STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1033

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	ORDER APPROVING
Pursuant to G.S. 62-133.2 and NCUC Rule	)	FUEL CHARGE
R8-55 Relating to Fuel and Fuel Related	)	ADJUSTMENT
Charge Adjustments for Electric Utilities	)	
	)	

HEARD: Tuesday, June 4, 2013, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioner ToNola D. Brown-Bland, Commissioner Bryan E. Beatty, Commissioner William T. Culpepper, III, Commissioner Lucy T. Allen

APPEARANCES:

For Duke Energy Carolinas, LLC:

Brian L. Franklin, Associate General Counsel, Duke Energy Corporation 550 South Tryon Street, DEC 45A/PO Box 1321, Charlotte, North Carolina 28201

and

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For the Using and Consuming Public:

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For North Carolina Sustainable Energy Association:

Michael Youth, Esq., 1111 Haynes Street, Suite 109, Raleigh, North Carolina 27604

For North Carolina Waste Awareness and Reduction Network:

John D. Runkle, Esq., P.O. Box 3793, Chapel Hill, North Carolina 27515

For Carolina Industrial Group for Fair Utility Rates III:

Adam Olls, Esq., Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, NC 27602-1351

BY THE COMMISSION: On March 6, 2013, Duke Energy Carolinas, LLC (Duke Energy Carolinas, DEC, or the Company), filed an Application pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities, along with the testimony and exhibits of Kim H. Smith, Sasha Weintraub, Joseph A. Miller, Jr., Robert J. Duncan, II and David C. Culp.

On March 13, 2013, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that the direct testimony of intervenors should be filed on May 17, 2013, that rebuttal testimony should be filed on May 24, 2013, and that a hearing on this matter would be conducted on June 4, 2013.

On March 25, 2013, Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) filed a petition to intervene. On March 26, 2013, North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene. On April 3, 2013, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene. These petitions were allowed in Orders dated April 1, 2013 and April 4, 2013.

On April 13, 2013, North Carolina Waste Awareness and Reduction Network (NC WARN) filed a petition to intervene. This petition was allowed in an Order dated April 18, 2013.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 17, 2013, the Public Staff filed a motion for extension of time to file testimony, and on May 20, 2013, the Commission granted the motion, extending the time for filing Public Staff and intervenor testimony to May 24, 2013, and for filing rebuttal testimony to May 31, 2013.

On May 22, 2013, DEC filed affidavits of publication indicating that public notice had been provided in accordance with the Commission’s procedural order.

On May 23, 2013, the Public Staff filed a second motion for extension of time to file testimony, and on May 24, 2013, the Commission granted the motion, extending the time for filing Public Staff and intervenor testimony to May 31, 2013, and for filing rebuttal testimony to June 3, 2013.

On May 31, 2013, the Company filed a Motion for Witnesses to be Excused from Appearance at Evidentiary Hearing, and on June 3, 2013, the Commission issued an Order excusing the appearances of the Company's witnesses David C. Culp and Joseph Miller, Jr. at the evidentiary hearing.

On June 3, 2013, the Company and the Public Staff (Stipulating Parties) filed a Joint Agreement and Stipulation of Settlement (Stipulation). Through the Stipulation, the Company updated its filing to reflect the impact of $431,799 of total system ($294,198 N.C. retail) fuel costs incurred in 2012 inadvertently omitted in its original filing. These fuel costs represent the fuel cost component of other purchased power from a qualifying facility.

Also on June 3, 2013, the Public Staff filed the testimony of James G. Hoard, Randy T. Edwards, and Kennie D. Ellis. On that same date, the Company filed supplemental testimony of Robert J. Duncan, II, and revised exhibits and workpapers of Kim H. Smith. No other party filed testimony, exhibits, or affidavits.

The case came on for hearing as scheduled on June 4, 2013. The prefiled testimony and affidavits and exhibits of the Stipulating Parties' witnesses were received into evidence. No other party presented witnesses, and no public witnesses appeared at the hearing.

On July 2, 2013, Duke and the Public Staff filed a joint motion requesting an extension of time to file briefs and proposed orders to July 15, 2013. On July 5, 2013, the Commission entered an Order granting the motion.

On July 12, 2013, NCSEA filed a letter in lieu of a post hearing brief. In the letter, NCSEA stated that it did not challenge the cost recovery in the Stipulation but requested that the Commission incorporate into its order in this proceeding DEC's commitment to file an updated fuel procurement practices report that includes its proposed natural gas hedging strategy.

On July 15, 2013, the Public Staff filed a motion requesting an extension of time to file briefs and proposed orders to July 19, 2013. On that same date, the Commission entered an Order granting the motion.

The Stipulating Parties filed a joint proposed order on July 18, 2013.

Based upon the Company's verified Application, the testimony and exhibits received into evidence at the hearing, the Stipulation, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT AND CONCLUSIONS

1. Duke Energy Carolinas is a duly organized limited liability company existing under the laws of the State of North Carolina and 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 North Carolina Utilities

Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12-month period ended December 31, 2012.

3. In its Application and testimony, DEC requested that its North Carolina retail revenue requirement associated with fuel and fuel-related costs remain essentially the same as that approved in DEC's last fuel proceeding (Docket No. E-7, Sub 1002). The fuel cost factors requested by DEC included Experience Modification Factor (EMF) riders that took into account fuel underrecoveries and overrecoveries experienced during calendar year 2012, with an overall overrecovery of approximately $47 million.

4. The Stipulation filed on June 3, 2013 comprehensively resolved all issues in this proceeding between DEC and the Public Staff. Neither CIGFUR III, CUCA, nor NC WARN filed statements expressing any opinion regarding the Stipulation. NCSEA filed a letter in which it stated it did not oppose the cost recovery agreed to by the Stipulating Parties in the Stipulation. Having carefully reviewed the Stipulation and all the evidence of record, the Commission finds and concludes that the provisions of the Stipulation are just and reasonable to all parties under the circumstances of this proceeding and should be approved in their entirety. The specific terms of the Stipulation are addressed in the following findings of fact and conclusions.

5. One factor contributing to the Company's actual test year fuel costs was the performance of its nuclear plants. G.S. 62-133.2(d) and Commission Rule R8-55 provide that the burden of proof as to the correctness and reasonableness of any charge and as to whether the test year fuel costs were reasonable and prudently incurred is on the utility. For purposes of determining the EMF rider, 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 5-year period available as reflected in the most recent North American Reliability Corporation's (NERC) Generating Availability Report, appropriately weighted for size and type of plant (NERC average) 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 NERC average, or a presumption is created that the utility imprudently incurred the increased fuel costs and that disallowance of those costs is appropriate.

6. Under the calculation of the most recent NERC average, DEC met and exceeded the performance standard for its plants with a 91.85% nuclear capacity factor, compared to the NERC average of 89.79%.

7. Nevertheless, DEC's nuclear performance was affected by the performance at McGuire Nuclear Station (McGuire), Unit 2 and Catawba Nuclear Station (Catawba), Units 1 and 2. Although McGuire exceeded the NERC average during the test period, it experienced an extended refueling outage at Unit 2. Catawba Unit 2 also exceeded the NERC average. Catawba Unit 1, however, experienced a forced outage event resulting from a cable failure further complicated by a loss of offsite

power event for the station, which extended the Unit 2 refueling and maintenance outage underway at the time. After extensive investigation, the Public Staff believes that some of the outage time at McGuire Unit 2 and Catawba Units 1 and 2 during the test year could have been avoided under efficient management and economic operations, and at least some of the associated replacement power costs should be excluded.

8. The Company disagrees with the Public Staff's position. The Company does acknowledge, however, that although its nuclear capacity factor exceeded the NERC average for the test year, the Catawba and McGuire outages exceeded the scheduled outage duration as a result of equipment and vendor execution challenges.

9. Consistent with the Stipulation, the Commission finds and concludes that it is appropriate for DEC to forgo recovery of a N.C. retail allocated amount of $4,542,857 of replacement power fuel expenses incurred during the test year due to the outage extension at McGuire Unit 2, as well as $757,143 of interest on that amount, for a total of $5,300,000. Additionally, consistent with the Stipulation, the Commission finds and concludes that to the extent DEC succeeds in recovering liquidated damages from the vendor involved in the McGuire Unit 2 outage work, DEC shall flow back half of the net amount, up to $257,143, to ratepayers in a future fuel case. The Commission finds and concludes that this aspect of the Stipulation is just and reasonable.

10. The Commission finds and concludes that any issues with respect to the performance of Catawba and McGuire Unit 2 are adequately addressed and resolved in the Stipulation and DEC managed its other baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

11. Except for the replacement power for which costs have been excluded pursuant to this Order, the Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

12. Duke Energy Carolinas' proposal to share pre-merger fuel savings between itself and Duke Energy Progress, Inc. (DEP), is consistent with the treatment of post-merger fuel savings related to the merger of Duke Energy Corporation and Progress Energy, Inc., (Merger) and is thus reasonable and appropriate, so long as DEP reflects the full offsetting amount in its upcoming fuel proceeding. In general, the validity of all Merger fuel-related savings shall remain subject to future Commission determination.

13. The test period per book system sales are 79,868,568 MWh. The test period per book system generation and purchased power is 86,013,644 MWh and is categorized as follows:

Type	MWh
Coal	27,969,376
Biomass	1,365
Oil & Combustion Turbine Gas	923,193
Combined Cycle Natural Gas	4,418,878
Nuclear	42,003,452
Hydro – Conventional	1,400,604
Hydro Pumped storage	(641,599)
Solar	10,479
Purchased Power – Economic and Dispatchable	8,093,358
Renewable Purchased Power	703,681
Other Purchased Power	907,292
Catawba Interchange	223,565
Total	86,013,644

14. The nuclear capacity factor appropriate for use in this proceeding is 92.84%.

15. The adjusted North Carolina retail test period sales for use in calculating the EMF are 55,534,611 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted kWh Sales
Residential	21,143,695
General Service/Lighting	22,112,646
Industrial	12,278,269
Total	55,534,611[1]

16. The projected billing period sales for use in this proceeding are 82,388,880 MWh on a system basis and 55,516,317 MWh on a N.C. retail basis. The projected billing period N.C. retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	20,955,314
General Service/Other	22,316,250
Industrial (Including Textiles)	12,244,753
Total	55,516,317

[1] Rounding difference of 1.

17. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 90,164,033 MWh and is categorized as follows:

Type	MWh
Coal	26,277,775
Gas CT and CC	10,016,167
Nuclear	43,440,823
Hydro	1,779,845
Net Pumped Storage Hydro	(798,620)
Purchased Power	9,448,043
Total	90,164,033

The difference of (7,775,153) MWh between projected billing period system generation and purchased power and projected billing period system sales is made up of mitigation sales of (803,900) MWh, intersystem sales of (1,683,858) MWh, and line losses and Company use of (5,287,395) MWh.

18. The appropriate fuel and fuel-related prices and expenses for use in this proceeding are as follows:

A. The coal fuel price is $38.023/MWh.
B. The gas CT and CC fuel price is $32.554/MWh.
C. The appropriate ammonia, limestone, urea and dibasic acid (collectively, Reagents) expense is $41,840,169.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.759/MWh.
E. The nuclear fuel price for Catawba Joint Owners generation is $6.759/MWh.
F. The total purchased power price (including the impact of JDA Savings Shared) is $36.52/MWh.
G. The adjustment to exclude the cost of mitigation sales is a reduction of $(29,839,400).
H. The adjusted level of fuel and fuel-related credits associated with intersystem sales is $(66,967,909).

19. The total projected N.C. retail fuel cost for use in this proceeding is $1,287,001,169. This consists of $12,302,413 of renewable and cogeneration power capacity costs and $1,274,698,756 of other fuel costs. Consistent with G.S. 62-133.2(a2), the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed two percent of DEC's total North Carolina jurisdictional gross revenues for 2012. In determining whether purchased power costs included in DEC's proposed rates should be limited pursuant to paragraph (a2), DEC performed its evaluation excluding the costs directly related to joint dispatch agreement transactions between DEC and DEP, which are providing merger savings to

DEC's North Carolina retail customers. The Commission finds that the exclusion of these costs from the calculation of the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs is just and reasonable.

20. The Company's N.C. retail fuel and fuel-related expense overcollection amounts were $8,086,940, $24,292,108, and $14,927,436 for the Residential, General Service/Lighting, and Industrial customer classes, respectively, for a total of $47,306,484. Including the impact of the costs forgone pursuant to the terms of the Stipulation, the adjusted fuel and fuel-related expense overcollection amount is $51,555,143.

21. Consistent with the Stipulation, the decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1002 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in Docket No. E-7, Sub 1002.

22. The appropriate prospective fuel cost factors for this proceeding for each of DEC's rate classes, excluding gross receipts tax (GRT) and the North Carolina Regulatory Fee (NCRF), are as follows: 2.2306¢/kWh for the Residential class, 2.3566¢/kWh for the General Service/Lighting class, and 2.3980¢/kWh for the Industrial class.

23. The appropriate decrement EMFs, including interest but excluding GRT and NCRF, established in this proceeding, are as follows: (0.0534)¢/kWh for the Residential class, (0.1371)¢/kWh for the General Service/Lighting class, and (0.1510)¢/kWh for the Industrial class.

24. The final total fuel and fuel-related cost factors to be billed to DEC's North Carolina retail customers during the 2013-2014 fuel clause billing period are 2.1772¢/kWh for the Residential class, 2.2195¢/kWh for the General Service/Lighting class, and 2.2470¢/kWh for the Industrial class, excluding GRT and NCRF.

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

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 charge adjustment proceeding for a historical 12-month test period. In Commission Rule R8-55(b), the Commission has prescribed the 12 months ending December 31st as the test period for DEC. The Company's filing was based on the 12 months ended December 31, 2012.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence for these findings of fact is found in the Application, the testimony of Company witness Smith, the Stipulation, and the entire record in this proceeding. These findings and conclusions are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-9

The evidence for these findings of fact is found in the Application, the testimony of Company witness Duncan and of Public Staff witness Ellis, and in the Stipulation.

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 Equipment Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Duncan testified that the Company's seven nuclear units operated at a system average capacity factor of 91.85% during the test period. This capacity factor exceeded the five-year industry weighted average capacity factor of 89.79% for the period 2007-2011 for pressurized water reactors rated at and above 800 MWs, as reported by NERC in its latest Generating Availability Report. According to Company witness Duncan, the Company's system average nuclear capacity factor has been above 90% for 13 consecutive years. Witness Duncan testified that the Company's nuclear performance has improved significantly over the course of the years of operating its nuclear fleet. In particular, shorter refueling outages and improved forced outage rates have contributed to increasing the capacity factors achieved by the Company's nuclear fleet.

Public Staff witness Ellis agreed that DEC's nuclear generation system achieved an overall actual capacity factor of 91.85% during the test period, above the most recent NERC average of 89.79%. He testified that since the Company's nuclear generation system achieved an overall capacity factor above the NERC average, no presumption of imprudence or disallowance of increased fuel costs was created under Commission Rule R8-55(k). However, he testified that the Rule states that the burden of proof as to the correctness and reasonableness of any charge shall be on the utility.

Witness Ellis testified that in particular, the Company's proposed EMF reflected increased fuel costs resulting from the purchase of replacement power during the Catawba Unit 1 forced outage in April 2012, the extension of the Catawba Unit 2 refueling outage during that same time period, and the extension of the McGuire Unit 2 refueling outage in the fall of 2012. Therefore, he testified, the Public Staff undertook to determine what caused these outages and outage extensions, whether the additional costs were reasonable and prudently incurred, and, if not, what adjustment to the Company's proposed EMF was appropriate. Company witness Duncan also testified regarding the causes of the Catawba and McGuire outages in his supplemental testimony.

CATAWBA UNITS 1 AND 2

Public Staff witness Ellis testified that with respect to the Catawba outages, in the spring of 2012, Catawba Unit 1 was operating at full power, while Catawba Unit 2 was in a scheduled refueling outage that had begun on March 20, 2012. On April 4, 2012, Catawba Unit 1 tripped following a trip of a reactor coolant pump. When generator power circuit breakers opened, the Zone G protective relaying system unexpectedly actuated, opening the switchyard breakers, isolating Unit 1 and resulting in a Loss of Offsite Power (LOOP). Because Unit 2's essential busses were aligned to Unit 1's offsite power at the time, those busses lost power when the LOOP occurred. Witness Ellis testified that the Company investigated the causes behind both the trip of the reactor coolant pump and the actuation of the Zone G protective relaying system.

Witness Ellis stated that the Company found that the trip of the reactor coolant pump occurred as a result of a phase to ground fault in the Y phase conductor (a power cable) for the pump motor. According to witness Ellis, in 2000 this reactor coolant pump experienced a similar trip as a result of the pump motor Y phase Elastimold bushing fault to ground, which likely caused thermal damage to the cable and ultimately led to the cable failure that occurred in the spring of 2012.

Witness Ellis testified that with respect to the unexpected actuation of the Zone G relaying system that resulted in the LOOP, the Company determined that during Catawba Unit 1's scheduled outage in 2011, the generator protective relaying was upgraded. The modification (Zone G relay modification) was intended to maximize the reliability of the protective relaying function while minimizing the likelihood of spurious relay actuation. The modification consisted, in part, of adding a redundant train of protective relays for each function and adding two additional functions. The Zone G relaying system trips the switchyard unit tie breakers in the event of a generator underfrequency, separating the turbine generator from the grid. The modification was supposed to include a blocking logic. This blocking logic was not fully incorporated into the Zone G digital relay upgrades.

According to witness Ellis, the omission of the blocking logic from the relay programming was not discovered during the testing phase of the modification because the testing procedures were based upon a calculation that was generated during the vendor's design portion of the modification rather than upon the original design specifications. Consequently, the programming error propagated through the rest of the implementation phase and was undetected during design, review, approval, implementation, and post-modification testing.

Witness Ellis testified that as a result of the omission of the blocking logic, when the reactor trip occurred due to the coolant pump trip, the relay mistakenly detected a generator underfrequency and unexpectedly opened, separating the generator from the grid and causing a LOOP. Catawba Unit 1 was in a forced outage until April 17, 2012, a total of 13 days, as a result of the above-described events.

Company witness Duncan testified that with respect to the Catawba outages, in May-June 2011, during Unit 1's 19th refueling and maintenance outage, DEC upgraded the generator protective relay system for the Unit. This system is designed to detect faults and other off-normal conditions affecting the switchyard or the main turbine generator. The turbine under-frequency protection design change was implemented to address equipment obsolescence and eliminate vulnerability in generator asset protection. The preexisting electro-mechanical relay scheme providing turbine under-frequency protection required upgrade and additional protection with digital components for the generator to protect against catastrophic damage if a ground fault should occur. According to witness Duncan, in implementing the project, DEC developed specifications for a qualified vendor. The scope specification did not specifically call out with particularity a design input for the complex relay scheme and led to the omission of a “block” protection feature that isolates the Unit from the grid when the generator circuit breakers are open following a generator trip.

Witness Duncan testified that the outage in question began on April 4, 2012, when Unit 1 tripped off-line following a trip of the “1D” reactor coolant pump. Shortly thereafter, a portion of the generator protective relay system unexpectedly actuated when it sensed the instantaneous under-frequency condition of the Unit. This actuation opened the switchyard circuit breakers, thereby isolating Unit 1 from the transmission grid which supplies backup power to the Unit, and thereby causing a LOOP. The two emergency standby diesel generators automatically started as designed and powered the Unit until, five and a half hours later, offsite power was restored. According to witness Duncan, both the loss of reactor coolant pump flow and resultant reactor trip and the LOOP are events analyzed for safety as part of the plant’s original license submittal, and the Unit is designed to safely shut down from such events.

Witness Duncan stated that the Company evaluated the situation and concluded that the 1D reactor coolant pump trip was caused by thermal damage to insulation on a reactor coolant pump motor power cable associated with a historic event in 2000, as well as degradation over time of the cable. The thermal damage was undetected and, in 2000, not readily detectable by cost-effective non-destructive testing methods then available. In April 2012, the cable “faulted to ground” at the location of the thermal damage. The faulted reactor coolant pump motor cable was replaced.

Witness Duncan testified that the old protection scheme used a series of relays and timers in a stepped protective relay scheme at various settings at different frequencies. Because the blocking scheme was not fully incorporated into the revised design, when the Unit’s main generator tripped, the Unit was isolated from the grid when, as intended, the upgraded design should have blocked the isolation.

According to witness Duncan, the Company utilized its highest level of risk management for the design change. Prior to the design change, DEC held numerous meetings with the vendor and reviewed the vendor’s efforts throughout the design change process. During this review process, DEC spent hundreds of hours in design review, including review of computer coding but not source code, which is proprietary to the vendor. This source code contains algorithms for “accumulating” time related to relay functions. Based on programming coding reviewed by DEC, the accumulating function appeared to be designed correctly.

Witness Duncan stated that the relay programming is proprietary to the vendor and represents the vehicle for ensuring relay logic and schemes are executed as designed. In their review of the relay programming, DEC personnel reviewed the coding language to ensure time accumulation functions were present in each of the four zones of protection designed. The DEC personnel were not aware, however, that while the code variable programmed for Zones 1, 2, and 3 would work as designed to accumulate minutes, it would not work in Zone 4 to accumulate milliseconds. Because the source code was proprietary, the time segmentation of these accumulation algorithms was not disclosed to DEC personnel. According to witness Duncan, the error in the accumulation algorithm in the protection scheme is the source of the design error and was carried forward into the accept testing.

MCGUIRE UNIT 2

Public Staff witness Ellis stated that the McGuire Unit 2 outage involved not only the refueling of the unit, but also the replacement of the generator stator and high pressure turbine rotor. He testified that although the Company had experience with replacing this type of equipment, this was a significant project for McGuire, and was one of the largest projects of its kind in DEC's nuclear history. He also testified that the contract to perform this work was awarded to Siemens USA (Siemens), which manufactured the stator, and that the outage started on September 15, 2012. According to Public Staff witness Ellis, soon after the outage began, vendor-related human performance issues emerged. The Company and Siemens' management repeatedly reminded workers to return to appropriate behaviors to minimize hazards. In a letter to Siemens dated October 4, 2012, Company management expressed dissatisfaction with Siemens' implementation performance, which included not only injuries and dropped objects, but also issues with foreign material in the generator stator and foreign material exclusion (FME) control issues. Witness Ellis testified that FME controls are developed and utilized to ensure that all tools and personnel entering in an FME area are logged in and checked for loose items, and checked again when exiting the FME area. Tools are checked for loose or missing parts, and workers are checked for loose items, such as coins or pens.

Public Staff witness Ellis testified that on October 14, 2012, during the course of the replacement of the main generator stator, it was discovered that a 5/16" nut and washer were missing from a tool (known as a "come along") that was used during the stator rebuild. The tool had been inspected and logged before being brought into the FME zone (FMEZ). At the time it was discovered that the nut and washer were missing, the generator rotor had already been reinstalled, and the turbine end and exciter end of the generator were being built. Witness Ellis testified that due to the risks associated with leaving the parts in the generator, DEC's management decided to undertake a search for the nut and washer by removing the generator rotor to ensure all foreign materials were in fact removed. The nut and washer were never found, but DEC did find metallic drill tailings from initial fabrication and installation, one of which was four inches long, which could have caused significant damage had they not been removed. Specifically, he noted that a loose metallic part left in the main generator (especially the windings or stator core) can result in damage to the windings, fault of the stator, subsequent generator, turbine and reactor trip, the potential for a complicated trip (e.g.

a LOOP) due to protective relay actuations, the potential for release of hydrogen from the generator, and the risk of explosive gas and fire, catastrophic failure, and personal injury. The search for the nut and washer, removal of the foreign material found, and reinstallation of the turbine rotor extended the outage for an additional 10 days.

Public Staff witness Ellis stated that on October 17, 2012, DEC again sent Siemens a letter expressing dissatisfaction with Siemens' performance and requested a face to face meeting to discuss a recovery plan for the project. On October 26, 2012, Siemens began to undertake final generator alignment. Witness Ellis explained that in undertaking this activity, it is important that the weight of the generator is evenly distributed on its four corners; otherwise, an unacceptable and unsustainable amount of vibration can result. Siemens recommended performing Frame Foot Loading (FFL) using strain gauges to ensure that the weight of the generator was evenly distributed on the four corners of the generator. Witness Ellis stated that although the FFL method is commonly used in the industry, DEC's experience with aligning generators had been to use the step shimming method, which steps down the shim configuration from the four corners of the generator to ensure the load is distributed appropriately. The Company agreed, however, with the use of FFL to accomplish this task. Witness Ellis testified that although the alignment using FFL progressed well at first, early on October 29, 2012, Siemens personnel began to note inconsistent and unexpected readings from the gauges. The Company's review of the FFL data indicated that the data was unpredictable and unreliable. In reviewing the details of the data on various moves made, DEC questioned the adequacy of Siemens' process controls and verification of key data points. Ultimately, DEC stopped the FFL process and resorted to using the manual validation of step shimming, but the poor execution of the FFL resulted in a delay of almost 5 days. Public Staff witness Ellis testified that the McGuire Unit 2 outage ended on November 30, 2012, approximately 38 days longer than originally scheduled.

Company witness Duncan testified that the McGuire outage involved a significant scope of work, including replacement of the main generator stator, exciter, and support systems, upgrade of the high pressure turbine, and modification of the turbine generator support systems. Generator-turbine projects such as this increase the capacity and improve the reliability of the unit. Witness Duncan testified that managing FME during an outage is highly challenging across the nuclear industry, and that loose metallic objects in the generator have potentially high adverse consequences, including damage to the generator, reactor trips and personnel injury.

Company witness Duncan testified that prior to a planned outage such as the McGuire Unit 2 outage, DEC develops a detailed schedule for the outage and for the major tasks to be performed, including sub-schedules for particular activities, and aggressively attempts to meet its best overall outage time for each outage and measures itself against that schedule. Additionally, DEC performs detailed self-critical analyses of each outage project and applies any lessons learned to ensure continuous improvement. Company witness Duncan also stated that rework due to foreign material contributed to the outage extension at McGuire. Specifically, on October 14, 2012, a day-shift craft millwright raised a concern that a 5/16" nut and lockwasher were missing from a 1.5-ton lever-operated hoist as the hoist was being removed from the Unit's FMEZ. After extensive inspections, including removal of the generator's rotor, the missing parts were not located. Company witness Duncan testified that the removal of the rotor was a decision that prolonged the outage, but also elevated plant equipment reliability and personnel safety over economic concerns.

Company witness Duncan stated that even though DEC and its contractor had implemented FME control efforts prior to the outage, and FME technicians inspected tools, including the hoist (i.e. the “come-along”), prior to entry into the FMEZ, the extensive searches were reasonable and appropriate to assure that the missing parts were not in the generator. In doing so, the Company talked to the craft laborer and the FME technician who inspected the hoist prior to its entry into the FMEZ. The FME technician who inspected the tool prior to entry into the FMEZ stated that he performed the inspection and that he understood his training and the FME procedures regarding checking tools for loose parts; however, he could not specifically recall whether the nut and lockwasher were missing when he logged the hoist. The technician could not recall whether the nut and lockwasher were present or missing when the hoist entered the FMEZ. Therefore, DEC could not rule out the possibility that the parts were in the FMEZ. Only in hindsight, after the search and the uneventful startup and operation of the generator, did DEC know that the missing parts may well have been missing prior to the hoist’s entry into the FMEZ.

Company witness Duncan testified that the outage extension was also affected by problems encountered by a qualified contractor in the FFL for the large electric main generator. The Company held the expectation that the leveling process, referred to as “shimming,” could be achieved in the time scheduled for the task. A new main turbine generator was installed during this outage, making extensive alignment necessary. Excessive vibration during generator startup would require the Unit to shut down until the source of the vibration, which in and of itself could cause equipment damage, could be identified and eliminated, so achieving an adequate alignment was a high priority. During outage planning, DEC and the contractor considered aligning the generator using either FFL or step shimming. According to witness Duncan, step shimming is simpler and more straightforward than FFL, but is much less accurate and can be inconclusive until generator startup. FFL produces a more accurate alignment but takes more time, is more complex, and requires more shim movements with a higher level of assurance of low vibration at startup. Before recent technological advances made FFL easier to perform, FFL was reserved for problematic alignments where excessive vibration had been observed in the main turbine generator.

Company witness Duncan testified that prior to the performance of the FFL at McGuire, DEC’s subject matter experts performed quality reviews of the contractor’s work packages for FFL, including the contractor’s proprietary documents that relate to FFL technique. The Company also developed procedures to govern DEC’s oversight of the contractor. Further, during execution efforts, DEC remained engaged asking questions of the contractor. Only after the contractor’s 16th move was DEC aware that the contractor, and the contractor’s technique, might not achieve desired results. At this point, DEC applied oversight resources to the contractor’s conduct of the work. While monitoring the contractor’s performance of FFL from moves 16 to 25, DEC noted several shortcomings in the contractor’s performance and brought these to the contractor’s attention. Following DEC’s decision to intervene, DEC achieved an acceptable alignment in approximately one day. Company witness Duncan testified that consistent with nuclear industry practice, DEC and its vendor actively engaged in a self-critical post-outage critique process and developed a project plan to incorporate lessons learned and guide a similar scope of work performed during the McGuire Unit 1 spring 2013 refueling outage. Company witness Duncan also testified that the Company believes it is key to place each outage event in its proper context and focus attention on the facts and circumstances as they existed at the time of each incident without the benefit of hindsight, including key decisions leading up to these events, and that DEC disagrees with the Public Staff's conclusions on certain portions of those outages.

Both the Company and the Public Staff acknowledged that notwithstanding the circumstances regarding the McGuire and Catawba outages and the delays and increased fuel costs involved, reasonable persons with knowledge and experience in nuclear operations can disagree as to, as Public Staff witness Ellis testified, the prudence of specific actions or inactions that caused delays and resulted in increased fuel costs during an outage, particularly an outage that included major upgrades to a nuclear unit, or as Company witness Duncan testified, the drivers of specific outage delays. The Public Staff acknowledged that the Company made efforts to mitigate the effects of the delays at McGuire caused by Siemens' performance and developed recovery plans for the project in conjunction with Siemens, and believes that DEC's decision to remove the rotor to conduct further searches for a potential missing nut and washer was reasonable and prudent under the circumstances. In addition, the Company developed corrective action plans for the Catawba LOOP event aimed at preventing future such events. Considering all of these factors, the Public Staff and DEC believed it appropriate to engage in settlement discussions regarding an adjustment to test period fuel costs that would be fair to the Company and to its ratepayers.

Consequently, the Stipulating Parties agree that DEC will forgo recovery of $4,542,857 of replacement power fuel expenses incurred during the test year due to the outage extension at McGuire, as well as $757,143 of interest on that amount, for a total of $5,300,000. Additionally, to the extent that DEC succeeds in recovering liquidated damages from the vendor involved in the McGuire outage work, DEC agrees to flow back half of the net amount, up to $257,143, to ratepayers in a future fuel case. The Stipulating Parties agree that the above amounts represent a fair and reasonable resolution of the issue of test year fuel costs that the Public Staff believes should not be recovered from ratepayers because of the challenges experienced at Catawba and McGuire. The Stipulating Parties further agree that by agreeing to settle this issue, DEC in no way concedes that it was imprudent, unreasonable, inefficient, or uneconomical in incurring its fuel costs during the test period or in managing its generation fleet, and that the Stipulation in no way constitutes a waiver or acceptance of the position of any Party concerning the requirements of G.S. 62-133.2, or Commission Rule R8-55, in any future proceeding, nor does it constitute a waiver of any right to assert or oppose a position in any future proceeding or any court. Moreover, the Stipulating Parties agree that the Stipulation does not establish any precedent with respect to the issues resolved herein, and in no way precludes any Stipulating Party herein from advocating an alternative position or methodology in any future proceeding. No party expressed any opposition to the Stipulation or its terms.

Having carefully reviewed the Stipulation and all the evidence of record, the Commission finds and concludes that these provisions of the Stipulation are just and reasonable to all parties under the circumstances of this proceeding and should be approved in their entirety.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is found in the testimony of Company witnesses Duncan and Miller and Public Staff witness Ellis.

Evidence concerning the performance of Catawba and McGuire during the test year is discussed in the Evidence and Conclusions for Findings of Fact Nos. 5-9. Company witness Duncan testified concerning the performance of the rest of the Company's nuclear fleet and the overall performance of the nuclear fleet during the test period. He testified that overall, DEC's nuclear stations operated well during 2012, and supplied 62% of the power used by its Carolinas customers in the test period. The seven nuclear units operated at a system average capacity factor of 91.85%. The capacity factor for McGuire Unit 1 was 104.67%, an annual record for the unit. McGuire Unit 2 concluded a 528-day continuous run leading up to the fall refueling outage – the longest continuous run in McGuire history. This also ended a 335-day continuous dual-unit run, setting another station record. Oconee Nuclear Station (Oconee), Unit 3 set a unit record by concluding a 446-day continuous run leading up to its refueling outage, and Oconee set a new record in the 2nd quarter of 2012 with a capacity factor of 102.68%.

Company witness Duncan also noted that in 2012 the Company implemented the second upgrade of an integrated digital reactor protection system and engineering safeguards (RPS/ES) technology on Oconee Unit 3. The Company was able to reduce the length of the outage on this second upgrade by 14 days from the Unit 1 upgrade, and more efficiently completed the refueling and maintenance work due in large part to the application of lessons learned from the Unit 1 RPS/ES implementation. As a follow-up to the Unit 1 upgrade, the Company was recognized and received multiple awards, including the "Engineering Project of the Year' Award at the 13th Annual Platt's Global Energy Awards ceremony, and the Nuclear Energy Institute's "Best of the Best" Top Industry Practice award.

Company witness Miller testified concerning the performance of the Company's fossil/hydro assets. He testified that the primary objective of the Company's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEC's customers, and that it achieves this objective by focusing on a number of key areas. He stated that environmental compliance is a "first principle", that DEC works very hard to achieve high level results, and that DEC achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers. Equipment inspection and maintenance outages are scheduled during the spring and fall months when electricity demand is reduced due to weather conditions.

Witness Miller testified that these outages are well-planned and executed with the primary purpose of preparing the unit for reliable operation until the next planned outage.

Company witness Miller also testified that during the test period, the coal-fired units achieved a fleet-wide availability factor of 90.0% for the review period, and 96.5% during the 2012 summer peak months. He further testified that the hydroelectric fleet had outstanding operational performance during the test period, with a system availability factor of 93.4%. This availability factor measurement refers to the percentage of a given time period that the coal-fired or hydroelectric units were available to operate at full power, if needed. This availability measure is not affected by the manner in which the unit is dispatched, but is impacted by the amount of unit outage time. Additionally, witness Miller noted that the Company's large combustion turbine units were available as needed with a starting reliability of 99.2%.

Company witness Miller also testified concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period. He testified that in general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize the units' availability during periods of peak demand. During the test period, while most of these units had at least one small planned outage to inspect and repair critical equipment or for the final tie-in of new environmental control equipment, three of the coal-fired units had extended planned outages of six weeks or more.

Public Staff witness Ellis testified that the Oconee Unit 1 and Unit 2 outages were within the scope of expected plant operations and that overall, except for Catawba and McGuire Unit 2, the DEC nuclear fleet performed well during the test year. No other party contested the reasonableness and prudence of DEC's operation of its nuclear or fossil/hydro generation system. Based upon the evidence in the record, the Commission concludes that any issues with respect to the performance of Catawba and McGuire Unit 2 are adequately addressed and resolved in the Stipulation and DEC managed its other baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

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 updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in July 2004, and were in effect throughout the 12 months ending December 31, 2012. 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 found in the testimony of Company witnesses Smith, Weintraub, Miller, and Culp.

Company witness Smith testified that DEC's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEC's ability to maintain lower fuel and fuel-related rates. Other key factors include DEC's diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; the combination of DEC's and DEP's respective skills in procuring, transporting, managing and blending fuels and reagents; and the increased and broader purchasing ability of the combined Company as well as the joint dispatch of DEC's and DEP's generation resources. Company witness Weintraub described the Company's fossil fuel procurement practices, set out in Weintraub Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, and conducting short-term and spot purchases to supplement term supply. According to witness Weintraub, the Company's average delivered coal cost per ton increased 5.3%, from $94.52 per ton in 2011 to $99.52 per ton in 2012. The Company's transportation costs increased approximately 8.6%, from $27.00 per ton in 2011 to $29.32 per ton in 2012. He testified that coal markets continue to be in a state of flux due to a number of factors, including (1) recent U.S. Environmental Protection Agency regulations for power plants that result in utilities retiring or modifying plants, which lower total domestic steam coal demand, and can result in some plants shifting coal sources to different basins; (2) continuing growth in global demand for both steam and metallurgical coal, which makes coal exports increasingly attractive to U.S. coal producers; (3) continued low gas prices combined with installation of new combined cycle (CC) generation by utilities, especially in the Southeast, which also lowers overall coal demand; and (4) increasingly stringent safety regulations for mining operations, which result in higher costs and lower productivity. According to witness Weintraub, due to increasingly lower power prices and reduced demand for coal generation, coal burn projections for 2013 and forward are forecasted to be lower than historical volumes. The actual coal burn for DEC's stations in 2012 was just over 10,700,000 tons, approximately 30% less than the average coal burn over the prior five-year period of over 15,900,000 tons. Based on the low coal burns in 2012, as well as the downward projection for coal burns in 2013 as compared to the amount of coal under contract for delivery in 2013, DEC expects coal inventories to be above target levels during 2013. Witness Weintraub testified that if the Company experiences mild weather and continued low purchased power prices, there likely will be further upward pressure on coal inventories. He also testified that combining coal and transportation costs, DEC projects average delivered coal costs of approximately $98.62 per ton for the billing period.

Company witness Weintraub also testified that DEC's primary source of coal supply is no longer the Central Appalachian region. Historically, fuel switching to a different coal basin has been difficult for DEC because coal quality characteristics vary greatly between coal producing basins, and the design of DEC's plants was meant to optimize the use of Central Appalachian coals. As a result of the Merger, however, DEC can achieve fuel savings by sharing best practices between DEC and DEP for coal blending at their respective coal-fired plants. Specifically, investments by DEP, which have included improvements to the coal-fired boilers as well as the balance-of-plant components, have expanded the types of coal that DEP can reliably burn at its units, and DEC has been able to learn via the Merger from the DEP practices of consuming non-traditional coals at the DEP coal units without impacting reliability or operations. Because of the sharing of best practices across the DEC and DEP coal generation fleet, DEC can now procure a wide variety of coals for its fleet, resulting in overall fuel savings passed on to customers.

Company witness Weintraub testified that the Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 42 billion cubic feet (Bcf) of natural gas in 2012, compared to approximately 10 Bcf in 2011. This increase was driven by the downward trend in natural gas prices as well as the operation of the Buck CC facility for its first full year ending on December 31, 2012. For 2013, DEC's current forecasted natural gas consumption is approximately 74 Bcf. This forecast is based on current natural gas prices, which are forecasted to remain low, and includes a full year of operations of the Dan River CC facility, which went into commercial service in December 2012. Witness Weintraub also testified that the development of shale gas has created a fundamental shift in the nation's natural gas market. Shale gas is natural gas that is trapped within shale formations, and which can provide an abundant source of petroleum and natural gas. Within recent years, improvements in production technologies have allowed greater access to the natural gas trapped in these formations, and has resulted in increased reserves that can produce natural gas supply more quickly and economically. Given continued production increases, natural gas prices continue to remain at lower levels. The Company's average price of gas purchased for calendar year 2012 was $3.34 per Million British Thermal Units (MMBtu), compared to $4.85 per MMBtu in 2011.

Witness Weintraub noted that DEC does not currently employ a hedging strategy to fix prices on a portion of the projected natural gas usage, and that the lower and unpredictable nature of DEC's historical natural gas usage was not suitable for a structured price hedging program. He also noted that DEC is currently evaluating the feasibility of a hedging program given the increased and more predictable natural gas consumption associated with the addition of the Buck and Dan River CCs. In an update to the Commission at the evidentiary hearing, the Company stated that no later than six months from the date of the evidentiary hearing, DEC would file an updated fuel procurement practices report in Docket No. E-100, Sub 47 that would include, for the first time, a proposed natural gas hedging strategy for DEC.

G.S. 62-133.2(a1)(2) permits DEC to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions" (referred to by DEC's witnesses as "reagents"). Company witness Miller testified that DEC has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions. The selective catalytic (SCR) technology that DEC currently operates uses ammonia or, in the case of Marshall Unit 3, urea that is converted to ammonia, for NO_x removal. The selective non-catalytic reduction (SNCR) technology injects urea into the boiler for NO_x removal and the scrubber technology employed by the Company uses crushed limestone for SO_2 removal. Dibasic acid can also be used with the scrubber technology for additional SO_2 removal. SCR equipment is also an integral part of the design of the Buck and Dan River CC Stations. The Company also uses aqueous ammonia for NO_x removal.

Witness Miller also testified that 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 emission reduction required. As a result, DEC uses chemicals such as limestone, ammonia, urea, and dibasic acid, as well as chemicals such as magnesium hydroxide and calcium carbonate, which are used in order to mitigate increased sulfur trioxide (SO_3) emissions due to consumption of higher sulfur coals pursuant to DEC's fuel flexibility efforts as described by Company witness Weintraub. Witness Miller stated that DEC is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals, and that DEC's goal is to effectively comply with emission regulations and provide the most efficient total-cost solution for operation of the unit.

Company witness Culp testified as to DEC's nuclear fuel procurement practices, which 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 spot and long-term contracts from diverse sources of supply, assessing spot market opportunities, and monitoring deliveries against contract commitments. As described by Company witness Culp, for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. The typical initial delivery under new long-term contracts has grown to several years after contract execution because many proven, reliable producers have sold their near-term capacity. For this reason, DEC 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, the Company'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. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis, using multi-year contracts.

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; 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. Witness Weintraub testified that DEC (and DEP) consider the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their customers.

No other party presented or elicited testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any direct testimony to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period. Consistent with the representation of DEC at the evidentiary hearing, no later than December 31, 2013, DEC will file an updated fuel procurement practices report in Docket No. E-100, Sub 47 that will include a natural gas hedging strategy for DEC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact and conclusion is contained in the testimony of Company witness Weintraub and Public Staff witness Hoard.

Company witness Weintraub testified about the Joint Dispatch Agreement (JDA), which is an agreement between DEP and DEC where DEC acts as the Joint Dispatcher for DEC's and DEP's power supply resources. The JDA has allowed DEC's and DEP's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. As a result, the joint dispatch process allows DEC and DEP to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis. The JDA also provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEC and DEP. The joint dispatch savings will automatically flow through to the Companies' retail customers through their fuel clauses. For native load wholesale customers, the joint dispatch savings are passed through as permitted by the applicable wholesale contracts. Under the joint dispatch process, the energy costs attributable to each utility's native load are the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the Joint Dispatcher, which are treated as purchases and sales between the Companies. As a result, the energy cost totals ultimately incurred by DEC and DEP to serve their respective native loads will be equal to the stand-alone costs they would have incurred but for the joint dispatch arrangement, less each utility's share of the joint dispatch savings.

Public Staff witness Hoard explained that pursuant to the Commission's June 29, 2012 Order, in Docket No. E-2, Sub 998 and E-7, Sub 986 (Merger Order), the North Carolina retail customers of DEC and DEP (Utilities) have been guaranteed receipt of their allocable share of $686.8 million in fuel and fuel-related cost savings resulting from the Merger over a five-year period through the annual fuel charge proceedings of the Utilities. The five-year period may be extended by 18 months if ratepayers have not received their allocable share of the guaranteed savings at the end of the five-year period and the decline in natural gas prices has resulted in the delivery of less coal to certain DEC coal-fired plants. In addition, DEC and DEP are required to file monthly reports of tracked fuel savings with their Monthly Fuel Reports filed under Commission Rule R8-52. These reports of tracked fuel savings must show fuel savings broken down by the following categories: (a) total system, (b) DEC, (c) DEC North Carolina retail, (d) DEP, and (e) DEP North Carolina retail. If at the end of the guaranteed savings period the North Carolina retail customers of the Utilities have not received their allocable shares of the guaranteed fuel savings, the remaining amount shall be reflected as an adjustment in the first fuel cost proceedings of DEC and DEP following the end of the guaranteed savings period.

Witness Hoard provided the following chart that shows details of the fuel savings through the end of the test period that have been reported by the Utilities:

TABLE 1

Item	DE Carolinas	DE Progress	Combined
	(a)	(b)	(c)
Joint Dispatch	$11,328,001	$2,820,299	$14,148,300
Coal Blending	23,524,131		23,524,131
Coal Procurement	1,624,630	2,475,010	4,099,640
Coal Transportation	2,181,451	1,805,939	3,987,390
Reagent Procurement & Transportation	450,300	689,849	1,140,149
Natural Gas Supply & Capacity	4,754,353		4,754,353
Avoided Trading Desk	215,724		215,724
Total	$44,078,590	$7,791,097	$51,869,687

The combined amounts shown in column (c) above are the sum of the savings that originated in each utility. These fuel savings are reflected in the actual expenses reported by the originating utility; the amount of the combined fuel savings is allocated between DEC and DEP each month based on the Utilities' relative MWh generation. As a result, an accounting entry has been recorded each month since the Merger closed to transfer savings that exceed the allocated share of the originating utility to the other utility. Witness Hoard also provided the following Table 2 that shows the amount of fuel savings that were transferred by DEC to DEP during the test period:

TABLE 2

	DE Carolinas		
Item	Gross Amount	Allocated Share	Transferred
	(a)	(b)	(c)
Joint Dispatch	$11,328,001	$8,316,083	$3,011,918
Coal Blending	23,524,131	17,514,516	6,009,615
Coal Procurement	1,624,630	2,399,044	(774,414)
Coal Transportation	2,181,451	2,165,421	16,030
Reagent Procurement & Transportation	450,300	560,574	(110,274)
Natural Gas Supply & Capacity	4,754,353	2,807,572	1,946,781
Avoided Trading Desk	215,724	127,539	88,185
Total	$44,078,590	$33,890,749	$10,187,841

The total amount shown in column (c) is the difference between the gross amount originating with DEC and its allocated share of combined savings. The Joint Dispatch amount shown above is composed of the savings transferred <u>to</u> DEP of $3,558,502 that is included in Schedule 3 of the Monthly Fuel Reports as Purchased Power, less the savings transferred <u>from</u> DEP of $546,584 that is included as Intersystem Sales. The increase in DEC's Purchased Power (debit) represents the DEP portion of Joint Dispatch savings that DEC realized on Joint Dispatch transactions, including energy transfers provided by DEP. The increase in DEC's Intersystem Sales (credit) represents the DEC portion of Joint Dispatch savings that DEP realized on Joint Dispatch transactions, including energy transfers provided by DEC.

Witness Hoard explained that the Coal Blending, Coal Procurement, and Coal Transportation fuel savings amounts transferred between DEC and DEP are reflected in the Steam Generation section, Account 0501016, of Monthly Fuel Report Schedule 2, page 1 of 2. According to witness Hoard, all of the Coal Blending savings originate in DEC, because they result from the implementation of coal blending at the DEC coal-fired plants. DEP, which implemented coal blending at its coal-fired plants in 2006, already has considerable experience with coal blending. Because DEP fully implemented coal blending before the Merger, there are no Merger-related coal blending savings for the DEP coal-fired plants. DEC, however, began some coal blending activities at its Marshall Steam Plant prior to the Merger, so the Utilities have excluded a portion of these savings from the computation of Merger-related Coal Blending savings. The Coal Procurement and Coal Transportation savings result from renegotiated and new contracts that the Utilities have entered into with coal and coal transportation services providers, and thus savings originate in both Utilities.

Similarly, witness Hoard explained, the Reagent Procurement and Transportation savings amounts result from renegotiated and new contracts that the Utilities have entered into with reagent and reagent transportation services providers. The net Reagent Procurement and Transportation savings amount transferred to DEC of $110,274 is reflected as a credit to Account 502160 – Reagent Procurement Merger Savings on Schedule 2, page 1 of 2, of the Monthly Fuel Report. All of the savings related to coal and reagent procurement and transportation reported through December 31, 2012, result from contract negotiations and renegotiations with fuel supply and transportation vendors that were premised upon the Merger, but undertaken by the Utilities prior to its closing.

Witness Hoard explained that the Natural Gas Supply and Capacity savings amount is composed of savings on purchases of gas supply, pipeline capacity costs, and purchases of oil. Monthly Fuel Report Schedule 2, Account 0547123 reflects $1,946,781 for the transfer of savings from DEC to DEP.

Witness Hoard further explained that the Avoided Trading Desk savings amount is a non-fuel and fuel-related cost item that is reflected on the Monthly Fuel Report, Schedule 2, page 2 of 2, in Account 0547127. Due to the Merger, only one natural gas trading desk is needed by the Utilities. As a result, the Utilities have avoided the personnel and related costs for a second trading desk that would have been needed had the Utilities not merged. The Avoided Trading Desk savings have been counted towards the fuel savings guarantee, but do not flow through the fuel clause.

Witness Hoard testified that Company witness Smith reflected an adjustment to her EMF computation for pre-Merger savings that DEC believes should be shared with DEP. DEC has not yet reflected the transfer of these savings from DEC to DEP in fuel and fuel-related expenses. The North Carolina retail amount of these savings, which total $2,282,619, is reflected on Smith Exhibit 3, pages 1 through 4, and decreases the overcollection that Company witness Smith has reflected in the EMF computation for the test period. The computation of this amount is shown on Smith Workpaper 18. Witness Hoard notes that Company witness Smith states in her testimony, at page 12, lines 18-22, that "[U]pon approval by the Commission to adjust the overcollection for calendar year 2012 to reflect the sharing of Merger fuel-related savings achieved during the period prior to the merger close, the Company will make the appropriate entries on its books to reflect the sharing of the savings."

Witness Hoard stated that both Utilities benefit from the Merger fuel-related savings, and the Company's proposal to share pre-Merger fuel savings between the two Utilities is consistent with the treatment of post-Merger fuel savings. Consequently, the Public Staff does not oppose this entry as long as DEP reflects the full offsetting amount in its upcoming fuel proceeding. He explained that the test period for DEP in its upcoming fuel proceeding begins April 1, 2012, so some of the pre-Merger period pre-dates the DEP test period. To ensure that ratepayers receive the full benefit of the savings, witness Hoard believes the offsetting entry made in the DEP proceeding should include savings for the January through March 2012 period that occurs prior to the beginning of the fuel proceeding test period. No party has objected to witness Hoard's recommendation for this offsetting entry.

Witness Hoard noted that the Public Staff has reviewed the tracked fuel savings computations but has not yet confirmed the validity of the amounts. He stated that the Public Staff will continue to review these fuel savings with due diligence. The Public Staff recommended that, should the Commission approve adjustments to the cumulative amount of reported fuel savings in a future proceeding, the Commission should address the accounting and ratemaking treatment of the adjustments at that time.

Based on the evidence presented, the Commission finds and concludes that DEC's proposal to share pre-merger fuel savings between itself and DEP is consistent with the treatment of post-Merger fuel savings related to the Merger and is thus reasonable and appropriate as long as DEP reflects the full offsetting amount in its upcoming fuel proceeding. In general, the cumulative amount of and accounting and ratemaking treatment of all Merger-related fuel and fuel-related cost savings shall remain subject to future Commission determination as described in the Merger Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is found in the testimony of Company witness Smith, the testimony of Public Staff witness Ellis, and the Stipulation.

According to the exhibits sponsored by Company witness Smith, the test period per book system sales were 79,868,568 MWh and test period per book system generation and purchased power was 86,013,644 MWh. The test period per book generation and purchased power is categorized as follows (Smith Exhibit 6, Schedules 1 and 3):

Type	MWh
Coal	27,969,376
Biomass	1,365
Oil & Combustion Turbine Gas	923,193
Combined Cycle Natural Gas	4,418,878
Nuclear	42,003,452
Hydro – Conventional	1,400,604
Hydro Pumped storage	(641,599)
Solar	10,479
Purchased Power – Economic and Dispatchable	8,093,358
Renewable Purchased Power	703,681
Other Purchased Power	907,292
Catawba Interchange	223,565
Total	86,013,644

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Findings of Fact Nos. 5-9 and 10.

No party took issue with the portions of witness Smith's exhibits setting forth per books N.C. retail 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 79,868,568 MWh and system generation and purchased power of 86,013,644 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Smith and Duncan, the testimony of Public Staff witnesses Ellis and Edwards, and the Stipulation.

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 Equipment Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. The Company proposed using a 92.84% 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 2013-2014 billing period. According to the exhibits sponsored by Company witness Smith, utilization of this capacity factor results in Company nuclear generation (net of that retained by the Catawba Joint Owners) of 43,440,823 MWh. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 89.79% for the period 2007-2011 for pressurized water reactors rated at and above 800 MWs, as reported by NERC in its latest Generating Availability Report. Public Staff witness Ellis did not dispute the Company's proposed use of a 92.84% capacity factor.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEC system, and the fact that the Public Staff and other parties did not dispute the Company's proposed capacity factor, the Commission concludes that the 92.84% nuclear capacity factor and its associated generation of 43,440,823 MWh, which excludes the Catawba Joint Owners' portion (Smith Exhibit 2, Schedule 1, Page 1), are reasonable and appropriate for determining the appropriate fuel costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-17

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Smith, the testimony of Public Staff witnesses Ellis and Edwards, and the Stipulation.

On Smith Exhibit 4, Company witness Smith set forth the test year per books North Carolina retail sales of 54,555,907 MWh, comprised of Residential class sales of 20,121,712 MWh, General Service/Lighting class sales of 22,116,267 MWh, and Industrial class sales of 12,317,928 MWh. Witness Smith made a decrement adjustment to per book North Carolina retail sales of (47,556) MWh for customer growth and an increment adjustment of 1,026,260 MWh for weather normalization, broken down as follows:

N.C. Retail Customer Class	Customer Growth	Weather Normalization
Residential	46,063	975,920
General Service/Lighting	(76,154)	72,533
Industrial	(17,466)	(22,193)
Total	(47,557)[2]	1,026,260

Based on these adjustments, witness Smith calculated an adjusted test year N.C. retail sales level of 55,534,611 MWh (Smith Exhibit 4,) for use in calculating the proposed EMF rates by customer class, broken down as follows and utilized as shown in Stipulation Exhibit 2:

N.C. Retail Customer Class	Adjusted kWh Sales
Residential	21,143,695
General Service/Lighting	22,112,646
Industrial	12,278,269
Total	55,534,610[3]

Witness Smith used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel rate. The

[2] Rounding difference.
[3] Rounding difference.

projected system sales level used, as set forth on Smith Exhibit 2, Schedule 1, Page 1 is 82,388,880 MWh. The projected level of generation and purchased power used was 90,164,033 MWh (calculated using the 92.84% capacity factor found reasonable and appropriate above), and was broken down by witness Smith as follows, as set forth on that same schedule:

Type	MWh
Coal	26,277,775
Gas CT and CC	10,016,167
Nuclear	43,440,823
Hydro	1,779,845
Net Pumped Storage Hydro	(798,620)
Purchased Power	9,448,043
Total	90,164,033

Per Smith Exhibit 2, Schedule 1, Page 1, the difference of (7,775,153) MWh between projected billing period system generation and purchased power and projected billing period system sales consists of the adjustment to exclude mitigation sales of (803,900) MWh, intersystem sales of (1,683,858) MWh, and line losses and Company use of (5,287,395) MWh. The total projected system fuel and fuel-related expense derived in part from the use of these generation and purchased power amounts was utilized in the Stipulation to calculate the prospective period fuel and fuel-related cost factors recommended by the Company and the Public Staff.

As part of her exhibits, Company witness Smith also presented an estimate of projected billing period N.C. retail residential, General Service/Lighting, and Industrial MWh sales (Smith Workpaper 9). According to this workpaper, the Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	20,955,314
General Service/Other	22,316,250
Industrial (Including Textiles)	12,244,753
Total	55,516,317

These class totals were used in Stipulation Exhibit 1, Schedule 3 in calculating the total fuel and fuel-related cost factors by customer class, as further discussed in the Evidence and Conclusions for Findings of Fact Nos. 20 through 24.

Public Staff witness Ellis testified that he had reviewed the calculations of the various prospective fuel factor components and agreed with them. In his testimony, Public Staff witness Edwards recommended EMF decrement billing factors calculated by using the adjusted test year North Carolina retail sales level of 55,534,611 MWh and the associated adjusted MWh customer class MWh sales amounts recommended by the Company and used in the Stipulation. No other party presented any evidence challenging the amounts presented by the Company.

Based on the evidence presented by the Company, the Public Staff's agreement with the amounts presented by the Company, and noting the absence of evidence presented to the contrary, the Commission concludes that the projected and normalized levels of sales, generation, and purchased power set forth in the Company's exhibits and the Stipulation are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Smith, Culp, and Weintraub, the testimony of Public Staff witness Ellis, and the Stipulation.

Company witness Smith recommended fuel and fuel-related prices and expenses as follows:

A. The coal fuel price is $38.023/MWh.
B. The gas CT and CC fuel price is $32.554/MWh.
C. The appropriate ammonia, limestone, urea and dibasic acid (collectively, Reagents) expense is $41,840,169.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.759/MWh.
E. The nuclear fuel price for Catawba Joint Owners generation is $6.759/MWh.
F. The total purchased power price (including the impact of JDA Savings Shared is $36.52/MWh.
G. The adjustment to exclude the cost of mitigation sales is a reduction of $(29,839,400).
H. The adjusted level of fuel and fuel-related credits associated with intersystem sales is $(66,967,909).

These amounts are set forth on or derived from Smith Exhibit 2, Schedule 1, Page 1. The total adjusted system fuel and fuel-related expense derived in part from the use of these amounts is utilized in the Stipulation to calculate the prospective fuel factors recommended by the Company and the Public Staff.

Company witness Culp testified that the billing period price of 0.676 ¢ per kWh for nuclear fuel will be about 18% higher than experienced during the test period. Despite the higher projected nuclear fuel costs, however, those costs represent approximately 15% of system fuel costs while nuclear fuel generation represents approximately 48% of the expected system generation and purchased power mix.

Additionally, as discussed by Company witness Weintraub, the proposed fuel and fuel-related cost factors include an average delivered cost for coal for the billing period of $98.62 per ton, which is less than 1% lower than the average delivered cost of coal during the test period. In addition, witness Weintraub notes an increase in natural gas prices as evidenced by the Henry Hub forward price of $4.03 per MMBtu used in the proposed fuel rates.

Public Staff witness Ellis testified that the Public Staff determined that the projected fuel prices set forth in the Application were calculated appropriately for this proceeding. He testified that the projected cost for fuel and fuel-related costs were affected by a small projected increase in the price of natural gas as evidenced by the Henry Hub projected forward prices. In addition, nuclear fuel costs also increased from the test year. The increases in natural gas and nuclear costs are offset by a slightly lower delivered price of coal, as well as Merger fuel-related savings and joint dispatch savings.

No other party presented evidence on the level of DEC's fuel prices and expenses set forth above.

Based upon the evidence in the record as to the appropriate fuel prices and expenses, the Commission concludes that the fuel prices recommended by Company witness Smith and accepted by the Public Staff are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Smith and Weintraub, the testimony of Public Staff witness Ellis, and the Stipulation.

Consistent with G.S. 62-133.2(a2), witness Smith demonstrated that the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed two percent of DEC's total North Carolina jurisdictional gross revenues for 2012. Witness Smith testified that when JDA-related costs are excluded from the purchased power calculation, the amount recoverable in the Company's proposed rates under the relevant sections of G.S. 62-133.2(a1) does not increase by more than 2% of DEC's gross revenues for its North Carolina retail jurisdiction for calendar year 2012. G.S. 62-133.2(a2) limits the amount of annual increase in certain purchased power costs identified in G.S. 62-133.2(a1) that the Company can recover to 2% of its North Carolina retail gross revenues for the preceding calendar year. In determining whether purchased power costs included in the Company's proposed rates should be limited, DEC performed its evaluation excluding the costs directly related to JDA transactions between DEC and DEP, which are providing Merger savings that the Company is passing through to its customers.

As explained by Company witness Weintraub, the JDA has allowed DEC's and DEP's generation resources to be dispatched as a single system to meet the two utilities' retail and firm wholesale customers' requirements at the lowest possible cost. The JDA was approved by the Commission in the Merger docket, and without it these specific purchased expenses between DEC and DEP would not exist. As a result, the

Company has included the full amount of its purchased power costs, including these transactions, in its cost recovery application.

Smith Exhibit 2, Schedule 1, page 3 of 3 and the Stipulation provide that the projected fuel costs for the North Carolina retail jurisdiction for use in this proceeding are $1,287,001,169 (consisting of $12,302,413 of renewable and cogeneration power capacity costs, and $1,274,698,756 of other fuel costs), calculated by using the sales, generation, pricing, and other amounts addressed in the various Findings of Fact discussed in this Order. Further, the Stipulating Parties noted that the annual increase in the aggregate amount of fuel-related expenses associated with certain purchased power costs identified in G.S. 62-133.2(a1) would have exceeded two percent of DEC's total North Carolina jurisdictional gross revenues for 2012 if the JDA-related costs were not excluded from the calculation. The Stipulation acknowledges, however, that the annual increase exceeded the North Carolina jurisdictional gross revenues because the Company jointly dispatched its generation fleet with DEP, consistent with the terms of the JDA as approved by the Commission in connection with the Merger, and has saved DEC's North Carolina retail customers $5,683,604 in fuel costs since the close of the Merger on July 2, 2012. But for the operation of the JDA, the Company would not have exceeded the two percent cap.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel 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 cost for the North Carolina retail jurisdiction of $1,287,001,169 is reasonable. Further, no party presented or elicited testimony contesting the Company's exclusion of the JDA-related costs from the calculation of the annual increase in the aggregate amount of the aforementioned fuel-related expenses. The Commission acknowledges that it did, in fact, approve the JDA because of the Merger savings that it will deliver – and is delivering – to customers, and that this aggregate increase is a coincidental effect of the approval of the JDA. The Commission finds, therefore, that DEC's exclusion of these costs from the calculation of the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs is just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-24

The evidence for these findings of fact is contained in the Stipulation, the testimony and exhibits of Company witness Smith, and the testimony of Public Staff witnesses Ellis and Edwards.

Company witness Smith presented DEC's original fuel and fuel-related expense overcollection and prospective fuel cost factors. Public Staff witness Ellis testified that the prospective components of the total fuel factor have been calculated in accordance with the statute and that the Public Staff agrees with them. The Stipulation sets forth the projected fuel costs, the amount of overcollection for purposes of the EMF, the method for allocating the increase in fuel costs, the composite fuel cost factors, and the EMFs along with schedules reflecting the stipulated adjustments. Public Staff witness Edwards reviewed the revised calculation of DEC's fuel and fuel-related cost overcollection set forth in the Stipulation and agreed.

Company witness Smith calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. The Stipulation provides that the decrease in fuel costs from the amounts approved in Docket No. E-7, Sub 1002 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in Docket No. E-7, Sub 1002. No party opposed the use of this allocation method.

Based upon the testimony and the Stipulation between the Company and the Public Staff as to the appropriate levels of sales, generation, purchased power, and unit fuel costs, as discussed in the Evidence and Conclusions for Findings of Fact Nos. 13 through 19, the Commission concludes that the prospective system fuel and fuel-related expense is $1,287,001,169 and the resulting prospective fuel and fuel-related cost factors of 2.2306¢/kWh for the Residential class, 2.3566¢/kWh for the General Service/Lighting class, and 2.3980¢/kWh for the Industrial class, excluding GRT and NCRF, are reasonable and appropriate for use in this proceeding.

G.S. 62-133.2(d) provides that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case." The overrecovery or underrecovery portion of the fuel factor is known as the EMF.

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 5-9, the Commission has concluded that the agreement between the Stipulating Parties that DEC will forgo recovery of $4,542,857 of replacement power fuel expenses incurred during the test year, as well as $757,143 of interest on that amount, for a total of $5,300,000, is appropriate and reasonable. Through the Stipulation, the Company updated its filing to reflect the impact of $431,799 of total system ($294,198 N.C. retail) fuel costs incurred in 2012 inadvertently omitted in its original filing, which represents the fuel cost component of other purchase power from a qualifying facility. Public Staff witness Edwards testified that the resulting test year North Carolina retail overrecovery amount of $51,555,143 and the related EMF interest amount of $8,592,520 are reasonable, broken down as follows:

	Test Year	
N.C. Retail Customer Class	Overrecovery	Interest
Residential	$ 9,676,332	$1,612,721
General Service/Other	$25,992,843	$4,332,139
Industrial (Including Textiles)	$15,885,968	$2,647,660
Total	$51,555,143	$8,592,520

As a result of these amounts, Public Staff witness Edwards recommended the following EMF and EMF interest decrement billing factors:

N.C. Retail Customer Class	EMF (cents/kWh)	EMF Interest (cents/kWh)
Residential	(0.0458)	(0.0076)
General Service/Other	(0.1175)	(0.0196)
Industrial (Including Textiles)	(0.1294)	(0.0216)

These factors are also set forth in Stipulation Exhibit 1, Schedule 1.

Based upon the Stipulation between the Company and the Public Staff as to the reduction of fuel expenses, as discussed in the Evidence and Conclusions for Findings of Fact Nos. 5-9, the Commission concludes that the EMF and EMF interest decrement billing factors set forth in the testimony of Public Staff witness Edwards and in the Stipulation are reasonable and appropriate for use in this proceeding.

Accordingly, the overall fuel calculation, incorporating the conclusions reached herein, results in total net fuel and fuel-related cost factors of 2.1772¢/kWh for the Residential class, 2.2195¢/kWh for the General Service/Lighting class, and 2.2470¢/kWh for the Industrial class, excluding GRT and NCRF, consisting of the prospective, EMF, and EMF interest factors approved herein.

The following tables summarize the impact of the rates stipulated in this case compared with the rates approved in Docket No. E-7, Sub 1002.

Approved in the last Docket No. E-7, Sub 1002 (excluding GRT and NCRF)

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	(0.1711) ¢/kWh	0.0360 ¢/kWh	(0.1351) ¢/kWh
General Service/Lighting	(0.1472) ¢/kWh	0.0323 ¢/kWh	(0.1149) ¢/kWh
Industrial	(0.1341) ¢/kWh	0.0318 ¢/kWh	(0.1023) ¢/kWh

Proposed in this Docket No. E-7, Sub 1033 (excluding GRT and NCRF)

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	(0.1629) ¢/kWh	(0.0534) ¢/kWh	(0.2163) ¢/kWh
General Service/Lighting	(0.0369) ¢/kWh	(0.1371) ¢/kWh	(0.1740) ¢/kWh
Industrial	0.0045 ¢/kWh	(0.1510) ¢/kWh	(0.1465) ¢/kWh

Summary of Differences Sub 1033 – Sub 1002 (excluding GRT and NCRF)

Rate Class	Prospective Component	EMF Component	Total Fuel Factor
Residential	0.0082 ¢/kWh	(0.0894) ¢/kWh	(0.0812) ¢/kWh
General Service/Lighting	0.1103 ¢/kWh	(0.1694) ¢/kWh	(0.0591) ¢/kWh
Industrial	0.1386 ¢/kWh	(0.1828) ¢/kWh	(0.0442) ¢/kWh

Summary of Differences Sub 1033 – Sub 1002 (including GRT and NCRF[4])

Rate Class	Total Fuel Factor
Residential	(0.0840) ¢/kWh
General Service/Lighting	(0.0611) ¢/kWh
Industrial	(0.0458) ¢/kWh

The Commission has carefully reviewed the Stipulation. The test period and projected fuel costs, the stipulated factors, including the EMF, and other issues addressed and resolved in the Stipulation are the result of negotiations between the Company and the Public Staff and are not opposed by any party. Therefore, based upon the evidence in this proceeding, the Commission finds and concludes that the terms of the Stipulation are fair and reasonable for the purposes of this proceeding.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after September 1, 2013, Duke Energy Carolinas shall adjust the base fuel and fuel-related costs in its North Carolina

[4] Based on a GRT and NCRF multiplier of 1.034554.

retail rates of 2.3935¢/kWh, as approved in Docket No. E-7, Sub 989, by amounts equal to (0.1629)¢/kWh, (0.0369)¢/kWh, and 0.0045¢/kWh for the Residential, General Service/Lighting and Industrial customer classes, respectively (excluding GRT and NCRF), and further, that Duke Energy Carolinas shall adjust the resultant approved fuel and fuel-related costs by decrements across the customer classes of (0.0534)¢/kWh for the Residential class, (0.1371)¢/kWh for the General Service/Lighting class, and (0.1510)¢/kWh for the Industrial class (excluding GRT and NCRF) for the EMF and EMF interest decrements. The EMF and EMF interest decrements are to remain in effect for service rendered through August 31, 2014;

2. That Duke Energy Carolinas shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments, as soon as practicable, but not later than ten (10) days from the date of this Order;

3. That Duke Energy Carolinas shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub 1034, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days, after the Commission issues orders in both dockets; and

4. That Duke Energy Carolinas shall file an updated fuel procurement practices report in Docket No. E-100, Sub 47 that includes a natural gas hedging strategy no later than December 31, 2013.

5. That the proposal of Duke Energy Carolinas to share pre-merger fuel savings with Duke Energy Progress is hereby approved subject to the condition that Duke Energy Progress reflects the full offsetting amount of the savings in its upcoming fuel proceeding.

ISSUED BY ORDER OF THE COMMISSION.

This the 20th day of August, 2013.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Chief Clerk

mr082013.01

Former Commissioners William T. Culpepper, III, and Lucy T. Allen, and present Commissioners Susan W. Rabon, Don M. Bailey, James G. Patterson and Jerry C. Dockham did not participate in this decision.