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October 21, 2021

VIA ELECTRONIC FILING

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

RE: Duke Energy Progress, LLC's Proposed Order
Docket No. E-2, Sub 1272

Dear Ms. Dunston:

Enclosed for filing in the above-referenced docket please find Duke Energy Progress, LLC's Proposed Order Approving Fuel Charge Adjustment. An electronic copy is being emailed to briefs@ncuc.net.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,

Jack E. Jirak

Enclosure

cc: Parties of Record

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	))))))	**DUKE ENERGY PROGRESS, LLC'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: Per Commission order, counsel was not present

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. Gen. Stat. § 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. Gen. Stat. § 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 but requiring that the parties 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, upon request, to provide additional information to the Sierra Club in future fuel clause proceedings. DEP and the Sierra Club requested that the letter be entered into the record in this proceeding and that request is 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 by Hearing Examiner Erin Duffy. No public witnesses were present. 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. Gen. Stat. § 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 $75.0 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 DEP's 2021 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 and ensure reliability.

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. Gen. Stat. § 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 this finding of fact is contained in the testimony of Company witnesses Waldrep and Walsh, Verderame and Swez, and the testimony of Public Staff witness Lawrence and the testimony of Sierra Club witness Glick.

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*	*2015-2019*	*Nbr of Units*
		DEP Operational Results	*NERC Average*	
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. Gas-fired facilities provided 71% of the DEP fossil/hydro/solar generation during the test period.

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 including the Experience Modification Factors ("EMFs") recommended by Public Staff affiant Boswell.

Public Staff witness Lawrence described the scope of the Public Staff's investigation and also testified that for the test year, the Company reported a single year system-wide nuclear capacity factor ("CF") of 93.55%, which is greater than the North American Electric Reliability Corporation weighted average nuclear CF of 93.18%. This met the benchmark set forth in Commission Rule R8-55(k). Based on his investigation, Mr. Lawrence stated that he was not recommending any adjustments to the projected fuel prices or the calculation of the total fuel factor.

Witness Verderame testified that both DEP and DEC use the same process to ensure that the generation assets of the Companies are reliable and economically committed and dispatched to serve ratepayers, using several factors, including: forecasted fuel prices, transportation rates, planned maintenance and refueling outages, performance parameters, and expected market conditions associated with power purchases.

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. 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 testified that DEP regularly committed its coal units at Mayo and Roxboro when it would have been less costly to serve retail ratepayers with other resources, which resulted in approximately $1.5 million of avoidable variable costs at its coal plants. She testified these costs were avoidable if DEP had turned its coal units off in the month during which each unit's production cost exceeded the system's marginal costs. Of the $1.5 million, approximately $1.4 million were fuel costs according to witness Glick. Witness Glick stated the marginal cost of production does not represent the average production cost passed on to ratepayers. Witness Glick testified that except in cases of extenuating circumstances, the Company should not commit a unit unless the unit would operate at below system lambda over a reasonable near-term period and should take the unit offline if it projected it would exceed system lambda.

Witness Glick testified the Company operated its coal units during many periods when its data showed it would be less expensive to operate other units on a marginal production cost basis. Witness Glick stated that while it is understandable that the Company may incur operational costs in excess of the system marginal costs for brief periods, it is not reasonable for the Company to exceed marginal cost over an extended period. According to Witness Glick, this is either because the Company is not using robust and complete input data to determine its unit commitment decisions, or the Company is ignoring the results of its unit commitment analysis.

Witness Glick testified that the information provided to the Sierra Club and to the Commission by DEP is insufficient to determine the reasonableness and prudence of the Company's commitment decisions. Witness Glick stated the Company produced hourly data with "modeled" unit costs for DEP's part of the system and actual system lambdas. Witness Glick testified this modeling occurs after the fact. Witness Glick represented that the Sierra Club requested contemporaneous documentation from DEP produced at the time the company made its commitment decisions, but the seven-day forecast sheets DEP provided had no cost information.

Witness Glick testified that DEP had coal unit fuel costs among some of the highest in the country and continued to operate the units. Witness Glick testified the coal used at Mayo cost \$2.62/MMBtu and \$2.55/MMBtu at Roxboro, which put those plants in the 83rd and 82nd percentile of the most expensive in the country.

Witness Glick testified that the marginal production costs used to make unit-commitment decisions omitted forty-six percent of the average of fuel and variable costs that the Company incurred to operate its coal units during the test year. In witness Glick's opinion, this omission resulted in DEP committing and dispatching its coal units significantly more often than if the Company based its commitment decisions on the actual fuel and variable costs for each unit. Witness Glick stated that DEP's marginal fuel costs represent the costs DEP would pay based on market prices by independent third-party vendors, variable transportation costs, and associated emissions control costs. However, actual fuel costs represent the cost of the fuel DEP actually uses for generation at each plant, which are the costs that DEP seeks to recover. Witness Glick testified that DEP incurred $315.4 million in fuel and production costs operating its coal plants, but only $157.8 million in variable costs were included in the Company's unit-commitment modeling.

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 recommended disallowance was subsequently withdrawn by the Sierra Club.

In response to the testimony of Sierra Club witness Glick, Company witnesses Verderame and Swez, in their joint rebuttal testimony, stated that the testimony of Witness Glick is inaccurate and relies on incorrect assumptions and flawed analytical approaches, which are based on theories that have consistently been rejected by the Commission in both general rate cases and fuel adjustment proceedings. Witnesses Verderame and Swez testified that the Sierra Club engages in the same "paper" exercise that was used in the recent fuel proceeding for Duke Energy Carolinas, LLC ("DEC"), which presents a hindsight view that ignores operational realities.

In their view, witness Glick fails to recognize that DEP's unit commitment seeks to minimize production costs to serve a given amount of customer demand within reliability constraints. By using a flawed analytical approach, witness Glick incorrectly assumes that the Company has an unlimited amount of generation available at the lambda price (or instantaneous system incremental cost). In the view of witnesses Verderame and Swez, the use of an average system lambda calculated over a long period to make instantaneous decisions is a faulty exercise. Additionally, they state that witness Glick's analysis fails to recognize the additional physical costs of a generator that are required to produce energy, such as startup and no-load costs, or the need to run generating units for the purpose of reliability, operating reserves, unit testing, or voltage support. Witness Glick selectively and improperly averages data over longer periods to reach certain short-term conclusions. To achieve a desired result of reducing coal generation, witness Glick implies that fixed costs should be included in unit commitment and discharge decisions, which would potentially result in uneconomic unit commitment and dispatch outcomes. Fixed costs are sunk costs and should not be used to make decisions regarding unit commitment or dispatch.

Witnesses Verderame and Swez categorically reject the Sierra Club's position that DEP's application in this docket is insufficient or fails to comply with applicable law. They note specifically that the Company's filing meets all the requirements contained in N.C.

Gen. Stat.. § 62-133.2 and Commission Rule R8-55 and is substantially identical to all recent fuel rider applications, none of which have been found to be deficient by the Public Staff or the Commission. Additionally, DEP's witnesses noted that the Company responded to extensive data requests from other parties, including multiple sets of data requests submitted by the Sierra Club. DEP's witnesses also expressly rebutted the assertion of witness Glick that DEP did not provide contemporaneous unit cost information that was produced at the time of DEP's daily unit commitment decisions. Specifically, in response to Sierra Club DR 1-33b, which requested "all reports that provide the contemporaneous unit cost projections and system marginal cost projections," the Company provided a download of the Unit Cost and Priority Report by day for the period 1/1/2020-3/31/2021. Included in this material was the daily Average Energy Cost to Commit ($/MWh) for each generating unit in the Carolinas system (DEC and DEP combined). This material details the variable production cost of each unit by day. The data in the Unit Cost and Priority spreadsheets is an output of the GenTrader unit commitment model. The 7-day forecast sheets and the Unit Loading Report are also outputs from the GenTrader model and do not output the modeled cost information but instead show the unit commitment and dispatch plans by day by hour. Specifically, the "Unit Loading Report" is a forecast of MWh loadings of each generating unit over the next seven days as determined by each GenTrader model run, which is developed to minimize total variable production costs over the seven-day planning period and include inputs (such as unit startup costs) that are not part of an hourly marginal cost. Not only did DEP provide this information to Sierra Club, but it also offered to meet with the Sierra Club to discuss the

Company's responses, but the Sierra Club failed to follow up or acknowledge that the offer had been made.

In the view of witnesses Verderame and Swez, witness Glick's criticism of the contents of DEP's application in this docket was simply a restatement of the same arguments made in previous dockets, which were rejected by the Commission in the 2020 fuel clause proceedings for both DEC and DEP and most recently in the 2021 DEC fuel proceeding. The rebuttal witnesses noted in the 2021 DEC fuel proceeding that the Commission stated that "the scope and level of detail contained in Company's application, testimony, exhibits, and workpapers as filed in this proceeding conforms with applicable law and is consistent with prior applications that have been deemed sufficient." In the view of Witnesses Verderame and Swez, DEP's filings in this docket met the same standards.

Although Sierra Club witness Glick stated that it would have been less costly for DEP to serve its retail customers with other resources, witnesses Verderame and Swez noted that witness Glick never identifies a specific set of less expensive "other resources" at the explicit times to replace more expensive supply while still ensuring reliability. Further, the Sierra Club witness does not even attempt to offer a specific explanation of how DEP could have replaced the 3,143 MW of reliable generation and capacity provided by the Company's coal units. Further, the Sierra Club failed to consider the necessity of maintaining day-ahead planning reserves, operating reserves, and regulating reserves needed to maintain system reliability. The Company's unit commitment plans include 1,195 MW of these reserves, which are available capacity above and beyond DEP's expected peak load to account for the potential loss of a unit, regulating reserves, or a load forecasting error. This capacity must be online or available within a short period of time.

At times, coal units must be run to ensure that the Company has 1,195 MW of day-ahead planning reserves, and this requirement was not considered in the Sierra Club analysis. By ignoring this reserve requirement, witnesses Verderame and Swez stated that witness Glick' s analysis produced flawed conclusions based on operational assumptions that do not align with the Company's real-world obligations to ensure reliability.

Rebuttal witnesses Verderame and Swez disagree with the Sierra Club's assessment that "economic performance" of the Company's coal units was not satisfactory because the units were "minimally utilized" based on the capacity factors of the units. Although the Company's coal units have capacity factors lower than in the past, the fact that certain units are not required to operate at times does not equate to poor performance or mean that the units are not needed to ensure reliability. In the view of DEP's rebuttal witnesses, the Sierra Club's characterizations ignore the Company's capacity reserve obligations, and that the annualized capacity factors were lower because DEP utilized more cost-effective units or, if available, purchased energy and capacity from the bi-lateral power market before committing or dispatching such units. However, a reduced capacity factor in a particular year does not eliminate the need for such units.

Witness Glick's comparison of DEP's coal units to all the coal units in the country is also invalid. As an initial statement, rebuttal witnesses Verderame and Swez question whether the comparison of the fuel costs of DEP's units to all the coal units in the United States is even relevant to a fuel proceeding. Further, they note that the Sierra Club compared units without regard to location, types of coal, or the technology required at each unit to burn various types of coal. The Sierra Club analysis reveals that the lowest cost coal units are in, or near, coal producing regions. It is common sense that such units have lower costs because these units have lower transportation costs and utilize lower cost Powder River coal.

As a threshold matter, 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. Nevertheless, the Commission has reviewed the testimony of Sierra Club witness Glick and is not persuaded that DEP's commitment and dispatch decisions in the test period were in any way imprudent. N.C. Gen. Stat. § 62-133.2(d) allows for the recovery of fuel costs that are "prudently incurred under efficient management and economic operations." The Commission has recently affirmed that its "seminal treatment of 'reasonable and prudent' costs is outlined in the Commission's Oder entered in Docket No. E-2, Sub 537."[1] The Commission's Order Granting Partial Increase in Rates and Charges in Docket No. E-2, Sub 537 (referred to herein as the "*1988 DEP Rate Order*") summarized the general standard of prudence as follows:

[1] *See Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction,* Docket Nos. E-7, Sub 1146, E-7, Sub 819, E-7, Sub 1152, E-7, Sub 1110 (June 22, 2018) ("*2018 DEC Rate Order*")

> [w]hether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time (citation omitted)…. The Commission notes that this standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments – is not permitted.

The *1988 Rate Order* went on to establish that, in addition to showing that a specific decision was imprudent, it also is necessary to "quantify the effects of the specific acts of imprudence by calculating the cost of the prudent alternative and comparing it with the costs incurred by the imprudent act."[2]

Witness Glick's testimony is flawed because it is fundamentally a hindsight-based analysis that assumed perfect knowledge regarding actual system conditions. Witness Glick failed to identify specific decisions and actions of the Company that were imprudent given the facts and circumstances known at the time decisions were made and fails to identify a set of alternative decisions that could have been made while still ensuring reliability for customers. As the Commission has stated, there must be a showing of the "prudent alternative" and, in this case, witness Glick has not presented a prudent alternative that would have ensured reliability for customers. Witness Glick asserts that "it would have been less costly to serve retail ratepayers with *other* resources,"[3] but never identifies which specific set of "other resources" could have actually been deployed at those times while still ensuring reliability. The Sierra Club does not offer a credible or specific explanation of how the Company could have replaced the approximately 3,143 MW of reliable generation energy and capacity (the total of the capability of the Mayo and Roxboro 1-4 units in question in this proceeding is 3,143 MW) provided by the Company's coal

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[2] *1988 DEP Rate Order* at 15.
[3] Glick Direct, at 8.

units nor identifies which specific resources should have been dispatched to serve customers absent these generators. In the same vein, witness Glick also failed to consider the necessity of maintaining day-ahead planning reserves, operating reserves, and regulating reserves in order to maintain system reliability. In fact, DEP's witnesses confirmed that had DEP made the resource decisions suggested in Sierra Club's analysis, customers would likely have been curtailed multiple times. A hindsight- based analysis that assumes perfect knowledge regarding system conditions but does not identify a specific set of alternative operational decisions that could have been made while still ensuring reliability, is insufficient to support a finding of imprudence.

The Commission concludes that the application, testimony, and supporting documents filed by DEP in this docket were in full compliance with the requirements of N.C. Gen. Stat. § 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 not accepted 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 Sierra Club initially recommended a disallowance but subsequently withdrew that recommendation. The Company has provided compelling evidence concerning the prudence of its dispatch and commitment decisions. 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 and ensure reliability.

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. For this reason, DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts. 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. The pandemic had a significant impact on forecasted spring and summer load in 2020 which reduced coal demand. Witness Verderame testified that DEP burned significantly less coal than anticipated and ratepayers benefited from greater utilization of low-cost natural gas. Due to this, DEP exhausted its rights to flex down contractual obligations for coal purchases at no cost to customers. Witness Verderame testified that after these measures were exhausted, DEP had to determine whether to force-run coal generation or continue to maximize customer savings by burning cheaper natural gas while negotiating to buy out the remaining balance of the 2020 coal obligations. Witness Verderame testified that, based on the Company production cost analysis, pursuing the contractual buyouts was projected to result in ratepayer savings totaling approximately $22 million versus force-running coal generation. 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 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 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 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. While there remains adequate coal transportation available, the Company's rail transportation providers have indicated that they will have limited operational flexibility to adapt to significant changes in scheduling demand resulting from the Company's burn volatility, specifically in higher than forecasted coal burn scenarios. 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. 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 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.

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. Gen. Stat. § 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. Coal-fired assets with emission control equipment enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content, thereby providing flexibility for DEP to procure the most cost-effective options for fuel supply. 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. Gen. Stat. §§ 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. To that end, both companies consider numerous factors such as the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating stations, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities, in order to determine the most economic and reliable means of serving customers.

Because the Sierra Club withdrew its recommended disallowance, 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 absence of any testimony to the contrary, 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 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. Gen. Stat. § 62-133.2.

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 testimony 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 testimony 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 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 the joint letter filed on September 21, 2021 by DEP and the Sierra Club is accepted and entered into evidence.

4. 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 G.S. 62-133.2 and Commission	)	NOTICE TO CUSTOMERS
Rule R8-55 Relating to Fuel and Fuel	)	OF CHANGE IN RATES
Related Cost Adjustments for Electric Utilities	)	

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[4]) 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).

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

[4] Based on a NCRF multiplier of 1.00130169

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC's Proposed Order, in Docket No. E-2, Sub 1272, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 21st day of October, 2021.

Jack E. Jirak
Deputy General Counsel
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