**STATE OF NORTH CAROLINA**
**UTILITIES COMMISSION**
**RALEIGH**

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

HEARD: Wednesday, September 14, 2022, at 10:00 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina (Public Witness Hearing, Hearing Examiner Heather Fennell, Presiding)

BEFORE: Commissioner Floyd B. McKissick, Jr., Presiding
Chairman Charlotte A. Mitchell
Commissioner ToNola D. Brown-Bland
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Karen M. Kemerait

APPEARANCES: (Counsel present for public witness hearing. Per Commission Order, (evidentiary hearing was cancelled.)

For Duke Energy Progress, LLC:

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For the Using and Consuming Public

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BY THE COMMISSION: On June 14, 2022, 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, the direct testimonies and exhibits of Matthew L. Cameron, Tom Ray, and John A. Verderame, and the direct testimonies of Bryan P. Walsh and David B. Johnson.

Petitions to intervene were filed by Carolina Utility Customers Association, Inc. ("CUCA") and Carolina Industrial Group for Fair Utility Rates II ("CIGFUR") on June 16, 2022, and by Southern Alliance for Clean Energy ("SACE") on August 9, 2022. The Commission granted CUCA's and CIGFUR's petitions to intervene on June 21, 2022, and SACE's petition to intervene on August 18, 2022.

On July 8, 2022, 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 the Public Staff and intervenors should be filed on or before August 24, 2022, that DEP rebuttal testimony and exhibits should be filed on or before September 1, 2022, that DEP should publish Public Notice in a newspaper or newspapers having general circulation in its service area once a week for two successive weeks beginning at least 45 days prior to the hearing; that DEP shall file affidavits of publication on or before the date of the hearing; and that a public hearing on this matter would be held on September 14, 2022.

On August 12, 2022, DEP filed the supplemental testimony and revised exhibits and workpapers of Dana M. Harrington.

On August 17, 2022, the Commission entered an *Order Requiring Second Public Notice*.

On September 12, 2022, DEP filed affidavits of publication indicating that public notices had been provided in accordance with the Commission's procedural orders issued on July 8, 2022, and August 17, 2022.

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 24, 2022, the Public Staff filed the Notices of Affidavits and affidavits of Fenge Zhang and Dustin Metz; and direct testimony and exhibits of John R. Hinton in accordance with N.C.G.S. 62-133.2 and Commission Rule R8-55.

On August 24, 2022, SACE filed the direct testimony and exhibits of Ronald J. Binz.

On September 1, 2022, DEP filed the rebuttal testimony of Dana M. Harrington and James J. McClay, III.

On September 8, 2022, DEP and the Public Staff filed a joint motion requesting that the Commission excuse DEP's witnesses Dana M. Harrington, Matthew L. Cameron, Tom Ray, John A. Verderame, Bryan L. Walsh, David B. Johnson, and James J. McClay, III, and Public Staff's affiants, Fenge Zhang and Dustin R. Metz and Public Staff witness, John R. Hinton, and SACE Witness Binz from appearing at the September 14, 2022, evidentiary hearing. The joint motion requested that the Commission accept the expert witnesses' testimony, affidavits, 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 affiants and SACE's witness listed in the motion.

On September 12, 2022, the Commission entered an *Order Excusing Witnesses, Accepting Testimony, Canceling Expert Witness Hearing, and Requiring Orders.*

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 14, 2022, by Hearing Examiner Heather Fennell. No public witnesses were present. The Public Staff and DEP each filed a proposed order on October 14, 2022.

Based upon the Company's verified application, direct testimony, supplemental testimony, rebuttal testimony, and exhibits received into evidence at the hearing, the testimony, affidavits, and exhibits of the Public Staff, the testimony and exhibits of SACE, the Commission makes the following:

## FINDINGS OF FACT

1. Duke Energy Progress is a licensed limited liability company, organized and 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 this 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, 2022 ("test period").

3. In its application and direct testimony in this proceeding, DEP requested a total increase of $302.3 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 of $210. 4 million

experienced during the test period. This balance excludes an 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 prior year Docket No. E-2, Sub 1272. This balance also includes the deferred under-recovered balance of $4.2 million in losses on the sale of by-products, which were approved for cost recovery through the fuel clause in the Commission's Order Allowing Recovery of Liquidated Damages and Transportation Charges dated July 28, 2020, in Docket No. E-2, Sub 1204.

4. In its direct supplemental testimony and exhibits in this proceeding, DEP updated its requested increase in the North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee, to $337.2 million, which included an updated under-recovered EMF to $255.4 million.

5. The Company's baseload plants were generally managed prudently and efficiently during the test period 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. It is appropriate for the Company to review its hedging program and recommend modifications in response to changing market signals to ensure that it remains appropriate based on market conditions.

7. The test period per book system sales are 60,559,875 megawatt-hours ("MWh"). The test period per book system generation (net of auxiliary use) and purchased power is 70,153,063 MWh and is categorized as follows:

| Net Generation Type | MWh |
|---|---|
| Nuclear | 29,581,602 |
| Natural Gas, Oil, and Biogas | 23,334,027 |
| Coal | 6,371,743 |
| Hydro – Conventional | 623,493 |
| Solar | 257,024 |
| Purchased Power–subject to economic dispatch or curtailment | 3,721,653 |
| Other Purchased Power | 6,263,521 |
| Total Net Generation (may not add to sum due to rounding) | 70,153,063 |

8. The appropriate nuclear capacity factor for use in this proceeding is 94. 05%.

9. The North Carolina retail test period sales, adjusted for weather and customer growth, for use in calculating the EMF are 37,740,216 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 | 16,792,596 |
| Small General Service | 1,956,415 |
| Medium General Service | 10,468,785 |
| Large General Service | 8,202,098 |
| Lighting | 320,322 |
| Total (may not add to sum due to rounding) | 37,740,216 |

10. The projected billing period (December 2022-November 2023) sales for use in this proceeding are 61,541,989 MWh on a system basis and 38,365,559 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 | 16,637,596 |
| Small General Service | 1,797,603 |
| Medium General Service | 10,360,942 |
| Large General Service | 9,189,937 |
| Lighting | 379,481 |
| Total (may not add to sum due to rounding) | 38,365,559 |

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 69,409,824 MWh and is categorized as follows:

| Generation Type | MWh |
|---|---|
| Nuclear | 29,601,651 |
| Gas Combustion Turbine ("CT") and Combined Cycle ("CC") | 19,494,222 |
| Coal | 9,087,592 |
| Hydro | 667,442 |
| Solar | 264,499 |
| Purchased Power | 10,294,418 |
| Total (may not add to sum due to rounding) | 69,409,824 |

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. 95/MWh.
B. The gas CT and CC fuel price is $38. 00/MWh.
C. The coal fuel price is $38. 66/MWh.
D. The appropriate system expense for ammonia, lime, limestone, sorbents, and catalysts consumed in reducing or treating emissions (collectively, "Reagents") is $21,815,046.

E. The appropriate system gain on the sale of by-products produced in the generation of electricity (collectively, "By-products") is $25,444,431.

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 $509,875,571.

G. System fuel expense recovered through intersystem sales is $213,736,707.

13. The projected fuel and fuel-related costs for the North Carolina retail billing period are $1,010,744,631. North Carolina General Statute § 62-133. 2(a2) prohibits the inclusion of select purchased power fuel and fuel-related cost increases in excess of 2.5% of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year; therefore, the Company is excluding $11,048,138 in costs from customer fuel rates in this proceeding. This brings the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding to $999,696,493. This reduction in projected costs used to set rates in this proceeding does not preclude the Company from seeking to recover the actual costs incurred on the purchased power costs described in N.C.G.S. § 62-133. 2(a2) in a future proceeding as a component of the EMF.

14. The Company's appropriate North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $255,408,714, consisting of under-recoveries of $108,941,580, $8,781,456, $61,349,694, $73,664,346, and $2,671,637, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively. These amounts include the deferred under-recovered losses on the sale of by-products from the prior year as follows: $1,800,492, $170,792, $1,075,183, $1,110,728, and $28,089, 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 1272 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: 2.808¢/kilowatt-hour ("kWh") for the Residential class; 3. 097¢/kWh for the Small General Service class; 2.580¢/kWh for the Medium General Service class; 2.138¢/kWh for the Large General Service class; and 3.376¢/kWh for the Lighting class.

17. The appropriate EMFs established in this proceeding, excluding the regulatory fee, are as follows: 0.649¢/kWh for the Residential class; 0.449¢/kWh for the Small General Service class; 0.586¢/kWh for the Medium General Service class; 0.898¢/kWh for the Large General Service class; and 0.834¢/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: 3.457¢/kWh for the Residential class; 3.546¢/kWh for the Small General Service class; 3.166¢/kWh for the Medium General Service class; 3.036¢/kWh for the Large General Service class; and 4.210¢/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, 2022.

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 Ray and Walsh and the testimony of Public Staff affiant Metz.

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 Ray 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 93.99% during the test period. Both this annual capacity factor, and the Company's 2-year average capacity factor of 93.77%, met the five-year industry average capacity factor of 93.49% for the period 2016-2020 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.

Public Staff affiant Metz affirms that the Company's actual system nuclear capacity factor for the test year was 93.99% and that the NERC five-year average (2016-2020) weighted for the size and type of reactors in DEP's nuclear fleet was 93.49%.

Company witness Walsh testified concerning the performance of DEP's fossil/hydro 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) starting reliability ("SR"), which represents the percentage of successful starts; and (4) equivalent forced outage rate ("EFOR"), which quantifies the number of period hours in a year during which the unit is unavailable because of forced outages and 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 2016 through 2020:

| Generator Type | Measure | Review Period | 2016-2020 | Nbr of Units |
|---|---|---|---|---|
| | | DEP Operational Results | NERC Average | |
| *Coal Fired Test Period* | EAF | 63.1% | 79.8% | 183 |
| | NCF | 23.0% | 53.2% | |
| | EFOF | 8.1% | n/a | |
| *Coal Fired Summer Peak* | EAF | 78.2% | n/a | n/a |
| *Total CC Average* | EAF | 81.0% | 84.9% | 345 |
| | NCF | 67.6% | 54.3% | |
| | EFOF | 0.7% | n/a | |
| *Total CT Average* | EAF | 83.8% | 86.6% | 709 |
| | SR | 99.2% | 98.5% | |
| *Hydro* | EAF | 78.5% | 79.4% | 1059 |
| *Solar* | NCF | 20.8% | n/a | n/a |

Company witness Walsh also testified that for the review period, approximately 51% of the Company's total system generation was provided by the Fossil/Hydro/Solar fleet of which 38% was contributed from gas facilities, 11% contributed from coal-fired stations, 1% contributed by hydro sources, and 0. 4% from solar facilities.

Based upon the evidence in the record, and the absence of any testimony to the contrary, the Commission concludes that DEP generally managed its baseload plants prudently and efficiently 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, 2022. 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, Cameron, Verderame, Walsh, and Public Staff affiant Metz. Additionally, Public Staff witness Hinton addressed the Company's natural gas hedging strategy.

Company witness Harrington testified that key factors in DEP's ability to maintain lower fuel and fuel-related rates include its diverse generating portfolio of nuclear, natural gas, coal, and hydro, the capacity factors of its nuclear fleet, and fuel procurement strategies, which mitigate volatility in supply costs. Witness Harrington also testified on other key factors that include DEP's and affiliate company Duke Energy Carolina's ("DEC") respective expertise in transporting, managing, and blending fuels, procuring reagents, and utilizing purchasing synergies of the combined companies, as well as the joint dispatch of DEP's and DEC's generation resources.

Company witness Cameron 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 Cameron 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, witness Cameron testified that 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, witness Cameron testified that 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, witness Cameron testified that DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Company witness Verderame described DEP's fossil fuel procurement practices, set forth in Verderame Exhibit 1. Witness Verderame testified that those practices include: computing near and long-term consumption forecasts using stochastic cost production modeling, 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, obtaining natural gas transportation for the generation fleet through a mix of long term firm transportation agreements and shorter-term pipeline capacity purchases, and managing a targeted percentage of the natural gas fuel price exposure via a rolling 60-month structured financial natural gas hedging program.

According to witness Verderame, the Company's average delivered coal cost per ton decreased approximately 9%, from $92.52 per ton in the prior test period to $84.26 per ton in the current test period. The Company's transportation costs decreased approximately 4%, from $36.75 per ton in the prior test period to $35.15 per ton in the current test period.

Witness Verderame also testified that the Company's average price of gas purchased for the current test period was $5.44 per Million British Thermal Units ("MMBtu"), compared to $3.76 per MMBtu in the prior test period, representing an increase of approximately 44%. He testified that the cost of gas is inclusive of gas supply, transportation, storage, and financial hedging.

Witness Verderame testified that the coal supply chain experienced increasing challenges throughout 2021 and early 2022 as historically low utility stockpiles—combined with rapidly increasing demand for coal, both domestically and internationally—made procuring additional coal supply increasingly challenging. Producers were unable to respond to this rapid rise in demand due to capacity constraints resulting from labor and resource shortages. These factors combined to drive both domestic and export coal prices in 2021 and early 2022 to record levels. Going into summer 2022, coal commodity costs remained at historically high levels as higher natural gas prices and strong domestic and foreign demand continued to put pressure on coal supplies. Witness Verderame also testified that in 2021 and early 2022, the Company experienced increased delivery delays created by rail transportation labor and resource shortages and that the Company expects rail transportation labor and resource constraints to continue into 2023.

Witness Verderame stated that DEP's current coal burn projection for the billing period is 3. 5 million tons compared to 2. 9 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 average delivered coal costs of approximately $100. 18 per ton for the billing period compared to $84. 26 per ton in the test period. This projected delivered cost is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of Central Appalachian coal DEP is able to purchase and deliver and the non-Central Appalachian coal DEP is able to consume; (3) changes in transportation rates; (4) performance of contract deliveries by suppliers and railroads that may not occur despite the Company's strong contract compliance monitoring process; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

Witness Verderame further testified that DEP's current natural gas burn projection for the billing period is approximately 140. 5 million MBtu, which is a decrease from the 174. 6 million MBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $5. 51 per MMBtu, compared to $4.41 per MMBtu in the test period.

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.

Public Staff witness Hinton testified regarding his analysis of the Company's fuel hedging program including the reasons why the Company has a hedging program in place. Witness Hinton stated that energy companies, like DEP, have hedging programs to protect their customers from fuel price volatility in the market by minimizing price changes and shocks. Witness Hinton further explained that volatility stems from the risks of the unknown future causing unforeseen substantial or frequent changes in prices that can unexpectedly happen at any time.

Witness Hinton testified that longer term deals entail an added degree of term risk where the expected benefits of stable prices are outweighed by the potential costs, and that DEP's forward volatility curves indicate that the expected volatility is drastically lower beyond future year three relative to one or two years. Witness Hinton also testified that even though long-term hedges entered into in 2017 and 2018 are currently producing net savings and reducing the cost of natural gas, he urged caution regarding entering into longer term deals greater than three years which have historically added costs to DEP's hedging program. Witness Hinton testified that based on his analysis of nine DEP annual fuel rider dockets[1], DEP's responses to data requests, monthly hedge reports from April 2012 to March 2022, and testimony within the referenced dockets that DEP's hedging programs are reasonable and that management of the hedging program has worked to stabilize natural gas price swings.

Witness Hinton testified that for the 2021-2022 test year, the DEP hedging program for natural gas reduced the cost of purchasing natural gas by $122. 6 million, translating to an annual savings of $22. 82 for the typical consumer at a system level. Witness Hinton notes that even with this recent large benefit, DEP's overall hedging program over the recent years (2012-2017) has reflected more net costs than savings as historical hedging contracts, with longer hedge horizons, meaning the length of time between the trade date and the

[1] Dockets No. E-2, Subs 1292, 1272, 1250, 1204, 1173, 1146, 1069, 1045, and 1031.

effective date of the contract, incurred large net costs as hedged natural gas prices were significantly higher than the actual market prices.

Witness Hinton testified that he did not question DEP's ability to gauge the gas markets during these years of significantly large costs. Rather, witness Hinton stated that during the 2008 through 2017 period industry participants were surprised by the continued decline in natural gas prices as shale gas came into the market and. He further noted that the vast majority of the Annual Energy Outlook (AEO) Retrospective Review forecasted natural gas prices in 2008-2013 for 2012-2017 predicted higher future prices as compared to the actual prices. Witness Hinton testified that natural gas price volatility has significantly increased over the last 12 months and that recent increases support the use of hedges to avoid having to purchase gas at relatively higher prices. Witness Hinton testified that he supports DEP's position that it cannot predict future prices and its hedging program does not involve speculation. Finally, witness Hinton recommends that DEP utilize a short-term hedging policy with one to three years lead time from the trade date and the effective date. Witness Hinton testified hedging beyond three years adds risk and urged caution regarding entering into longer term hedging greater than three years since it historically added costs to DEP's hedging program. If DEP decides to hedge beyond three years, witness Hinton recommends that it stay on the lower side of the percentage band.

In response to the testimony of Public Staff witness Hinton, Company witness McClay in his rebuttal testimony, disagreed with Witness Hinton's recommendation to shorten its hedging program from a phased financial hedging program over a rolling 60-month period to a shorter program over a rolling 36-month period. Witness McClay testified that as DEP's use of natural gas continues to increase and make up larger component of overall fuel costs, DEP believes hedging natural gas over a rolling 60-month time horizon represents a balanced fuel price risk management approach that results in greater fuel cost certainty for a portion of forecasted natural gas burns. Witness McClay testified that the Company does not disagree that targeting a lower hedging percentage for the period beyond 36 months is reasonable as neither DEP nor any forecaster can predict with certainty where actual natural gas prices and volatility will be in the future. Witness McClay further testified that this is consistent with DEP's documented approach of targeting higher hedging percentages in the first 12 to 36 months and lower hedging percentages in the 37 to 60-month period.

Witness McClay testified that the results of the Company's hedging activity may or may not result in net fuel cost savings and prior results are not an indication or expectation of future hedging results. Instead, the program's purpose is to provide a reasonable and prudent approach to mitigate price volatility in uncertain fuel markets and that following DEP's current methodology to financially hedge a portion for the rolling future periods beyond the front 36 months provides the benefit of greater fuel cost certainty for an additional portion of forecasted natural gas burns given the number of risk factors that can impact price volatility.

Witness McClay also testified that DEP believes continuing to hedge periods beyond the 36-month hedge horizon at lower hedging targets is reasonable and continues to be an important part of prudently managing the risk of volatility in customers' future fuel costs and that DEP will continue to review its hedging program and recommend modifications in response to changing market signals to ensure that it remains appropriate based on market conditions and the Company's strategy.

SACE witness Binz expressed his opinion on the use of a fuel adjustment process as a regulatory tool and testified to the need to introduce solar and storage considerations into the long-term planning process due to the volatility of fuel prices. However, witness Binz did not propose any disallowance in this fuel proceeding but instead, he made the following recommendations that he asserts will further mitigate customer exposure to fossil fuel price volatility: (1) that Commission must consider the volatility of gas prices when making decisions about planning and resource acquisition; (2) the Company should consider solar generation paired with storage; and (3) that the Commission should practice "risk aware" regulation in evaluating and making decisions regarding DEP's resource mix, rates, and other choices that affect customer risk.

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. Witness Walsh testified that this inventory of 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.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 both DEP and DEC perform the same detailed daily process to determine the unit commitment plan that economically and reliably meets the Company's projected system needs over the next seven days. The Company utilizes a production cost model to determine an optimal unit commitment plan to economically and reliably meet system requirements. Witness Verderame testified that the model minimizes the production costs needed to serve the projected customer demand within reliability and other system constraints over a period of time, using numerous factors, including:

forecasted energy demand; forecasted fuel prices; variable transportation rates; planned maintenance and refueling outages; generating unit performance parameters; generating unit reliability constraints; and expected market conditions associated with power purchases. Witness Verderame testified that the production cost model output produces the optimized hourly unit commitment plan for the 7-day forecast period. This unit commitment plan also provides the starting point for dispatch, but dispatch is then also subject to real time adjustments due to changing system conditions including management of natural gas transportation constraints. The unit commitment plan is prepared daily and adjusted, as needed, throughout any given day to respond to changing real time system conditions.

Based upon the fuel procurement practices report and the evidence in the record, the Commission concludes that these practices were reasonable and prudent during the test period though, noting the evidence presented by Public Staff witness Hinton on additional term risk associated with longer term hedge contracts, the Commission also concludes that it is prudent for the Company to periodically consult with the Public Staff and review the Company’s hedging program and recommend modifications, as needed, in response to changing market signals to ensure that it remains appropriate based on market conditions.

Based on the evidence presented by witness Hinton on additional term risk associated with longer term hedge contracts, the DEP shall review its hedging program and recommend modifications in response to changing market signals to ensure that it remains appropriate based on market conditions.

The Commission acknowledges Mr. Binz’s general comments regarding the fuel clause as a regulatory device but concludes that the Commission is bound by North Carolina law and that a general discussion of the fuel adjustment process is not appropriate for this proceeding. With respect to Mr. Binz’s assertion that the Company should use wind and solar energy to the fullest extent possible to hedge against fossil fuel price volatility, including building additional utility scale wind and solar facilities, the Commission agrees that renewable energy resources are important components of the continued reliability and resiliency of the electric grid. The Commission notes that there are other proceedings conducted regularly that address the issues raised by Mr. Binz and concludes that this fuel proceeding is not the appropriate forum in which to evaluate those resources or resource planning in general.

## EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

According to the exhibits sponsored by Company witness Harrington, the test period per book system sales were 60,559,875 MWh, and test period per book system generation (net of auxiliary use) and purchased power amounted to 70,153,063 MWh.

The test period per book system generation and purchased power are categorized as follows (Harrington Exhibit 6):

| Net Generation Type | MWh |
|---|---|
| Nuclear | 29,581,602 |
| Natural Gas, Oil and Biogas | 23,334,027 |
| Coal | 6,371,743 |
| Hydro – Conventional | 623,493 |
| Solar | 257,024 |
| Purchased Power–subject to economic dispatch or curtailment | 3,721,653 |
| Other Purchased Power | 6,263,521 |
| Total Net Generation (may not add to sum due to rounding) | 70,153,063 |

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 60,559,875 MWh and system generation and purchased power of 70,153,063 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 witnesses Ray and Harrington and the testimony of Public Staff affiant Metz.

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. Witness Ray proposed using a 94.05% 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 2022-2023 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 93.49% for the period 2016-2020 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Public Staff affiant Metz stated that although the Company's projected nuclear capacity factor for the billing period is slightly higher than the NERC five-year average, the Company's proposed use of a 94.05% capacity factor is not unreasonable given historic performance and no major unit outages.

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 94.05% nuclear capacity factor, and its associated generation of 29,601,651 MWh per Harrington Exhibit 2, Schedule 1, Page 1, 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 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 37,740,216 MWh, comprised of Residential class sales of 16,792,596 MWh, Small General Service sales of 1,956,415 MWh, Medium General Service sales of 10,468,785 MWh, Large General Service sales 8,202,098 MWh, and Lighting class sales of 320,322 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 is 61,541,989 MWh. The projected level of generation and purchased power used was 69,409,824 MWh (calculated using the 94.05% 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 | 29,601,651 |
| Gas Combustion Turbine and Combined Cycle | 19,494,222 |
| Coal | 9,087,592 |
| Hydro | 667,442 |
| Solar | 264,499 |
| Purchased Power | 10,294,418 |
| Total (may not add to sum due to rounding) | 69,409,824 |

On 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 | 16,637,596 |
| Small General Service | 1,797,603 |
| Medium General Service | 10,360,942 |
| Large General Service | 9,189,937 |
| Lighting | 379,481 |
| Total (may not add to sum due to rounding) | 38,365,559 |

These class totals were used in Revised Harrington Exhibit 2, Schedule 1, Page 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 affidavit of Public Staff affiant Metz.

On her Exhibit 2, Schedule 1, Page 1, 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.

In his affidavit, Public Staff affiant Metz stated that, based on his investigation, the projected fuel and reagent prices set forth in the testimony of Company witnesses were calculated appropriately and in accordance with the requirements of N.C.G.S § 62-133.2. He also notes that eight months of next year's test period will have passed before the billing period in this case begins, which creates a high potential of continued under-recovery if commodity prices remain at their current elevated levels.

No other party presented evidence on the level of DEP's fuel and fuel-related prices and expenses.

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.

According to Revised Harrington Exhibit 2, Schedule 1, Page 3, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $999,696,493. This amount has capped the inclusion of select purchased power fuel and fuel-related cost increases at 2. 5% of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year in accordance with N.C.G.S. § 62-133. 2(a2).

No party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction.

Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $999,696,493 is reasonable and complies with the requirements in accordance with N.C.G.S. § 62-133. 2(a2). Any deviation between the projected fuel and fuel-related costs for the North Carolina retail jurisdiction projected in this proceeding versus actual costs when incurred will be reviewed for prudency and considered for cost recovery in a future fuel proceeding according to the appropriate EMF periods.

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

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Harrington, the affidavits of Public Staff affiants Zhang and Metz, and the testimony and exhibits of SACE witness Binz.

Company witness Harrington presented DEP's fuel and fuel-related expense 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 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. Public Staff affiant Zhang agreed that DEP's EMF increment riders for each customer class should be approved based on the following under-recoveries, which include the deferred under-recovered losses on the sale of by-products of $4.2 million, which were approved to be included in recoverable fuel costs in Docket No. E-2, Sub 1204:

| N. C. Retail Customer Class | Under-Recovery |
|---|---|
| Residential | $108,941,580 |
| Small General Service | 8,781,456 |
| Medium General Service | 61,349,694 |
| Large General Service | 73,664,346 |
| Lighting | 2,671,637 |
| Total (may not add to sum due to rounding) | $255,408,714 |

As a result of these amounts, Public Staff affiant Zhang recommended approval of the following EMF increment billing factors, excluding the regulatory fee:

| N. C. Retail Customer Class | EMF Increment (cents/kWh) |
|---|---|
| Residential | 0. 649 |
| Small General Service | 0. 449 |
| Medium General Service | 0. 586 |
| Large General Service | 0. 898 |
| Lighting | 0. 834 |

Public Staff affiant Metz noted concern regarding the significant under-recovery that took place during the test year. He further stated that, after reviewing discovery and discussing the issue with DEP representatives and the recent trends in commodity prices, the Public Staff was satisfied that the 2022 test year fuel costs were reasonable and prudently incurred.

In reference to the Company's EMF balance as of June 30, 2022, SACE witness Binz testified that, as updated in DEP witnesses Harrington's supplemental testimony, the base fuel rates during the test period under collected actual fuel costs, resulting in the $255.4 million shortfall, which would be added to the fuel and fuel-related costs for the billing period. Witness Binz went on to conclude that because customers underpaid their fuel costs in the review period, they would overpay their fuel costs in the billing period.

DEP witness Harrington filed rebuttal testimony indicating that witness Binz was incorrect in making his conclusion. She testified that Commission rules and general statutes serve to safeguard customers from paying more or less than the actual fuel costs incurred by the Company and that the Company does not earn a return (i.e., make a profit) on fuel costs incurred. She further elaborated that in order to make all parties (NC Retail ratepayers and the Company) whole, the: (1) fuel rate approved in the most recent general rate case; (2) the annual fuel and fuel-related cost rider; and (3) the EMF rider, collectively ensure that NC Retail customers only pay for the actual cost of fuel, no more, nor less. She further noted that N.C.G. S. § 62-133. 2 and Rule R8-55 mandate an annual fuel proceeding to reconcile all components of the fuel rate so that, over a period of 32 months, DEP customers do not over or under pay for the cost of fuel needed to supply their electricity.

Absent any evidence counter to the under-recovered fuel cost balance of $255,408,714 as of June 30, 2022, the Commission concludes that the EMF increment billing factors as set forth in the affidavit of Public Staff affiant Li 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 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 affiant Metz recommended the approval of the total fuel and fuel-related cost factors (excluding regulatory fee) set forth in Table 1 of his affidavit, which align with the total fuel and fuel-related cost factors proposed by the Company in the supplemental testimony of witness Harrington as shown on Revised Harrington Exhibit 1.

Based upon the testimony and exhibits in the record, the Commission concludes that DEP's projected fuel and fuel-related cost of $999,696,493 for the North Carolina retail jurisdiction for use in this proceeding is reasonable and the Public Staff's prospective fuel and fuel-related cost factors set forth in the affidavit of Public Staff witness Metz's affidavit are appropriate.

The Commission also concludes that DEP's EMF under-recovery balance of $255,408,714 was prudently incurred and increment riders for each class set forth in the affidavits of Public Staff affiants Metz and Zhang, excluding the regulatory fee, 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 1272 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this 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, excluding the regulatory fee, of 3.457¢/kWh for the Residential class, 3.546¢/kWh for the Small General Service class, 3.166¢/kWh for the Medium General Service class, 3.036¢/kWh for the Large General Service class, and 4.210¢/kWh for the Lighting class, consisting of the prospective fuel and fuel-related cost factors of 2. 808¢/kWh, 3.097¢/kWh, 2. 580¢/kWh, 2. 138¢/kWh, and 3.376¢/kWh, and EMF increments of 0.649¢, 0.449¢, 0.586¢, 0.898¢, and 0.834¢/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, 2022, 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 0.728¢/kWh, 0.971¢/kWh, 0.352¢/kWh, (0. 066¢)/kWh and 1.984¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.649¢/kWh for the Residential class, 0.449¢/kWh for the Small General Service class, 0.586¢/kWh for the Medium General Service class, 0.898¢/kWh for the Large General Service class, and 0.834¢/kWh for the Lighting class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through November 30, 2023.

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 ________________ 2022.

NORTH CAROLINA UTILITIES COMMISSION

________________________________________

A. Shonta Dunston, 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 | 0.728 | 2.808 | 0.649 | - | 3.457 |
| Small General Service | 2.126 | 0.971 | 3.097 | 0.449 | - | 3.546 |
| Medium General Service | 2.228 | 0.352 | 2.580 | 0.586 | - | 3.166 |
| Large General Service | 2.204 | (0.066) | 2.138 | 0.898 | - | 3.036 |
| Lighting | 1.392 | 1.984 | 3.376 | 0.834 | - | 4.210 |

| 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 | 0.729 | 2.812 | 0.65 | - | 3.462 |
| Small General Service | 2.129 | 0.972 | 3.101 | 0.45 | - | 3.551 |
| Medium General Service | 2.231 | 0.352 | 2.583 | 0.587 | - | 3.170 |
| Large General Service | 2.207 | (0.066) | 2.141 | 0.899 | - | 3.040 |
| Lighting | 1.394 | 1.987 | 3.381 | 0.835 | - | 4.216 |

**Appendix B**

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1292

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

NOTICE IS GIVEN that the North Carolina Utilities Commission entered an Order in Docket No. E-2, Sub 1292, on __________ __, 2022, after public hearing, approving net fuel and fuel-related rate increases of 1.377, 1.420, 0.938, 0.832, and 2.818 cents per kWh (excluding regulatory fee[2]) for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively, or an approximate increase of $337 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, 2022. 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, 2022, 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 3.457¢/kWh, 3.546¢/kWh, 3.166¢/kWh, 3.036¢/kWh, and 4.210¢/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 $10. 88 for each 1,000 kWh of residential usage (including regulatory fee).

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of ________________2022.

NORTH CAROLINA UTILITIES COMMISSION

____________________________________
A. Shonta Dunston, Chief Clerk

[2] Based on a NCRF multiplier of 1.00140196