NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

October 21, 2021

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-2, Sub 1272, Application Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities

Dear Ms. Dunston:

Attached for filing is the Public Staff's Proposed Order in the above-referenced docket. By copy of this letter, I am forwarding a copy to all parties of record by electronic delivery.

Sincerely,

Electronically submitted
s/John D. Little
Staff Attorney
john.little@psncuc.nc.gov

s/William E. H. Creech
Staff Attorney
zeke.creech@psncuc.nc.gov

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1272

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC Pursuant to N.C. Gen. Stat. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	**PUBLIC STAFF'S PROPOSED ORDER APPROVING FUEL CHARGE ADJUSTMENT**

HEARD: Tuesday, September 21, 2021, at 10:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina (Public Witness Hearing, Hearing Examiner Erin Duffy, Presiding)

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

APPEARANCES: No appearances

BY THE COMMISSION: On June 15, 2021, Duke Energy Progress, LLC (Duke Energy Progress, DEP, or the Company), filed an application pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony, exhibits, and workpapers of Dana M. Harrington, and the testimony and exhibits of Kenneth D. Church, John A. Verderame, Ben Waldrep, and Bryan P. Walsh.

Petitions to intervene were filed by North Carolina Sustainable Energy Association (NCSEA) on June 25, 2021, by Carolina Utility Customers Association, Inc. (CUCA) on July 6, 2021, by Carolina Industrial Group for Fair Utility Rates II (CIGFUR) on July 8, 2021, and by Sierra Club on July 26, 2021. The Commission granted NCSEA's petition to intervene on June 28, 2021, CUCA's petition to intervene on July 7, 2021, CIGFUR's petition to intervene on July 9, 2021, and Sierra Club's petition to intervene on July 28, 2021.

On July 7, 2021, the Commission entered an *Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice*. That order provided that direct testimony of intervenors should be filed on or before August 31, 2021, that rebuttal testimony should be filed on or before September 9, 2021, and that a hearing on this matter would be held on September 21, 2021. On August 30, 2021, the Commission entered an *Order Requiring Second Public Notice*. On September 20, 2021, and September 24, 2021, DEP filed affidavits of publication indicating that public notices had been provided in accordance with the Commission's procedural orders issued on July 7, 2021, and August 30, 2021. Subsequent affidavits of publication were file on September 20, 2021, and September 24, 2021.

On August 31, 2021, the Commission issued an *Order Changing Expert Witness Hearings to be Remotely Held and Setting Procedures*. All parties consented to remote hearings. On September 17, 2021, the Commission issued an *Order Changing Start Time of Expert Witness Hearing*. The date and time for the public hearing was not changed.

On August 27, 2021, DEP filed the supplemental testimony and revised exhibits and workpapers of Dana M. Harrington.

The intervention of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). On August 31, 2021, the Public Staff filed the direct testimony and exhibits of Evan D. Lawrence and the affidavit of Michelle M. Boswell, in accordance with N.C.G.S. § 62-68.

On August 31, 2021, Sierra Club filed the direct testimony and exhibit of Devi Glick.

On September 9, 2021, DEP filed the joint rebuttal testimony of John D. Swez and John A. Verderame.

On September 16, 2021, DEP and the Public Staff filed a joint motion requesting that the Commission excuse DEP's witnesses Kenneth D. Church, Dana M. Harrington, and Ben Waldrep, and Public Staff's witness Evan D. Lawrence and affiant Michelle M. Boswell from appearing at the September 21, 2021 evidentiary hearing. The joint motion requested that the Commission accept the expert witnesses' testimony, affidavit, and exhibits into the record and represented that all parties to the proceeding had agreed to waive cross-examination of DEP's witnesses and the Public Staff's witness and affiant listed in the Motion. On September 17, 2021, DEP and the Sierra Club filed another joint motion waiving cross examination and requesting that the Commission also excuse DEP witnesses John A. Verderame and John D. Swez and Sierra Club witness Devi Glick from appearing at the September 21, 2021 hearing, representing that all parties consented to the motion and asking that the expert testimony and exhibits of these witnesses be entered into the record. On

September 20, 2021, the Commission granted both joint motions, excusing all expert witnesses from appearing at the evidentiary hearing, and canceling the expert witness hearing, and the Order also required the parties to file proposed orders, or a joint proposed order, on or before October 21, 2021, and briefs, if desired, by the same date.

On September 21, 2021, DEP and the Sierra Club filed a joint letter with the Commission in which the Sierra Club withdrew its request for a disallowance of $1.4 million in fuel expenses and DEP agreed to provide additional information to the Sierra Club in future fuel clause proceedings upon request. DEP and the Sierra Club requested that the letter be entered into the record in this proceeding and that request be granted by the Commission as part of this Order.

The expert phase of this hearing having been cancelled by order of the Commission, the public portion of the hearing was called to order as scheduled on September 21, 2021. No public witnesses appeared at the hearing. The Public Staff and DEP each filed a proposed order on October 21, 2021.

Based upon the Company's verified application, direct testimony, supplemental testimony, rebuttal testimony, and exhibits received into evidence at the hearing, the testimony, affidavit, and exhibits of the Public Staff, the testimony and exhibit of Sierra Club, and the joint letter of DEP and the Sierra Club, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Progress is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Progress is lawfully before the Commission based upon its application filed pursuant to N.C.G. S. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended March 31, 2021 (test period).

3. In its application and testimony in this proceeding, DEP requested a total decrease of $3.1 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEP included Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost under-recoveries experienced during the test period of $75 million.

4. In its direct supplemental testimony and exhibits in this proceeding, DEP updated its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee, to an increase of $34.9 million, which included an updated under-recovered EMF of $113.1 million. This balance includes the under-recovered balance of $38.1 million, incurred during the months of April through June of 2021, which was included in the EMF balance within the update period in the current fuel cost rider proceeding.

5. The Company's generation units were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

6. The Company’s fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

7. The test period per book system sales are 59,917,347 megawatt-hours (“MWh”). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 68,264,626 MWh and is categorized as follows:

Net Generation Type	MWh
Nuclear	29,445,201
Natural Gas, Oil, and Biogas	21,183,771
Coal	7,475,010
Hydro – Conventional	919,344
Solar	243,635
Purchased Power	
– subject to economic dispatch or curtailment	2,720,623
Other Purchased Power	6,277,042
Total Net Generation (may not add to sum due to rounding)	68,264,626

8. The appropriate nuclear capacity factor for use in this proceeding is 93.21%.

9. The North Carolina retail test period sales, adjusted for weather and customer growth, for use in calculating the EMF are 37,898,465 MWh. The normalized test period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Normalized Test Period MWh Sales
Residential	16,764,534
Small General Service	1,891,247
Medium General Service	10,497,319
Large General Service	8,403,471
Lighting	341,894
Total (may not add to sum due to rounding)	37,898,465

10. The projected billing period (December 2021-November 2022) sales for use in this proceeding are 61,963,546 MWh on a system basis and 38,341,063 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected Billing Period MWh Sales
Residential	16,610,751
Small General Service	1,792,730
Medium General Service	10,332,062
Large General Service	9,225,261
Lighting	380,260
Total (may not add to sum due to rounding)	38,341,063

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 69,850,902 MWh and is categorized as follows:

Generation Type	MWh
Nuclear	29,337,015
Gas Combustion Turbine (CT) and Combined Cycle (CC)	21,918,020
Coal	7,518,351
Hydro	647,824
Solar	265,105
Purchased Power	10,164,587
Total (may not add to sum due to rounding)	69,850,902

12. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

A. The total nuclear fuel price is $5.87/MWh.

B. The gas CT and CC fuel price is $25.02/MWh.

C. The coal fuel price is $27.22/MWh.

D. The appropriate expense for ammonia, lime, limestone, urea, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $15,852,947.

E. The appropriate net gains or losses on the sale of byproducts (collectively, Byproducts) is losses of $18,313,021.

F. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared and the impact of House Bill 589, N.C. Sess. L. 2017-192) is $456,960,876.

G. System fuel expense recovered through intersystem sales is $118,111,645.

13. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $807,419,658.

14. The Company’s appropriate North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF is $113,060,434, consisting of under-recoveries of $41,096,455, $3,513,037, $24,639,071, $42,661,660, and $1,150,209, for the Residential, Small General

Service, Medium General Service, Large General Service, and Lighting classes, respectively.

15. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-2, Sub 1250 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

16. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 2.126¢/kilowatt-hour ("kWh") for the Residential class; 2.111¢/kWh for the Small General Service class; 2.169¢/kWh for the Medium General Service class; 2.019¢/kWh for the Large General Service class; and 1.682¢/kWh for the Lighting class.

17. The appropriate EMFs established in this proceeding, excluding the regulatory fee, are as follows: 0.245¢/kWh for the Residential class; 0.186¢/kWh for the Small General Service class; 0.235¢/kWh for the Medium General Service class; 0.508¢/kWh for the Large General Service class; and 0.336¢/kWh for the Lighting class.

18. The total net fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 2.371¢/kWh for the Residential class; 2.297¢/kWh for the Small General Service class; 2.404¢/kWh for the Medium General Service class; 2.527¢/kWh for the Large General Service class; and 2.018¢/kWh for the Lighting class.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

N.C.G.S. § 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending March 31 as the test period for DEP. The Company's filing in this proceeding was based on the 12 months ended March 31, 2021.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the Application, the direct testimony of Company witness Harrington, and the entire record in this proceeding. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the supplemental direct testimony of Company witness Harrington. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for these findings of fact is contained in the testimony of Company witnesses Waldrep and Walsh, Verderame and Swez, and the testimony of Public Staff witness Lawrence.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Waldrep testified that DEP's nuclear fleet consists of three generating stations and a total of four units. He testified that the Company's four nuclear units operated at a system average capacity factor of 93.55% during the test period. The Company's test period capacity factor exceeded the five-year industry weighted average capacity factor of 93.18% for the period 2015-2019 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Unit Statistical Brochure. The current test period included two refueling outages.

Company witness Walsh testified concerning the performance of DEP's fossil/hydro/solar assets. He stated that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor (EAF), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (*i.e.*, forced) outage time); (2) net capacity factor (NCF), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF *is* affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate (EFOR), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and (4) starting reliability (SR), which represents the percentage of successful starts. For 2021, the Company is including another measure to assess plant reliability, equivalent forced outage factor (EFOF), which quantifies the number of period hours in a year during which the unit is unavailable because of forced outages or forced deratings.

Witness Walsh presented the following chart, which shows operational results, categorized by generator type, as well as results from the most recently published NERC Generating Availability Brochure for the period 2015 through 2019:

Generator Type	*Measure*	*Review Period* *DEP Operational Results*	*2015-2019* *NERC Average*	*Nbr of Units*
Coal-Fired Test Period	EAF	61.6%	80.1%	188
	NCF	26.7%	55.7%	
	EFOF	10.2%	n/a	
Coal-Fired Summer Peak	EAF	75.6%	n/a	n/a
Total CC Average	EAF	79.1%	84.9%	350
	NCF	62.6%	54.8%	
	EFOR	3.9%	4.9%	
Total CT Average	EAF	83.6%	86.9%	746
	SR	99.3%	98.4%	
Hydro	EAF	70.2%	79.9%	1,060
Solar	NCF	19.7%	n/a	n/a

Company witness Walsh also testified that the Company, like other utilities across the United States, has experienced a change in the dispatch order for each type of generating facility due to continued favorable economics resulting from the lower pricing of natural gas.

Public Staff witness Lawrence testified that for the test year, the Company reported a single year system-wide nuclear capacity factor of 93.55%, which is greater than the North American Electric Reliability Corporation weighted average nuclear capacity factor of 93.18%. This met the benchmark of achieving an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities set forth in Commission Rule R8-55(k). Witness Lawrence stated that based on his investigation, he was not recommending any adjustments to the projected fuel prices or the calculation of the total fuel factor.

Witness Verderame stated DEP's average delivered cost of coal for the test period was $92.52 per ton, compared to $86.94 in the previous test period. This included an average transportation cost of $36.75 per ton, compared to $31.76 in the previous test period. Witness Verderame testified that the cost of delivered coal also included is $12.5 million in costs associated with the mitigation of coal contracts related to COVID-19 load losses. DEP's average price of gas was $3.76 per million British thermal units (MMBtu or MBtu), representing an increase of about one percent from the previous test period. DEP's coal burn for the test period was 3.4 million tons, a decrease of six percent, and the natural gas burn was 166.6 million MBtus, a decrease of five percent. Due to the pandemic, low natural gas prices, and mild winter weather, the Company experienced a shift in generation from coal to natural gas in the first half of the test period.

Sierra Club witness Glick addressed several issues in her testimony. Witness Glick stated the Commission should compare the level of fuel and other variable costs incurred at its coal plants to the cost to operate other units on the system. Witness Glick testified that, in the past, utilities operated coal-fired plants as baseload resources, but in recent years, low gas prices and nearly zero variable cost energy from renewable sources have made coal generation marginal on many systems. Witness Glick continued that committing coal plants to run, when there are lower cost resources on a Company's system, results in avoidable excess fuel costs, which should not be recovered.

Witness Glick initially recommended the Commission disallow $1.4 million in what witness Glick alleged to be excess fuel costs incurred at Mayo and

Roxboro, and recommended the Commission require DEP to provide more transparency and documentation on which costs it is using to determine commitment and dispatch of its resources.

The Commission notes that on September 21, 2021, DEP and the Sierra Club filed a letter with the Commission in which DEP agreed to provide certain information to the Sierra Club in future fuel proceedings and Sierra Club advised the Commission that it was withdrawing the recommendation of Sierra Club witness Glick for a $1.4 million disallowance of fuel-related expenses. The Commission notes that no other parties opposed the request and that both DEP and the Sierra Club requested that the September 21, 2012, letter be entered into evidence. The Commission concludes that the joint request should be granted, and the Commission approves the request as part of this order.

As a result of the withdrawal of the recommended disallowance, the Commission concludes that there is currently no party before the Commission seeking a disallowance.

The Commission concludes that the application, testimony, and supporting documents filed by DEP in this docket were in full compliance with the requirements of G.S. § 62-133.2 and Commission Rule R8-55. The Commission further notes that the filings made by the Company in this docket are also consistent with the filings made in recent fuel adjustment proceedings, and that neither the Commission nor any other party other than the Sierra Club have suggested or found them to be otherwise. The Commission is also persuaded by

DEP's explanation, that contrary to Sierra Club's assertion, DEP did provide contemporaneous unit cost information produced at the time of the Company's unit commitment decisions and further offered to meet with Sierra Club to answer any questions (an offer to which Sierra Club did not respond). Accordingly, the Commission concludes that DEP's filings in this matter meet all legal requirements, and the Sierra Club's recommendation that the existing procedures be altered are not accepted. It should also be mentioned that the arguments made by the Sierra Club regarding filing requirements are not new. The arguments repeat the same arguments made by the Sierra Club in the 2020 DEC and DEP fuel proceedings and in the recently concluded 2021 DEC fuel proceeding. The Sierra Club's arguments were rejected in those proceedings, and the Sierra Club has offered no additional information to the Commission to support a change. The Commission notes that, in the absence of any change in the underlying facts or law, it is not in the interest of regulatory efficiency for parties to raise arguments that have been previously rejected.

The Company has provided sufficient evidence concerning the prudence of DEP's operation of its baseload units. Accordingly, the Commission concludes that the Company managed its generating plants during the test period prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's revised fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in 2015, and were in effect throughout the 12 months ending March 31, 2021. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses Harrington, Church, Verderame, and Walsh.

Company witness Harrington testified that DEP's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEP's ability to maintain lower fuel and fuel-related rates. Other key factors include: DEP's diverse generating portfolio mix of nuclear, natural gas, coal, and hydro; the capacity factors of its nuclear fleet, the combination of DEP's and DEC's respective expertise in transporting, managing and blending fuels, procuring reagents, and utilizing purchasing synergies of the combined Company, as well as the joint dispatch of DEP's and DEC's generation resources.

Company witness Church testified that DEP's nuclear fuel procurement practices involve: computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Church explained that for uranium concentrates, conversion, and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that, throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. He further stated that diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Witness Church further summarized DEP's nuclear fuel procurement practices in Church Exhibit 2.

Company witness Verderame described DEP's fossil fuel procurement practices, set forth in Verderame Exhibit 1. Those practices include: computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the highest customer value, monitoring delivered coal volume and quality against contract commitments, conducting short-term and spot purchases to supplement term natural gas supply, and obtaining natural gas transportation for the generation fleet through a mix of long term firm transportation agreements and shorter-term pipeline capacity purchases.

According to witness Verderame, the Company's average delivered coal cost per ton increased approximately 6%, from $86.94 per ton in the prior test period to $92.52 per ton in the test period. Included within these amounts, the Company's transportation costs increased approximately 16%, from $31.76 per ton in the prior test period to $36.75 per ton in the test period. He testified that due to the pandemic, low natural gas prices, and mild winter weather, the Company experienced a shift in generation from coal to natural gas in the first half of the test period. Further, he stated that the pandemic had a significant impact on forecasted spring and summer load in 2020, which reduced coal demand. Witness Verderame further testified that the average delivered cost of coal for the test period included the $12.5 million in costs associated with the mitigation of DEP coal contracts related to COVID-19 load losses.

Witness Verderame testified that coal markets continue to be distressed and increasingly volatile due to the deteriorating financial health of coal suppliers because of declining demand, low natural gas prices, uncertainty around EPA regulations, changing demand in global markets for coal, uncertain regulations for mining operations, deteriorating credit quality of coal manufacturers, and corrections in production levels due to lower demand.

Witness Verderame testified that the nation's natural gas supply has grown significantly, supported by enhanced production techniques, efficiencies, and lower production costs. He also testified that while production is adequate, pipeline infrastructure regulatory practices are challenging due to increased reviews and interventions, specifically for DEP, due to the cancellation of the Atlantic Coast Pipeline.

Witness Verderame testified that declining demand for coal in the utility sector is driving rail transportation providers to modify their business models to be less dependent on coal-related transportation revenues. According to witness Verderame, the declining flexibility of coal transportation will limit DEP's ability to effectively manage extreme burn volatility, and its current fixed/variable contract does not provide ongoing customer value in a declining burn environment. Witness Verderame testified that DEP is currently negotiating a 100 percent variable tiered pricing contract structure with the goal of creating a structure that provides incremental ratepayer savings compared to the conventional structure and also ensures secure, reliable deliveries.

Witness Lawrence testified that, since the filing of Witness Verderame's testimony, the Company has entered into the new variable tiered pricing contract. He stated that the Public Staff has reviewed the contract and does not take issue with the new structure. However, the integration of this 100 percent variable tiered pricing contract impacts dispatch methodology. Witness Lawrence testified that the Public Staff will review the implementation of the new contract and associated costs and make applicable recommendations in DEP's next fuel rider proceeding.

According to Witness Verderame, DEP continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner. The strategy includes: having an appropriate mix of term contract and spot purchases for coal, staggering coal contract expirations to limit exposure to price changes, diversifying coal sourcing, and working with coal suppliers to incorporate additional flexibility into DEP's supply contracts. Witness Verderame stated that DEP conducts spot market solicitations throughout the year to supplement term contract purchases considering that there are changes in projected coal burns and coal inventory levels.

Witness Verderame testified that DEP has implemented natural gas procurement practices that include periodic requests for proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply. These include contracting for volumetric optionality to provide flexibility in responding to changes in forecasted fuel consumption and maintaining a short-term financial natural gas hedging plan to manage fuel cost risk to customers. [Finally, DEP procures longer-term, firm interstate and intrastate transportation of natural gas to DEP's generating facilities.]

N.C.G.S. § 62-133.2(a1)(3) permits DEP to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Walsh testified that the Company's fossil/hydro/solar generation portfolio consists of 8,868 MWs of generating capacity, 3,143 MWs of which is coal-fired generation across two generating stations and a total of five units. These units are equipped with emission control equipment, including: selective catalytic reduction (SCR) equipment for removing nitrogen oxides (NOx), flue gas desulfurization (FGD or scrubber) equipment for removing sulfur dioxide (SO_2), and low NOx burners. Company witness Walsh further testified that overall, the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emissions reduction required.

N.C.G.S. §§ 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch or economic curtailment, capacity costs of power purchases associated with qualifying facilities subject to economic dispatch, certain costs associated with power purchases from renewable energy facilities, and the fuel costs of other power purchases. Company witness Verderame testified that DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers.

Aside from the Sierra Club, no party presented testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the Commission concludes that these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the direct and supplemental testimony and exhibits of Company witness Harrington.

According to the supplemental exhibits sponsored by Company witness Harrington, the test period per book system sales were 59,917,347 MWh, and test period per book system generation and purchased power amounted to 68,264,626 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Harrington Exhibit 6):

Net Generation Type	MWh
Nuclear	29,445,201
Natural Gas, Oil and Biogas	21,183,771
Coal	7,475,010
Hydro – Conventional	919,344
Solar	243,635
Purchased Power	
– subject to economic dispatch or curtailment	2,720,623
Other Purchased Power	6,277,042
Total Net Generation	
(may not add to sum due to rounding)	68,264,626

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 5.

No party contested witness Harrington's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 59,917,347 MWh and system generation and purchased power of 68,264,626 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Waldrep and the testimony of Public Staff witness Lawrence.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. The Company proposed using a 93.21% capacity factor in this proceeding based on the operational history of the Company's nuclear units, and the number of planned outage days scheduled during the 2021-2022 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 93.18% for the period 2015-2019 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report. Public Staff witness Lawrence did not dispute the Company's proposed use of a 93.21% capacity factor.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEP system, and the fact that the Public Staff did not dispute the Company's proposed capacity factor, the

Commission concludes that the 93.21% nuclear capacity factor, and its associated generation of 29,337,015 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence supporting these findings of fact is contained in the direct and supplemental testimony and exhibits of Company witness Harrington.

On her Revised Exhibit 4, Company witness Harrington set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 37,898,465 MWh, comprised of Residential class sales of 16,764,534 MWh, Small General Service sales of 1,891,247 MWh, Medium General Service sales of 10,497,319 MWh, Large General Service sales 8,403,471 MWh, and Lighting class sales of 341,894 MWh.

Witness Harrington used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Harrington Exhibit 2, Schedule 1, Page 1 of 3, is 61,963,546 MWh. The projected level of generation and purchased power used was 69,850,902 MWh (calculated using the 93.21% capacity factor found reasonable and appropriate above), and was broken down by witness Harrington as follows, as set forth on that same schedule:

Generation Type	MWh
Nuclear	29,337,015
Gas Combustion Turbine and Combined Cycle	21,918,020
Coal	7,518,351
Hydro	647,824
Solar	265,105
Purchased Power	10,164,587
Total (may not add to sum due to rounding)	69,850,902

As part of her Workpaper 8, Company witness Harrington also presented an estimate of the projected billing period North Carolina retail Residential, Small General Service, Medium General Service, Large General Service, and Lighting MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	16,610,751
Small General Service	1,792,730
Medium General Service	10,332,062
Large General Service	9,225,261
Lighting	380,260
Total (may not add to sum due to rounding)	38,341,063

These class totals were used in Revised Harrington Exhibit 2, Schedule 1, Page 2 of 3, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the Commission concludes that the projected North Carolina retail levels of sales set forth in the Company's exhibits (normalized for weather and customer growth), as well as the projected levels of generation and purchased power, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Harrington and Verderame and the testimony of Public Staff witness Lawrence.

In her Exhibit 2, Schedule 1, Page 1 of 3, Company witness Harrington recommended the fuel and fuel-related prices and expenses. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff. Witness Harrington testified that DEP's prospective fuel and fuel-related cost factors were reasonable and in accordance with the requirements of N.C.G.S. § 62-133.2.

Witness Verderame stated that DEP's current coal burn projection for the billing period is 2.9 million tons compared to 3.4 million tons consumed during the test period. DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: delivered natural gas prices versus the average delivered cost of coal, volatile power prices, and electric demand. Combining coal and transportation costs, DEP projects the average delivered coal cost to be approximately $67.06 per ton for the billing period compared to $92.52 per ton in the test period, which is subject to change based on exposure to market prices and the impact on open coal positions, the amount of non-central Appalachian coal DEP is able to consume, performance of contract deliveries by suppliers, changes in transportation rates, and the potential for increased costs due to compliance with legal and statutory changes.

Witness Verderame testified that DEP's current natural gas burn projection for the billing period is approximately 156.7 million MBtu, which is a decrease from the 157.5 million MBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.71 per MMBtu, compared to $2.26 per MMBtu in the test period. Witness Verderame also testified that the Company's average price of gas purchased for the test period was $3.76 per MMBtu, compared to $3.74 per MMBtu in the prior test period, representing an increase of approximately one percent.

In his testimony, Public Staff witness Lawrence stated that, based on his investigation, he did not recommend any adjustments to the projected fuel prices or the calculation of the total fuel factor.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission concludes that the fuel and fuel-related prices recommended by Company witness Harrington and accepted by the Public Staff for purposes of determining projected system fuel expense are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Harrington and the testimony of Public Staff witness Lawrence.

According to Revised Harrington Exhibit 2, Schedule 1, Page 3 of 3, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $807,419,658. Public Staff witness Lawrence did not take issue with her calculation.

Based upon the evidence in the record and the absence of any direct testimony to the contrary in the record, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $807,419,658 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-18

The evidence supporting these findings of fact is contained in the direct and supplemental testimonies and exhibits of Company witness Harrington and the testimony of Public Staff witness Lawrence and the affidavit of Public Staff witness Boswell.

Company witness Harrington presented DEP's fuel and fuel-related expense (over)/under-collection and prospective fuel and fuel-related cost factors. Company witness Harrington's direct and supplemental testimonies sets forth the projected fuel and fuel-related costs, the amount of (over)/under-collection for purposes of the EMF, the method for allocating the increase in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and EMFs, along with supplemental revised exhibits and workpapers. Public Staff witness Lawrence presented the Public Staff's recommendations regarding the proposed prospective fuel and fuel-related cost factors for the residential, small general service, medium general service, large general service and lighting customers as outlined in the Company's application filed on June 15, 2021, and supplemented on August 27,

2021. Witness Lawrence also presented the Public Staff's recommended total fuel and fuel-related cost factors, which include the EMFs recommended by Public Staff affiant Boswell. Public Staff affiant Boswell agreed that DEP's EMF increment/(decrement) riders for each customer class should be approved based on the following under-recoveries:

N.C. Retail Customer Class	Under-Recovery
Residential	$41,096,455
Small General Service	3,513,037
Medium General Service	24,639,071
Large General Service	42,661,660
Lighting	1,150,209
Total (may not add to sum due to rounding)	$113,060,434

As a result of these amounts, Public Staff affiant Boswell recommended approval of the following EMF increment/(decrement) billing factors, excluding the regulatory fee:

N.C. Retail Customer Class	EMF Increment/ (Decrement) (cents/kWh)
Residential	0.245
Small General Service	0.186
Medium General Service	0.235
Large General Service	0.508
Lighting	0.336

The Commission concludes that the EMF increment/(decrement) billing factors as set forth in the affidavit of Public Staff affiant Boswell are reasonable and appropriate for use in this proceeding.

Company witness Harrington calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the increase in fuel costs from the amounts approved in Docket No. E-2, Sub 1250 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEP fuel cases approved by this Commission. No party opposed the use of this allocation method. Public Staff witness Lawrence recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in the supplemental testimony of witness Harrington.

Based upon the testimony and exhibits in the record, the Commission concludes that DEP's projected fuel and fuel-related cost of $807,419,658 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that the EMF increment/(decrement) riders for each class set forth in the testimony of Public Staff witness Lawrence and the affidavit of Public Staff affiant Boswell in this proceeding, excluding the regulatory fee, and the Public Staff's prospective fuel and fuel-related cost factors proposed in this proceeding for each of the rate classes, are appropriate. Additionally, the Commission concludes that DEP's increase in fuel and fuel-related costs from the amounts approved in Docket No. E-2, Sub 1250 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by the Commission in DEP's past fuel cases.

The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 2.371¢/kWh for the

Residential class, 2.297¢/kWh for the Small General Service class, 2.404¢/kWh for the Medium General Service class, 2.527¢/kWh for the Large General Service class, and 2.018¢/kWh for the Lighting class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 2.126¢/kWh, 2.111¢/kWh, 2.169¢/kWh, 2.019¢/kWh, and 1.682¢/kWh, and EMF increments/(decrements) of 0.245¢/kWh, 0.186¢/kWh, 0.235¢/kWh, 0.508¢/kWh, and 0.336¢/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively, all excluding the regulatory fee. The billing factors, both excluding and including the regulatory fee, are shown in Appendix A to this order.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after December 1, 2021, DEP shall adjust the base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in Docket No. E-2, Sub 1219, amounting to 2.080¢/kWh for the Residential class, 2.126¢/kWh for the Small General Service class, 2.228¢/kWh for the Medium General Service class, 2.204¢/kWh for the Large General Service class, and 1.392¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to 0.046¢/kWh, (0.015)¢/kWh, (0.059)¢/kWh, (0.185)¢/kWh and 0.290¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.245¢/kWh for the Residential class, 0.186¢/kWh for the Small General Service class, 0.235¢/kWh for the Medium General Service class, 0.508¢/kWh for the Large General Service class, and 0.336¢/kWh for the

Lighting class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through November 30, 2022.

2. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order.

3. That DEP shall notify its North Carolina retail customers of these rate adjustments by including the “Notice to Customers of Change in Rates” attached as Appendix B as a bill insert with bills rendered during the Company's next normal billing cycle.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of _______, 2021.

NORTH CAROLINA UTILITIES COMMISSION

____

Chief Clerk

Appendix A

Rates in ¢/kWh excluding regulatory fee:						
	A	B	C	D	E	F
Class	Base Fuel Rate	Increment / (Decrement) to Base Fuel Rate	Prospective Rate: Columns A+B	EMF Increment / (Decrement)	EMF Interest (Decrement)	Billed Rate: Columns C+D+E
Residential	2.080	0.046	2.126	0.245	-	2.371
Small General Service	2.126	(0.015)	2.111	0.186	-	2.297
Medium General Service	2.228	(0.059)	2.169	0.235	-	2.404
Large General Service	2.204	(0.185)	2.019	0.508	-	2.527
Lighting	1.392	0.290	1.682	0.336	-	2.018

Rates in ¢/kWh including regulatory fee:						
	A	B	C	D	E	F
Class	Base Fuel Rate	Increment / (Decrement) to Base Fuel Rate	Prospective Rate: Columns A+B	EMF Increment / (Decrement)	EMF Interest (Decrement)	Billed Rate: Columns C+D+E
Residential	2.083	0.046	2.129	0.245	-	2.374
Small General Service	2.129	(0.015)	2.114	0.186	-	2.300
Medium General Service	2.231	(0.059)	2.172	0.235	-	2.407
Large General Service	2.207	(0.185)	2.022	0.509	-	2.531
Lighting	1.394	0.290	1.684	0.336	-	2.020

Appendix B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1272

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC Pursuant to N.C. Gen. Stat. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	**NOTICE TO CUSTOMERS OF CHANGE IN RATES**

NOTICE IS GIVEN that the North Carolina Utilities Commission entered an Order in Docket No. E-2, Sub 1272, on __________ __, 2021, after public hearing, approving net fuel and fuel-related rate increases of 0.111, 0.122, 0.080, 0.056, and 0.245 cents per kWh (excluding regulatory fee[1]) for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively, or an approximate increase of $35 million on an annual basis, in the fuel and fuel-related rates and charges paid by the retail customers of Duke Energy Progress in North Carolina, effective for service rendered on and after December 1, 2021. The rate increase was ordered by the Commission after review of Duke Energy Progress' fuel and fuel-related expenses during the 12-month period ended March 31, 2021, and represents actual changes experienced by the Company with respect to its reasonable cost of fuel and fuel-related costs during the test period. The total fuel and fuel-related cost factors for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting, and Industrial customer classes are 2.371¢/kWh, 2.297¢/kWh, 2.404¢/kWh, 2.527¢/kWh, and 2.018¢/kWh respectively (excluding regulatory fee).

[1] Based on a NCRF multiplier of 1.00130169

Overall, the changes in the approved fuel and fuel-related rates described above will result in monthly net rate increases of approximately $1.11 for each 1,000 kWh of residential usage (including regulatory fee).

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of _______, 2021.

NORTH CAROLINA UTILITIES COMMISSION

____
Chief Clerk