STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 558

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities	)))))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Monday, November 5, 2018, and Thursday, November 8, 2018, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

Mary Lynne Grigg and Andrea R. Kells, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For Carolina Industrial Group for Fair Utility Rates I:

Ralph McDonald, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For Nucor Steel-Hertford:

Christopher J. Blake, Nelson, Mullins, Riley & Scarborough, 4140 Parklake Avenue, Suite 200, Raleigh, North Carolina 27612

For the Using and Consuming Public:

Lucy E. Edmondson, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On August 30, 2018, Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC or the Company), filed its Application for a fuel charge adjustment, along with accompanying testimony and exhibits, pursuant to N.C. Gen. Stat. § 62-133.2, and North Carolina Utilities Commission (Commission) Rule R8-55 relating to fuel and fuel-related cost adjustments for electric utilities (Application).[1] The Application was supported by the testimony and exhibits of Bruce E. Petrie, Ronnie T. Campbell, Tom A. Brookmire, Gregory A. Workman, and George G. Beasley, as well the additional information and workpapers required by Commission Rule R8-55.

On September 7, 2018, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice.

On September 28, 2018, the Public Staff filed a Motion to Amend Procedural Schedule to provide the Public Staff additional time to investigate, conduct discovery, and prepare testimony.

By Order issued on October 2, 2018, the Commission granted the Public Staff's Motion to Amend Procedural Schedule. The Commission established a deadline of October 25, 2018, for the filing of petitions to intervene, and the direct testimony and exhibits of expert witnesses for the Public Staff and other intervenors. Further, the Commission scheduled a public witness hearing for November 5, 2018, and an expert witness hearing for November 8, 2018.

On October 15, 2018, Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed a Petition to Intervene.

On October 23, 2018, Nucor Steel-Hertford (Nucor) filed a Petition to Intervene.

On October 25, 2018, the Commission granted the Petitions to Intervene of Nucor and CIGFUR.

On October 26, 2018, Nucor filed the direct testimony of Paul J. Wielgus, CIGFUR filed the direct testimony of Nicholas Phillips, Jr., and the Public Staff filed the direct testimony of Dustin R. Metz, Darlene P. Peedin, and Michelle M. Boswell (collectively, Public Staff Panel).

On October 29, 2018, DENC filed its Affidavit of Publication.

On November 5, 2018, the Company filed the rebuttal testimony of Bruce E. Petrie and George G. Beasley.

Also on November 5, 2018, the matter came on for the public witness hearing as scheduled. No public witnesses appeared at the hearing.

[1] Pursuant to N.C.G.S. § 62-133.2(a1) and (a3), which were enacted as part of Session Law 2017-192 (House Bill 589) and Session Law 2018-114 (House Bill 374), the Company is now eligible to recover certain non-fuel (but still fuel-related) costs through the annual rate adjustments authorized pursuant to N.C.G.S. § 62-133.2. For ease of reference, however, throughout this order the costs being considered for recovery shall be termed "fuel costs," and the proceeding shall be termed the "fuel charge proceeding."

On November 6, 2018, the Public Staff, on behalf of all parties, filed a Joint Motion to Excuse Witnesses from appearing at the November 8, 2018 expert witness hearing, stating that all parties had agreed to waive cross-examination of each other's witnesses, and had stipulated to the introduction of all pre-filed testimony and exhibits into the record.

On November 7, 2018, the Commission issued an order granting the parties' Joint Motion to Excuse Witnesses.

The matter came on for the expert witness hearing on November 8, 2018, as scheduled. At the hearing, the Company's Application and the parties' direct and rebuttal testimony and exhibits were received into evidence.

On December 10, 2018, proposed orders were filed by DENC and the Public Staff, and CIGFUR filed a Post-Hearing Brief.

On January 15, 2019, DENC filed a letter correcting the projected nuclear capacity factor that was stated in DENC's proposed order, 93.9%, to its proposed nuclear capacity factor, 94.1%.

Based upon the evidence presented and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. The Company is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. The Company is lawfully before the Commission based on 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 June 30, 2018.

3. The rate period for purposes of this proceeding is the 12 months beginning on February 1, 2019, and ending on January 31, 2020.

4. The Company's fuel procurement practices during the test period were reasonable and prudent.

5. The per books test period system sales are 86,260,348,958 kilowatt-hours (kWh).

6. The per books test period system generation is 89,584,657 megawatt-hours (MWh), which includes various types of generation as follows:

Generation Types	MWh
Nuclear	27,650,942
Coal	13,543,704
Heavy Oil	357,813
Wood and Natural Gas Steam	1,374,673
Combined Cycle and Combustion Turbine	29,436,131
Solar and Hydro – Conventional and Pumped	3,437,770
Net Power Transactions	17,153,828
Less: Energy for Pumping	(3,370,203)

7. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

8. The nuclear capacity factor appropriate for use in this proceeding is 94.1%, which is the estimated nuclear capacity factor for the 12 months beginning February 1, 2019.

9. The adjusted test period system sales for use in this proceeding are 85,266,747,633 kWh.

10. The adjusted test period system generation for use in this proceeding is 88,445,965 MWh, which is categorized as follows:

Generation Types	MWh
Nuclear	27,578,419
Coal (including wood and natural gas steam)	14,686,411
Heavy Oil	352,223
Combined Cycle and Combustion Turbine	28,978,466
Hydro	3,337,366
Solar	100,404[2]
Net Power Transactions	16,883,282
Less: Energy for Pumping	(3,370,203)

11. A marketer percentage serves as a proxy for fuel costs when actual fuel costs associated with power purchases are not available. The current marketer percentage of 78% should be used in calculating the projected fuel costs during the rate period, subject to further review and true-up based on evidence presented in DENC's 2019 fuel case and/or next general rate case.

12. The adjusted test period system fuel expense for use in this proceeding is $1,824,035,658.

[2] The adjusted test period system generation total of 88,445,965 MWh does not include the solar MWh.

13. The proper fuel factors for Rider A for this proceeding, including the regulatory fee, are as follows:

Customer Class	Rider A
Residential	0.071 ¢/kWh
SGS & PA	0.071 ¢/kWh
LGS	0.068 ¢/kWh
Schedule NS	0.068 ¢/kWh
6VP	0.069 ¢/kWh
Outdoor Lighting	0.071 ¢/kWh
Traffic	0.071 ¢/kWh

14. The appropriate North Carolina retail test period jurisdictional fuel expense under collection is ($16,162,154), and the adjusted North Carolina retail jurisdictional test period system sales are 4,175,472,287 kWh.

15. It is appropriate to accept the Company's full recovery proposal and to establish rates in this proceeding to recover 100% of the test period fuel expense under collection in the upcoming rate period.

16. The appropriate Experience Modification Factors (EMF or Rider B) for this proceeding (including the regulatory fee) are as follows:

Customer Class	EMF Billing Factor
Residential	0.392 ¢/kWh
SGS & PA	0.392 ¢/kWh
LGS	0.389 ¢/kWh
Schedule NS	0.377 ¢/kWh
6VP	0.383 ¢/kWh
Outdoor Lighting	0.392 ¢/kWh
Traffic	0.392 ¢/kWh

17. The total fuel factors to be billed to the Company's retail customers during the February 1, 2019 through January 31, 2020 fuel charge billing period, including the regulatory fee, are as follows:

Customer Class	Class-Specific Prospective Factor
Residential	2.558 ¢/kWh
SGS & PA	2.556 ¢/kWh
LGS	2.536 ¢/kWh
Schedule NS	2.459 ¢/kWh
6VP	2.495 ¢/kWh
Outdoor Lighting	2.558 ¢/kWh
Traffic	2.558 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

North Carolina General Statute Section 62-133.2(c) sets out the verified, annualized information that each electric utility is required to provide to the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending June 30 as the test period for the Company. The Company's filing was based on the 12 months ended June 30, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding is contained in the Commission's rules, the direct testimony of Company witnesses Petrie and Beasley, and the direct testimony of Public Staff witness Metz.

Commission Rule R8-55(b) provides for annual public hearings to review changes in each electric public utility's cost of fuel and fuel-related costs. Company witness Petrie testified that in previous years the Company has proposed Rider A and Rider B rates to be effective for a calendar year rate period. Based on discussions with the Public Staff following the conclusion of DENC's 2017 fuel and other two rider proceedings (DSM/EE and REPS), the Company is proposing that its updated fuel and other two riders become effective for a February 1, 2019 through January 31, 2020 rate period. Witness Petrie explained that this adjustment will extend the time for the Commission to issue orders in the Company's three annual rider proceedings, and allow the Company additional time to finalize rates and customer notices, including allowing reasonable time for Public Staff review, prior to the updated annual riders' effective date. He stated that the Company intends to continue to use a February 1 through January 31 rate period in future rider cases.

Company witness Beasley testified that because the existing tariffs approved in the Company's last fuel factor proceeding, Docket No. E-22, Sub 546, will expire on December 31, 2018, DENC is proposing interim tariffs for January 2019 showing Riders A and B both set to zero, and updated rate period tariffs for February 2019 through January 2020.

No party other than the Public Staff offered testimony on the above rate adjustment guidelines of DENC. The Public Staff recommended acceptance of the Company's proposed rates with an effective date of February 1, 2019. In addition, the Company's proposal to change the rate period to begin on February 1 is consistent with the Petition filed by the Public Staff in Docket No. E-100, Sub 160 on September 6, 2018, wherein the Public Staff opined that moving the effective date of DENC's new cost recovery riders to February 1 would alleviate the burden on the Commission, the Public Staff, and the Company to file and issue proposed and final orders and implement revised rates by January 1 each year. On October 11, 2018, the Commission issued an order adopting the Public Staff's recommendation.

Based on the evidence presented, the Commission finds and concludes that DENC's proposal to adjust the rate period for its fuel rider to February 1 through January 31 is reasonable and should be approved. In addition, for January 2019, the Company shall reduce the rates charged under Rider A and Rider B to zero, as proposed, and shall begin charging the updated rates under the schedules approved herein beginning February 1, 2019.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the direct testimony and exhibits of Company witnesses Workman and Brookmire.

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 current fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, on December 20, 2013.

In his direct testimony, Company witness Workman explained that because of rising global oil prices, natural gas exports, and an increase in domestic natural gas demand, domestic natural gas production increased during the test period. He stated that natural gas prices were relatively high during January 2018, and that coal and oil prices also rose as compared to prices in the prior test period.

Witness Workman described the Company's fuel procurement practices and explained that the Company continues to follow the same procurement practices that it has followed in the past, in accordance with its report filed in Docket No. E-100, Sub 47A. He also testified to the Company's price hedging program under which it price hedges commodities needed for power generation using a range of volume targets, gradually decreasing over a three-year period.

With regard to natural gas procurement, witness Workman explained that the Company employs a disciplined natural gas procurement plan to ensure a reliable supply of natural gas at competitive prices. He stated that through periodic solicitations and the open market, the Company serves its gas-fired fleet using a combination of day-ahead, monthly, seasonal, and multi-year physical gas supply purchases. Witness Workman also described how the Company evaluates its diverse portfolio of pipeline transportation and storage contracts to determine the most reliable and economical delivered fuel options for each power station, and how this portfolio of natural gas transportation contracts provides access to multiple natural gas supply and trading points from the Marcellus shale region to the southeast region. He also noted that the Company actively participates in the interstate pipeline capacity release and physical supply markets, as well as longer term pipeline expansion projects that will augment its transportation portfolio and enhance reliability at a reasonable cost. Further, witness Workman testified that since the Company's 2017 fuel charge adjustment proceeding the Company has continued to utilize more natural gas to serve its customers' electricity needs, noting that during the test period in this case energy production at its gas-fired power stations accounted for about 33% of the electricity produced for customers. Finally, he testified that in late 2018 the Company will add the Greensville County Power Station (Greensville Station or Greensville) to its regulated fleet.

With respect to coal procurement, witness Workman testified that the Company employs a multi-year physical procurement plan to ensure a reliable supply of coal, delivered to its generating stations by truck or rail, at competitive prices. According to witness Workman, the Company accomplishes this by procuring long-term coal requirements primarily through periodic solicitations and secondarily on the open market for short-term or spot needs. He noted that this blend of contract terms creates a diverse coal fuel portfolio, and allows the Company to proactively manage its fuel procurement strategy, contingency plans, and any risk of supplier non-performance.

Witness Workman also testified that the Company has a varied procurement strategy for its biomass stations depending on their geographical region. He stated that the Company's biomass stations at Hopewell and Southampton continue to be served by multiple suppliers under long-term agreements, which enables the Company to increase the reliability of its biomass supply by diversifying it supplier base. He also stated that the Company continues to purchase long-term fuel supply through one supplier for its Altavista Power Station, and to procure biomass needs for the Virginia City Hybrid Energy Center via short-term contracts with various suppliers.

Finally, witness Workman described how, with respect to its oil procurement practices, the Company purchases No. 2 fuel oil and No. 6 fuel oil requirements on the spot market, and optimizes its inventory, storage, and transportation to ensure reliable supply.

Company witness Brookmire testified that the nuclear fuel market has softened considerably in the past six to seven years, largely due to the earthquake and tsunami in Japan in March 2011, but also due to reductions in demand. He stated that some reductions in supply have in part offset some of the downward trend in demand, and that the spot market price for conversion services has dropped significantly due to reduced near-term demand, while long-term prices have remained high. He also testified that the cost for enrichment services has declined slightly due to reduced demand and the addition of new centrifuge capacity in Europe in recent years. He explained that the price trend in the U.S. domestic nuclear fuel fabrication industry continues to be difficult to measure due to the lack of a spot market, but the general consensus is that costs will continue to increase due to regulatory requirements, reduced competition, new reactor demand in the U.S. and abroad, and financial distress recently experienced by parent companies for U.S. nuclear fuel fabricators. He also pointed out that there might be some short-term price lift on front-end components due to the potential restart of several more reactors in Japan and the growth of China's nuclear energy program.

Witness Brookmire stated that these changes in market costs have not significantly impacted the Company's projected near-term costs, as the Company's current mix of longer-term front-end component contracts has reduced the Company's exposure to the market price escalation and volatility that has occurred over the past several years. Witness Brookmire also pointed out that the 18-month refueling schedule for the Company's nuclear plants delays the full effect of any significant changes in a component price. He also stated that the Company has been active in the market and has some market-based and fixed price contracts that allow the Company to take advantage of current lower prices. In addition, witness Brookmire testified that the Company continues to follow the same procurement practices as it has in the past, in accordance with the procedures filed in Docket No. E-100, Sub 47A.

Witness Brookmire also testified that the Company does not currently anticipate that any significant effect on its nuclear fuel supply will result from Westinghouse filing for Chapter 11 bankruptcy in March 2017. He also stated that the outcome of the Section 232 petition filed by two U.S. miners in January 2018 is uncertain at this time, but that the Company expects to hear the results of the Department of Commerce investigation by late 2019.

No party offered testimony contesting the Company's fuel procurement practices. Based on the evidence, the Commission concludes that the Company's fuel procurement and power purchasing practices during the test period were reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-6

The evidence for these findings of fact is contained in the direct testimony and exhibits of Company witnesses Campbell and Petrie.

Company witness Campbell testified that the Company's per books test period system sales were 86,260,348,958 kWh, and witness Petrie testified that the Company's per books test period system generation was 89,584,657 MWh. Witness Petrie stated that the per books test period system generation is categorized as follows:

Generation Types	MWh
Nuclear	27,650,942
Coal	13,543,704
Heavy Oil	357,813
Wood and Natural Gas Steam	1,374,673
Combined Cycle and Combustion Turbine	29,436,131
Solar and Hydro – Conventional and Pumped	3,437,770
Net Power Transactions	17,153,828
Less: Energy for Pumping	(3,370,203)

No other party offered or elicited testimony on the level of per books test period system MWh sales or generation. Based on the evidence, the Commission finds and concludes that the foregoing test period per books levels of sales and generation are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is contained in the direct testimony of Company witness Petrie and the testimony of Public Staff witness Metz.

For purposes of determining the EMF rider, Commission Rule R8-55(k) requires that a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent five-year period available as reflected in the most recent Generating Availability Report of the North American Electric Reliability Corporation (NERC), appropriately weighted for size and type of plant, or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent five-year period available as reflected in the most recent NERC Generating Availability Report, appropriately weighted for size and type of plant. Pursuant to Rule R8-55(k), if a utility does not meet either standard, a rebuttable presumption is created that the increased cost of fuel was incurred imprudently and a disallowance may be appropriate. Further, 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.

In his direct testimony, Company witness Petrie testified to the performance of the Company's major generating units during the test period. Witness Petrie also testified that the Company's net capacity factors during the test period for its four nuclear units were:

North Anna Unit 1	91.4%
North Anna Unit 2	92.7%
Surry Unit 1	90.3%
Surry Unit 2	102.7%

Witness Petrie stated that the aggregate capacity factor for the Company's nuclear units during the test period was 94.2%, which exceeded the five-year industry weighted average capacity factor of 89.8% for the period 2012-2016 for 800-999 megawatt (MW) units, as reported by NERC in its latest Generating Availability Report. In addition, witness Petrie testified that for the same five-year period (i.e., 2012-2016), the Company's net nuclear capacity factor was 93.5%, compared to the national average of 89.8%. Based on these figures, he stated that the Company's nuclear fleet performance during the test period was clearly better than the industry five-year average for comparable units.

Public Staff witness Metz testified that the Company met the standards of Commission Rule R8-55(k) with both an actual system-wide capacity factor and a two-year simple average of the system wide capacity factor that exceeded the NERC weighted average capacity factor.

Based upon the evidence in the record, the Commission concludes that DENC managed its nuclear baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is contained in the direct testimony of Company witness Petrie.

Witness Petrie testified that for the 12-month rate period ending January 31, 2020, North Anna Unit 1 is projected to operate at a net capacity factor of 93.9%, North Anna Unit 2 is projected to operate at a net capacity factor of 90.3%, Surry Unit 1 is projected to operate at a net capacity factor of 91.8%, and Surry Unit 2 is projected to operate at a net capacity factor of 100.2%. Witness Petrie testified that based on this projection, the Company normalized expected nuclear generation and fuel expenses in developing the proposed fuel cost rider, and that DENC's projected fuel costs are based on a 94.1% nuclear capacity factor, which is what DENC anticipates for the 12 months from February 1, 2019 through January 31, 2020, the period the new rates will be in effect. No party offered testimony contesting the projected normalized system nuclear capacity factor.

On January 15, 2019, DENC filed a letter correcting the projected nuclear capacity factor stated in DENC's proposed order, 93.9%, to its proposed nuclear capacity factor, 94.1%. DENC stated that this change does not impact the fuel rates it has proposed in this docket. In addition, DENC stated that it notified the other parties of this clarification, and none of the parties object to DENC's filing of this letter for clarification.

Based on the foregoing evidence, the Commission concludes that a projected normalized system nuclear capacity factor of 94.1% is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is contained in the direct testimony of Company witness Beasley and the testimony of the Public Staff Panel.

Witness Beasley testified that he was sponsoring the calculation of the adjustment to the Company's system sales for the 12 months ended June 30, 2018, due to changes in usage, weather normalization, and customer growth. Witness Beasley stated that the adjustment is consistent with the methodology used in the Company's last general rate case (Docket No. E-22, Sub 532), and the Company's last fuel charge adjustment case (Docket No. E-22, Sub 534). Witness Beasley adjusted total system Company sales by 993,601,325 kWh. He stated that this adjustment is the sum of adjustments for changes in usage, weather normalization, and customer growth. The Public Staff reviewed and accepted these adjustments. No other party offered or elicited testimony on the adjustment.

Based on the evidence, the Commission finds and concludes that DENC's adjustments for changes in usage, weather normalization, and customer growth are reasonable and appropriate adjustments for use in this proceeding, resulting in 85,266,747,633 kWh as the adjusted system sales for the 12 months ended June 30, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the direct testimony of Company witness Petrie, and the testimony of the Public Staff Panel.

Company witness Petrie presented an adjustment to per books MWh generation for the 12-month period ended June 30, 2018, to incorporate nuclear generation based upon the expected future operating parameters for each unit. Other sources of generation were then normalized, including an adjustment for weather, customer growth, and increased usage. According to Company witness Petrie, this methodology for normalizing test period generation resulted in an adjusted generation level of 88,445,965 MWh. The Public Staff accepted this adjusted generation level, which includes various types of generation as follows:

Generation Types	MWh
Nuclear	27,578,419
Coal (including wood and natural gas steam)	14,686,411
Heavy Oil	352,223
Combined Cycle and Combustion Turbine	28,978,466
Hydro	3,337,366
Solar	100,404[3]
Net Power Transactions	16,883,282
Less: Energy for Pumping	(3,370,203)

No other party offered or elicited testimony on the adjusted test period system generation for use in this proceeding. Based on the evidence, the Commission concludes that the adjusted test period system generation level of 88,445,965 MWh is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact is contained in the Commission's Order Approving Rate Increase issued December 22, 2016, in Docket No. E-22, Sub 532 (Sub 532 Order), the Commission's final order in DENC's 2017 fuel adjustment proceeding (Docket No. E-22, Sub 546), the direct testimony of Company witness Campbell, the direct and rebuttal testimony of Company witness Petrie, and the testimony of the Public Staff Panel.

In his direct testimony, Company witness Petrie testified that the Company believes that its current marketer percentage of 78% is reasonable, and, therefore, that DENC is not proposing a change to the marketer percentage in this case. In his direct testimony, Company witness Campbell explained that the 78% marketer percentage was agreed to between the Company and the Public Staff and approved by the Commission in the Company's 2016 fuel factor proceeding in Docket No. E-22, Sub 534. He stated that in accounting for non-utility generator (NUG) energy costs, for dispatchable NUGs that do not provide actual fuel costs, the Company included 78% of the reasonable and prudent energy costs in the EMF calculation, and to the extent a dispatchable NUG provides market-based energy rather than dispatching its facility, DENC included 78% of the reasonable and prudent energy costs for that market-based energy in the EMF calculation.

Public Staff witness Peedin testified to the origin and purpose of the marketer percentage. She testified that costs recoverable by DENC in an annual fuel proceeding are set forth in N.C.G.S. § 62-133.2(a3). She explained that because DENC buys substantial amounts of purchased power in transactions where the fuel cost component of the purchased power is not disclosed, a marketer percentage is used as a proxy to determine the cost to be recovered by the Company through the fuel factor. Witness

[3] The adjusted test period system generation total of 88,445,965 MWh does not include the solar MWh.

Peedin testified that the Commission approved a Stipulation between the Public Staff and DENC in the Sub 532 Order that provided in Section IV.A:

> The Stipulating Parties agree to adjust the Company's base fuel and non-fuel expenses to reflect 78% as a proxy for the fuel cost component of energy purchases for which the actual fuel cost is unknown (Marketer Percentage). This represents a reduction from the Company's current Marketer Percentage of 85%. The 78% Marketer Percentage shall remain in effect until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

Sub 532 Order, at p. 18.

Witness Peedin also pointed out that the Commission directed in Sub 546 that the marketer percentage would be reviewed in the 2018 fuel proceeding or the next general rate case, whichever occurred first.[4] Further, witness Peedin stated that the Public Staff agrees with the Company's application of the 78% marketer percentage for the test year EMF, but does not agree that it should remain at 78% for the rate period. She stated that the Public Staff used two methods to determine an appropriate marketer percentage. First, using a methodology proposed by DENC in its 2008 fuel proceeding, Docket No. E-22, Sub 451, she took the fuel component of the cost of energy from the 2016 and 2017 State of the Market reports for PJM, along with data provided by the Company that blended DENC's internal data with PJM State of the Market report data for the Dominion Zone for calendar years 2016 and 2017, and applied a proprietary calculation, filed as confidential information, that yielded a 75% marketer percentage, as set forth in Confidential Peedin Exhibit 1.

In addition, witness Peedin testified that the Public Staff performed a second analysis to serve as a test of reasonableness of the proposed 75% marketer percentage. She stated that the Public Staff used the off-system sales of Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), during calendar years 2016 and 2017, to determine what their marketer percentage would have been using fuel costs embedded in off-system sales as a measure. She stated that the fuel to energy cost ratio resulting from this calculation was 66.19% for DEC and 55.75% for DEP.

Finally, witness Peedin testified that the Public Staff is not recommending that the 75% marketer percentage be used by DENC in calculating its prospective fuel rates in the present case because that would result in higher rates than those recommended by DENC. Instead, the Public Staff recommends that DENC true-up PJM purchases, certain NUGs, and the effect of the fuel savings due to the addition of the Greensville Station in next year's EMF (July 2018 – June 2019) to reflect the implementation of the 75% marketer percentage effective February 1, 2019.

In rebuttal, DENC witness Petrie testified that the Company disagrees with the Public Staff's proposed 75% marketer percentage because it would deny the Company

[4] Order Deciding Contested Issues and Requiring Compliance Filing, at p. 23 (January 25, 2018).

an opportunity to recover all of its prudently incurred PJM costs. He contended that any change in the percentage should be made in conjunction with the Company's next base rate case. Witness Petrie further contended that the 78% marketer percentage is a better representation of fuel-related costs, and is consistent with the Company's method used in the Sub 532 general rate proceeding.

The burden of proving the amount of DENC's fuel costs, including the fuel portion of purchased power, is on DENC. N.C.G.S. § 62-133.2(d). DENC provided no substantial evidence to support its position that the marketer percentage should remain at 78%. Company witnesses Petrie and Campbell merely stated that the Company believes that its current marketer percentage of 78% is reasonable, that the 78% marketer percentage was agreed to between the Company and the Public Staff and approved by the Commission in the Company's 2016 fuel factor proceeding in Docket No. E-22, Sub 534, and that it should not be changed until DENC's next general rate case.

The Commission finds it appropriate to review the marketer percentage in this proceeding, as provided in the Stipulation agreed to by DENC and the Public Staff and approved by the Commission in the Sub 532 Order. There is no requirement that the marketer percentage be reviewed and changed only in conjunction with a rate case. Indeed, such a requirement could result in the marketer percentage not being reviewed for several years, and possibly becoming inaccurate as a proxy for DENC's purchased power fuel costs. The Sub 532 and Sub 546 Orders both contemplate that the marketer percentage may be reviewed and changed in this fuel adjustment proceeding.

However, the Commission is not persuaded that it should change the marketer percentage in the present case. Although the Commission gives weight to the Public Staff's evidence for a reduction in the marketer percentage, the Commission also gives countervailing weight to the Public Staff's proposal that the 75% marketer percentage should not be used in calculating DENC's prospective fuel rates, but, rather, that it should be applied to true-up DENC's fuel cost recovery as a part of DENC's July 2018 – June 2019 EMF in DENC's 2019 fuel adjustment proceeding. The Commission understands the Public Staff's reasoning in recommending this approach, but also concludes that adopting the Public Staff's proposed 75% marketer percentage today for application a year from now would be premature. Instead, the Commission concludes that ratepayers and the parties will be better served by revisiting the marketer percentage issue in DENC's 2019 fuel adjustment proceeding, and/or DENC's next general rate case. At that time, the parties and the Commission will have more current data to use in determining what the marketer percentage should be for DENC's fuel costs from February 1, 2019 forward.

The Commission acknowledges that this approach may create some uncertainty for DENC. However, it is the same uncertainty that exists in projecting the other factors that are used in setting prospective fuel rates, such as baseload capacity factors and the mix of generation that will occur during the rate period. That inherent uncertainty is the reason that actual fuel costs and revenues are reviewed each year and trued-up in an EMF. Further, the marketer percentage is a proxy for DENC's purchased power fuel costs. It assists DENC to meet its burden of proof where DENC purchases power from sellers that wish to maintain their fuel costs as confidential information. Based on these circumstances, it is fair to appropriate a reasonable level of uncertainty to DENC, rather than to require DENC's ratepayers to pay what might be excess fuel costs.

Based on a preponderance of the evidence, the Commission finds and concludes that it is reasonable in this proceeding for the Company to use the existing 78% marketer percentage as a proxy for fuel costs associated with purchases from suppliers that do not provide DENC with actual fuel costs in projecting its fuel costs from February 2019 forward, subject to the Commission's review of all marketer percentage evidence to be presented in DENC's 2019 fuel adjustment case, and/or DENC's next general rate case, and subject to a possible change in the marketer percentage to be applied to fuel costs effective February 1, 2019 forward, based on that more current evidence.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-13

The evidence for these findings of fact is contained in the direct testimony of Company witnesses Petrie and Beasley, and the testimony of Public Staff witnesses Metz and Peedin.

Company witness Petrie presented the Company's system fuel expense for the test period and the normalized system fuel expenses for the upcoming rate period of $1,824,035,658. He testified that the fuel under-recovery experienced by the Company during the test year was primarily driven by colder winter weather and higher commodity prices. He noted that the energy use in January 2018 reached a peak of 21,232 MW, which is close to the Company's all-time peak experienced in the winter of 2015. He also noted that the fuel expense created by the extended period of cold weather in January was a major factor in the amount of the EMF in this case. He stated that the Company offset the higher market fuel prices by optimizing its diverse fleet of generating assets to reduce system fuel expense. He further testified that he used the expense normalization methodology that has been used by the Company and approved in previous North Carolina annual fuel factor proceedings. Specifically, he testified that the first step in computing normalized system fuel expense is to calculate nuclear generation based on the expected future operating parameters for each unit, and that the expected generation from the nuclear units was calculated for the 12-month period ending January 2020, with other sources of generation then normalized for the test period. He further testified that the total of coal, heavy oil, combustion turbine and combined cycles, non-utility generation (NUG), and purchased energy during the test period was then calculated, and a percentage of this total was then calculated for each of these resources. According to witness Petrie, a normalized generation was computed by applying these percentages to a new total, including an adjustment for weather, customer growth, increased usage, and the net change in nuclear generation. He stated that this methodology for normalizing the test period generation resulted in adjusted annual system energy requirements of 88,445,965 MWh.

Witness Petrie also testified that the addition of DENC's 1,588 MW Greensville Station in December 2018 will benefit system fuel expense. He stated that the system fuel expense in this case was adjusted to reflect the expected fuel benefits related to the

Greensville Station. He stated that the Company does not anticipate a significant impact to system fuel expense from the placement of several generating units in cold reserve until 2021. Finally, he noted that due to the enactment of House Bill 589 and House Bill 374, the Company can now recover the total delivered costs, including capacity and non-capacity costs, associated with certain purchases of power from qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 that are not subject to economic dispatch or curtailment. He stated that reflecting those costs in DENC's fuel costs increases system fuel expense by approximately $29.4 million.

Company witness Beasley presented the Company's calculation of the Fuel Cost Rider A applicable for each North Carolina retail jurisdiction customer class. He first determined the average system fuel factor of 2.142 ¢/kWh, based on system fuel expenses of $1,824,035,658, and system sales of 85,266,747,633 kWh, that reflected adjustments for changes in usage, weather normalization, and customer growth. Witness Beasley also presented the calculations used to differentiate the jurisdictional base fuel component by voltage to determine the class fuel factors, and he testified that these are consistent with the methodology used in the Company's previous fuel proceeding, Docket No. E-22, Sub 546. In his testimony, Public Staff witness Metz stated that he agreed with the Company's determination and calculation of its proposed Rider A.

Based upon the foregoing, the Commission concludes that the appropriate level of fuel expenses to be used to set the prospective, or forward-looking, fuel factor in this proceeding is $1,824,035,658.

The Commission further concludes that the proper prospective Rider A fuel factors for use in this proceeding, including the regulatory fee, are as follows:

Customer Class	Rider A
Residential	0.071 ¢/kWh
SGS &PA	0.071 ¢/kWh
LGS	0.068 ¢/kWh
Schedule NS	0.068 ¢/kWh
6VP	0.069 ¢/kWh
Outdoor Lighting	0.071 ¢/kWh
Traffic	0.071 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-16

The evidence for these findings of fact is contained in the Company's Application, the direct testimony of Company witness Petrie, the direct and rebuttal testimony of Company witness Beasley, the testimony of Public Staff witnesses Boswell and Metz, the testimony of Nucor witness Wielgus, and the testimony of CIGFUR witness Phillips.

In his direct testimony, Company witness Beasley testified that DENC's fuel cost under-recovery deferral balance for the test period applicable to the North Carolina jurisdiction is $16,162,154. He stated that this substantial under-recovery is largely due to cold winter weather and higher commodity prices, specifically for an extended period in January 2018. He clarified that the Company is seeking Commission approval of the full recovery rates, which will allow the Company to recover 100% of the June 30, 2018 fuel deferral account balance of $16,162,154 over the February 1, 2019 through January 31, 2020 rate period. He also testified, however, that while North Carolina law allows prompt recovery of these expenses, the Company recognizes the impact of such an increase in fuel rates on its customers. Therefore, as an alternative to the full recovery rate, the Company proposed a recovery alternative that would help mitigate the increase. Under the mitigation alternative, the Company would waive its right to recover the full deferral balance over the upcoming rate period in favor of recovering the balance on a dollar-for-dollar basis over the next two rate periods, with a final true-up to be recovered or refunded during the rate period commencing on February 1, 2022. As a result, the rates established in this proceeding would recover 50% of the deferral balance in the upcoming rate period, and the Company would establish rates in the 2019 fuel factor proceeding to recover the remaining deferral balance in the February 1, 2020 through January 31, 2021 rate period. Further, in the 2021 fuel proceeding the Company would establish rates during the February 1, 2022 through January 31, 2023 rate period to recover or refund any final over- or under-recovery of the original deferred balance. Witness Beasley testified that if the Commission declines to approve the Company's full recovery request and approves the mitigation alternative, DENC would further agree to ensure that its customers will see no incremental cost associated with financing the deferral balance over the extended period.

Public Staff witness Boswell testified that she reviewed the calculations of the EMF provided by DENC, and based on that review recommends that DENC's EMF increment rider for each customer class, Rider B, be based on a net under-recovery of fuel and fuel-related costs of $16,162,154 and the Company's pro forma North Carolina retail sales of 4,175,472,287 kWh. She stated that this conclusion is consistent with the Company's Application, and that this produces an aggregate EMF increment rider, before class-specific voltage differentiation, of $0.00388 per kWh, including the regulatory fee, for all North Carolina retail customer classes.

Witness Boswell also testified that the Public Staff supports the Company's request for full recovery in this case. She explained that the increased fuel expenses due to periods of cold weather are not new to the region or to DENC, and are likely to occur again, impacting future fuel cases. She noted that if similar weather occurs again, resulting in another under-recovery, then that under-recovery would presumably need to be recovered along with the under-recovery related to the mitigation alternative, and, therefore, if full EMF recovery was ordered in that case as normally expected, the mitigation alternative would compound any under-recovery in future fuel cases, and further increase the rates to be collected in those future years. She opined that this could result in a snowball effect as past costs continue to be deferred for future recovery beyond the time periods contemplated by statutes, Commission rules, and normal Commission practices. She also noted witness Metz's testimony that DENC overstated its fuel credit related to the Greensville Station, which the Public Staff believes will result in an under-recovery in the 2019 EMF period. In addition, she stated that if the Company receives a base rate increase in 2019, customers would likely pay higher base rates and fuel costs than they would without the mitigation alternative. She concluded that, in the long term, it is in customers' interest for DENC to recover the under-recovery in full over the upcoming rate period. Witness Boswell also indicated that if the Commission accepts the mitigation alternative, the Public Staff recommends that the Commission also accept the Public Staff's proposal regarding the Greensville Station credit adjustment, as detailed by witness Metz, and include the adjustment in the rate period increment calculations.

Public Staff witness Metz testified that the Public Staff was particularly concerned in its investigation of the test-year fuel costs with the significant under-recovery that took place due to greater than expected fuel costs in January 2018. He stated that after reviewing discovery responses and discussing the issue with the Company, the Public Staff believes that the January 2018 fuel costs were reasonably and prudently incurred.

In his testimony, Nucor witness Wielgus testified in support of the Company's proposed mitigation alternative. He stated that the full deferral amount is materially significant, and that the impact on Nucor's facility in North Carolina is estimated to be almost $300,000 per month if the deferral is collected on a 12-month basis. He stated that this would amount to rate shock and would negatively impact Nucor's competitiveness.

CIGFUR witness Phillips testified that the mitigation alternative would result in less rate shock to the Company's North Carolina retail customers, particularly its declining industrial base, at no additional cost to ratepayers, and that it is, therefore, in the public interest. He also noted that the Commission approved a mitigation proposal by the Company in its 2014 fuel proceeding that amortized a similar $16,602,670 under-collection over two years without interest.

In his rebuttal testimony, Company witness Beasley stated that on October 31, 2018, subsequent to the Company filing its Application and direct testimony and exhibits, DENC's Rider EDIT expired. He provided a schedule showing the updated impact to typical bills for both the full recovery and mitigation alternatives, considering the expiration of Rider EDIT. He also noted that on October 25, 2018, the Company made a filing in Docket No. E-22, Sub 560 to reduce its non-fuel base rates to reflect the reduction in the federal corporate income tax rate as provided in the Tax Cuts and Jobs Act (Tax Act), as directed by the Commission in its October 5, 2018 Order issued in Docket No. M-100, Sub 148. Noting that the proposed reduction in non-fuel base rates has not been approved by the Commission, he also provided a schedule showing the impact on typical customer bills of both the full recovery and mitigation alternative combined with the proposed Tax Act reduction.

Witness Beasley further testified that the Company recognizes and is sensitive to the concerns of large industrial customers, as expressed by CIGFUR witness Phillips and Nucor witness Wielgus. He stated that the Tax Act reduction would help offset in part the impact of the fuel increase on customers, and noted that the Company proposed a re-billing back to January 1, 2018, of the final approved rates in the Sub 560 tax docket, which will provide a one-time credit to customers if approved. He also recognized, however, that even when the proposed Tax Act reduction is considered, the impact of the full recovery of fuel expense on these customer classes still results in a substantial increase. He testified that the Company, therefore, continues to offer the mitigation alternative.

Public Staff witness Peedin noted that the Company did not use a fuel cost marketer percentage in the Greensville Station Credit Adjustment, instead reflecting the Adjustment at a 100% fuel level. Witness Metz testified that the capacity factor used for Greensville is likely higher than should be reasonably expected for the February through June 2019 portion of the test period that will be included in the next fuel proceeding. Witness Metz stated that it is not unusual when a new generation plant becomes commercially available that it undergoes tests and inspections over the first six months or so to ensure proper operation, resulting in its average capacity factor for the first six months of operation being lower than for the next six months. He stated that had the marketer percentage been applied to Greensville, along with a lower capacity factor for the first six months of operation, the expected overall fuel cost savings from Greensville for the billing period beginning February 1, 2019, would be diminished, resulting in higher rate period fuel costs than were included in the Company's Application. He further stated that if the Commission approves the Company's mitigation alternative, the Public Staff recommends that DENC include in this year's rider the cost savings from Greensville with the 75% marketer percentage, and a modification to the proposed capacity factor for the first six months of commercial operation of Greensville to better align with the 2019 fuel case test period.

In his rebuttal testimony, Company witness Petrie stated that if the Commission accepts the rate mitigation alternative, the Company would work with the Public Staff to revise the Greensville Station adjustment to account for a lower initial capacity factor, and to apply the marketer percentage to the Greensville savings estimate.

In its Post-Hearing Brief, CIGFUR recounted the testimony of CIGFUR witness Phillips and Nucor witness Wielgus in support of the mitigation alternative. CIGFUR cited their testimony concerning rate shock for industrial customers, and the potential for cascading negative effects on regional economies. In conclusion, CIGFUR recommended that the Commission accept DENC's mitigation alternative.

Based on the evidence in this proceeding, the Commission concludes that it is appropriate to accept the Company's full recovery proposal. The Commission recognizes the difficulty that this will place on the Company's customers, including the specific burden on the industrial customers. However, the Commission finds persuasive the testimony of the Public Staff regarding the risk of a snowball effect should the Company experience another under-recovery during the upcoming rate period, which would only continue to burden DENC's customers, perhaps to an even greater degree. The Commission is also persuaded by Company witness Beasley's rebuttal testimony as to the impact of the Tax Act non-fuel base rate reductions proposed in Docket No. E-22, Sub 560. While these have not yet been ruled upon, some reduction in DENC's non-fuel base rates due to the Tax Act is likely to occur in the coming year, and that reduction will help to offset, in part, the increase in fuel rates approved in this proceeding. Because the Commission concludes that full recovery is appropriate, the Public Staff's proposal to adjust the projected savings for the Greensville Station and to apply the marketer percentage to the Greensville adjustment as a part of the mitigation alternative is moot.

The Commission further concludes that the appropriate North Carolina retail test period jurisdictional fuel expense under-collection is $16,162,154, and that the adjusted North Carolina jurisdictional test period sales appropriate for computing the EMF, Rider B, are 4,175,472,287 kWh.

The appropriate EMF factors, Rider B, for this proceeding, including interest and the regulatory fee, are as follows:

Customer Class	EMF Billing Factor
Residential	0.392 ¢/kWh
SGS & PA	0.392 ¢/kWh
LGS	0.389 ¢/kWh
Schedule NS	0.377 ¢/kWh
6VP	0.383 ¢/kWh
Outdoor Lighting	0.392 ¢/kWh
Traffic	0.392 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is cumulative and is contained in the direct testimony and exhibits of Company witnesses Petrie, Campbell, Workman, Brookmire, and Beasley, the testimony of the Public Staff Panel, and the rebuttal testimony and exhibits of Company witnesses Petrie and Beasley.

Based upon the above findings and conclusions, the Commission finds and concludes that the total net fuel factors, including the regulatory fee, are as follows:

Customer Class	Total Net Fuel Factor
Residential	2.558 ¢/kWh
SGS & PA	2.556 ¢/kWh
LGS	2.536 ¢/kWh
Schedule NS	2.459 ¢/kWh
6VP	2.495 ¢/kWh
Outdoor Lighting	2.558 ¢/kWh
Traffic	2.558 ¢/kWh

Further, the Commission finds good cause to require DENC to work with the Public Staff to develop a joint Notice to Customers of the fuel charge changes approved herein, as well as the REPS charges approved on January 4, 2019 in Docket No. E-22, Sub 557, and the DSM/EE charges approved on January 10, 2019 in Docket No. E-22, Sub 556, and to file the proposed joint Notice to Customers no later than three business days from the date of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after February 1, 2019, the Company shall implement a Fuel Cost Rider A and an increment EMF Rider Rider B for all customer classes as approved and set forth in the body of this Order.

2. That a total fuel factor as approved and set forth in the Evidence and Conclusions for Finding of Fact No. 17 above, which includes the regulatory fee, shall be instituted and remain in effect for usage from February 1, 2019, through January 31, 2020.

3. That the Company shall implement a Fuel Cost Rider A and an EMF Rider B of zero, which includes the regulatory fee, for all classes for services rendered during January 2019.

4. That the Company shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein no later than five working days from the date of this Order.

5. That the Company shall work with the Public Staff to prepare a joint proposed Notice to Customers of the rate adjustments ordered by the Commission herein, as well as the rate adjustments ordered in Docket Nos. E-22, Subs 556 and 557, and the Company shall file such proposed notice for Commission approval no later than three business days from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION

This the 23rd day of January, 2019.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk