	—	—	—	—	—	2
Total net property, plant and equipment		$ 115,315	$ 36,774	$ 45,344	$ 24,056	$ 21,286	$ 9,759	$ 12,399	$ 9,649

(a) Includes finance leases of $697 million, $335 million, $615 million, $552 million, $63 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 $292 million, $119 million and $173 million, respectively, of accumulated amortization of finance leases.
(b) Includes $1,793 million, $991 million, $802 million and $802 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 $3 million, $67 million and $4 million at Duke Energy, Duke Energy Carolinas and Duke Energy Indiana, respectively.
(d) Includes accumulated amortization of finance leases of $7 million at Duke Energy

		December 31, 2022							
(in millions)	Average Remaining Useful Life (Years)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Land		$ 2,232	$ 565	$ 993	$ 496	$ 497	$ 230	$ 124	$ 295
Plant – Regulated									
Electric generation, distribution and transmission	39	126,016	46,640	55,872	33,336	22,536	6,900	16,604	—
Natural gas transmission and distribution	56	13,174	—	—	—	—	3,773	—	9,401
Other buildings and improvements	40	2,537	973	647	341	306	398	336	183
Nuclear fuel		3,081	1,723	1,358	1,358	—	—	—	—
Equipment	13	2,959	710	936	567	369	441	356	125
Construction in process		7,381	2,671	3,073	1,317	1,756	375	381	478
Other	13	6,459	1,368	1,943	1,460	476	380	320	387
Total property, plant and equipment[(a)]		163,839	54,650	64,822	38,875	25,940	12,497	18,121	10,869
Total accumulated depreciation – regulated[(b)(c)]		(50,544)	(18,669)	(20,584)	(14,201)	(6,377)	(3,250)	(6,021)	(2,081)
Total accumulated depreciation – other[(d)]		(1,556)	—	—	—	—	—	—	—
Facilities to be retired, net		9	—	—	—	—	—	—	9
Total net property, plant and equipment		$ 111,748	$ 35,981	$ 44,238	$ 24,674	$ 19,563	$ 9,247	$ 12,100	$ 8,797

(a) Includes finance leases of $818 million, $335 million, $674 million, $590 million, $84 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 $233 million, $81 million and $152 million, respectively, of accumulated amortization of finance leases.
(b) Includes $1,683 million, $934 million, $749 million and $749 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 $7 million, $51 million, and $4 million at Duke Energy, Duke Energy Carolinas and Duke Energy Indiana, respectively.
(d) Includes accumulated amortization of finance leases of ($1 million) at Duke Energy.

Duke Energy has continued to execute on its business transformation strategy, including the evaluation of in-office work policies considering the experience with the COVID-19 pandemic and also workforce realignment of roles and responsibilities. In May 2021, Duke Energy management approved the sale of certain properties and entered into an agreement to exit certain leased space on December 31, 2021. The sale of the properties was subject to abandonment accounting and resulted in an impairment charge. Additionally, the exit of the leased space resulted in the impairment of related furniture, fixtures and equipment. During the year ended December 31, 2021, Duke Energy recorded a pretax charge to earnings of $192 million on the Consolidated Statements of Operations, which includes $133 million within Impairment of assets and other charges, $42 million within Operations, maintenance and other and $17 million within Depreciation and amortization.

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

	Years Ended December 31,		
(in millions)	2023	2022	2021
Duke Energy	$ 201	$ 118	$ 66
Duke Energy Carolinas	62	50	29
Progress Energy	41	26	20
Duke Energy Progress	35	19	14
Duke Energy Florida	6	7	6
Duke Energy Ohio	16	14	20
Duke Energy Indiana[(a)]	21	3	(17)
Piedmont	8	4	9

(a) In 2021, Duke Energy Indiana is primarily compromised of ($24 million) of PISCC amortization, which is partially offset by $7 million of the debt component of AFUDC.

12. GOODWILL AND INTANGIBLE ASSETS

GOODWILL

Duke Energy

Duke Energy's Goodwill balance of $19.3 billion is allocated $17.4 billion to EU&I and $1.9 billion to GU&I on Duke Energy's Consolidated Balance Sheets at December 31, 2023, and 2022. There are no accumulated impairment charges.

Duke Energy Ohio

Duke Energy Ohio's Goodwill balance of $920 million, allocated $596 million to EU&I and $324 million to GU&I, is presented net of accumulated impairment charges of $216 million on the Consolidated Balance Sheets at December 31, 2023, and 2022.

Progress Energy

Progress Energy's Goodwill is included in the EU&I segment and there are no accumulated impairment charges.

Piedmont

Piedmont's Goodwill is included in the GU&I 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 2023.

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, 2023, and 2022.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2023							
Emission allowances	$ 8	$ —	$ 5	$ 2	$ 3	$ —	$ 2	$ —
Renewable energy certificates	232	97	133	133	—	2	—	—
Other	56	—	5	1	3	—	—	22
Total gross carrying amounts	296	97	143	136	6	2	2	22
Accumulated amortization – other	(14)	—	(3)	—	(3)	—	—	(6)
Total intangible assets, net	$ 282	$ 97	$ 140	$ 136	$ 3	$ 2	$ 2	$ 16

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2022							
Emission allowances	$ 8	$ —	$ 5	$ 2	$ 3	$ —	$ 2	$ —
Renewable energy certificates	210	84	124	124	—	2	—	—
Other	55	—	4	1	3	—	—	22
Total gross carrying amounts	273	84	133	127	6	2	2	22
Accumulated amortization – other	(8)	—	(1)	—	(1)	—	—	(2)
Total intangible assets, net	$ 265	$ 84	$ 132	$ 127	$ 5	$ 2	$ 2	$ 20

Amortization Expense

Amortization expense amounts for other intangible assets are immaterial for the years ended December 31, 2023, 2022 and 2021, and are expected to be immaterial for the next five years as of December 31, 2023.

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, for periods presented in this filing.

	Years Ended December 31,				
	2023		2022		2021
(in millions)	Investments	Equity in earnings	Investments	Equity in earnings	Equity in earnings
Electric Utilities and Infrastructure	$ 97	$ 7	$ 99	$ 7	$ 7
Gas Utilities and Infrastructure	259	40	240	21	8
Other	136	66	116	85	47
Total	$ 492	$ 113	$ 455	$ 113	$ 62

During the years ended December 31, 2023, 2022 and 2021, Duke Energy received distributions from equity investments of $50 million, $111 million and $56 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, 2023, 2022 and 2021, Duke Energy received distributions from equity investments of $16 million, $6 million and $14 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, 2023, 2022 and 2021, Piedmont received distributions from equity investments of $9 million, $31 million and $8 million, respectively, which are included in Other assets within Cash Flows from Operating Activities. During the years ended December 31, 2023, and 2021, Piedmont received distributions from equity investments of $1 million and $2 million, respectively, which are included within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows. Amounts received during the year ended December 31, 2022, included in Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows were immaterial.

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

Electric Utilities and Infrastructure

Duke Energy owns 50% interests in both DATC and Pioneer, which build, own and operate electric transmission facilities in North America.

Gas Utilities and Infrastructure

Pipeline Investments

Piedmont owns a 21.49% investment in Cardinal, an intrastate pipeline located in North Carolina.

Duke Energy owns a 7.5% interest in Sabal Trail, a 517-mile interstate natural gas pipeline, which provides natural gas to Duke Energy Florida and Florida Power and Light.

Storage Facilities

Piedmont owns a 45% interest in Pine Needle, an interstate LNG storage facility located in North Carolina, and a 50% interest in Hardy Storage, an underground interstate natural gas storage facility located in West Virginia.

Renewable Natural Gas Investments

Duke Energy owns a 29.68% investment in SustainRNG, a developer of renewable natural gas projects, a 70% interest in Sustain T&W, SustainRNG's renewable natural gas project located in Georgia, and a 70% interest in Sustain Liberty, SustainRNG's renewable natural gas project located in North Carolina.

Other

Duke Energy has a 17.5% indirect economic ownership interest and a 25% board representation and voting rights interest in NMC, which owns and operates a methanol and MTBE business in Jubail, Saudi Arabia.

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.

(in millions)		2023		2022		2021
		Years Ended December 31,				
Duke Energy Carolinas						
Corporate governance and shared service expenses[a]	$	823	$	838	$	894
Indemnification coverages[b]		34		28		24
JDA revenue[c]		34		109		41
JDA expense[c]		177		600		207
Intercompany natural gas purchases[d]		11		12		11
Progress Energy						
Corporate governance and shared service expenses[a]	$	736	$	818	$	856
Indemnification coverages[b]		47		43		41
JDA revenue[c]		177		600		207
JDA expense[c]		34		109		41
Intercompany natural gas purchases[d]		75		76		75
Duke Energy Progress						
Corporate governance and shared service expenses[a]	$	434	$	469	$	504
Indemnification coverages[b]		29		20		19
JDA revenue[c]		177		600		207
JDA expense[c]		34		109		41
Intercompany natural gas purchases[d]		75		76		75
Duke Energy Florida						
Corporate governance and shared service expenses[a]	$	302	$	349	$	352
Indemnification coverages[b]		27		23		22
Duke Energy Ohio						
Corporate governance and shared service expenses[a]	$	294	$	334	$	329
Indemnification coverages[b]		5		5		4
Duke Energy Indiana						
Corporate governance and shared service expenses[a]	$	366	$	447	$	409
Indemnification coverages[b]		8		8		8
Piedmont						
Corporate governance and shared service expenses[a]	$	149	$	155	$	139
Indemnification coverages[b]		4		3		3
Intercompany natural gas sales[d]		86		88		86
Natural gas storage and transportation costs[e]		24		23		22

(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, 2023														
Intercompany income tax receivable	$	—	$	—	$	—	$	—	$	91	$	53	$	—
Intercompany income tax payable		81		92		94		114		—		—		57
December 31, 2022														
Intercompany income tax receivable	$	—	$	95	$	36	$	17	$	—	$	—	$	—
Intercompany income tax payable		37		—		—		—		17		18		38

15. DERIVATIVES AND HEDGING

The Duke Energy Registrants use commodity, interest rate and foreign currency contracts to manage commodity price risk, interest rate risk and foreign currency exchange 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. Foreign currency derivatives are used to manage risk related to foreign currency exchange rates on certain issuances of debt.

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 or financing 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, 2023, 2022, and 2021, were not material. Duke Energy's interest rate derivatives designated as hedges include 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.

(in millions)		Duke Energy		Duke Energy Carolinas		Progress Energy		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio
		December 31, 2023												
Cash flow hedges	$	2,300	$	—	$	—	$	—	$	—	$	—	$	—
Undesignated contracts		2,727		1,850		1,250		925		325		400		27
Total notional amount	$	5,027	$	1,850	$	1,250	$	925	$	325	$	400	$	27

(in millions)		December 31, 2022 Duke Energy		Duke Energy Carolinas		Progress Energy		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio
Cash flow hedges	$	500	$	—	$	—	$	—	$	—	$	—	$	—
Undesignated contracts		2,377		1,250		800		500		300		300		27
Total notional amount	$	2,877	$	1,250	$	800	$	500	$	300	$	300	$	27

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 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. To manage risk associated with commodity prices, the Duke Energy Registrants may enter into long-term power purchase or sales contracts and long-term natural gas supply agreements.

Undesignated Contracts

For the Subsidiary Registrants, bulk power electricity 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 natural 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, 2023 Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Electricity (GWh)	13,608	—	—	—	1,616	11,992	—
Natural gas (millions of Dth)	846	279	274	274	—	38	283

	December 31, 2022 Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Electricity (GWh)	14,086	—	—	—	1,820	12,266	—
Natural gas (millions of Dth)	909	307	292	292	—	11	299

FOREIGN CURRENCY RISK

Duke Energy may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates, such as that arising from the issuance of debt denominated in a currency other than U.S. dollars.

Fair Value Hedges

Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings on the same income statement line item, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Duke Energy has elected to exclude the cross-currency basis spread from the assessment of effectiveness in the fair value hedges of its foreign currency risk and record any difference between the change in the fair value of the excluded components and the amounts recognized in earnings as a component of other comprehensive income or loss.

The following table shows Duke Energy's outstanding derivatives related to foreign currency risk. There were no fair value hedges in 2021.

		Pay Notional (in millions)	Pay Rate	Receive Notional (in millions)	Receive Rate	Hedge Maturity Date		Fair Value Gain (Loss)[a] (in millions) Years Ended December 31, 2023	2022
Fair value hedges									
	$	645	4.75 %	600 euros	3.10 %	June 2028	$	17	(3)
		537	5.31 %	500 euros	3.85 %	June 2034		15	(2)
Total notional amount	$	1,182		1,100 euros			$	32	(5)

(a) Amounts are recorded in Other income and expenses, net on the Consolidated Statement of Operations, which offsets an equal translation adjustment of the foreign denominated debt. See the Consolidated Statements of Comprehensive Income for amounts excluded from the assessment of effectiveness for which the difference between changes in fair value and periodic amortization is recorded.

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 (in millions)		December 31, 2023 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	$	25	$	1	$	3	$	1	$	2	$	1	$	18	$	1
Noncurrent		57		26		31		31		—		—		—		—
Total Derivative Assets – Commodity Contracts	$	82	$	27	$	34	$	32	$	2	$	1	$	18	$	1
Interest Rate Contracts																
Designated as Hedging Instruments																
Current	$	31	$	—	$	—	$	—	$	—	$	—	$	—	$	—
Noncurrent		17		—		—		—		—		—		—		—
Not Designated as Hedging Instruments																
Current	$	6	$	5	$	—	$	—	$	—	$	—	$	—	$	—
Noncurrent		10		3		—		—		—		—		7		—
Total Derivative Assets – Interest Rate Contracts	$	63	$	8	$	—	$	—	$	—	$	—	$	7	$	—
Foreign Currency Contracts																
Designated as Hedging Instruments																
Noncurrent		44		—		—		—		—		—		—		—
Total Derivative Assets – Foreign Currency Contracts	$	44	$	—	$	—	$	—	$	—	$	—	$	—	$	—
Total Derivative Assets	$	189	$	36	$	34	$	32	$	2	$	1	$	25	$	1

Derivative Liabilities	December 31, 2023							
(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	$ 354	$ 177	$ 138	$ 138	$ —	$ —	$ 18	$ 20
Noncurrent	255	67	61	61	—	—	—	127
Total Derivative Liabilities – Commodity Contracts	$ 609	$ 244	$ 199	$ 199	$ —	$ —	$ 18	$ 147
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 25	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	28	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	13	2	11	11	—	—	—	—
Noncurrent	39	14	24	9	15	1	—	—
Total Derivative Liabilities – Interest Rate Contracts	$ 103	$ 16	$ 35	$ 20	$ 15	$ 1	$ —	$ —
Foreign Currency Contracts								
Designated as Hedging Instruments								
Current	$ 17	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Total Derivative Liabilities – Foreign Currency Contracts	$ 17	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Total Derivative Liabilities	$ 729	$ 260	$ 234	$ 219	$ 15	$ 1	$ 18	$ 147

Derivative Assets	December 31, 2022							
(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	$ 265	$ 132	$ 99	$ 99	$ —	$ 5	$ 29	$ —
Noncurrent	213	104	108	108	—	—	—	—
Total Derivative Assets – Commodity Contracts	$ 478	$ 236	$ 207	$ 207	$ —	$ 5	$ 29	$ —
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 101	$ —	$ —	$ —	$ —	$ —	$ —	—
Not Designated as Hedging Instruments								
Current	$ 218	$ 94	$ 41	$ 23	$ 17	$ —	$ 81	$ —
Total Derivative Assets – Interest Rate Contracts	$ 317	$ 94	$ 41	$ 23	$ 17	$ —	$ 81	$ —
Total Derivative Assets	$ 795	$ 330	$ 248	$ 230	$ 17	$ 5	$ 110	$ —

Derivative Liabilities	December 31, 2022							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Not Designated as Hedging Instruments								
Current	$ 175	$ 96	$ 36	$ 18	$ 19	$ —	$ 16	$ 27
Noncurrent	202	31	30	30	—	—	—	141
Total Derivative Liabilities – Commodity Contracts	$ 377	$ 127	$ 66	$ 48	$ 19	$ —	$ 16	$ 168
Interest Rate Contracts								
Not Designated as Hedging Instruments								
Noncurrent	2	—	—	—	—	2	—	—
Total Derivative Liabilities – Interest Rate Contracts	$ 2	$ —	$ —	$ —	$ —	$ 2	$ —	$ —
Foreign Currency Contracts								
Designated as Hedging Instruments								
Current	$ 18	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	40	—	—	—	—	—	—	—
Total Derivative Liabilities – Foreign Currency Contracts	$ 58	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Total Derivative Liabilities	$ 437	$ 127	$ 66	$ 48	$ 19	$ 2	$ 16	$ 168

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 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, 2023							
(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	$ 61	$ 6	$ 3	$ 1	$ 2	$ 1	$ 18	$ 1
Offset	(2)	(1)	(1)	(1)	—	—	—	—
Net amounts presented in Current Assets: Other	$ 59	$ 5	$ 2	$ —	$ 2	$ 1	$ 18	$ 1
Noncurrent								
Gross amounts recognized	$ 128	$ 29	$ 31	$ 31	$ —	$ —	$ 7	$ —
Offset	(37)	(14)	(22)	(22)	—	—	—	—
Net amounts presented in Other Noncurrent Assets: Other	$ 91	$ 15	$ 9	$ 9	$ —	$ —	$ 7	$ —

Derivative Liabilities	December 31, 2023							
(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	$ 409	$ 179	$ 149	$ 149	$ —	$ —	$ 18	$ 20
Offset	(2)	(1)	(1)	(1)	—	—	—	—
Cash collateral posted	(96)	(48)	(30)	(30)	—	—	(18)	—
Net amounts presented in Current Liabilities: Other	$ 311	$ 130	$ 118	$ 118	$ —	$ —	$ —	$ 20
Noncurrent								
Gross amounts recognized	$ 320	$ 81	$ 85	$ 79	$ 15	$ 1	$ —	$ 127
Offset	(37)	(14)	(22)	(22)	—	—	—	—
Cash collateral posted	(66)	(38)	(28)	(28)	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities: Other	$ 217	$ 29	$ 35	$ 29	$ 15	$ 1	$ —	$ 127

Derivative Assets	December 31, 2022							
(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	$ 562	$ 226	$ 140	$ 122	$ 17	$ 5	$ 110	$ —
Offset	(33)	(15)	(18)	(18)	—	—	—	—
Cash collateral received	(31)	(18)	(12)	(12)	—	—	—	—
Net amounts presented in Current Assets: Other	$ 518	$ 193	$ 110	$ 92	$ 17	$ 5	$ 110	$ —
Noncurrent								
Gross amounts recognized	$ 213	$ 104	$ 108	$ 108	$ —	$ —	$ —	$ —
Offset	(59)	(29)	(30)	(30)	—	—	—	—
Cash collateral received	(38)	(11)	(27)	(27)	—	—	—	—
Net amounts presented in Other Noncurrent Assets: Other	$ 116	$ 64	$ 51	$ 51	$ —	$ —	$ —	$ —

Derivative Liabilities	December 31, 2022							
(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	$ 193	$ 96	$ 36	$ 18	$ 19	$ —	$ 16	$ 27
Offset	(33)	(15)	(18)	(18)	—	—	—	—
Cash collateral posted	(16)	—	—	—	—	—	(16)	—
Net amounts presented in Current Liabilities: Other	$ 144	$ 81	$ 18	$ —	$ 19	$ —	$ —	$ 27
Noncurrent								
Gross amounts recognized	$ 244	$ 31	$ 30	$ 30	$ —	$ 2	$ —	$ 141
Offset	(59)	(29)	(30)	(30)	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities, Other	$ 185	$ 2	$ —	$ —	$ —	$ 2	$ —	$ 141

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, 2023			
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress
Aggregate fair value of derivatives in a net liability position	$ 342	$ 175	$ 166	$ 166
Fair value of collateral already posted	144	86	58	58
Additional cash collateral or letters of credit in the event credit risk-related contingent features were triggered	198	89	108	108

	December 31, 2022				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Aggregate fair value of derivatives in a net liability position	$ 141	$ 86	$ 55	$ 48	$ 7
Fair value of collateral already posted	—	—	—	—	—
Additional cash collateral or letters of credit in the event credit risk-related contingent features were triggered	141	86	55	48	7

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 through 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 investment manager agreements and 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 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 has a credit loss. The Duke Energy Registrants analyze all investment holdings each reporting period to determine whether a decline in fair value is related to a credit loss. If a credit loss exists, the unrealized credit loss is included in earnings. There were no material credit losses as of December 31, 2023, and 2022.

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.

(in millions)	December 31, 2023 Gross Unrealized Holding Gains	December 31, 2023 Gross Unrealized Holding Losses	December 31, 2023 Estimated Fair Value	December 31, 2022 Gross Unrealized Holding Gains	December 31, 2022 Gross Unrealized Holding Losses	December 31, 2022 Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 133	$ —	$ —	$ 215
Equity securities	4,942	22	7,278	3,658	105	5,871
Corporate debt securities	12	43	632	1	85	841
Municipal bonds	6	16	347	—	39	330
U.S. government bonds	24	65	1,676	2	112	1,423
Other debt securities	1	13	176	—	18	156
Total NDTF Investments	$ 4,985	$ 159	$ 10,143	$ 3,661	$ 359	$ 8,836
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 31	$ —	$ —	$ 22
Equity securities	33	—	158	21	16	128
Corporate debt securities	—	6	82	—	12	84
Municipal bonds	1	2	77	—	3	78
U.S. government bonds	—	2	66	—	2	62
Other debt securities	—	2	47	—	3	41
Total Other Investments	$ 34	$ 12	$ 466	$ 21	$ 36	$ 415
Total Investments	$ 5,019	$ 171	$ 10,603	$ 3,682	$ 395	$ 9,051

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, 2023, 2022 and 2021, were as follows.

(in millions)	Years Ended December 31, 2023	2022	2021
FV-NI:			
Realized gains	$ 129	$ 201	$ 724
Realized losses	146	316	141
AFS:			
Realized gains	44	28	56
Realized losses	149	151	54

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.

(in millions)	December 31, 2023 Gross Unrealized Holding Gains	December 31, 2023 Gross Unrealized Holding Losses	December 31, 2023 Estimated Fair Value	December 31, 2022 Gross Unrealized Holding Gains	December 31, 2022 Gross Unrealized Holding Losses	December 31, 2022 Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 51	$ —	$ —	$ 117
Equity securities	2,886	14	4,196	2,147	51	3,367
Corporate debt securities	4	35	390	1	62	401
Municipal bonds	—	4	60	—	10	64
U.S. government bonds	13	33	828	1	51	685
Other debt securities	1	13	172	—	18	148
Total NDTF Investments	$ 2,904	$ 99	$ 5,685	$ 2,149	$ 192	$ 4,782

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, 2023, 2022 and 2021, were as follows.

(in millions)	Years Ended December 31, 2023	2022	2021
FV-NI:			
Realized gains	$ 82	$ 124	$ 440
Realized losses	78	177	96
AFS:			
Realized gains	22	22	38
Realized losses	65	66	37

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.

(in millions)	December 31, 2023 Gross Unrealized Holding Gains	December 31, 2023 Gross Unrealized Holding Losses	December 31, 2023 Estimated Fair Value	December 31, 2022 Gross Unrealized Holding Gains	December 31, 2022 Gross Unrealized Holding Losses	December 31, 2022 Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 82	$ —	$ —	$ 98
Equity securities	2,056	8	3,082	1,511	54	2,504
Corporate debt securities	8	8	242	—	23	240
Municipal bonds	6	12	297	—	29	266
U.S. government bonds	11	32	749	1	61	738
Other debt securities	—	—	6	—	—	8
Total NDTF Investments	$ 2,081	$ 60	$ 4,458	$ 1,512	$ 167	$ 3,854
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 18	$ —	$ —	$ 11
Municipal bonds	—	1	23	—	—	25
Total Other Investments	$ —	$ 1	$ 41	$ —	$ —	$ 36
Total Investments	$ 2,081	$ 61	$ 4,499	$ 1,512	$ 167	$ 3,890

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, 2023, 2022 and 2021, were as follows.

(in millions)		Years Ended December 31, 2023		2022		2021
FV-NI:						
Realized gains	$	47	$	77	$	284
Realized losses		67		139		45
AFS:						
Realized gains		22		8		16
Realized losses		75		48		14

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, 2023						December 31, 2022					
(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	$	—	$	—	$	55	$	—	$	—	$	56
Equity securities		1,956		8		2,970		1,431		54		2,411
Corporate debt securities		7		8		229		—		22		230
Municipal bonds		6		12		297		—		29		266
U.S. government bonds		10		18		518		1		37		460
Other debt securities		—		—		6		—		—		7
Total NDTF Investments	$	1,979	$	46	$	4,075	$	1,432	$	142	$	3,430
Other Investments												
Cash and cash equivalents	$	—	$	—	$	14	$	—	$	—	$	9
Total Other Investments	$	—	$	—	$	14	$	—	$	—	$	9
Total Investments	$	1,979	$	46	$	4,089	$	1,432	$	142	$	3,439

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, 2023, 2022 and 2021, were as follows.

(in millions)		Years Ended December 31, 2023		2022		2021
FV-NI:						
Realized gains	$	44	$	76	$	283
Realized losses		66		136		44
AFS:						
Realized gains		20		6		15
Realized losses		70		44		13

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, 2023						December 31, 2022					
(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	$	—	$	—	$	42
Equity securities		100		—		112		80		—		93
Corporate debt securities		1		—		13		—		1		10
U.S. government bonds		1		14		231		—		24		278
Other debt securities		—		—		—		—		—		1
Total NDTF Investments[(a)]	$	102	$	14	$	383	$	80	$	25	$	424
Other Investments												
Cash and cash equivalents	$	—	$	—	$	3	$	—	$	—	$	1
Municipal bonds		—		1		23				—		25
Total Other Investments	$	—	$	1	$	26	$	—	$	—	$	26
Total Investments	$	102	$	15	$	409	$	80	$	25	$	450

(a) During the years ended December 31, 2023, and 2022, Duke Energy Florida received reimbursements from the NDTF for costs related to ongoing decommissioning activity of Crystal River Unit 3.

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, 2023, 2022 and 2021, were immaterial.

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, 2023						December 31, 2022					
(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												
Cash and cash equivalents	$	—	$	—	$	1	$	—	$	—	$	1
Equity securities		4		—		98		2		16		79
Corporate debt securities		—		—		8		—		1		8
Municipal bonds		1		1		46		—		3		45
U.S. government bonds		—		—		10		—		—		7
Total Investments	$	5	$	1	$	163	$	2	$	20	$	140

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, 2023, 2022 and 2021, were immaterial.

DEBT SECURITY MATURITIES

The table below summarizes the maturity date for debt securities.

(in millions)		December 31, 2023 Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana
Due in one year or less	$	116 $	9 $	89 $	13 $	76 $	7
Due after one through five years		696	226	391	254	137	20
Due after five through 10 years		598	333	217	204	13	11
Due after 10 years		1,593	870	620	579	41	26
Total	$	3,003 $	1,438 $	1,317 $	1,050 $	267 $	64

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 the 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 net asset value 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. Commodity derivatives with observable forward curves are classified as Level 2. 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 certain 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.

Foreign currency derivatives

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

Other fair value considerations

See Note 2 for further information on the valuation of the Commercial Renewables Disposal Groups. 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.

(in millions)		December 31, 2023 Total Fair Value	Level 1	Level 2	Level 3	Not Categorized
NDTF cash and cash equivalents	$	133 $	133 $	— $	— $	—
NDTF equity securities		7,278	7,241	—	—	37
NDTF debt securities		2,732	829	1,903	—	—
Other equity securities		158	158	—	—	—
Other debt securities		271	55	216	—	—
Other cash and cash equivalents		31	31	—	—	—
Derivative assets		189	37	137	15	—
Total assets		10,792	8,484	2,256	15	37
Derivative liabilities		(729)	(60)	(669)	—	—
Net assets	$	10,063 $	8,424 $	1,587 $	15 $	37

(in millions)		December 31, 2022 Total Fair Value	Level 1	Level 2	Level 3	Not Categorized
NDTF cash and cash equivalents	$	215 $	215 $	— $	— $	—
NDTF equity securities		5,871	5,829	—	—	42
NDTF debt securities		2,550	780	1,770	—	—
Other equity securities		128	128	—	—	—
Other debt securities		265	55	210	—	—
Other cash and cash equivalents		22	22	—	—	—
Derivative assets		795	1	760	34	—
Total assets		9,846	7,030	2,740	34	42
Derivative liabilities		(437)	(16)	(421)	—	—
Net assets	$	9,409 $	7,014 $	2,319 $	34 $	42

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

(in millions)		Derivatives (net) Years Ended December 31, 2023		2022
Balance at beginning of period	$	34	$	24
Purchases, sales, issuances and settlements:				
Purchases		47		78
Settlements		(72)		(36)
Total gains (losses) included on the Consolidated Balance Sheet		6		(32)
Balance at end of period	$	15	$	34

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, 2023			
(in millions)	Total Fair Value	Level 1	Level 2	Not Categorized
NDTF cash and cash equivalents	$ 51	$ 51	$ —	$ —
NDTF equity securities	4,196	4,159	—	37
NDTF debt securities	1,438	375	1,063	—
Derivative assets	35	—	35	—
Total assets	5,720	4,585	1,098	37
Derivative liabilities	(260)	—	(260)	—
Net assets	$ 5,460	$ 4,585	$ 838	$ 37

	December 31, 2022			
(in millions)	Total Fair Value	Level 1	Level 2	Not Categorized
NDTF cash and cash equivalents	$ 117	$ 117	$ —	$ —
NDTF equity securities	3,367	3,325	—	42
NDTF debt securities	1,298	323	975	—
Derivative assets	330	—	330	—
Total assets	5,112	3,765	1,305	42
Derivative liabilities	(127)	—	(127)	—
Net assets	$ 4,985	$ 3,765	$ 1,178	$ 42

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, 2023			December 31, 2022		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF cash and cash equivalents	$ 82	$ 82	$ —	$ 98	$ 98	$ —
NDTF equity securities	3,082	3,082	—	2,504	2,504	—
NDTF debt securities	1,294	454	840	1,252	457	795
Other debt securities	23	—	23	25	—	25
Other cash and cash equivalents	18	18	—	11	11	—
Derivative assets	34	—	34	248	—	248
Total assets	4,533	3,636	897	4,138	3,070	1,068
Derivative liabilities	(234)	—	(234)	(66)	—	(66)
Net assets	$ 4,299	$ 3,636	$ 663	$ 4,072	$ 3,070	$ 1,002

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, 2023			December 31, 2022		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF cash and cash equivalents	$ 55	$ 55	$ —	$ 56	$ 56	$ —
NDTF equity securities	2,970	2,970	—	2,411	2,411	—
NDTF debt securities	1,050	266	784	963	225	738
Other cash and cash equivalents	14	14	—	9	9	—
Derivative assets	32	—	32	230	—	230
Total assets	4,121	3,305	816	3,669	2,701	968
Derivative liabilities	(219)	—	(219)	(48)	—	(48)
Net assets	$ 3,902	$ 3,305	$ 597	$ 3,621	$ 2,701	$ 920

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, 2023			December 31, 2022		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF cash and cash equivalents	$ 27	$ 27	$ —	$ 42	$ 42	$ —
NDTF equity securities	112	112	—	93	93	—
NDTF debt securities	244	188	56	289	232	57
Other debt securities	23	—	23	25	—	25
Other cash and cash equivalents	3	3	—	1	1	—
Derivative assets	2	—	2	17	—	17
Total assets	411	330	81	467	368	99
Derivative liabilities	(15)	—	(15)	(19)	—	(19)
Net assets	$ 396	$ 330	$ 66	$ 448	$ 368	$ 80

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, 2023, and 2022.

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, 2023				December 31, 2022			
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
Other equity securities	$ 98	$ 98	$ —	$ —	$ 79	$ 79	$ —	$ —
Other debt securities	64	—	64	—	50	—	50	—
Other cash equivalents	1	1	—	—	1	1	—	—
Derivative assets	25	5	7	13	110	—	91	29
Total assets	188	104	71	13	250	80	141	29
Derivative liabilities	(18)	(18)	—	—	(16)	(16)	—	—
Net assets	$ 170	$ 86	$ 71	$ 13	$ 234	$ 64	$ 141	$ 29

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)	2023	2022
Balance at beginning of period	$ 29	$ 22
Purchases, sales, issuances and settlements:		
Purchases	42	74
Settlements	(68)	(32)
Total gains (losses) included on the Consolidated Balance Sheet	10	(35)
Balance at end of period	$ 13	$ 29

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, 2023			December 31, 2022		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
Derivative assets	$ 1	$ 1	$ —	$ —	$ —	$ —
Derivative liabilities	(147)	—	(147)	(168)	—	(168)
Net (liabilities) assets	$ (146)	$ 1	$ (147)	$ (168)	$ —	$ (168)

QUANTITATIVE INFORMATION ABOUT UNOBSERVABLE INPUTS

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

	December 31, 2023					
Investment Type	Fair Value (in millions)	Valuation Technique	Unobservable Input	Range		Weighted Average Range
Duke Energy Ohio						
FTRs	$ 2	RTO auction pricing	FTR price – per MWh	$ 0.36 –	$ 2.11	$ 0.71
Duke Energy Indiana						
FTRs	13	RTO auction pricing	FTR price – per MWh	(1.06) –	9.64	1.26
Duke Energy						
Total Level 3 derivatives	$ 15					

	December 31, 2022					
Investment Type	Fair Value (in millions)	Valuation Technique	Unobservable Input	Range		Weighted Average Range
Duke Energy Ohio						
FTRs	$ 5	RTO auction pricing	FTR price – per MWh	$ 0.89 –	$ 6.25	$ 3.35
Duke Energy Indiana						
FTRs	29	RTO auction pricing	FTR price – per MWh	0.09 –	21.79	2.74
Duke Energy						
Total Level 3 derivatives	$ 34					

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, 2023		December 31, 2022	
(in millions)	Book Value	Fair Value	Book Value	Fair Value
Duke Energy[(a)]	$ 76,252	$ 69,790	$ 69,751	$ 61,985
Duke Energy Carolinas	16,012	15,077	14,266	12,943
Progress Energy	23,759	22,553	22,439	20,467
Duke Energy Progress	11,714	10,696	11,087	9,669
Duke Energy Florida	10,401	10,123	9,709	8,991
Duke Energy Ohio	3,518	3,318	3,245	2,927
Duke Energy Indiana	4,502	4,230	4,307	3,913
Piedmont	3,668	3,336	3,363	2,940

(a) Book value of long-term debt includes $1.0 billion as of December 31, 2023, and $1.2 billion as of December 31, 2022, 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, 2023, and December 31, 2022, 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 Variable Interest Entity (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, 2023, 2022 and 2021, 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, which generally exclude receivables past due more than a predetermined number of days and reserves for expected past-due balances. The sole source of funds to satisfy the related debt obligations is cash collections from the receivables. Amounts borrowed under the DERF and DEPR credit facilities are reflected on the Consolidated Balance Sheets as Long-Term Debt. Amounts borrowed under the DEFR credit facility are reflected on the Consolidated Balance Sheets as Current maturities of 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, which generally exclude receivables past due more than a predetermined number of days and reserves for expected past-due balances. 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 2025	January 2025	April 2025	April 2024
Credit facility amount	$ 350	$ 500	$ 400	$ 325
Amounts borrowed at December 31, 2023	312	500	400	325
Amounts borrowed at December 31, 2022	350	471	400	250
Restricted Receivables at December 31, 2023	663	991	833	532
Restricted Receivables at December 31, 2022	917	928	793	490

Nuclear Asset-Recovery Bonds – Duke Energy Florida Project Finance

Duke Energy Florida Project Finance, LLC (DEFPF) is a bankruptcy remote, wholly owned special purpose subsidiary of Duke Energy Florida. DEFPF was formed in 2016 for the sole purpose of issuing nuclear asset-recovery bonds to finance Duke Energy Florida's unrecovered regulatory asset related to Crystal River Unit 3.

In 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)	2023	2022
Receivables of VIEs	$ —	$ 6
Regulatory Assets: Current	59	55
Current Assets: Other	37	41
Other Noncurrent Assets: Regulatory assets	803	826
Current Liabilities: Other	8	9
Current maturities of long-term debt	59	56
Long-Term Debt	831	890

Storm Recovery Bonds – Duke Energy Carolinas NC Storm Funding and Duke Energy Progress NC Storm Funding

Duke Energy Carolinas NC Storm Funding, LLC. (DECNCSF) and Duke Energy Progress NC Storm Funding, LLC. (DEPNCSF) are bankruptcy remote, wholly owned special purpose subsidiaries of Duke Energy Carolinas and Duke Energy Progress, respectively. These entities were formed in 2021 for the sole purpose of issuing storm recovery bonds to finance certain of Duke Energy Carolinas' and Duke Energy Progress' unrecovered regulatory assets related to storm costs.

In November 2021, DECNCSF and DEPNCSF issued $237 million and $770 million of senior secured bonds, respectively and used the proceeds to acquire storm recovery property from Duke Energy Carolinas and Duke Energy Progress. The storm recovery property was created by state legislation and NCUC financing orders for the purpose of financing storm costs incurred in 2018 and 2019. The storm recovery property acquired includes the right to impose, bill, collect and adjust a non-bypassable charge from all Duke Energy Carolinas' and Duke Energy Progress' retail customers until the bonds are paid in full and all financing costs have been recovered. The storm recovery bonds are secured by the storm recovery property and cash collections from the storm recovery charges are the sole source of funds to satisfy the debt obligation. The bondholders have no recourse to Duke Energy Carolinas or Duke Energy Progress.

DECNCSF and DEPNCSF are considered VIEs primarily because the equity capitalization is insufficient to support their operations. Duke Energy Carolinas and Duke Energy Progress have the power to direct the significant activities of the VIEs as described above and therefore Duke Energy Carolinas and Duke Energy Progress are considered the primary beneficiaries and consolidate DECNCSF and DEPNCSF, respectively.

The following table summarizes the impact of these VIEs on Duke Energy Carolinas' and Duke Energy Progress' Consolidated Balance Sheets.

	Duke Energy Carolinas		Duke Energy Progress	
	December 31,		December 31,	
(in millions)	2023	2022	2023	2022
Regulatory Assets: Current	$ 12	$ 12	$ 39	$ 39
Current Assets: Other	[illegible]	8	31	29
Other Noncurrent Assets: Regulatory assets	198	208	643	681
Other Noncurrent Assets: Other	1	1	2	2
Current maturities of long-term debt	10	10	34	34
Current Liabilities: Other	3	3	8	8
Long-Term Debt	208	219	680	714

Purchasing Company – Duke Energy Florida

Duke Energy Florida Purchasing Company, LLC (DEF ProCo) is a wholly owned special purpose subsidiary of Duke Energy Florida. DEF ProCo was formed in 2023 as the primary procurement agent for equipment, materials and supplies for Duke Energy Florida. DEF ProCo interacts with third party suppliers on Duke Energy Florida's behalf with credit and risk support provided by Duke Energy Florida. DEF ProCo is a qualified reseller under Florida tax law and conveys acquired assets to Duke Energy Florida through leases on each acquired asset.

As of December 31, 2023, Duke Energy Florida's Consolidated Balance Sheets included Inventory and Accounts Payable for DEF ProCo of $462 million and $188 million, respectively.

NON-CONSOLIDATED VIEs

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

	December 31, 2023		
(in millions)	Duke Energy Natural Gas Investments	Duke Energy Ohio	Duke Energy Indiana
Receivables from affiliated companies	$ —	$ 150	$ 208
Investments in equity method unconsolidated affiliates	67	—	—
Other noncurrent assets	43	—	—
Total assets	$ 110	$ 150	$ 208
Other current liabilities	4	—	—
Other noncurrent liabilities	5	—	—
Total liabilities	9	$ —	$ —
Net assets	$ 101	$ 150	$ 208

	December 31, 2022		
(in millions)	Duke Energy Natural Gas Investments	Duke Energy Ohio	Duke Energy Indiana
Receivables from affiliated companies	$ —	$ 198	$ 317
Investments in equity method unconsolidated affiliates	43	—	—
Other noncurrent assets	45	—	—
Total assets	$ 88	$ 198	$ 317
Other current liabilities	59	—	—
Other noncurrent liabilities	47	—	—
Total liabilities	$ 106	$ —	$ —
Net (liabilities) assets	$ (18)	$ 198	$ 317

The Duke Energy Registrants are not aware of any situations where the maximum exposure to loss significantly exceeds the carrying values shown above.

Natural Gas Investments

Duke Energy has investments in various joint ventures including pipeline and renewable natural gas projects. 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.

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 other-than-temporary impairment has occurred.

Key assumptions used in estimating fair value are detailed in the following table.

	Duke Energy Ohio		Duke Energy Indiana	
	2023	2022	2023	2022
Anticipated credit loss ratio	0.6 %	0.5 %	0.4 %	0.3 %
Discount rate	6.1 %	2.7 %	6.1 %	2.7 %
Receivable turnover rate	13.9 %	13 5 %	12.0 %	11.3 %

The following table shows the gross and net receivables sold.

(in millions)	Duke Energy Ohio December 31, 2023	Duke Energy Ohio December 31, 2022	Duke Energy Indiana December 31, 2023	Duke Energy Indiana December 31, 2022
Receivables sold	$ 381	$ 423	$ 351	$ 508
Less: Retained interests	160	198	208	317
Net receivables sold	$ 211	$ 225	$ 143	$ 191

The following table shows sales and cash flows related to receivables sold.

(in millions)	Duke Energy Ohio Years Ended December 31, 2023	2022	2021	Duke Energy Indiana Years Ended December 31, 2023	2022	2021
Sales						
Receivables sold	$ 2,678	$ 2,562	$ 2,023	$ 3,223	$ 3,744	$ 2,909
Loss recognized on sale	34	18	10	39	26	13
Cash flows						
Cash proceeds from receivables sold	2,591	2,424	2,018	3,294	3,498	2,909
Collection fees received	1	1	1	2	2	1
Return received on retained interests	19	10	4	25	15	8

Cash flows from sales of receivables are reflected within Cash Flows From Operating Activities and Cash Flows from Investing 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 Daily Simple SOFR plus a fixed rate of 1%.

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. Absent decoupling mechanisms, the variability in expected cash flows of the majority of Duke Energy's revenue is 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, EU&I and GU&I.

Electric Utilities and Infrastructure

EU&I 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:

(in millions)	Remaining Performance Obligations 2024	2025	2026	2027	2028	Thereafter	Total
Progress Energy	$ 72	$ 30	$ 7	$ 7	$ 7	$ 29	$ 152
Duke Energy Progress	8	—	—	—	—	—	8
Duke Energy Florida	64	30	7	7	7	29	144
Duke Energy Indiana	16	17	17	15	5	—	70

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

GU&I 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 may 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 GU&I 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:

(in millions)	Remaining Performance Obligations 2024	2025	2026	2027	2028	Thereafter	Total
Piedmont	$ 66	$ 61	$ 51	$ 49	$ 46	$ 195	$ 468

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 EU&I and GU&I 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. Disaggregated revenues are presented as follows:

(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
	Year Ended December 31, 2023							
Electric Utilities and Infrastructure								
Residential	$ 12,098 $	3,409 $	6,510 $	2,640 $	3,970 $	947 $	1,233 $	—
General	7,895	2,670	3,762	1,488	2,174	652	911	—
Industrial	3,416	1,334	1,106	733	372	191	786	—
Wholesale	2,175	492	1,388	1,240	148	46	248	—
Other revenues	952	318	590	325	265	93	157	—
Total Electric Utilities and Infrastructure revenue from contracts with customers	$ 26,546 $	8,223 $	13,355 $	6,426 $	6,929 $	1,829 $	3,335 $	—
Gas Utilities and Infrastructure								
Residential	$ 1,226 $	— $	— $	— $	— $	435 $	— $	792
Commercial	605	—	—	—	—	154	—	450
Industrial	141	—	—	—	—	26	—	115
Power Generation	—	—	—	—	—	—	—	31
Other revenues	119	—	—	—	—	24	—	95
Total Gas Utilities and Infrastructure revenue from contracts with customers	$ 2,091 $	— $	— $	— $	— $	639 $	— $	1,483
Other								
Revenue from contracts with customers	$ 37 $	— $	— $	— $	— $	— $	— $	—
Total revenue from contracts with customers	$ 28,674 $	8,223 $	13,355 $	6,426 $	6,929 $	2,468 $	3,335 $	1,483
Other revenue sources[(a)]	$ 386 $	65 $	189 $	62 $	107 $	39 $	64 $	145
Total revenues	$ 29,060 $	8,288 $	13,544 $	6,488 $	7,036 $	2,507 $	3,399 $	1,628

(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.

(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
	Year Ended December 31, 2022							
Electric Utilities and Infrastructure								
Residential	$ 11,377 $	3,275 $	5,812 $	2,378 $	3,434 $	862 $	1,430 $	—
General	7,356	2,396	3,396	1,480	1,916	517	1,049	—
Industrial	3,504	1,251	1,095	770	325	202	956	—
Wholesale	2,856	561	1,785	1,346	439	127	383	—
Other revenues	795	372	994	768	226	61	19	—
Total Electric Utilities and Infrastructure revenue from contracts with customers	$ 25,888 $	7,855 $	13,082 $	6,742 $	6,340 $	1,769 $	3,837 $	—
Gas Utilities and Infrastructure								
Residential	$ 1,462 $	— $	— $	— $	— $	488 $	— $	974
Commercial	765	—	—	—	—	180	—	585
Industrial	170	—	—	—	—	24	—	144
Power Generation	—	—	—	—	—	—	—	94
Other revenues	360	—	—	—	—	25	—	271
Total Gas Utilities and Infrastructure revenue from contracts with customers	$ 2,757 $	— $	— $	— $	— $	717 $	— $	2,068
Other								
Revenue from contracts with customers	$ 30 $	— $	— $	— $	— $	— $	— $	—
Total revenue from contracts with customers	$ 28,675 $	7,855 $	13,082 $	6,742 $	6,340 $	2,486 $	3,837 $	2,068
Other revenue sources[(a)]	$ 93 $	2 $	43 $	11 $	13 $	28 $	85 $	56
Total revenues	$ 28,768 $	7,857 $	13,125 $	6,753 $	6,353 $	2,514 $	3,922 $	2,124

(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.

(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
	Year Ended December 31, 2021							
Electric Utilities and Infrastructure								
Residential	$ 10,097 $	3,054 $	5,084 $	2,156 $	2,928 $	787 $	1,188 $	—
General	6,375	2,210	2,883	1,378	1,505	440	825	—
Industrial	2,924	1,145	894	634	260	135	750	—
Wholesale	2,199	472	1,385	1,164	221	56	285	—
Other revenues	879	264	716	387	329	63	86	—
Total Electric Utilities and Infrastructure revenue from contracts with customers	$ 22,474 $	7,145 $	10,962 $	5,719 $	5,243 $	1,481 $	3,134 $	—
Gas Utilities and Infrastructure								
Residential	$ 1,131 $	— $	— $	— $	— $	354 $	— $	777
Commercial	561	—	—	—	—	143	—	418
Industrial	158	—	—	—	—	20	—	137
Power Generation	—	—	—	—	—	—	—	92
Other revenues	133	—	—	—	—	28	—	45
Total Gas Utilities and Infrastructure revenue from contracts with customers	$ 1,983 $	— $	— $	— $	— $	545 $	— $	1,469
Other								
Revenue from contracts with customers	$ 29 $	— $	— $	— $	— $	— $	— $	—
Total revenue from contracts with customers	$ 24,486 $	7,145 $	10,962 $	5,719 $	5,243 $	2,026 $	3,134 $	1,469
Other revenue sources[(a)]	$ 135 $	(43) $	95 $	61 $	16 $	11 $	40 $	100
Total revenues	$ 24,621 $	7,102 $	11,057 $	5,780 $	5,259 $	2,037 $	3,174 $	1,569

(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.

The following table presents the reserve for credit losses for trade and other receivables.

(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, 2020	$	146 $	23 $	37 $	23 $	14 $	4 $	3 $	12
Write-Offs		(58)	(21)	(25)	(12)	(13)	—	—	(9)
Credit Loss Expense		53	27	25	11	14	—	—	7
Other Adjustments		(20)	13	(1)	(1)	1	—	—	5
Balance at December 31, 2021	$	121 $	42 $	36 $	21 $	16 $	4 $	3 $	15
Write-Offs		(158)	(73)	(70)	(36)	(34)	—	—	(12)
Credit Loss Expense		160	40	72	17	55	2	1	11
Other Adjustments		93	59	43	42	(1)	—	—	—
Balance at December 31, 2022	$	216 $	68 $	81 $	44 $	36 $	6 $	4 $	14
Write-Offs		(164)	(71)	(84)	(41)	(42)	—	—	(10)
Credit Loss Expense		101	35	48	12	37	3	1	7
Other Adjustments		52	24	29	29	—	—	—	—
Balance at December 31, 2023	$	205 $	56 $	74 $	44 $	31 $	9 $	5 $	11

Trade and other receivables are evaluated based on an estimate of the risk of loss over the life of the receivable and current and historical conditions using supportable assumptions. Management evaluates the risk of loss for trade and other receivables by comparing the historical write-off amounts to total revenue over a specified period. Historical loss rates are adjusted due to the impact of current conditions, as well as forecasted conditions over a reasonable time period. The calculated write-off rate can be applied to the receivable balance for which an established reserve does not already exist. Management reviews the assumptions and risk of loss periodically for trade and other receivables.

The aging of trade receivables is presented in the table below.

		December 31, 2023							
(in millions)		Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unbilled Receivables[(a)(b)]	$	1,273 $	399 $	401 $	280 $	121 $	4 $	22 $	108
Current		2,306	680	1,009	612	395	48	87	199
1-30 days past due		275	97	91	41	50	12	14	9
31-60 days past due		78	20	34	23	11	3	7	2
61-90 days past due		47	15	17	10	7	2	4	1
91+ days past due		253	67	69	24	45	46	27	3
Deferred Payment Arrangements[(c)]		104	34	43	26	17	6	—	—
Trade and Other Receivables	$	4,336 $	1,312 $	1,664 $	1,016 $	646 $	121 $	161 $	322

		December 31, 2022							
(in millions)		Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unbilled Receivables[(a)(b)]	$	1,457 $	486 $	355 $	232 $	123 $	20 $	28 $	160
Current		2,347	577	1,059	637	417	15	52	265
1-30 days past due		261	96	60	15	45	5	17	15
31-60 days past due		123	23	61	49	12	6	2	3
61-90 days past due		74	25	18	9	9	3	11	2
91+ days past due		209	70	74	27	47	26	6	4
Deferred Payment Arrangements[(c)]		160	57	62	35	27	4	—	1
Trade and Other Receivables	$	4,631 $	1,334 $	1,689 $	1,004 $	680 $	79 $	116 $	450

(a) Unbilled revenues are recognized by applying customer billing rates to the estimated volumes of energy or natural gas delivered but not yet billed and are included within Receivables and Receivables of VIEs on the Consolidated Balance Sheets.
(b) 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 $141 million and $197 million for Duke Energy Ohio and Duke Energy Indiana, respectively, as of December 31, 2023, and $148 million and $260 million for Duke Energy Ohio and Duke Energy Indiana, respectively, as of December 31, 2022.
(c) Due to ongoing financial hardships impacting customers, Duke Energy has permitted customers to defer payment of past-due amounts through installment payment plans.

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 and accumulated preferred dividends, 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 and accumulated preferred dividends, 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 equity forward sale agreements or convertible debt, were exercised or settled. Duke Energy applies the if-converted method for calculating any potential dilutive effect of the conversion of the outstanding convertible notes on diluted EPS, if applicable. 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 an adjustment 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)		2023		2022		2021
Net income available to Duke Energy common stockholders	$	2,735	$	2,444	$	3,802
Less: (Loss) Income from discontinued operations attributable to Duke Energy common stockholders		(1,391)		(1,215)		200
Accumulated preferred stock dividends adjustment		—		—		—
Less: Impact of participating securities		6		2		3
Income from continuing operations available to Duke Energy common stockholders	$	4,120	$	3,657	$	3,599
Loss from discontinued operations, net of tax	$	(1,455)	$	(1,323)	$	(144)
Add: Loss attributable to NCI		64		108		344
(Loss) Income from discontinued operations attributable to Duke Energy common stockholders	$	(1,391)	$	(1,215)	$	200
Weighted average common shares outstanding – basic and diluted		771		770		769
EPS from continuing operations available to Duke Energy common stockholders						
Basic and Diluted[(a)]	$	5.35	$	4.74	$	4.68
(Loss) Earnings Per Share from discontinued operations attributable to Duke Energy common stockholders						
Basic and Diluted[(a)]	$	(1.81)	$	(1.57)	$	0.26
Potentially dilutive items excluded from the calculation[(b)]		2		2		2
Dividends declared per common share	$	4.06	$	3.98	$	3.90
Dividends declared on Series A preferred stock per depositary share[(c)]	$	1.437	$	1.437	$	1.437
Dividends declared on Series B preferred stock per share[(d)]	$	48.750	$	48.750	$	48.750

(a) For the periods presented subsequent to issuance in April 2023, the convertible notes were excluded from the calculations of diluted EPS because the effect was antidilutive.
(b) Performance stock awards were not included in the dilutive securities calculation because the performance measures related to the awards had not been met.
(c) 5.75% Series A Cumulative Redeemable Perpetual Preferred Stock dividends are payable quarterly in arrears on the 16th day of March, June, September and December. The preferred stock has a $25 liquidation preference per depositary share.
(d) 4.875% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock dividends are payable semiannually in arrears on the 16th day of March and September. The preferred stock has a $1,000 liquidation preference per share. On September 16, 2024, the First Call Date, and any fifth anniversary of the First Call Date, the dividend rate will reset based on the then current five-year U.S. Treasury rate plus a spread of 3.388%.

Common Stock

In November 2022, Duke Energy filed a prospectus supplement and executed an Equity Distribution Agreement (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 2025.

Preferred Stock

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.

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 2023, as Duke Energy transitions from the foundational work of clean energy strategy planning to the launch of the largest power generation build period in its history, it is streamlining certain functions and changing how it is structured and staffed to ensure the resulting organization reflects best-in-class standards, is optimally aligned with its jurisdictions, and is best positioned to serve its customers, stakeholders and investors. As a result, Duke Energy is extending involuntary severance benefits to certain employees in specific areas as a part of its organizational optimization. For the year ended December 31, 2023, Duke Energy recorded severance charges of approximately $97 million within Operations, maintenance and other on the Consolidated Statements of Income. These charges, along with amortization of severance regulatory deferrals and reversals of certain prior period severance costs, resulted in a total severance charge of $102 million in 2023.

During 2022, Duke Energy identified opportunities to eliminate work and create sustainable savings through a workload reduction initiative with a focus on process improvement through digital technology, governance simplification and elimination of low-value work. As a result, Duke Energy extended involuntary severance benefits to certain employees in specific areas as a part of this initiative.

During 2021, Duke Energy reviewed its operations and identified opportunities for improvement to better serve its customers. This operational review included workforce realignment to ensure the Company is staffed with the right skill sets and number of teammates to execute the long-term vision for Duke Energy. As such, Duke Energy extended involuntary severance benefits to certain employees in specific areas as a part of these workforce realignment efforts.

The following table presents the direct and allocated severance and related charges accrued for 682 employees in 2023, 233 employees in 2022 and 290 employees in 2021 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, 2023[a][b][c]	$ 102	$ 53	$ 33	$ 21	$ 12	$ 3	$ 6	$ 4
Year Ended December 31, 2022[d][e]	65	40	20	17	3	1	2	2
Year Ended December 31, 2021[f][g]	69	33	28	20	6	2	3	2

(a) Includes amortization of deferred severance charges of approximately $22 million, $14 million, $8 million and $8 million for Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Progress, respectively.
(b) Includes adjustments associated with 2021 severance charges of approximately $(6) million, $(2) million, $(3) million, $(2) million, $(1) million and $(1) million for Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana, respectively.
(c) Includes adjustments associated with 2022 severance charges of approximately $(14) million, $(7) million, $(5) million, $(3) million, $(2) million, $(1) million and $(1) million for Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana, respectively.
(d) Includes amortization of deferred severance charges of approximately $33 million, $22 million, $11 million and $11 million for Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Progress, respectively.
(e) Includes adjustments associated with 2021 severance charges of approximately $(19) million, $(6) million, $(8) million, $(4) million, $(4) million, $(1) million, $(2) million and $(1) million for Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana and Piedmont, respectively.
(f) Includes amortization of deferred severance charges of approximately $33 million, $22 million, $11 million and $11 million for Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Progress, respectively.
(g) Includes adjustments associated with 2018 severance charges of approximately $(3) million, $(2) million and $(1) million for Duke Energy, Duke Energy Carolinas and Duke Energy Indiana, respectively.

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, 2021	$ 39	$ 2	$ 2	$ 1	$ 1	$ —	$ —	—
Provision/Adjustments	33	14	4	3	1	—	—	1
Cash Reductions	(8)	(1)	—	—	—	—	—	—
Balance at December 31, 2022	$ 64	$ 15	$ 6	$ 4	$ 2	$ —	$ —	1
Provision/Adjustments	80	30	13	6	7	1	4	2
Cash Reductions	(42)	(10)	(3)	(2)	(1)	—	—	(1)
Balance at December 31, 2023	$ 102	$ 35	$ 16	$ 8	$ 8	$ 1	$ 4	2

22. STOCK-BASED COMPENSATION

The Duke Energy Corporation 2023 Long-Term Incentive Plan (the 2023 Plan) provides for the grant of stock-based compensation awards to employees and outside directors. The 2023 Plan supersedes the Duke Energy Corporation 2015 Long-Term Incentive Plan (the 2015 Plan). No additional grants will be made from the 2015 Plan. The 2023 Plan reserved 15 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)	2023	2022	2021
Duke Energy	$ 71	$ 74	$ 64
Duke Energy Carolinas	26	27	23
Progress Energy	28	27	24
Duke Energy Progress	17	17	15
Duke Energy Florida	11	10	9
Duke Energy Ohio	5	5	5
Duke Energy Indiana	7	7	6
Piedmont	4	4	3

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

	Years Ended December 31,		
(in millions)	2023	2022	2021
RSU awards	$ 54	$ 58	$ 49
Performance awards	43	42	39
Pretax stock-based compensation cost	$ 97	$ 100	$ 88
Stock-based compensation costs capitalized	6	5	5
Stock-based compensation expense	$ 91	$ 95	$ 83
Tax benefit associated with stock-based compensation expense	$ 20	$ 21	$ 19

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,		
	2023	2022	2021
Shares granted (in thousands)	670	654	673
Fair value (in millions)	$ 65	$ 64	$ 59

The following table summarizes information about RSU awards outstanding.

	Shares (in thousands)		Weighted Average Grant Date Fair Value (per share)
Outstanding at December 31, 2022	1,097	$	95
Granted	670		97
Vested	(548)		95
Forfeited	(104)		96
Outstanding at December 31, 2023	1,115		96
RSU awards expected to vest	1,064		96

The total grant date fair value of shares vested during the years ended December 31, 2023, 2022 and 2021, was $52 million, $49 million and $45 million, respectively. At December 31, 2023, Duke Energy had $33 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of 23 months.

PERFORMANCE AWARDS

Stock-based performance awards generally vest after three years to the extent 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 2023, the model used a risk-free interest rate of 4.43%, which reflects the yield on three-year Treasury bonds as of the grant date, and an expected volatility of 28.6% 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,				
		2023		2022	2021
Shares granted assuming target performance (in thousands)		422		408	380
Fair value (in millions)	$	42	$	40	$ 33

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, 2022	1,033	$	97
Granted	422		100
Vested	(298)		105
Forfeited	(42)		96
Outstanding at December 31, 2023	1,115		96
Stock-based performance awards expected to vest	1,086		96

The total grant date fair value of shares vested during the years ended December 31, 2023, 2022 and 2021, was $31 million, $25 million and $25 million, respectively. At December 31, 2023, Duke Energy had $23 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, which consist of the Duke Energy Retirement Cash Balance Plan (RCBP) and the Duke Energy Legacy Pension Plan (DELPP) These 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-, four- or five-year average earnings, (ii) highest three-, four- 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 uses a December 31 measurement date for its defined benefit retirement plan assets and obligations. Actuarial gains experienced by the defined benefit retirement plans in remeasuring plan assets on December 31, 2023, were primarily attributable to actual investment performance that exceeded expected investment performance. Actuarial losses experienced by the defined benefit retirement plans in remeasuring plan obligations as of December 31, 2023 were primarily attributable to the decrease in the discount rate used to measure plan obligations. Actuarial losses experienced by the defined benefit retirement plans in remeasuring plan assets on December 31, 2022, were primarily attributable to actual investment performance that was less than expected investment performance. Actuarial gains experienced by the defined benefit retirement plans in remeasuring plan obligations as of December 31, 2022, were primarily attributable to the increase in the discount rate used to measure plan 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 service cost and interest cost on projected benefit obligation components of net periodic benefit costs) for one of its qualified pension plans, Duke Energy recognized settlement charges of $117 million, of which $95 million was recorded to Regulatory Assets within Other Noncurrent Assets on the Consolidated Balance Sheets and $22 million was recorded to Other income and expenses, net, within the Consolidated Statement of Operations as of December 31, 2022.

Settlement charges recognized by the Subsidiary Registrants as of December 31, 2022, 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, and recorded to Regulatory Assets within Other Noncurrent Assets on the Consolidated Balance Sheets were $35 million for Duke Energy Carolinas, $23 million for Progress Energy, $16 million for Duke Energy Progress, $7 million for Duke Energy Florida, $8 million for Duke Energy Indiana and $29 million for Piedmont. Settlement charges recognized by the Subsidiary Registrants as of December 31, 2022, recorded to Other income and expenses, net, within the Consolidated Statement of Operations were $3 million for Duke Energy Carolinas, $5 million for Progress Energy, $5 million for Duke Energy Progress, $1 million for Duke Energy Florida, $5 million for Duke Energy Ohio and $6 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, 2022. 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.

Effective December 31, 2022, Duke Energy Florida changed its method for calculating the market related value of plan assets (MRVA) from the fair value method to a method that recognizes changes in fair value of its plan assets over a five-year period. This represents a change in regulatory treatment that will serve to mitigate the impact of market volatility on retail customer rates, resulting in the timing of net periodic pension cost recognition that is more consistent with treatment of the related cost in the ratemaking process. The three-year retrospective impact of this method change of $24 million was recognized by Duke Energy, Progress Energy and Duke Energy Florida, respectively, and was recorded to Other income and expenses, net, within the Consolidated Statement of Operations as of December 31, 2022, and has been 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. The following table includes information related to the Duke Energy Registrants' contributions to its qualified defined benefit pension plans. There were no contributions made in the year ended December 31, 2021.

(in millions)		Duke Energy		Duke Energy Carolinas		Progress Energy		Duke Energy Progress		Duke Energy Florida		Duke Energy Ohio		Duke Energy Indiana		Piedmont
Contributions Made:																
2023	$	109	$	26	$	22	$	13	$	9	$	6	$	8	$	3
2022		56		15		13		8		5		3		5		2

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	Year Ended December 31, 2023															
(in millions)		Duke Energy		Duke Energy Carolinas		Progress Energy		Duke Energy Progress		Duke Energy Florida		Duke Energy Ohio		Duke Energy Indiana		Piedmont
Service cost	$	117	$	38	$	33	$	19	$	13	$	3	$	6	$	4
Interest cost on projected benefit obligation		344		84		107		49		57		18		27		9
Expected return on plan assets		(588)		(160)		(198)		(93)		(104)		(24)		(40)		(20)
Amortization of actuarial loss		10		2		4		2		2		—		2		—
Amortization of prior service credit		(14)		(1)		—		—		—		—		(2)		(7)
Amortization of settlement charges		19		9		5		3		1		—		1		4
Net periodic pension costs[(a)(b)]	$	(112)	$	(28)	$	(49)	$	(20)	$	(31)	$	(3)	$	(6)	$	(10)

	Year Ended December 31, 2022							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 152	$ 48	$ 43	$ 25	$ 17	$ 4	$ 9	$ 5
Interest cost on projected benefit obligation	249	59	77	35	41	13	20	8
Expected return on plan assets	(558)	(152)	(183)	(88)	(94)	(23)	(37)	(24)
Amortization of actuarial loss	81	16	23	12	12	4	9	5
Amortization of prior service credit	(18)	(3)	—	—	—	—	(2)	(7)
Amortization of settlement charges[c]	32	9	8	7	1	5	1	7
MRVA method change	24	—	24	—	24	—	—	—
Net periodic pension costs[a][b]	$ (38)	$ (23)	$ (8)	$ (9)	$ 1	$ 3	$ —	$ (6)

	Year Ended December 31, 2021							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 176	$ 56	$ 50	$ 29	$ 21	$ 5	$ 10	$ 6
Interest cost on projected benefit obligation	220	51	70	30	39	13	18	7
Expected return on plan assets	(558)	(141)	(187)	(84)	(102)	(28)	(40)	(20)
Amortization of actuarial loss	133	29	38	18	20	7	13	10
Amortization of prior service credit	(29)	(8)	(2)	(1)	(1)	(1)	(2)	(9)
Amortization of settlement charges	9	5	2	2	1	—	—	1
Net periodic pension costs[a][b]	$ (49)	$ (6)	$ (29)	$ (6)	$ (22)	$ (4)	$ (1)	$ (5)

(a) Duke Energy amounts exclude $3 million, $3 million and $3 million for the years ended December 2023, 2022 and 2021, 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 $1 million, $1 million and $1 million for the years ended December 2023, 2022 and 2021, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.
(c) Includes settlement charges not deferred as a regulatory asset.

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets

	Year Ended December 31, 2023							
(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)	$ 6	$ (14)	$ 8	$ —	$ 9	$ (3)	$ (2)	$ 13
Accumulated other comprehensive loss (income)								
Deferred income tax expense	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amortization of prior year actuarial losses	(2)	—	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ (2)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

	Year Ended December 31, 2022							
(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)	$ 367	$ 221	$ 107	$ 101	$ 5	$ (1)	$ (12)	$ 9
Accumulated other comprehensive loss (income)								
Deferred income tax expense	$ (7)	$ —	$ (1)	$ —	$ —	$ —	$ —	$ —
Amortization of prior year actuarial losses	37	—	2	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ 30	$ —	$ 1	$ —	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Net Amount Recognized

	Year Ended December 31, 2023							
(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	$ 6,358	$ 1,654	$ 1,975	$ 909	$ 1,055	$ 333	$ 499	$ 170
Service cost	110	36	30	18	12	3	6	3
Interest cost	344	84	107	49	57	18	27	9
Actuarial loss	94	11	47	18	29	2	4	9
Benefits paid	(607)	(177)	(159)	(80)	(78)	(31)	(40)	(16)
Transfers	—	6	(10)	(3)	(6)	—	—	—
Obligation at measurement date	$ 6,299	$ 1,614	$ 1,990	$ 911	$ 1,069	$ 325	$ 496	$ 175
Accumulated Benefit Obligation at measurement date	$ 6,287	$ 1,617	$ 1,976	$ 912	$ 1,053	$ 317	$ 494	$ 176
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 6,993	$ 1,815	$ 2,371	$ 1,083	$ 1,271	$ 323	$ 501	$ 203
Employer contributions	100	26	22	13	9	5	8	3
Actual return on plan assets	676	183	229	107	120	29	45	23
Benefits paid	(607)	(177)	(159)	(80)	(78)	(31)	(40)	(16)
Transfers	—	6	(10)	(3)	(6)	—	—	—
Plan assets at measurement date	$ 7,162	$ 1,853	$ 2,453	$ 1,120	$ 1,316	$ 326	$ 514	$ 213
Funded status of plan	$ 863	$ 339	$ 463	$ 209	$ 247	$ 1	$ 18	$ 38

(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, 2022							
Change in Projected Benefit Obligation								
Obligation at prior measurement date	$ 8,207	$ 1,803	$ 2,560	$ 1,153	$ 1,392	$ 450	$ 680	$ 273
Service cost	145	47	40	24	18	4	8	5
Interest cost	249	59	77	35	41	13	20	8
Actuarial gain	(1,490)	(301)	(513)	(197)	(312)	(84)	(143)	(47)
Benefits paid	(753)	(159)	(184)	(101)	(82)	(50)	(66)	(69)
Transfers	—	5	(5)	(5)	—	—	—	—
Obligation at measurement date	$ 6,358	$ 1,554	$ 1,975	$ 909	$ 1,055	$ 333	$ 499	$ 170
Accumulated Benefit Obligation at measurement date	$ 6,324	$ 1,558	$ 1,959	$ 910	$ 1,038	$ 327	$ 495	$ 170
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 9,235	$ 2,365	$ 3,053	$ 1,421	$ 1,610	$ 438	$ 669	$ 334
Employer contributions	58	15	13	8	5	3	5	2
Actual return on plan assets	(1,547)	(411)	(506)	(240)	(262)	(68)	(107)	(64)
Benefits paid	(753)	(159)	(184)	(101)	(82)	(50)	(66)	(69)
Transfers	—	5	(5)	(5)	—	—	—	—
Plan assets at measurement date	$ 6,993	$ 1,815	$ 2,371	$ 1,083	$ 1,271	$ 323	$ 501	$ 203
Funded status of plan	$ 635	$ 261	$ 396	$ 174	$ 216	$ (10)	$ 2	$ 33

Amounts Recognized in the Consolidated Balance Sheets

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2023							
Prefunded pension[(a)]	$ 863	$ 339	$ 463	$ 209	$ 247	$ 74	$ 105	$ 38
Noncurrent pension liability[(b)]	$ —	$ —	$ —	$ —	$ —	$ 73	$ 87	$ —
Net asset (liability) recognized	$ 863	$ 339	$ 463	$ 209	$ 247	$ 1	$ 18	$ 38
Regulatory assets	$ 2,021	$ 531	$ 678	$ 353	$ 325	$ 89	$ 176	$ 97
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (27)	$ —	$ (1)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(1)	—	—	—	—	—	—	—
Net actuarial loss	127	—	3	—	—	—	2	—
Net amounts recognized in accumulated other comprehensive loss	$ 99	$ —	$ 2	$ —	$ —	$ —	$ 2	$ —

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2022							
Prefunded pension[(a)]	$ 885	$ 261	$ 396	$ 174	$ 218	$ 62	$ 90	$ 33
Noncurrent pension liability[(b)]	$ 250	$ —	$ —	$ —	$ —	$ 72	$ 88	$ —
Net asset (liability) recognized	$ 635	$ 261	$ 396	$ 174	$ 218	$ (10)	$ 2	$ 33
Regulatory assets	$ 2,016	$ 545	$ 670	$ 353	$ 316	$ 82	$ 178	$ 84
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (27)	$ —	$ (1)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(1)	—	—	—	—	—	—	—
Net actuarial loss	129	—	3	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 101	$ —	$ 2	$ —	$ —	$ —	$ —	$ —

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

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

(in millions)	Duke Energy Ohio	Duke Energy Indiana
	December 31, 2023	
Projected benefit obligation	$ 105	$ 288
Accumulated benefit obligation	100	203
Fair value of plan assets	31	121

(in millions)	Duke Energy	Duke Energy Ohio	Duke Energy Indiana
	December 31, 2022		
Projected benefit obligation	$ 3,323	$ 103	$ 198
Accumulated benefit obligation	3,268	99	193
Fair value of plan assets	3,073	31	110

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 RCBP contains a mostly active participant population while the DELPP contains a mostly inactive participant population. The average remaining service period for RCBP participants is nine years and the average life expectancy of DELPP participants is 15 years. Unrecognized net actuarial gains/losses and prior service credit are amortized over 12 years for Duke Energy and Duke Energy Florida, 14 years for Duke Energy Ohio, 13 years for Duke Energy Indiana, 11 years for Duke Energy Carolinas, Progress Energy and Duke Energy Progress and nine years for Piedmont.

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

	December 31, 2023	2022	2021
Benefit Obligations			
Discount rate	5.40%	5.60%	2.90%
Interest crediting rate	4.15%	4.35%	4.00%
Salary increase	3.50 % – 4.00%	3.50 % – 4.00%	3.50 % – 4.00%
Net Periodic Benefit Cost			
Discount rate	5.60%	2.90 % – 5.70%	2.60%
Interest crediting rate	4.35%	4.00%	4.00%
Salary increase	3.50 % – 4.00%	3.50 % – 4.00%	3.50 % – 4.00%
Expected long-term rate of return on plan assets	6.50 % – 8.25 %	6.50%	6.50%

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Years ending December 31,								
2024	$ 834	$ 176	$ 180	$ 95	$ 84	$ 31	$ 45	$ 18
2025	824	171	182	97	84	30	44	16
2026	601	162	177	89	86	30	43	16
2027	582	153	175	87	86	29	42	15
2028	565	146	171	84	86	29	42	15
2029-2033	2,481	590	779	355	420	131	200	73

NON-QUALIFIED PENSION PLANS

The accumulated benefit obligation, which equals the projected benefit obligation for non-qualified pension plans, was $224 million for Duke Energy, $10 million for Duke Energy Carolinas, $78 million for Progress Energy, $23 million for Duke Energy Progress, $31 million for Duke Energy Florida, $2 million for Duke Energy Ohio, $2 million for Duke Energy Indiana and $2 million for Piedmont as of December 31, 2023.

Employer contributions, which equal benefits paid for non-qualified pension plans, were $24 million for Duke Energy, $1 million for Duke Energy Carolinas, $8 million for Progress Energy, $3 million for Duke Energy Progress and $3 million for Duke Energy Florida for the year ended December 31, 2023. Employer contributions were not material for Duke Energy Ohio, Duke Energy Indiana or Piedmont for the year ended December 31, 2023.

Net periodic pension costs for non-qualified pension plans were not material for the years ended December 31, 2023, 2022 or 2021.

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 satisfied the applicable eligibility requirements (e.g., age and service) at retirement, as defined in the plans. The health care benefits include medical, dental, vision 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, 2023, 2022 or 2021.

Components of Net Periodic Other Post-Retirement Benefit Costs

	Year Ended December 31, 2023							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 2	$ 1	$ —	$ —	$ —	$ —	$ —	$ —
Interest cost on accumulated post-retirement benefit obligation	22	5	9	4	4	1	1	1
Expected return on plan assets	(11)	(7)	—	—	—	—	—	(2)
Amortization of actuarial (gain) loss	(6)	(3)	8	6	2	(2)	(3)	—
Amortization of prior service credit	(23)	(5)	(11)	(6)	(5)	—	(5)	—
Net periodic post-retirement benefit costs[(a)(b)]	$ (16)	$ (9)	$ 6	$ 4	$ 1	$ (1)	$ (7)	$ (1)

	Year Ended December 31, 2022							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 3	$ 1	$ —	$ —	$ —	$ —	$ —	$ —
Interest cost on accumulated post-retirement benefit obligation	17	4	7	4	3	1	1	1
Expected return on plan assets	(10)	(6)	—	—	—	—	—	(2)
Amortization of actuarial loss	2	—	1	1	1	—	—	—
Amortization of prior service credit	(8)	(3)	(2)	(1)	(1)	—	—	(2)
Net periodic post-retirement benefit costs[(a)(b)]	$ 4	$ (4)	$ 6	$ 4	$ 3	$ 1	$ 1	$ (3)

	Year Ended December 31, 2021							
(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	$ —
Interest cost on accumulated post-retirement benefit obligation	18	4	7	4	3	1	1	1
Expected return on plan assets	(11)	(7)	—	—	—	—	—	(2)
Amortization of actuarial loss	2	—	1	—	1	—	4	—
Amortization of prior service credit	(13)	(4)	(2)	(1)	(1)	(1)	(1)	(2)
Net periodic post-retirement benefit costs[(a)(b)]	$ —	$ (6)	$ 7	$ 3	$ 3	$ —	$ 5	$ (3)

(a) Duke Energy amounts exclude $4 million, $4 million and $5 million for the years ended December 2023, 2022 and 2021, 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 $1 million, $1 million and $1 million for the years ended December 2023, 2022 and 2021, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

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

	Year Ended December 31, 2023							
(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)	$ 73	$ 79	$ (7)	$ (5)	$ —	$ (2)	$ (2)	$ 1
Regulatory liabilities, net increase (decrease)	$ 41	$ 62	$ —	$ —	$ —	$ (4)	$ (8)	$ —
Accumulated other comprehensive (income) loss								
Amortization of prior year service credit	$ 1	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amortization of prior year actuarial gain	—	—	(1)	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ 1	$ —	$ (1)	$ —	$ —	$ —	$ —	$ —

	Year Ended December 31, 2022							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Regulatory assets, net (decrease) increase	$ (79)	$ —	$ (80)	$ (45)	$ (36)	$ —	$ (3)	$ —
Regulatory liabilities, net increase (decrease)	$ 27	$ —	$ —	$ —	$ —	$ —	$ 19	$ (5)
Accumulated other comprehensive (income) loss								
Amortization of prior year actuarial gain	$ 1	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Net amount recognized in accumulated other comprehensive income	$ 1	$ —	$ —	$ —	$ —	$ —	$ —	$ —

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

(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, 2023							
Change in Projected Benefit Obligation								
Accumulated post-retirement benefit obligation at prior measurement date	$ 437	$ 112	$ 168	$ 95	$ 69	$ 20	$ 30	$ 21
Service cost	2	1	—	—	—	—	—	—
Interest cost	22	5	9	5	4	1	1	1
Plan participants' contributions	4	1	1	1	1	—	—	—
Actuarial (gains) losses	(10)	(2)	(10)	(6)	(4)	1	(1)	1
Transfers	(50)	(34)	—	—	—	—	—	(6)
Benefits paid	(58)	(14)	(22)	(11)	(10)	(3)	(6)	(2)
Accumulated post-retirement benefit obligation at measurement date	$ 347	$ 69	$ 146	$ 84	$ 60	$ 19	$ 24	$ 15
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 162	$ 105	$ —	$ (2)	$ (2)	$ 7	$ 3	$ 31
401(h) asset transfers	—	(8)	—	—	—	—	—	—
Actual return on plan assets	19	8	—	—	—	1	—	4
Benefits paid	(58)	(14)	(22)	(11)	(10)	(3)	(6)	(2)
Transfers	(13)	4	—	—	—	—	—	(7)
Employer contributions	42	6	20	11	10	2	6	1
Plan participants' contributions	4	1	1	1	1	—	—	—
Plan assets at measurement date	$ 156	$ 102	$ (1)	$ (1)	$ (1)	$ 7	$ 3	$ 27
Funded status of plan	$ (191)	$ 33	$ (147)	$ (85)	$ (61)	$ (12)	$ (21)	$ 12

(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, 2022							
Change in Projected Benefit Obligation								
Accumulated post-retirement benefit obligation at prior measurement date	$ 625	$ 149	$ 263	$ 147	$ 112	$ 25	$ 54	$ 27
Service cost	3	1	—	—	—	—	—	—
Interest cost	17	4	7	4	3	1	1	1
Plan participants' contributions	11	2	4	2	2	1	1	—
Actuarial gains	(80)	(17)	(43)	(27)	(16)	(3)	(1)	(5)
Plan amendments	(71)	(11)	(37)	(18)	(19)	—	(17)	—
Benefits paid	(68)	(16)	(26)	(13)	(13)	(4)	(8)	(2)
Accumulated post-retirement benefit obligation at measurement date	$ 437	$ 112	$ 168	$ 95	$ 69	$ 20	$ 30	$ 21
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 211	$ 135	$ (1)	$ (2)	$ (2)	$ 9	$ 6	$ 39
Actual return on plan assets	(31)	(19)	—	—	—	(2)	—	(7)
Benefits paid	(68)	(16)	(26)	(13)	(13)	(4)	(8)	(2)
Employer contributions	39	3	23	11	11	3	4	1
Plan participants' contributions	11	2	4	2	2	1	1	—
Plan assets at measurement date	$ 162	$ 105	$ —	$ (2)	$ (2)	$ 7	$ 3	$ 31
Funded status of plan	$ (275)	$ (7)	$ (168)	$ (97)	$ (71)	$ (13)	$ (27)	$ 10

Amounts Recognized in the Consolidated Balance Sheets

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2023							
Prefunded post-retirement benefit	$ —	$ 61	$ —	$ —	$ —	$ 1	$ —	$ 12
Current post-retirement liability[(a)]	12	3	5	3	2	1	—	—
Noncurrent post-retirement liability[(b)]	179	25	142	82	59	12	21	—
Net liability (asset) recognized	$ 191	$ (33)	$ 147	$ 85	$ 61	$ 12	$ 21	$ (12)
Regulatory assets	$ 123	$ 79	$ 39	$ 28	$ 11	$ 2	$ 23	$ 1
Regulatory liabilities	$ 230	$ 106	$ —	$ —	$ —	$ 17	$ 74	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 3	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Net actuarial gain	(13)	—	(1)	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive income	$ (10)	$ —	$ (1)	$ —	$ —	$ —	$ —	$ —

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2022							
Prefunded post-retirement benefit	$ —	$ —	$ —	$ —	$ —	$ 1	$ —	$ 10
Current post-retirement liability[(a)]	9	—	5	3	2	2	—	—
Noncurrent post-retirement liability[(b)]	266	7	163	94	69	12	27	—
Net liability (asset) recognized	$ 275	$ 7	$ 168	$ 97	$ 71	$ 13	$ 27	$ (10)
Regulatory assets	$ 50	$ —	$ 46	$ 34	$ 11	$ 4	$ 25	$ —
Regulatory liabilities	$ 189	$ 44	$ —	$ —	$ —	$ 21	$ 82	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 3	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(1)	—	—	—	—	—	—	—
Net actuarial gain	(13)	—	—	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive income	$ (11)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(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 seven years for Duke Energy, Duke Energy Carolinas and Duke Energy Florida, six years for Duke Energy Ohio, Duke Energy Indiana and Piedmont and five years for Progress Energy and Duke Energy Progress.

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

	December 31, 2023	2022	2021
Benefit Obligations			
Discount rate	5.40 %	5.60 %	2.90 %
Net Periodic Benefit Cost			
Discount rate	5.60 %	2.90 %	2.60 %
Expected long-term rate of return on plan assets	6.50 % – 8.25 %	6.50 %	6.50 %

Assumed Health Care Cost Trend Rate

	December 31, 2023	2022
Health care cost trend rate assumed for next year – pre-65 trend	6.50 %	6.50 %
Health care cost trend rate assumed for next year – post-65 trend	— %	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	2031-2032	2030-2032

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,								
2024	$ 57	$ 14	$ 18	$ 11	$ 8	$ 3	$ 4	$ 2
2025	47	11	17	10	7	3	3	2
2026	42	10	15	9	6	3	3	2
2027	37	8	14	8	6	2	3	2
2028	34	7	13	8	5	2	2	2
2029-2033	124	23	55	32	23	7	8	7

PLAN ASSETS

Description and Allocations

Duke Energy Corporation Master Retirement Trust

Assets for both the qualified pension and other post-retirement benefits are maintained in the Duke Energy Corporation Master Retirement Trust. Approximately 98% of the Duke Energy Corporation 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, 2023, and 2022. The investment objective of the Duke Energy Corporation 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, 2023, Duke Energy assumes qualified pension and other post-retirement plan assets will generate a long-term rate of return of 8.50% for the RCBP pension and RCBP 401(h) account assets and 7.00% for the DELPP pension and DELPP 401(h) account assets. The expected long-term rate of return was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers, where applicable. The asset allocation targets were set after considering the investment objective and the risk profile. Equity securities are held for their higher expected returns. Debt securities are primarily held to hedge the qualified pension plan. Return seeking debt securities, 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, 2024, the target asset allocation for the RCBP assets is 35% liability hedging and 65% return-seeking assets and the target asset allocation for the DELPP assets is 80% liability hedging assets and 20% 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 Corporation 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 Corporation 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 Corporation 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 Corporation Master Retirement Trust to sell the securities. The Duke Energy Corporation 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. Effective December 31, 2023, the Duke Energy Corporation Master Retirement Trust discontinued lending plan assets. The fair value of securities on loan was approximately $2 million and $390 million at December 31, 2023, and 2022, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned at December 31, 2023, and 2022, respectively. Securities lending income earned by the Duke Energy Corporation Master Retirement Trust was immaterial for the years ended December 31, 2023, 2022 and 2021, respectively.

Qualified pension and other post-retirement benefits for the Subsidiary Registrants are derived from the Duke Energy Corporation 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, 2023, and the actual asset allocations for the RCBP assets.

	Target Allocation	Actual Allocation at December 31, 2023	2022
Global equity securities	45 %	45 %	49 %
Global private equity securities	2 %	2 %	2 %
Debt securities	35 %	35 %	30 %
Return seeking debt securities	7 %	6 %	7 %
Hedge funds	4 %	4 %	6 %
Real estate and cash	7 %	8 %	6 %
Total	100 %	100 %	100 %

The following table includes the target asset allocations by asset class at December 31, 2023, and the actual asset allocations for the DELPP assets.

	Target Allocation	Actual Allocation at December 31, 2023	2022
Global equity securities	14 %	14 %	14 %
Global private equity securities	1 %	— %	— %
Debt securities	80 %	79 %	80 %
Return seeking debt securities	2 %	2 %	2 %
Hedge funds	1 %	2 %	2 %
Real estate and cash	2 %	3 %	2 %
Total	100 %	100 %	100 %

Other post-retirement assets

Duke Energy's other post-retirement assets are comprised of Voluntary Employees' Beneficiary Association (VEBA) trusts and 401(h) accounts held within the Duke Energy Corporation 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, 2023.

	Target Allocation	Actual Allocation at December 31, 2023	2022
U.S. equity securities	29 %	30 %	12 %
Non-U.S. equity securities	15 %	15 %	5 %
Real estate	5 %	7 %	3 %
Debt securities	47 %	30 %	11 %
Cash	4 %	18 %	69 %
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.

Duke Energy Corporation Master Retirement Trust

The following tables provide the fair value measurement amounts for the Duke Energy Corporation Master Retirement Trust qualified pension and other post-retirement assets.

	December 31, 2023				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized[(b)]**
Equity securities	$ 2,221	$ 1,995	$ 211	$ —	$ 15
Corporate debt securities	2,807	—	2,807	—	—
Short-term investment funds	233	—	233	—	—
Partnership interests	76	—	—	76	—
Hedge funds	164	—	—	—	164
U.S. government securities	1,671	—	1,671	—	—
Governments bonds – foreign	107	—	107	—	—
Cash	7	7	—	—	—
Government and commercial mortgage-backed securities	1	—	1	—	—
Net pending transactions and other investments	54	40	14	—	—
Total assets[(a)]	$ 7,241	$ 2,042	$ 4,944	$ 76	$ 179

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana and Piedmont were allocated approximately 27%, 33%, 15%, 18%, 5%, 7% and 3%, respectively, of the Duke Energy Corporation Master Retirement Trust at December 31, 2023. 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, 2022				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized[(b)]**
Equity securities	$ 2,234	$ 2,014	$ 194	$ —	$ 26
Corporate debt securities	2,944	—	2,944	—	—
Short-term investment funds	193	1	192	—	—
Partnership interests	62	—	—	62	—
Hedge funds	209	—	—	—	209
U.S. government securities	1,254	—	1,254	—	—
Governments bonds – foreign	112	—	112	—	—
Cash	45	45	—	—	—
Government and commercial mortgage-backed securities	6	—	6	—	—
Net pending transactions and other investments	14	5	9	—	—
Total assets[(a)]	$ 7,073	$ 2,065	$ 4,711	$ 62	$ 235

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana and Piedmont were allocated approximately 27%, 33%, 15%, 18%, 5%, 7% and 3%, respectively, of the Duke Energy Corporation Master Retirement Trust at December 31, 2022. 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 Corporation 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)	**2023**	**2022**
Balance at January 1	$ 62	$ 95
Sales	(8)	(18)
Total gains and other, net	22	(8)
Transfer of Level 3 assets from other classifications	—	(7)
Balance at December 31	$ 76	$ 62

Other post-retirement assets

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

	December 31, 2023	
(in millions)	**Total Fair Value**	**Level 2**
Cash and cash equivalents	$ 4	$ 4
Real estate	1	1
Equity securities	9	9
Debt securities	6	6
Total assets	$ 20	$ 20

	December 31, 2022	
(in millions)	**Total Fair Value**	**Level 2**
Cash and cash equivalents	$ 11	$ 11
Real estate	2	2
Equity securities	12	12
Debt securities	8	8
Total assets	$ 33	$ 33

EMPLOYEE SAVINGS PLANS

Retirement Savings Plan

Duke Energy Corporation sponsors, 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.

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,								
2023	$ 238	$ 76	$ 62	$ 40	$ 22	$ 6	$ 13	$ 13
2022	246	76	65	43	22	6	12	13
2021	229	70	60	39	21	5	12	11

24. INCOME TAXES

Inflation Reduction Act

On August 16, 2022, the IRA was signed into law. Among other provisions, the IRA implemented a new 15% corporate alternative minimum tax based on GAAP net income, with certain adjustments as defined by the IRA, and clean energy-related provisions. The IRA's clean energy provisions included, among other provisions, the extension and modification of existing investment and PTCs for projects placed in service through 2024 and introduced new technology-neutral clean energy related credits beginning in 2025. In addition, the IRA created a new, zero-emission nuclear power PTC and a clean hydrogen PTC.

There were no material impacts on the results of operations, financial position, or cash flows in the periods presented for the Duke Energy Registrants as a result of the IRA being signed into law. Based on the review of the IRA provisions, future annual cash flow impacts related to the energy credits could be material to the Duke Energy Registrants. However, the majority of Duke Energy's operations are regulated and the FERC and state utility commissions will determine the regulatory treatment. We anticipate the Subsidiary Registrants will defer and expect to pass along the net financial impact associated with the IRA to customers over time. See Note 4 for further details on the IRA as it relates to Duke Energy Florida. Duke Energy will continue to assess the IRA as new information and anticipated guidance from the U.S. Department of the Treasury becomes available.

North Carolina's 2021 Appropriations Act

On November 18, 2021, North Carolina Senate Bill 105 (SB 105) was signed into law. Starting with tax year 2025, SB 105 begins phasing out the North Carolina corporate income tax rate over five years, from a statutory rate of 2.5% to zero. Duke Energy recorded a net reduction of approximately $490 million to its North Carolina deferred tax liability in the fourth quarter of 2021. The majority of this deferred tax liability reduction was offset by recording a regulatory liability pending NCUC determination of the disposition of the amounts related to Duke Energy Carolinas, Duke Energy Progress and Piedmont. In addition, Duke Energy recorded a net reduction of North Carolina consolidating deferred tax assets of approximately $25 million to deferred state income tax expense in the fourth quarter of 2021. North Carolina SB 105 did not have a significant impact on the financial position, results of operation, or cash flows of Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress or Piedmont.

Income Tax Expense

Components of Income Tax Expense

Tax benefit from discontinued operations, in the following tables, includes income tax benefits related to the Commercial Renewables Disposal Groups. See Note 2 for further details.

	Year Ended December 31, 2023							
(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[(b)]	$ 71	$ 173	$ 459	$ 198	$ 279	$ (46)	$ 10	$ 44
State	1	22	38	4	71	(3)	9	3
Foreign	3	—	—	—	—	—	—	—
Total current income taxes	75	195	497	202	350	(49)	19	47
Deferred income taxes								
Federal	319	(43)	(154)	(69)	(89)	111	77	25
State	53	(7)	38	19	—	1	14	12
Total deferred income taxes[(a)]	372	(50)	(116)	(50)	(89)	112	91	37
ITC amortization	(9)	(4)	(4)	(3)	—	—	—	—
Income tax expense from continuing operations	438	141	377	149	261	63	110	84
Tax benefit from discontinued operations	(359)	—	—	—	—	—	—	—
Total income tax expense included in Consolidated Statements of Operations	$ 79	$ 141	$ 377	$ 149	$ 261	$ 63	$ 110	$ 84

(a) Total deferred income taxes includes the utilization of NOL carryforwards and tax credit carryforwards of $214 million at Duke Energy and $54 million at Duke Energy Indiana. In addition, total deferred income taxes includes the generation of NOL carryforwards and tax credit carryforwards of $2 million at Duke Energy Carolinas, $116 million at Progress Energy, $59 million at Duke Energy Progress, $5 million at Duke Energy Florida, $22 million at Duke Energy Ohio, and $15 million at Piedmont.

(b) Total current federal income tax at Duke Energy includes corporate alternative minimum tax, net of tax credit utilization, of $69 million. In addition, under the IRA transferability provision, Progress Energy elected to sell $28 million of PTCs generated by Duke Energy Florida. Cash received and paid related to the transfer of tax credits is included in Cash paid for (received from) income taxes on the Consolidated Statements of Cash Flows.

	Year Ended December 31, 2022							
(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	$ 1	$ (71)	$ (13)	$ 37	$ (37)	$ (2)	$ 38	$ 32
State	(8)	(13)	(3)	—	(23)	1	2	2
Foreign	4	—	—	—	—	—	—	—
Total current income taxes	(3)	(84)	(16)	37	(60)	(1)	40	34
Deferred income taxes								
Federal	328	230	310	118	201	(22)	(63)	12
State	(14)	(16)	59	7	84	3	—	(7)
Total deferred income taxes[(a)]	314	214	369	125	285	(19)	(63)	5
ITC amortization	(11)	(4)	(5)	(4)	—	(1)	(1)	—
Income tax expense from continuing operations	300	126	348	158	225	(21)	(24)	39
Tax benefit from discontinued operations	(503)	—	—	—	—	—	—	—
Total income tax (benefit) expense included in Consolidated Statements of Operations	$ (203)	$ 126	$ 348	$ 158	$ 225	$ (21)	$ (24)	$ 39

(a) Total deferred income taxes includes the generation of NOL carryforwards and tax credit carryforwards of $550 million at Duke Energy, $97 million at Duke Energy Carolinas, $128 million at Progress Energy, $9 million at Duke Energy Progress, $111 million at Duke Energy Florida, $7 million at Duke Energy Ohio, $13 million at Duke Energy Indiana, and $12 million at Piedmont.

	Year Ended December 31, 2021							
(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	$ (2)	$ 241	$ (15)	$ 113	$ (75)	$ (8)	$ 65	$ 23
State	1	23	(4)	8	(17)	(2)	7	3
Foreign	2	—	—	—	—	—	—	—
Total current income taxes	1	264	(19)	121	(92)	(10)	72	26
Deferred income taxes								
Federal	275	(130)	203	(16)	202	35	19	17
State	—	(79)	47	(26)	77	5	16	(13)
Total deferred income taxes[(a)]	275	(209)	250	(42)	279	40	35	4
ITC amortization	(8)	(4)	(4)	(4)	—	—	—	—
Income tax expense from continuing operations	268	51	227	75	187	30	107	30
Tax benefit from discontinued operations	(76)	—	—	—	—	—	—	—
Total income tax expense included in Consolidated Statements of Operations	$ 192	$ 51	$ 227	$ 75	$ 187	$ 30	$ 107	$ 30

(a) Total deferred income taxes includes the generation of NOL carryforwards and tax credit carryforwards of $32 million at Duke Energy Carolinas, $8 million at Duke Energy Indiana, and $3 million at Piedmont. In addition, total deferred income taxes includes utilization of NOL carryforwards and tax credit carryforwards of $250 million at Duke Energy, $95 million at Progress Energy, $14 million at Duke Energy Progress, $64 million at Duke Energy Florida and $2 million at Duke Energy Ohio.

Duke Energy Income from Continuing Operations before Income Taxes

	Years Ended December 31,		
(in millions)	2023	2022	2021
Domestic	$ 4,700	$ 3,991	$ 3,947
Foreign	67	87	44
Income from continuing operations before income taxes	$ 4,767	$ 4,078	$ 3,991

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.

(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, 2023							
Income tax expense, computed at the statutory rate of 21%	$ 1,001	$ 338	$ 490	$ 241	$ 268	$ 83	$ 128	$ 97
State income tax, net of federal income tax effect	43	12	60	18	56	(2)	18	12
Amortization of EDIT	(388)	(197)	(114)	(91)	(23)	(22)	(33)	(20)
AFUDC equity income	(41)	(19)	(14)	(11)	(3)	(2)	(2)	(4)
AFUDC equity depreciation	37	18	13	6	7	2	4	—
Tax credits[b]	(63)	(11)	(46)	(7)	(39)	(2)	(2)	(1)
Interest on company-owned life insurance[a]	(114)	—	—	—	—	—	—	—
Other items, net	(37)	—	(12)	(7)	(5)	6	(3)	—
Income tax expense from continuing operations	$ 438	$ 141	$ 377	$ 149	$ 261	$ 63	$ 110	$ 84
Effective tax rate	9.2 %	8.8 %	16.2 %	13.9 %	20.4 %	15.9 %	18.1 %	18.1 %

(a) During 2023, the Company evaluated the deductibility of certain items spanning periods currently open under federal statute, including items related to interest on company-owned life insurance. As a result of this analysis, the Company recorded a favorable federal adjustment of approximately $114 million and a favorable state adjustment of approximately $6 million. The favorable state adjustment is included in State income tax, net of federal income tax effect, in the above table.
(b) Tax credits at Progress Energy and Duke Energy Florida include $28 million of certain eligible PTCs, net of discount, that were elected to be sold in 2023 under the transferability provisions of the IRA. Cash received and paid related to the transfer of tax credits is included in Cash paid for (received from) income taxes on the Consolidated Statements of Cash Flows.

(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, 2022							
Income tax expense, computed at the statutory rate of 21%	$ 856	$ 362	$ 457	$ 245	$ 238	$ 58	$ 24	$ 76
State income tax, net of federal income tax effect	(17)	(23)	44	6	48	3	2	(4)
Amortization of EDIT	(481)	(195)	(133)	(74)	(59)	(78)	(48)	(23)
AFUDC equity income	(41)	(20)	(14)	(11)	(3)	(1)	(2)	(2)
AFUDC equity depreciation	36	18	12	6	6	1	4	—
Other tax credits	(43)	(12)	(16)	(9)	(7)	(2)	(3)	(8)
Other items, net	(10)	(4)	(2)	(5)	2	(2)	(1)	—
Income tax expense (benefit) from continuing operations	$ 300	$ 126	$ 348	$ 158	$ 225	$ (21)	$ (24)	$ 39
Effective tax rate	7.4 %	7.3 %	16.0 %	13.6 %	19.8 %	(7.5)%	(21.2)%	10.8 %

(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, 2021							
Income tax expense, computed at the statutory rate of 21%	$ 838	$ 291	$ 384	$ 224	$ 194	$ 49	$ 123	$ 71
State income tax, net of federal income tax effect	1	(44)	34	(14)	47	2	18	(8)
Amortization of EDIT	(438)	(184)	(174)	(120)	(54)	(22)	(34)	(25)
AFUDC equity income	(34)	(14)	(11)	(7)	(3)	(2)	(4)	(4)
AFUDC equity depreciation	35	18	10	5	5	2	5	—
Other tax credits	(30)	(12)	(11)	(8)	(3)	(1)	(2)	(4)
Valuation allowance[a]	(85)	—	—	—	—	—	—	—
Other items, net	(19)	(4)	(5)	(5)	1	2	1	—
Income tax expense from continuing operations	$ 268	$ 51	$ 227	$ 75	$ 187	$ 30	$ 107	$ 30
Effective tax rate	6.7 %	3.7 %	12.4 %	7.0 %	20.2 %	12.8 %	18.2 %	8.8 %

(a) In 2021, the Company recognized a federal capital gain in the amount of $428 million. As a result, a valuation allowance of $85 million related to a federal capital loss carryforward was released. This valuation allowance was originally recorded as a result of the 2019 sale of minority interest of certain renewable assets within the Commercial Renewables Disposal Groups.

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.

DEFERRED TAXES

Net Deferred Income Tax Liability Components

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
	December 31, 2023							
Deferred credits and other liabilities	$ 327	$ 194	$ 77	$ 21	$ 66	$ 13	$ 18	$ 42
Lease obligations	418	86	256	179	77	4	15	3
Pension, post-retirement and other employee benefits	65	(41)	(22)	(1)	(25)	5	2	(5)
Progress Energy merger purchase accounting adjustments[a]	260	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	4,489	445	686	230	425	44	154	50
Regulatory liabilities and deferred credits	—	—	—	—	—	—	47	—
Investments and other assets	—	—	—	—	—	—	1	—
Other	102	29	22	12	3	5	5	9
Valuation allowance	(544)	—	—	—	—	—	—	—
Total deferred income tax assets	5,117	713	1,019	441	541	71	242	99
Investments and other assets	(1,812)	(1,213)	(596)	(520)	(91)	—	—	(37)
Accelerated depreciation rates	(11,969)	(3,411)	(4,557)	(1,823)	(2,778)	(1,314)	(1,678)	(944)
Regulatory assets and deferred debits, net	(1,892)	(468)	(1,063)	(658)	(405)	(29)	—	(51)
Total deferred income tax liabilities	(15,673)	(5,092)	(6,216)	(3,001)	(3,274)	(1,343)	(1,678)	(1,032)
Net deferred income tax liabilities	$ (10,556)	$ (4,379)	$ (5,197)	$ (2,560)	$ (2,733)	$ (1,272)	$ (1,436)	$ (933)

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

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

(in millions)	December 31, 2023 Amount	Expiration Year		
General Business Credits	$ 2,388	2029	—	2043
Foreign Tax Credits[d]	1,155	2024	—	2028
State Carryforwards and Credits[b] [e]	390	2024	—	Indefinite
Corporate AMT Credits	278			Indefinite
Federal Capital Loss[f]	73	2027	—	2028
Federal NOL carryforwards[a] [e]	193	2024	—	Indefinite
Foreign NOL carryforwards[c]	12	2027	—	2038
Total tax credits and NOL carryforwards	$ 4,489			

(a) A valuation allowance of $4 million has been recorded on the Federal NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.
(b) A valuation allowance of $110 million has been recorded on the state NOL and attribute 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 $389 million has been recorded on the foreign tax credits, as presented in the Net Deferred Income Tax Liability Components table.
(e) Indefinite carryforward for Federal NOLs, and NOLs for states that have adopted the Tax Act's NOL provisions, generated in tax years beginning after December 31, 2017.
(f) A valuation allowance of $29 million has been recorded on the Federal Capital Loss, as presented in the Net Deferred Income Tax Liability Components table.

				December 31, 2022				
		Duke		Duke	Duke	Duke	Duke	
	Duke	Energy	Progress	Energy	Energy	Energy	Energy	
(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Deferred credits and other liabilities	$ 348	$ 170	$ 117	$ 33	$ 83	$ 12	$ 23	$ 24
Lease obligations	405	89	263	197	65	4	15	3
Pension, post-retirement and other employee benefits	192	(1)	12	18	(10)	9	10	(2)
Progress Energy merger purchase accounting adjustments[(a)]	301	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	4,426	444	618	167	412	20	208	37
Regulatory liabilities and deferred credits	—	—	—	—	—	3	61	—
Investments and other assets	—	—	—	—	—	3	—	—
Other	106	18	22	12	10	5	2	9
Valuation allowance	(519)	—	—	—	—	—	—	—
Total deferred income tax assets	5,259	720	1,032	427	560	56	319	71
Investments and other assets	(1,671)	(983)	(521)	(432)	(102)	—	(12)	(28)
Accelerated depreciation rates	(11,478)	(3,410)	(4,358)	(1,844)	(2,576)	(1,192)	(1,606)	(892)
Regulatory assets and deferred debits, net	(2,074)	(480)	(1,300)	(628)	(671)	—	—	(21)
Total deferred income tax liabilities	(15,223)	(4,873)	(6,179)	(2,904)	(3,349)	(1,192)	(1,618)	(941)
Net deferred income tax liabilities	$ (9,964)	$ (4,153)	$ (5,147)	$ (2,477)	$ (2,789)	$ (1,136)	$ (1,299)	$ (870)

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

UNRECOGNIZED TAX BENEFITS

The following tables present changes to unrecognized tax benefits.

				Year Ended December 31, 2023				
		Duke		Duke	Duke	Duke	Duke	
	Duke	Energy	Progress	Energy	Energy	Energy	Energy	
(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Unrecognized tax benefits – January 1	$ 65	$ 17	$ 19	$ 13	$ 5	$ 1	$ 2	$ 9
Gross decreases – tax positions in prior periods	(15)	—	—	—	—	—	—	—
Gross increases – current period tax positions	12	4	5	5	1	1	1	2
Total changes	(3)	4	5	5	1	1	1	2
Unrecognized tax benefits – December 31	$ 62	$ 21	$ 24	$ 18	$ 6	$ 2	$ 3	$ 11

				Year Ended December 31, 2022				
		Duke		Duke	Duke	Duke	Duke	
	Duke	Energy	Progress	Energy	Energy	Energy	Energy	
(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Unrecognized tax benefits – January 1	$ 51	$ 13	$ 15	$ 10	$ 4	$ 1	$ 2	$ 4
Gross increases – current period tax positions	14	4	4	3	1	—	—	5
Total changes	14	4	4	3	1	—	—	5
Unrecognized tax benefits – December 31	$ 65	$ 17	$ 19	$ 13	$ 5	$ 1	$ 2	$ 9

				Year Ended December 31, 2021				
		Duke		Duke	Duke	Duke	Duke	
	Duke	Energy	Progress	Energy	Energy	Energy	Energy	
(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Unrecognized tax benefits – January 1	$ 125	$ 10	$ 10	$ 6	$ 3	$ 1	$ 1	$ 1
Gross decreases – tax positions in prior periods[(a)]	(86)	—	—	—	—	—	—	—
Gross increases – current period tax positions	12	3	5	4	1	—	1	3
Total changes	(74)	3	5	4	1	—	1	3
Unrecognized tax benefits – December 31	$ 51	$ 13	$ 15	$ 10	$ 4	$ 1	$ 2	$ 4

(a) In 2021, the Company recognized a federal capital gain in the amount of $426 million. As a result of the capital gain, a previously recorded unrecognized tax benefit related to the character of a taxable loss has been reversed. See note (a) under the Statutory Rate Reconciliation table for more details.

The following table includes additional information regarding the Duke Energy Registrants' unrecognized tax benefits at December 31, 2023. None of Duke Energy Registrants anticipates a material increase or decrease in unrecognized tax benefits within the next 12 months.

				December 31, 2023				
		Duke		Duke	Duke	Duke	Duke	
	Duke	Energy	Progress	Energy	Energy	Energy	Energy	
(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Amount that if recognized, would affect the effective tax rate or regulatory liability[(a)]	$ 67	$ 20	$ 22	$ 18	$ 6	$ 2	$ 3	$ 10

(a) The Duke Energy Registrants are unable to estimate the specific amounts that would affect the ETR versus the regulatory liability.

Duke Energy and its subsidiaries are no longer subject to federal, state, local or non-U.S. income tax examinations by tax authorities for years before 2018, aside from certain tax attributes carried forward for utilization in future years.

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, 2023				
		Duke		Duke	Duke	Duke	Duke	
	Duke	Energy	Progress	Energy	Energy	Energy	Energy	
(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Interest income	$ 29	$ 10	$ 14	$ 9	$ 7	$ 25	$ 25	$ 19
AFUDC equity	198	91	67	52	15	9	10	21
Post-in-service equity returns	39	19	19	19	—	1	—	—
Nonoperating income, other	332	118	101	44	56	6	41	17
Other income and expense, net	$ 598	$ 238	$ 201	$ 124	$ 78	$ 41	$ 76	$ 57

				Year Ended December 31, 2022				
		Duke		Duke	Duke	Duke	Duke	
	Duke	Energy	Progress	Energy	Energy	Energy	Energy	
(in millions)	Energy	Carolinas	Energy	Progress	Florida	Ohio	Indiana	Piedmont
Interest income	$ 27	$ 2	$ 24	$ 4	$ 20	$ 11	$ 15	$ 19
AFUDC equity	197	98	68	52	16	7	13	11
Post-in-service equity returns	34	14	18	18	—	1	1	—
Nonoperating income, other	134	107	71	40	38	—	7	16
Other income and expense, net	$ 392	$ 221	$ 181	$ 114	$ 74	$ 19	$ 36	$ 46

(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, 2021							
Interest income	$ 13	$ 4	$ 8	$ 6	$ 2	$ 4	$ 6	$ 19
AFUDC equity	171	65	51	34	16	7	27	20
Post-in-service equity returns	39	21	16	16	—	1	1	—
Nonoperating income, other	413	180	140	87	53	6	8	16
Other income and expense, net	$ 636	$ 270	$ 215	$ 143	$ 71	$ 18	$ 42	$ 55

26. SUBSEQUENT EVENTS

For information on subsequent events related to regulatory matters, commitments and contingencies, debt and credit facilities, and asset retirement obligations, see Notes 4, 5, 7 and 10, respectively.

27. QUARTERLY FINANCIAL DATA (UNAUDITED)

DUKE ENERGY

Quarterly EPS amounts may not sum to the full-year total due to changes in the weighted average number of common shares outstanding and rounding.

(in millions, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2023					
Operating revenues	$ 7,276	$ 6,578	$ 7,994	$ 7,212	$ 29,060
Operating income	1,674	1,430	2,111	1,855	7,070
Income from continuing operations	960	761	1,473	1,135	4,329
Loss from discontinued operations, net of tax	(209)	(955)	(152)	(139)	(1,455)
Net income (loss)	761	(204)	1,321	996	2,874
Net income (loss) available to Duke Energy Corporation common stockholders	765	(234)	1,213	991	2,735
Earnings per share,					
Income from continuing operations available to Duke Energy Corporation common stockholders					
Basic and diluted	$ 1.20	$ 0.91	$ 1.83	$ 1.41	$ 5.35
Loss from discontinued operations attributable to Duke Energy Corporation common stockholders					
Basic and diluted	$ (0.19)	$ (1.23)	$ (0.24)	$ (0.14)	$ (1.81)
Net income (loss) available to Duke Energy Corporation common stockholders					
Basic and diluted	$ 1.01	$ (0.32)	$ 1.59	$ 1.27	$ 3.54
2022					
Operating revenues	$ 7,011	$ 6,564	$ 7,842	$ 7,351	$ 28,768
Operating income	1,314	1,448	2,056	1,194	6,012
Income from continuing operations	835	898	1,410	635	3,778
(Loss) Income from discontinued operations, net of tax	(15)	(18)	3	(1,293)	(1,323)
Net income (loss)	820	880	1,413	(658)	2,455
Net income (loss) available to Duke Energy Corporation common stockholders	818	893	1,383	(650)	2,444
Earnings per share:					
Income from continuing operations available to Duke Energy Corporation common stockholders					
Basic and diluted	$ 1.06	$ 1.11	$ 1.78	$ 0.80	$ 4.74
Income (Loss) from discontinued operations attributable to Duke Energy Corporation common stockholders					
Basic and diluted	$ 0.02	$ 0.03	$ 0.03	$ (1.66)	$ (1.57)
Net income (loss) available to Duke Energy Corporation common stockholders					
Basic and diluted	$ 1.08	$ 1.14	$ 1.81	$ (0.86)	$ 3.17

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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)	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 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year					(51,093)	(54,627)	(105,720)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income						31,554	31,554		
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)						31,554	31,554	1,010,255,250	1,010,286,804
5	Balance of Account 219 at End of Preceding Quarter/Year					(51,093)	(23,073)	(74,166)		
6	Balance of Account 219 at Beginning of Current Year					(51,093)	(23,073)	(74,166)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income						31,554	31,554		
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)						31,554	31,554	995,109,890	995,141,444
10	Balance of Account 219 at End of Current Quarter/Year					(51,093)	8,481	(42,612)		

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	31,900,536,949	31,900,536,949					
4	Property Under Capital Leases	869,695,761	(a)869,695,761					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	3,309,258,081	3,309,258,081					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	36,079,490,791	36,079,490,791					
9	Leased to Others							
10	Held for Future Use	36,526,451	36,526,451					
11	Construction Work in Progress	1,660,121,830	1,660,121,830					
12	Acquisition Adjustments	349,801,943	349,801,943					
13	Total Utility Plant (8 thru 12)	38,125,941,015	38,125,941,015					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	15,283,946,602	15,283,946,602					
15	Net Utility Plant (13 less 14)	22,841,994,413	22,841,994,413					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	14,634,385,797	14,634,385,797					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	542,174,799	542,174,799					
22	Total in Service (18 thru 21)	15,176,560,596	15,176,560,596					
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	Amortization of Plant Acquisition Adjustment	107,386,006	107,386,006					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	15,283,946,602	15,283,946,602					

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases

Property Under Capital Leases includes both Net Capital Leases of $552,113,756 and Net Operating Leases of $317,582,005.

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)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	12,009,180	29,813,581		[a]20,077,799	21,744,962
3	Nuclear Materials	204,171,433	168,018,633		[b]71,657,886	300,532,180
4	Allowance for Funds Used during Construction	15,486,043	14,499,895		[c]4,414,721	25,571,217
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)	231,666,655				347,848,358
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)		96,150,406		[d]96,150,406	
9	In Reactor (120.3)	783,079,291	96,150,406		[e]87,848,039	791,381,658
10	SUBTOTAL (Total 8 & 9)	783,079,291				791,381,658
11	Spent Nuclear Fuel (120.4)	342,972,447	87,848,039		[f]133,172,830	297,647,656
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	749,081,141		(186,250,121)	[g]133,172,830	802,158,432
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	608,637,252				634,719,240
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer of Nuclear Fuel Materials and Assemblies to Stock

(b) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer of Nuclear Fuel Materials and Assemblies to Stock

(c) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer of Nuclear Fuel Materials and Assemblies to Stock

(d) Concept: NuclearFuelMaterialsAndAssembliesInStockOtherReductions

Transfer to Reactor

(e) Concept: NuclearFuelAssembliesInReactorOtherReductions

Reflects Nuclear Fuel Assemblies transferred to Spent Fuel Pool

(f) Concept: SpentNuclearFuelOtherReductions

Reflects Nuclear Fuel Asselmblies retired from Reactor

(g) Concept: AccumulatedProvisionForAmortizationOfNuclearFuelAssembliesOtherReductions

Reflects Nuclear Fuel Asselmblies retired from Reactor

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 the 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) 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.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	115,161		40,263			74,898
3	(302) Franchise and Consents	78,228,470					78,228,470
4	(303) Miscellaneous Intangible Plant	967,391,159	16,863,581	457,014		2,946,129	986,743,855
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	1,045,734,790	16,863,581	497,277		2,946,129	1,065,047,223
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	23,385,652	323,089				23,708,741
9	(311) Structures and Improvements	572,731,187	12,554,438	34,919		(553,697)	584,697,009
10	(312) Boiler Plant Equipment	2,628,886,373	14,093,416	10,358,629			2,632,621,160
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	344,512,721	9,173,887	3,989,918			349,696,690
13	(315) Accessory Electric Equipment	238,817,056	1,716,059	111,703			240,421,412
14	(316) Misc. Power Plant Equipment	53,446,199	2,051,640	116,582			55,381,257
15	(317) Asset Retirement Costs for Steam Production	1,069,169,224		(140,007,731)	(177,360,989)		1,031,815,966
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,930,948,412	39,912,529	(125,395,980)	(177,360,989)	(553,697)	4,918,342,235
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	67,855,764		376,957			67,478,807
19	(321) Structures and Improvements	3,277,817,250	52,261,915	9,950,400			3,320,128,765
20	(322) Reactor Plant Equipment	2,814,315,257	66,200,367	22,351,402			2,858,164,222
21	(323) Turbogenerator Units	1,450,931,697	26,473,956	8,268,495			1,469,137,158
22	(324) Accessory Electric Equipment	1,304,814,288	16,650,561	2,848,837			1,318,616,012
23	(325) Misc. Power Plant Equipment	736,020,196	31,717,416	110,708			767,626,904
24	(326) Asset Retirement Costs for Nuclear Production	1,574,990,350			(1,700,000,000)		(125,009,650)
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	11,226,744,802	193,304,215	43,906,799	(1,700,000,000)		9,676,142,218
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	2,740,441					2,740,441

28	(331) Structures and Improvements	23,952,651	1,553,123	64,452			25,441,322
29	(332) Reservoirs, Dams, and Waterways	123,961,315	12,245,854	3,402,610			132,804,559
30	(333) Water Wheels, Turbines, and Generators	61,892,108	6,461,334	539,420			67,814,022
31	(334) Accessory Electric Equipment	28,143,662	1,982,009	(4,992)			30,130,663
32	(335) Misc. Power Plant Equipment	5,541,091	731,789	707			6,272,173
33	(336) Roads, Railroads, and Bridges	21,205					21,205
34	(337) Asset Retirement Costs for Hydraulic Production	1,734,119					1,734,119
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	247,986,592	22,974,109	4,002,197			266,958,504
36	D. Other Production Plant						
37	(340) Land and Land Rights	10,027,014		23			10,026,991
38	(341) Structures and Improvements	434,787,406	(5,314,910)	548,370		553,697	429,477,823
39	(342) Fuel Holders, Products, and Accessories	397,120,384	(2,934,747)	1,892,274			392,293,363
40	(343) Prime Movers	2,301,114,141	79,265,996	24,131,042			2,356,249,095
41	(344) Generators	756,834,436	725,898	89,599			757,470,735
42	(345) Accessory Electric Equipment	413,017,848	8,029,313	2,755,090			418,292,071
43	(346) Misc. Power Plant Equipment	68,802,016	2,485,371	52,452			71,234,935
44	(347) Asset Retirement Costs for Other Production	7,642,438	2,267,154				9,909,592
44.1	(348) Energy Storage Equipment - Production	5,406,795	23,750,251				29,157,046
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	4,394,752,478	108,274,326	29,468,850		553,697	4,474,111,651
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	20,800,432,284	364,465,179	(48,018,134)	(1,877,360,989)		19,335,554,608
47	3. Transmission Plant						
48	(350) Land and Land Rights	208,255,499	6,724,436	4,380		660,101	215,635,656
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	177,344,119	8,167,650	1,433,603		(1,024,544)	183,053,622
50	(353) Station Equipment	1,329,264,422	92,217,938	(4,073,876)		(20,221,404)	1,405,334,832
51	(354) Towers and Fixtures	69,006,252	20,081,091	(92,382)			89,179,725
52	(355) Poles and Fixtures	1,022,056,089	110,585,260	(428,331)		(3,669,805)	1,129,399,875
53	(356) Overhead Conductors and Devices	878,574,167	111,058,986	5,670,505		3,669,805	987,632,453
54	(357) Underground Conduit	1,358,373	268,169	24,356			1,602,186
55	(358) Underground Conductors and Devices	21,801,273	453,495				22,254,768
56	(359) Roads and Trails	827,652					827,652
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	3,708,487,846	349,557,025	2,538,255		(20,585,847)	4,034,920,769
59	4. Distribution Plant						
60	(360) Land and Land Rights	106,139,655	8,203,142	66,170		4,720,294	118,996,921
61	(361) Structures and Improvements	149,428,454	19,397,796	734,591		1,026,633	169,118,292
62	(362) Station Equipment	1,068,711,005	108,544,172	(1,683,856)		20,658,336	1,199,597,369
63	(363) Energy Storage Equipment – Distribution	5,406,795	3,871,608	1,653			9,276,750
64	(364) Poles, Towers, and Fixtures	1,007,052,313	116,849,205	6,484,198			1,117,417,320
65	(365) Overhead Conductors and Devices	1,691,818,956	243,774,292	32,015,958			1,903,577,290

66	(366) Underground Conduit	252,978,455	34,967,632	119,153			287,826,934
67	(367) Underground Conductors and Devices	1,644,878,540	227,554,453	3,616,593			1,868,816,400
68	(368) Line Transformers	1,356,414,933	107,408,695	(1,878,763)		(448,217)	1,465,254,174
69	(369) Services	919,790,473	99,158,067	(5,155,970)			1,024,104,510
70	(370) Meters	337,756,067	18,317,122	31,058		3,560,943	359,603,074
71	(371) Installations on Customer Premises	369,091,246	15,847,959	4,808,473		(3,560,959)	376,569,773
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	326,590,182	21,364,824	3,986,667		16	343,968,355
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	9,236,057,074	1,025,258,967	43,145,925		25,957,046	10,244,127,162
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	8,259,546				3,678,527	11,938,073
87	(390) Structures and Improvements	339,285,171	37,567,958	3,238,635		9,197	373,623,691
88	(391) Office Furniture and Equipment	123,203,610	18,775,562	7,409,683			134,569,489
89	(392) Transportation Equipment	56,455,131	1,030,250	46,776			57,438,605
90	(393) Stores Equipment	2,049,787	84,775	14,692			2,119,870
91	(394) Tools, Shop and Garage Equipment	108,698,767	6,702,566	1,204,627			114,196,706
92	(395) Laboratory Equipment	4,970,495	222,001	281,191		55,634	4,966,939
93	(396) Power Operated Equipment	13,215,502	582,829	690,221			13,108,110
94	(397) Communication Equipment	297,156,280	70,170,757	2,035,692			365,291,345
95	(398) Miscellaneous Equipment	14,640,730	2,070,257	363,262		21,465	16,369,190
96	SUBTOTAL (Enter Total of lines 86 thru 95)	967,935,019	137,206,955	15,284,779		3,764,823	1,093,622,018
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	2,717,588	3,399,070		(17,479,654)		(11,362,996)
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	970,652,607	140,606,025	15,284,779	(17,479,654)	3,764,823	1,082,259,022
100	TOTAL (Accounts 101 and 106)	35,761,364,601	1,896,750,777	13,448,102	(1,894,840,643)	12,082,151	35,761,908,784
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)	35,761,364,601	1,896,750,777	13,448,102	(1,894,840,643)	12,082,151	35,761,908,784

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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47	TOTAL					

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report, End of: 2023/ 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	VOLVO DEALERSHIP SUBSTATION LAND - BUNCOMBE, NC	12/01/2017	12/31/2030	8,084,116
3	CAPE FEAR - SILVER CITY 230KV LINE RIGHT OF WAY - CHATHAM, NC	11/01/2009	12/31/2024	5,260,176
4	ASHEVILLE SOLAR LAND - BUNCOMBE, NC	01/01/2020	12/31/2024	4,325,516
5	FLORENCE - MARION 230KV LINE RIGHT OF WAY - FLORENCE, SC	11/01/2009	12/31/2024	2,728,374
6	MCDOWELL STREET SUBSTATION LAND - BUNCOMBE, NC	06/01/2016	12/31/2026	2,305,226
7	FUQUAY BROAD STREET 115KV SUBSTATION LAND - WAKE, NC	02/01/2017	12/31/2025	1,476,200
8	MAYO UNIT 1 LAND - PERSON, NC	03/21/1983	12/31/2025	1,458,908
9	CAPE FEAR - SILVER CITY 230KV LINE RIGHT OF WAY - LEE, NC	11/01/2009	12/31/2024	1,375,369
10	NEWPORT 230KV SWITCHING STATION LAND - CARTERET, NC	11/01/2020	12/31/2024	1,361,668
11	REEMS CREEK 150KV SUBSTATION LAND - BUNCOMBE, NC	06/01/2019	12/31/2027	1,360,141
12	ASHEVILLE PATTON SUBSTATION LAND - BUNCOMBE, NC	04/01/2019	12/31/2025	1,267,446
13	CHATHAM PARK SUBSTATION LAND - CHATHAM, NC	08/01/2018	12/31/2028	1,043,619
14	HARMON 230KV SUBSTATION LAND - ONSLOW, NC	08/01/2016	12/31/2026	991,126
15	ASHEVILLE FLAT CREEK 115KV SUBSTATION LAND - BUNCOMBE, NC	02/01/2017	12/31/2027	963,966
16	FLORENCE - MARION 230KV LINE RIGHT OF WAY - MARION, SC	11/01/2009	12/31/2024	551,685
17	FLORENCE - MARION 230KV LINE RIGHT OF WAY - DILLON, SC	11/01/2009	12/31/2024	477,074
18	KENLY 115KV SUBSTATION LAND - JOHNSTON, NC	06/01/2011	12/31/2025	416,389
19	HARRIS EMERGENCY SPILLWAY LAND - WAKE, NC	05/01/2022	12/31/2030	266,503
20	Other Land and Land Rights < $250K Each (13 Items)			812,949
21	Other Property:			
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47	TOTAL			36,526,451

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - NORTH CAROLINA	53,140,885
3	SMART GRID CIRCUIT SECT SELF HEALING DEP	23,731,937
4	SMART GRID DEP - FEEDER CAPACITY	22,747,471
5	DEP WOODFIN SOLAR	9,072,024
6	SUBOPT - WENDELL 230KV - B02	7,870,302
7	PORTERS NECK 230KV - CONSTRUCT SUB	7,869,618
8	01CH5 ROUTINE MASTER	7,113,545
9	SUBOPT - CANDLER 115KV - B01	6,645,360
10	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - SOUTH CAROLINA	5,675,934
11	OXFORD SOUTH 230 KV SUB- ADD 2ND BA	5,331,697
12	SUBOPT - PITTSBORO 230K - B02	4,926,924
13	SUBOPT - PITTSBORO 230K - B03	4,836,630
14	SUBOPT - ASHEBORO WEST - B04	4,792,670
15	ATLANTIC BEACH 115KV - REBUILD SUBS	4,223,129
16	HOLLY SPRINGS UTLEY CREEK 230 KV SU	4,192,744
17	MORRISVILLE 230KV - ADD BANK #2	4,150,630
18	SUBOPT - RALEIGH HONEYCUTT 23 - B12	4,073,004
19	SUBOPT - RALEIGH DURHAM AIRPO - B03	3,850,880
20	DISTRIBUTION LIGHTING INSTALLATION	3,688,224
21	PENDER COMMERCE PARK DIST. COMMON	3,571,010
22	SUBOPT - RALEIGH SIX FORKS 23 - B03	3,561,344
23	SUBOPT - LAUREL HILL 23 - B05	3,449,522
24	SUBOPT - ASHEBORO WEST - B01	3,428,713
25	SUBOPT - ASHEBORO NORTH - B05	3,360,033
26	HARTSVILLE SONOCO 115KV - INSTALL C	3,287,774
27	SUBOPT - METHOD 230KV - B35	3,270,242
28	SUBOPT - RALEIGH DURHAM AIRPO - B02	3,264,472
29	DEP RIVERSIDE BESS	3,199,311
30	SUBOPT - FAIRVIEW 115KV - B03	3,050,309
31	DEP STRATEGIC COMMUNICATION	2,852,638
32	SUBOPT - FAIRVIEW 115KV - B01	2,792,593
33	SUBOPT - RALEIGH SIX FORKS 23 - B02	2,784,545

34	SUBOPT - RALEIGH WORTHD - B02		2,712,824
35	SUBOPT - RALEIGH SIX FORKS 23 - B04		2,696,914
36	SUBOPT - RALEIGH HONEYCUTT 23 - B11		2,415,640
37	SUBOPT - RALEIGH DURHAM AIRPO - B05		2,393,580
38	SUBOPT - LAKEVIEW 115KV - B12		2,366,346
39	SUBOPT - FUQUAY WADE NA - B21		2,352,736
40	SUMTER NORTH 230KV - REBUILD SUBSTA		2,343,352
41	SUBOPT - RALEIGH SIX FORKS 23 - B05		2,271,520
42	SUBOPT - FUQUAY 230KV - B03		2,271,235
43	TWIN HARBOR PHASE 3 AND 4		2,254,365
44	SUBOPT - EDMONDSON 230K - B03		2,226,608
45	SUBOPT - OLANTA 230KV - B01		2,211,137
46	SUBOPT - WENDELL 230KV - B01		2,183,226
47	SUBOPT - FUQUAY 230KV - B04		2,175,576
48	MOBILE STORAGE FACILITY		2,168,035
49	SUBOPT - REYNOLDS 115KV - B13		2,140,629
50	SUBOPT - BLACK MOUNTAIN - B02		2,127,277
51	2022 CE FAILED EQUIPMENT NONENG		2,070,250
52	SUBOPT - MORRISVILLE 23 - B03		2,064,817
53	SUBOPT - WADESBORO-BOWM - B03		1,982,923
54	SUBOPT - KNIGHTDALE HOD - B11		1,976,679
55	SUBOPT - GARNER 115KV - B02		1,901,153
56	SUBOPT - AMBERLY 230KV - B13		1,888,330
57	NEW GRIFOLS LOAD AT POWHATAN AND CL		1,875,069
58	SUBOPT - BLACK MOUNTAIN - B01		1,872,272
59	SUBOPT - GARLAND 230KV - B01		1,805,569
60	SUBOPT - HENDERSON NORTH 115KV-B01		1,804,191
61	HARTSVILLE 115KV - REBUILD SUBSTATI		1,794,822
62	TABOR CITY 115KV - REBUILD SUBSTATI		1,791,017
63	SUBOPT - ASHEBORO NORTH - B01		1,782,243
64	SUBOPT - CLINTON FERREL - B02		1,766,427
65	SUBOPT - CLIFDALE 230KV - B01		1,737,806
66	CARY TRIANGLE EXPRESSWAY 230KV - CO		1,706,816
67	SUBOPT - BAHAMA 230KV - B01		1,698,354
68	SUBOPT - WILMINGTON EAST 230KV		1,694,863
69	RTP 230 - ADD 3RD BANK		1,689,661
70	SUBOPT - SCOTT'S HILL 2 - B21		1,672,146
71	SUMTER NORTH 230 KV - REPLACE T2 TR		1,669,664
72	SUBOPT - ASHEBORO NORTH - B11		1,614,833
73	SUBOPT - SUMTER WEDGEFI - B05		1,604,994

74	SMARTGRID DEP TRANSFORMER RETROFIT		1,590,962
75	SUBOPT - ELIZABETHTOWN - B01		1,588,465
76	NORTH HILLS TOWER 5 PROJECT		1,578,314
77	SUBOPT - LAKEVIEW 115KV - B13		1,569,575
78	SUBOPT - CLIFDALE 230KV - B03		1,564,687
79	SUBOPT - PITTSBORO 230K - B01		1,550,565
80	SUBOPT - SILER CITY 115 - B02		1,509,475
81	SUBOPT - WEST ASHEVILLE - B12		1,508,449
82	SUBOPT - RALEIGH SIX FORKS 23 - B01		1,487,059
83	SUBOPT - WHITEVILLE SOU - B11		1,467,843
84	SUBOPT - ASHEBORO SOUTH - B05		1,437,980
85	SUBOPT - RALEIGH DURHAM AIRPO - B04		1,437,808
86	SUBOPT - REYNOLDS 115KV - B12		1,434,538
87	SELMA BUFFALO ROAD 230KV - ACQUIRE		1,426,499
88	RIEGELWOOD TRANSFORMER BANK		1,394,418
89	SUBOPT - TOPSAIL 230KV - B03		1,380,531
90	RUSD ASHEVILLE PATTON SUBSTATION		1,354,850
91	VANDERBILT 115KV SUBSTATION - REBUI		1,348,702
92	SUBOPT - CASTLE HAYNE 2 - B11		1,340,516
93	SUBOPT - CLINTON FERREL - B01		1,338,268
94	SUBOPT-WARSAW 23KV		1,325,482
95	SUBOPT - RALEIGH DURHAM - B12		1,322,014
96	SUBOPT - ASHEBORO NORTH - B02		1,311,085
97	SUBOPT - WILMINGTON EAS - B01		1,299,238
98	SUBOPT - FLORENCE 230KV - B21		1,294,522
99	SUBOPT - VANDERBILT 115 - B02		1,285,991
100	SUBOPT - CARY TRIANGLE - B02		1,282,477
101	SUBOPT - ASHEBORO SOUTH - B03		1,280,360
102	SUBOPT - EDMONDSON 230K - B21		1,273,500
103	SUBOPT - WEST ASHEVILLE - B16		1,267,520
104	SUBOPT-FOXPORT 23KV		1,256,945
105	SUBOPT - BLACK MOUNTAIN - B03		1,252,795
106	SUBOPT - JONESBORO 230K - B01		1,220,925
107	SUBOPT - SPRING LAKE 11 - B11		1,208,589
108	SUBOPT - ZEBULON 115KV - B15		1,195,087
109	DEP LONG DURATION OUTAGES		1,189,366
110	CHADBOURN 115KV - REBUILD SUBSTATIO		1,162,747
111	SUBOPT - LAKE CITY 230K - B03		1,158,336
112	WAKE TECH 230KV - ADD 2ND BANK		1,154,284
113	SUBOPT - MORDECAI 115KV - B04		1,147,490

114	SUBOPT - OXFORD SOUTH 2 - B03	1,133,904
115	50205.1.1, R-5709, WEST PALMER ST &	1,127,790
116	SUBOPT - FAIRVIEW 115KV - B02	1,118,913
117	SUBOPT - WEST ASHEVILLE - B11	1,102,923
118	SUBOPT - NEW HOPE 115KV - B03	1,099,089
119	SUBOPT - JONESBORO 230K - B05	1,075,964
120	SUBOPT - NEW BERN WEST - B05	1,075,387
121	ABERDEEN 115KV SUBSTATION RELIEF	1,072,802
122	SUBOPT - GARNER WHITE O - B11	1,065,564
123	SUBOPT - ASHEVILLE ROCK - B01	1,057,492
124	SUBOPT - ZEBULON 115KV - B04	1,055,219
125	SUBOPT - CLEVELAND MATT - B21	1,042,080
126	RIVER ROUTE	1,039,892
127	SUBOPT - AMBERLY 230KV - B11	1,027,952
128	SUBOPT - SOUTHERN PINES - B02	1,014,083
129	SUBOPT - RHEMS 230KV - B02	1,008,154
130	SUBOPT - FAIRVIEW 115KV - B04	1,007,766
131	SUBOPT - GARNER 115KV - B01	1,007,513
132	SUBOPT - TOPSAIL 230KV - B01	1,007,146
133	PROJECTS LESS THAN $1 MILLION	178,019,049
134	GENERAL PLANT	
135	DEP LMR PROJECT 4 DEP	40,872,841
136	CARY-LINE & SERVICE BUILDING	27,742,101
137	DEP STRATEGIC COMMUNICATION	14,215,575
138	IT FUNDING PROJECT 50126	12,257,330
139	FLEET DEP VEHICLES	8,849,425
140	DEP TOWERS, SHELTERS, & POWER SUPPLIES	8,470,519
141	ENERGY SERVICES DEP REG FUNDING PROJECT	7,696,220
142	PROGRESS ENERGY CAROLINAS ACCRUAL	6,600,670
143	SMART GRID - DUKE ENERGY ENTERPRISE DISTRIBUTED MANAGEMENT SYSTEM ADMS	3,286,099
144	DEP MICROWAVE	3,134,094
145	FUNDING PROJECT FOR IT DEMAND	2,615,296
146	SG DEP 2G/3G REPLACE	2,420,763
147	WEBFG REPLACEMENT	1,400,558
148	DEP GRIDWAN CORE ROUTER UPFIT	1,343,076
149	GENERIC CAPITAL COSTS	1,271,416
150	FUNDING PROJECT 2023 TELECOM DVV	1,233,316
151	DEP OPTICAL ELECTRONICS	1,033,244
152	DEE CONSOLES PROJECT	1,029,351
153	PROJECTS LESS THAN $1 MILLION	5,810,956

154	INTANGIBLE PLANT	
155	SMART GRID - DUKE ENERGY ENTERPRISE DISTRIBUTED MANAGEMENT SYSTEM ADMS	28,230,386
156	IT FUNDING PROJECT 50126	6,409,932
157	DEE DER DISPATCH DESIGN AND DEVELOP	5,780,081
158	IT PE CAROLINAS CUSTOMER FUNDING	2,756,272
159	DEE EAM NEXTGEN GIS	2,729,292
160	DEE GRID HOSTING CAPACITY	2,260,849
161	ENERGY ORCHESTRATION CAPITAL	2,256,000
162	DEP DMS UPGRADE	2,198,371
163	DEP SCADA UPGRADE	2,127,045
164	CUSTOMER CONNECT FUNDING PROJECT	1,789,406
165	HARRIS NUCLEAR PLANT - FATIGUEPRO METAL MONITORING	1,712,442
166	FUNDING PROJECT FOR IT DEMAND	1,364,241
167	HEAT RATE OPTIMIZATION - DEP	1,207,479
168	DEE VEG MGMT REMOTE SENSING	1,117,319
169	OUTDOOR LIGHT CONTRLS SOFTWARE	1,011,797
170	PROJECTS LESS THAN $1 MILLION	7,578,356
171	PRODUCTION PLANT	
172	BLEWETT HYDROELECTRIC FISH PASSAGE	72,455,438
173	CCP ROX-505 AFTERBAY DAM OVERTOP	21,540,652
174	WARSAW ENERGY STORAGE	20,929,405
175	BRUNWICK NUCLEAR U2 ERFIS	20,750,373
176	OPTIM CT HGP SMITH 6 & AGP PEAKER	20,294,470
177	HARRIS PLANT PROCESS COMPUTER	19,870,765
178	RNP SUBSEQUENT LICENSE RENEWAL	19,474,059
179	ROBINSON PLANT PROCESS COMPUTERS	14,324,472
180	HNP TRANSFORMERS (ASUT BUAT SPARE)	14,009,545
181	GIDEON SOLAR	11,289,992
182	BNP U1 ERFIS	11,237,478
183	HNP DICSP TECH REFRESH	10,424,708
184	HARRIS LICENSE RENEWAL	10,264,805
185	TL U1 TURBINE RUNNER REPLACE DO	9,583,731
186	BRUNSWICK UNIT 2 PPC/ERFIS SOFTWARE	9,478,701
187	ROBINSON NUCLEAR DCS SFTWR LIC & LIFE CYCL MGMT	8,792,166
188	SAFETY RELATED BATTERY CHARGERS	8,788,529
189	BNP RADWASTE REGEN VESSEL LINER REP	8,576,446
190	BRUNSWICK UNIT 1 FEEDWATER HEATER	8,075,586
191	RNP SPILLWAY GATE AND GATE HOIST RE	7,364,940
192	NGO STEAM GEN INSPECTION EQ	7,065,244
193	HNP TRANSFORMER REPLACEMENT	6,558,102

194	BNP UNIT 1 PLANT PROCESS COMPUTER (		6,539,037
195	BNP CONTROL ROOM HVAC UPGRADE		6,334,550
196	RNP PHASE 5 DRY STORAGE OVERPACKS		5,879,841
197	BNP PHASE 4 DRY STORAGE OVERPACKS		5,841,954
198	LTSA U10 ROTOR REPLACEMENT ADDER		5,787,705
199	LTSA U9 ROTOR REPLACEMENT ADDER		5,765,388
200	TL U3 TURBINE RUNNER REPLACE DO		5,611,071
201	BNP U2 SERVICE WATER BURIED PIPING		5,066,707
202	RNP-RPL MAIN GEN VOLTG REGULATOR		5,021,589
203	BRUNSWICK PERIMETER INTRUSION DETECTION		4,880,812
204	PB5 NEW COMPRESSOR BUILDING		4,844,694
205	TL U4 GENERATOR REWIND CORE REPL		4,723,503
206	HNP GSI 191 IN-VESSEL EFFECTS		4,618,049
207	BRUNSWICK UNIT 2 TRAVEL SCREEN INSTRUMENT IMPROVEMENT		4,520,215
208	HNP IMAC 3		4,200,200
209	SAFETY RELATED CHILLERS		4,181,367
210	RNP-SPILLWAY ELECTRICAL UPGRADES		3,881,527
211	DEP DISTRIBUTED ENERGY STUDY		3,831,943
212	BNP UNIT 2 MSIV PERFORMANCE ENHANCE		3,771,451
213	HARRIS FIRE DETECTION SYSTEM		3,768,706
214	BRUNSWICK UNIT 1 TRAVEL SCREEN INSTRUMENT IMPROVEMENT		3,686,839
215	BNP- NON-DCS RECORDER (L&N)		3,585,329
216	HARRIS HEATER DRAIN SYSTEM TO DCS		3,559,321
217	SMITH PB4 CT7 HEAT RATE UPGRADE		3,415,967
218	SMITH PB4 CT8 HEAT RATE UPGRADE		3,415,967
219	BNP FW HEATER REPL 5A/5B U2		2,945,467
220	RNP U2 CORE BARREL UPPER GIRTH WELD		2,931,214
221	BNP PLC FOR FUEL POOL COOLING FLOW		2,876,152
222	BNP UNIT1 MSIV PERFORMANCE ENHANCE		2,873,116
223	BNP U2 CWOD 2C PUMP REPLACEMENT		2,799,933
224	HNP FEEDWATER REGULATING VALVES		2,781,075
225	RX00 STATION GMA		2,762,677
226	REPLACE VITAL AREA DOOR CONTROLLERS		2,760,461
227	BPO U1 TB PERMANENT TEMP POWER INS		2,753,129
228	BNP U1 CWOD 1A PUMP REPLACEMENT		2,712,868
229	BRUNSWICK UNIT 2 MOISTURE SEPARATER REHEATER		2,617,998
230	BNP GENERATOR VOLTAGE REGULATOR REP		2,511,731
231	ROBINSON CONDENSATE POLISHING DCS		2,372,607
232	NGO EDE REPLACEMENT		2,361,654
233	BNP SIMULATOR MIGRATION		2,215,136

234	BNP RHR PUMP SEAL COOLER RPLCMENT		2,124,197
235	BPO U1 SW BURIED PIPING B1R25		2,118,806
236	RNP SPILLWAY VALVE REPLACEMENTS		2,081,757
237	BNP U1 EHC SKID		2,046,676
238	ROBINSON UNDER VESSEL INSULATION		2,040,161
239	RX00 ROXBORO MILLS GMA 2021		1,915,470
240	BNP INTAKE BANKING PROJECT		1,909,184
241	BNP U2 BNP VFD MODIFICATION		1,906,382
242	CNTRLS SNCC OVATION EVERGREEN		1,830,417
243	BNP UPGRADE U1 MSR C/H DRAIN VALVES		1,744,832
244	RNP STEAM GENERATOR BLOWN/WET LAY		1,678,950
245	BNP U1 VFD MODIFICATIONS		1,643,086
246	BNP U1 TB ROOF REPLACEMENT		1,599,134
247	BPO SITE COM UPGRADE AND BROADCAST		1,568,608
248	BNP RADWASTE U1 CPS TANK/PIPES/VALV		1,535,825
249	NGO RNP NPS TOWER SECTION REPL		1,531,500
250	RX00 ROX COAL MILL CAP UOP REPLACE		1,521,424
251	BNP VALVE BLANKET		1,520,925
252	MLH U2-COMMON ELECTRICAL LIFE EXT		1,510,910
253	BNP U2 DIGITAL FW CONTROLS		1,504,306
254	HNP FIRE DET PANELS 6, 7-1, & 7 -2		1,498,300
255	RNP - WASTE WATER RE-ROUTING		1,479,087
256	ROBINSON UNIT 2 MAKE-UP WATER TREATMENT DCS		1,478,339
257	BNP DICSP HARD/SOFTWARE LIFE MGMT		1,417,880
258	TL FLOODGATE LIFE EXTENSION		1,403,304
259	DEP WSC0 CT DIGITAL AUTOMATION		1,379,373
260	OPTIM CT MJR AND REOL UNIT 7		1,336,080
261	BRUNSWICK UNIT 1 REMOTE ELECTRIC LIFT & TRAVERSING CRANE		1,323,596
262	NGO FLEET FIREWALL UPGRADES		1,288,756
263	DEP BLC0 CT DIGITAL AUTOMATION		1,275,865
264	BNP 13-0182 EOF-TSC AHU		1,249,847
265	BNP U1 SPV 1(2)IA-PCV-2878		1,248,296
266	RNP- BLDG 320 RENOVATION		1,243,853
267	MY00 STATION GMA		1,175,228
268	BNP MSIV TOOL UPGRADE		1,156,230
269	RX03 3A/B NH3 VAPORIZER REPLACEMENT		1,151,691
270	HNP R25 PCCP REPLACEMENT		1,143,388
271	BRUNSWICK UNIT 2 REMOTE ELECTRIC LIFT & TRAVERSING CRANE		1,140,613
272	BNP-17-0017; EDG OVERSPEED TRIP MOD		1,130,980
273	BNP U1 CWOD 1D PUMP REPLACEMENT		1,129,456

274	BNP U2 CWOD 2B PUMP REPLACEMENT		1,129,456
275	BNP U2 RWCU VALVE 2-G31-F001/F004		1,127,799
276	2022/23 FIT- CAMERAS OPS/MONITORING		1,112,969
277	BNP STATION SCIENCES 23 EQUIP		1,101,551
278	BNP GROUNDWATER SWIM		1,098,032
279	BNP SIPHON STRUCTURE UPGRADES		1,087,955
280	BNP CWIP MOTOR REPLACEMENTS		1,048,235
281	RX02 BURNER REPLACEMENTS		1,044,882
282	NGO PMMD SERVER INFRASTRUCTURE UPGR		1,036,926
283	HNP CTMU-1X PUMP & MOTOR REPLACEMEN		1,015,471
284	PROJECTS LESS THAN $1 MILLION		107,138,861
285	TRANSMISSION PLANT		
286	MAYO-PERSON 500 REPLACE LATTICE TOW		27,696,333
287	PROJECT HIBERNIAN - 200MW SOLUTION		18,692,612
288	CONSTRUCT NEW CRAGGY-ENKA 230 KV LINE		18,000,790
289	REEMS CREEK 115KV - CONSTRUCT SUBST		13,779,373
290	CAMP KANATA 230KV - CONSTRUCT NEW S		12,132,822
291	VINFAST - PHASE 1		8,574,497
292	VEGETATION MASTER PROJECT		7,265,358
293	BARNARD CREEK 230- SPLIT BNP LINE		7,258,106
294	ROCKINGHAM 230KV-REBUILD SUBSTATION		7,246,646
295	PITTSBORO HANKS CHAPEL 230KV SUB -		6,587,805
296	LAURINBURG 230 REPLACE 8 TOIL CIRCU		5,334,885
297	PORTERS NECK 230KV - CONSTRUCT SUB		4,618,049
298	FAYETTEVILLE 230KV - SB17 WORK		4,293,426
299	GREENVILLE 230KV - FLOODED SUBSTATI		3,959,327
300	ROXBORO 115 - ADD 18 MVAR CAPACITOR		3,177,361
301	ERWIN-FAYETTEVILLE EAST 230KV LINE		2,875,007
302	FAYETTEVILLE 230 KV SUBSTATION, ADD		2,606,858
303	CASTLE HAYNE-FOLKSTONE 115KV - LINE		2,599,922
304	CANTON-PISGAH FOREST-EXPAND ROW		2,295,452
305	DEP TOWERS, SHELTERS, & POWER SUPPLIES		1,960,581
306	CAPE FEAR WEST END 230KV LINE - RE		1,841,192
307	HNP - SB17 WORK		1,710,391
308	ROBINSON PLANT ROCKINGHAM 230KV LI		1,226,838
309	BNP U2 WHITEVILLE RELAY PANEL REPLA		1,207,756
310	CAPE FEAR TO SILER CITY LINES		1,162,686
311	PROJECTS LESS THAN $1 MILLION		30,183,279
43	Total		1,660,121,830

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 12, column (c), and that reported for electric plant in service, page 204, column (d), 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.

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)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	13,834,288,688	13,834,288,688		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	938,737,716	938,737,716		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,783,466	1,783,466		
7	Other Clearing Accounts	2,646	2,646		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
9.2	NDTF Decom	(3,933,666)	(3,933,666)		
9.3	Asheville CC Deferrals/Amort	(2,298,116)	(2,298,116)		
9.4	Wayne	(331,031)	(331,031)		
9.5	ABSAT Deferrals/Amort	(1,385,928)	(1,385,928)		
9.6	Sutton	(196,669)	(196,669)		
9.7	Rotable Spares Amortization	2,978,613	2,978,613		
9.8	Meter Reporting	298,847	298,847		
9.9	SmartGrid Deferral/Amort	3,955,068	3,955,068		
9.10	Other Misc. Depreciation	13,420	13,420		
9.11	Deferral of Accelerated Depreciation	11,911,278	11,911,278		
9.12	ARO Depr Expense Deferred	158,435,552	158,435,552		
9.13	ARO Depr Expense Deferred - (Coal Ash update)	(140,007,731)	(140,007,731)		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	969,963,465	969,963,465		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(21,464,940)	(a)(21,464,940)		
13	Cost of Removal	(208,399,359)	(208,399,359)		
14	Salvage (Credit)	69,999,095	69,999,095		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(159,865,204)	(159,865,204)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):				
17.2	Net Gain on Real Estate Transactions	(6,345,642)	(6,345,642)		

17.3	Transfer of Rotable Fleet Spares	(3,607,030)	(3,607,030)		
17.4	Mayo Settlement Impairment	(35,490)	(35,490)		
17.5	Wilmington Settlement Impairment	(12,990)	(12,990)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	14,634,385,797	14,634,385,797		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,761,917,130	[a]2,761,917,130		
21	Nuclear Production	5,663,712,863	[a]5,663,712,863		
22	Hydraulic Production-Conventional	60,637,337	[a]60,637,337		
23	Hydraulic Production-Pumped Storage				
24	Other Production	1,347,745,065	[a]1,347,745,065		
25	Transmission	962,037,502	[a]962,037,502		
26	Distribution	3,524,112,979	[a]3,524,112,979		
27	Regional Transmission and Market Operation				
28	General	314,222,921	[a]314,222,921		
29	TOTAL (Enter Total of lines 20 thru 28)	14,634,385,797	14,634,385,797		

FOOTNOTE DATA

(a) Concept: BookCostOfRetiredPlant

Intangible Retirements (0111100) of ($497,277) not reported on FERC Page 219 & Future Use Retirements of $8,514,120 not reported on FERC Page 204-207.

(b) Concept: AccumulatedDepreciationSteamProduction

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of accumulated provision in the current year are (a) $2,741,724,142 for Steam Production Plant, (b) $5,664,036,186 for Nuclear Production Plant, (c) $60,577,195 for Hyrdaulic Production Plant, (d) $1,349,302,547 for Other Production Plant, (e) $961,809,315 for Transmission Plant, (f) $3,523,620,001 for Distribution Plant and (g) $312,913,785 for General Plant.

(c) Concept: AccumulatedDepreciationNuclearProduction

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of accumulated provision in the current year are (a) $2,741,724,142 for Steam Production Plant, (b) $5,664,036,186 for Nuclear Production Plant, (c) $60,577,195 for Hyrdaulic Production Plant, (d) $1,349,302,547 for Other Production Plant, (e) $961,809,315 for Transmission Plant, (f) $3,523,620,001 for Distribution Plant and (g) $312,913,785 for General Plant.

(d) Concept: AccumulatedDepreciationHydraulicProductionConventional

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of accumulated provision in the current year are (a) $2,741,724,142 for Steam Production Plant, (b) $5,664,036,186 for Nuclear Production Plant, (c) $60,577,195 for Hyrdaulic Production Plant, (d) $1,349,302,547 for Other Production Plant, (e) $961,809,315 for Transmission Plant, (f) $3,523,620,001 for Distribution Plant and (g) $312,913,785 for General Plant.

(e) Concept: AccumulatedDepreciationOtherProduction

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of accumulated provision in the current year are (a) $2,741,724,142 for Steam Production Plant, (b) $5,664,036,186 for Nuclear Production Plant, (c) $60,577,195 for Hyrdaulic Production Plant, (d) $1,349,302,547 for Other Production Plant, (e) $961,809,315 for Transmission Plant, (f) $3,523,620,001 for Distribution Plant and (g) $312,913,785 for General Plant.

(f) Concept: AccumulatedDepreciationTransmission

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of accumulated provision in the current year are (a) $2,741,724,142 for Steam Production Plant, (b) $5,664,036,186 for Nuclear Production Plant, (c) $60,577,195 for Hyrdaulic Production Plant, (d) $1,349,302,547 for Other Production Plant, (e) $961,809,315 for Transmission Plant, (f) $3,523,620,001 for Distribution Plant and (g) $312,913,785 for General Plant.

(g) Concept: AccumulatedDepreciationDistribution

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of accumulated provision in the current year are (a) $2,741,724,142 for Steam Production Plant, (b) $5,664,036,186 for Nuclear Production Plant, (c) $60,577,195 for Hyrdaulic Production Plant, (d) $1,349,302,547 for Other Production Plant, (e) $961,809,315 for Transmission Plant, (f) $3,523,620,001 for Distribution Plant and (g) $312,913,785 for General Plant.

(h) Concept: AccumulatedDepreciationGeneral

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of accumulated provision in the current year are (a) $2,741,724,142 for Steam Production Plant, (b) $5,664,036,186 for Nuclear Production Plant, (c) $60,577,195 for Hyrdaulic Production Plant, (d) $1,349,302,547 for Other Production Plant, (e) $961,809,315 for Transmission Plant, (f) $3,523,620,001 for Distribution Plant and (g) $312,913,785 for General Plant.

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder 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.
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 from investments, including such revenues from 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 different 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	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)
1	CaroFund, Inc. Equity Contribution	08/15/1995		2,501,227	10,432		2,511,659	
2	CaroHome, LLC Equity Contribution	04/21/1995		24,372,169	1,538,789		25,910,958	
3	PowerHouse Square, LLC Equity Contribution	01/16/1998		513,039			513,039	
42	Total Cost of Account 123.1 $		Total	27,386,435	1,549,221		28,935,656	

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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)	186,850,138	263,768,961	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)	(a)475,914,498	(b)656,734,370	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	284,808,674	222,175,744	RRE
8	Transmission Plant (Estimated)	3,874,577	5,813,150	Transmission
9	Distribution Plant (Estimated)	14,328,931	29,771,399	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)	778,926,680	914,494,663	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	(14,813)	3,696	Customer Service
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	(c)40,273,508	(d)48,634,307	Electric
17				
18				
19				
20	TOTAL Materials and Supplies	1,006,035,513	1,226,901,627	

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Assigned to Construction: Production 312,082,013 Transmission 34,346,182 Distribution 129,486,303

(b) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Assigned to Construction: Production 411,713,981 Transmission 40,024,689 Distribution 204,995,701

(c) Concept: StoresExpenseUndistributed

Stores Expense: Production 31,005,998 Transmission 1,942,860 Distribution 7,324,650

(d) Concept: StoresExpenseUndistributed

Stores Expense: Production 33,602,200 Transmission 2,455,532 Distribution 12,576,575

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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.
6. Report on Line 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 acquired 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 and 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.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	[a]846,993	2,197,394	68,536		52,908		52,908		1,375,608		2,396,953	2,197,394
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
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												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													

28	Total												
29	Balance-End of Year	(a)846,993	2,197,394	68,536		52,908		52,908		1,375,608		2,396,953	2,197,394
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												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AllowanceInventoryNumber
Balance Includes allowances for Cross State Air Pollution Rule and Acid Rain Program
(b) Concept: AllowanceInventoryNumber
Balance Includes allowances for Cross State Air Pollution Rule and Acid Rain Program

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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.
6. Report on Line 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 acquired 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 and 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.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	(a)(b)62,216		11,703								73,919	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
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												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													

27													
28	Total												
29	Balance-End of Year	[a]62,216		11,703								73,919	
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												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AllowanceInventoryNumber

As of January 1, 2017, DE Progress is no longer subject to the requirements of the Cross State Air Pollution Rule Seasonal NOX Program

(b) Concept: AllowanceInventoryNumber

Balance Includes allowances for Cross State Air Pollution Rule and Acid Rain Program

(c) Concept: AllowanceInventoryNumber

Balance Includes allowances for Cross State Air Pollution Rule and Acid Rain Program

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
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11						
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16						
17						
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20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Mayo Unit 2 WS, 07/88 to 08/23	70,767				70,767
22	Rob Nuc Des, 02/95 to 07/30	1,441,006		407	52,242	1,388,764
23	Bruns Nuc Des, 02/95 to 08/36	7,795,907		407	231,562	7,564,345
24	Cape Fear Fsl WS, 10-18 yr	4,301,035		407	642,390	3,658,645
25	Lee Fsl WS, 23-31 yr	6,630,798		407	348,766	6,282,032
26	Rob Fsl WS, 27 yr	10,233,639		407	553,700	9,679,939
27	Sutton Fsl WS, 10-27 yr	9,268,369		407	981,296	8,287,073
28	Weatherspoon Fsl WS, 22-28 yr	1,908,188		407	128,146	1,780,042
29	Cape Fear CT WS, 10 yr	(27,690)		407	(27,690)	
30	Lee CT WS, 10 yr	92,701		407	92,701	
31	Morehead CT WS, 10 yr	(350)		407	(350)	
32	Harris Nuc NC Ret, 03/18 to 03/26 Auth 3/31/2017	13,853,037		407	4,317,831	9,535,206
33	Harris Nuc SC Ret, 06/19 to 05/27 Auth 3/31/2017	3,360,733		407	760,920	2,599,813
34	Harris Nuc WS, 11/16 to 04/29 Auth 3/31/2017	3,644,458		407	575,441	3,069,017
35	Asheville Fsl NC Ret, 02/20-12/27 Auth 02/2020	55,483,525	3,051,305	407	16,957,148	41,577,682
36	Asheville Fsl WS , 02/20-12/27 Auth 02/2020	30,799,586	1,424,898	407	5,170,149	27,054,335
37	Asheville Fsl SC Ret, 02/20-12/27 Auth 02/2020	9,756,756	433,993	407	1,785,700	8,405,049
38	Roxboro WWT NC, 06/22 to 06/33 Auth 06/2022	13,071,853	4,405	407	1,172,175	11,904,083
39	Roxboro WWT WS, 06/22 to 06/33 Auth 06/2022	6,096,732	2,039	407	567,348	5,531,423
40	Roxboro WWT SC, 06/22 to 06/33 Auth 06/2022		1,604,904	407	95,307	1,509,597
49	TOTAL	177,781,050	6,521,544		34,404,782	149,897,812

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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			0561600		0561601
20	Total				
21	**Generation Studies**				
22	35 MW SOLAR - BLADEN COUNTY	6,533	0561700	(25,635)	0561701
23	ASHEVILLE ROCK HILL ESS		0561700	(164,711)	0561701
24	B&K SOLAR, LLC	25,953	0561700	(24,604)	0561701
25	BANJO SOLAR	2,765	0561700		0561701
26	BEAR POINT	25,642	0561700	(24,309)	0561701
27	BELLFLOWER SOLAR, LLC		0561700	114,669	0561701
28	BLACK WALNUT SOLAR, LLC - SOLAR	157,555	0561700		0561701
29	BLUE GRANITE SOLAR		0561700	(2,753)	0561701
30	BLUE HERON - URBAN GRID - SIS FERC		0561700	(1,000)	0561701
31	BLUE HERON SOLAR PROJECT		0561700	(2,170)	0561701
32	BRANTLEY FARM SOLAR FAC	(19)	0561700		0561701
33	CARDINAL ENERGY STORAGE, LLC	33,933	0561700		0561701
34	CHERRY RIDGE SOLAR NEXTERA - Q447		0561700	13,732	0561701
35	CLARK SOLAR FARM LLC		0561700	3,000	0561701
36	CLOUDLESS SOLAR PROJECT	1,793	0561700		0561701
37	CLOUDLESS SOLAR, LLC		0561700	(4,389)	0561701
38	CMDAJ HOLDINGS, LLC - BROGDON	4,816	0561700		0561701
39	COVATION BIOMATERIALS SOLAR	236	0561700		0561701
40	CROOKED RUN SOLAR	52,144	0561700		0561701
41	CROOKED RUN SOLAR, LLC	(5,000)	0561700		0561701
42	CULPEPPER SOLAR, LLC	25,953	0561700	(24,604)	0561701
43	FAC CROOKED RUN SOLAR	97	0561700	(97)	0561701
44	FACILITY IMPACT STUDY FOR Q370	(92)	0561700		0561701
45	FACILITY STUDY Q358	240	0561700	(1,485)	0561701
46	FAIR BLUFF		0561700	(5,336)	0561701
47	FAIR BLUFF SOLAR	2,189	0561700		0561701

48	FILO SOLAR, LLC		0561700	(5,336)	0561701
49	FILO SOLAR, LLC - SOLAR	2,666	0561700		0561701
50	FLAX HOLDINGS, LLC	7,710	0561700	(2,254)	0561701
51	FRIESIAN HOLDINGS, LLC - SOLAR		0561700	(5,652)	0561701
52	FRIESIAN SOLAR PROJECT	5,049	0561700		0561701
53	GEB SOLAR, LLC		0561700	(4,389)	0561701
54	GUM SWAMP	27,555	0561700	(26,124)	0561701
55	HAWFINCH SOLAR LLC		0561700	(14,745)	0561701
56	HOBNOB		0561700	(5,652)	0561701
57	HOBNOB SOLAR PROJECT	2,766	0561700		0561701
58	HOMER		0561700	(5,336)	0561701
59	HOMER SOLAR	2,189	0561700		0561701
60	HURDLE MILLS SOLAR SIS	(16,572)	0561700		0561701
61	HYCO SOLAR, LLC - SOLAR - STATE	27,555	0561700	(26,124)	0561701
62	INNOVATIVE SOLAR	(214)	0561700		0561701
63	INTERNATIONAL PAPER COMPANY	1,210	0561700		0561701
64	IP SOLAR, LLC - SOLAR	25,984	0561700	(24,634)	0561701
65	JUNIPER SOLAR, LLC	25,953	0561700	(24,604)	0561701
66	KINGSTREE 115 SOLAR FACILITIES FERC	538	0561700		0561701
67	LOTUS SOLAR	25,984	0561700	(24,634)	0561701
68	LUMBER RIVER		0561700	(5,020)	0561701
69	LUMBER RIVER SOLAR	2,988	0561700		0561701
70	MAPLE LEAF SOLAR	27,552	0561700		0561701
71	MOCCASIN SOLAR		0561700	(3,863)	0561701
72	STATE STUDIES	(315,651)	0561700	496,666	0561701
73	OAK HILL SOLAR, LLC - SOLAR		0561700	(5,336)	0561701
74	OXBOW SOLAR	2,838	0561700		0561701
75	PANTHER BRANCH	27,555	0561700	(26,124)	0561701
76	RAIN TREE SOLAR		0561700	(10,659)	0561701
77	RIDGELINE SOLAR		0561700	(5,652)	0561701
78	ROLLINS SOLAR, LLC	25,953	0561700	(24,604)	0561701
79	ROSEMARY		0561700	(5,652)	0561701
80	ROSEMARY SOLAR PROJECT	2,321	0561700		0561701
81	ROSS SOLAR, LLC	25,953	0561700	(24,604)	0561701
82	SANDHILLS SOLAR	17,503	0561700	(16,590)	0561701
83	SASSER SOLAR LLC		0561700	(5,652)	0561701
84	SHADY GROVE SOLAR, LLC - SOLAR	157,555	0561700		0561701
85	SHORTHORN SOLAR, LLC	21,273	0561700	(20,165)	0561701
86	SILKIE HOLDINGS, LLC	1,793	0561700		0561701
87	SIS CROOKED RUN SOLAR	14,191	0561700	(66,335)	0561701

88	SIS Q365	18,142	0561700	(25,081)	0561701
89	SISQ358- INNOVATIVE SOLAR 54	18,057	0561700	(29,136)	0561701
90	SISQ359- INNOVATIVE SOLAR 67	18,037	0561700	(28,029)	0561701
91	SKYLIGHT SOLAR	155,347	0561700		0561701
92	SLEEPY CREEK SOLAR	27,555	0561700	(26,124)	0561701
93	SLENDER BRANCH SOLAR	2,321	0561700		0561701
94	SLENDER BRANCH SOLAR, LLC - SOLAR		0561700	(5,652)	0561701
95	SOFOS HARBERT DEVELOPMENT SC-CREED	17,504	0561700	(16,590)	0561701
96	STEVENS MILL SOLAR, LLC	27,555	0561700	(26,124)	0561701
97	STRAWHORN SOLAR, LLC - SOLAR		0561700	(3,264)	0561701
98	SYSTEM IMPACT STUDY FOR Q370	36,880	0561700	(36,880)	0561701
99	T CLUSTER P2 SHORT CIRCUIT STAB	27,664	0561700		0561701
100	TALL OAK SOLAR		0561700	(3,078)	0561701
101	TES KINSTON SOLAR 23, LLC BANK 2		0561700	23,106	0561701
102	TRANS CLUSTER PHASE 2 OVERHEAD	11,710	0561700		0561701
103	TRANSITIONAL CLUSTER FACILITY STUDY	16,827	0561700		0561701
104	TRENT RIVER SOLAR SIS STUDY	34,107	0561700	(34,107)	0561701
105	TVA 1500MW AFFECTED SYSTEM STUDY	125	0561700		0561701
106	TWELVE OUNCE SOLAR ENERGY LLC		0561700	(3,264)	0561701
39	Total	896,766		(256,989)	
40	Grand Total	896,766		(256,989)	

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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 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)	475,109	186,683,969			187,159,078
2	SFAS 158 Regulatory Asset (NC Docket E-100, Sub 913)	390,500,944	(5,110,119)			385,390,825
3	Grid South Deferal SC (SC Docket 218-318-E)	1,041,687	6,051	407	741,255	306,483
4	Deferred Fuel Clause NC Retail (NC Docket E2, Sub 1142)	631,723,001	139,857,461	557	256,754,267	514,826,195
5	Deferred Fuel Clause SC Retail (SC Docket 2020-1-E)	73,716,592	(9,668,057)	557		64,048,535
6	NC Reps Deferral (NC Docket E-2, Sub 1175)	669,549	4,996,184	407,456	8,946,640	(3,280,907)
7	SFAS 143 Regulatory Assets (NC Docket E-2, Sub 826, SC Docket 2003-84-E)	884,309,079	245,282,640	403,411	3,933,666	1,125,658,053
8	Regulatory Asset Related to Income Taxes	181,176,041	15,586,839	282,283	8,698,742	188,064,138
9	Accrued Vacation (NC Docket, Sub 859)	42,627,651	(59,733)			42,567,918
10	Gas Pipeline Upgrade (Amortized over 25 yrs endng 2026)	177,356		547	54,570	122,786
11	Pollution Control SC (SC Docket No. 2008-435-E) (Amortized over 14 years, beginning 2017)	20,109,401		407	2,513,675	17,595,726
12	DSM/EE Deferral NC (NC Docket E-2, Sub 931)	171,150,509	97,706,302	407,408,419	100,115,732	168,741,079
13	DSM/EE Deferral SC (SC Docket 2016-153-E)	8,671,211	15,713,184	407, 408	26,704,762	(2,320,367)
14	Wayne County Plant Deferred Costs SC (SC Docket 2016-227-E) - (Amortized 5 years, beginning 2017)	16,049,357		407, 421, 403	656,180	15,393,177
15	Rate Case Cost Deferral (NC Docket E-2, Sub 1142) - (Amortized over 5 years, beginning 2018) - NC Docket E-2, Sub 1219 - (Amortized over 5 years, beginning 2020)	1,754,816	17,237,594	928	2,556,127	16,436,283
16	Rate Case Cost Def (SC Docket 2016-227-E) - (Amortized over 5 years, beginning 2017)	486,167	8,962,554	928	842,445	8,606,276
17	Nuclear Levelization Deferral NC and SC (SC Docket 2016-227-)	54,281,437	23,545,814	517, 519, 520, 523, 524	44,924,390	32,902,861
18	Sutton Plant Deferred Costs SC (SC Docket 2013-472-E)	8,672,453		407, 403, 408, 421	343,829	8,328,624
19	Fukishima/Cyber Security Def-SC(SC Docket 2018-318-E)	1,556,084	(54,690)	407	1,059,804	441,590
20	Coal Ash Deferred Costs - (NC Coal Ash Management Act of 2014) - (SC Docket 2016-227-E & NC Docket E-2 Sub 1142), SC Docket 2018-318-E, SC Docket 2022-254-E, NC Docket No. E-2, Sub 1300	1,417,887,033	(46,021,919)	407	154,145,276	1,217,719,838
21	Interest Rate Swap (NC Docket E-2, Sub 1006; SC Docket 2015-95-E)		9,003,008			9,003,008
22	Storm Costs Deferral SC Ice Storms (SC Docket 2014-482-E)	18,562,294	211,007	431	2,145,285	16,628,016
23	NCEMPA Purchase Deferral NC (NC Docket E-2, Sub 1027)	152,428,670	213,489,881	407	198,382,583	167,535,968
24	NCEMPA Purchase Deferral SC (SC Docket 2016-227-E)	9,065,137		407	276,984	8,788,153
25	DERP Deferral (SC Docket 2015-53-E)	6,596,034		407	619,562	5,976,472
26	Regulatory Fee Deferral NC (NC Docket M-100 Sub 142)	88,444	285,395	928	88,444	285,395
27	Deferred VOP Costs (SC Docket 2016-227-E)			920		

28	NC Storm Costs Deferral - Hurricane Matthew - (NC Docket E-2, Sub 1142)			480, 481, 489		
29	SC Storm Costs Deferral - Hurricane Matthew - (SC Docket 2016-227-E)	70,978,980	2,211,327	431	3,427,995	69,762,312
30	Customer Connect Deferral NC (NC Docket E-2, Sub 1142)	53,134,917	(380,086)	407, 421	3,460,990	49,293,841
31	Customer Connect Deferral SC (SC Docket 2018-206-E)	506,119		407	487,239	18,880
32	Renewable Energy Certificate Biogas NC	3,592,101	982,808	509		4,574,909
33	EPA Emissions Allowances (NC Docket E-2, Sub 1142)	(20,832)		407		(20,832)
34	Coal Inventory Deferral NC (NC Docket E-2, Sub 1142)			421, 456		
35	Grid Deferred Costs (SC Docket 2018-318-E, SC Docket 2022-254-E and 281-E, NC Docket No. E-2, Sub 1300	40,423,011	12,737,641	403, 407, 408, 421	2,249,222	50,911,430
36	Non-AMI Meter NBV (NC Docket E-2; Sub 1142)	71,097,028		403, 407, 408, 421	13,608,441	57,488,587
37	AMI Meter SC (SC Docket 2018-318-E)	9,990,545	982,300	403, 407, 408, 421	577,216	10,395,629
38	Competitive Procurement of Renewable Energy (NC House Bill 589)	3,639,128	270,496	407	(1,509,170)	5,418,794
39	Excess Amortization Asset NC (NC Docket E-2, Sub 1142)	(31,197)		407		(31,197)
40	ABSAT Projects Deferred Costs NC (NC Docket E-2, Sub 112)	17,556,749		407, 421	3,032,380	14,524,369
41	ABSAT Projects Deferred Costs SC (SC Docket 2018-318-E)	7,229,728	489,866	403,407,421	906,191	6,813,403
42	COR Settlement NC (NC Docket E-2; Sub 1142)	16,515,151		407	727,273	15,787,878
43	COR Settlement SC (SC Docket 2018-318-E)	15,276,515		407	672,727	14,603,788
44	Depreciation Deferral SC - (SC Docket 2018-204-E)			403, 407		
45	Interest Rate Hedge; Amortized over 3 yrs, beginning 2019	54,041,310		427	1,771,222	52,270,088
46	NC Solar Rebate (NC House Bill 589)	20,670,360	3,085,904	407		23,756,264
47	Rotable Fleet Spare (NC Docket E-2, Sub 998A)		2,056,960	403	528,933	1,528,027
48	Wholesale Storm Deferral Costs - (Docket No. ER19-1339-000 & 001)	850,499	(25,499)	571	825,000	
49	SC H3659 Implentation - South Carolina Bill 3659	2,272,018	1,263,010	426	526,471	3,008,557
50	SC Certain Teed Asset - (SC Docket 2018-318-E)	4,684,617	926,064	403, 407, 408, 421	830,004	4,780,677
51	SC Storm Costs - Michael, Florence, Diego - (SC Docket 2019-26-E)	77,337,072	1,935,607	426, 431	2,568,386	76,704,293
52	Asheville CC - (NC Docket E-2, Sub 1219)	15,978,144	8,056,619	403, 407, 408, 421	5,899,403	18,135,360
53	SC Credit Card Program - (SC Docket 2018-319-E)					
54	Deferred Severance Charges - (NC Docket No. E-7, Sub 1146)	7,252,945		920	7,252,952	(7)
55	Storm Reg Asset - Upfront Cost (NCUC Docket E-2, Sub 1262)					
56	Storm Securitization Return - NCUC Docket E-2, Sub 1262	(66,435,913)		431, 146, 421, 232	(3,575,027)	(62,860,886)
57	Pension Deferred Costs					
58	COVID - NC Docket No. E-2, Sub 1300, NC Docket No. E-2, Sub 1258		82,080,818	421, 407	2,558,919	79,521,899
59	Coal Plant NBV Securitization (Docket E-Sub 1300)		11,911,278			11,911,278
60	NC Residential Decoupling (Docket E-Sub 1300)		8,167,318			8,167,318
44	TOTAL	4,520,315,051	1,054,405,796		861,330,985	4,713,389,862

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Interest Rate Hedges - Amortized over various periods			427		
2	Gas Pipeline Charges (2001-2026 amortization period)	1,563,104		547	480,955	1,082,149
3	Workers Comp Insurance Reimb	1,811,281	(294,906)	925		1,516,375
4	Fukushima Pooled Inventory	1,805,782				1,805,782
5	NCEMPA SC Equity Reserve (2017-2040 amortization period)	(4,467,690)		421	19,620	(4,487,310)
6	Deferred Storm Costs	66,690,445	(14,362,946)	426, 431	66,959	52,260,540
7	Gypsum Settlement Agreement	22,598,668				22,598,668
8	Camp Lejeune Incremental Costs	697,308	981,319	417	698,293	980,334
9	ASC 842 Fixed Rate Leases	13,931,231	100,603,522	242, 243, 547, 931	93,432,529	21,102,224
10	SC ORS Consultant Costs	134,667				134,667
11	Pension Settlement Costs (2019-2029 amortization period)	26,014,684	(3,343,560)	926		22,671,124
12	COVID-19 Deferrals	78,158,658	24,720,054	182, 426	102,878,712	
13	HomeServ Acquisition	1,051,413		417	291,596	759,817
14	Lease Receivable	7,677,029		253	165,284	7,511,745
15	Roxboro WWT Defer - SC	1,616,180		182	1,616,180	
16	Electric Vehicle Charging Stations		3,086,850			3,086,850
17	Other Minor Items	863,344	(13,596)	—		849,748
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)	16,992,793	10,024,992	182, 426	26,955,156	62,629
49	TOTAL	237,138,897				131,935,342

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric		
7	Other	2,192,293,660	1,912,828,231
8	TOTAL Electric (Enter Total of lines 2 thru 7)	2,192,293,660	1,912,828,231
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	2,192,293,660	1,912,828,231

Notes

FERC FORM NO. 1 (ED. 12-88)

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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.
3. Give 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 noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. 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 purpose of pledge.

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)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2										
3										
4										
5	Total									
6	Preferred Stock (Account 204)									
7										
8										
9										
10	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2024-04-15	Year/Period of Report End of: 2023/ Q4

Other Paid-in Capital

1. 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 a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
Gain or 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.
Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	2,784,376,969
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	(74,831)
16	Ending Balance Amount	2,784,302,138
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	2,784,302,138

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the 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. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. 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, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, 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) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	[a] DEP 500M 4.15% 12/1/44	0221043	500,000,000		4,443,471		4,375,000	11/20/2014	12/01/2044	11/20/2014	12/01/2044	500,000,000	20,750,000
3	DEP 650M 2.00% 8/15/2031	0221044	650,000,000		4,036,500		4,225,000	08/12/2021	08/15/2031	08/12/2021	08/15/2031	650,000,000	13,223,811
4	DEP 500M 3.25% 8/15/25	0221051	500,000,000		2,812,775		3,250,000	08/13/2015	08/15/2025	08/13/2015	08/15/2025	500,000,000	16,250,000
5	DEP 700M 4.20% 8/15/45	0221052	700,000,000		6,027,165		6,125,000	08/13/2015	08/15/2045	08/13/2015	08/15/2045	700,000,000	29,400,000
6	DEP 450M 3.70% 10/15/46	0221053	450,000,000		3,836,700		3,937,500	09/16/2016	10/15/2046	09/16/2016	10/15/2046	450,000,000	16,650,000
7	DEP 500M 3.60% 9/15/47	0221058	500,000,000		4,247,291		1,050,000	09/08/2017	09/15/2047	09/08/2017	09/15/2047	500,000,000	18,000,000
8	DEP 300M 3.375% 9/1/23	0221059	300,000,000		1,333,157		1,800,000	08/09/2018	09/01/2023	08/09/2018	09/01/2023		6,750,000
9	DEP 450M 2.90% 8/15/2051	0221061	450,000,000		4,185,000		3,937,500	08/12/2021	08/15/2051	08/12/2021	08/15/2051	450,000,000	12,826,189
10	DEP 500M 3.70% 9/1/28	0221065	500,000,000		2,721,928		3,250,000	08/09/2018	09/01/2028	08/09/2018	09/01/2028	500,000,000	18,500,000
11	DEP 400M 4.375% 3/30/44	0221075	400,000,000		3,563,688		3,500,000	03/06/2014	03/30/2044	03/06/2014	03/30/2044	400,000,000	17,500,000
12	DEP 200M 5.70% 4/1/35	0221544	200,000,000		1,928,655		518,000	03/22/2005	04/01/2035	03/22/2005	04/01/2035	200,000,000	11,400,000
13	DEP 325M 6.30% 4/1/38	0221546	325,000,000		2,843,750		581,750	03/13/2008	04/01/2038	03/13/2008	04/01/2038	325,000,000	20,475,000
14	DEP 200M 6.125% 9/15/33	0221549	200,000,000		2,048,641		3,104,000	09/11/2003	09/15/2033	09/11/2003	09/15/2033	200,000,000	12,250,000
15	DEP 500M 4.10% 5/15/42	0221572	500,000,000		5,025,000		2,480,000	05/18/2012	05/15/2042	05/15/2012	05/15/2042	500,000,000	20,500,000
16	DEP 500M 4.10% 3/15/43	0221573	500,000,000		4,330,566		3,675,000	03/12/2013	03/15/2043	03/15/2013	03/15/2043	500,000,000	20,500,000
17	DEP 48.485M 4% Wake 2002REFIN 6/1/41	0221574	48,485,000		603,686		552,000	06/06/2013	06/01/2041	06/01/2013	06/01/2041	48,485,000	1,939,000
18	DEP 600M 3.45% 3/15/29	0221584	600,000,000		3,281,921		3,900,000	03/07/2019	03/15/2029	03/07/2019	03/15/2029	600,000,000	20,700,000
19	DEP 600M 2.50% 8/15/50	0221588	600,000,000		8,500,000		5,250,000	08/20/2020	08/15/2020	08/20/2020	08/15/2020	600,000,000	15,000,000
20	DEP 500M 3.40% 4/1/32	0221083	500,000,000		2,633,604		1,315,000	03/17/2022	04/01/2032	03/17/2022	04/01/2032	500,000,000	16,000,000
21	DEP 400M 4.00% 4/1/52	0221084	400,000,000		3,306,883		3,464,000	03/17/2022	04/01/2052	03/17/2022	04/01/2052	400,000,000	17,000,000
22	DEP 210M 3.70% 10/1/2046	0221074	210,000,000		993,121			09/27/2022	10/01/2046	09/27/2022	10/01/2046	210,000,000	7,770,000
23	DEP 41.7M 4.00% 10/1/2046	0221079	41,700,000		190,172			09/27/2022	10/01/2046	09/27/2022	10/01/2046	41,700,000	6,600,000
24	DEP 200M 3.30% 10/1/2046	0221073	200,000,000		929,730			09/27/2022	10/01/2046	09/27/2022	10/01/2046	200,000,000	1,668,000

25	(a) DEP 500M 5.25% 3/15/33	0221518	500,000,000		2,714,181		120,000	03/09/2023	03/15/2033	03/09/2023	03/15/2033	500,000,000	21,291,667
26	(a) DEP 500M 5.35% 3/15/53	0221519	500,000,000		4,214,181		2,965,000	03/09/2023	03/15/2053	03/09/2023	03/15/2053	500,000,000	21,697,222
27	Subtotal		10,275,185,000		80,751,766		63,374,750					9,975,185,000	384,640,889
28	Reacquired Bonds (Account 222)												
29													
30													
31													
32	Subtotal												
33	Advances from Associated Companies (Account 223)												
34	Commercial Paper Series Due 3/16/2024 (1.9165% at 12/31/2019)	0223306	150,000,000					12/09/2015	03/16/2024			150,000,000	8,051,732
35	Subtotal		150,000,000									150,000,000	8,051,732
36	Other Long Term Debt (Account 224)												
37	DEPR Debt Due 4-11-2025	224550	400,000,000		4,289,005			12/20/2013	04/13/2025	12/20/2013	04/13/2025	400,000,000	24,279,749
38	Subtotal		400,000,000		4,289,005							400,000,000	24,279,749
33	TOTAL		10,825,185,000									10,525,185,000	416,972,369

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FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

All First Mortgage Bonds were pledged to The Bank of New York Mellon, as Trustee. Ingeneral, first mortgage bonds were pledged to finance the construction of various plantfacilities, 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, tofinance the retirement of previously issued pollution control bonds outstanding, whichwere issued to finance the construction of pollution control facilities at the Company'sHarris, Mayo and Roxboro plants.

(b) Concept: ClassAndSeriesOfObligationCouponRateDescription

$500,000,000 First Mortgage Bonds, 5.25% Series due 2033

(c) Concept: ClassAndSeriesOfObligationCouponRateDescription

$500,000,000 First Mortgage Bonds, 5.35% Series due 2053

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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)	995,109,890
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Subtotal	
9	Deductions Recorded on Books Not Deducted for Return	
10	Subtotal	
14	Income Recorded on Books Not Included in Return	
15	Subtotal	
19	Deductions on Return Not Charged Against Book Income	
20	AFUDC Equity Income	51,915,772
21	AFUDC Interest	34,797,430
22	Bad Debts	728,751
23	Benefits Accruals	77,347,826
24	Book Depreciation	(1,015,695,952)
25	Capitalized 174 R&D Exp	(12,000,000)
26	Capitalized Hardware/Software	(1,185,680)
27	Certain Teed Settlement - SC Retail	96,060
28	Certain Teed Settlement Accrual	7,201,625
29	Charitable Contribution	(3,648,106)
30	Coal Ash Spend, Net of Capitalized Portion	92,320,281
31	COLI Adjustments	1,634,377
32	Contributions in Aid of Construction	(33,951,202)
33	Cost of Removal	123,273,557
34	Deferred Book Gain/Loss	11,863
35	Deferred Compensation	2,203,721
36	Deferred Cost - Electric Vehicle	3,086,850
37	Deferred Fuel	(140,773,172)
38	Deferred Revenue	32,729,705
39	Design Basis Amortization	(283,803)
40	Dividends Received Exclusion	1,676,000

41	DOE Receivable	15,084,467
42	Earnings of Subsidiaries	1,549,221
43	End of Life Nuclear Fuel Cost Reserve	(12,697,397)
44	Environmental Reserve	(1,586,148)
45	Equipment/T&D Repairs	492,959,748
46	Extra Facility Lighting	214,938
47	Fukushima Cybersecurity Deferral	(1,114,494)
48	Impairment of Plant Assets	(778,465)
49	Investment Tax Credit Amortization	3,310,248
50	Lawsuit Contingency	9,971,866
51	Lease Adjustments	(26,996)
52	Lobbying	(1,810,000)
53	Meals & Entertainment	(3,300,000)
54	MGP Sites	495,508
55	Miscellaneous NC Taxable Income Ad	(2,583,996)
56	Non-Cash Overhead Basis Adjustment	(17,436,306)
57	Nuclear Decommissioning Contributions/Earnings	25,006,534
58	Nuclear Fuel Book Burned	(193,440,810)
59	Other Items	(1,724,567)
60	Penalties	(12,531)
61	Provision for Current Federal Income Taxes	(198,960,038)
62	Provision for Current State Income Taxes	(569,853)
63	Provision for Deferred Income Taxes	51,333,748
64	Regulatory Asset - ABSAT	(3,448,704)
65	Regulatory Asset - AMI/Non-AMI Meters	(13,203,357)
66	Regulatory Asset - Asheville Deferred Costs	383,825
67	Regulatory Asset - COR Settlement	(1,400,000)
68	Reg Asset - Costs to Achieve One Utility	11,494
69	Regulatory Asset - COVID Deferral	1,363,243
70	Regulatory Asset - Customer Connect	(4,328,315)
71	Reg Asset -- Depreciation	11,911,278
72	Reg Asset - Distribution Decoupling Rider	8,167,318
73	Regulatory Asset - Early Retired Plant	(19,002,802)
74	Regulatory Asset - Energy Efficiency	(13,401,008)
75	Regulatory Asset - FAS 158	(7,199,785)
76	Regulatory Asset - Grid Deferred Costs	10,488,419
77	Regulatory Asset - Grid South	(735,204)
78	Regulatory Asset - Harris COLA	(5,654,192)
79	Regulatory Asset - Lee CC Deferred Costs	1,773,391
80	Regulatory Asset - NC Solar Rebate Program	3,085,904

81	Regulatory Asset - NCEMPA Purchase Deferrals	14,810,694
82	Regulatory Asset - Nuclear Levelization	(21,378,576)
83	Regulatory Asset - Pension Costs	(165)
84	Regulatory Asset - Plant Related Retirements	(2,435,933)
85	Regulatory Asset - Rate Case Expenses	5,871,410
86	Regulatory Asset - SC Pollution Control Deferral	(2,513,675)
87	Regulatory Asset - SC Solar Bill	54,167
88	Regulatory Asset - Severance	(7,252,952)
89	Regulatory Asset - Storm Securitization	(35,138,702)
90	Regulatory Asset - Wayne & Sutton Deferrals	(1,000,009)
91	Regulatory Asset/Liability - CPRE Rider	1,779,666
92	Regulatory Asset/Liability - Rotable Spare Parts	2,978,613
93	Regulatory Fee - North Carolina	196,950
94	Regulatory Liability - NCEMPA	(6,975,255)
95	Regulatory Liability - Rate Case Expenses	12,758,010
96	Renewable Energy Liability	(8,204,625)
97	REPs Incremental Costs	(3,950,455)
98	Returns on Federal Excess Deferred Income Taxes	(1,811,734)
99	Returns on State Excess Deferred Income Taxes	238,007
100	Roxboro Deferred Costs	(1,839,662)
101	SC Distributive Energy Resource Program	(619,562)
102	Severance Accrual	(4,527,860)
103	Spent Fuel Canisters	7,190,689
104	Storm Cost Deferral	(19,064,129)
105	Storm Cost Reserve	12,988,976
106	Surplus Materials Write-off	(225,607)
107	Tax Depreciation/Amortization	1,047,332,040
108	Tax Gains/Losses	37,910,000
109	Tax Interest Capitalized	(33,805,942)
110	Transportation Benefits	(446,874)
111	Unbilled Revenue	(8,960,675)
112	Workers Compensation Reserve	(4,580,605)
113	Subtotal	333,558,310
27	Federal Tax Net Income	661,551,580
28	Show Computation of Tax.	
29	21% of line 27	138,925,832
30	Net Oprating Loss Utilization	(4,451,693)
31	Prior Year Federal Tax Adjustments - Prior Year Tax True-Ups	6,596,824
32	Tax Credit Utilization	(2,250,926)
33	Corporate Alternative Minimum Tax	60,140,000

34	Total Federal Income Tax	[a]198,960,037

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ComputationOfTax

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: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

TAXES ACCRUED, PREPAID AND CHARGES 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 known, 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 (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) 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.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) 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 (l) through (o) how the taxes were distributed. Report in column (o) 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 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) 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 BEGINNING OF YEAR					BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include In Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included In Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	Highway Use	Federal Tax	Federal	2023											
2	Social Security Tax	Federal Tax	Federal	2023	(3,170,765)		46,494,991	40,602,619		2,721,607		32,699,967			13,795,024
3	**Subtotal Federal Tax**				(3,170,765)		46,494,991	40,602,619		2,721,607		32,699,967			13,795,024
4	SC kilowatt Hour	State Tax	SC	2023	0		1,922,232	1,922,232		0		1,922,232			
5	**Subtotal State Tax**				0		1,922,232	1,922,232		0		1,922,232			
6	NC Property Tax	Property Tax	NC	2023	50,643		80,068,857	80,116,191		3,309		81,179,846			(1,110,989)
7	SC Property Tax	Property Tax	SC	2023	52,849,365		52,916,259	50,209,765		55,555,859		53,867,933			(951,674)
8	**Subtotal Property Tax**				52,900,008		132,985,116	130,325,956		55,559,168		135,047,779			(2,062,663)
9	Fed Unemployment Tax	Unemployment Tax	Federal	2023	5,788		205,232	207,398		3,622		207,802			(2,570)
10	Other Unemployment Tax	Unemployment Tax	Other	2023	23,238		1,375	1,189		23,424		1,375			
11	NC Unemployment Tax	Unemployment Tax	NC	2023	(18,284)		68,797	69,497		(18,984)		68,797			
12	SC Unemployment Tax	Unemployment Tax	SC	2023	(1,861)		22,204	22,831		(2,488)		22,204			
13	**Subtotal Unemployment Tax**				8,881		297,608	300,915		5,574		300,178			(2,570)
14	NC Sales and Use Tax	Sales And Use Tax	NC	2023	1,069,048		18,568,882	19,245,097		392,833		(8,872,281)			27,441,163
15	SC Sales and Use Tax	Sales And Use Tax	SC	2023	(55,546)		3,108,860	3,290,122		(236,808)		110,865			2,997,995
16	Other Sales and Use Tax	Sales And Use Tax	Other	2023			46,907			46,907		(313,142)			360,049
17	**Subtotal Sales And Use Tax**				1,013,502		21,724,649	22,535,219		202,932		(9,074,558)			30,799,207
18	Fed Income Tax	Income Tax	Federal	2023	435,176		198,960,037	68,633,475	[(a)](30,081,434)	100,680,304		208,643,419			(9,683,382)
19	NC Income Tax	Income Tax	NC	2023			2,066,615	4,417,777	[(b)]2,351,162			3,073,821			(1,007,206)
20	SC Income Tax	Income Tax	SC	2023	(1)		1,898,802	488,333	[(c)](1,032,653)	377,815		2,136,172			(237,370)
21	**Subtotal Income Tax**				435,175		202,925,454	73,539,585	(28,762,925)	101,058,119		213,853,412			(10,927,958)
22	NC Franchise Tax	Franchise Tax	NC	2023	5,751,685		365,456	11,578,854	[(d)]2,945,244	(2,516,469)		455,895			(90,439)
23	SC Franchise Tax	Franchise Tax	SC	2023	539,263		2,767,703	2,514,383		792,583		2,767,703			
24	Other Franchise Tax	Franchise Tax	Other	2023											

25	**Subtotal Franchise Tax**				6,290,948		3,133,159	14,093,237	2,945,244	(1,723,886)		3,223,598			(90,439)
26	**Subtotal Miscellaneous Other Tax**				0										
27	SC Muncipal License Tax	Other State Tax	SC	2023	6,792,860				[(a)](6,792,860)						
28	SC Pub Ser Comm Tax	Other State Tax	SC	2023	1,571		9,198	9,143		1,626					9,198
29	SC Kilowatt Hour	Other State Tax	SC	2023											
30	NC Municipal License Tax	Other State Tax	NC	2023	19			19				1,064,190			(1,064,190)
31	**Subtotal Other State Tax**				6,794,450		9,198	9,162	(6,792,860)	1,626		1,064,190			(1,054,992)
40	TOTAL				64,272,199		409,492,407	283,328,925	(32,610,541)	157,825,140		379,036,798			30,455,609

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: TaxAdjustments

Offset to account 146

(b) Concept: TaxAdjustments

Offset to account 146

(c) Concept: TaxAdjustments

Offset to account 146

(d) Concept: TaxAdjustments

Offset to account 146

(e) Concept: TaxAdjustments

Offset to account 241

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%	1,757,823			411.4	134,170		1,623,653		
4	7%									
5	10%	37,936,263			411.4	2,965,039		34,971,224		
6	6%	194,574			411.4	13,328		181,246		
7	8%	1,323,328			411.4	102,160		1,221,168		
8	30%	82,989,927	190	6,415,049	411.4	95,551		89,309,425		
9	26%		190	1,456,098				1,456,098		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	124,201,915		7,871,147		3,310,248		128,762,814		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
47	OTHER TOTAL									
48	GRAND TOTAL	124,201,915		7,871,147		3,310,248		128,762,814		

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

OTHER DEFERRED 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	CATV Pole Rent	4,027,469	454	4,023,717	4,512,075	4,515,827
2	Nuclear Generator Equipment				4,698,027	4,698,027
3	Manufactured Gas Plant Reserve	892,773	146	337,539	38,046	593,280
4	Utility Energy Service Programs	32,795,061	146, 417	40,130,308	6,728,022	(607,225)
5	Long Term Def Rev - OL	363,082	417, 454	54,458		308,624
6	Deferred Prepaid EF-Lighting	1,773,270	454	232,711	17,772	1,558,331
7	Shareholder Contributions		146, 426	2,500,000	8,000,000	5,500,000
8	SCHM Exec Cash Bal Plan	6,194,077	124, 128	572,891	752,926	6,374,112
9	SC Coal Ash Insurance Proceeds	6,318,984	182, 407, 431	6,435,746	116,762	
10	NC EDIT - SC Retail	17,311,006			202,880	17,513,886
11	NC EDIT - Gross Up	5,209,720			61,057	5,270,777
12	Other	17,110,447	417, 419, 454	1,237,271	(12,786,039)	3,087,137
47	TOTAL	91,995,889		55,524,641	12,341,528	48,812,776

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other										
5.2	Other										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other										
12.2	Other										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
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										

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED 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.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	3,066,937,436	468,520,811	824,673,879	9,490,412	340,634				42,023,378 [a]	2,761,957,524
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	3,066,937,436	468,520,811	824,673,879	9,490,412	340,634				42,023,378	2,761,957,524
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	3,066,937,436	468,520,811	824,673,879	9,490,412	340,634				42,023,378	2,761,957,524
10	Classification of TOTAL										
11	Federal Income Tax	2,978,063,330	373,139,738	691,325,985	8,382,725	300,876				(4,079,613)	2,663,879,319
12	State Income Tax	88,874,106	95,381,073	133,347,894	1,107,687	39,758				46,102,991	98,078,205
13	Local Income Tax										

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherPropertyAdjustmentsCreditedToAccount

Offset to account 182	5,305,667
Offset to account 253	2,626,241
Offset to account 254	33,911,392
Offset to account 146	180,078
Total	42,023,378

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED 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.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits: Account Credited (g)	ADJUSTMENTS Debits: Amount (h)	ADJUSTMENTS Credits: Account Debited (i)	ADJUSTMENTS Credits: Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Electric	1,601,849,135	294,644,531	165,428,740	11,684,189	18,401,089		17,121,690[(a)]	182	1,582,430	1,708,808,766
9	TOTAL Electric (Total of lines 3 thru 8)	1,601,849,135	294,644,531	165,428,740	11,684,189	18,401,089		17,121,690		1,582,430	1,708,808,766
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,601,849,135	294,644,531	165,428,740	11,684,189	18,401,089		17,121,690		1,582,430	1,708,808,766
20	Classification of TOTAL										
21	Federal Income Tax	1,479,932,456	258,469,401	144,335,205	10,320,454	16,253,381		(4,284,276)		1,634,724	1,594,052,725
22	State Income Tax	121,916,679	36,175,130	21,093,535	1,363,735	2,147,708		21,405,966		(52,294)	114,756,041
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxLiabilitiesOtherAdjustmentsDebitedToAccount

Offset to account 253 1,642,316Offset to account 254 15,241,443Offset to account 146 237,931Total 17,121,690

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Regulatory Liability Related to Income Taxes -Amortization period follows the book depreciable asset lives	45,843,078	190, 410, 411	1,732,392	2,368,809	46,479,495
2	Depreciation adjustment for NCEMPA assets (NC Docket E-2, Sub 1219)	12,020,063			6,975,255	18,995,318
3	Deferred Fuel Clause SC Retail (SC Docket 2019-1-E)				14,208,309	14,208,309
4	SFAS 143 Regulatory Liabilities - NC Docket E-2, Sub 826; SC Docket 2003-84-E	15,264,104				15,264,104
5	Nuclear Decommissiong Trust-Unrealized Gains - NC Docket E-2, Sub 826; SC Docket 2003-84-E	1,290,669,572			642,125,264	1,932,794,836
6	NC REPS Deferral NC Docket E-2, Sub 1175; NC Docket E2-Sub 1205 and E2-Sub 1251, Amoritized Annually Dec-Nov each year	119,708,724	407	26,205,149	40,974,192	134,477,767
7	Nuclear Fuel Last Core Reserve - NC Docket E-2, Sub 112 and SC Docket 2018-318-E	113,672,586			12,697,397	126,369,983
8	NC State Excess Deferred Income Tax - NC Retail -NCUC Docket E-2, Sub 1219:- Amortization from June 2021 to May 2023	5,109,312	190, 410, 411	5,109,312		
9	Rotable Fleet Spare (NC Docket E-2, Sub 998A; NC Docket E-7, Sub 986A) Amortized Annualily various start thru the year	7,056,697	403	3,566,316	490,066	3,980,447
10	TCJA Federal Excess Deferred Income Taxes - NC Retail -NCUC Docket E-2, Sub 1219, NCUC Docket E-2, Sub 1300:Protected PPE: ARAM, 25 - 50 yrs, Beginning September 2020Unprotected: Amortization from June 2021 to May 2026	685,206,376	411	65,712,165		619,494,211
11	NC State Excess Deferred Income Taxes - SC Retail, PSC Doc #2018-318-E, Ord #2019-341, Ord #2020-348, & Ord # 2021-327		190, 410, 411			
12	TCJA Fed Excess Deferred Income Tax - Gross Up	314,741,658	190	28,829,919	652,476	286,564,215
13	Levelized NC State EDIT Rider - NC Retail -NCUC Docket E-2, Sub 1219:- Amortization from June 2021 to May 2023	238,007	407	294,964	56,957	
14	TCJA Federal Excess Deferred Income Taxes - SC Retail -PSCSC Docket No. 2018-318-E, 2022-254-EOrder Nos.: 2019-341, 2020-348, 2021-327, 2022-338Protected PPE: ARAM, 25 - 50 years, Beginning June 2019Unprotected PPE: 33 Months, Beginning April 2023Unprotected Non-PPE: 5 years, Beginning June 2019	133,541,272	411	15,994,490		117,546,782
15	TCJA Federal Excess Deferred Income Taxes - Wholesale -Production Amortization: Beginning January 2018Contract Nos.: ER20-1706-000, 1717-000, 1704-000, 1999-000, 1990-000, 1993-000, 2006-000Transmission Amortization: Beginning June 2020Contract No.: ER20-1837, ER23-1206Protected PPE: ARAM, 25- 50 yearsUnprotected PPE: 20 yearsUnprotected Non-PPE :5 years	300,261,859	411	14,090,231		286,171,628
16	Open Interest Swap - (NC Docket E-2, Sub 1006; SC Docket 2015-95-E)	191,024,050			(184,549,515)	6,474,535
17	Excess Amortization Liability - (NC Docket E-2, Sub 1142) - Amortized beg. 4-2018 ending 2020	12,695,938	407	773,042	(9,400,973)	2,521,923
18	Sale of Land Harris Deferral (NC Docket E-2, Sub 1300)	21,338,032	407	4,249,584	4,237,721	21,326,169
19	WS Coal Ash Settlement (NC Docket E-2, Sub 1103)	179,722	421	179,722		

20	Levelized NC Federal EDIT Rider - NC Retail -NCUC Docket E-2, Sub 1219, NCUC Docket E-2, Sub 1300:- Amortization from June 2021 to May 2026	9,273,702	407	9,074,277	10,886,010	11,085,435
21	OPEB Regulatory Liability (Docket AI07-1-000)				(249,070)	(249,070)
22	NC Storm Secur Srvc/Admin - NCUC Docket E-2, Sub 1300	817,146	407, 903	354,077	296,749	759,818
23	Closed Def Int Hedge - Liab NO. E-2, SUB 1130 & E-2, SUB 1049 2017	60,477,787	428	(20,404,394)		80,882,181
24	NC State Excess Deferred Income Taxes (2.5% to 0%) - Wholesale	39,541,983			(1,677,872)	37,864,111
25	NC State Excess Deferred Income Taxes (2.5% to 0%) - NC Retail	145,614,922			(2,647,655)	142,967,267
26	NC State Excess Deferred Income Taxes (2.5% to 0%) - Gross Up	55,722,404			(1,301,490)	54,420,914
27	SC Storm Reserve Fund - SC - PSCSC Docket 2022-254-E				(12,988,976)	(12,988,976)
28	Nuclear Refueling Outages	(142)				(142)
41	TOTAL	3,580,018,852		155,761,246	523,153,654	3,947,411,260

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

Electric Operating Revenues

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.
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 page 108, 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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	[a]2,498,550,403	2,317,008,994	17,550,362	19,016,880	1,464,921	1,434,751
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	1,447,758,587	1,343,346,521	13,195,863	13,733,325	247,420	247,957
5	Large (or Ind.) (See Instr. 4)	722,228,721	746,900,125	9,693,833	10,564,012	3,290	3,325
6	(444) Public Street and Highway Lighting	30,173,942	14,591,545	85,683	25,383	2,492	2,552
7	(445) Other Sales to Public Authorities	94,153,851	98,320,969	1,365,646	1,512,135	5	5
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	4,792,865,504	4,520,168,154	41,891,387	44,851,735	1,718,128	1,688,590
11	(447) Sales for Resale	1,416,955,595	1,946,337,013	24,826,058	25,586,436	8	8
12	TOTAL Sales of Electricity	6,209,821,099	6,466,505,167	66,717,445	70,438,171	1,718,136	1,688,598
13	(Less) (449.1) Provision for Rate Refunds	(23,407,294)	(57,720,543)				
14	TOTAL Revenues Before Prov. for Refunds	6,233,228,393	6,524,225,710	66,717,445	70,438,171	1,718,136	1,688,598
15	Other Operating Revenues						
16	(450) Forfeited Discounts	8,945,504	2,531,292				
17	(451) Miscellaneous Service Revenues	[b]2,122,199	(1,385,965)				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	39,115,255	38,383,765				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[c]5,312,339	3,246,440				
22	(456.1) Revenues from Transmission of Electricity of Others	97,760,701	100,954,062				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	153,255,998	143,729,594				

27	TOTAL Electric Operating Revenues	6,386,484,391	6,667,955,304				

Line12, column (b) includes $ (7,563,614) of unbilled revenues.
Line12, column (d) includes (346,396) MWH relating to unbilled revenues

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ResidentialSales

Includes $8,162,686 of Residential Decoupling revenues.

(b) Concept: MiscellaneousServiceRevenues

Includes $2,751,435 of service charges and ($628,043) of miscellaneous service revenue.

(c) Concept: OtherElectricRevenue

Includes $1,660,320 of contributions in aid of construction and $802,736 from cogeneration/small power producers.

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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)
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45					
46	TOTAL				

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	ALS - AREA LIGHTING SERVICE	66,549	25,414,047	145,130	459	0.3819
2	RES - RESIDENTIAL SERVICE	17,270,309	2,412,339,931	1,421,007	12,154	0.1397
3	R-TOU - RESIDENTIAL SERVICE TIME-OF-USE	53,512	7,433,904	4,115	13,004	0.1389
4	R-TOUD - RESIDENTIAL SERVICE TIME-OF-USE	335,315	41,338,245	17,755	18,886	0.1233
5	SLS - STREET LIGHTING SERVICE	0	304	4	0	
6	SLR - STREET LIGHTING SERVICE - RESIDENTIAL SUBDIVISIONS	16,765	7,806,461	138,307	121	0.4656
7	TFS - TRAFFIC SIGNAL SERVICE METERED	0	326	1	0	
8	Decoupling Revenues	0	8,162,686	0	0	
9	Duplicate Customers			(261,398)		
41	TOTAL Billed Residential Sales	17,742,450	2,502,495,904	1,464,921	44,624	0.1410
42	TOTAL Unbilled Rev. (See Instr. 6)	(192,088)	(3,945,501)			0.0205
43	TOTAL	17,550,362	[(a)]2,498,550,403	1,464,921	44,624	0.1424

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ResidentialSales
Includes $8,162,686 of Residential Decoupling revenues.

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	ALS - AREA LIGHTING SERVICE	217,075	66,073,139	47,766	4,545	0.3044
2	APH-TES - AGRICULTURAL POST-HARVEST SERVICE	308	32,752	2	154,000	0.1063
3	CH-TOUE - CHURCH SERVICE EXPERIMENTAL TIME-OF-USE	7,528	1,116,010	239	31,498	0.1482
4	CSE - CHURCH AND SCHOOL SERVICE	1,779	301,158	63	28,238	0.1693
5	CSG - CHURCH AND SCHOOL SERVICE	87	14,695	3	29,000	0.1689
6	GS - GENERAL SERVICE	2,893	516,898	91	31,791	0.1787
7	LGS - LARGE GENERAL SERVICE	320,035	28,872,105	33	9,698,030	0.0902
8	LGS-RTP-TOU - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING) TOU	16,933	1,402,158	2	8,466,500	0.0828
9	LGS-TOU - LARGE GENERAL SERVICE TIME-OF-USE	907,731	74,265,736	69	13,155,522	0.0818
10	MGS - MEDIUM GENERAL SERVICE	2,782,577	332,343,788	20,986	132,592	0.1194
11	MGS-TOU - MEDIUM GENERSAL SERVICE TIME-OF-USE	1,408,237	134,778,576	14,734	95,577	0.0957
12	SFLS - SPORTS FIELD LIGHTING SERVICE	1,593	314,377	110	14,482	0.1973
13	SGS - SMALL GENERAL SERVICE	2,019,887	307,511,724	188,686	10,705	0.1522
14	SGS-TES - SMALL GENERAL SERVICE THERMAL ENERGY STORAGE	15,335	1,337,714	5	3,067,000	0.0872
15	SGS-TOU - SMALL GENERAL SERVICE TIME-OF-USE	5,509,467	482,581,328	17,781	309,851	0.0876
16	SGS-TOU-CLR - SMALL GENERAL SERVICE TIME-OF-USE CONSTANT LOAD RATE	58,822	8,669,355	9,100	6,464	0.1474
17	SGS-TOUE - SMALL GENERAL SERVICE ALL-ENERGY TIME-OF-USE	23,311	2,862,283	1,218	19,139	0.1228
18	SI - SEASONAL OR INTERMITTENT SERVICE	54,650	8,529,417	1,006	54,324	0.1561
19	SLR - STREET LIGHTING SERVICE - RESIDENTIAL SUBDIVISIONS	22	12,737	178	124	0.5790
20	SLS - STREET LIGHTING SERVICE	1,700	832,781	260	6,538	0.4899
21	TFS - TRAFFIC SIGNAL SERVICE METERED	20	5,704	14	1,429	0.2852
22	TSS - TRAFFIC SIGNAL SERVICE	69	7,398	1	69,000	0.1072
23	Duplicate Customers			(54,927)		
41	TOTAL Billed Small or Commercial	13,350,059	1,452,381,833	247,420	35,386,349	0.1088
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(154,196)	(4,623,246)			0.0300
43	TOTAL Small or Commercial	13,195,863	1,447,758,587	247,420	35,386,349	0.1097

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. 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	ALS - AREA LIGHTING SERVICE	15,029	4,121,949	1,171	12,834	0.2743
2	GS - GENERAL SERVICE	125	23,131	1	125,000	0.1850
3	LGS - LARGE GENERAL SERVICE	1,136,823	100,039,841	95	11,966,558	0.0880
4	LGS-CRTL-TOU - LARGE GENERAL SERVICE CURTAILMENT TIME-OF-USE (SPECIAL)	639,138	33,816,447	2	319,569,000	0.0529
5	LGS-RTP-TOU - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING) TOU	53	5,811	1	53,000	0.1096
6	LGS-TOU - LARGE GENERAL SERVICE TIME-OF-USE	5,721,807	382,498,944	154	37,154,591	0.0668
7	MGS - MEDIUM GENERAL SERVICE	455,569	54,093,107	1,143	398,573	0.1187
8	MGS-TOU - MEDIUM GENERSAL SERVICE TIME-OF-USE	360,927	32,425,481	1,284	281,096	0.0898
9	SGS - SMALL GENERAL SERVICE	18,629	2,767,469	1,101	16,920	0.1486
10	SGS-TOU - SMALL GENERAL SERVICE TIME-OF-USE	1,342,368	111,840,101	1,088	1,233,794	0.0833
11	SGS-TOUE - SMALL GENERAL SERVICE ALL-ENERGY TIME-OF-USE	0	0	0	0	
12	SGS-TOU-CLR - SMALL GENERAL SERVICE TIME-OF-USE CONSTANT LOAD RATE	19	3,256	1	19,000	0.1714
13	SI - SEASONAL OR INTERMITTENT SERVICE	2,087	297,464	19	109,842	0.1425
14	SLS - STREET LIGHTING SERVICE	3	681	1	3,000	0.2270
15	Duplicate Customers			(2,771)		
41	TOTAL Billed Large (or Ind.) Sales	9,692,577	721,933,682	3,290	370,943,208	0.0745
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	1,256	295,039			0.2349
43	TOTAL Large (or Ind.)	9,693,833	722,228,721	3,290	370,943,208	0.0745

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	ALS - AREA LIGHTING SERVICE	134	95,936	9	14,889	0.7159
2	SLR - STREET LIGHTING SERVICE - RESIDENTIAL SUBDIVISIONS	2	(3,159)	425	5	(1.5795)
3	SLS - STREET LIGHTING SERVICE	79,573	29,180,381	1,815	43,842	0.3667
4	TFS - TRAFFIC SIGNAL SERVICE METERED	1,286	268,705	612	2,101	0.2089
5	TSS - TRAFFIC SIGNAL SERVICE	4,980	632,433	632	7,880	0.1270
6	Duplicate Customers			(1,001)		
41	TOTAL Billed Public Street and Highway Lighting	85,975	30,174,296	2,492	68,717	0.3510
42	TOTAL Unbilled Rev. (See Instr. 6)	(292)	(354)			0.0012
43	TOTAL	85,683	30,173,942	2,492	68,717	0.3522

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	ALS - AREA LIGHTING SERVICE	2	271	1	2,000	0.1355
2	LGS-RTP-TOU - LARGE GENERAL SERVICE (EXPERIMENTAL REALTIME PRICING) TOU	44,091	3,599,810	1	44,091,000	0.0816
3	LGS-TOU - LARGE GENERAL SERVICE TIME-OF-USE	1,322,631	89,843,322	7	188,947,286	0.0679
4	Duplicate Customers			(4)		
41	TOTAL Billed Other Sales to Public Authorities	1,366,724	93,443,403	5	233,040,286	0.0684
42	TOTAL Unbilled Rev. (See Instr. 6)	(1,078)	710,448			(0.6590)
43	TOTAL	1,365,646	94,153,851	5	233,040,286	0.0689

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		(23,407,294)			

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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)
41	TOTAL Billed - All Accounts	42,237,785	4,800,429,118	1,718,128	639,483,183	0.1137
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(346,398)	(7,563,614)			0.0218
43	TOTAL - All Accounts	41,891,387	4,792,865,504	1,718,128	639,483,183	0.1144

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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).
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.

   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 (g) 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,line 24.
10. Footnote entries as required and provide explanations following all required data.

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)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	Non-Requirement Sales										
2	Duke Energy Carolinas, LLC	LF	190				7,299,247		183,790,704		183,790,704
3	Duke Energy Carolinas, LLC	AD	190				(8,091)		(6,873,877)		(6,873,877)
4	Duke Energy Carolinas, LLC	LF	45								
5	Duke Energy Carolinas, LLC	LF	198					25,969			25,969
6	PJM Interconnection LLC	OS	7				151,175		4,041,925		4,041,925
7	PJM Interconnection LLC	AD	7						(750)		(750)
8	Dominion Energy South Carolina, Inc.	OS	104				239		1,028,543		1,028,543
9	Requirement Sales										
10	City of Camden, SC	RQ	197								
11	City of Camden, SC AD	RQ	197					(29,246)			(29,246)
12	PWC of the City of Fayetteville	RQ	184	337	347	337	1,995,707	70,010,071	60,330,270		130,340,341
13	PWC of the City of Fayetteville AD	RQ	184					(624,557)	146,633		(477,924)
14	French Broad EMC	RQ	210	66	81	73	523,111	14,407,155	15,813,693		30,220,848

15	French Broad EMC AD	RQ	210					(147,082)	38,607		(108,475)
16	Haywood EMC	RQ	180	21	34	29	150,996	4,902,853	4,564,624		9,467,477
17	Haywood EMC AD	RQ	180					22,383	5,717		28,100
18	NC Electric Membership Corporation	OS	4				131,459	7,830,000	4,665,390		12,495,390
19	NC Electric Membership Corporation	AD	4								
20	NC Electric Membership Corporation	RQ	134								
21	NC Electric Membership Corporation AD	RQ	134					(19,816)	137,970		118,154
22	NC Electric Membership Corporation	RQ	182	1,533	1,601	1,533	7,105,568	361,844,770	214,801,506		576,646,276
23	NC Electric Membership Corporation AD	RQ	182				115	(1,613,556)	390,884		(1,222,672)
24	NC Eastern Municipal Power Agency	RQ	200	1,047	1,239	1,047	7,399,806	249,053,302	222,956,137		472,009,439
25	NC Eastern Municipal Power Agency AD	RQ	200					(1,523,210)	537,185		(986,025)
26	Piedmont EMC	RQ	172	19	20	19	76,225	4,518,974	2,296,540		6,815,514
27	Piedmont EMC AD	RQ	172					(150,671)	5,593		(145,078)
28	Other Services										
29	NC Electric Membership Corporation	OS	134				501		(15,322)		(15,322)
30	NC Eastern Municipal Power Agency	OS	268						(23,189)		(23,189)
31	Piedmont EMC	OS	322						(675)		(675)
32	Haywood EMC	OS	300						(1,142)		(1,142)
33	Town of Black Creek, NC	OS	293						(25)		(25)
34	City of Camden, SC	OS	309						(57)		(57)
35	PWC of the City of Fayetteville	OS	324						(6,528)		(6,528)
36	French Broad EMC	OS	326						(2,324)		(2,324)
37	Town of Lucama, NC	OS	294						(32)		(32)
38	Town of Sharpsburg, NC	OS	296						(31)		(31)
39	Town of Stantonsburg, NC	OS	295						(35)		(35)
40	Town of Waynesville	OS	303						(327)		(327)
41	Town of Winterville	OS	321						(78)		(78)
42	The Energy Authority	OS	70						(847)		(847)
43	SCANA Energy Marketing	OS	129						(1,009)		(1,009)
44	Macquarie Energy LLC	OS	342						(437)		(437)
45	Transmission Other	AD							(176,981)		(176,981)
15	Subtotal - RQ						17,251,528	700,651,370	522,025,359		1,222,676,729
16	Subtotal-Non-RQ						7,574,530	7,855,969	186,422,896		194,278,866
17	Total						24,826,058	708,507,339	708,448,255		1,416,955,595

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

These sales are out of Period adjustments related to requirement 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.

(b) Concept: StatisticalClassificationCode

These sales are out of Period adjustments related to requirement 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.

(c) Concept: StatisticalClassificationCode

These sales are out of Period adjustments related to requirement 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.

(d) Concept: StatisticalClassificationCode

These sales are out of Period adjustments related to requirement 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.

(e) Concept: StatisticalClassificationCode

These sales are out of Period adjustments related to requirement 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.

(f) Concept: StatisticalClassificationCode

These sales are out of Period adjustments related to requirement 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.

(g) Concept: StatisticalClassificationCode

These sales are out of Period adjustments related to requirement 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.

(h) Concept: StatisticalClassificationCode

These sales are out of Period adjustments related to requirement services. The sales were classified as RQ to ensure the Page 311 total column g, for RQ and Non-RQ tie to page 401 line 23 and 24 column b respectively.

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	5,803,677	5,901,474
5	(501) Fuel	266,719,373	258,205,111
6	(502) Steam Expenses	12,473,577	17,180,407
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,455	
10	(506) Miscellaneous Steam Power Expenses	3,274,857	6,411,446
11	(507) Rents		
12	(509) Allowances	26,205,149	41,037,035
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	314,478,088	328,735,473
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,552,886	3,180,180
16	(511) Maintenance of Structures	3,495,042	1,843,436
17	(512) Maintenance of Boiler Plant	26,949,221	27,334,206
18	(513) Maintenance of Electric Plant	4,186,393	2,835,044
19	(514) Maintenance of Miscellaneous Steam Plant	10,621,812	9,030,283
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	48,805,354	44,223,149
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	363,283,442	372,958,622
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	46,772,400	44,680,052
25	(518) Fuel	186,704,837	176,589,012
26	(519) Coolants and Water	27,516,674	24,213,907
27	(520) Steam Expenses	46,532,984	46,952,095
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	6,790,871	6,528,084
31	(524) Miscellaneous Nuclear Power Expenses	142,985,334	133,795,886
32	(525) Rents		

33	TOTAL Operation (Enter Total of lines 24 thru 32)	457,303,100	432,759,036
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	39,967,635	44,268,960
36	(529) Maintenance of Structures	8,633,421	8,490,180
37	(530) Maintenance of Reactor Plant Equipment	49,084,852	55,239,791
38	(531) Maintenance of Electric Plant	28,622,851	30,631,925
39	(532) Maintenance of Miscellaneous Nuclear Plant	30,642,445	33,779,832
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	156,951,204	172,410,688
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	614,254,304	605,169,724
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,077,854	2,138,185
45	(536) Water for Power	62,500	62,500
46	(537) Hydraulic Expenses	(373,063)	(194,265)
47	(538) Electric Expenses	113,363	148,844
48	(539) Miscellaneous Hydraulic Power Generation Expenses	811,419	952,822
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	2,692,073	3,108,086
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	291,900	363,939
54	(542) Maintenance of Structures	143,866	134,652
55	(543) Maintenance of Reservoirs, Dams, and Waterways	858,593	799,257
56	(544) Maintenance of Electric Plant	561,680	364,935
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,162,186	1,487,810
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	3,018,225	3,150,593
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	5,710,298	6,258,679
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	5,596,742	6,135,052
63	(547) Fuel	977,019,679	1,494,147,201
64	(548) Generation Expenses	3,690,828	3,974,510
64.1	(548.1) Operation of Energy Storage Equipment	189,204	112,735
65	(549) Miscellaneous Other Power Generation Expenses	9,063,689	10,848,750
66	(550) Rents	1,034	
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	995,561,176	1,515,218,248
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	5,442,383	6,617,111
70	(552) Maintenance of Structures	7,571,408	6,833,823

71	(553) Maintenance of Generating and Electric Plant	23,147,730	29,838,719
71.1	(553.1) Maintenance of Energy Storage Equipment		602
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	11,250,933	10,705,508
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	47,412,454	53,995,763
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	1,042,973,630	1,569,214,011
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	607,703,537	926,940,696
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	1,796,588	1,694,658
78	(557) Other Expenses	226,607,513	(325,366,352)
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	836,107,638	603,269,002
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	2,862,329,312	3,156,870,038
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,828	12,730
85	(561.1) Load Dispatch-Reliability	3,653,754	3,608,488
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,361,508	2,224,833
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,032,596	938,364
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	437,055	304,993
90	(561.6) Transmission Service Studies		(16,100)
91	(561.7) Generation Interconnection Studies	639,777	(312,556)
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	692,747	913,478
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	1,113,466	1,421,179
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	1,772	
97	(566) Miscellaneous Transmission Expenses	5,357,467	6,796,480
98	(567) Rents	2,895,143	2,856,105
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	18,193,113	18,747,992
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	57,769	81,056
102	(569) Maintenance of Structures	335,989	364,310
103	(569.1) Maintenance of Computer Hardware	354,743	32,791
104	(569.2) Maintenance of Computer Software	1,377,567	1,535,021
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,270,373	5,243,035

107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	10,931,652	17,629,271
109	(572) Maintenance of Underground Lines	923	1,071
110	(573) Maintenance of Miscellaneous Transmission Plant	484	8,053
111	TOTAL Maintenance (Total of Lines 101 thru 110)	15,329,500	24,894,608
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	33,522,613	43,642,600
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 Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	698,839	591,994
135	(581) Load Dispatching	4,074,781	3,335,535
136	(582) Station Expenses	612,085	737,871
137	(583) Overhead Line Expenses	(455,785)	581,761
138	(584) Underground Line Expenses	8,954,082	7,332,901
138.1	(584.1) Operation of Energy Storage Equipment	140,631	
139	(585) Street Lighting and Signal System Expenses	6,191	6,161
140	(586) Meter Expenses	4,832,817	4,789,683
141	(587) Customer Installations Expenses	5,552,050	5,334,334
142	(588) Miscellaneous Expenses	23,418,100	24,779,632
143	(589) Rents	1,418,563	4,115,395
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	49,252,354	51,605,267

145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,411,518	1,364,697
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,258,413	3,902,824
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	80,682,978	119,401,831
150	(594) Maintenance of Underground Lines	4,960,373	5,477,957
151	(595) Maintenance of Line Transformers	1,026,607	739,127
152	(596) Maintenance of Street Lighting and Signal Systems	7,004,640	6,319,110
153	(597) Maintenance of Meters	1,549,271	1,382,160
154	(598) Maintenance of Miscellaneous Distribution Plant	(27,062)	77,389
155	TOTAL Maintenance (Total of Lines 146 thru 154)	99,866,738	138,665,095
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	149,119,092	190,270,362
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	34,333	47,626
160	(902) Meter Reading Expenses	1,462,925	2,168,023
161	(903) Customer Records and Collection Expenses	49,101,828	55,567,921
162	(904) Uncollectible Accounts	10,894,735	15,289,426
163	(905) Miscellaneous Customer Accounts Expenses	2,044	18,239
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	61,495,865	73,091,235
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	190,835	63,593
169	(909) Informational and Instructional Expenses	146,124	269,286
170	(910) Miscellaneous Customer Service and Informational Expenses	12,126,287	3,992,273
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	12,463,246	4,325,152
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	11	588
175	(912) Demonstrating and Selling Expenses	2,570,207	9,245,229
176	(913) Advertising Expenses	323,277	164,559
177	(916) Miscellaneous Sales Expenses	146,195	134,187
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	3,039,690	9,544,563
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	91,678,489	104,805,553
182	(921) Office Supplies and Expenses	63,208,732	65,601,674

183	(Less) (922) Administrative Expenses Transferred-Credit		(3,446)
184	(923) Outside Services Employed	43,705,284	37,968,159
185	(924) Property Insurance	15,706,047	20,596,899
186	(925) Injuries and Damages	15,686,410	11,820,559
187	(926) Employee Pensions and Benefits	61,688,699	74,309,212
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	14,584,631	12,162,582
190	(929) (Less) Duplicate Charges-Cr.	3,357,445	4,272,123
191	(930.1) General Advertising Expenses	2,477,088	4,000,433
192	(930.2) Miscellaneous General Expenses	(28,643,960)	(10,875,970)
193	(931) Rents	38,165,166	29,434,701
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	314,899,141	345,555,125
195	Maintenance		
196	(935) Maintenance of General Plant	(457,768)	893,929
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	314,441,373	346,449,054
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	3,436,411,191	3,824,193,004

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

PURCHASED POWER (Account 555)

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.

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, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) 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 (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) 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 columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

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)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES: MegaWatt Hours Received (i)	POWER EXCHANGES: MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER: Demand Charges ($) (k)	COST/SETTLEMENT OF POWER: Energy Charges ($) (l)	COST/SETTLEMENT OF POWER: Other Charges ($) (m)	COST/SETTLEMENT OF POWER: Total (k+l+m) of Settlement ($) (n)
1	1025 Traveller Solar	LU	Note 1	0.0000	0.0000	0.0000	8,897					562,294		562,294
2	1034 Catherine Lake	LU	Note 1	0.0000	0.0000	0.0000	7,416					472,973		472,973
3	1073 Onslow	LU	Note 1	0.0000	0.0000	0.0000	6,918					432,706		432,706
4	10855 Bailey LLC	LU	Note 1	0.0000	0.0000	0.0000	7					877		877
5	1529 Properties, LLC	LU	Note 1	0.0000	0.0000	0.0000	48					1,344		1,344
6	1634 Solar	LU	Note 1	0.0000	0.0000	0.0000	4,341					252,386		252,386
7	200 Cornerstone, LLC	LU	Note 1	0.0000	0.0000	0.0000	8					315		315
8	2315 Atlantic Ave Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	544					41,666		41,666
9	A&G/Kitty Hawk Solar	LU	Note 1	0.0000	0.0000	0.0000	148					12,396		12,396
10	Abbot Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,905					227,094		227,094
11	ABCZ Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	0							
12	ABD Farm Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,081					579,343		579,343

13	Achilles Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,681					654,612		654,612
14	Acme Solar	LU	Note 1	0.0000	0.0000	0.0000	8,064					511,956		511,956
15	AGA TAG SOLAR IV	LU	Note 1	0.0000	0.0000	0.0000	8,743					552,494		552,494
16	Albert Adcock	LU	Note 1	0.0000	0.0000	0.0000	33					2,512		2,512
17	Albertson Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	10,467					703,439		703,439
18	Alice Rosser	LU	Note 1	0.0000	0.0000	0.0000	11					281		281
19	Alvin Easton	LU	Note 1	0.0000	0.0000	0.0000	15					1,170		1,170
20	AM Best Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,901					651,074		651,074
21	Ambient Advisory Services INC	LU	Note 1	0.0000	0.0000	0.0000	2					89		89
22	Anderson Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	3,943					293,094		293,094
23	Andrew Solar	LU	Note 1	0.0000	0.0000	0.0000	8,895					563,894		563,894
24	Angier Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	7,096					594,772		594,772
25	Arba Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	2,824					234,858		234,858
26	Arborgate Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,567					650,579		650,579
27	Arden Solar	LU	Note 1	0.0000	0.0000	0.0000	116					4,120		4,120
28	Argand Rooftop 1 LLC	LU	Note 1	0.0000	0.0000	0.0000	659					50,470		50,470
29	Argand Rooftop 3 LLC	LU	Note 1	0.0000	0.0000	0.0000	255					19,553		19,553
30	Argand Rooftop 4 LLC	LU	Note 1	0.0000	0.0000	0.0000	638					48,826		48,826
31	Argand SPP2 LLC	LU	Note 1	0.0000	0.0000	0.0000	282					17,683		17,683
32	Arthur Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,077					581,610		581,610
33	Aspen Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	9,251					625,707		625,707
34	Atkinson Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,352					593,643		593,643
35	Atkinson Solar II	LU	Note 1	0.0000	0.0000	0.0000	3,804					239,159		239,159
36	ATOOD Solar IV	LU	Note 1	0.0000	0.0000	0.0000	7,593					471,666		471,666
37	Axiom Environmental INC	LU	Note 1	0.0000	0.0000	0.0000	9					588		588
38	B & K Timber LLC	LU	Note 1	0.0000	0.0000	0.0000	11					874		874
39	B.V. Hedrick Gravel & Sand Co	LU	Note 1	0.0000	0.0000	0.0000	16					1,220		1,220
40	Badger Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,356					651,184		651,184
41	Bailey Farm	LU	Note 1	0.0000	0.0000	0.0000	9,057					657,037		657,037
42	Balsam Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,070					612,321		612,321
43	Baltimore Church	LU	Note 1	0.0000	0.0000	0.0000	5,282					331,221		331,221
44	Bani Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,287					250,710		250,710
45	Banner Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,433					524,201		524,201
46	Barker Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,330					588,306		588,306
47	Battye Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	31					1,948		1,948
48	Bay Branch Solar	LU	Note 1	0.0000	0.0000	0.0000	10,716					672,403		672,403
49	Bay Tree Solar	LU	Note 1	0.0000	0.0000	0.0000	147,972					6,639,318		6,639,318
50	Bayboro Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	9,270					580,515		580,515
51	Bayer Cropscience LP	LU	Note 1	0.0000	0.0000	0.0000	0							
52	Beaker Farm	LU	Note 1	0.0000	0.0000	0.0000	10,482					709,562		709,562

53	Bearford Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,043					609,318		609,318
54	Bearford Solar II, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,449					570,491		570,491
55	Beaufort Solar	LU	Note 1	0.0000	0.0000	0.0000	27,683					1,850,612		1,850,612
56	Belafonte Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,344					462,980		462,980
57	Benson Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	7,893					502,450		502,450
58	Bertram Kalet	LU	Note 1	0.0000	0.0000	0.0000	11					912		912
59	Beulaville Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	3,135					261,532		261,532
60	BGE Carolina Sunsense I LLC	LU	Note 1	0.0000	0.0000	0.0000	545					41,761		41,761
61	Biltmore Natural Resources INC	LU	Note 1	0.0000	0.0000	0.0000	0							
62	Biscoe Solar	LU	Note 1	0.0000	0.0000	0.0000	8,556					502,686		502,686
63	Bizzell Church Solar	LU	Note 1	0.0000	0.0000	0.0000	9,222					624,770		624,770
64	Bizzell Church Solar 2	LU	Note 1	0.0000	0.0000	0.0000	8,548					579,435		579,435
65	Blacktip Solar	LU	Note 1	0.0000	0.0000	0.0000	3,902					225,592		225,592
66	Bladen Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	103,976					5,708,935		5,708,935
67	Bladenboro Farm 2	LU	Note 1	0.0000	0.0000	0.0000	8,806					554,655		554,655
68	Bladenboro Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,954					747,145		747,145
69	Bladenboro Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,891					600,803		600,803
70	Bloom Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,793					221,511		221,511
71	Blueberry One	LU	Note 1	0.0000	0.0000	0.0000	9,380					636,077		636,077
72	Bo Biggs Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,651					541,699		541,699
73	Boaz Farm	LU	Note 1	0.0000	0.0000	0.0000	8,842					597,743		597,743
74	Bolton Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,277					675,346		675,346
75	Bond Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,917					228,081		228,081
76	Bonefish Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,564					208,902		208,902
77	Boston Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,948					624,358		624,358
78	Brantley Farm Solar	LU	Note 1	0.0000	0.0000	0.0000	100,497					5,791,311		5,791,311
79	BRE NC Solar 1 LLC	LU	Note 1	0.0000	0.0000	0.0000	8,822					596,533		596,533
80	BRE NC Solar 3 LLC	LU	Note 1	0.0000	0.0000	0.0000	10,506					659,889		659,889
81	Brick City Solar	LU	Note 1	0.0000	0.0000	0.0000	9,207					579,354		579,354
82	Broadridge Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,879					666,745		666,745
83	Broadway Road Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,028					252,290		252,290
84	Broadway Solar	LU	Note 1	0.0000	0.0000	0.0000	7,637					635,939		635,939
85	Brooks Energy	LU	Note 1	0.0000	0.0000	0.0000	0							
86	Bruce Ford	LU	Note 1	0.0000	0.0000	0.0000	5					196		196
87	Buckleberry Solar	LU	Note 1	0.0000	0.0000	0.0000	95,099					5,472,225		5,472,225
88	Bullock Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	101,894					5,630,211		5,630,211
89	Buncombe County Landfill	LU	Note 1	0.0000	0.0000	0.0000	4,641					151,747		151,747
90	Bunn Level Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,270					778,998		778,998
91	Burgaw Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,135					511,479		511,479
92	Buttercup	LU	Note 1	0.0000	0.0000	0.0000	10,905					756,213		756,213

93	C II METHANE MANAGEMENT IV LLC	LU	Note 1	0.0000	0.0000	0.0000	9,517					693,424		693,424
94	Camp Rockmont for Boys INC	LU	Note 1	0.0000	0.0000	0.0000	8					289		289
95	Candace Solar	LU	Note 1	0.0000	0.0000	0.0000	8,826					598,591		598,591
96	Canton Solar Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	442					27,672		27,672
97	Cardinal Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	16,337					542,277		542,277
98	Carolina Poultry RG1	LU	Note 1	0.0000	0.0000	0.0000	0							
99	Carolina Solar Energy, PCSP1	LU	Note 1	0.0000	0.0000	0.0000	745					46,637		46,637
100	Carolina Solar Energy-EMJ	LU	Note 1	0.0000	0.0000	0.0000	303					19,000		19,000
101	Carolina Tractor & Equipment Co	LU	Note 1	0.0000	0.0000	0.0000	(16)					(980)		(980)
102	Cash Solar	LU	Note 1	0.0000	0.0000	0.0000	8,173					495,777		495,777
103	Castalia Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	3,691					274,390		274,390
104	Catherine Willis	LU	Note 1	0.0000	0.0000	0.0000	8					292		292
105	CB Bladen Solar	LU	Note 1	0.0000	0.0000	0.0000	9,643					651,491		651,491
106	CBC Alternative Energy LLC (NEW)	LU	Note 1	0.0000	0.0000	0.0000	3,254					269,522		269,522
107	CBC Alternative Energy LLC (OLD)	LU	Note 1	0.0000	0.0000	0.0000	1,515					115,969		115,969
108	Cedar Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	8,319					562,897		562,897
109	Chadbourn Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,560					621,131		621,131
110	Changeup Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,812					241,110		241,110
111	Charles Lewis	LU	Note 1	0.0000	0.0000	0.0000	0					2		2
112	Chauncey Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	9,264					557,469		557,469
113	Chei Solar	LU	Note 1	0.0000	0.0000	0.0000	8,955					566,299		566,299
114	Cherry Blossom Solar	LU	Note 1	0.0000	0.0000	0.0000	20,883					802,754		802,754
115	Choco Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	10,171					685,620		685,620
116	Chocowinity Solar	LU	Note 1	0.0000	0.0000	0.0000	8,159					553,445		553,445
117	Christiansted Port Terminal Corp.	LU	Note 1	0.0000	0.0000	0.0000	394					24,210		24,210
118	Cirrus Solar	LU	Note 1	0.0000	0.0000	0.0000	8,568					580,096		580,096
119	City of Asheville	LU	Note 1	0.0000	0.0000	0.0000	92					2,686		2,686
120	City of Raleigh Parks Recreation Department	LU	Note 1	0.0000	0.0000	0.0000	33					2,045		2,045
121	Clipperton Holdings	LU	Note 1	0.0000	0.0000	0.0000	9,421					634,016		634,016
122	Clovelly Solar	LU	Note 1	0.0000	0.0000	0.0000	9,551					594,132		594,132
123	Coats Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,563					604,779		604,779
124	Cohen Farm Solar	LU	Note 1	0.0000	0.0000	0.0000	9,665					653,982		653,982
125	Coogee Solar	LU	Note 1	0.0000	0.0000	0.0000	11,512					724,044		724,044
126	Cookstown Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	9,830					619,527		619,527
127	Corc Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	229					19,037		19,037
128	Cornwall Solar	LU	Note 1	0.0000	0.0000	0.0000	5,831					485,987		485,987
129	Cotten Farm	LU	Note 1	0.0000	0.0000	0.0000	9,597					604,232		604,232
130	Cougar Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	272					14,473		14,473
131	County Home	LU	Note 1	0.0000	0.0000	0.0000	9,655					566,043		566,043
132	Covey Run Apartments LLC	LU	Note 1	0.0000	0.0000	0.0000	2					90		90

133	Cox Lake Hydro Electric	LU	Note 1	0.0000	0.0000	0.0000	839					63,465		63,465
134	Craven County Wood Energy, LP	LU	Note 1	0.0000	0.0000	0.0000	326,526					16,267,077		16,267,077
135	Creech Solar 2, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,126					617,539		617,539
136	Crestwood Solar	LU	Note 1	0.0000	0.0000	0.0000	8,745					592,321		592,321
137	Crockett Farm	LU	Note 1	0.0000	0.0000	0.0000	9,090					558,396		558,396
138	Crooked Run Solar	LU	Note 1	0.0000	0.0000	0.0000	138,482					6,179,137		6,179,137
139	Cube Yadkin Generation, LLC	LU	Note 1	0.0000	0.0000	0.0000	1,420					46,365		46,365
140	Cubera Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,746					234,984		234,984
141	Currin Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	8,024					476,777		476,777
142	Custom Packaging Inc	LU	Note 1	0.0000	0.0000	0.0000	91					6,947		6,947
143	Darlington Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	19,608					1,051,087		1,051,087
144	Daystar Solar	LU	Note 1	0.0000	0.0000	0.0000	9,499					597,483		597,483
145	Deep Branch Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,462					595,954		595,954
146	Deep River Hydro	LU	Note 1	0.0000	0.0000	0.0000	0							
147	Delco Farm	LU	Note 1	0.0000	0.0000	0.0000	8,820					596,563		596,563
148	Deltec Homes Inc	LU	Note 1	0.0000	0.0000	0.0000	54					1,999		1,999
149	Dement Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,534					711,665		711,665
150	Dessie Solar Center	LU	Note 1	0.0000	0.0000	0.0000	8,117					677,723		677,723
151	DRPFC I LLC	LU	Note 1	0.0000	0.0000	0.0000	23					1,466		1,466
152	DSM Nutritional	LU	Note 1	0.0000	0.0000	0.0000	749					40,438		40,438
153	Dunn Solar	LU	Note 1	0.0000	0.0000	0.0000	3,280					274,047		274,047
154	Duplin Solar I, LLC	LU	Note 1	0.0000	0.0000	0.0000	5,650					475,936		475,936
155	Duplin Solar II LLC	LU	Note 1	0.0000	0.0000	0.0000	7,922					658,241		658,241
156	Eagle Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	6,919					429,269		429,269
157	East Wayne Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	3,802					316,850		316,850
158	Easters Holdings LLC	LU	Note 1	0.0000	0.0000	0.0000	12					772		772
159	Eastover Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	8,923					663,150		663,150
160	Elm Solar	LU	Note 1	0.0000	0.0000	0.0000	9,358					633,377		633,377
161	EnergyXchange INC	LU	Note 1	0.0000	0.0000	0.0000	0							
162	Ennis Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	5,856					375,963		375,963
163	Environmental Science US Inc	LU	Note 1	0.0000	0.0000	0.0000	0							
164	Eros Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,898					623,362		623,362
165	Erwin Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	7,161					441,379		441,379
166	ESA Boston	LU	Note 1	0.0000	0.0000	0.0000	9,816					616,804		616,804
167	ESA Buies Creek	LU	Note 1	0.0000	0.0000	0.0000	5,600					353,604		353,604
168	ESA Church Road	LU	Note 1	0.0000	0 0000	0.0000	7,047					410,293		410,293
169	ESA Four Oaks	LU	Note 1	0.0000	0.0000	0.0000	8,260					544,168		544,168
170	ESA Four Oaks 2 NC	LU	Note 1	0.0000	0.0000	0.0000	3,018					191,721		191,721
171	ESA Hamlet	LU	Note 1	0.0000	0.0000	0.0000	8,079					546,327		546,327
172	ESA NC Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	601					46,005		46,005

173	ESA Newton Grove 1 NC LLC	LU	Note 1	0.0000	0.0000	0.0000	1,991					147,068		147,068
174	ESA Princeton NC	LU	Note 1	0.0000	0.0000	0.0000	7,941					524,405		524,405
175	ESA RENEWABLES III LLC	LU	Note 1	0.0000	0.0000	0.0000	1,446					90,510		90,510
176	EWP LLC	LU	Note 1	0.0000	0.0000	0.0000	713					45,510		45,510
177	Exhibit Court Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	207					16,701		16,701
178	Exum Farm Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,344					633,916		633,916
179	F & D Huebner LLC	LU	Note 1	0.0000	0.0000	0.0000	29					1,823		1,823
180	Faison Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	2,367					154,689		154,689
181	Farrington Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	1,467					112,360		112,360
182	Ferguson Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	41					1,704		1,704
183	First Citizens Bank & Trust Co 1.14MW	LU	Note 1	0.0000	0.0000	0.0000	1,400					52,119		52,119
184	First Citizens Bank & Trust Co 566KW	LU	Note 1	0.0000	0.0000	0.0000	690					25,520		25,520
185	Firstfloor Jones	LU	Note 1	0.0000	0.0000	0.0000	446					13,043		13,043
186	Flatwood Farm	LU	Note 1	0.0000	0.0000	0.0000	9,033					571,456		571,456
187	Flowers Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,777					490,728		490,728
188	Floyd Solar	LU	Note 1	0.0000	0.0000	0.0000	9,406					635,005		635,005
189	FLS Solar 100 LLC	LU	Note 1	0.0000	0.0000	0.0000	6,504					542,534		542,534
190	FLS Solar 110 LLC	LU	Note 1	0.0000	0.0000	0.0000	3,101					258,208		258,208
191	FLS Solar 170 LLC	LU	Note 1	0.0000	0.0000	0.0000	3,340					226,835		226,835
192	FLS Solar 20, LLC	LU	Note 1	0.0000	0.0000	0.0000	0							
193	FLS Solar 200, LLC	LU	Note 1	0.0000	0.0000	0.0000	6,333					428,137		428,137
194	FLS Solar 230, LLC - Warren Place	LU	Note 1	0.0000	0.0000	0.0000	8,888					561,816		561,816
195	FLS Solar 260 LLC	LU	Note 1	0.0000	0.0000	0.0000	9,097					614,982		614,982
196	Fox Creek Farm	LU	Note 1	0.0000	0.0000	0.0000	88,234					5,081,191		5,081,191
197	Foxfire Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	9,050					569,283		569,283
198	Franklin Solar 2, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,800					315,421		315,421
199	Franklin Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	2,224					183,580		183,580
200	Franklinton Solar	LU	Note 1	0.0000	0.0000	0.0000	8,510					577,215		577,215
201	Freedom Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,658					398,965		398,965
202	Fremont Farms, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,251					585,642		585,642
203	Fresh Air Energy - Carter	LU	Note 1	0.0000	0.0000	0.0000	8,972					605,891		605,891
204	Fresh Air Energy - Langley	LU	Note 1	0.0000	0.0000	0.0000	9,369					633,785		633,785
205	Fresh Air Energy - Pecan	LU	Note 1	0.0000	0.0000	0.0000	9,071					612,956		612,956
206	Fresh Air Energy XI, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,019					631,203		631,203
207	Fresh Air Energy XXXI - Little River	LU	Note 1	0.0000	0.0000	0.0000	8,832					599,614		599,614
208	Fresh Air Thornton (Fresh Air XVI LLC)	LU	Note 1	0.0000	0.0000	0.0000	8,442					573,433		573,433
209	Fresh Air XXXVIII (Boykin)	LU	Note 1	0.0000	0.0000	0.0000	30,306					1,803,603		1,803,603
210	Fuquay Farms, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,542					625,629		625,629
211	Gaines Solar	LU	Note 1	0.0000	0.0000	0.0000	4,456					259,030		259,030
212	Gainey Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,324					295,183		295,183

213	Garrell Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	7,228					603,196		603,196
214	Gary Shaver	LU	Note 1	0.0000	0.0000	0.0000	(1)					(13)		(13)
215	Gary Solar	LU	Note 1	0.0000	0.0000	0.0000	4,243					246,961		246,961
216	Gilead Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	6,634					417,654		417,654
217	Gladstone Farm	LU	Note 1	0.0000	0.0000	0.0000	10,118					640,217		640,217
218	Glen Raven Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	535					33,493		33,493
219	Goldenrod Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,905					227,350		227,350
220	Gordon Koncal	LU	Note 1	0.0000	0.0000	0.0000	11					781		781
221	Granville Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	4,737					362,693		362,693
222	Green Square Solar, LLC (FLS Solar 20, LLC)	LU	Note 1	0.0000	0.0000	0.0000	280					21,474		21,474
223	Gregory Poole Equip Co	LU	Note 1	0.0000	0.0000	0.0000	238					14,911		14,911
224	Grove Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,220					640,461		640,461
225	Hanover Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,079					584,414		584,414
226	Happy Solar	LU	Note 1	0.0000	0.0000	0.0000	7,215					455,206		455,206
227	Harrell's Hill Solar	LU	Note 1	0.0000	0.0000	0.0000	5,897					438,058		438,058
228	Harrison Solar	LU	Note 1	0.0000	0.0000	0.0000	10,144					642,486		642,486
229	Harvest Beulaville	LU	Note 1	0.0000	0.0000	0.0000	3,587					225,460		225,460
230	Haywood Farm Solar	LU	Note 1	0.0000	0.0000	0.0000	8,762					589,619		589,619
231	HCE Johnston I, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,368					228,091		228,091
232	HCE Moore I, LLC	LU	Note 1	0.0000	0.0000	0.0000	2,738					172,614		172,614
233	Hector Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,098					576,920		576,920
234	Heedeh Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,241					424,109		424,109
235	Henry Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,787					554,809		554,809
236	Hessler 115KW	LU	Note 1	0.0000	0.0000	0.0000	7					462		462
237	Hew Fulton Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	9,278					581,622		581,622
238	Hickory Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,442					704,938		704,938
239	Highest Power Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	89,347					3,666,810		3,666,810
240	Highland Solar Center	LU	Note 1	0.0000	0.0000	0.0000	7,566					514,852		514,852
241	Highwater Solar	LU	Note 1	0.0000	0.0000	0.0000	9,625					609,074		609,074
242	Holstein Holdings	LU	Note 1	0.0000	0.0000	0.0000	35,931					2,393,307		2,393,307
243	Hood Farm Solar	LU	Note 1	0.0000	0.0000	0.0000	8,848					598,131		598,131
244	Howard Plemmons	LU	Note 1	0.0000	0.0000	0.0000	10					365		365
245	Hydrodyne-Little River	LU	Note 1	0.0000	0.0000	0.0000	75					5,755		5,755
246	Ideal Fastner Corp	LU	Note 1	0.0000	0.0000	0.0000	269					20,566		20,566
247	Ingenco Renewables	LU	Note 1	0.0000	0.0000	0.0000	47,731					3,253,331		3,253,331
248	Ingenco Wholesale	LU	Note 1	0.0000	0.0000	0.0000	27,882					1,315,235		1,315,235
249	Innovative Solar 10	LU	Note 1	0.0000	0.0000	0.0000	2,924					184,050		184,050
250	Innovative Solar 31, LLC	LU	Note 1	0.0000	0.0000	0.0000	63,780					4,032,259		4,032,259
251	Innovative Solar 35, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,537					221,428		221,428
252	Innovative Solar 37, LLC	LU	Note 1	0.0000	0.0000	0.0000	143,361					8,375,054		8,375,054

253	Innovative Solar 42	LU	Note 1	0.0000	0.0000	0.0000	140,017					7,548,693		7,548,693
254	Innovative Solar 43, LLC	LU	Note 1	0.0000	0.0000	0.0000	67,686					4,032,039		4,032,039
255	Innovative Solar 44 LLC	LU	Note 1	0.0000	0.0000	0.0000	8,679					544,983		544,983
256	Innovative Solar 46, LLC	LU	Note 1	0.0000	0.0000	0.0000	143,188					9,552,884		9,552,884
257	Innovative Solar 47 LLC	LU	Note 1	0.0000	0.0000	0.0000	70,161					4,051,463		4,051,463
258	Innovative Solar 48 LLC	LU	Note 1	0.0000	0.0000	0.0000	8,751					550,570		550,570
259	Innovative Solar 54	LU	Note 1	0.0000	0.0000	0.0000	96,947					5,388,638		5,388,638
260	Innovative Solar 55 LLC	LU	Note 1	0.0000	0.0000	0.0000	8,868					561,793		561,793
261	Innovative Solar 59, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,674					229,592		229,592
262	Innovative Solar 6	LU	Note 1	0.0000	0.0000	0.0000	1,742					117,254		117,254
263	Innovative Solar 60, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,721					233,783		233,783
264	Innovative Solar 63	LU	Note 1	0.0000	0.0000	0.0000	8,270					523,147		523,147
265	Innovative Solar 64 LLC	LU	Note 1	0.0000	0.0000	0.0000	8,231					521,471		521,471
266	Innovative Solar 65, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,942					561,414		561,414
267	Innovative Solar 67	LU	Note 1	0.0000	0.0000	0.0000	69,082					3,848,130		3,848,130
268	Innovative Solar6 P1	LU	Note 1	0.0000	0.0000	0.0000	1,749					117,807		117,807
269	Innovative Solar6 P2	LU	Note 1	0.0000	0.0000	0.0000	3,680					248,759		248,759
270	International Paper Company	LU	Note 1	0.0000	0.0000	0.0000	774					34,067		34,067
271	Jackson & Sons, Inc	LU	Note 1	0.0000	0.0000	0.0000	23					1,409		1,409
272	James Young (Asheville Alternative)	LU	Note 1	0.0000	0.0000	0.0000	44					1,624		1,624
273	James Young (Asheville Alt Energy)	LU	Note 1	0.0000	0.0000	0.0000	49					1,808		1,808
274	Jessamine Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,711					214,933		214,933
275	Jester Solar	LU	Note 1	0.0000	0.0000	0.0000	9,731					615,148		615,148
276	John Reese	LU	Note 1	0.0000	0.0000	0.0000	5					179		179
277	Johnson Breeders	LU	Note 1	0.0000	0.0000	0.0000	450					65,504		65,504
278	Jordan Hydroelectric LLC	LU	Note 1	0.0000	0.0000	0.0000	3,549					236,292		236,292
279	Joseph Callahan	LU	Note 1	0.0000	0.0000	0.0000	0							
280	Joseph Ponzi	LU	Note 1	0.0000	0.0000	0.0000	6					215		215
281	JT Hobby & Sons, Inc.	LU	Note 1	0.0000	0.0000	0.0000	0							
282	K & HB Enterprises LLC - Waynesville	LU	Note 1	0.0000	0.0000	0.0000	33					2,061		2,061
283	K & HB Enterprises LLC - Asheville	LU	Note 1	0.0000	0.0000	0.0000	31					1,922		1,922
284	Kalish Farm Solar	LU	Note 1	0.0000	0.0000	0.0000	8,882					600,459		600,459
285	Kathleen Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,991					631,530		631,530
286	Keen Farm	LU	Note 1	0.0000	0.0000	0.0000	8,835					556,991		556,991
287	Kelly Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	9,282					623,672		623,672
288	Kenansville Solar 2 LLC	LU	Note 1	0.0000	0.0000	0.0000	2,832					175,852		175,852
289	Kenansville Solar Farm LLC (Heelstone Energy)	LU	Note 1	0.0000	0.0000	0.0000	5,809					486,931		486,931
290	Kenansville Solar LLC (FLS Energy)	LU	Note 1	0.0000	0.0000	0.0000	3,321					276,784		276,784
291	Kendall Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,706					613,529		613,529
292	Kennedy Solar	LU	Note 1	0.0000	0.0000	0.0000	8,686					584,872		584,872

293	Kenneth Solar	LU	Note 1	0.0000	0.0000	0.0000	4,806					304,214		304,214
294	Kinston Davis Farm	LU	Note 1	0.0000	0.0000	0.0000	8,956					552,152		552,152
295	Kinston Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	3,880					323,099		323,099
296	Kirkwall Holdings LLC	LU	Note 1	0.0000	0.0000	0.0000	10,081					640,892		640,892
297	Kojak farm	LU	Note 1	0.0000	0.0000	0.0000	8,683					587,384		587,384
298	L&D Incorporated	LU	Note 1	0.0000	0.0000	0.0000	0							
299	Land of the Sky MT (Eden Solar/Innovative Solar 34)	LU	Note 1	0.0000	0.0000	0.0000	74,582					4,993,088		4,993,088
300	Lane Solar Farm II	LU	Note 1	0.0000	0.0000	0.0000	10,436					654,329		654,329
301	Lane Solar Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,775					615,233		615,233
302	Laney Development Inc	LU	Note 1	0.0000	0.0000	0.0000	13					977		977
303	Lang Solar	LU	Note 1	0.0000	0.0000	0 0000	9,232					622,914		622,914
304	Langdon Solar	LU	Note 1	0.0000	0.0000	0.0000	8,738					550,822		550,822
305	Lanier Solar	LU	Note 1	0.0000	0.0000	0.0000	8,938					606,375		606,375
306	Laurinburg Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	3,894					261,724		261,724
307	Legacy Biogas	LU	Note 1	0.0000	0.0000	0.0000	7					436		436
308	Lenior Farm 1, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,290					605,129		605,129
309	Lenior Farm 2, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,054					589,059		589,059
310	Lillington Solar	LU	Note 1	0.0000	0.0000	0.0000	9,156					576,829		576,829
311	Logan Trading Co, Inc.	LU	Note 1	0.0000	0.0000	0.0000	46					2,848		2,848
312	M B Haynes Corporation 12KW	LU	Note 1	0.0000	0.0000	0.0000	13					962		962
313	M B Haynes Corporation 24KW	LU	Note 1	0.0000	0.0000	0.0000	30					2,292		2,292
314	Madison Hydro Partners	LU	Note 1	0.0000	0.0000	0.0000	2,701					174,576		174,576
315	Mahadev Enterprises LLC	LU	Note 1	0.0000	0.0000	0.0000	10					736		736
316	Manway Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	9,304					587,403		587,403
317	Marguerite Rogers	LU	Note 1	0.0000	0.0000	0.0000	6					241		241
318	Mark Parker	LU	Note 1	0.0000	0.0000	0.0000	4					160		160
319	Marshall Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,578					265,972		265,972
320	Marshall's Locksmith Services Inc	LU	Note 1	0.0000	0.0000	0.0000	13					979		979
321	Martin Creek Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	5,492					456,541		456,541
322	Maxton Solar 1	LU	Note 1	0.0000	0.0000	0.0000	9,627					607,594		607,594
323	McCallum Farm	LU	Note 1	0.0000	0.0000	0.0000	8,967					655,637		655,637
324	McGoogan Farm	LU	Note 1	0.0000	0.0000	0.0000	9,394					633,868		633,868
325	McGrigor Farm Solar	LU	Note 1	0.0000	0.0000	0.0000	9,729					614,297		614,297
326	McKenzie Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	9,339					563,011		563,011
327	Meadowlark Solar	LU	Note 1	0.0000	0.0000	0 0000	9,598					607,092		607,092
328	Melinda Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	8,324					524,282		524,282
329	Meriwether Farm	LU	Note 1	0.0000	0.0000	0.0000	9,093					570,061		570,061
330	Metropolitan Sewerage	LU	Note 1	0.0000	0.0000	0.0000	6					239		239
331	Michael Ian McGregor	LU	Note 1	0.0000	0.0000	0.0000	0							
332	Mile Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	7,694					638,829		638,829

333	Mill Pond Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	9,059					568,160		568,160
334	Millers Chapel Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	9,731					612,271		612,271
335	Mills Anson Farm	LU	Note 1	0.0000	0.0000	0.0000	8,713					587,880		587,880
336	Moncure Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	6,143					513,875		513,875
337	Montgomery Solar	LU	Note 1	0.0000	0.0000	0.0000	35,731					2,235,362		2,235,362
338	Moorings Farm 2, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,011					567,076		567,076
339	Moorings Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,969					581,463		581,463
340	Morgan Farm	LU	Note 1	0.0000	0.0000	0.0000	8,718					591,961		591,961
341	Mount Olive Solar	LU	Note 1	0.0000	0.0000	0.0000	2,802					188,577		188,577
342	MP Wayne County Landfill	LU	Note 1	0.0000	0.0000	0.0000	(174)					(10,610)		(10,610)
343	Mt Olive Farm	LU	Note 1	0.0000	0.0000	0.0000	9,588					712,847		712,847
344	Mt Olive Farm 2 LLC	LU	Note 1	0.0000	0.0000	0.0000	9,259					676,849		676,849
345	Mt Olive Solar 1 LLC	LU	Note 1	0.0000	0.0000	0.0000	7,175					455,632		455,632
346	Mule Farm Solar	LU	Note 1	0.0000	0.0000	0.0000	3,680					232,518		232,518
347	Murdock Solar	LU	Note 1	0.0000	0.0000	0.0000	6,069					383,162		383,162
348	Mustang Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	9,284					585,682		585,682
349	Nash 58 Farm	LU	Note 1	0.0000	0.0000	0.0000	9,189					761,848		761,848
350	Nash 64 Farm	LU	Note 1	0.0000	0.0000	0.0000	7,006					518,092		518,092
351	Nash 97 Solar	LU	Note 1	0.0000	0.0000	0.0000	9,134					577,243		577,243
352	Nash 97 Solar 2, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,513					578,421		578,421
353	Nashville Farms LLC	LU	Note 1	0.0000	0.0000	0.0000	3,263					243,477		243,477
354	NC State Museum of Nat Science	LU	Note 1	0.0000	0.0000	0.0000	6					215		215
355	NCEMC - Ajax	LU	Note 1	0.0000	0.0000	0.0000	3,962					226,229		226,229
356	NCEMC - Bear Creek Solar	LU	Note 1	0.0000	0.0000	0.0000	3,949					225,802		225,802
357	NCEMC - Bondi Solar	LU	Note 1	0.0000	0.0000	0.0000	9,577					494,746		494,746
358	NCEMC - Carolina Poultry	LU	Note 1	0.0000	0.0000	0.0000	4,193					205,578		205,578
359	NCEMC - Copperfield Solar	LU	Note 1	0.0000	0.0000	0.0000	3,365					134,196		134,196
360	NCEMC - Cruise Solar	LU	Note 1	0.0000	0.0000	0.0000	3,542					143,365		143,365
361	NCEMC - Flint Hill	LU	Note 1	0.0000	0.0000	0.0000	8,398					427,305		427,305
362	NCEMC - Freight Line Solar	LU	Note 1	0.0000	0.0000	0.0000	4,337					151,809		151,809
363	NCEMC - Holly Swamp	LU	Note 1	0.0000	0.0000	0.0000	4,344					151,918		151,918
364	NCEMC - Hopewell Friends Solar	LU	Note 1	0.0000	0.0000	0.0000	1,774					71,135		71,135
365	NCEMC - Jersey Holdings Solar	LU	Note 1	0.0000	0.0000	0.0000	9,671					521,751		521,751
366	NCEMC - Long Henry Solar	LU	Note 1	0.0000	0.0000	0.0000	3,983					226,487		226,487
367	NCEMC - Morning View Solar	LU	Note 1	0.0000	0.0000	0.0000	4,038					162,472		162,472
368	NCEMC - Panda NC 1	LU	Note 1	0.0000	0.0000	0.0000	1,802					53,619		53,619
369	NCEMC - Panda NC 10	LU	Note 1	0.0000	0.0000	0.0000	3,355					101,567		101,567
370	NCEMC - Panda NC 11	LU	Note 1	0.0000	0.0000	0.0000	4,047					121,028		121,028
371	NCEMC - Panda NC 2	LU	Note 1	0.0000	0.0000	0.0000	3,916					117,152		117,152
372	NCEMC - Panda NC 3	LU	Note 1	0.0000	0.0000	0.0000	1,821					53,863		53,863

373	NCEMC - Panda NC 4	LU	Note 1	0.0000	0.0000	0.0000	1,615					47,733		47,733
374	NCEMC - Panda NC 5	LU	Note 1	0.0000	0.0000	0.0000	2,813					83,448		83,448
375	NCEMC - Panda NC 6	LU	Note 1	0.0000	0.0000	0.0000	3,513					104,338		104,338
376	NCEMC - Panda NC 7	LU	Note 1	0.0000	0.0000	0.0000	4,333					129,984		129,984
377	NCEMC - Panda NC 8	LU	Note 1	0.0000	0.0000	0.0000	4,193					126,002		126,002
378	NCEMC - Panda NC 9	LU	Note 1	0.0000	0.0000	0.0000	3,621					107,161		107,161
379	NCEMC - PG Solar	LU	Note 1	0.0000	0.0000	0.0000	3,044					106,513		106,513
380	NCEMC - Revolution Dail Road	LU	Note 1	0.0000	0.0000	0.0000	55					3,774		3,774
381	NCEMC - Revolution Ezzell Road	LU	Note 1	0.0000	0.0000	0.0000	446					30,460		30,460
382	NCEMC - Richlands Solar	LU	Note 1	0.0000	0.0000	0.0000	3,411					137,750		137,750
383	NCEMC - Robeson Landfill (Phase 1)	LU	Note 1	0.0000	0.0000	0.0000	2					113		113
384	NCEMC - Robeson Landfill (Phase 2)	LU	Note 1	0.0000	0.0000	0.0000	0							
385	NCEMC - Rosewood Solar	LU	Note 1	0.0000	0.0000	0.0000	3,879					221,720		221,720
386	NCEMC - Ruskin Solar	LU	Note 1	0.0000	0.0000	0.0000	3,863					220,100		220,100
387	NCEMC - Scarlett Solar	LU	Note 1	0.0000	0.0000	0.0000	3,845					219,007		219,007
388	NCEMC - Snow Camp Solar	LU	Note 1	0.0000	0.0000	0.0000	10,849					596,068		596,068
389	NCEMC - Solar 41	LU	Note 1	0.0000	0.0000	0.0000	951					18,405		18,405
390	NCEMC - Storm Hog Partners	LU	Note 1	0.0000	0.0000	0.0000	2,720					187,845		187,845
391	NCEMC - Storm Hog Partners 2	LU	Note 1	0.0000	0.0000	0.0000	11					667		667
392	NCEMC - Strider Solar	LU	Note 1	0.0000	0.0000	0.0000	9,098					473,793		473,793
393	NCEMC - Sunny Point	LU	Note 1	0.0000	0.0000	0.0000	1,842					112,126		112,126
394	NCEMC - Viper Solar	LU	Note 1	0.0000	0.0000	0.0000	4,012					228,811		228,811
395	NCEMPA	LU	Note 1	0.0000	0.0000	0.0000	231,330					14,760,293		14,760,293
396	Neal Hydro	LU	Note 1	0.0000	0.0000	0.0000	1,079					86,642		86,642
397	Neuse River Solar Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	1,519					95,089		95,089
398	New Bern Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	8,385					611,365		611,365
399	Nickelson Solar 2	LU	Note 1	0.0000	0.0000	0.0000	9,051					573,640		573,640
400	Nickelson Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,957					624,933		624,933
401	Nitro Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	8,637					584,759		584,759
402	North Carolina Solar I LLC	LU	Note 1	0.0000	0.0000	0.0000	2,530					193,723		193,723
403	North Carolina Solar II LLC	LU	Note 1	0.0000	0.0000	0.0000	3,109					259,367		259,367
404	North Carolina Solar III Lessee LLC	LU	Note 1	0.0000	0.0000	0.0000	8,893					742,054		742,054
405	North Nash Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	9,169					577,757		577,757
406	Oakboro Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	8,459					558,404		558,404
407	Old Webbs Mill Hydro LLC	LU	Note 1	0.0000	0.0000	0.0000	0							
408	Old Wire Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,213					641,952		641,952
409	Onslow Power Producers, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,639					768,287		768,287
410	Orion Energy Marketing & Consulting, Inc.	LU	Note 1	0.0000	0.0000	0.0000	0							
411	Overhill Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,749					675,984		675,984
412	Overman Solar	LU	Note 1	0.0000	0.0000	0.0000	10,659					672,748		672,748

413	P K Ventures Inc	LU	Note 1	0.0000	0.0000	0.0000	0							
414	Page Solar Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	2,389					151,090		151,090
415	Pate Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	9,127					667,147		667,147
416	PCIP Solar Lessee LLC	LU	Note 1	0.0000	0.0000	0.0000	1,670					104,586		104,586
417	PCSP3 Airport LLC	LU	Note 1	0.0000	0.0000	0.0000	3,812					291,870		291,870
418	Peake Road Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,385					591,944		591,944
419	Pecan Grove Solar	LU	Note 1	0.0000	0.0000	0.0000	8,483					533,671		533,671
420	Perkins Solar	LU	Note 1	0.0000	0.0000	0.0000	3,853					243,373		243,373
421	Pikeville Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,750					616,960		616,960
422	Pine Valley Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	10,002					627,680		627,680
423	Pinedale Springs	LU	Note 1	0.0000	0.0000	0.0000	76					4,779		4,779
424	Pinesage Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	7,502					478,788		478,788
425	Plott Hound	LU	Note 1	0.0000	0.0000	0.0000	6,572					423,472		423,472
426	Polk Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,979					691,631		691,631
427	Pollocksville Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,986					609,565		609,565
428	Porter Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	8,256					487,315		487,315
429	Prestage Agenergy NC	LU	Note 1	0.0000	0.0000	0.0000	2,538					138,494		138,494
430	Prestage Farms, Inc.	LU	Note 1	0.0000	0.0000	0.0000	210					16,668		16,668
431	Progress Solar I LLC	LU	Note 1	0.0000	0.0000	0.0000	5,522					459,613		459,613
432	Progress Solar II, LLC	LU	Note 1	0.0000	0.0000	0.0000	5,520					460,718		460,718
433	Progress Solar III, LLC	LU	Note 1	0.0000	0.0000	0.0000	5,947					496,635		496,635
434	Quarter Horse Farm	LU	Note 1	0.0000	0.0000	0.0000	9,460					594,920		594,920
435	Quarters LLC (new name Quarters Houston)	LU	Note 1	0.0000	0.0000	0.0000	496					37,999		37,999
436	Quincy Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,241					455,368		455,368
437	Raeford Farm	LU	Note 1	0.0000	0.0000	0.0000	6,937					572,269		572,269
438	Railroad Farm	LU	Note 1	0.0000	0.0000	0.0000	6,510					542,971		542,971
439	Railroad Farm 2, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,495					705,982		705,982
440	Railroad Solar Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	6,429					432,652		432,652
441	Ramp Solar	LU	Note 1	0.0000	0.0000	0.0000	4,116					260,630		260,630
442	Rankin Solar Center	LU	Note 1	0.0000	0.0000	0.0000	19,310					695,187		695,187
443	Red Hill Solar	LU	Note 1	0.0000	0.0000	0.0000	7,105					592,241		592,241
444	Red Oak Solar Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,450					591,711		591,711
445	Red Toad 315 Vinson	LU	Note 1	0.0000	0.0000	0.0000	4,850					301,215		301,215
446	Red Toad 4451	LU	Note 1	0.0000	0.0000	0.0000	4,072					256,499		256,499
447	Red Toad 5840	LU	Note 1	0.0000	0.0000	0.0000	4,481					280,379		280,379
448	Red Toad A Powatan Road LLC	LU	Note 1	0.0000	0.0000	0.0000	3,784					248,478		248,478
449	Red Toad II LLC	LU	Note 1	0.0000	0.0000	0.0000	93					7,114		7,114
450	Red Toad Powatan (Phase 2)	LU	Note 1	0.0000	0.0000	0.0000	4,653					290,740		290,740
451	Redwing Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,681					214,374		214,374
452	Renewable Power LLC (Foodlion)	LU	Note 1	0.0000	0.0000	0.0000	183					11,427		11,427

453	Ridgeback Solar	LU	Note 1	0.0000	0.0000	0.0000	4,517					285,244		285,244
454	River Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,797					222,878		222,878
455	Robert Beatty	LU	Note 1	0.0000	0.0000	0.0000	0							
456	Robin Solar	LU	Note 1	0.0000	0.0000	0.0000	8,071					510,016		510,016
457	Rock Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	9,571					705,367		705,367
458	Rockingham Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	9,449					637,687		637,687
459	Rocky Mount Mills	LU	Note 1	0.0000	0.0000	0.0000	0							
460	Rose Hill Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	2,964					245,717		245,717
461 .	Roxboro Farm LLC	LU	Note 1	0.0000	0.0000	0 0000	9,017					748,501		748,501
462	Roxboro Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	8,985					534,695		534,695
463	Royal Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	8,418					530,307		530,307
464	Sabattus Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,053					568,855		568,855
465	Sadiebrook Solar	LU	Note 1	0.0000	0.0000	0.0000	9,011					567,754		567,754
466	Samarcand Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	8,311					694,968		694,968
467	Sampson Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	3,871					261,789		261,789
468	Sandy Cross Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	1,961					150,189		150,189
469	Sapphire Solar	LU	Note 1	0.0000	0.0000	0.0000	3,679					215,281		215,281
470	Sarah Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	7,830					529,605		529,605
471	SAS - 1200KW	LU	Note 1	0.0000	0.0000	0.0000	1,690					106,936		106,936
472	Sauced Realty	LU	Note 1	0.0000	0.0000	0.0000	0							
473	Scotch Bonnet	LU	Note 1	0.0000	0.0000	0.0000	6,271					393,321		393,321
474	Seagrove Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,659					547,191		547,191
475	Sedberry Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,608					580,067		580,067
476	Sellers Farm Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,629					668,619		668,619
477	Selma Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	7,676					642,019		642,019
478	Selwyn Farm	LU	Note 1	0.0000	0.0000	0.0000	10,867					685,462		685,462
479	Shannon Farm	LU	Note 1	0.0000	0.0000	0.0000	7,526					545,118		545,118
480	Shelter Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,692					614,717		614,717
481	Shoe Creek Solar	LU	Note 1	0.0000	0.0000	0.0000	142,200					7,864,241		7,864,241
482	Siler 421 Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,610					649,685		649,685
483	Siler City Solar 2	LU	Note 1	0.0000	0.0000	0.0000	9,488					600,051		600,051
484	Siler Solar	LU	Note 1	0 0000	0.0000	0.0000	8,779					555,308		555,308
485	SMB Holding 10 LLC	LU	Note 1	0.0000	0.0000	0.0000	0							
486	Smith Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	10,516					706,558		706,558
487	Sneads Grove Farm, LLC	LU	Note 1	0 0000	0.0000	0.0000	9,903					622,935		622,935
488	Snow Hill Solar 2	LU	Note 1	0.0000	0 0000	0.0000	3,670					271,256		271,256
489	Sol Sencia Ventures LLC (Paul Kazmer)	LU	Note 1	0.0000	0.0000	0.0000	87					2,402		2,402
490	Solar 55 LLC	LU	Note 1	0.0000	0.0000	0.0000	2,112					160,423		160,423
491	Solar Lee	LU	Note 1	0.0000	0.0000	0.0000	7,760					494,074		494,074
492	Solarworks RCC LLC	LU	Note 1	0.0000	0.0000	0.0000	332					25,421		25,421

493	Soluga Farm I, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,282					570,295		570,295
494	Soluga Farm II LLC	LU	Note 1	0.0000	0.0000	0.0000	9,081					558,095		558,095
495	Soluga Farm III LLC	LU	Note 1	0.0000	0.0000	0.0000	9,138					620,196		620,196
496	Soluga Farms IV, LLC	LU	Note 1	0.0000	0.0000	0.0000	5,837					369,898		369,898
497	Sonne One LLC	LU	Note 1	0.0000	0.0000	0.0000	9,981					679,523		679,523
498	Soul City Solar	LU	Note 1	0.0000	0.0000	0.0000	5,242					354,604		354,604
499	South Atlantic Services	LU	Note 1	0.0000	0.0000	0.0000	3,061					200,901		200,901
500	South Louisburg Solar	LU	Note 1	0.0000	0.0000	0.0000	9,655					653,695		653,695
501	South Robeson Solar Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,315					608,790		608,790
502	South Solar	LU	Note 1	0.0000	0.0000	0.0000	3,883					226,126		226,126
503	Southeastern Freight Lines	LU	Note 1	0.0000	0.0000	0.0000	498					12,385		12,385
504	Southerland Farms	LU	Note 1	0.0000	0.0000	0.0000	9,706					609,359		609,359
505	Spicewood Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	8,499					522,777		522,777
506	Spring Hope 3	LU	Note 1	0.0000	0.0000	0.0000	5,962					377,675		377,675
507	Spring Hope Solar 2	LU	Note 1	0.0000	0.0000	0.0000	9,043					570,357		570,357
508	Spring Valley Solar 2	LU	Note 1	0.0000	0.0000	0.0000	9,240					581,639		581,639
509	St. Pauls Solar 1, LLC	LU	Note 1	0.0000	0.0000	0.0000	5,731					357,374		357,374
510	St. Pauls Solar 2, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,337					560,401		560,401
511	Stagecoach Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	8,375					564,473		564,473
512	Stainback Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	9,195					533,387		533,387
513	Starr Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,157					641,278		641,278
514	Steve Zarnowski (FLAT CREEK)	LU	Note 1	0.0000	0.0000	0.0000	33					1,244		1,244
515	Stone Solar Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,635					609,551		609,551
516	Summit Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	6,579					394,984		394,984
517	Sumter Heat & Power LLC	LU	Note 1	0.0000	0.0000	0.0000	(349)					(8,836)		(8,836)
518	Sun Devil Solar	LU	Note 1	0.0000	0.0000	0.0000	8,508					534,422		534,422
519	Suncaster	LU	Note 1	0.0000	0.0000	0.0000	3,694					235,900		235,900
520	SunE Bearpond Lessee	LU	Note 1	0.0000	0.0000	0.0000	5,674					476,245		476,245
521	SunE Graham Lessee	LU	Note 1	0.0000	0.0000	0.0000	8,297					689,954		689,954
522	SunE NC Progress, LLC	LU	Note 1	0.0000	0.0000	0.0000	1,123					70,294		70,294
523	SunE Shankle Lessee	LU	Note 1	0.0000	0.0000	0.0000	8,741					732,994		732,994
524	Sunenergy1-Asheville LLC	LU	Note 1	0.0000	0.0000	0.0000	238					14,884		14,884
525	Sunfish Solar	LU	Note 1	0.0000	0.0000	0.0000	8,631					542,052		542,052
526	Sunsense	LU	Note 1	0.0000	0.0000	0.0000	0							
527	Sunstruck Energy LLC	LU	Note 1	0.0000	0.0000	0.0000	54					3,722		3,722
528	Susan Emerick	LU	Note 1	0.0000	0.0000	0.0000	18					1,080		1,080
529	Swansboro	LU	Note 1	0.0000	0.0000	0.0000	7,115					453,620		453,620
530	Sweet Tea	LU	Note 1	0.0000	0.0000	0.0000	6,237					396,227		396,227
531	Sweetgum Solar	LU	Note 1	0.0000	0.0000	0.0000	9,239					623,307		623,307
532	Tamworth Holdings	LU	Note 1	0.0000	0.0000	0.0000	9,074					569,503		569,503

533	Tanager Holdings	LU	Note 1	0.0000	0.0000	0.0000	6,713					426,435		426,435
534	Tart Farm	LU	Note 1	0.0000	0.0000	0.0000	8,457					574,047		574,047
535	Tate Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	10,022					627,801		627,801
536	Tedder Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	4,556					264,791		264,791
537	Thaddeus Burgess Trust	LU	Note 1	0.0000	0.0000	0.0000	27					1,666		1,666
538	Thanksgiving Solar	LU	Note 1	0.0000	0.0000	0.0000	3,840					241,420		241,420
539	The Big Chicken LLC	LU	Note 1	0.0000	0.0000	0.0000	12					433		433
540	The N C Growers Assoc Inc	LU	Note 1	0.0000	0.0000	0.0000	12					782		782
541	The Rock Solar Energy Plant LLC	LU	Note 1	0.0000	0.0000	0.0000	486					37,177		37,177
542	Three Bridge Farm	LU	Note 1	0.0000	0.0000	0.0000	3,351					211,110		211,110
543	Thunderhead Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,033					255,574		255,574
544	Tides Lane Farm	LU	Note 1	0.0000	0.0000	0.0000	6,434					406,018		406,018
545	Tinker Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,088					442,126		442,126
546	Town of Cary	LU	Note 1	0.0000	0.0000	0.0000	1,974					157,177		157,177
547	Town of Warsaw Solar	LU	Note 1	0.0000	0.0000	0.0000	1,113					70,203		70,203
548	Tracy Solar	LU	Note 1	0.0000	0.0000	0.0000	16,159					1,046,987		1,046,987
549	Trent River Farm	LU	Note 1	0.0000	0.0000	0.0000	8,461					530,504		530,504
550	Trent River Solar	LU	Note 1	0.0000	0.0000	0.0000	140,379					5,421,711		5,421,711
551	Trojan Solar	LU	Note 1	0.0000	0.0000	0.0000	10,274					646,308		646,308
552	Truman Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,699					612,640		612,640
553	Trustees of Haywood	LU	Note 1	0.0000	0.0000	0.0000	112					9,277		9,277
554	Turkey Branch Solar (FLS 2014 SOLAR A)	LU	Note 1	0.0000	0.0000	0.0000	8,075					474,404		474,404
555	TWE Chocowinity	LU	Note 1	0.0000	0.0000	0.0000	5,731					365,858		365,858
556	TWE Kinston Solar	LU	Note 1	0.0000	0.0000	0.0000	5,788					365,984		365,984
557	TWE Laurinburg	LU	Note 1	0.0000	0.0000	0.0000	8,821					555,038		555,038
558	TWE New Bern Solar	LU	Note 1	0.0000	0.0000	0.0000	6,134					415,473		415,473
559	Uwharrie Mountain Renewables	LU	Note 1	0.0000	0.0000	0.0000	34,893					1,988,890		1,988,890
560	Van Buren	LU	Note 1	0.0000	0.0000	0.0000	4,484					283,804		283,804
561	Vance Solar 1	LU	Note 1	0.0000	0.0000	0.0000	8,755					592,893		592,893
562	Vandy LLC	LU	Note 1	0.0000	0.0000	0.0000	0							
563	Vickers Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	3,682					225,739		225,739
564	Vicksburg Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	8,953					605,099		605,099
565	Vincent Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,595					208,938		208,938
566	Wadesboro Farm	LU	Note 1	0.0000	0.0000	0.0000	8,476					522,629		522,629
567	Wadesboro Farm 2	LU	Note 1	0.0000	0.0000	0.0000	9,311					627,814		627,814
568	Wadesboro Farm 3	LU	Note 1	0.0000	0.0000	0.0000	9,197					575,643		575,643
569	Wadesboro Farm 4	LU	Note 1	0.0000	0.0000	0.0000	3,795					239,073		239,073
570	Wadesboro Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,404					590,250		590,250
571	Wadford Storage	LU	Note 1	0.0000	0.0000	0.0000	0							
572	Wagstaff Farm 1, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,698					721,940		721,940

573	Wake Tech Innovations Inc	LU	Note 1	0.0000	0.0000	0.0000	426					32,639		32,639
574	Wakefield Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	9,861					619,026		619,026
575	Wallace Solar	LU	Note 1	0.0000	0.0000	0.0000	3,187					265,536		265,536
576	Walter Henry Bundy	LU	Note 1	0.0000	0.0000	0.0000	63					2,475		2,475
577	Warren Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	8,617					534,233		534,233
578	Warrenton Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,370					612,097		612,097
579	Warrenton Solar I	LU	Note 1	0.0000	0.0000	0.0000	9,041					571,330		571,330
580	Warsaw Solar	LU	Note 1	0.0000	0.0000	0.0000	3,269					272,134		272,134
581	Warsaw Solar 2 LLC	LU	Note 1	0.0000	0.0000	0.0000	3,351					279,253		279,253
582	Watauga Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,076					237,340		237,340
583	Watts Farm	LU	Note 1	0.0000	0.0000	0.0000	7,380					616,080		616,080
584	Wayne County Public Schools	LU	Note 1	0.0000	0.0000	0.0000	111					7,009		7,009
585	Wayne Solar I, LLC	LU	Note 1	0.0000	0.0000	0.0000	2,444					200,923		200,923
586	Wayne Solar II, LLC	LU	Note 1	0.0000	0.0000	0.0000	5,969					501,269		501,269
587	Wayne Solar III, LLC	LU	Note 1	0.0000	0.0000	0.0000	5,655					486,915		486,915
588	Weaver Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,260					249,103		249,103
589	Wedge Solar	LU	Note 1	0.0000	0.0000	0.0000	10,464					661,676		661,676
590	Wellons Farm	LU	Note 1	0.0000	0.0000	0.0000	9,192					621,894		621,894
591	Wendell Solar Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,234					513,981		513,981
592	West Siler Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,459					641,373		641,373
593	Westgate Auto Group LLC	LU	Note 1	0.0000	0.0000	0.0000	123					9,390		9,390
594	Whiskey Solar	LU	Note 1	0.0000	0.0000	0.0000	12,395					780,783		780,783
595	Whitetail Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	23,248					850,010		850,010
596	Willard Solar	LU	Note 1	0.0000	0.0000	0.0000	8,738					550,624		550,624
597	Willis Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,961					230,697		230,697
598	Wilson Farm 1, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,071					588,929		588,929
599	Woodland Church Farm	LU	Note 1	0.0000	0.0000	0.0000	9,062					571,753		571,753
600	Woodsdale Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	3,548					223,899		223,899
601	Wortham Solar	LU	Note 1	0.0000	0.0000	0.0000	8,821					555,359		555,359
602	Wyse Fork Solar Farm	LU	Note 1	0.0000	0.0000	0.0000	3,505					221,795		221,795
603	Yanceyville Farm 2 LLC	LU	Note 1	0.0000	0.0000	0.0000	9,180					565,010		565,010
604	Yanceyville Farm 3	LU	Note 1	0.0000	0.0000	0.0000	8,656					542,633		542,633
605	Yanceyville Farm LLC	LU	Note 1	0.0000	0.0000	0.0000	8,548					711,729		711,729
606	ZV Solar 1	LU	Note 1	0.0000	0.0000	0.0000	9,573					603,784		603,784
607	ZV Solar 2	LU	Note 1	0.0000	0.0000	0.0000	9,188					618,337		618,337
608	ZV Solar 3	LU	Note 1	0.0000	0.0000	0.0000	9,297					625,693		625,693
609	Vitesse Enterprises, LLC	LU	Note 1	0.0000	0.0000	0.0000	0							
610	Shieldwall Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	11,217					666,716		666,716
611	Jefferson Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	17,837					626,867		626,867
612	Terreva Wayne County RNG, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,147					469,416		469,416

613	SC Excess Net Energy Credit	LU	Note 1	0.0000	0.0000	0.0000	1,975					39,407		39,407
614	Ogburn Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,297					249,891		249,891
615	Hominy Baptist Church	LU	Note 1	0.0000	0.0000	0.0000	154					5,634		5,634
616	Hickson Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,624					269,611		269,611
617	Phobos Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	150,734					5,051,511		5,051,511
618	Monday Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	5,318					317,297		317,297
619	Cabin Creek Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	139,603					4,947,240		4,947,240
620	Beckwith Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	9,658					615,832		615,832
621	Washington Solar LLC - (SC)	LU	Note 1	0.0000	0.0000	0.0000	3,106					186,981		186,981
622	MTBT RNG, LLC	LU	Note 1	0.0000	0.0000	0.0000	0							
623	Hubble Solar, LLC	LU	Note 1	0.0000	0.0000	0.0000	3,163					204,033		204,033
624	Arthur Solar 2, LLC	LU	Note 1	0.0000	0.0000	0.0000	7,574					488,136		488,136
625	Enact Mortgage Insurance Corporation	LU	Note 1	0.0000	0.0000	0.0000	0							0
626	Bishopville Solar II LLC	LU	Note 1	0.0000	0.0000	0.0000	15,616					549,806		549,806
627	Shorthorn Holdings, LLC	LU	Note 1	0.0000	0.0000	0.0000	8,246					270,090		270,090
628	McLean Homestead, LLC	LU	Note 1	0.0000	0.0000	0.0000	4,210					277,880		277,880
629	Magdaline Solar LLC	LU	Note 1	0.0000	0.0000	0.0000	959					52,164		52,164
630	RUNNYMEDE SOLAR LLC	LU	Note 1	0.0000	0.0000	0.0000	376					20,646		20,646
631	Aberdeen Farm, LLC	LU	Note 1	0.0000	0.0000	0.0000	1,334					70,211		70,211
632	Fresh Air Energy XXIII, LCC - East Nash	LU	Note 1	0.0000	0.0000	0.0000	0							0
633	D&D of NC Holdings LLC	LU	Note 1	0.0000	0.0000	0.0000	3							0
634	Broad River Energy, LLC	LU	Note 2	0.0000	0.0000	0.0000	285,649				34,723,147	17,760,689		52,483,836
635	Broad River Energy, LLC (ADJ)	AD	Note 2	0.0000	0.0000	0.0000	0					246,354		246,354
636	City of Fayetteville (Butler Warner)	OS	Note 2	0.0000	0.0000	0.0000	22,827				12,669,000	2,266,243		14,935,243
637	City of Fayetteville (Butler Warner) (ADJ)	AD	Note 2	0.0000	0.0000	0.0000	0					(209,805)		(209,805)
638	Southern Power Co	LU	Note 2	0.0000	0.0000	0.0000	1,369,961				25,507,560	48,293,431		73,800,991
639	Southern Power Co (ADJ)	AD	Note 2	0.0000	0.0000	0.0000	0				10,470	182,900		193,370
640	Hamlet (NCEMC)	LU	Note 2	0.0000	0.0000	0.0000	46,835				6,027,840	2,362,118		8,389,958
641	Hamlet (NCEMC (ADJ)	AD	Note 2	0.0000	0.0000	0.0000	69					(784,267)		(784,267)
642	PJM Settlements, Inc	OS	188.0000	0.0000	0.0000	0.0000	7,500					274,228		274,228
643	PJM Settlements, Inc (ADJ)	AD	188.0000	0.0000	0.0000	0.0000	0				0	301,858		301,858
644	Haywood Electric Membership Corporation	LF	Note 2	0.0000	0.0000	0.0000	0				362,615			362,615
645	Haywood Electric Membership Corporation (ADJ)	AD	Note 2	0.0000	0.0000	0.0000	0				0			0
646	North Carolina Electric Membership Corporation	LF	Note 2	0.0000	0.0000	0.0000	95,533				34,132,811	6,407,460		40,540,271
647	North Carolina Electric Membership Corporation (ADJ)	AD	Note 2	0.0000	0.0000	0.0000	98				0	67,446		67,446
648	Duke Energy Carolinas, LLC (1)	OS	190.0000	0.0000	0.0000	0.0000	880,504				0	30,982,902		30,982,902
649	Duke Energy Carolinas, LLC (ADJ)	AD	190.0000	0.0000	0.0000	0.0000	(3,045)				0	(2,826,148)		(2,826,148)
650	Duke Energy Carolinas, LLC (2)	OS	190.0000	0.0000	0.0000	0.0000	107,879				6,583	5,693,444		5,700,027

651	Duke Energy Carolinas, LLC (3)	OS	190.0000	0.0000	0.0000	0.0000	0				0	(394,821)		(394,821)
652	Stone Container Corporation	OS	0.0000	0.0000	0.0000	0.0000	6,608					196,546		196,546
653	City of Camden	EX	0.0000	0.0000	0.0000	0.0000	3,710					95,166		95,166
654	Town of Black Creek	EX	0.0000	0.0000	0.0000	0.0000	(43)					(1,797)		(1,797)
655	Town of Lucama	EX	0.0000	0.0000	0.0000	0.0000	545					14,322		14,322
656	Town of Sharpsburg	EX	0.0000	0.0000	0.0000	0.0000	535					13,786		13,786
657	Town of Stantonsburg	EX	0.0000	0.0000	0.0000	0.0000	347					9,744		9,744
658	Town of Waynesville	EX	0.0000	0.0000	0.0000	0.0000	(142)					(3,573)		(3,573)
659	Town of Winterville	EX	0.0000	0.0000	0.0000	0.0000	915					24,004		24,004
660	NC Electric Memebership Corp	EX	0	0	0	0	4,847					74,048		74,048
15	TOTAL						9,323,143	0	0	0	113,440,026	494,263,511	0	607,703,537

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber
This company is Qualifying Facility (QF) pursuant to PURPA. Rates for purchase from QF's are set by the North Carolina Utilities Commission and the South Carolina Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.
(b) Concept: RateScheduleTariffNumber
Purchase Power Agreement with Seller.

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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.
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.
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 (0) 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.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY: Megawatt Hours Received (i)	TRANSFER OF ENERGY: Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	Southeastern Power Administration	Various	Various	OLF							1,835,497.00	0.00	0.00	1,835,497
2	Duke Power Company NF	Various	Various	NF							252,706.00	0.00	16,233.00	268,939
3	Duke Power Company SFP	Various	Various	SFP							692,247.00	0.00	43,621.00	735,868
4	Duke Power Company Revenue Sharing	Various	Various	OS							3,818,893.00	0.00		3,818,893
5	Brookfield Renewable Trading & Marketing LP NF	Various	Various	NF							101.00	0.00	7.00	108
6	Eagle Energy Partners NF	Various	Various	NF							6,553.00	0.00	419.00	6,972
7	Exelon Power Team	Various	Various	NF							16,103.00	0.00		16,103
8	Mercuria Energy American	Various	Various	NF							413.00	0.00	0.00	413
9	Macquarie Energy LLC SFP	Various	Various	SFP							64,437.00	0.00	4,127.00	68,564
10	Macquarie Energy LLC NF	Various	Various	NF							30,359.00	0.00	1,928.00	32,287
11	Morgan Stanley Capital Group Inc NF	Various	Various	NF							9,549.00	0.00		9,549
12	North Carolina EMC LFP	Various	Various	LFP				315			3,925,955.00	0.00	248,094.00	4,174,049
13	North Carolina EMC NF	Various	Various	NF							2,614.00	0.00	167.00	2,781
14	North Carolina Municipal Power Agency 1 SFP	Various	Various	SFP							10,634.00	0.00	661.00	11,295
15	North Carolina Municipal Power Agency 1 NF	Various	Various	NF							89,068.00	0.00	5,641.00	94,709
16	Carolina Power Partners NF	Various	Various	NF							49,290.00	0.00	3,234.00	52,524
17	Carolina Power Partners SFP	Various	Various	SFP							4,932.00	0.00	306.00	5,238
18	The Energy Authority NF	Various	Various	NF							20,310.00	0.00		20,310
19	Point to Point MWHs for all entries above								661,483	652,619		0.00		
20	City of Camden	Various	Various	FNO							924,740.00	0.00	141,251.00	1,065,991

21	Industrial Power Generating Co	Various	Various	FNO							(973.00)	0.00	2,700.00	1,727
22	French Broad EMC	Various	Various	FNO							1,931,858.00	0.00	192,304.00	2,124,162
23	Haywood EMC	Various	Various	FNO							810,717.00	0.00	72,278.00	882,995
24	North Carolina Eastern Municipal Power Agency	Various	Various	FNO							25,408,774.00	0.00	1,602,612.00	27,011,386
25	North Carolina EMC	Various	Various	FNO							43,914,516.00	0.00	2,893,565.00	46,808,081
26	Piedmont EMC	Various	Various	FNO							573,601.00	0.00	66,178.00	639,779
27	Public Works Comm of the City of Fayetteville	Various	Various	FNO							8,067,000.00	0.00	545,204.00	8,612,204
28	Town of Black Creek	Various	Various	FNO							62,875.00	0.00	14,083.00	76,958
29	Town of Lucama	Various	Various	FNO							95,363.00	0.00	18,874.00	114,237
30	Town of Sharpsburg	Various	Various	FNO							94,531.00	0.00	18,756.00	113,287
31	Town of Stantonsburg	Various	Various	FNO							107,323.00	0.00	20,903.00	128,226
32	Town of Waynesville	Various	Various	FNO							288,991.00	0.00	42,759.00	331,750
33	Town of Winterville	Various	Various	FNO							261,464.00	0.00	46,986.00	308,450
34	Uwharrie Mountain Renewable Energy	Various	Various	OS							0.00	0.00	7,200.00	7,200
35	Craven County Wood Energy	Various	Various	OS								0.00	10,500.00	10,500
36	Lumberton Energy LLC	Various	Various	OS								0.00	3,600.00	3,600
37	SEEMS P2P											0.00		
38	NC Electric Memebership Corp SEEM NF	Various	Various	NF							5,601.00	0.00	0.00	5,601
39	SCE&G Company	Various	Various	NF							4.00	0.00		4
40	Duke Power Company SEEM	Various	Various	NF							52,697.00	0.00	0.00	52,697
41	Tennessee Valley Authority	Various	Various	NF							632.00	0.00		632
42	Associated Electric Coop	Various	Various	NF							6.00	0.00		6
43	Louisville Gas and Eléctric Co SEEM	Various	Various	NF							80.00	0.00		80
44	The Energy Authority - MEAG SEEM	Various	Various	NF							24.00	0.00		24
45	Accrual for Mutually Agreed Items	Various	Various								(1,693,158.00)	0.00		(1,693,158)
46	Southern Wholesale SEEM	Various	Various	NF							28.00	0.00	0.00	28
47	The Energy Authority - GVL SEEM	Various	Various	NF							4.00	0.00		4
48	Energy Trading - FPC Back Offi SEEM	Various	Various	NF							131.00	0.00		131
49	Tampa Electric Company SEEM	Various	Various	NF							10.00	0.00		10
50	TEA of behalf of JEA SEEM	Various	Various	NF							10.00	0.00		10
35	TOTAL							315	661,483	652,619	91,736,510	0	6,024,191	97,760,701

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

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: MegaWatt Hours Received (c)	TRANSFER OF ENERGY: MegaWatt Hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Progress	LFP	661,483	652,619				0
2	SC Dominion Energy	SFP			1,069			1,069
3	Tennessee Valley Transmission Pymt	SFP			486			486
4	Dominion Energy South Carolina, Inc	SFP			75			75
5	Midcontinent Independent System Op	SFP			142			142
	TOTAL		661,483	652,619	1,772	0	0	1,772

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	874,331.00
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,343,721.00
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	146,178.00
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Transferred Employees Homes	1,006,502.00
7	Director's Fees and Expenses	922,326.00
8	Consultants and Contract Services	721,987.00
9	Suspense Clearing	492,180.00
10	Other Contracts	475,629.00
11	Miscellaneous Dues and Subscriptions	252,782.00
12	Postage and Freight	42,149.00
13	Allocated Labor	32,851.00
14	Travel Expenses	14,033.00
15	Miscellaneous	13,981.00
16	IT Software Maintenance	10,137.00
17	Asheville Pipeline Lease	(88,182.00)
18	Direct Purchase Allocations	(140,393.00)
19	Labor Accrual	(4,084,673.00)
20	Service Company Allocation	(31,066,270.00)
21	Dues and Subscriptions to various organizations > $500:	
22	ELECTRIC POWER RESEARCH INSTITUTE EPRI	109,311.00
23	GREATER RALEIGH CHAMBER OF COMMERCE	60,555.00
24	POWER 4 TOMORROW INC	50,000.00
25	SOUTH CAROLINA CHAMBER OF COMMERCE	24,413.00
26	SOUTHEASTERN ELECTRIC EXCHANGE INC	24,190.00
27	ASHEVILLE AREA CHAMBER OF COMMERCE	10,780.00
28	GREATER FLORENCE CHAMBER OF COMMERCE	8,622.00
29	GREATER WHITEVILLE CHAMBER OF COMMERCE	8,550.00
30	E4 CAROLINAS	8,000.00
31	GREATER WILMINGTON CHAMBER OF COMMERCE	5,629.00
32	CARY CHAMBER OF COMMEREСE	5,445.00
33	GREATER SMITHFIELD-SELMA AREA CHAM OF CO	3,700.00
34	MORRISVILLE CHAMBER OF COMMERCE INC	3,142.00
35	CLAYTON CHAMBER OF COMMERCE	3,000.00

36	FUQUAY-VARINA AREA CHAMBER OF COMMERCE	3,000.00
37	LENOIR COUNTY CHAMBER OF COMMERCE	2,834.00
38	PALMETTO AGRIBUSINESS COUNCIL	2,500.00
39	ZEBULON CHAMBER OF COMMERCE	2,500.00
40	GARNER CHAMBER OF COMMERCE	2,495.00
41	DUNN AREA CHAMBER OF COMMERCE	2,255.00
42	RICHMOND COUNTY CHAMBER OF COMMERCE	2,200.00
43	SANFORD AREA CHAMBER OFCOMMERCE	2,100.00
44	PALMETTO BUSINESS FORUM	2,000.00
45	CHAMBER OF COMMERCE OF WAYNE COUNTY INC	1,695.00
46	KERSHAW COUNTY CHAMBER OF COMMERCE	1,558.00
47	CLINTON-SAMPSON CHAMBER OF COMMERCE	1,500.00
48	GREATER SUMTER CHAMBER OF COMMERCE	1,500.00
49	LAURINBURG SCOTLAND COUNTY AREA CHAMBER	1,500.00
50	ROTARY CLUB OF DOWNTOWN WILMINGTON	1,500.00
51	ROCKY MOUNT AREA CHAMBER OF COMMERCE	1,250.00
52	GREATER HARTSVILLE CHAMBER OF COMMERCE	1,136.00
53	LILLINGTON AREA CHAMBER OF COMMERCE	1,100.00
54	JACKSONVILLE-ONSLOW CHAMBER OF COMMERCE	1,080.00
55	GREATER HAVELOCK ARE CHAMBER OF	1,075.00
56	HENDERSON-VANCE CHAMBER OF COMMERCE	1,038.00
57	CARTERET COUNTY CHAMBER OF COMMERCE	1,004.00
58	DILLON COUNTY CHAMBER OF COMMERCE	1,000.00
59	GREATER FAYETTEVILLE CHAMBER	1,000.00
60	GREATER SANDHILLS CHAMBER INC	1,000.00
61	LEE COUNTY CHAMBER OF COMMERCE	1,000.00
62	WAKE FOREST AREA CHAMBER OF COMMERCE	900.00
63	LUMBERTON AREA CHAMBER OF COMMERCE	810.00
64	ROTARY INTERNATIONAL	808.00
65	ROXBORO AREA CHAMBER OF COMMERCE	767.00
66	ROLESVILLE CHAMBER OF COMMERCE	750.00
67	WENDELL CHAMBER OF COMMERCE	750.00
68	FLORENCE ROTARY CLUB	745.00
69	APEX CHAMBER OF COMMERCE	735.00
70	WILLIAMSBURG HOME TOWN CHAMBER	720.00
71	GREATER MULLINS CHAMBER OF COMMERCE	630.00
72	CHERAW CHAMBER OF COMMERCE	625.00
73	MARION CHAMBER OF COMMERCE	620.00
74	ELIZABETHTOWN-WHITE LAKE AREA CHAMBER	580.00
75	GREATER HAYWOOD COUNTY	545.00

76	MAGGIE VALLEY AREA CHAMBER OF COMMERCE	500.00
77	Chamber of Commerce <$500 (24)	8,129.00
46	TOTAL	(28,643,960)

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

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 B 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 of 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			54,518,832		54,518,832
2	Steam Production Plant	176,198,055				176,198,055
3	Nuclear Production Plant	194,505,972				194,505,972
4	Hydraulic Production Plant-Conventional	8,481,414				8,481,414
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	180,708,126				180,708,126
7	Transmission Plant	83,900,540				83,900,540
8	Distribution Plant	240,856,770				240,856,770
9	Regional Transmission and Market Operation					
10	General Plant	54,086,839		2,646		54,089,485
11	Common Plant-Electric					
12	TOTAL	938,737,716		54,521,478		993,259,194

B. Basis for Amortization Charges

Limited term electric depreciable plant base is $269,365,349 which is the cost of capitalized software and generating plant relicensing. Intangible plant is amortized over 3, 5, 10 and 15 years. The generating plant relicensing is amortized over the life of the license.

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	311 - Mayo Unit 1	270,407	100 years	(4)	6	R2.5	7 years
13	311 - Roxboro Common	230,992	100 years	(5)	6	R2.5	10 years
14	311 - Roxboro Unit 1	16,941	100 years	(5)	4	R2.5	5 years
15	311 - Roxboro Unit 2	5,306	100 years	(5)	5	R2.5	5 years
16	311 - Roxboro Unit 3	37,257	100 years	(5)	1	R2.5	10 years
17	311 - Roxboro Unit 4	19,397	100 years	(5)	4	R2.5	10 years
18	312 - Mayo Unit 1	824,448	60 years	(4)	6	S0	7 years
19	312 - Roxboro Common	472,987	60 years	(5)	5	S0	10 years
20	312 - Roxboro Unit 1	216,452	60 years	(5)	7	S0	5 years
21	312 - Roxboro Unit 2	321,061	60 years	(5)	6	S0	5 years
22	312 - Roxboro Unit 3	347,307	60 years	(5)	5	S0	10 years

23	312 - Roxboro Unit 4	403,861	60 years	(5)	3	S0	10 years
24	312.10 - Mayo Unit 1	7,201	10 years	(4)	2	S1	7 years
25	312.10 - Roxboro Unit 1	7,925	10 years	(5)	4	S1	5 years
26	312.10 - Roxboro Unit 2	5,857	10 years	(5)	1	S1	5 years
27	312.10 - Roxboro Unit 3	6,794	10 years	(5)	5	S1	10 years
28	312.10 - Roxboro Unit 4	7,262	10 years	(5)	1	S1	10 years
29	314 - Mayo Unit 1	107,489	55 years	(4)	4	R1.5	7 years
30	314 - Roxboro Common	580	55 years	(5)	3	R1.5	10 years
31	314 - Roxboro Unit 1	45,926	55 years	(5)	7	R1.5	5 years
32	314 - Roxboro Unit 2	45,607	55 years	(5)	8	R1.5	5 years
33	314 - Roxboro Unit 3	73,667	55 years	(5)	5	R1.5	10 years
34	314 - Roxboro Unit 4	73,101	55 years	(5)	5	R1.5	10 years
35	315 - Mayo Unit 1	70,514	70 years	(4)	5	R1	7 years
36	315 - Roxboro Common	24,719	70 years	(5)	5	R1	10 years
37	315 - Roxboro Unit 1	29,202	70 years	(5)	7	R1	5 years
38	315 - Roxboro Unit 2	30,233	70 years	(5)	7	R1	5 years
39	315 - Roxboro Unit 3	42,229	70 years	(5)	5	R1	10 years
40	315 - Roxboro Unit 4	42,535	70 years	(5)	4	R1	10 years
41	316 - Mayo Unit 1	15,988	45 years	(4)	7	S0.5	7 years
42	316 - Roxboro Common	20,394	45 years	(5)	5	S0.5	10 years
43	316 - Roxboro Unit 1	5,356	45 years	(5)	7	S0.5	5 years
44	316 - Roxboro Unit 2	4,290	45 years	(5)	5	S0.5	5 years
45	316 - Roxboro Unit 3	3,685	45 years	(5)	5	S0.5	10 years
46	316 - Roxboro Unit 4	5,429	45 years	(5)	4	S0.5	10 years
47	321 - Brunswick Common	208,464	75 years	(5)	3	S1	33 years
48	321 - Brunswick Unit 1	376,037	75 years	(5)	2	S1	33 years
49	321 - Brunswick Unit 2	385,401	75 years	(5)	1	S1	31 years
50	321 - Harris Unit 1	1,855,475	75 years	(7)	1	S1	43 years
51	321 - Robinson Unit 2	401,285	75 years	(4)	2	S1	27 years
52	322 - Brunswick Common	35,851	50 years	(5)	3	R2	33 years
53	322 - Brunswick Unit 1	632,346	50 years	(5)	2	R2	33 years
54	322 - Brunswick Unit 2	654,973	50 years	(5)	2	R2	31 years
55	322 - Harris Unit 1	1,113,938	50 years	(7)	2	R2	33 years
56	322 - Robinson Unit 2	478,397	50 years	(4)	2	R2	27 years
57	323 - Brunswick Common	2,306	39 years	(5)	4	S0	33 years
58	323 - Brunswick Unit 1	293,100	39 years	(5)	3	S0	33 years
59	323 - Brunswick Unit 2	264,744	39 years	(5)	3	S0	31 years
60	323 - Harris Unit 1	519,261	39 years	(7)	3	S0	43 years
61	323 - Robinson Unit 2	370,827	39 years	(4)	4	S0	27 years
62	324 - Brunswick Common	12,058	51 years	(5)	3	R2.5	33 years

63	324 - Brunswick Unit 1	204,693	51 years	(5)	2	R2.5	33 years
64	324 - Brunswick Unit 2	240,554	51 years	(5)	2	R2.5	31 years
65	324 - Harris Unit 1	772,841	51 years	(7)	2	R2.5	43 years
66	324 - Robinson Unit 2	283,534	51 years	(4)	3	R2.5	27 years
67	325 - Brunswick Common	118,681	52 years	(5)	3	R1.5	33 years
68	325 - Brunswick Unit 1	146,066	52 years	(5)	2	R1.5	33 years
69	325 - Brunswick Unit 2	60,289	52 years	(5)	2	R1.5	31 years
70	325 - Harris Unit 1	271,475	52 years	(7)	2	R1.5	43 years
71	325 - Robinson Unit 2	211,115	52 years	(4)	2	R1.5	27 years
72	331 - Blewett	8,277	110 years	(12)	3	R2	32 years
73	331 - Marshall	1,480	110 years	(11)	7	R2	12 years
74	331 - Tillery	8,167	110 years	(21)	3	R2	32 years
75	331 - Walters	6,394	110 years	(4)	5	R2	11 years
76	332 - Blewett	72,484	120 years	(12)	3	R3	32 years
77	332 - Marshall	5,796	120 years	(11)	5	R3	12 years
78	332 - Tillery	10,050	120 years	(21)	2	R3	32 years
79	332 - Walters	44,372	120 years	(4)	4	R3	11 years
80	333 - Blewett	13,831	65 years	(12)	3	R1.5	32 years
81	333 - Marshall	7,703	65 years	(11)	5	R1.5	12 years
82	333 - Tillery	19,402	65 years	(21)	4	R1.5	32 years
83	333 - Walters	25,158	65 years	(4)	8	R1.5	11 years
84	334 - Blewett	8,597	60 years	(12)	3	S0	32 years
85	334 - Marshall	1,208	60 years	(11)	3	S0	12 years
86	334 - Tillery	4,444	60 years	(21)	3	S0	32 years
87	334 - Walters	14,409	60 years	(4)	6	S0	11 years
88	335 - Blewett	2,228	45 years	(12)	4	S0.5	32 years
89	335 - Marshall	201	45 years	(11)	5	S0.5	12 years
90	335 - Tillery	1,712	45 years	(21)	3	S0.5	32 years
91	335 - Walters	2,115	45 years	(4)	5	S0.5	11 years
92	336 - Marshall	13	75 years	(11)	2	R3	12 years
93	336 - Walters	8	75 years	(4)		R3	11 years
94	341 - Asheville Combined Cycle	170,884	55 years	(5)	3	R2	36 years
95	341 - Asheville IC Turbine	32,083	55 years	(3)	3	R2	16 years
96	341 - Blewett IC Turbines	926	55 years	(8)		R2	7 years
97	341 - Darlington IC Turbine Units 12 and 13	10,098	55 years	(9)	2	R2	14 years
98	341 - H.F. Lee Combined Cycle (Wayne County)	38,027	55 years	(6)	3	R2	29 years
99	341 - H.F. Lee IC Turbines (Wayne County Unit 14)	1,357	55 years	(5)	3	R2	26 years

100	341 - H.F. Lee IC Turbines (Wayne County Units 10-13)	9,145	55 years	(5)	3	R2	17 years
101	341 - Smith Combined Cycle Power Block 4 (Richmond County)	50,251	55 years	(5)	1	R2	19 years
102	341 - Smith Combined Cycle Power Block 5 (Richmond County)	40,213	55 years	(7)	3	R2	28 years
103	341 - Smith IC Turbines (Richmond County)	20,620	55 years	(3)	3	R2	18 years
104	341 - Sutton Blackstart	11,656	55 years	(9)	3	R2	34 years
105	341 - Sutton Combined Cycle	30,338	55 years	(4)	3	R2	30 years
106	341 - Weatherspoon IC Turbines	7,409	55 years	(18)	7	R2	7 years
107	341.20 - Camp Lejune Solar	667	30 years	(9)	5	S2.5	22 years
108	341.20 - Elm City	700	30 years	(14)	5	S2.5	23 years
109	341.20 - Fayetteville Solar	490	30 years	(11)	5	S2.5	22 years
110	341.20 - Hot Springs Solar	143	30 years	(14)	5	S2.5	29 years
111	341.20 - Warsaw Solar	5,153	30 years	(11)	5	S2.5	22 years
112	342 - Asheville Combined Cycle	23,604	50 years	(5)	3	R2.5	36 years
113	342 - Asheville IC Turbine	5,623	50 years	(3)	3	R2.5	16 years
114	342 - Blewett IC Turbines	413	50 years	(8)	1	R2.5	7 years
115	342 - Darlington IC Turbine Units 12 and 13	6,042	50 years	(9)		R2.5	14 years
116	342 - H.F. Lee Combined Cycle (Wayne County)	24,865	50 years	(6)	3	R2.5	29 years
117	342 - H.F. Lee IC Turbines (Wayne County Unit 14)	1,461	50 years	(5)	3	R2.5	26 years
118	342 - H.F. Lee IC Turbines (Wayne County Units 10-13)	7,438	50 years	(5)	3	R2.5	17 years
119	342 - Smith Combined Cycle Power Block 4 (Richmond County)	14,677	50 years	(5)	3	R2.5	19 years
120	342 - Smith Combined Cycle Power Block 5 (Richmond County)	24,034	50 years	(7)	3	R2.5	28 years
121	342 - Smith IC Turbines (Richmond County)	10,924	50 years	(3)	3	R2.5	18 years
122	342 - Sutton Blackstart	5,968	50 years	(9)	3	R2.5	34 years
123	342 - Sutton Combined Cycle	21,470	50 years	(4)	3	R2.5	30 years
124	342 - Weatherspoon IC Turbines	1,406	50 years	(18)	1	R2.5	7 years
125	343 - Asheville Combined Cycle	185,752	30 years	(5)	4	L0	36 years
126	343 - Asheville IC Turbine	54,281	30 years	(3)	5	L0	16 years
127	343 - Blewett IC Turbines	8,480	30 years	(8)	1	L0	7 years

128	343 - Darlington IC Turbine Units 12 and 13	46,538	30 years	(9)	7	L0	14 years
129	343 - H.F. Lee Combined Cycle (Wayne County)	368,466	30 years	(6)	4	L0	29 years
130	343 - H.F. Lee IC Turbines (Wayne County Unit 14)	46,542	30 years	(5)	4	L0	26 years
131	343 - H.F. Lee IC Turbines (Wayne County Units 10-13)	106,290	30 years	(5)	3	L0	17 years
132	343 - Smith Combined Cycle Power Block 4 (Richmond County)	67,636	30 years	(5)	6	L0	19 years
133	343 - Smith Combined Cycle Power Block 5 (Richmond County)	275,200	30 years	(7)	4	L0	28 years
134	343 - Smith IC Turbines (Richmond County)	301,726	30 years	(3)	5	L0	18 years
135	343 - Sutton Blackstart	64,964	30 years	(9)	4	L0	34 years
136	343 - Sutton Combined Cycle	370,445	30 years	(4)	4	L0	30 years
137	343 - Weatherspoon IC Turbines	12,958	30 years	(18)		L0	7 years
138	343.10 - Asheville Combined Cycle	43,445	7 years	40	8	L1	36 years
139	343.10 - H.F. Lee Combined Cycle (Wayne County)	169,361	7 years	40	8	L1	29 years
140	343.10 - Smith Combined Cycle Power Block 4 (Richmond County)	111,892	7 years	40	7	L1	19 years
141	343.10 - Smith Combined Cycle Power Block 5 (Richmond County)	60,607	7 years	40	4	L1	28 years
142	343.10 - Sutton Combined Cycle	42,716	7 years	40	1	L1	30 years
143	344 - Asheville Combined Cycle	303,752	55 years	(5)	3	R2	36 years
144	344 - Asheville IC Turbine	8,111	55 years	(3)	3	R2	16 years
145	344 - Blewett IC Turbines	1,988	55 years	(8)		R2	7 years
146	344 - Darlington IC Turbine Units 12 and 13	17,231	55 years	(9)	6	R2	14 years
147	344 - H.F. Lee Combined Cycle (Wayne County)	55,340	55 years	(6)	3	R2	29 years
148	344 - H.F. Lee IC Turbines (Wayne County Unit 14)	13,181	55 years	(5)	3	R2	26 years
149	344 - H.F. Lee IC Turbines (Wayne County Units 10-13)	23,581	55 years	(5)	3	R2	17 years
150	344 - Smith Combined Cycle Power Block 4 (Richmond County)	41,593	55 years	(5)	3	R2	19 years
151	344 - Smith Combined Cycle Power Block 5 (Richmond County)	33,031	55 years	(7)	3	R2	28 years
152	344 - Smith IC Turbines (Richmond County)	40,466	55 years	(3)	5	R2	18 years
153	344 - Sutton Blackstart	2,131	55 years	(9)	3	R2	34 years

154	344 - Sutton Combined Cycle	44,352	55 years	(4)	3	R2	30 years
155	344 - Weatherspoon IC Turbines	2,096	55 years	(18)		R2	7 years
156	344.20 - Hot Springs Solar	4,585	25 years	(14)	5	S2.5	24 years
157	344.20 - Camp Lejune Solar	14,946	25 years	(9)	5	S2.5	22 years
158	344.20 - Elm City	37,516	25 years	(14)	5	S2.5	23 years
159	344.20 - Fayetteville Solar	30,386	25 years	(11)	5	S2.5	22 years
160	344.20 - Warsaw Solar	83,163	25 years	(11)	5	S2.5	23 years
161	345 - Asheville Combined Cycle	54,327	50 years	(5)	3	R2	36 years
162	345 - Asheville IC Turbine	12,035	50 years	(3)	4	R2	16 years
163	345 - Blewett IC Turbines	1,867	50 years	(8)	1	R2	7 years
164	345 - Darlington IC Turbine Units 12 and 13	10,349	50 years	(9)	4	R2	14 years
165	345 - H.F. Lee Combined Cycle (Wayne County)	78,177	50 years	(6)	3	R2	29 years
166	345 - H.F. Lee IC Turbines (Wayne County Unit 14)	10,578	50 years	(5)	3	R2	26 years
167	345 - H.F. Lee IC Turbines (Wayne County Units 10-13)	20,618	50 years	(5)	3	R2	17 years
168	345 - Smith Combined Cycle Power Block 4 (Richmond County)	20,840	50 years	(5)	4	R2	19 years
169	345 - Smith Combined Cycle Power Block 5 (Richmond County)	51,725	50 years	(7)	3	R2	28 years
170	345 - Smith IC Turbines (Richmond County)	29,662	50 years	(3)	3	R2	18 years
171	345 - Sutton Blackstart	13,500	50 years	(9)	3	R2	34 years
172	345 - Sutton Combined Cycle	63,272	50 years	(4)	3	R2	30 years
173	345 - Weatherspoon IC Turbines	3,374	50 years	(18)	4	R2	7 years
174	345.20 - Hot Springs Solar	641	25 years	(14)	6	S1.5	24 years
175	345.20 - Camp Lejune Solar	5,866	25 years	(9)	5	S1.5	22 years
176	345.20 - Elm City	21,216	25 years	(14)	5	S1.5	23 years
177	345.20 - Fayetteville Solar	6,598	25 years	(11)	6	S1.5	22 years
178	345.20 - Warsaw Solar	13,584	25 years	(11)	6	S1.5	22 years
179	346 - Asheville Combined Cycle	7,036	35 years	(5)	3	S1.5	36 years
180	346 - Asheville IC Turbine	4,200	35 years	(3)	4	S1.5	16 years
181	346 - Blewett IC Turbines	334	35 years	(8)	6	S1.5	7 years
182	346 - Darlington IC Turbine Units 12 and 13	1,910	35 years	(9)	5	S1.5	14 years
183	346 - H.F. Lee Combined Cycle (Wayne County)	13,873	35 years	(6)	4	S1.5	29 years

184	346 - H.F. Lee IC Turbines (Wayne County Unit 14)	1,159	35 years	(5)	3	S1.5	26 years
185	346 - H.F. Lee IC Turbines (Wayne County Units 10-13)	1,680	35 years	(5)	3	S1.5	17 years
186	346 - Smith Combined Cycle Power Block 4 (Richmond County)	7,570	35 years	(5)	4	S1.5	19 years
187	346 - Smith Combined Cycle Power Block 5 (Richmond County)	9,509	35 years	(7)	3	S1.5	28 years
188	346 - Smith IC Turbines (Richmond County)	10,020	35 years	(3)	5	S1.5	18 years
189	346 - Sutton Blackstart	2,053	35 years	(9)	4	S1.5	34 years
190	346 - Sutton Combined Cycle	10,299	35 years	(4)	4	S1.5	30 years
191	346 - Weatherspoon IC Turbines	861	35 years	(18)	7	S1.5	7 years
192	346.20 - Elm City	270	30 years	(11)	468	S2.5	29 years
193	346.20 - Fayetteville Solar	28	30 years	(11)	5	S2.5	22 years
194	346.20 - Warsaw Solar	276	30 years	(11)	4	S2.5	22 years
195	348 - Energy Storage Equip - Production	29,050	15 years		7	L3	22 years
196	352 Structures and improvements	147,834	66 years	(15)	2	R2.5	52 years
197	353 Station equipment	1,392,345	55 years	(15)	2	R1.5	46 years
198	354 Towers and fixtures	88,164	75 years	(15)	1	R4	44 years
199	355 Poles and fixtures	1,127,192	52 years	(50)	3	R1.5	40 years
200	356 Overhead conductors and devices	1,004,474	70 years	(50)	2	R2.5	59 years
201	357-UNDERGROUND CONDUIT	1,603	60 years		2	R4	60 years
202	359 Roads and Trials	828	75 years		1	R3	64 years
203	361 Structures and improvements	157,269	60 years	(15)	2	R1.5	42 years
204	362 Station equipment	1,185,248	45 years	(15)	3	R1	37 years
205	363 Storage battery equipment	9,277	15 years		7	L3	12 years
206	364 Poles, towers, and fixtures	1,107,306	45 years	(100)	4	R2.5	31 years
207	365 Overhead conductors and devices	1,876,559	45 years	(50)	3	R1	36 years
208	366 Underground conduit	285,505	50 years	(10)	2	S2.5	34 years
209	367 Underground conductors and devi	1,852,757	44 years	(10)	2	R2.5	29 years
210	368 Line transformers	1,452,314	40 years	(10)	3	R2	27 years
211	369 Services	1,009,500	55 years	(30)	2	R3	40 years
212	370 Meters	68,051	21 years	(5)	2	S1.5	15 years
213	370.02 Meters - UOF	282,354	15 years	(5)	7	S2.5	11 years
214	370.7 - EV Chargers	10,762	10 years	(2)	11	S3	9 years

215	371 Installations on customers prem	380,724	26 years	(15)	3	S0.5	11 years
216	371.7 - EV Chargers LV 2 Customer Premise	7	10 years	(1)	11	S4	0 years
217	373 Street lighting and signal syst	341,850	25 years	(10)	5	R1	21 years
218	390 Structures and improvements	356,487	40 years	(5)	3	S0.5	36 years
219	391 Office furniture and equipment	38,896	20 years		5	SQ	13 years
220	391.1 Office furniture & equip-EDP	89,359	8 years		13	SQ	5 years
221	392 Transportation equipment	57,492	11 years	20		L2	0 years
222	393 Stores equipment	2,120	20 years		5	SQ	10 years
223	394 Tools, shop and garage equip	112,668	20 years		5	SQ	13 years
224	394.7 - EV Chargers Fleet	1,345	10 years	(2)	11	S3	9 years
225	395 Laboratory equipment	4,967	15 years		7	SQ	4 years
226	396 Power operated equipment	13,126	12 years		9	S6	8 years
227	397 Communication Equip	351,507	20 years		5	SQ	14 years
228	398 Miscellaneous equipment	17,117	20 years		5	SQ	11 years
229	321 - 325 Harris Disallowance	(551,297)			1		43 years

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of depreciation expense in the current year are (a) $166,530,417 for Steam Production, (b) $190,895,630 for Nuclear Production, (c) $8,421,272 for Hydraulic Production, (d) $182,411,613 for Other Production, (e) $84,093,821 for Transmission Plant, (f) $242,941,671 for Distribution Plant, and (g) $54,052,484 for General Plant.

(b) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The portion for nuclear decommissioning amortization accrued in the current year to Account 403 (Depreciation Expense) was $4,250,498.

(c) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of depreciation expense in the current year are (a) $166,530,417 for Steam Production, (b) $190,895,630 for Nuclear Production, (c) $8,421,272 for Hydraulic Production, (d) $182,411,613 for Other Production, (e) $84,093,821 for Transmission Plant, (f) $242,941,671 for Distribution Plant, and (g) $54,052,484 for General Plant.

(d) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of depreciation expense in the current year are (a) $166,530,417 for Steam Production, (b) $190,895,630 for Nuclear Production, (c) $8,421,272 for Hydraulic Production, (d) $182,411,613 for Other Production, (e) $84,093,821 for Transmission Plant, (f) $242,941,671 for Distribution Plant, and (g) $54,052,484 for General Plant.

(e) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of depreciation expense in the current year are (a) $166,530,417 for Steam Production, (b) $190,895,630 for Nuclear Production, (c) $8,421,272 for Hydraulic Production, (d) $182,411,613 for Other Production, (e) $84,093,821 for Transmission Plant, (f) $242,941,671 for Distribution Plant, and (g) $54,052,484 for General Plant.

(f) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of depreciation expense in the current year are (a) $166,530,417 for Steam Production, (b) $190,895,630 for Nuclear Production, (c) $8,421,272 for Hydraulic Production, (d) $182,411,613 for Other Production, (e) $84,093,821 for Transmission Plant, (f) $242,941,671 for Distribution Plant, and (g) $54,052,484 for General Plant.

(g) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of depreciation expense in the current year are (a) $166,530,417 for Steam Production, (b) $190,895,630 for Nuclear Production, (c) $8,421,272 for Hydraulic Production, (d) $182,411,613 for Other Production, (e) $84,093,821 for Transmission Plant, (f) $242,941,671 for Distribution Plant, and (g) $54,052,484 for General Plant.

(h) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The system values in the table above represent the sum of NC Retail, SC Retail, and Wholesale (FERC-jurisdictional) amounts. The Wholesale amounts, grossed up to a system level (for OATT and Power Supply Formula rate purposes only), of depreciation expense in the current year are (a) $166,530,417 for Steam Production, (b) $190,895,630 for Nuclear Production, (c) $8,421,272 for Hydraulic Production, (d) $182,411,613 for Other Production, (e) $84,093,821 for Transmission Plant, (f) $242,941,671 for Distribution Plant, and (g) $54,052,484 for General Plant.

(i) Concept: DepreciablePlantBase

Depreciable Plant Base represents balances as of December 31, 2023, and excludes plant related to non-utility, asset retirement obligations, plant held for future use, capital and operating leases, land and intangibles.

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
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 columns (f), (g), and (h), expenses incurred during the 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						
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 Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	North Carolina Utilities Commission:											
2	NCUC Regulatory Fee – Electric	6,879,959		6,879,959	88,444	Electric	928	6,879,959	353,547	182.3	156,596	285,395
3	NC Rate Case Amort		2,556,127	2,556,127	1,754,817	Electric	928	2,556,127	17,237,593	182.3	2,556,127	16,436,282
4	The Public Service Commission Of South Carolina:											
5	Service Commission Annual Fees	1,119,975		1,119,975		Electric	928	1,119,975				
6	SC Rate Case Amort		842,445	842,445	486,167	Electric	928	842,445	8,962,554	182.3	842,445	8,606,276
7	Federal Energy Regulatory Commission:											
8	FERC Order 472 Annual Charges	2,814,131		2,814,131		Electric	928	2,814,131				
9	Misc. Legal Expenses:											
10	Transmission		270,505	270,505		Electric	928	270,505				
11	Distribution		15,852	15,852		Electric	928	15,852				
12	Production		111,291	111,291		Electric	928	111,291				
13	Other		(25,654)	(25,654)		Electric	928	(25,654)				
46	TOTAL	10,814,065	3,770,566	14,584,631	2,329,428			14,584,631	26,553,694		3,555,168	25,327,953

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 and 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 and 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:

Electric R, D and D Performed Internally:
- Generation
  - hydroelectric
    - Recreation fish and wildlife
    - Other hydroelectric
  - Fossil-fuel steam
  - Internal combustion or gas turbine
  - Nuclear
  - Unconventional generation
  - Siting and heat rejection
- Transmission
  - Overhead
  - Underground
- Distribution
- Regional Transmission and Market Operation
- Environment (other than equipment)
- Other (Classify and include items in excess of $50,000.)
- Total Cost Incurred

Electric, R, D and D Performed Externally:
- Research Support to the electrical Research Council or the Electric Power Research Institute
- Research Support to Edison Electric Institute
- Research Support to Nuclear Power Groups
- Research Support to Others (Classify)
- Total Cost Incurred

3. Include in column (c) all R, D and 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 and 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 and 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 and 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.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	A. Electric R, D&D Performed Internally:						
2	Distribution	Research & Development Administration Costs	20,630		930.7	20,630	
3	TOTAL ELECTRIC R, D&D PERFORMED INTERNALLY		20,630			20,630	
4	B. Electric R, D&D Performed Externally:						
5	Electric Power Research Institute	Electric Power Research Institute Membership		3,393,000	506, 524, 566, 923, 930	3,393,000	
6		Other (Less than $50K each)		35,572	590, 600, 690, 694, 697, 923	35,572	
7	Research Support to Others	Alternative Energy (Advanced Energy Research)		1,304,959.0	930.8	1,304,959	
8	TOTAL ELECTRIC R, D&D PERFORMED EXTERNALLY			4,733,532		4,733,532	

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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	210,634,899		
4	Transmission	7,754,746		
5	Regional Market			
6	Distribution	18,488,191		
7	Customer Accounts	18,921,657		
8	Customer Service and Informational	8,978,921		
9	Sales	1,162,243		
10	Administrative and General	92,230,500		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	358,171,157		
12	Maintenance			
13	Production	115,888,905		
14	Transmission	3,892,013		
15	Regional Market			
16	Distribution	21,775,738		
17	Administrative and General	14,974		
18	TOTAL Maintenance (Total of lines 13 thru 17)	141,571,630		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	326,523,804		
21	Transmission (Enter Total of lines 4 and 14)	11,646,759		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	40,263,928		
24	Customer Accounts (Transcribe from line 7)	18,921,657		
25	Customer Service and Informational (Transcribe from line 8)	8,978,921		
26	Sales (Transcribe from line 9)	1,162,243		
27	Administrative and General (Enter Total of lines 10 and 17)	92,245,474		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	499,742,786	119,523	499,862,309
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			
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)	499,742,786	119,523	499,862,309
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	210,491,709	21,279,825	231,771,534
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	210,491,709	21,279,825	231,771,534

72	Plant Removal (By Utility Departments)			
73	Electric Plant	32,655,457		32,655,457
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	32,655,457		32,655,457
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Non-Regulated Products and Services	4,703,822		4,703,822
80	Other Work in Progress	2,963,060		2,963,060
81	Other Accounts	6,095,064		6,095,064
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	13,761,946		13,761,946
96	TOTAL SALARIES AND WAGES	756,651,899	21,399,348	778,051,247

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Electric 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 the order of the Commission or other authorization.

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	577,487	537,571	537,977	576,085
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	885,207	3,209,459	3,529,195	4,041,175
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
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32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	1,462,694	3,747,030	4,067,172	4,617,260

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) 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)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				41,578		1,517,587
2	Reactive Supply and Voltage				42,131		3,741,196
3	Regulation and Frequency Response				925		43,933
4	Energy Imbalance	5,869	MHW	151,652			
5	Operating Reserve - Spinning				925		64,800
6	Operating Reserve - Supplement				925		46,309
7	Other						
8	Total (Lines 1 thru 7)	5,869		151,652	86,484		5,413,825

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

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)
	NAME OF SYSTEM: Duke Energy Progress									
1	January	12,337	24	8	8,155	3,612	570	0	0	0
2	February	12,003	4	9	7,893	3,540	570	0	0	0
3	March	11,904	21	8	7,836	3,498	570	0	0	0
4	Total for Quarter 1				23,884	10,650	1,710	0	0	0
5	April	9,336	6	17	6,222	2,544	570	0	0	0
6	May	10,172	16	19	6,810	2,792	570	0	0	0
7	June	12,337	26	18	8,178	3,589	570	0	0	0
8	Total for Quarter 2				21,210	8,925	1,710	0	0	0
9	July	13,297	27	17	8,823	3,904	570	0	0	0
10	August	13,528	14	14	8,750	4,208	570	0	0	0
11	September	13,538	6	17	8,993	3,975	570	0	0	0
12	Total for Quarter 3				26,566	12,087	1,710	0	0	0
13	October	9,042	2	18	6,010	2,462	570	0	0	0
14	November	12,783	29	8	8,444	3,769	570	0	0	0
15	December	12,500	20	8	8,246	3,684	570	0	0	0
16	Total for Quarter 4				22,700	9,915	1,710	0	0	0
17	Total				94,360	41,577	6,840	0	0	0

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import 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)
	NAME OF SYSTEM: Enter System									
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2024-04-15	Year/Period of Report End of: 2023/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	41,891,387
3	Steam	5,257,790	23	Requirements Sales for Resale (See instruction 4, page 311.)	17,251,528
4	Nuclear	30,961,728	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	7,574,530
5	Hydro-Conventional	603,157	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	85,587
7	Other	23,114,199	27	Total Energy Losses	2,424,406
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	59,936,874	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	69,227,438
10	Purchases (other than for Energy Storage)	9,323,143			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	661,483			
17	Delivered	652,619			
18	Net Transmission for Other (Line 16 minus line 17)	8,864			
19	Transmission By Others Losses	(41,443)			
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	69,227,438			

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Duke Energy Progress					
29	January	5,826,866	538,742	11,437	24	8
30	February	4,875,786	329,472	11,084	4	8
31	March	5,133,886	530,956	11,013	21	8
32	April	4,888,626	480,103	8,429	6	17
33	May	5,291,102	679,003	9,212	16	18
34	June	5,877,970	636,419	11,414	26	18
35	July	7,270,656	641,721	12,339	27	17
36	August	7,227,400	774,195	12,630	14	14
37	September	6,047,718	805,510	12,608	6	18
38	October	5,231,557	873,710	8,163	2	18
39	November	5,692,216	851,412	11,902	29	8
40	December	5,863,655	433,287	11,626	20	8
41	Total	69,227,438	7,574,530			

PAGE 402	PAGE 403
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.	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.

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) — STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

Line No	Item	Plant Name:	Asheville Steam		Plant Name:	Asheville Gas Turbine		Plant Name:	Asheville CC		Plant Name:	Blewett		Plant Name:	Brunswick	
	(a)	(b)			(c)			(d)			(e)			(f)		
0	Plant Name	Asheville Steam			Asheville Gas Turbine			Asheville CC			Blewett			Brunswick		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Gas Turbine			Gas			Gas Turbine			Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Conventional			Combined Cycle			Conventional			Conventional		
3	Year Originally Constructed	1964			1999			2019			1971			1975		
4	Year Last Unit was Installed	1971			2000			2020			1971			1977		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)				424			588			70			2,003		
6	Net Peak Demand on Plant - MW (60 minutes)				358			557			60			1,925		
7	Plant Hours Connected to Load				1,011			8,532			29			8,760		
8	Net Continuous Plant Capability (Megawatts)				—			—			—			—		
9	When Not Limited by Condenser Water				370			560			68			1,928		
10	When Limited by Condenser Water				320			494			52			1,870		
11	Average Number of Employees				0			37			—			719		
12	Net Generation, Exclusive of Plant Use - KWh				134,076,000			3,744,892,000			27,000			15,658,076,000		
13	Cost of Plant: Land and Land Rights				565,402			—			—			4,060,633		
14	Structures and Improvements				31,914,083			170,883,642			926,386			975,660,817		
15	Equipment Costs				84,250,024			893,799,639			13,120,752			2,669,096,236		
16	Asset Retirement Costs										—			(79,257,380)		
17	Total Cost	—			116,729,509			1,064,683,281			14,047,138			3,569,560,306		
18	Cost per KW of Installed Capacity (line 17/5) Including				275.3054			1,810.6859			200.6734			1,782.1070		
19	Production Expenses: Oper, Supv, & Engr	25			74,650			673,573			20,030			21,711,750		
20	Fuel	17			9,057,974			156,763,552			194,950			95,687,576		
21	Coolants and Water (Nuclear Plants Only)	—			—			—			—			14,858,597		
22	Steam Expenses	356			—			—			—			25,463,131		
23	Steam From Other Sources	—			—			—			—			—		
24	Steam Transferred (Cr)	—			—			—			—			—		
25	Electric Expenses	15			124,673			1,022,285			3,245			3,092,105		
26	Misc Steam (or Nuclear) Power Expenses	120,739			270,430			1,828,232			38,353			52,256,273		
27	Rents	—			53			126			8			—		
28	Allowances	147,278			—			—			—			—		
29	Maintenance Supervision and Engineering	129			153,805			909,001			14,230			21,301,997		
30	Maintenance of Structures	140,812			262,332			141,532			26,868			3,953,606		
31	Maintenance of Boiler (or reactor) Plant	1			—			—			—			30,522,149		
32	Maintenance of Electric Plant	1,805			1,467,487			1,961,013			99,422			15,691,670		
33	Maintenance of Misc Steam (or Nuclear) Plant	3,831			319,090			906,989			180,517			20,278,098		
34	Total Production Expenses	415,006			11,730,494			164,206,303			577,623			304816954		
35	Expenses per Net KWh				0 0875			0.0438			21.3934			0.0195		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Coal		Oil	Gas		Oil	Gas		Oil			Nuclear	Nuclear (1)	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	bbl	T		bbl	Mcf		bbl	Mcf		bbl			MMBTU	MWd	
38	Quantity (Units) of Fuel Burned (from the Unit Type Registry)				1123	1540097		1553	24111507		1737			164,259,495	2,005,317	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)				136649	1031468		136539	1031827		139981					
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year				141.300	5.756		141.300	6.490		138.700					
41	Average Cost of Fuel per Unit Burned				135.333	5.756		135.334	6.490		108 298				47.717	
42	Average Cost of Fuel Burned per Million BTU				23.580	5.580		23 599	6.290		18.421			0.583		
43	Average Cost of Fuel Burned per KWh Net Gen				0.067	0.067		0.042	0.042		6.967			0.006	0.006	
44	Average BTU per KWh Net Generation				11896.000	11896.000		6646.000	6646.000		-			10,490	10,490	

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) / STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

Line No.	Item	Plant Name: *Cape Fear Steam*	Plant Name: *Cape Fear Gas Turbine*	Plant Name: *Darlington*	Plant Name: *H.F. Lee Steam*	Plant Name: *H.F. Lee Gas Turbine*
	(a)	(b)	(c)	(d)	(e)	(f)
0	Plant Name	Cape Fear Steam	Cape Fear Gas Turbine	Darlington	H.F. Lee Steam	H.F. Lee Gas Turbine
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Gas Turbine	Gas Turbine	Steam	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conv & Full Outdoor		Conventional	Full Outdoor	Conventional
3	Year Originally Constructed	1923	1969	1974	1951	1968
4	Year Last Unit was Installed	1958	1969	1997	1962	2012
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			316		1,068
6	Net Peak Demand on Plant - MW (60 minutes)			235		25
7	Plant Hours Connected to Load			192		3,978
8	Net Continuous Plant Capability (Megawatts)			—		—
9	When Not Limited by Condenser Water			264		1,059
10	When Limited by Condenser Water			230		888
11	Average Number of Employees			4	1	—
12	Net Generation, Exclusive of Plant Use - KWh			22,124,000		6,374,580,000
13	Cost of Plant: Land and Land Rights			50,044		698,267
14	Structures and Improvements			10,097,806		38,357,680
15	Equipment Costs			82,196,944		672,109,869
16	Asset Retirement Costs					
17	Total Cost	0	0	92,344,794	0	711,165,816
18	Cost per KW of Installed Capacity (line 17/5) Including			292.2304		665.8856
19	Production Expenses: Oper, Supv, & Engr	18		50,730	8,042	331,918
20	Fuel	114,311		2,006,560	5,301	267,270,726
21	Coolants and Water (Nuclear Plants Only)	—		—	—	—
22	Steam Expenses	1,445		—	3,115	—
23	Steam From Other Sources	—		—	—	—
24	Steam Transferred (Cr)	—		—	—	—
25	Electric Expenses	—		38,466	936	1,037,310
26	Misc Steam (or Nuclear) Power Expenses	85,112		188,444	41,731	2,339,734
27	Rents	—		38	—	179
28	Allowances	105,260		—	65,439	—
29	Maintenance Supervision and Engineering	66		219,773	84	870,870
30	Maintenance of Structures	54,388		268,606	95,101	1,528,746
31	Maintenance of Boiler (or reactor) Plant	—		—	1	—
32	Maintenance of Electric Plant	16		139,833	20	1,113,386
33	Maintenance of Misc Steam (or Nuclear) Plant	21,164		368,607	—	731,107
34	Total Production Expenses	381,780	—	3,281,057	219,770	275,223,976
35	Expenses per Net KWh			0.1483		0.0432

Line No.	Item	(b)			(c)			(d)			(e)			(f)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)							Oil	Gas					Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)							bbl	Mcf					bbl	Mcf	
38	Quantity (Units) of Fuel Burned (from the Unit Type Registry)							8173	246044					12	45416071	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)							139117	1030099					137570	1033120	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year							-	4.691					142.750	5.883	
41	Average Cost of Fuel per Unit Burned							100.526	4.691					121.627	5.883	
42	Average Cost of Fuel Burned per Million BTU							17.205	4.554					21.050	5.694	
43	Average Cost of Fuel Burned per KWh Net Gen							0.089	0.089					0.042	0.042	
44	Average BTU per KWh Net Generation							13614.000	13614.000					7361.000	7361.000	

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) — STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

Line No.	Item	Plant Name: *H.B. Robinson Nuclear*	Plant Name: *H.B. Robinson Gas Turbine*	Plant Name: *H.B. Robinson Steam*	Plant Name: *Harris*	Plant Name: *L.V. Sutton Gas Turbine*
	(a)	(b)	(c)	(d)	(e)	(f)
0	Plant Name	H.B. Robinson Nuclear	H.B. Robinson Gas Turbine	H.B. Robinson Steam	Harris	L.V. Sutton Gas Turbine
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	Gas Turbine	Steam	Nuclear	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional		Full Outdoor	Conventional	Conventional
3	Year Originally Constructed	1971	1968	1960	1987	1968
4	Year Last Unit was Installed	1971	1968	1960	1987	2017
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	769			951	851
6	Net Peak Demand on Plant - MW (60 minutes)	794			1,009	2,275
7	Plant Hours Connected to Load	8,688			8,760	6,273
8	Net Continuous Plant Capability (Megawatts)	—			—	—
9	When Not Limited by Condenser Water	793			1,009	817
10	When Limited by Condenser Water	759			964	698
11	Average Number of Employees	527			502	42
12	Net Generation, Exclusive of Plant Use - KWh	6,694,374,000			8,609,278,000	3,890,097,000
13	Cost of Plant: Land and Land Rights	2,013,925		—	61,284,052	1,208,203
14	Structures and Improvements	402,651,324		—	1,941,816,381	41,151,352
15	Equipment Costs	1,346,046,608		—	2,398,243,126	640,606,573
16	Asset Retirement Costs	(68,823,453)		—	23,071,182	—
17	Total Cost	1,681,888,404	0	0	4,424,414,741	682,966,128
18	Cost per KW of Installed Capacity (line 17/5) Including	2,187.1111			4,652.3814	802.5454
19	Production Expenses: Oper, Supv, & Engr	13,294,685	5,827	134	11,765,965	565,218
20	Fuel	41,126,249	—	—	49,891,012	182,337,007
21	Coolants and Water (Nuclear Plants Only)	3,202,697	—	—	9,455,380	—
22	Steam Expenses	10,251,177	—	—	10,818,676	—
23	Steam From Other Sources	—	—	—	—	—
24	Steam Transferred (Cr)	—	—	—	—	—
25	Electric Expenses	1,850,392	131	—	1,848,374	381,273
26	Misc Steam (or Nuclear) Power Expenses	40,678,711	413	1,217	50,050,350	1,168,236
27	Rents	—	—	—	—	127
28	Allowances	—	—	1,643	—	—
29	Maintenance Supervision and Engineering	12,123,838	40	6,448	6,541,800	915,846
30	Maintenance of Structures	2,320,224	—	28,879	2,359,589	1,243,563
31	Maintenance of Boiler (or reactor) Plant	8,048,899	—	—	10,513,804	—
32	Maintenance of Electric Plant	7,200,517	203	2,286	5,730,664	3,099,231
33	Maintenance of Misc Steam (or Nuclear) Plant	4,137,226	69	—	6,227,121	3,713,300
34	Total Production Expenses	144,234,615	6,683	40,607	165,202,735	193,423,801
35	Expenses per Net KWh	0.0215			0.0192	0.0497

Line No.	Item	(b)	(b)	(b)	(c)	(c)	(c)	(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear	Nuclear (1)								Nuclear	Nuclear (1)		Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MMBTU	MWd								MMBTU	MWd		bbl	Mcf	
38	Quantity (Units) of Fuel Burned (from the Unit Type Registry)	68,887,580	840,995								88,019,360	1,074,560		2858	27093459	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)													140000	1033016	
40	Avg Cost of Fuel/unit, as Delvd f o.b. during year													-	6.714	
41	Average Cost of Fuel per Unit Burned		48.902									46.429		117.788	6.714	
42	Average Cost of Fuel Burned per Million BTU	0.597									0 567			96.126	6.500	
43	Average Cost of Fuel Burned per KWh Net Gen	0.006	0.006								0.006	0.006		0 047	0.047	
44	Average BTU per KWh Net Generation	10,290	10,290								10,224	10,224		7196.000	7196.000	

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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.

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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.

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) / STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

Line No.	Item	Plant Name: L.V. Sutton Steam	Plant Name: Mayo	Plant Name: Morehead	Plant Name: Roxboro	Plant Name: Smith Energy Complex
	(a)	(b)	(c)	(d)	(e)	(f)
0	Plant Name	L.V. Sutton Steam	Mayo	Morehead	Roxboro	Smith Energy Complex
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam	Gas Turbine	Steam	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor	Full Outdoor		Full Outdoor	Conventional
3	Year Originally Constructed	1954	1983	1968	1966	2001
4	Year Last Unit was Installed	1972	1983	1968	1980	2011
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		763		2,558	2,245
6	Net Peak Demand on Plant - MW (60 minutes)		712		2,177	2,133
7	Plant Hours Connected to Load		3,163		6,219	11,799
8	Net Continuous Plant Capability (Megawatts)		—		—	—
9	When Not Limited by Condenser Water		713		2,484	2,210
10	When Limited by Condenser Water		704		2,439	1,855
11	Average Number of Employees		61		174	47
12	Net Generation, Exclusive of Plant Use - KWh		1,216,965,000		4,040,825,000	8,597,617,000
13	Cost of Plant: Land and Land Rights		15,130,546	—	8,051,236	2,839,730
14	Structures and Improvements		274,644,320	—	309,881,810	111,083,709
15	Equipment Costs		1,040,510,003	—	2,237,463,445	1,112,587,133
16	Asset Retirement Costs		346,754,180	—	685,066,982	—
17	Total Cost	0	1,677,039,049	—	3,240,463,473	1,226,510,572
18	Cost per KW of Installed Capacity (line 17/5) Including		2,197.9542		1,266.7957	546.3299
19	Production Expenses: Oper, Supv, & Engr	14	2,173,333	—	3,611,470	3,638,981
20	Fuel	25	58,283,864	—	193,499,038	353,225,853
21	Coolants and Water (Nuclear Plants Only)	—	—	—	—	—
22	Steam Expenses	520	3,353,862	—	9,114,279	—
23	Steam From Other Sources	—	—	—	—	—
24	Steam Transferred (Cr)	—	—	—	—	—
25	Electric Expenses	292	111	—	101	798,537
26	Misc Steam (or Nuclear) Power Expenses	64,574	1,026,997	—	1,865,517	2,069,167
27	Rents	—	—	—	—	352
28	Allowances	79,514	7,968,820	—	17,740,403	—
29	Maintenance Supervision and Engineering	121	682,067	—	2,863,860	1,756,109
30	Maintenance of Structures	79,993	982,405	—	1,986,804	3,574,075
31	Maintenance of Boiler (or reactor) Plant	1	4,432,096	—	22,517,121	—
32	Maintenance of Electric Plant	49,189	1,668,655	—	2,464,396	12,729,531
33	Maintenance of Misc Steam (or Nuclear) Plant	8,106	6,144,743	—	4,443,968	4,202,974
34	Total Production Expenses	282,349	86,716,953	—	260,106,957	381,995,579
35	Expenses per Net KWh		0.0713		0.0644	0.0444

Line No.	Item	(b)			(c)			(d)			(e)			(f)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)				Oil	Coal					Oil	Coal		Oil	Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				bbl	T					bbl	T		bbl	Mcf	
38	Quantity (Units) of Fuel Burned (from the Unit Type Registry)				33104	494109					51354	1778846		3868	64217758	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)				137805	12710					137721	12609		140000	1033052	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year				137.900	110.970					137.620	118.280		150.000	5 542	
41	Average Cost of Fuel per Unit Burned				142.963	108.108					145.074	104.246		112.992	5.542	
42	Average Cost of Fuel Burned per Million BTU				24.701	4.253					23.943	4.129		19.216	5 365	
43	Average Cost of Fuel Burned per KWh Net Gen				0.048	0 048					0.048	0.048		0.041	0.041	
44	Average BTU per KWh Net Generation				10478.000	10478.000					11191.000	11191.000		7719 000	7719.000	

PAGE 402	PAGE 403
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.	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.

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large		STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)								
Line No.	Item	Plant Name:	Wayne County		Plant Name:	W.H. Weatherspoon Steam		Plant Name:	W.H. Weatherspoon Gas Turbine	
	(a)	(b)			(c)			(d)		
0	Plant Name	Wayne County			W H. Weatherspoon Steam			W.H. Weatherspoon Gas Turbine		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Steam			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Outdoor Boiler			Conventional		
3	Year Originally Constructed	2000			1949			1970		
4	Year Last Unit was Installed	2009			1952			1971		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	980						40		
6	Net Peak Demand on Plant - MW (60 minutes)	674						131		
7	Plant Hours Connected to Load	496						26		
8	Net Continuous Plant Capability (Megawatts)	—						—		
9	When Not Limited by Condenser Water	975						164		
10	When Limited by Condenser Water	822						124		
11	Average Number of Employees									
12	Net Generation, Exclusive of Plant Use - KWh	90,748,000						104,000		
13	Cost of Plant: Land and Land Rights	4,581,022						84,323		
14	Structures and Improvements	10,502,136						7,408,630		
15	Equipment Costs	256,560,634						20,711,734		
16	Asset Retirement Costs	—						—		
17	Total Cost	271,643,792			0			28,204,687		
18	Cost per KW of Installed Capacity (line 17/5) Including	277 1875						705.1172		
19	Production Expenses: Oper, Supv, & Engr	205,672			10,641			30,178		
20	Fuel	5,748,571			5,871			414,486		
21	Coolants and Water (Nuclear Plants Only)	—			—			—		
22	Steam Expenses	—			—			—		
23	Steam From Other Sources	—			—			—		
24	Steam Transferred (Cr)	—			—			—		
25	Electric Expenses	465,117			—			8,995		
26	Misc Steam (or Nuclear) Power Expenses	986,630			68,970			174,050		
27	Rents	132			—			19		
28	Allowances	—			96,792			—		
29	Maintenance Supervision and Engineering	563,970			111			38,739		
30	Maintenance of Structures	437,660			126,660			88,026		
31	Maintenance of Boiler (or reactor) Plant	—			1			—		
32	Maintenance of Electric Plant	2,399,979			26			137,645		
33	Maintenance of Misc Steam (or Nuclear) Plant	604,083			—			224,197		
34	Total Production Expenses	11,411,814			309,072			1,116,335		
35	Expenses per Net KWh	0.1258						10.7340		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas					Oil		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	bbl	Mcf					bbl		
38	Quantity (Units) of Fuel Burned (from the Unit Type Registry)	7218	1034466					3273		
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	132434	1033025					139965		
40		142 750	4.616					143 700		
41	Average Cost of Fuel per Unit Burned	121.667	4.616					121 687		
42	Average Cost of Fuel Burned per Million BTU	22 049	4.469					20.700		
43	Average Cost of Fuel Burned per KWh Net Gen	0 062	0 062					3 832		
44	Average BTU per KWh Net Generation	12211 000	12211 000					-		

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantKind

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)

(b) Concept: PlantKind

Asheville coal units 1 and 2 were retired January 29, 2020.

(c) Concept: PlantKind

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)

(d) Concept: PlantKind

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.

(e) Concept: PlantKind

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)

(f) Concept: PlantKind

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.

(g) Concept: PlantKind

Cape Fear coal units 3,4,5 & 6 were retired on October 1, 2012.

(h) Concept: PlantKind

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)

(i) Concept: PlantKind

Darlington CT unit 11 was retired on November 8, 2015; unit 9 was retired on June 30, 2017; unit 5 was retired on May 31, 2018; units 1-4, 6-8, and 10 were all retired on March 31, 2020.

(j) Concept: PlantKind

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)

(k) Concept: PlantKind

Robinson CT unit 3 was retired April 1, 2013.

(l) Concept: PlantKind

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.

(m) Concept: PlantKind

H.B. Robinson coal unit 1 was retired on October 1, 2012.

(n) Concept: PlantKind

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)

(o) Concept: PlantKind

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)

(p) Concept: PlantKind

Lee coal units 1,2 & 3 were retired on September 15, 2012.

(q) Concept: PlantKind

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.

(r) Concept: PlantKind

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.

(s) Concept: PlantKind

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)

(t) Concept: PlantKind

Sutton Steam unit 3 was retired on November 3, 2013; units 1 & 2 were retired December 31, 2013.

(u) Concept: PlantKind

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)

(v) Concept: PlantKind

Morehead CT was retired on October 1, 2012.
(w) Concept: PlantKind
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)
(x) Concept: PlantKind
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)
(y) Concept: PlantKind
Weatherspoon fossil steam units were retired on October 1, 2011.
(z) Concept: PlantKind
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)
(aa) Concept: FuelSteamPowerGeneration
Asheville Steam Total fuel costs reflect Sale of Fly Ash.
(ab) Concept: FuelSteamPowerGeneration
Cape Fear Steam Total fuel costs reflect Sale of Fly Ash. Accounts 501007 and 501009 for Coal Ash Beneficial Reuse in the amount of $2,513,150 are excluded.
(ac) Concept: FuelSteamPowerGeneration
Lee Steam Total fuel costs reflect Sale of Fly Ash. Accounts 501007, 501008, and 501009 for Coal Ash Beneficial Reuse in the amount of $1,548,789 are excluded.
(ad) Concept: FuelSteamPowerGeneration
Sutton Steam Total fuel costs reflect Sale of Fly Ash.
(ae) Concept: FuelSteamPowerGeneration
Mayo Steam Total fuel costs include Fuel Handling and Sale of Fly Ash.
(af) Concept: FuelSteamPowerGeneration
Roxboro Steam Total fuel costs include Fuel Handling, Coal Sampling and Sale of Fly Ash.
(ag) Concept: FuelSteamPowerGeneration
Smith Energy Complex Total fuel costs include Biogas accounts 547106, 547107 and 547108 in the amount of $936,788.
(ah) Concept: FuelSteamPowerGeneration
Weatherspoon Steam Total fuel costs reflect Sale of Fly Ash. Accounts 501007, 501008, and 501009 for Coal Ash Beneficial Reuse in the amount of $6,263,640 are excluded.
(ai) Concept: AverageCostOfFuelPerUnitBurned
Mayo Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling and Sale of Fly Ash.
(aj) Concept: AverageCostOfFuelPerUnitBurned
Roxboro Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling and Sale of Fly Ash.
(ak) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(al) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(am) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(an) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(ao) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(ap) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(aq) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(ar) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(as) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(at) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(au) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(av) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(aw) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration

Calculated on all fuels basis only.
(ax) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(ay) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(az) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(ba) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bb) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bc) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bd) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(be) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bf) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bg) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bh) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bi) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bj) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bk) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bl) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bm) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bn) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bo) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bp) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bq) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(br) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bs) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.
(bt) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
Calculated on all fuels basis only.

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

Hydroelectric Generating Plant Statistics

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.
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.

Line No.	Item (a)	FERC Licensed Project No. 2206 Plant Name: Blewett Hydro	FERC Licensed Project No. 2206 Plant Name: Tillery Hydro	FERC Licensed Project No. 432 Plant Name: Walters Hydro
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional	Conventional
3	Year Originally Constructed	1912	1928	1930
4	Year Last Unit was Installed	1912	1960	1930
5	Total installed cap (Gen name plate Rating in MW)	25	84	108
6	Net Peak Demand on Plant-Megawatts (60 minutes)	43	81	114
7	Plant Hours Connect to Load	8,704	5,127	8,617
8	**Net Plant Capability (in megawatts)**			
9	(a) Under Most Favorable Oper Conditions	27	85	113
10	(b) Under the Most Adverse Oper Conditions	27	85	113
11	Average Number of Employees	5	4	7
12	Net Generation, Exclusive of Plant Use - kWh	116,082,000	166,394,000	321,045,000
13	**Cost of Plant**			
14	Land and Land Rights	500,333	1,063,214	712,606
15	Structures and Improvements	8,276,971	8,167,439	7,516,830
16	Reservoirs, Dams, and Waterways	72,542,053	10,049,767	44,391,833
17	Equipment Costs	27,599,873	25,559,118	41,942,364
18	Roads, Railroads, and Bridges			8,258
19	Asset Retirement Costs	706,699	440,012	587,409
20	Total cost (total 13 thru 20)	109,625,929	45,279,549	95,159,300
21	Cost per KW of Installed Capacity (line 20 / 5)	4,385.0372	539.0423	881.1046
22	**Production Expenses**			
23	Operation Supervision and Engineering	628,797	570,594	834,294
24	Water for Power	27,949	34,551	
25	Hydraulic Expenses	(3,725)	(364,148)	(5,302)
26	Electric Expenses	18,878	64,461	28,695
27	Misc Hydraulic Power Generation Expenses	108,174	295,821	400,103
28	Rents			
29	Maintenance Supervision and Engineering	36,418	75,665	172,405

30	Maintenance of Structures	11,362	11,579	119,563
31	Maintenance of Reservoirs, Dams, and Waterways	59,176	605,597	192,208
32	Maintenance of Electric Plant	321,419	16,971	132,064
33	Maintenance of Misc Hydraulic Plant	267,319	502,262	349,209
34	Total Production Expenses (total 23 thru 33)	1,475,767	1,813,353	2,223,239
35	Expenses per net kWh			

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

Pumped Storage Generating Plant Statistics

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 that 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."
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.

Line No.	Item (a)	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:	FERC Licensed Project No. Plant Name:
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	62,500	62,500	62,500	62,500
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)				
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))				

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1	Marshall Hydro	1910	5	0	(364,000)	16,864,803	3,372,961	52,931		145,008			Hydro

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1	Camp Lejeune Battery	Production	Camp Lejeune, NC	1,020	754	754	0	266	266	0					11,028	19,876,074	19,876,074		
2																			
3																			
4																			
5																			
35	TOTAL			1,020	754	754	0	266	266	0	0	0	0	0	11,028		19,876,074	0	0

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1	Asheville - Rock Hill Battery	Production	Asheville, NC	5,149,730		51,845			
2	Asheville - Rock Hill Battery	Distribution	Asheville, NC	5,147,161		51,845			
3	Hot Springs Microgrid	Production	Hot Springs, NC	4,131,242		90,686			
4	Hot Springs Microgrid	Distribution	Hot Springs, NC	4,131,242		90,686			
36	TOTAL			18,559,375	0	285,062	0	0	0

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
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. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. 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.
5. 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.
6. 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).
7. 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.
8. 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.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

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	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Cumberland	Richmond	500.00	500.00	T	56.62		1	1590MCMA(B)							
2	Cumberland	Wake	500.00	500.00	T	67.26		1	1590MCMA(B)							
3	Durham	Wake	500.00	500.00	T	27.90		1	3-1590MCMA							
4	Mayo	Durham	500.00	500.00	T	45.41		1	3-1590MCMA							
5	Mayo	Person	500.00	500.00	T	9.94		1	1590MCMA(B)							
6	Richmond	Newport (DPC)	500.00	500.00	T	32.69		1	2515MCMA(B)							
7	Wake	Heritage (VEPCO)	500.00	500.00	T	52.60		1	2515MCMA(B)							
8	Tot. 500KV Lines									26,159,511	98,080,573	124,240,084				
9	Asheboro	Biscoe	230.00	230.00	S-HFR	0.88		1	1272MCMA							
10	Asheboro	Biscoe	230.00	230.00	W-HRF	24.97		1	1272MCMA							
11	Asheboro	DPC Pleasant Garden	230.00	230.00	S-HFR	18.48		1	2-1590MCMA							
12	Asheboro	Siler City	230.00	230.00	W-HRF	8.24		1	1272MCMA(B)							
13	Asheboro	Siler City	230.00	230.00	S-HFR	1.68		1	1272MCMA(B)							
14	Asheboro	Siler City	230.00	230.00	C-HFR	15.69		1	1272MCMA(B)							
15	Asheville CC Plant	Asheville Plant	230.00	230.00	S-SP	0.52		1	1272MCMA							
16	Asheville Plant	Enka	230.00	230.00	DC T	6.60		2	1272MCMA							
17	Asheville Plant	Enka	230.00	230.00	S-SP	0.71		1	1272MCMA							
18	Asheville Plant	Pisgah Forest (DPC) (Black)	230.00	230.00	DC T	0.18		2	1272MCMA							
19	Asheville Plant	Pisgah Forest (DPC) (Black)	230.00	230.00	W-HFR	3.31		1	1272MCMA							
20	Asheville Plant	Pisgah Forest (DPC) (Black)	230.00	230.00	S-SP	0.16		1	1272MCMA							
21	Asheville Plant	Pisgah Forest (DPC) (White)	230.00	230.00	W-HFR	3.35		1	1272MCMA							

22	Asheville Plant	Pisgah Forest (DPC) (White)	230.00	230.00	DC T	0.18		2	1272MCMA							
23	Asheville Plant	Pisgah Forest (DPC) (White)	230.00	230.00	S-SP	0.12		1	1272MCMA							
24	Aurora	Aurora PCS (Black)	230.00	230.00	W-HFR	2.18		1	795MCMA							
25	Aurora	Aurora PCS (Black)	230.00	230.00	DC S-HFR	5.49		2	795MCMA							
26	Aurora	Aurora PCS (Black)	230.00	230.00	S-SP	0.28		1	795MCMA							
27	Aurora	Aurora PCS (White)	230.00	230.00	DC S-HFR	5.47		2	795MCMA							
28	Aurora	Aurora PCS (White)	230.00	230.00	S-SP	0.25		1	795MCMA							
29	Aurora	Aurora PCS (White)	230.00	230.00	W-HFR	2.20		1	795MCMA							
30	Aurora	Greenville	230.00	230.00	DC T	1.78		2	1109MCMA							
31	Aurora	Greenville	230.00	230.00	W-HFR	36.50		1	1272&1109MCMA							
32	Aurora	Greenville	230.00	230.00	DC S-SP	0.33		2	1109MCMA							
33	Aurora	New Bern	230.00	230.00	W-HFR	27.69		1	1272MCMA							
34	Barnard Creek	Town Creek (Overhead)	230.00	230.00	DC T	1.15		2	2500MCMA							
35	Barnard Creek	Town Creek (Overhead)	230.00	230.00	W-HFR	0.41		1	2515MCMA							
36	Barnard Creek	Wilmington Corning Sw Sta	230.00	230.00	W-HFR	3.33		1	1272&2515MCMA							
37	Barnard Creek	Wilmington Corning Sw Sta	230.00	230.00	S-SP	7.04		1	1272MCMA							
38	Bennettsville Sw Sta	Laurinburg	230.00	230.00	W-HFR	7.31		1	2515MCMS							
39	Biscoe	Rockingham	230.00	230.00	S-HFR	0.77		1	1272MCMA							
40	Biscoe	Rockingham	230.00	230.00	W-HFR	36.23		1	1272MCMA							
41	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	S-HFR	1.21		1	2515MCMA							
42	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	DC T	1.15		2	2500MCMA							
43	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	W-HFR	24.43		1	1272&2515MCMA							
44	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	S-SP	7.21		1	2515MCMA							
45	Brunswick Plant Unit #1	Castle Hayne (East)	230.00	230.00	C-SP	0.70		1	1272MCMA							
46	Brunswick Plant Unit #1	Delco (East)	230.00	230.00	DC T	0.17		2	1272MCMA							
47	Brunswick Plant Unit #1	Delco (East)	230.00	230.00	W-HFR	29.85		1	1272MCMA							
48	Brunswick Plant Unit #1	Delco (East)	230.00	230.00	S-HFR	1.13		1	1272MCMA							
49	Brunswick Plant Unit #1	Jacksonville	230.00	230.00	W-HFR	75.21		1	1272MCMA							
50	Brunswick Plant Unit #2	Town Creek	230.00	230.00	S-HFR	1.36		1	2515MCMA							
51	Brunswick Plant Unit #2	Town Creek	230.00	230.00	W-HFR	13.31		1	2515MCMA							
52	Brunswick Plant Unit #1	Weatherspoon Plant	230.00	230.00	DC T	0.28		2	1272MCMA							
53	Brunswick Plant Unit #1	Weatherspoon Plant	230.00	230.00	W-HFR	77.65		1	1272MCMA							
54	Brunswick Plant Unit #2	Delco (West)	230.00	230.00	W-HFR	30.35		1	1272MCMA							
55	Brunswick Plant Unit #2	Delco (West)	230.00	230.00	S-HFR	1.08		1	1272MCMA							
56	Brunswick Plant Unit #2	Wallace	230.00	230.00	W-HFR	53.57		1	1272MCMA							
57	Brunswick Plant Unit #2	Wallace	230.00	230.00	S-HFR	1.25		1	1272MCMA							
58	Brunswick Plant Unit #2	Whiteville	230.00	230.00	W-HFR	47.75		1	1272MCMA							
59	Brunswick Plant Unit #2	Whiteville	230.00	230.00	S-HFR	1.07		1	1272MCMA							

60	Brunswick Plant Unit #1	Brunswick Plt Bus 1A Cap Bk	230.00	230.00	S-HFR	0.12		1	795MCMA							
61	Brunswick Plant Unit #1	Brunswick Plt Bus 1B Cap Bk	230.00	230.00	S-HFR	0.08		1	795MCMA							
62	Brunswick Plant Unit #2	Brunswick Plt Bus 2A Cap Bk	230.00	230.00	S-HFR	0.12		1	795MCMA							
63	Brunswick Plant Unit #2	Brunswick Plt Bus 2B Cap Bk	230.00	230.00	S-HFR	0.08		1	795MCMA							
64	Cane River	Cane River SVC	230.00	230.00	S-SP	0.08		1	795MCMA							
65	Cane River	Nagel East & West (APCO)	230.00	230.00	DC T	15.01		2	1590MCMA							
66	Cane River	Craggy	230.00	230.00	S-HFR	26.39		1	1590MCMA							
67	Cape Fear Plant	Cape Fear Plant Cap Bank	230.00	230.00	W-HFR	0.07		1	795MCMA							
68	Cape Fear Plant	Harris Plant (North)	230.00	230.00	W-HFR	7.12		1	2515&1272MCMA(							
69	Cape Fear Plant	Harris Plant (North)	230.00	230.00	S-HFR	0.25		1	1272MCMA(B)							
70	Cape Fear Plant	Harris Plant (South)	230.00	230.00	W-HFR	6.14		1	1272MCMA(B)							
71	Cape Fear Plant	Harris Plant (South)	230.00	230.00	S-HFR	0.38		1	1272MCMA(B)							
72	Cape Fear Plant	Jonesboro	230.00	230.00	W-HFR	10.10		1	795&1272MCMA(B)							
73	Cape Fear Plant	West End	230.00	230.00	DC T	0.24		2	1272MCMA							
74	Cape Fear Plant	West End	230.00	230.00	W-HFR	37.30		1	1272&2515MCMA							
75	Cary Regency Park	Method	230.00	230.00	DC S-SP	0.26		2	2515MCMA							
76	Cary Regency Park	Method	230.00	230.00	S-SP	4.49		1	2515&1272MCMA							
77	Cary Regency Park	Method	230.00	230.00	W-HFR	4.00		1	1272MCMA(B)							
78	Cary Regency Park	RTP	230.00	230.00	S-HFR	11.03		1	1272MCMA							
79	Castle Hayne	Folkstone	230.00	230.00	S-HFR	0.24		1	1272MCMA							
80	Castle Hayne	Folkstone	230.00	230.00	W-HFR	24.77		1	1272MCMA							
81	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	S-SP	0.45		1	1272MCMA							
82	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	W-HFR	5.12		1	1272MCMA							
83	Clinton	Erwin	230.00	230.00	S-SP	1.76		1	1272MCMA							
84	Clinton	Erwin	230.00	230.00	W-HFR	32.03		1	1272MCMA							
85	Clinton	Erwin	230.00	230.00	S-HFR	0.52		1	1272MCMA							
86	Clinton	Mt Olive	230.00	230.00	S-HFR	0.43		1	1590MCMA							
87	Clinton	Mt Olive	230.00	230.00	S-SP	14.60		1	1590MCMA							
88	Clinton	Wallace	230.00	230.00	W-HFR	36.68		1	1272&556MCMA(B)							
89	Concord	East Danville (AEP)	230.00	230.00	S-HFR	1.21		1	1590MCMA							
90	Concord	East Danville (AEP)	230.00	230.00	DC S-HFR	7.26		2	1590MCMA							
91	Concord	East Danville (AEP)	230.00	230.00	DC S-SP	1.74		2	1590MCMA							
92	Cumberland	Delco	230.00	230.00	W-HFR	54.37		1	1272MCMA							
93	Cumberland	Fayetteville (North)	230.00	230.00	DC S-SP	5.16		2	2515MCMA							
94	Cumberland	Fayetteville (North)	230.00	230.00	W-HFR	8.58		1	2515MCMA							
95	Cumberland	Fayetteville (South)	230.00	230.00	W-HFR	8.57		1	2515MCMA							
96	Cumberland	Fayetteville (South)	230.00	230.00	DC S-SP	5.16		2	2515MCMA							

97	Cumberland	Whiteville	230.00	230.00	W-HFR	40.93		1	1272&2515MCMA							
98	Durham	East Durham (DPC)	230.00	230.00	DC S-HFR	0.75		2	1272MCMA(B)							
99	Durham	East Durham (DPC)	230.00	230.00	C-HFR	0.60		1	1272MCMA(B)							
100	Durham	East Durham (DPC)	230.00	230.00	W-HFR	8.31		1	1272MCMA(B)							
101	Durham	Falls	230.00	230.00	S-HFR	4.28		1	1590MCMA(B)							
102	Durham	Falls	230.00	230.00	DC S-HFR	3.35		2	1590MCMA(B)							
103	Durham	Falls	230.00	230.00	S-SP	2.79		1	1590MCMA(B)							
104	Durham	Falls	230.00	230.00	W-HFR	4.12		1	1272MCMA							
105	Durham	Method	230.00	230.00	DC S-SP	1.52		2	2515MCMA							
106	Durham	Method	230.00	230.00	S-SP	1.56		1	2515MCMA							
107	Durham	Method	230.00	230.00	W-HFR	13.12		1	2515&1272MCMA(							
108	Durham	RTP	230.00	230.00	S-HFR	0.46		1	1272MCMA							
109	Durham	RTP	230.00	230.00	W-HFR	7.41		1	1272MCMA							
110	Durham	RTP	230.00	230.00	S-SP	2.23		1	1272MCMA							
111	Erwin	Fayetteville East	230.00	230.00	W-HFR	22.94		1	1272MCMA							
112	Erwin	Fayetteville East	230.00	230.00	S-HFR	0.23		1	1590MCMA(B)							
113	Erwin	Milburnie	230.00	230.00	S-HFR	0.50		1	1272MCMA							
114	Erwin	Milburnie	230.00	230.00	S-SP	0.71		1	1272MCMA							
115	Erwin	Milburnie	230.00	230.00	DC T	1.33		2	1272MCMA							
116	Erwin	Milburnie	230.00	230.00	W-HFR	34.08		1	1272MCMA							
117	Erwin	Selma	230.00	230.00	S-SP	1.09		1	1272MCMA							
118	Erwin	Selma	230.00	230.00	W-HFR	24.14		1	1272MCMA							
119	Falls	Milburnie	230.00	230.00	DC T	10.92		2	1272MCMA							
120	Falls	Milburnie	230.00	230.00	S-HFR	0.32		1	1272MCMA							
121	Fayetteville	Fayetteville East	230.00	230.00	DC T	0.97		2	1272MCMA							
122	Fayetteville	Fayetteville East	230.00	230.00	W-HFR	9.82		1	1272MCMA							
123	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	0.21		2	1272MCMA(B)							
124	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.00		1	2515&1272MCMA(							
125	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	W-HFR	17.70		1	1272MCMA(B)							
126	Fayetteville	Raeford	230.00	230.00	DC S-SP	2.08		2	1272MCMA(B)							
127	Fayetteville	Raeford	230.00	230.00	W-HFR	14.78		1	1272MCMA(B)							
128	Fayetteville	Raeford	230.00	230.00	S-HFR	0.16		1	1272MCMA(B)							
129	Fayetteville	Rockingham	230.00	230.00	W-HFR	49.09		1	1272MCMA							
130	Fayetteville	Rockingham	230.00	230.00	DC S-HFR	2.30		2	1272MCMA							
131	Fayetteville	Rockingham	230.00	230.00	DC S-SP	2.08		2	1272MCMA							
132	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC S-HFR	6.58		2	1590MCMA							
133	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	S-P	3.60		1	1590MCMA							
134	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	0.27		2	1590MCMA							
135	Folkstone	Jacksonville	230.00	230.00	W-HFR	20.00		1	1272MCMA							
136	Folkstone	Jacksonville	230.00	230.00	S-HFR	0.10		1	1272MCMA							

137	Fort Bragg Woodruff St.	Raeford	230.00	230.00	S-SP	7.20		1	1590MCMA(B)							
138	Fort Bragg Woodruff St.	Raeford	230.00	230.00	DC S-HFR	2.77		2	1590MCMA(B)							
139	Fort Bragg Woodruff St.	Raeford	230.00	230.00	S-HFR	19.88		1	1590MCMA(B)							
140	Grants Creek	Havelock	230.00	230.00	S-HFR	0.90		1	1272MCMA							
141	Grants Creek	Havelock	230.00	230.00	W-HFR	24.76		1	1272&556MCMA(B)							
142	Grants Creek	Jacksonville (North)	230.00	230.00	S-HFR	11.25		1	795MCMACSS(B)							
143	Grants Creek	Jacksonville (North)	230.00	230.00	DC S-SP	0.57		2	795MCMACSS(B)							
144	Grants Creek	Jacksonville (South)	230.00	230.00	S-HFR	0.88		1	1272MCMA							
145	Grants Creek	Jacksonville (South)	230.00	230.00	W-HFR	7.83		1	1272MCMA							
146	Grants Creek	Jacksonville (South)	230.00	230.00	DC T	5.61		2	1272MCMA							
147	Greenville	Everetts (VP)	230.00	230.00	DC T	1.83		2	1109MCMA							
148	Greenville	Kinston Dupont	230.00	230.00	S-HFR	24.82		1	795MCMA(B)							
149	Greenville	Kinston Dupont	230.00	230.00	S-SP	0.17		1	795MCMA(B)							
150	Greenville	Kinston Dupont	230.00	230.00	DC S-SP	0.33		2	795MCMA(B)							
151	Greenville	Wilson	230.00	230.00	W-HFR	33.69		1	1272&546MCMA(B)							
152	Greenville	Wilson	230.00	230.00	S-HFR	0.30		1	1272MCMA							
153	Harlowe	Newport	230.00	230.00	S-HFR	6.84		1	1590MCMA							
154	Harris Plant	Siler City	230.00	230.00	S-HFR	1.44		1	1272MCMA(B)							
155	Harris Plant	Siler City	230.00	230.00	W-HFR	30.04		1	2515&1272MCMA(							
156	Harris Plant	Cary Regency Park	230.00	230.00	W-HFR	10.01		1	1272MCMA(B)							
157	Harris Plant	Cary Regency Park	230.00	230.00	S-HFR	0.87		1	1590MCMA(B)							
158	Harris Plant	Erwin	230.00	230.00	S-HFR	0.27		1	1272MCMA(B)							
159	Harris Plant	Erwin	230.00	230.00	W-HFR	29.50		1	1272MCMA(B)							
160	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	DC S-SP	1.15		2	1272MCMA(B)							
161	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	S-HFR	0.20		1	1272MCMA(B)							
162	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	W-HFR	34.30		1	1272MCMA(B)							
163	Harris Plant	RTP	230.00	230.00	S-SP	16.96		1	1590MCMA(B)							
164	Harris Plant	RTP	230.00	230.00	S-HFR	3.71		1	1590MCMA(B)							
165	Harris Plant	Wake	230.00	230.00	S-SP	5.39		1	1590MCMA(B)							
166	Harris Plant	Wake	230.00	230.00	S-HFR	32.61		1	1590MCMA(B)							
167	Harris Plant	Harris Plt Start-Up Tran 1A	230.00	230.00	S-SP	0.17		1	795MCMA							
168	Harris Plant	Harris Plt Start-Up Tran 1B	230.00	230.00	S-HFR	0.28		1	2515MCMA(B)							
169	Havelock	New Bern	230.00	230.00	DC T	0.13		2	1272MCMA							
170	Havelock	New Bern	230.00	230.00	W-HFR	23.34		1	1272MCMA							
171	Havelock	Newport	230.00	230.00	W-HFR	8.91		1	1590MCMA							
172	Havelock Sub	Havelock Cap Bank	230.00	230.00	S-HFR	0.07		1	795MCMA							
173	Henderson	Person	230.00	230.00	DC T	2.46		2	1272MCMA							
174	Henderson	Person	230.00	230.00	W-HFR	37.47		1	1272MCMA							
175	Jacksonville	Jacksonville SVC	230.00	230.00	S-HFR	0.10		1	795MCMA							

176	Jacksonville	New Bern	230.00	230.00	W-HFR	29.47		1	1272MCMA							
177	Jacksonville	New Bern	230.00	230.00	DC S-SP	0.63		2	795MCMACSS(B)							
178	Jacksonville	New Bern	230.00	230.00	S-HFR	0.44		1	1272MCMA							
179	Jacksonville	Wallace	230.00	230.00	W-HFR	30.82		1	1272MCMA							
180	Kinston Dupont	Wommack	230.00	230.00	S-SP	0.14		1	795MCMA(B)							
181	Kinston Dupont	Wommack	230.00	230.00	S-HFR	19.06		1	795MCMA(B)							
182	Laurinburg	Richmond Sub	230.00	230.00	C-SP	3.31		1	2515MCMA							
183	Laurinburg	Richmond Sub	230.00	230.00	W-HFR	17.12		1	2515&1272MCMA(							
184	Lee CC Plant	Lee Sub	230.00	230.00	S-HFR	0.87		1	1590MCMA(B)							
185	Lee Sub	Milburnie	230.00	230.00	S-SP	0.43		1	1272MCMA							
186	Lee Sub	Milburnie	230.00	230.00	W-HFR	37.72		1	1272MCMA							
187	Lee Sub	Milburnie	230.00	230.00	DC T	1.36		2	1272MCMA							
188	Lee Sub	Milburnie	230.00	230.00	S-HFR	0.68		1	1272MCMA							
189	Lee Sub	Mt. Olive	230.00	230.00	S-HFR	0.23		1	1590MCMA							
190	Lee Sub	Mt. Olive	230.00	230.00	S-SP	10.39		1	1590MCMA							
191	Lee Sub	Mt. Olive	230.00	230.00	DC S-HFR	3.21		2	1590MCMA							
192	Lee Sub	Selma	230.00	230.00	S-SP	0.24		1	2515&1272MCMA(							
193	Lee Sub	Selma	230.00	230.00	W-HFR	16.54		1	1272MCMA(B)							
194	Lee Sub	Wommack (North)	230.00	230.00	W-HFR	30.42		1	1272MCMA(B)							
195	Lee Sub	Wommack (South)	230.00	230.00	S-HFR	29.45		1	1272MCMA(B)							
196	Lilesville	DPC Oakboro (Black)	230.00	230.00	S-HFR	0.30		1	1272MCMA							
197	Lilesville	DPC Oakboro (Black)	230.00	230.00	DC T	24.40		2	1272MCMA							
198	Lilesville	DPC Oakboro (White)	230.00	230.00	S-HFR	0.32		1	1272MCMA							
199	Lilesville	DPC Oakboro (White)	230.00	230.00	DC T	24.38		2	1272MCMA							
200	Lilesville	Rockingham (White)	230.00	230.00	S-HFR	10.36		1	1272MCMA							
201	Lilesville	Rockingham (South)	230.00	230.00	S-HFR	10.35		1	1272MCMA							
202	Lilesville	Whiteville	230.00	230.00	S-HFR	12.70		1	2515MCMA							
203	Marion	Whiteville	230.00	230.00	S-SP	14.49		1	1590MCMA							
204	Marion	Whiteville	230.00	230.00	S-HFR	2.38		1	1590MCMA							
205	Method	East Durham (DPC)	230.00	230.00	DC S-HFR	5.04		2	1590MCMA							
206	Method	East Durham (DPC)	230.00	230.00	DC S-HFR	0.70		2	1272MCMA(B)							
207	Method	East Durham (DPC)	230.00	230.00	S-SP	4.36		1	2515MCMA							
208	Method	East Durham (DPC)	230.00	230.00	C-HFR	0.55		1	1272MCMA(B)							
209	Method	East Durham (DPC)	230.00	230.00	W-HFR	14.17		1	2515&1272MCMA(							
210	Method	East Durham (DPC)	230.00	230.00	S-HFR	0.55		1	12727MCMA(B)							
211	Method	East Durham (DPC)	230.00	230.00	DC S-SP	1.53		2	1272MCMA(B)							
212	Method	Milburnie	230.00	230.00	DC S-SP	3.64		2	1272MCMA							
213	Method	Milburnie	230.00	230.00	S-SP	3.79		1	1272MCMA							
214	Method	Milburnie	230.00	230.00	W-SP	5.31		1	1272MCMA							
215	Milburnie	Person	230.00	230.00	DC T	58.66		2	1272MCMA							

216	Milburnie	Person	230.00	230.00	S-HFR	0.49		1	1272MCMA							
217	Milburnie	Person	230.00	230.00	W-HFR	0.49		1	1272MCMA							
218	Milburnie	Wake	230.00	230.00	W-HFR	7.20		1	1272MCMA(B)							
219	Morehead Wildwood	Newport	230.00	230.00	S-SP	0.23		1	1590MCMA							
220	Morehead Wildwood	Newport	230.00	230.00	DC S-SP	0.27		2	1590MCMA							
221	Morehead Wildwood	Newport	230.00	230.00	W-HFR	5.94		1	1590MCMA							
222	New Bern	Wommack (North)	230.00	230.00	S-HFR	2.57		1	1272MCMA							
223	New Bern	Wommack (North)	230.00	230.00	S-SP	0.14		1	1272MCMA							
224	New Bern	Wommack (North)	230.00	230.00	W-HFR	29.32		1	1272MCMA							
225	New Bern	Wommack (South)	230.00	230.00	W-HFR	33.33		1	1272MCMA							
226	New Bern	Wommack (South)	230.00	230.00	S-HFR	0.54		1	1272MCMA							
227	Person	Rocky Mount	230.00	230.00	S-HFR	0.13		1	1272MCMA							
228	Person	Rocky Mount	230.00	230.00	DC S-SP	0.18		2	1272MCMA							
229	Person	Rocky Mount	230.00	230.00	T	8.59		1	1272MCMA							
230	Person	Rocky Mount	230.00	230.00	W-HFR	69.41		1	1272MCMA							
231	Person	Rocky Mount	230.00	230.00	DC T	2.47		2	1272MCMA							
232	Person	Hendrick (VP)	230.00	230.00	W-HFR	4.86		1	1272MCMA							
233	Raeford	Richmond Substation 230KV	230.00	230.00	W-HFR	33.74		1	1272MCMA(B)							
234	Raeford	Richmond Substation 230KV	230.00	230.00	S-HFR	1.40		1	1272MCMA(B)							
235	Raeford	Richmond Substation 230KV	230.00	230.00	S-SP	2.48		1	1590MCMA(B)							
236	Raeford	Richmond Substation 230KV	230.00	230.00	S-HFR	37.81		1	1590MCMA(B)							
237	Richmond Sub	Rockingham (East)	230.00	230.00	S-HFR	0.39		1	1272MCMA(B)							
238	Richmond Sub	Rockingham (East)	230.00	230.00	W-HFR	5.57		1	1272MCMA(B)							
239	Richmond Sub	Rockingham (West)	230.00	230.00	DC S-HFR	1.21		1	1590MCMA(B)							
240	Richmond Sub	Rockingham (West)	230.00	230.00	S-HFR	6.63		1	1590MCMA(B)							
241	Richmond County Plant	Richmond Sub (Black)	230.00	230.00	S-HFR	1.13		1	2159MCMA(B)							
242	Richmond County Plant	Richmond Sub (White)	230.00	230.00	S-HFR	0.88		1	21590MCMA(B)							
243	Richmond County Plant	Richmond Sub (Orange)	230.00	230.00	S-HFR	1.56		1	21590MCMA							
244	Robinson Plant	Rockingham	230.00	230.00	DC S-HFR	1.21		2	1590MCMA(B)							
245	Robinson Plant	Rockingham	230.00	230.00	S-HFR	0.20		1	1590MCMA(B)							
246	Robinson Plant	Rockingham	230.00	230.00	W-HFR	7.53		1	1272&1590MCMA(							
247	Rockingham	West End (West)	230.00	230.00	DC T	5.73		2	1272MCMA							
248	Rockingham	West End (west)	230.00	230.00	W-HFR	28.26		1	1272MCMA							
249	Rockingham	West End (East)	230.00	230.00	DC S-HFR	2.30		2	2-1590MCMA							
250	Rockingham	West End (East)	230.00	230.00	S-HFR	29.81		1	2-1590MCMA							
251	Rocky Mount	Hathaway (VP) (East)	230.00	230.00	DC T	4.74		2	1272MCMA							
252	Rocky Mount	Hathaway (VP) (East)	230.00	230.00	DC S-SP	0.30		2	1272MCMA							
253	Rocky Mount	Hathaway (VP) (West)	230.00	230.00	DC T	4.74		2	1272MCMA							

254	Rocky Mount	Hathaway (VP) (West)	230.00	230.00	DC S-SP	0.30		2	1272MCMA						
255	Rocky Mount	Wilson	230.00	230.00	S-SP	0.85		1	1590MCMA						
256	Rocky Mount	Wilson	230.00	230.00	DC S-SP	8.26		2	1590MCMA						
257	Rocky Mount	Wilson	230.00	230.00	DC S-HFR	3.68		2	1590MCMA						
258	Roxboro Plant	East Danville (AEP)	230.00	230.00	S-HFR	1.79		1	1590MCMA						
259	Roxboro Plant	East Danville (AEP)	230.00	230.00	DC S-HFR	7.26		2	1590MCMA						
260	Roxboro Plant	East Danville (AEP)	230.00	230.00	DC S-SP	1.74		2	1590MCMA						
261	Roxboro Plant	Concord	230.00	230.00	S-HFR	0.61		1	1590MCMA						
262	Roxboro Plant	Falls	230.00	230.00	DC T	47.89		2	1272MCMA						
263	Roxboro Plant	Falls	230.00	230.00	C-SP	0.21		1	1590MCMA						
264	Roxboro Plant	Falls	230.00	230.00	S-HFR	0.17		1	1272MCMA						
265	Roxboro Plant	Falls	230.00	230.00	W-HFR	1.55		1	1272&1590MCMA						
266	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	C-HFR	1.68		1	1272MCMA(B)						
267	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	W-HFR	31.99		1	1272MCMA(B)						
268	Roxboro Plant	East Durham (DPC) (East)	230.00	230.00	DC S-HFR	0.76		2	1272MCMA(B)						
269	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	C-HFR	1.71		1	1272MCMA(B)						
270	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	W-HFR	31.99		1	1272MCMA(B)						
271	Roxboro Plant	East Durham (DPC) (West)	230.00	230.00	DC S-HFR	0.77		2	1272MCMA(B)						
272	Roxboro Plant	Eno (DPC) (Black)	230.00	230.00	DC T	16.66		2	1272MCMA(B)						
273	Roxboro Plant	Eno (DPC) (Black)	230.00	230.00	C-SP	0.22		1	1272MCMA(B)						
274	Roxboro Plant	Eno (DPC) (White)	230.00	230.00	DC T	16.66		2	1272MCMA(B)						
275	Roxboro Plant	Eno (DPC) (White)	230.00	230.00	C-SP	0.22		1	1272MCMA(B)						
276	Roxboro Plant	Person (Middle)	230.00	230.00	C-HFR	0.10		1	1272MCMA(B)						
277	Roxboro Plant	Person (Middle)	230.00	230.00	T	0.14		1	1272MCMA(B)						
278	Roxboro Plant	Person (Middle)	230.00	230.00	S-HFR	1.83		1	1590MCMA(B)						
279	Roxboro Plant	Person (Ceffo)	230.00	230.00	C-SP	0.21		1	1590MCMA(B)						
280	Roxboro Plant	Person (Ceffo)	230.00	230.00	DC T	0.15		2	1590MCMA(B)						
281	Roxboro Plant	Person (Ceffo)	230.00	230.00	W-HFR	1.90		1	1590MCMA(B)						
282	Roxboro Plant	Person (Hyco)	230.00	230.00	T	0.08		1	2515MCMA						
283	Roxboro Plant	Person (Hyco)	230.00	230.00	W-HFR	1.18		1	1272&2515MCMA(						
284	Selma	Wake	230.00	230.00	W-HFR	21.00		1	2515&1272MCMA(						
285	Sutton CC Plant	Sutton Plant	230.00	230.00	S-HFR	0.16		1	1590MCMA						
286	Sutton Plant	Castle Hayne	230.00	230.00	W-HFR	12.97		1	1272MCMA						
287	Sutton Plant	Castle Hayne	230.00	230.00	DC T	0.11		2	1272MCMA						
288	Sutton Plant	Castle Hayne	230.00	230.00	W-HFR	0.93		2	1272MCMA						
289	Sutton Plant	Delco	230.00	230.00	W-HFR	14.57		1	1272MCMA						
290	Sutton Plant	Delco	230.00	230.00	S-HFR	0.44		1	1272MCMA						

291	Sutton Plant	Delco	230.00	230.00	DC T	0.28		2	1272MCMA							
292	Sutton Plant	Wallace	230.00	230.00	T	0.45		1	1272MCMA							
293	Sutton Plant	Wallace	230.00	230.00	W-HFR	31.89		1	1272MCMA							
294	Wake	Zebulon	230.00	230.00	W-HFR	10.74		1	1272MCMA(B)							
295	Wake	Zebulon	230.00	230.00	S-HFR	0.49		1	1272MCMA(B)							
296	Wayne County Plant	Lee Sub	230.00	230.00	S-HFR	0.35		1	1590MCMA(B)							
297	Weatherspoon Plant	Fayetteville	230.00	230.00	W-HFR	32.52		1	1272MCMA							
298	Weatherspoon Plant	Fayetteville	230.00	230.00	DC T	0.97		2	1272MCMA							
299	Weatherspoon Plant	Latta	230.00	230.00	T	0.37		1	1272MCMA							
300	Weatherspoon Plant	Latta	230.00	230.00	W-HFR	18.29		1	1272MCMA							
301	Weatherspoon Plant	Latta	230.00	230.00	DC T	0.28		2	1272MCMA							
302	Weatherspoon Plant	Laurinburg	230.00	230.00	W-HFR	31.46		1	1272&2515MCMA							
303	Weatherspoon Plant	Laurinburg	230.00	230.00	S-HFR	0.99		1	1272MCMA							
304	Wayne County Plant	Lee Substation	230.00	230.00	S-HFR	0.31		1	1590MCMA(B)							
305	Wilmington Corning SW Sta.	Wilmington Corning Sub. (n)	230.00	230.00	S-SP	0.48		1	795MCMA							
306	Wilmington Corning SW Sta.	Wilmington Corning Sub (S)	230.00	230.00	S-SP	0.43		1	795MCMA							
307	Wilson	Zebulon	230.00	230.00	W-HFR	25.92		1	1272MCMA(B)&251							
308	Wilson	Zebulon	230.00	230.00	S-HFR	0.46		1	1272MCMA(B)							
309	Tap Point	Ansonville	230.00	230.00	S-SP	0.03		1	795MCMA							
310	Tap Point	Apex (Bank #1)	230.00	230.00	W-HFR	0.01		1	795MCMA							
311	Tap Point	Apex (Bank #2)	230.00	230.00	S-HFR	0.01		1	795MCMA							
312	Tap Point	Auburn	230.00	230.00	W-HFR	0.10		1	1272MCMA							
313	Tap Point	Aurora PCS Mine POD	230.00	230.00	S-HFR	0.02		1	795MCMA							
314	Tap Point	Bahama	230.00	230.00	W-HFR	0.06		1	795MCMA							
315	Tap Point	Bailey	230.00	230.00	W-HFR	1.38		1	795MCMA							
316	Tap Point	Bayboro	230.00	230.00	W-HFR	2.12		1	1272MCMA							
317	Tap Point	Benson	230.00	230.00	W-HFR	0.01		1	795MCMA							
318	Tap Point	Benson PGI	230.00	230.00	W-HFR	1.98		1	795MCMA							
319	Tap Point	Bladenboro Solar	230.00	230.00	S-HFR	0.09		1	795MCMA							
320	Tap Point	Brunswick EMC Bolivia	230.00	230.00	S-HFR	0.02		1	1272MCMA							
321	Tap Point	Brunswick EMC Daws Crk	230.00	230.00	S-HFR	0.02		1	1272MCMA							
322	Tap Point	Buies Creek	230.00	230.00	W-HFR	0.06		1	795MCMA							
323	Tap Point	Bynum	230.00	230.00	S-HFR	0.06		1	795MCMA							
324	Tap Point	Bynum	230.00	230.00	W-HFR	9.26		1	795MCMA							
325	Tap Point	Camp Geiger	230.00	230.00	S-SP	1.94		1	1272MCMA							
326	Tap Point	Camp LeJeune Sub #1	230.00	230.00	W-HFR	4.65		1	795MCMA							
327	Tap Point	Camp LeJeune Sub #2	230.00	230.00	W-HFR	0.04		1	795MCMA							
328	Tap Point	Camp LeJeune French Creek	230.00	230.00	S-SP/S-HFR	2.92		1	795MCMA							

329	Tap Point	Cary	230.00	230.00	W-HFR	0.93		1	795MCMA						
330	Tap Point	Cary Evans Road (East)	230.00	230.00	W-HFR	0.04		1	795MCMA						
331	Tap Point	Cary Evans Road (West)	230.00	230.00	S-HFR	0.04		1	795MCMA						
332	Tap Point	Cary Trenton Road	230.00	230.00	S-SP-11	4.34		1	795MCMA						
333	Tap Point	Cary Triangle Foreest	230.00	230.00	W-HFR	0.04		1	795MCMA						
334	Tap Point	Catherine Lake	230.00	230.00	W-HFR	0.08		1	795MCMA						
335	Tap Point	Chocowinity	230.00	230.00	W-HFR	0.05		1	1272MCMA						
336	Tap Point	City of Lumberton POD #3	230.00	230.00	S-SP	0.70		1	795MCMA						
337	Tap Point	Clifdale	230.00	230.00	W-HFR	0.54		1	795MCMA						
338	Tap Point	Concord	230.00	230.00	S-HFR	0.13		1	795MCMA						
339	Tap Point	County Line Solar	230.00	230.00	S-HFR	0.08		1	795MCMA						
340	Tap Point	Craven County Wood Energy	230.00	230.00	W-HFR	1.86		1	795MCMA						
341	Tap Point	Dover	230.00	230.00	S-HFR	0.04		1	795MCMA						
342	Tap Point	Dudley Georgia Pacific	230.00	230.00	W-HFR	2.64		1	795MCMA						
343	Tap Point	Eden Solar	230.00	230.00	S-HFR	0.06		1	795MCMA						
344	Tap Point	Ellerbe	230.00	230 00	W-HFR	0.04		1	795MCMA						
345	Tap Point	Fort Bragg Knox St.	230.00	230.00	W-HFR	0.08		1	795MCMA						
346	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	S-SP	0.47		1	795MCMA						
347	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	DC S-HFR	2.75		2	795MCMA						
348	Tap Point	Fort Bragg Main	230.00	230.00	S-SP	0.04		1	795MCMA						
349	Tap Point	Fort Bragg Woodruff St.	230.00	230.00	S-HFR	0.07		1	795MCMA						
350	Tap Point	Four Oaks (East)	230.00	230.00	S-HFR	0.05		1	1272MCMA						
351	Tap Point	Four Oaks (West)	230.00	230.00	W-HFR	0.07		1	795MCMA						
352	Tap Point	Fuquay	230.00	230.00	W-HFR	0.45		1	795MCMA						
353	Tap Point	Fuquay Bells Lake	230.00	230.00	W-HFR	0.15		1	795MCMA						
354	Tap Point	Garland	230.00	230.00	W-HFR	0.06		1	795MCMA						
355	Tap Point	Garner Panther Branch(East)	230.00	230.00	W-HFR	0.15		1	795MCMA						
356	Tap Point	Gamer Panther Branch(West)	230.00	230.00	S-HFR	0.07		1	795MCMA						
357	Tap Point	Grantham	230.00	230.00	W-HFR	0.12		1	795MCMA						
358	Tap Point	Hamlet (North)	230.00	230.00	W-HFR	0.02		1	1272MCMA						
359	Tap Point	Hamlet (South)	230.00	230.00	S-HFR	0.02		1	1272MCMA						
360	Tap Point	Henderson East	230.00	230.00	W-HFR	0.06		1	1272MCMA						
361	Tap Point	Holly Springs (East)	230.00	230.00	S-HFR	0.11		1	795MCMA						
362	Tap Point	Holly Springs (West)	230.00	230.00	S-HFR	0.11		1	795MCMA						
363	Tap Point	Holly Springs Industrial	230.00	230.00	S-HFR	0.83		1	795MCMA						
364	Tap Point	Hope Mills Rockfish Road	230.00	230.00	W-HFR	0.07		1	795MCMA						
365	Tap Point	Jacksonville Tarawa	230.00	230.00	W-HFR	0.04		1	795MCMA						

366	Tap Point	Knightdale Square D	230.00	230.00	W-HFR	0.95		1	795MCMA							
367	Tap Point	Laurel Hills	230.00	230.00	W-HFR	0.02		1	795MCMA							
368	Tap Point	Laurinburg City	230.00	230.00	W-HFR	0.03		1	795MCMA							
369	Tap Point	Leesville Wood Valley	230.00	230.00	W-HFR	0.15		1	795MCMA							
370	Tap Point	Masonboro	230.00	230.00	S-SP	0.03		1	795MCMA							
371	Tap Point	Mayo Plant	230.00	230.00	W-HFR	3.06		1	795MCMA							
372	Tap Point	Morrisville	230.00	230.00	W-HFR	0.11		1	795MCMA							
373	Tap Point	NCSU CBC	230.00	230.00	S-HFR	0.20		1	795MCMA							
374	Tap Point	New Bern West	230.00	230.00	W-HFR	0.04		1	795MCMA							
375	Tap Point	New Hill	230.00	230.00	W-HFR	0.20		1	795MCMA							
376	Tap Point	Newton Grove	230.00	230.00	W-HFR	2.13		1	795MCMA							
377	Tap Point	Oxford North	230.00	230.00	W-HFR	0.92		1	1272MCMA							
378	Tap Point	Oxford South	230.00	230.00	W-HFR	6.30		1	795MCMA							
379	Tap Point	Person Sub 230/24kV Bank	230.00	230.00	S-HFR	0.11		1	795MCMA							
380	Tap Point	Pitt Greene EMC Farmville	230.00	230.00	S-HFR	0.04		1	795MCMA							
381	Tap Point	Pittsboro	230.00	230.00	W-HFR	0.03		1	795MCMA							
382	Tap Point	Prospect	230.00	230.00	TOTAL	0.04		1								
383	Tap Point	Raleigh Blue Ridge Road	230.00	230.00	S-SP	0.03		1	795MCMA							
384	Tap Point	Raleigh Durham Airport	230.00	230.00	W-HFR	0.09		1	795MCMA							
385	Tap Point	Raleigh Foxcroft	230.00	230.00	W-HFR	0.03		1	795MCMA							
386	Tap Point	Raleigh Homestead (North)	230.00	230.00	S-HFR	0.07		1	1272MCMA							
387	Tap Point	Raleigh Homestead (South)	230.00	230.00	S-HFR	0.07		1	1272MCMA							
388	Tap Point	Raleigh Leesville Road	230.00	230.00	W-HFR	0.04		1	795MCMA							
389	Tap Point	Raleigh NCSU Centennial	230.00	230.00	S-SP	0.05		1	1272MCMA							
390	Tap Point	Raleigh Oakdale	230.00	230.00	S-SP	1.26		1	795MCMA							
391	Tap Point	Raleigh Six Forks	230.00	230.00	S-HFR	0.07		1	1272MCMA							
392	Tap Point	Rockingham Aberdeen Road	230.00	230.00	W-HFR	0.60		1	795MCMA							
393	Tap Point	Rolesville	230.00	230.00	W-HFR	5.67		1	1590MCMA							
394	Tap Point	Rose Hill	230.00	230.00	W-HFR	0.16		1	795MCMA							
395	Tap Point	Rowan Creek Solar	230.00	230.00	S-HFR	0.07		1	795MCMA							
396	Tap Point	Rowland	230.00	230.00	W-HFR	6.86		1	795MCMA							
397	Tap Point	Roxboro Bowmantown Road	230.00	230.00	S-HFR	0.04		1	1272MCMA							
398	Tap Point	Roxboro Cogentrix	230.00	230.00	W-HFR	0.60		1	795MCMA							
399	Tap Point	Rox. Plt Unit #3 C. Tower	230.00	230.00	W-HFR	0.24		1	795MCMA							
400	Tap Point	Sanford Deep River	230.00	230.00	W-HFR	2.63		1	795MCMA							
401	Tap Point	Sanford Deep River	230.00	230.00	S-HFR	0.09		1	795MCMA							
402	Tap Point	Sanford Garden Street	230.00	230.00	W-HFR	3.26		1	1590MCMA							

403	Tap Point	Sanford Horner Blvd.	230.00	230.00	W-HFR	0.04		1	795MCMA							
404	Tap Point	Sandhills Util. Ft. Brg 3rd	230.00	230.00	S-HFR	0.35		1	795MCMA							
405	Tap Point	Scotts Hill	230.00	230.00	S-SP	3.37		1	795MCMA							
406	Tap Point	Shoe Heel Creek Solar	230.00	230.00	S-HFR	0.08		1	795MCMA							
407	Tap Point	Siler City Hwy. 64	230.00	230.00	S-HFR	0.53		1	795MCMA							
408	Tap Point	Southport	230.00	230.00	W-HFR	1.88		1	1272MCMA							
409	Tap Point	Southport ADM (West)	230.00	230.00	W-HFR	0.48		1	1272MCMA							
410	Tap Point	Southport Cogentrix	230.00	230.00	W-HFR	0.30		1	795MCMA							
411	Tap Point	Swansboro	230.00	230.00	W-HFR	0.07		1	795MCMA							
412	Tap Point	Tideland EMC Edwards	230.00	230.00	S-SP	0.61		1	1590MCMA							
413	Tap Point	Topsail	230.00	230.00	W-HFR	1.55		1	795MCMA							
414	Tap Point	Town of Apex POD #4	230.00	230.00	S-HFR	0.12		1	795MCMA							
415	Tap Point	Town of Farmville	230.00	230.00	S-HFR	0.03			795MCMA							
416	Tap Point	Turnbull Creek Solar	230.00	230.00	S-HFR	0.07		1	795MCMA							
417	Tap Point	Wadesboro	230.00	230.00	S-HFR	0.02		1	795MCMA							
418	Tap Point	Wadesboro Bowman School	230.00	230.00	S-HFR	12.98		1	1590MCMA							
419	Tap Point	Wake Tech	230.00	230.00	S-HFR	0.06		1	795MCMA							
420	Tap Point	Warsaw	230.00	230.00	S-SP	0.61		1	795MCMA							
421	Tap Point	Warsaw	230.00	230.00	W-HFR	2.46		1	795MCMA							
422	Tap Point	Warsaw Solar	230.00	230.00	S-HFR	0.06		1	795MCMA							
423	Tap Point	Weatherspoon Sub	230.00	230.00	W-HFR	0.09		1	795MCMA							
424	Tap Point	Wendell	230.00	230.00	W-HFR	0.07		1	795MCMA							
425	Tap Point	Wilmington Invista	230.00	230.00	W-HFR	0.58		1	1272MCMA							
426	Tap Point	Wilmington Cedar Avenue	230.00	230.00	S-SP	0.21		1	795MCMA							
427	Tap Point	Wilmington East	230.00	230.00	W-HFR	0.01		1	1272MCMA							
428	Tap Point	Wilmington Ninth & Orange	230.00	230.00	S-SP	2.01		1	1272MCMA							
429	Tap Point	Wilmington Ogden (East)	230.00	230.00	W-HFR	0.06		1	795MCMA							
430	Tap Point	Wilmington Ogden (West)	230.00	230.00	S-HFR	0.06		1	795MCMA							
431	Tap Point	Wilmington Praxair	230.00	230.00	W-HFR	0.58		1	795MCMA							
432	Tap Point	Wilmington BASF	230.00	230.00	W-HFR	0.22		1	795MCMA							
433	Tap Point	Wilmington Winter Park	230.00	230.00	S-HFR	0.02		1	1272MCMA							
434	Tap Point	Wilson Mills	230.00	230.00	W-HFR	0.09		1	795MCMA							
435	Tap Point	Yanceyville	230.00	230.00	S-SP	10.36		1	795MCMA							
436	Barnard Creek	Town Creek	230.00	230.00	UNDERGROU	1.42		1	2-2500MCMA							
437	Bennettsville Sw Sta	Laurinburg	230.00	230.00	S-HFR	0.12		1	2515MCMA							
438	Bennettsville Sw Sta	Laurinburg	230.00	230.00	W-HFR	9.90		1	2515MCMA							
439	Camden	Lugoff(SCPSA)	230.00	230.00	W-HFR	5.37		1	1272MCMA							
440	Darlington County Plant	Bennettsville Sw Sta	230.00	230.00	S-HFR	0.13		1	2515MCMA							
441	Darlington County Plant	Bennettsville Sw Sta	230.00	230.00	W-HFR	34.09		1	2515MCMA							

442	Darlington County Plant	Darlington IC Turbine Yard	230.00	230.00	S-HFR	0.20		1	1590MCMA							
443	Darlington County Plant	Florence	230.00	230.00	S-SP	37.28		1	1590MCMA							
444	Darlington County Plant	Robinson Plant (South)	230.00	230.00	W-HFR	1.73		1	2515MCMA							
445	Darlington County Plant	Robinson Plant (North)	230.00	230.00	S-HFR	1.66		1	2515MCMA							
446	Darlington County Plant	South Bethune (SCPSA)	230.00	230.00	W-HFR	0.06		1	1272MCMA							
447	Darlington County Plant	Sumter	230.00	230.00	DC S-SP	5.33		2	1272MCMA							
448	Darlington County Plant	Sumter	230.00	230.00	W-HFR	48.39		1	1272MCMA							
449	Florence	Kingstree	230.00	230.00	W-HFR	49.47		1	1272MCMA							
450	Florence	Latta	230.00	230.00	W-HFR	23.42		1	1272MCMA							
451	Florence	Latta	230.00	230.00	S-SP	0.22		1	1272MCMA							
452	Florence	Darlington (SCPSA)	230.00	230.00	W-HFR	11.07		1	1272MCMA							
453	Latta	Marion	230.00	230.00	W-HFR	8.43		1	1590MCMA							
454	Marion	Marion (SCPSA) (North)	230.00	230.00	S-HFR	0.07		1	1272MCMA(B)							
455	Marion	Marion (SCPSA) (South)	230.00	230.00	S-HFR	0.06		1	1272MCMA(B)							
456	Marion	Whiteville	230.00	230.00	S-SP	6.60		1	1590MCMA							
457	Marion	Whiteville	230.00	230.00	W-HFR	14.81		1	1590MCMA							
458	Robinson Plant	Florence	230.00	230.00	DC T	1.40		2	1272MCMA							
459	Robinson Plant	Florence	230.00	230.00	W-HFR	38.41		1	1272MCMA							
460	Robinson Plant	Rockingham	230.00	230.00	S-SP	0.23		1	1272MCMA							
461	Robinson Plant	Rockingham	230.00	230.00	W-HFR	38.95		1	1272MCMA							
462	Robinson Plant	Rockingham	230.00	230.00	DC T	1.40		2	1272MCMA							
463	Robinson Plant	Darlington (SCPSA)	230.00	230.00	DC T	0.60		2	1272MCMA							
464	Robinson Plant	Darlington (SCPSA)	230.00	230.00	W-HFR	17.95		1	1272MCMA							
465	Robinson Plant	Sumter	230.00	230.00	W-HFR	40.56		1	1272MCMA							
466	Robinson Plant	Sumter	230.00	230.00	DC T	0.60		2	1272MCMA							
467	Sumter	St. George (SCE&G)	230.00	230.00	DC T	7.26		2	795MCMA							
468	Sumter	St. George (SCE&G)	230.00	230.00	C-SP	1.74		1	795MCMA							
469	Sumter	St. George (SCE&G)	230.00	230.00	W-HFR	21.33		1	795MCMA							
470	Sumter	Wateree Plant (SCE&G)	230.00	230.00	W-HFR	16.58		1	1272MCMA							
471	Sumter	Wateree Plant (SCE&G)	230.00	230.00	DC T	7.26		2	1272MCMA							
472	Weatherspoon	Latta	230.00	230.00	W-HFR	13.45		1	1272MCMA							
473	Tap Point	Bishopville	230.00	230.00	W-HFR	0.17		1	795MCMA							
474	Tap Point	Camden 230/23kv Yard	230.00	230.00	W-HFR	0.18		1	1272MCMA							
475	Tap Point	Cheraw Cash Rd.	230.00	230.00	S-SP	1.08		1	795MCMA							
476	Tap Point	Cheraw Reid Park	230.00	230.00	W-HFR	5.30		1	1272MCMA							
477	Tap Point	Dillion North	230.00	230.00	S-SP	3.51		1	795MCMA							
478	Tap Point	Dillon Maple	230.00	230.00	W-HFR	4.39		1	795MCMA							
479	Tap Point	Dovesville Nucor	230.00	230.00	W-HFR	6.81		1	1272MCMA							
480	Tap Point	Elliott	230.00	230.00	W-HFR	2.15		1	795MCMA							
481	Tap Point	Florence Cashua	230.00	230.00	C-SP	1.30		1	795MCMA							

482	Tap Point	Florence Ebenezer	230.00	230.00	W-HFR	0.08		1	1590MCMA							
483	Tap Point	Florence West	230.00	230.00	W-HFR	0.04		1	795MCMA							
484	Tap Point	Hartsville Segars Mill	230.00	230.00	W-HFR	0.06		1	795MCMA							
485	Tap Point	Hartsville Talley Metals	230.00	230.00	W-HFR	0.31		1	795MCMA							
486	Tap Point	Hartsville Talley Metals	230.00	230.00	S-SP	0.70		1	1590MCMA							
487	Tap Point	Kingstree North	230.00	230.00	W-HFR	0.14		1	795MCMA							
488	Tap Point	Lake City	230.00	230.00	W-HFR	0.08		1	795MCMA							
489	Tap Point	McColl	230.00	230.00	W-HFR	0.90		1	795MCMA							
490	Tap Point	Olanta	230.00	230.00	W-HFR	0.05		1	795MCMA							
491	Tap Point	Society Hill	230.00	230.00	W-SP	1.16		1	795MCMA							
492	Tap Point	Summerton	230.00	230.00	W-HFR	2.70		1	795MCMA							
493	Tap Point	Sumter Alive Drive	230.00	230.00	W-HFR	0.30		1	795MCMA							
494	Tap Point	Sumter Continental Tire	230.00	230.00	S-HFR	0.31		1	795MCMA							
495	Tap Point	Sumter North	230.00	230.00	S-SP	0.74		1	795MCMA							
496	Tap Point	Sumter Wedgefield Rd.	230.00	230.00	W-HFR	0.05		1	795MCMA							
497	Tap Point	Bayboro	230.00	230.00	S-HFR	0.06		1	795MCMA							
498	Tap Point	Powhatan Industrial	230.00	230.00	S-HFR	1.61		1	795MCMA							
499	Tap Point	Buckleberry Canal Solar	230.00	230.00	S-HFR	0.10		1	795MCMA							
500	Tap Point	Sandy Bottom Solar	230.00	230.00	S-HFR	0.22		1	795MCMA							
501	Tap Point	Willard Solar	230.00	230.00	S-HFR	0.04		1	795MCMA							
502	Tap Point	Crooked Run Solar	230.00	230.00	S-HFR	0.04		1	795MCMA							
503	Tap Point	Green Level (East)	230.00	230.00	S-HFR	0.07		1	795MCMA							
504	Tap Point	Green Level (West)	230.00	230.00	S-HFR	0.06		1	795MCMA							
505	Tap Point	Hope Mills Rockfish Rd Bk 2	230.00	230.00	S-HFR	0.07		1	795MCMA							
506	Tap Point	Roxboro Plant Waste Water	230.00	230.00	S-HFR	0.19		1	795MCMA							
507	Tap Point	Angier (West)	230.00	230.00	S-HFR	0.04		1	795MCMA							
508	Tap Point	Angier (East)	230.00	230.00	S-HFR	0.07		1	795MCMA							
509	Tap Point	Cleveland Matthews Road	230.00	230.00	S-HFR	11.53		1	1590MCMA							
510	Tap Point	Royal Oak Cap Bank	230.00	230.00	S-HFR	0.17		1	795MCMA							
511	Tap Point	Trent River Solar	230.00	230.00	S-HFR	0.05		1	795MCMA							
512	Tap Point	Bay Tree Solar	230.00	230.00	S-HFR	0.05		1	795MCMA							
513	Tap Point	Bailey Bank #2	230.00	230.00	S-HFR	0.05		1	795MCMA							
514	Tap Point	Garner Rock Quarry	230.00	230.00	S-HFR	0.30		1	1272MCMA							
515	Tap Point	Roxboro Old Durham Road	230.00	230.00	S-HFR	0.71		1	795MCMA							
516	Tap Point	Holly Springs Utley Creek	230.00	230.00	S-HFR	2.09		1	1272MCMA							
517	Tot. 230kV Lines									144,992,438	1,247,874,738	1,392,867,176				
518	Tot. 115kV Lines				Tower and	2,563.87		568		35,591,587	871,777,539	907,369,126				
519	Tot. 66kV - 69kV Lines				Tower and	11.34		1,136		57,228	3,828,018	3,885,246				

520	Expenses (Columns M & N)												1,113,466	10,932,575		12,046,041
36	TOTAL					6,300.98	0.00	2,300		206,800,764	2,221,560,868	2,428,361,632	1,113,466	10,932,575	0	12,046,041

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the 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.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Tap Point	Holly Springs Utley Creek	2.09	S-HFR	9.00	1	1	1272	MCMA	FLAT	230		5,724,429	2,064,582		7,789,011	
2	Aurora	New Bern	1.46	S-HFR	8.00	1	1	1272	MCMA	FLAT	230						
3	Aurora	New Bern	(1.51)	W-HFR	8.00	(1.00)	(1.00)	1272	MCMA	FLAT	230		(83,493)	(33,901)	(35,661)	(153,055)	
4	Tap Point	New Bern Weyerhaeuser	0.07	S-HFR		1.00	1.00	336	MCMA	FLAT	115		595,296	22,741		618,037	
5	Tap Point	Nutbush Solar	0.06	S-HFR		1.00	1.00	336.40	MCMA	FLAT	115		225	61		286	
6	Tap Point	Sapony Creek Solar	0.05	S-HFR		1	1	795	MCMA	FLAT	115						
7	Tap Point	Cherry Point #2 Sub Cap Bank	0.03	S-SP		1	1	795	MCMA	VERT	115		245,912	242,680	55,459	544,051	
8	Tap Point	Delco	(0.01)	W-HFR		(1.00)	(1.00)	2/0	CU	FLAT	115				254,987	254,987	
9	Tap Point	Wake Forest (South Tap)	(0.04)	W-HFR		(1.00)	(1.00)	795	MCMA	FLAT	115				66,873	66,873	
10	Tap Point	Wilmington Atlantic Scrap Metal	(0.18)	W-HFR		(1.00)	(1.00)	795	MCMA	FLAT	115				31,285	31,285	
11	Sutton Plant	Delco 230 kv Sub (North Line)	0.16	S-HFR		1.00	1.00	795.00	MCMA	FLAT	115			985,300		985,300	
44	TOTAL		2.18		25	3	3						6,482,369	3,281,463	372,943	10,136,775	

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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).
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.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	Aberdeen 115kV Aberdeen	Distribution	Unattended	115.00	24.00		30	2	0			
2	Amberly 230KV Cary	Distribution	Unattended	230.00	24.00		80	2	0			
3	Andrews 115kV Andrews	Distribution	Unattended	115.00	24.00		25	1	0			
4	Angier 230kV Angier	Distribution	Unattended	230.00	24.00		40	2	0			
5	Ansonville 230kV Wadesboro	Distribution	Unattended	230.00	24.00		13	1	0			
6	Apex 230kV Apex	Distribution	Unattended	230.00	24.00		100	4	0			
7	Archer Lodge 230kV Archer Lodge	Distribution	Unattended	230.00	24.00		80	2	0			
8	Arden 115kV Asheville	Distribution	Unattended	115.00	24.00		40	1	0			
9	Asheboro 230kV Asheboro	Transmission	Unattended	230.00	115.00		600	2	0			
10	Asheboro East 115kV Asheboro	Distribution	Unattended	115.00	24.94		45	1	0			
11	Asheboro North 115kV Asheboro	Distribution	Unattended	115.00	24.00		50	2	0			
12	Asheboro South 115kV Asheboro	Distribution	Unattended	115.00	24.00		50	2	0			
13	Asheboro West 115kV Asheboro	Distribution	Unattended	115.00	24.00		25	1	0			
14	Asheville Bent Creek 115kV Asheville	Distribution	Unattended	115.00	24.00		25	1	0	Mb. Sp. (115/23/12kV)	2	25
15	Asheville Rock Hill 115kV	Distribution	Unattended	115.00	23.00		25	1	0			
16	Asheville S. E. Plant Asheville	Transmission	Attended	230.00	115.00		896	2	1			
17	Asheville S. E. Plant Asheville	Transmission	Attended	115.00	17.20		0	0	0			
18	Asheville S. E. Plant Asheville	Transmission	Attended	115.00	23.00		0	0	0			
19	Atlantic Beach 115kV Atlantic Beach	Distribution	Unattended	115.00	12.00		25	1	0			
20	Auburn 230kV Raleigh	Distribution	Unattended	230.00	24.00		25	1	0			
21	Avery Creek 115kV Skyland	Distribution	Unattended	115.00	24.00		40	1	0			
22	Bahama 230kV Bahama	Distribution	Unattended	230.00	24.00		25	1	0			
23	Bailey 230kV Bailey	Distribution	Unattended	230.00	24.00		73	2	0			
24	Baldwin 115kV Arden	Distribution	Unattended	115.00	24.00		25	1	0			
25	Barnard Creek 230kV Wilmington	Transmission	Unattended	230.00	115.00	13.80	224	1	0			
26	Barnardsville 115kV Barnardsville	Distribution	Unattended	115.00	12.00		19	3	1			

27	Bayboro 230kV Alliance	Distribution	Unattended	230.00	24.00		48	2				
28	Bear Branch 230KV	Distribution	Unattended	230.00	24.00		40	1				
29	Beard 115KV Eastover	Distribution	Unattended	115.00	13.00		25	4				
30	Beaufort 115kV Beaufort	Distribution	Unattended	115.00	12.47		34	1				
31	Beaverdam 115kV Asheville	Distribution	Unattended	115.00	24.00		25	1				
32	Belfast 115kV Goldsboro	Distribution	Unattended	115.00	23.00		50	2				
33	Bennettsville 230kV	Distribution	Unattended	230.00	24.00		50	2				
34	Benson 230kV Benson	Distribution	Unattended	230.00	24.00		50	2	1	Step Down 23/12kV	3	13
35	Bethune 115kV Bethune	Distribution	Unattended	115.00	12.00		25	1				
36	Beulaville 115KV	Distribution	Unattended	115.00	23.00		25	1				
37	Biltmore 115kV Asheville	Distribution	Unattended	115.00	12.00		55	1				
38	BILTMORE FARMS INDUSTRIAL 230KV ASHEVILLE	Transmission	Unattended	230.00	24.00		90	2				
39	Biscoe 115kV	Distribution	Unattended	115.00	24.00		25	1		Mb.Sp. (115/23/12kV)	2	33
40	Biscoe 230kV	Transmission	Unattended	230.00	115.00		300	1				
41	Bishopville 230kV Bishopville	Distribution	Unattended	230.00	24.00		50	2				
42	Black Mountain 115kV Black Mountain	Distribution	Unattended	115.00	13.00		19	3	1			
43	Bladenboro 115kV Bladenboro	Distribution	Unattended	115.00	24.00		19	3				
44	Blewett H. E. Plant	Transmission	Attended	115.00	13.20		74	1				
45	Bridgeton 115kV Ernul	Distribution	Unattended	115.00	24.00	0.00	28	1				
46	Brunswick S. E. Plant	Transmission	Attended	230.00	24.00		2400	6	2			
47	Bules Creek 230kV	Distribution	Unattended	230.00	24.00		25	1				
48	Burgaw 115kV Burgaw	Distribution	Unattended	115.00	23.00		25	1				
49	Butler 115KV laurinburg	Distribution	Unattended	115.00	12.00		10	3				
50	Bynum 230kV Bynum	Distribution	Unattended	230.00	24.00		50	2				
51	Camden 230kV Lugoff	Distribution	Unattended	230.00	24.00		25	1				
52	Camden 230kV Lugoff	Transmission	Unattended	230.00	115.00		200	1				
53	Camden Steeplechase 115kV Camden	Distribution	Unattended	115.00	24.00		25	1				
54	Camp Lejeune French Creek 230kV Jacksonville	Distribution	Unattended	230.00	13.80		40	1				
55	Candler 115kV Candler	Distribution	Unattended	115.00	24.00		25	1				
56	Candor 115kV Candor	Distribution	Unattended	115.00	24.00		25	1				
57	Cane River 230kV Burnsville	Transmission	Unattended	230.00	115.00		448	4				
58	Cane River 230kV Burnsville	Transmission	Unattended	230.00	26.00		150	3	1			
59	Canton 115kV Canton	Distribution	Unattended	115.00	12.00		80	2				
60	Cape Fear S. E. Plant Moncure	Transmission	Attended	230.00	115.00	13.80	336	1				
61	Cape Fear S. E. Plant Moncure	Transmission	Attended	230.00	115.00		392	1				
62	Caraleigh 230kV Raleigh	Transmission	Unattended	230.00	24.94		70	3				
63	Carolina Beach 115kV Carolina Beach	Distribution	Unattended	115.00	24.00		50	2				
64	Carthage 115kV Carthage	Transmission	Unattended	115.00	13.09		34	1				

65	Cary 230kV Cary	Distribution	Unattended	230.00	23.00		50	2				
66	Cary Evans Road 230kV Cary	Distribution	Unattended	230.00	24.00		90	3				
67	Cary Piney Plains 230kV Cary	Distribution	Unattended	230.00	24.00		90	3				
68	Cary Regency Park 230kV Cary	Distribution	Unattended	230.00	23.00		50	2				
69	Cary Trenton Road 230kV Cary	Distribution	Unattended	230.00	25.00		80	2				
70	Cary Triangle Forest 230kV Cary	Distribution	Unattended	230.00	23.00		50	2				
71	Castalia 230kV	Distribution	Unattended	230.00	24.00		25	1				
72	Castle Hayne Carolinas Cement 115KV CASTLE HAYNE	Distribution	Unattended	115.00	24.00		100	6				
73	Castle Hayne Carolinas Cement 115KV CASTLE HAYNE	Transmission	Unattended	230.00	115.00	13.80	500	2				
74	Catherine Lake 230kV	Distribution	Unattended	230.00	24.00		25	1				
75	Chadbourn 115kV Chadbourn	Distribution	Unattended	115.00	24.00		19	3				
76	Cheraw 115kV Wallace	Distribution	Unattended	115.00	24.00		25	1				
77	Cheraw Cash Road 230kV Cheraw	Distribution	Unattended	230.00	23.00		25	1				
78	Cheraw Reid Park 230KV	Distribution	Unattended	230.00	24.00		50	2				
79	Cherry Point #1 115KV Havelock	Distribution	Unattended	115.00	12.00		50	2				
80	Cherry Point #2 115KV Havelock	Distribution	Unattended	115.00	12.00		26	4				
81	Chesterfield 115kV	Distribution	Unattended	115.00	24.00		25	1				
82	Chestnut Hills 115kV Raleigh	Distribution	Unattended	115.00	24.00		100	5	1			
83	Chocowinity 230kV	Distribution	Unattended	230.00	23.00		50	2				
84	Clarkton 115kV Clarkton	Distribution	Unattended	115.00	24.00		25	1				
85	Clayton 115kV Clayton	Distribution	Unattended	115.00	24.00		90	3				
86	Clayton Industrial 115kV Clayton	Distribution	Unattended	115.00	24.00		80	2				
87	Cleveland Matthews Road 230KV Clayton	Transmission	Unattended	230.00	24.00		90	2				
88	Clifdale 230kV Fayetteville	Distribution	Unattended	230.00	24.00		50	2				
89	Clinton 230KV Clinton	Transmission	Unattended	230.00	115.00	13.80	200	1				
90	Clinton Ferrell Street 115kV Clinton	Distribution	Unattended	115.00	23.00		50	3	1			
91	Clinton North 115kV Clinton	Distribution	Unattended	115.00	23.00		50	2				
92	Concord 230kV	Transmission	Unattended	230.00	115.00		300	1				
93	Craggy 230kV Woodfin	Transmission	Unattended	230.00	115.00		600	2				
94	Cumberland 500kV Fayetteville	Transmission	Unattended	500.00	230.00	13.80	1000	3	1			
95	Darlington 115kV	Distribution	Unattended	115.00	24.00		50	3	1			
96	Darlington I.C. Plant Darlington	Transmission	Attended	230.00	14.00		1084	8	0			
97	Darlington Pineville Road 115kV	Distribution	Unattended	115.00	24.00		40	1	0			
98	Delco 115kV Delco	Distribution	Unattended	115.00	24.00		90	2	0			
99	Delco 230kV Delco	Transmission	Unattended	230.00	115.00	13.80	500	2				
100	Dillon 115kV Dillon	Distribution	Unattended	115.00	24.00		50	3	1			
101	Dillon Maple 230kV	Distribution	Unattended	230.00	24.00		25	1				
102	Dillon North 230kV	Distribution	Unattended	230.00	24.00		25	1				
103	Dover 230kV Kinston	Distribution	Unattended	230.00	24.00		40	1				

104	DPC Pisgah Forest 230kV Pisgah Forest	Transmission	Unattended	115.00	100.00	13.00	100	1				
105	Duncan 230kV Fuquay Varina	Distribution	Unattended	230.00	24.00		90	2				
106	Dunn 230kV Dunn	Distribution	Unattended	230.00	23.00		50	2				
107	Durham 500kV	Transmission	Unattended	500.00	230.00	13.80	1125	3	1			
108	Eagle Island 115kV Wilmington	Transmission	Unattended	115.00	24.94		96	4	1			
109	Eagle Island 115kV Wilmington	Transmission	Unattended	15.00	13.00		0	0	0			
110	Edmondson 230kV Willow Springs	Distribution	Unattended	230.00	24.00		80	2				
111	Elgin 115kV Elgin	Distribution	Unattended	115.00	24.00		23	2				
112	Elizabethtown 115kV Elizabethtown	Distribution	Unattended	115.00	24.00		25	1				
113	Elk Mountain 115kV Woodfin	Distribution	Unattended	115.00	24.00		50	2				
114	Ellerbe 230kV Ellerbe	Distribution	Unattended	230.00	23.00		25	1				
115	Elliott 230kV Elliott	Distribution	Unattended	230.00	24.00		25	1				
116	Elm City 115kV Elm City	Distribution	Unattended	115.00	24.00		13	2				
117	Emma 115kV Asheville	Distribution	Unattended	115.00	12.00		25	1				
118	Enka 230kV Asheville	Transmission	Unattended	230.00	115.00		300	1				
119	Enka Sardis Road 115kV	Transmission	Unattended	115.00	4.16	0.00	13	3				
120	Erwin 230kV	Transmission	Unattended	230.00	115.00	13.80	300	2				
121	Erwin 230kV	Distribution	Unattended	115.00	24.00	12.00	15	3	1			
122	Erwin 230kV	Distribution	Unattended	115.00	24.00		25	1				
123	Erwin Mills 115kv Erwin	Distribution	Unattended	115.00	12.00		25	1				
124	Fair Bluff 115kV Fair Bluff	Distribution	Unattended	115.00	24.00		7	1				
125	Fairmont 115kV Fairmont	Distribution	Unattended	115.00	23.00		40	1				
126	Fairview 115kV Fairview	Distribution	Unattended	115.00	12.00		30	1				
127	Falls 230kV	Distribution	Unattended	230.00	24.00		40	1				
128	Falls 230kV	Transmission	Unattended	230.00	115.00		600	2				
129	Farmville 230kV Farmville	Distribution	Unattended	230.00	12.00		25	1				
130	Fayetteville 230kV Fayetteville	Distribution	Unattended	115.00	24.00	13.20	25	3	1			
131	Fayetteville 230kV Fayetteville	Transmission	Unattended	230.00	115.00		600	2				
132	Fayetteville Slocomb 115kV Fayetteville	Distribution	Unattended	115.00	12.00		25	1				
133	Florence 230kV Florence	Distribution	Unattended	115.00	24.00		75	3				
134	Florence 230kV Florence	Transmission	Unattended	230.00	115.00		600	2				
135	Florence Burchs Crossroads 115kV Florence	Distribution	Unattended	115.00	23.00		40	1	1			
136	Florence Cashua 230kV	Distribution	Unattended	230.00	23.00		25	1				
137	Florence Ebenezer 230kV	Distribution	Unattended	230.00	24.00		25	1				
138	Florence Mars Bluff 115KV Florence	Distribution	Unattended	115.00	24.00		25	1				
139	Florence Mt Hope 115KV Florence	Distribution	Unattended	115.00	23.00		50	2				
140	Florence South 115kV Florence	Distribution	Unattended	115.00	24.00		50	3	1			
141	Florence West 230kV Florence	Distribution	Unattended	230.00	24.00		50	2				
142	Folkstone 230kV Holly Ridge	Transmission	Unattended	230.00	115.00		200	1				

143	Fort Bragg Longstreet Rd. 230KV Fayetteville	Distribution	Unattended	230.00	12.00		50	2				
144	Fort Bragg Main 230kV Fayetteville	Distribution	Unattended	230.00	23.00		25	1				
145	Fort Bragg Main 230kV Fayetteville	Distribution	Unattended	230.00	12.00		50	2				
146	Fort Bragg Woodruff Street 230kV Fayetteville	Transmission	Unattended	230.00	12.00		25	1				
147	Fort Bragg Woodruff Street 230kV Fayetteville	Transmission	Unattended	230.00	115.00		600	2				
148	Four Oaks 230kV Four Oaks	Transmission	Unattended	230.00	24.94		73	2				
149	Franklinton 115KV	Distribution	Unattended	115.00	24.00		25	1				
150	Franklinton Novo 115kV Franklinton	Transmission	Unattended	115.00	13.00	0.00	34	1				
151	Fremont 115kV Fremont	Distribution	Unattended	115.00	12.00		25	1				
152	Fuquay 230kV Fuquay Varina	Distribution	Unattended	230.00	23.00		50	2				
153	Fuquay Bells Lake 230kV Fuquay Varina	Distribution	Unattended	230.00	23.00		50	2				
154	Fuquay Wade Nash Road 115KV Fuquay Varina	Distribution	Unattended	115.00	24.00		40	2				
155	Garland 230kV Garland	Distribution	Unattended	230.00	23.00		15	3	1			
156	Garner 115kV Garner	Distribution	Unattended	115.00	24.00		50	2				
157	Garner I-40 230KV Raleigh	Distribution	Unattended	230.00	24.00		40	1				
158	Garner Panther Branch 230kV Garner	Distribution	Unattended	230.00	23.00		90	3				
159	Garner Rock Quarry 230KV Raleigh	Distribution	Unattended	230.00	24.00		45	1	0		0	0
160	Garner Tryon Hills 115kV Garner	Distribution	Unattended	115.00	24.00		40	1				
161	Garner White Oak 230kV Garner	Distribution	Unattended	230.00	24.00		90	2	0			
162	Global TransPark 115kV Snow Hill	Distribution	Unattended	115.00	23.00		13	3				
163	Godwin 115kV Godwin	Distribution	Unattended	115.00	23.00		23	1				
164	Goldsboro City 115kV Goldsboro	Distribution	Unattended	115.00	12.00		50	2				
165	Goldsboro Hemlock 115kV Goldsboro	Distribution	Unattended	115.00	12.00		25	1				
166	Goldsboro Langston 115kV Goldsboro	Transmission	Unattended	115.00	24.00		45	1				
167	Goldsboro Langston 115kV Goldsboro	Transmission	Unattended	115.00	24.94		45	1				
168	Goldsboro Weil 115KV Goldsboro	Distribution	Unattended	115.00	24.00		25	1				
169	Grantham 230kV	Distribution	Unattended	230.00	24.00		25	1				
170	Grants Creek 230KV	Distribution	Unattended	230.00	115.00		336	1				
171	Green Level 230KV Apex	Distribution	Unattended	230.00	24.00		80	2				
172	Grifton 115kV	Distribution	Unattended	115.00	23.00		25	1				
173	Hamlet 230kV Dobbins Heights	Distribution	Unattended	230.00	24.00		65	3				
174	Harlowe 230KV	Transmission	Unattended	230.00	115.00		336	1				
175	Hartsville 115kV	Distribution	Unattended	115.00	24.00		50	3	1			
176	Hartsville Segars Mill 230KV Hartsville	Distribution	Unattended	230.00	24.00		50	2				
177	Hartsville Sonoco 115kV Hartsville	Distribution	Unattended	115.00	14.00		50	2				
178	Havelock 230kV	Distribution	Unattended	115.00	24.00		56	2	0			
179	Havelock 230kV	Transmission	Unattended	230.00	115.00	13.80	536	2	0			
180	Hazelwood 115kV Waynesville	Distribution	Unattended	115.00	24.00		65	2				

181	Hemingway 115kV Hemingway	Distribution	Unattended	115.00	24.00		20	3				
182	Henderson 230kV Henderson	Transmission	Unattended	230.00	115.00	13.20	600	2				
183	Henderson 230kV Henderson	Distribution	Unattended	115.00	24.00		50	2				
184	Henderson East 230kV	Distribution	Unattended	230.00	24.00		50	3				
185	Henderson North 115kV Henderson	Distribution	Unattended	115.00	24.00		50	2				
186	Holly Ridge 115kV Holly Ridge	Distribution	Unattended	115.00	23.00		9	1				
187	Holly Springs 230kV Holly Springs	Distribution	Unattended	230.00	24.00		80	2				
188	Holly Springs Industrial 230kV Apex	Distribution	Unattended	230.00	24.00		40	1				
189	Holly Springs Utley Creek 230KV Holly Springs	Distribution	Unattended	230.00	24.00		28	1	0		0	0
190	Hope Mills Church St 115kV Hope Mills	Distribution	Unattended	115.00	23.00		25	1				
191	Hope Mills Rockfish Rd 230kV Hope Mills	Distribution	Unattended	230.00	24.00		73	2				
192	Jacksonville 230kV Jacksonville	Transmission	Unattended	230.00	115.00		600	2				
193	Jacksonville Blue Creek 115KV Jacksonville	Distribution	Unattended	115.00	24.00		40	1				
194	Jacksonville City 115kV Jacksonville	Distribution	Unattended	115.00	24.00		50	3	1			
195	Jacksonville Northwoods 115kV Jacksonville	Distribution	Unattended	115.00	23.00		50	2				
196	Jacksonville Tarawa 230kV Jacksonville	Distribution	Unattended	230.00	24.00		25	1				
197	Jefferson 115kV Jefferson	Distribution	Unattended	115.00	23.00		6	1				
198	Jonesboro 230kV Sanford	Distribution	Unattended	230.00	24.00		75	3				
199	Kenly 115KV Kenly	Distribution	Unattended	115.00	24.00		28	1	0			
200	Kings Bluff 115kV Sandyfield	Transmission	Unattended	115.00	24.94		14	1				
201	Kingstree 230kV Kingstree	Transmission	Unattended	230.00	115.00	13.80	150	1				
202	Kingstree 230kV Kingstree	Distribution	Unattended	115.00	24.00		25	1				
203	Kingstree North 230kV	Distribution	Unattended	230.00	24.00		65	2				
204	Kinston 115kV Kinston	Distribution	Unattended	115.00	24.00		50	2				
205	Kinston 115KV Kinston	Distribution	Unattended	115.00	12.00		100	4				
206	Kinston Dupont 230KV Grifton	Transmission	Unattended	230.00	115.00		300	1				
207	Knightdale 115kV Knightdale	Distribution	Unattended	115.00	25.00		69	4	1			
208	Knightdale Hodge Road 230KV Knightdale	Distribution	Unattended	230.00	24.00		40	1	0			
209	Knightdale Hodge Road 230KV Knightdale	Distribution	Unattended	115.00	24.00	0.00	0	0	0			
210	Knightdale Square D 230kV Knightdale	Distribution	Unattended	230.00	24.00		25	1				
211	Kornegay 115kV	Distribution	Unattended	115.00	24.00		28	1	0			
212	LaGrange 115kV La Grange	Distribution	Unattended	115.00	12.00		25	1				
213	Lake City 230kV	Distribution	Unattended	230.00	24.00		30	3	1			
214	Lake Junaluska 115kV LK Junaluska	Distribution	Unattended	115.00	24.00		65	2				
215	Lake Waccamaw 115KV Lake Waccamaw	Distribution	Unattended	115.00	24.00		25	1				
216	Lakestone 115kV Raleigh	Transmission	Unattended	115.00	13.00		67	2				
217	Lakeview 115kv Carthage	Distribution	Unattended	115.00	24.00		40	1				
218	Laurel Hill 230kV Laurel Hill	Distribution	Unattended	230.00	23.00		50	2				
219	Laurinburg 230kV	Transmission	Unattended	230.00	115.00	13.80	400	2				

220	Laurinburg 230kV	Distribution	Unattended	115.00	24.00		50	2				
221	Laurinburg City 230kV Laurinburg	Distribution	Unattended	230.00	23.00		50	2				
222	Lee 230kV	Transmission	Unattended	230.00	115.00		600	2				
223	Lee 230kV	Transmission	Unattended	115.00	13.80		13	3				
224	Lee Combined Cycle Plant	Transmission	Attended	230.00	115.00							
225	Leesville Wood Valley 230kV Raleigh	Distribution	Unattended	230.00	24.00		90	3				
226	Leicester 115kV Leicester	Distribution	Unattended	115.00	24.00		50	2				
227	Leland 115kV Leland	Distribution	Unattended	115.00	24.00		25	1				
228	Leland Industrial 115kV leland	Distribution	Unattended	115.00	24.00		50	2				
229	Liberty 115kV Liberty	Distribution	Unattended	115.00	23.00		25	1				
230	Lillington 115kV Lillington	Distribution	Unattended	115.00	24.00		50	2				
231	Linden 230KV Erwin	Transmission	Unattended	230.00	24.00		28	1				
232	Littleton 115kV	Distribution	Unattended	115.00	24.00		25	1				
233	Louisburg 115kV Louisburg	Transmission	Unattended	115.00	24.00		45	1				
234	Lumberton 115KV Lumberton	Distribution	Unattended	115.00	24.00		25	1				
235	Maggie Valley 115kV Maggie Valley	Distribution	Unattended	115.00	24.00		40	1				
236	Manning 115kV Manning	Distribution	Unattended	115.00	24.00		25	1				
237	Marion 230kv	Distribution	Unattended	115.00	24.00	12.00	25	1				
238	Marion 230kv	Transmission	Unattended	230.00	115.00	13.80	400	2				
239	Marion Bypass 115kV Marion	Distribution	Unattended	115.00	23.00		50	3	1			
240	Marshall H E Plant	Distribution	Unattended	115.00	23.00		6	1				
241	Marshall H E Plant	Transmission	Unattended	23.00	4.00		6	1				
242	Masonboro 230kV Wilmington	Distribution	Unattended	230.00	23.00		75	3				
243	Maxton 115kV Maxton	Distribution	Unattended	115.00	24.00		25	1				
244	Maxton Airport 115kV Maxton	Distribution	Unattended	115.00	23.00		25	1				
245	McColl 230kV McColl	Distribution	Unattended	230.00	24.00		25	1				
246	Method 230kV Raleigh	Transmission	Unattended	115.00	12.47		56	2				
247	Method 230kV Raleigh	Transmission	Unattended	230.00	115.00	13.80	336	1				
248	Micaville 115kV Micaville	Distribution	Unattended	115.00	12.00		13	1	1			
249	Milburnie 230kV Raleigh	Distribution	Unattended	115.00	23.00		50	3	1			
250	Milburnie 230kV Raleigh	Transmission	Unattended	230.00	115.00	13.80	600	2				
251	Moncure 115kV Moncure	Transmission	Unattended	115.00	12.47		28	1				
252	Monte Vista 115kV Candler	Distribution	Unattended	115.00	23.00		80	2				
253	Mordecai 115kV Raleigh	Transmission	Unattended	115.00	13.09		67	2	0			
254	Morehead 115kV Morehead City	Distribution	Unattended	115.00	13.00		67	2	0			
255	Morehead Wildwood 230kV	Distribution	Unattended	115.00	24.00		25	1				
256	Morehead Wildwood 230kV	Transmission	Unattended	230.00	115.00		300	1				
257	Morrisville 230kV Morrisville	Distribution	Unattended	230.00	23.00		50	2				
258	Mt Gilead 115kV Mount Gilead	Distribution	Unattended	115.00	12.00		19	3				
259	Mt Gilead Industrial 115kV Mt Gilead	Distribution	Unattended	115.00	13.00		25	1				

260	Mt Olive 115kV Mount Olive	Distribution	Unattended	115.00	12.00		25	1				
261	Mt Olive 230kV Mt Olive	Transmission	Unattended	230.00	115.00		200	1				
262	Mt Olive West 115kV Mt Olive	Distribution	Unattended	115.00	24.00		25	1				
263	Mullins 115kV Mullins	Distribution	Unattended	115.00	24.00		50	2				
264	Murraysville 230KV Wilmington	Distribution	Unattended	230.00	23.00		40	1				
265	Nagel (APCO) 500kV Hawkins, Tn.	Transmission	Unattended	500.00	230.00	13.80	0	0	1			
266	Nashville 115kV Nashville	Transmission	Unattended	115.00	24.94		26	3	1			
267	Neuse 115kV Raleigh	Distribution	Unattended	115.00	23.00		50	2				
268	New Bern 230kV New Bern	Transmission	Unattended	230.00	115.00	13.20	400	2				
269	New Bern Amital S B Power Tool Co 115KV New Bern	Distribution	Unattended	115.00	12.00		25	1				
270	New Bern West 230kV New Bern	Distribution	Unattended	230.00	23.00		50	2				
271	New Hill 230kV New Hill	Distribution	Unattended	230.00	23.00		25	1				
272	New Hope 115kV Goldsboro	Distribution	Unattended	115.00	23.00		50	3	1			
273	New Salem 115kV Swannanoa	Distribution	Unattended	115.00	12.00		30	1				
274	Newport 115kV Newport	Distribution	Unattended	115.00	23.00		25	1				
275	Newton Grove 230kV Newton Grove	Distribution	Unattended	230.00	23.00		25	1				
276	Nichols 115kV Nichols	Distribution	Unattended	115.00	24.00		15	3				
277	North River 115kV Beaufort	Distribution	Unattended	115.00	34.50		50	2			3	1
278	Olanta 230kV	Distribution	Unattended	230.00	24.00		25	1				
279	Oteen 115kV Asheville	Distribution	Unattended	115.00	12.00		50	3	1			
280	Oxford North 230kV	Distribution	Unattended	230.00	24.00		50	2	0			
281	Oxford South 230kV	Distribution	Unattended	230.00	24.00		50	2	0			
282	Pageland 115kV Pageland	Distribution	Unattended	115.00	24.00		25	1				
283	Pamplico 115kV Pamplico	Distribution	Unattended	115.00	24.00		25	1				
284	Pembroke 115kV Pembroke	Distribution	Unattended	115.00	23.00		40	1				
285	Person 500kV	Transmission	Unattended	500.00	230.00	13.80	1000	3	1			
286	Person 500kV	Distribution	Unattended	230 00	24.00		25	1				
287	Pine Lake 230kV Raleigh	Transmission	Unattended	230.00	24.94		73	3				
288	Pinehurst 115kV Taylortown	Distribution	Unattended	115.00	24.00		80	2				
289	Pittsboro 230kV Pittsboro	Transmission	Unattended	230.00	24.00	0.00	45	1				
290	Powhatan Industrial 230KV Clayton	Distribution	Unattended	230.00	24.00		24	1				
291	Princeton 115kV	Distribution	Unattended	115.00	24.00		24	1				
292	Raeford 115kV Raeford	Distribution	Unattended	115.00	13.00		62	2	0			
293	Raeford 230kV Raeford	Transmission	Unattended	230.00	115.00		896	3	0			
294	Raeford South 115kV Raeford	Distribution	Unattended	115.00	12.00		15	3				
295	Raleigh 115kV Raleigh	Distribution	Unattended	115.00	12.00		50	2				
296	Raleigh Atlantic Avenue 115kV Raleigh	Distribution	Unattended	115.00	23.00		25	1				
297	Raleigh Blue Ridge 230kV Raleigh	Distribution	Unattended	230.00	23.00		50	2				
298	Raleigh Brier Creek 230kV Raleigh	Distribution	Unattended	230.00	24.00		80	2				
299	Raleigh Durham Airport 230KV Morrisville	Distribution	Unattended	230.00	23.00		50	2				

300	Raleigh East Street 230kV Raleigh	Distribution	Unattended	230.00	12.00		80	2				
301	Raleigh Foxcroft 230kV Raleigh	Distribution	Unattended	230.00	24.00		40	1				
302	Raleigh Harrington Street 115kV Raleigh	Distribution	Unattended	115.00	13.20		60	2				
303	Raleigh Homestead 230kV Raleigh	Distribution	Unattended	230.00	24.00		80	2				
304	Raleigh Honeycutt 230kV	Distribution	Unattended	230.00	24.00		40	1				
305	Raleigh Leesville Road 230kV Raleigh	Distribution	Unattended	230.00	24.00		90	3				
306	Raleigh NCSU Sullivan 115 (CUST)	Transmission	Unattended	115.00	12.17		37	2	1			
307	Raleigh Northside 115KV Raleigh	Distribution	Unattended	115.00	12.00		50	2				
308	Raleigh Oakdale 230kV Raleigh	Distribution	Unattended	230.00	23.00		50	2				
309	Raleigh Prison Farm 230kV Raleigh	Distribution	Unattended	230.00	24.00		50	2				
310	Raleigh Six Forks 230kV Raleigh	Distribution	Unattended	230.00	24.00		56	2				
311	Raleigh South 115kV Raleigh	Distribution	Unattended	115.00	23.00		50	2				
312	Raleigh Timberlake 115kV Raleigh	Distribution	Unattended	115.00	23.00		50	2				
313	Raleigh Worthdale 230kV Raleigh	Distribution	Unattended	230.00	23.00		50	2				
314	Raleigh Yonkers Road 115kV Raleigh	Distribution	Unattended	115.00	23.00		40	1				
315	Ramseur 115kV Ramseur	Transmission	Unattended	115.00	69.00	12.00	53	3	2		1	2
316	Ramseur 115kV Ramseur	Distribution	Unattended	115.00	24.00		40	1				
317	Red Springs 115kV Red Springs	Distribution	Unattended	115.00	23.00		25	1				
318	Reynolds 115kV	Distribution	Unattended	115.00	12.00		30	1				
319	Rhems 230kV Pollocksville	Distribution	Unattended	230.00	24.00		40	1				
320	Rhems 230kV Pollocksville	Distribution	Unattended	115.00	24.00		40	1				
321	Richmond 500kV	Transmission	Unattended	500.00	230.00	13.80	1500	6	1			
322	Richmond County Plant	Transmission	Attended	230.00	13.80	0.00	67	2				
323	Robbins 115kV Robbins	Distribution	Unattended	115.00	24.00		25	1				
324	Robinson S. E. Plant	Transmission	Attended	230.00	115.00	14.00	672	2				
325	Rockingham 230kV	Transmission	Unattended	230.00	115.00	13.80	550	2		230Kv Phase Angle	2	1,080
326	Rockingham 230kV	Distribution	Unattended	115.00	23.00		50	3	1			
327	Rockingham Aberdeen Road 230kV Rockingham	Distribution	Unattended	230.00	23.00		25	1				
328	Rockingham West 115kV Rockingham	Distribution	Unattended	115.00	24.00		75	4	1			
329	Rocky Mount 230kV Rocky Mount	Distribution	Unattended	115.00	24.00		25	1				
330	Rocky Mount 230kV Rocky Mount	Transmission	Unattended	230.00	69.00	13.20	300	2				
331	Rocky Mount 230kV Rocky Mount	Transmission	Unattended	230.00	115.00	13.80	400	2				
332	Rocky Point 230KV Rocky Point	Distribution	Unattended	230.00	24.00		25	1				
333	Rolesville 230kV Rolesville	Distribution	Unattended	230.00	24.00		80	2				
334	Rose Hill 230kV Rose Hill	Distribution	Unattended	230.00	24.00		25	1				
335	Roseboro 115kV Roseboro	Distribution	Unattended	115.00	23.00		25	1				
336	Rosewood 115kV Goldsboro	Distribution	Unattended	115.00	24.00		40	1				
337	Rowland 230kV	Distribution	Unattended	230.00	24.00		13	1				
338	Roxboro 115kV Roxboro	Distribution	Unattended	115.00	24.00		50	3	1			

339	Roxboro 115kV Roxboro	Transmission	Unattended	115.00	24.00		60	1				
340	Roxboro Bowmantown Road 230kV Roxboro	Distribution	Unattended	230.00	23.00		25	1				
341	Roxboro Old Durham Road 230KV Roxboro	Distribution	Unattended	230.00	24.00	0.00	90	2	0			
342	Roxboro S. E. Plant	Transmission	Attended	230.00	25.00		795	3	2			
343	Roxboro S. E. Plant	Transmission	Unattended	115.00	4.00		45	1				
344	Roxboro S.E. Plant (Cooling Tower)	Transmission	Attended	230.00	4.00		45	2				
345	Roxboro South 230kV Roxboro	Distribution	Unattended	230.00	24.00		0	0	0			
346	RTP 230KV Morrisville	Transmission	Unattended	230.00	24.00		90	2	0			
347	Samaria 115kV	Distribution	Unattended	115.00	24.00		40	1				
348	Sanford Deep River 230kV Sanford	Distribution	Unattended	230.00	24.00		65	2				
349	Sanford Garden St 230kV Sanford	Distribution	Unattended	230.00	23.00		50	2				
350	Sanford Horner Blvd 230kV Sanford	Distribution	Unattended	230.00	24.00		50	2				
351	Sanford U. S. #1 230KV Sanford	Distribution	Unattended	230.00	24.00		50	2		23/12Kv Step-Down	4	5
352	Sapona C. M. #2 69KV Franklinville	Distribution	Unattended	69.00	0.60		4	3				
353	Sardis 230kV	Distribution	Unattended	230.00	24.00		40	1				
354	Scotts Hill 230kV	Distribution	Unattended	230.00	24.00		65	2				
355	Seagrove 115kV Seagrove	Distribution	Unattended	115.00	12.00		13	1				
356	Selma 230kV Selma	Distribution	Unattended	115.00	12.00		19	3	1			
357	Selma 230kV Selma	Distribution	Unattended	115.00	24.00	13.20	50	2				
358	Selma 230kV Selma	Transmission	Unattended	230.00	115.00		200	1				
359	Seymour Johnson 115kV Goldsboro	Distribution	Unattended	115.00	12.00		31	3	1			
360	Shannon 115kV Shannon	Distribution	Unattended	115.00	23.00		25	1				
361	Shaw Field 115kV Sumter	Distribution	Unattended	115.00	12.00		50	3	1	12/23kV Step-Up	1	25
362	Shearon Harris S. E. Plant	Transmission	Attended	230.00	21.50		1008	3				
363	Siler City 115KV Siler City	Distribution	Unattended	115.00	24.00		50	3	1			
364	Siler City 230kV Siler City	Transmission	Unattended	230.00	115.00	13.80	200	1				
365	Siler City Hwy 64E 230kV Siler City	Distribution	Unattended	230.00	24.00		25	1				
366	Skyland 115kv Skyland	Transmission	Unattended	115.00	24.00	0.00	90	2				
367	Smithfield 115kV Smithfield	Distribution	Unattended	115.00	12.00		50	3	1			
368	Snow Hill 115kV Snow Hill	Transmission	Unattended	115.00	24.00		28	1				
369	Society Hill 230kV Society Hill	Distribution	Unattended	230.00	24.00		25	1				
370	Southern Pines 115kV Southern Pnes	Distribution	Unattended	115.00	23.00		50	2				
371	Southern Pines Center Park 115KV Southern Pines	Distribution	Unattended	115.00	24.00		101	3	0			
372	Southport 230kV Southport	Distribution	Unattended	230.00	23.00		50	2				
373	Spring Hope 115kV Spring Hope	Distribution	Unattended	115.00	23.00		25	1				
374	Spring Lake 230kV Spring Lake	Distribution	Unattended	230.00	24.00		40	1				
375	Spruce Pine 115kV Spruce Pine	Distribution	Unattended	115.00	23.00		50	3	1			
376	St Pauls 115kV St Pauls	Distribution	Unattended	115.00	23.00		25	1				

377	Stallings Crossroads 115kV Louisburg	Distribution	Unattended	115.00	23.00		25	1				
378	Summerton 230kV Summerton	Distribution	Unattended	230.00	24.00		25	1				
379	Sumter 230kV	Distribution	Unattended	115.00	23.00		75	3				
380	Sumter 230kV	Transmission	Unattended	230.00	115.00	13.80	600	2				
381	Sumter Alice Drive 230kV Sumter	Distribution	Unattended	230.00	23.00		25	1				
382	Sumter Industrial 115KV Sumter	Distribution	Unattended	115.00	23.00		50	3	1			
383	Sumter North 230kV Sumter	Distribution	Unattended	230.00	24.00		50	2				
384	Sumter Wedgefield Rd. 230KV Sumter	Distribution	Unattended	230.00	24.00		50	2				
385	Sutton S. E. Plant Wilmington	Transmission	Attended	115.00	16.50		290	1				
386	Sutton S. E. Plant Wilmington	Transmission	Attended	230.00	23.50		740	2				
387	Swannanoa 115kV Black Mountain	Transmission	Unattended	115.00	12.47		28	1				
388	Swannanoa 115kV Black Mountain	Transmission	Unattended	115.00	13.00		34	1				
389	Swansboro 230kV Maysville	Distribution	Unattended	115.00	23.00		50	2				
390	Tillery H. E. Plant	Transmission	Attended	115.00	13.20		110	4				
391	Topsail 230kV	Distribution	Unattended	115.00	23.00		40	1				
392	Tri-Towns 115KV (CUST)	Transmission	Unattended	115.00	24.94		0	0	1			
393	Troy 115kV Troy	Distribution	Unattended	115.00	12.00		25	2				
394	Troy Burnette St. 115kV Troy	Distribution	Unattended	115.00	12.00		30	1				
395	Vanceboro West Craven 115KV	Distribution	Unattended	115.00	24.00		28	1				
396	Vander 115kV	Transmission	Unattended	115.00	24.00		25	1				
397	Vander DAK 115KV	Distribution	Unattended	115.00	12.00		50	2				
398	Vander DAK/Dupont-TeiJin/Praxair 115KV	Distribution	Unattended	115.00	12.00		48	2				
399	Vanderbilt 115kV Asheville	Distribution	Unattended	115.00	12.00		50	2				
400	Vista 115KV Hampstead	Distribution	Unattended	115.00	24.00		40	1				
401	Wadesboro 230KV Wadesboro	Distribution	Unattended	230.00	24.00		50	2				
402	Wadesboro Bowman School 230KV Wadesboro	Distribution	Unattended	230.00	24.00		25	1				
403	Wake 500kV	Transmission	Unattended	115.00	0.00	0.00	25	1				
404	Wake 500kV	Transmission	Unattended	230.00	0.00	0.00	25	1				
405	Wake 500kV	Transmission	Unattended	500.00	230.00	0.00	2238	6	1			
406	Wake Forest 115kV Wake Forest	Transmission	Unattended	115.00	69.00	13.20	0	0	0			
407	Wake Tech 230kV Raleigh	Distribution	Unattended	230.00	24.00		40	1				
408	Wallace 115kV	Transmission	Unattended	115.00	69.00	13.20	80	3	1			
409	Wallace 115kV	Distribution	Unattended	115.00	24.00		50	2	1			
410	Wallace 230kV Wallace	Transmission	Unattended	230.00	115.00	13.80	150	1				
411	Walters H E Plant	Transmission	Attended	161.00	115.00	13.80	336	1				
412	Walters H E Plant	Distribution	Attended	115.00	12.00		5	3				
413	Walters H E Plant	Transmission	Attended	115.00	12.00		150	3	1			
414	Walters H E Plant	Transmission	Attended	138.00	115.00	8.60	100	1				
415	Warrenton 115kV Warrenton	Distribution	Unattended	115.00	24.00		50	2				
416	Warsaw 230kV Warsaw	Distribution	Unattended	230.00	24.00		50	2				

417	Wayne County Plant	Transmission	Attended	230.00	18.00		1186	7				
418	Waynesville 115kV Waynesville	Distribution	Unattended	115.00	12.00		20	3	1			
419	Weatherspoon 230kV	Transmission	Unattended	230.00	24.00		56	2				
420	Weatherspoon S. E. Plant Lumberton	Transmission	Attended	230.00	115.00	0.00	448	2				
421	Weaverville 115kV Weaverville	Distribution	Unattended	115.00	12.00		30	1				
422	Wendell 230kV Wendell	Distribution	Unattended	230.00	23.00		50	2				
423	West Asheville 115kV Asheville	Distribution	Unattended	115.00	12.00		50	3	1			
424	West End 230kV	Distribution	Unattended	230.00	24.00		50	2				
425	West End 230kV	Transmission	Unattended	230.00	115.00	13.80	600	2		Mb.Sp. (230/23kV)	1	25
426	Whiteville 230kV Whiteville	Transmission	Unattended	230.00	115.00	13.80	300	1				
427	Whiteville-Southeast Regional Park 115KV Whiteville	Distribution	Unattended	115.00	24.00		25	1				
428	Wilmington Cedar Ave 230kV Wilmington	Distribution	Unattended	230.00	23.00		50	2				
429	Wilmington East 230kV Wilmington	Distribution	Unattended	230.00	24.00		50	2				
430	Wilmington Invista 230KV Wilmington	Distribution	Unattended	230.00	12.00		50	2				
431	Wilmington Ninth and Orange 230KV Wilmington	Distribution	Unattended	230.00	24.00		50	2				
432	Wilmington Ogden 230kV Wilmington	Distribution	Unattended	230.00	23.00		100	4				
433	Wilmington River Road 115KV Wilmington	Distribution	Unattended	115.00	24.00		90	2				
434	Wilmington Sunset Park 115KV Wilmington	Distribution	Unattended	115.00	24.00		90	2				
435	Wilmington Winter Park 230KV Wilmington	Distribution	Unattended	230.00	23.00		90	3				
436	Wilson 230kV Wilson	Transmission	Unattended	230.00	115.00	13.80	336	1				
437	Wilson Mills 230KV Wilson's MILLS	Distribution	Unattended	230.00	24.00		40	1				
438	Wommack 230kV Kinston	Transmission	Unattended	230.00	115.00	13.80	400	2				
439	Wrightsville Beach 230kV Wilmington	Distribution	Unattended	230.00	24.00		100	4				
440	Yanceyville 230kV Yancyville	Distribution	Unattended	230.00	12.00		25	1				
441	Youngsville 115kV	Distribution	Unattended	115.00	24.00		40	1				
442	Zebulon 115kV Zebulon	Transmission	Unattended	115.00	69.00		50	3	1			
443	Zebulon 115kV Zebulon	Distribution	Unattended	115.00	24.00		50	2				
444	Zebulon 230kV	Transmission	Unattended	115.00	69.00		56	1				
445	Zebulon 230kV	Transmission	Unattended	230.00	115.00		336	1				
446	TOTAL Transmission Substations						39101	220	21	—	4	1,107
447	TOTAL Distribution Substations						14223	578	34	—	15	102
448	TOTAL Generation Substations									—		
449	TOTAL						53324	798	55	—	19	1,209

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ 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 Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	[a] Services provided by Duke Energy Business Services	Duke Energy Business Services, LLC	Various	608,750,392
3	Customer and Market Services	Duke Energy Carolinas, LLC	Various	60,245,885
4	Generation Services	Duke Energy Carolinas, LLC	Various	346,429,479
5	Other Goods and Services	Duke Energy Carolinas, LLC	Various	63,293,204
6	Transmission and Distribution Services	Duke Energy Carolinas, LLC	Various	40,236,939
7	Customer and Market Services	Duke Energy Florida, LLC	Various	2,081,315
8	Generation Services	Duke Energy Florida, LLC	Various	222,971
9	Other Goods and Services	Duke Energy Florida, LLC	Various	47,182
10	Transmission and Distribution Services	Duke Energy Florida, LLC	Various	(661,596)
11	Customer and Market Services	Duke Energy Indiana, LLC	Various	95,750
12	Generation Services	Duke Energy Indiana, LLC	Various	149,368
13	Other Goods and Services	Duke Energy Indiana, LLC	Various	77,494
14	Transmission and Distribution Services	Duke Energy Indiana, LLC	Various	4,468
15	Gas Distribution Services	Piedmont Natural Gas Company, Inc.	Various	75,026,174
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Non-power Goods or Services Provided for Affiliate			
22	Customer and Market Services	Duke Energy Carolinas, LLC	Various	4,430,464
23	Generation Services	Duke Energy Carolinas, LLC	Various	13,829,856
24	Other Goods and Services	Duke Energy Carolinas, LLC	Various	4,166,647
25	Transmission and Distribution Services	Duke Energy Carolinas, LLC	Various	21,628,977
26	Customer and Market Services	Duke Energy Florida, LLC	Various	1,776,240
27	Generation Services	Duke Energy Florida, LLC	Various	1,162,799
28	Other Goods and Services	Duke Energy Florida, LLC	Various	1,544,699
29	Transmission and Distribution Services	Duke Energy Florida, LLC	Various	3,216,421
30	Customer and Market Services	Duke Energy Indiana, LLC	Various	1,050,596
31	Generation Services	Duke Energy Indiana, LLC	Various	584,699
32	Other Goods and Services	Duke Energy Indiana, LLC	Various	301,413
33	Transmission and Distribution Services	Duke Energy Indiana, LLC	Various	1,972,290
34	Customer and Market Services	Duke Energy Kentucky, Inc.	Various	142,367
35	Generation Services	Duke Energy Kentucky, Inc.	Various	137,937

36	Other Goods and Services	Duke Energy Kentucky, Inc.	Various	162,637
37	Transmission and Distribution Services	Duke Energy Kentucky, Inc.	Various	127,702
38	Customer and Market Services	Duke Energy Ohio, Inc.	Various	613,941
39	Generation Services	Duke Energy Ohio, Inc.	Various	8,898
40	Other Goods and Services	Duke Energy Ohio, Inc.	Various	31,788
41	Transmission and Distribution Services	Duke Energy Ohio, Inc.	Various	862,461
42	Customer and Market Services	Cinergy Solutions-Utility, Inc	Various	2,173,718
43	Transmission and Distribution Services	Cinergy Solutions-Utility, Inc	Various	46,670
44	Customer and Market Services	Piedmont Natural Gas	Various	356,750
45	Generation Services	Piedmont Natural Gas	Various	17,108
46	Other Goods and Services	Piedmont Natural Gas	Various	5,140
47	Transmission and Distribution Services	Piedmont Natural Gas	Various	2,186
42	[illegible]	[illegible]	[illegible]	[illegible]

Name of Respondent: Duke Energy Progress, LLC	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/15/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

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