NORTH
CAROLINA
UTILITIES
COMMISSION

Volume I

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106th
REPORT
JAN. 1, 2016
DEC. 31, 2016

ONE-HUNDRED SIXTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume I

ISSUED FROM
JANUARY 1, 2016 THROUGH DECEMBER 31, 2016

ONE-HUNDRED SIXTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2016, through December 31, 2016

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

ToNola D. Brown-Bland, Commissioner

Don M. Bailey, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

*Lyons Gray, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
M. Lynn Jarvis
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

*Lyons Gray, appointed January 26, 2016, replacing Susan W. Rabon

LETTER OF TRANSMITTAL

December 31, 2016

The Governor of North Carolina
Raleigh, North Carolina

Sir:

Pursuant to the provisions of Section 62-17(b) of the General Statutes of North Carolina, providing for the annual publication of the final decisions of the Utilities Commission on and after January 1, 2016, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2016, and ending December 31, 2016.

The additional report provided under G.S. 62-17(a), comprising the statistical and analytical report of the Commission, is printed separately from this volume and will be transmitted immediately upon completion of printing.

Respectfully submitted,

NORTH CAROLINA UTILITIES COMMISSION

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

ToNola D. Brown-Bland, Commissioner

Don M. Bailey, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

Lyons Gray, Commissioner

M. Lynn Jarvis, Chief Clerk

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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In the Matter of	)	
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	)	
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In the Matter of	)	ORDER APPROVING REVISED
Application of Public Service Company of	)	TARIFFS, EFFECTIVE
North Carolina, Inc., for Authorization to	)	JANUARY 1, 2017
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	)	
DOCKET NO. G-5, SUB 565	)	
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In the Matter of	)	
Application of Public Service Company	)	
of North Carolina, Inc. for a General Increase	)	
in its Rates and Charges	)	

BY THE COMMISSION: Pursuant to Section 2.4.(a) of Session Law 2015-6 (House Bill (HB) 41), the Commission must adjust the rate for the sale of electricity, piped natural gas, and water and wastewater service to reflect all of the tax changes as enacted in Session Law 2013-316 (HB 998). Under G.S. 105-130.3A, as enacted in HB 998, an automatic reduction in the State corporate income tax rate from 4% to 3% will become effective for the taxable year beginning on or after January 1, 2017, because certain net General Fund tax collection levels were met for the State's fiscal year 2015-2016.

On September 19, 2016, the Commission issued its Order Requiring Revised Tariff Filings, Proposed Customer Notices, and Requesting Review and Comments by the Public Staff – North Carolina Utilities Commission (Public Staff). In the Order, the Commission concluded, among other things, that natural gas public utilities[1] must adjust their rates, effective for the taxable year

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[1] The Order required that all natural gas utilities, with the exception of Toccoa Natural Gas (Toccoa), Frontier Natural Gas Company, LLC (Frontier), and Piedmont Natural Gas Company, Inc. (Piedmont), each for a specific reason as outlined in the September 19, 2016, Order, file revised tariffs by October 12, 2016.

beginning on or after January 1, 2017, to reflect the reduction from 4% to 3% in the State corporate income tax rate. Therefore, the Commission required, among other things, that all natural gas public utilities file revised tariffs and proposed customer notices by no later than October 12, 2016, reflecting the new rates at the 3% State corporate income tax rate.

On October 12, 2016, Public Service Company of North Carolina, Inc. (PSNC or the Company) filed a letter in Docket No. M-100, Sub 138. The Company noted in its letter that it is proposing to address the reduction in the State corporate income tax rate from 4% to 3% effective for the taxable year beginning on or after January 1, 2017, through its general rate case proceeding pending at the time before the Commission in Docket No. G-5, Sub 565. The Company noted that Section 8 of the Amended Stipulation provides that the 2017 SIT rate is being addressed through the Company's updated base rates. PSNC stated that, accordingly, its rates will not be required to be changed within the context of Docket No. M-100, Sub 138.

On November 2, 2016, the Public Staff filed its comments as requested by the Commission in its September 19, 2016 Order. The Public Staff stated that it agrees that the reduction in the State corporate income tax rate from 4% to 3% should be addressed through PSNC's rate case pending before the Commission in Docket No. G-5, Sub 565.

On December 15, 2016, PSNC filed a letter in Docket Nos. M-100, Sub 138, G-5, Sub 525, and G-5, Sub 565. The Company noted that the parties to the Amended Stipulation in the general rate case proceeding agreed to work together on determining the appropriate revenue reduction reflecting the State income tax change and to file with the Commission notice of such reductions prior to implementation. PSNC stated that pursuant to that agreement, the Company was filing, as attached, a schedule setting forth the allocation of the revenue reduction and the Company's revised tariffs reflecting the revenue reduction attributable to the reduction in the State corporate income tax rate. The Company also included a statement of revised "R" factors for PSNC's Customer Usage Tracker. PSNC noted that the revised tariffs also reflect the expiration of the Alternative Motor Fuel Excise Tax Credits. The Company stated that by Order dated March 1, 2016, in Docket No. G-5, Sub 525, the Commission authorized PSNC to implement its proposal to flow through the tax credits associated with the retail sale of compressed natural gas for motor fuel purposes for its Rate Schedule 135. PSNC stated that the tax credits will expire December 31, 2016, and the revised tariffs filed by PSNC reflect the removal of the tax credit decrement applicable to Rate Schedule 135, effective January 1, 2017.

On December 20, 2016, PSNC filed a revised tariff to correct Rate Schedule 135 that concerns the expiration of the tax credits associated with the retail sale of compressed natural gas for motor fuel purposes.

On December 21, 2016, the Public Staff filed a letter stating that it had reviewed the tariffs filed by PSNC on December 15, 2016, as revised on December 20, 2016, believes that they comply with the Commission's orders in the described dockets, and recommended approval.

Based on the record of evidence, the Commission finds good cause to approve the tariffs filed by PSNC on December 15, 2016, as revised on December 20, 2016, effective for service rendered on and after January 1, 2017. PSNC shall notify its customers of the changes in rates approved herein.

IT IS, THEREFORE, ORDERED as follows:

1. That the revised tariffs filed by PSNC on December 15, 2016, as revised on December 20, 2016, are hereby approved and are deemed filed with the Commission pursuant to G.S. 62-138. The revised tariffs are effective for service rendered on and after January 1, 2017.

2. That PSNC shall notify its customers of the changes in rates approved herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of December, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

GENERAL ORDERS – ELECTRIC

DOCKET NO. E-100, SUB 101

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Generator Interconnection Standard,	)	ORDER REGARDING DUKE
Tariffs and Contract Forms	)	SETTLEMENT AGREEMENT
	)	WITH GENERATION
	)	INTERCONNECTION CUSTOMERS

BY THE COMMISSION: On August 29, 2016, Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, (collectively Duke), jointly filed for informational purposes a Settlement Agreement among Duke and seven solar developers representing 33 generation interconnection customers.

On September 8, 2016, the Commission issued an Order directing Duke to answer questions attached to the Order by September 22, 2016. The Public Staff was also requested to file comments as indicated in the Order and any other matters raised by the Settlement Agreement.

On September 16, 2016, Strata Solar, LLC, (Strata Solar) filed a petition to intervene and file comments that was granted by Order dated September 21, 2016.

On September 22, 2016, O2 EMC, LLC, (O2 EMC) filed a petition to intervene and to allow responses to answers Duke provides to the questions posed in the September 8, 2016 Order.

Duke filed its response on September 22, 2016, to the questions included in the September 8, 2016 Order. The Public Staff and Strata Solar each filed comments on that same date.

On September 23, 2016, O2 EMC filed a supplement to its petition to intervene.

On September 28, 2016, the Commission issued an Order granting the petition of O2 EMC to intervene but denying their request to file comments in response to DEP and DEC.

On October 11, 2016, O2 EMC filed a supplemental request to file comments, as well as providing such comments to responses to certain questions posed in Appendix A of the Commission's Order dated September 8, 2016.

The Commission finds the comments and answers to questions are complete and responsive to the Order. The Commission also finds that the Settlement Agreement among Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, and the settling interconnection customers does not create a need for the Interconnection Standard to be revised. The Commission is satisfied that Duke is taking appropriate steps to ensure electric service to retail customers is not degraded due to the operations of newly interconnected generation facilities. Therefore, the Commission finds there is no need for additional action at this time.

The Commission is of the opinion that good cause exists to accept the comments of O2 EMC, LLC, included in its Second Supplement to Petition to Intervene and Request for Leave to File Comments dated October 11, 2016.

The Commission recognizes that the Settlement Agreement required parties to mutually agree to specific additional language not included in the Commission-approved North Carolina Interconnection Procedures (NCIP). In the future, similar language or details shall not be presented as revisions to the NCIP but rather additional terms and conditions. The Commission concludes that all changes to the Interconnection Standard approved in Docket E-100, Sub 101 shall be presented to the Commission for review and approval.

ISSUED BY ORDER OF THE COMMISSION.
This the _1st_ day of November, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement	)	ORDER MODIFYING THE SWINE
Session Law 2007-397	)	AND POULTRY WASTE SET-ASIDE
	)	REQUIREMENTS AND PROVIDING
	)	OTHER RELIEF

BY THE COMMISSION: On August 11, 2016, a verified motion to modify and delay the 2016 requirements of G.S. 62-133.8(e) and (f) was filed by Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (Dominion); GreenCo Solutions, Inc.; Public Works Commission of the City of Fayetteville; EnergyUnited Electric Membership Corporation; Halifax Electric Membership Corporation; the Tennessee Valley Authority (TVA); North Carolina Eastern Municipal Power Agency (NCEMPA); and North Carolina Municipal Power Agency Number 1 (NCMPA1) (hereinafter referred to collectively as the Joint Movants).[1] The Joint Movants seek Commission approval of the following requests: 1) to delay the requirements of G.S. 62-133.8(e) (Compliance With [North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS)] Requirement Through Use of Swine Waste Resources) until 2017; 2) to modify the requirements of G.S. 62-133.8(f) (Compliance With REPS Requirement Through Use of Poultry Waste Resources) by lowering the 2016 requirement to 170,000 MWh and delaying subsequent increases until 2017; 3) to allow Joint Movants "to bank any swine and/or poultry renewable energy certificates (RECs) previously or subsequently acquired for use in future compliance years;" and 4) to "allow Joint Movants to replace compliance with the poultry and swine waste requirements in 2016 with other compliance measures in accordance with G.S. 62-133.8(b), (c), and (d)." The Joint Movants state that they have individually and collectively made reasonable efforts to comply with the REPS poultry and swine waste resource provisions, and that the relief sought is in the public interest. Finally, the Joint Movants request that the Commission consider and approve their motion without an evidentiary hearing because they believe that through required semiannual reports and stakeholder meetings, stakeholders and regulatory staff have ample information surrounding the Joint Movants' compliance efforts.

[1] DEC asserts that it is also acting in its capacity as REPS compliance aggregator for Blue Ridge Electric Membership Corporation (EMC), Rutherford EMC, the City of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands and the City of Kings Mountain. DEP asserts that it is also acting in its capacity as REPS compliance aggregator for the Towns of Sharpsburg, Lucama, Black Creek, Winterville and Stantonsburg. Dominion asserts that it is also acting in its capacity as REPS compliance aggregator for the Town of Windsor. TVA asserts that it is acting in its capacity as REPS compliance aggregator for Blue Ridge Mountain EMC, Mountain Electric Cooperative, Tri-State EMC and Murphy Electric Power Board. NCEMPA asserts that it is acting in its capacity as REPS compliance aggregator for its 32 member municipalities, which are electric power suppliers. NCMPA1 asserts that it is acting in its capacity as REPS compliance aggregator for its 19 member municipalities, which are electric power suppliers.

On August 31, 2016, the Commission issued an Order Requesting Comments. On September 26, 2016, the Commission granted a motion for an extension of time filed by the Public Staff, extending the deadline by which parties may file comments until September 30, 2016.

Between September 22, 2016 and September 30, 2016, the North Carolina Poultry Federation (NCPF), the North Carolina Pork Council (NCPC), the Public Staff, and the North Carolina Sustainable Energy Association (NCSEA) filed comments on Joint Movants' motion. No other party filed comments on the motion.

SUMMARY OF THE COMMENTS

NCPF, in its comments, states that it "does not oppose" the portion of the motion requesting to modify the requirements of G.S. 62-133.8(f) by lowering the 2016 compliance requirement to 170,000 MWh and delaying the subsequent increases in compliance requirements until calendar year 2017. NCPF limits its comments to the motion and its application to G.S. 62-133.8(f). Thus, NCPF takes no position with regard to banking poultry waste RECs and substituting other types of RECs for 2016 compliance purposes. NCPF stipulates and agrees that the Commission may enter an order on the motion on the basis of written submissions without the need for an evidentiary hearing. Finally, NCPF requests that the Commission "continue to monitor the process" and "continue to use its authority to motivate the parties to achieve compliance with the poultry waste set-aside as soon as practicable."

NCPC, in its comments, states that it recognizes the impediments to compliance facing the electric power suppliers and does not oppose the relief requested in the motion. Nevertheless, NCPC states that it believes that progress continues to be achieved and the modified set-aside requirement should be obtainable in the near term. NCPC devotes a substantial portion of its comments to addressing the Joint Movant's description of the swine waste set-aside requirement as a "collective" or "aggregate" requirement despite the Commission's adoption of a pro rata allocation method. See NCPC's Comments at 2-3, Docket No. E-100, Sub 113 (September 23, 2016) (citing Order on Pro Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification, Docket E-100, Sub 113 (March 31, 2010)). NCPC further states that the confidential semiannual progress reports submitted by electric power suppliers in Docket No. E-100, Sub 113A, and relied upon in support of the motion, lack sufficient detail to provide adequate information for making the required findings and determination. Therefore, while NCPC recommends that the Commission grant the delay or modification requested, it further recommends that the Commission inform the electric power suppliers that any future similar requests will be considered on an individual basis supported by specific detailed information related to each electric power supplier's compliance efforts.

The Public Staff, in its comments, states that it has reviewed the motion, the semiannual reports, and the data in the North Carolina Renewable Energy Tracking System (NC-RETS). In addition, the Public Staff states that it has obtained useful information from the swine waste and poultry waste stakeholder meetings. The Public Staff's comments include a review of detailed data available in the triannual and semiannual reports filed with the Commission in Docket E-100, Sub 113A, showing the approximate overall compliance position of the electric power suppliers. Based upon this review of the data, the Public Staff concludes that the Joint Movants are making good faith efforts to comply with the swine and poultry waste set-aside requirements, but will fall short for 2016. Therefore, the Public Staff recommends that the Commission: (1) delay for one year the swine waste set-aside requirement; (2) modify the poultry waste set-aside requirements to maintain the current 170,000 MWh or equivalent for calendar year 2016 and delay all of the additional poultry waste set-aside compliance obligations for one year; (3) allow the electric power suppliers to bank any swine and poultry waste RECs previously or subsequently acquired for use in the future, exclusive of poultry waste RECs retired in 2014, 2015, and 2016; (4) "allow the electric power suppliers to replace compliance with G.S. 62-133.8(e) in 2016 with compliance measures in accordance with G.S. 62-133.8(b), (c), and (d);" and (5) not require an evidentiary hearing on this matter.

NCSEA, in its comments, states that it does not object to the Joint Movants' request to modify the poultry waste set-aside requirement by lowering the 2016 compliance requirement to 170,000 MWh. NCSEA requests that the Commission consider whether to modify, rather than to delay, the swine waste set-aside requirement to positively impact the swine waste market. NCSEA argues that the modification of the swine waste set-aside requirement, allowing for partial compliance and requiring the retirement of swine waste RECs, will have a stimulative effect on the market for swine waste fueled electric generation projects similar to that experienced in the poultry waste market after the Commission's 2015 delay order modifying the poultry waste set-aside requirement. In support of its position, NCSEA states that DEC's and DEP's 2016 Integrated Resource Plan (IRP) and 2016 REPS Compliance Plan filings demonstrate that DEC and DEP should be in a position to comply with the swine waste set-aside requirements for future years. In response to the other parties' comments, NCSEA notes that compliance with the set-aside requirements has been a struggle for all stakeholders and states that incremental steps can be taken to improve transparency into electric power suppliers' compliance efforts. Thus, NCSEA supports and endorses the request by NCPC to require electric power suppliers to provide additional information about their compliance efforts when they seek similar relief under G.S. 62-133.8(i)(2) in the future and to account for their compliance efforts on an individual basis. In conclusion, NCSEA requests that the Commission exercise its authority and modify the set-aside requirements to require partial compliance with both set-aside requirements in 2016 and requests that the Commission require the additional and individualized reporting as proposed by NCPC.

DISCUSSION

Pursuant to G.S. 62-133.8(i)(2), the Commission, in developing rules implementing the REPS, shall:

> Include a procedure to modify or delay the provisions of subsections (b), (c), (d), (e), and (f) of this section in whole or in part if the Commission determines that it is in the public interest to do so. The procedure adopted pursuant to this subdivision shall include a requirement that the electric power supplier demonstrate that it made a reasonable effort to meet the requirements set out in this section.

Commission Rule R8-67(c)(5) states:

> In any year, an electric power supplier or other interested party may petition the Commission to modify or delay the provisions of G.S. 62-133.8(b), (c), (d), (e) and (f), in whole or in part. The Commission may grant such petition upon a finding

> that it is in the public interest to do so. If an electric power supplier is the petitioner, it shall demonstrate that it has made a reasonable effort to meet the requirements of such provisions.

The Commission has previously exercised this authority and delayed compliance with the swine and/or poultry waste set-aside requirements on several occasions by the following orders in this docket: the November 29, 2012 Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief (2012 Delay Order); the March 26, 2014 Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief (2013 Delay Order); the November 13, 2014 Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief (2014 Delay Order), and the December 1, 2015 Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief (2015 Delay Order).

As an initial matter, the Commission considers Joint Movants' request to consider and approve their motion without the need for an evidentiary hearing. In support of this request, Joint Movants state that the compliance status for the swine and poultry waste set-aside requirements is essentially unchanged since the Commission issued its 2015 Delay Order. The motion is verified by David B. Fountain, North Carolina President of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, pursuant to Commission Rule R1-7 on behalf of the Joint Movants. The Public Staff, like the Joint Movants, recommends that the Commission approve the request without an evidentiary hearing. No party filed comments opposing this portion of the motion. Based upon the foregoing, the Commission finds that the material facts in this matter, including those contained in Joint Movants' verified motion and in the semiannual reports filed in Docket No. E-100, Sub 113A, are uncontroverted and concludes that the motion may be decided without an evidentiary hearing.

Based on the triannual and semiannual reports submitted by the electric power suppliers in Docket No. E-100, Sub 113A, the verified motion, the parties' comments, and the entire record herein, the Commission finds that the State's electric power suppliers have made a reasonable effort to comply with the 2016 statewide swine waste set-aside requirements established by G.S. 62-133.8(e), but will not be able to comply. Compliance with the swine waste set-aside requirement has been hindered by the fact that the technology of power production from swine waste continues to be in its early stages of development. No party presented evidence that the aggregate 2016 swine waste set-aside requirement could be met. However, the Commission notes that the electric power suppliers report encouraging developments in the technology of power production from swine waste that, combined with the availability of RECs banked from current and prior years, increase the likelihood that compliance with the swine waste set-aside requirements will be achieved in 2017. The Commission further notes that it has permitted the Joint Movants to bank RECs for four consecutive years and the cumulative effect of this banking has yet to result in the ability to comply with the initial swine waste set-aside requirement. To require that the Joint Movants retire their banked swine RECs would, thus, result in wiping the slate clean for compliance purposes in future years. Therefore, consistent with the 2015 Delay Order, the Commission finds that it is in the public interest to delay the entire requirement of G.S. 62-133.8(e) for one additional year. Electric power suppliers that have acquired swine waste RECs for 2016 REPS compliance should be allowed to bank such RECs for swine waste set-aside compliance in future years. Electric power suppliers should continue to make efforts to comply with the swine waste set-aside requirement as modified by this Order.

The Commission carefully considered NCPC's recommendations related to the level of detail included in the electric power suppliers' semiannual reports and NCSEA's expression of support for, and endorsement of, these recommendations. The Commission, at this time, is not persuaded that the semiannual reporting requirements should be further amended beyond that information additionally required in the 2015 Delay Order. The Commission notes that two sets of semiannual reports have been filed since the Commission issued its 2015 Delay Order. Further, the minutes of the most recent stakeholder meeting on swine waste set-aside requirement compliance filed by the Public Staff on August 23, 2016, in Docket No. E-100, Sub 113A, do not reflect that a discussion occurred among the interested parties regarding the specificity or level of detail of the semiannual reports. Therefore, the Commission finds that the issues NCPC raises related to the appropriate level of detail of the semiannual reports, though not without merit, are best addressed through the semiannual stakeholder meetings, or, if necessary, through a proceeding before the Commission that brings the issues into sharper relief. Thus, the Commission will continue to require the filing of semiannual reports consistent with Ordering Paragraph 3 of the 2015 Delay Order and to require and/or encourage participation in the semiannual stakeholder meetings. The Commission encourages the parties to the stakeholder meetings to address NCPC's concerns to the end that the semiannual reports will provide an appropriate level of transparency into the electric power suppliers' individual and aggregate efforts to comply with the swine waste set-aside requirements.

Based on the semiannual reports submitted by the electric power suppliers in Docket No. E-100, Sub 113A, the verified motion, the parties' comments, and the entire record herein, the Commission similarly finds that the State's electric power suppliers have made a reasonable effort to comply with the 2016 statewide poultry waste set-aside requirement established by G.S. 62-133.8(f), but will not be able to comply. As with the swine waste set-aside requirement, compliance with the poultry waste set-aside requirement has been hindered by the fact that the technology of power production from poultry waste continues to be in its early stages of development. No party presented evidence that the aggregate 2016 poultry waste set-aside requirement could be met; however, the parties agree that the 2015 compliance level of 170,000 MWh, if maintained for 2016, can be met. Therefore, the Commission finds that it is in the public interest to modify the entire requirement of G.S. 62-133.8(f) for one year. Consistent with the 2015 Delay Order, the Commission finds good cause to modify the poultry waste set-aside requirement established by G.S. 62-133.8(f) by adding an additional year (2016) of compliance at the 170,000 MWh threshold, prior to escalating the requirement to 700,00 MWh. Electric power suppliers should continue to make efforts to comply with the poultry waste set-aside requirements as modified by this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the 2016 swine waste set-aside requirements of G.S. 62-133.8(e), as established in the Commission's 2015 Delay Order, are delayed for one additional year. The electric power suppliers, in the aggregate, shall comply with the requirements of G.S. 62-133.8(e) according to the following schedule:

Calendar Year	Requirement for Swine Waste Resources
2017-2018	0.07%
2019-2021	0.14%
2022 and thereafter	0.20%

Electric power suppliers shall be allowed to bank any swine waste RECs previously or subsequently acquired for use in future compliance years and to replace compliance with the swine waste set-aside requirement in 2016 with other compliance measures pursuant to G.S. 62-133.8(b) and (c), including the use of solar RECs beyond the requirements of G.S. 62 133.8(d);

2. That the 2016 poultry waste set-aside requirement of G.S. 62-133.8(f), as established in the Commission's 2015 Delay Order, is modified to maintain the same level as the 2015 requirement, and that the scheduled increases in the requirement be delayed by one year. The electric power suppliers, in the aggregate, shall comply with the requirements of G.S. 62 133.8(f) according to the following schedule:

Calendar Year	Requirement for Poultry Waste Resources
2015	170,000 MWh
2016	170,000 MWh
2017	700,000 MWh
2018 and thereafter	900,000 MWh;

3. That the electric power suppliers subject to the semiannual filing requirement shall continue to report on the schedule established in the 2015 Delay Order. These reports shall continue to include the information specified in Ordering Paragraph 3 of the Commission's 2015 Delay Order; and

4. That the Public Staff shall continue to arrange and facilitate stakeholder meetings within six weeks of the filing of a semiannual report. The electric power suppliers subject to the semiannual filing requirement shall attend. Developers and other stakeholders are encouraged to participate and discuss potential obstacles to achieving the swine and poultry waste set-aside requirements, options for addressing them, and the need for more detailed individualized semiannual reports. The Public Staff shall continue to file minutes of the stakeholder meetings in Docket No. E-100, Sub 113A.

ISSUED BY ORDER OF THE COMMISSION.
This the ___17th___ day of October, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-100, SUB 145

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2015 REPS Compliance Plans and 2014 REPS Compliance Reports	)))	ORDER APPROVING 2014 REPS COMPLIANCE REPORTS

BY THE COMMISSION: North Carolina General Statute 62-133.8 requires all electric power suppliers in North Carolina to meet specific percentages of their retail sales using renewable energy and energy efficiency. Commission Rule R8-67(c)(3) requires each municipal electricity supplier and electric membership corporation (EMC), or its utility compliance aggregator, to file a verified Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance report on or before September 1 of each year. Commission Rule R8-67(b) requires each electric power supplier, or its utility compliance aggregator, to file a REPS compliance plan on or before September 1 each year.

On May 14, 2012, the Commission issued an Order Requiring Electric Membership Corporations and Municipal Power Suppliers to File Measurement and Verification Plans and Results for Energy Efficiency and Demand-Side Management Programs.[1] The Order amended Rule R8-67(b) to require each electric power supplier to include in its annual REPS compliance plan a measurement and verification (M&V) plan for energy efficiency (EE) and demand-side management (DSM) measures that it intends to use toward REPS compliance, if such M&V plan has not otherwise been filed with the Commission. In addition, the Order amended Commission Rule R8-67(c) to require EMCs and municipal electric suppliers to include in their annual REPS compliance reports, "the results of each [EE and DSM] program's measurement and verification plan, or other documentation supporting an estimate of the program's energy reductions achieved in the previous year pending implementation of a measurement and verification plan. Supporting documentation shall be retained and made available for audit."

On March 26, 2014, the Commission issued an Order in Docket No. E-100, Sub 113 establishing 170,000 MWh as the 2014 aggregate poultry waste set-aside requirement as. This Order also delayed the 2013 swine waste set-aside requirement until 2014. On November 13, 2014, the Commission issued an Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief (Delay Order) in Docket No. E-100, Sub 113. This second Order established that the 2014 swine waste set-aside requirement would be delayed until 2015, and that the 2014 aggregate poultry waste set-aside requirement would remain at 170,000 MWhs.

On August 28, 2015, the Town of Fountain (Fountain) filed its REPS compliance plan and 2014 REPS compliance report. On August 31, 2015, the Tennessee Valley Authority (TVA) filed a REPS compliance plan and report on behalf of Blue Ridge Mountain EMC, Mountain Electric Cooperative, Murphy Electric Power Board, and Tri-State EMC (collectively, the TVA distributors). Also on August 31, 2015, EnergyUnited EMC filed public and confidential versions of its REPS compliance plan and compliance report.

[1] See Order in Docket Nos. E-43, Sub 6; E-100, Sub 113; EC-33, Sub 58; and EC-83, Sub 1.

On September 1, 2015, a 2015 REPS report was filed by North Carolina Eastern Municipal Power Agency (NCEMPA) on behalf of its 32[1] municipal members. Also on September 1, 2015, the North Carolina Municipal Power Agency Number 1 (NCMPA1) filed a REPS compliance plan and 2014 REPS compliance report on behalf of its 19[2] municipal members. Both agencies filed confidential, as well as public, versions of their plans and reports. On that same date, GreenCo Solutions, Inc. (GreenCo), filed confidential and public versions of its REPS compliance report and its REPS compliance plan.[3] Also on September 1, 2015, Halifax EMC (Halifax) filed its REPS compliance report and its REPS compliance plan. Halifax stated that its report included compliance for the Town of Enfield (Enfield). On that same date, Fayetteville Public Works Commission (Fayetteville PWC) filed a confidential and public version of its 2014 compliance report and a confidential version of its compliance plan. On September 15, 2015, Fayetteville PWC filed a public version of its compliance plan.

On September 15, 2015, the Commission issued an Order Establishing Dates for Comments on REPS Compliance Plans and REPS Compliance Reports. In that Order the Commission established December 18, 2015, as the deadline for petitions to intervene in this docket, and also established that date as the deadline for the Public Staff and other parties to file initial comments on the REPS compliance plans and reports in this docket. Finally, the Order established January 15, 2016, as the deadline for all parties to file reply comments.

Also on September 15, 2015, the Administrator of the North Carolina Renewable Energy Tracking System (NC-RETS) filed a letter explaining that the 2013 retail sales for some electric power suppliers were corrected well after the June 1, 2014 deadline established in Commission Rule R8-67(h)(11). This caused NC-RET's software to re-allocate the 170,000-MWh 2014 poultry waste resource obligation among electric power suppliers. On September 21, 2015, the Commission issued an Order Requesting Comments on Options for Addressing Poultry REC Shortfall in which it requested comments on what actions, if any, the Commission should take to address an apparent 599 MWh short-fall in the electric power suppliers' aggregate 2014 poultry waste resource requirement. On October 2, 2015, comments were filed by: Dominion North Carolina Power (Dominion); jointly by NCEMPA and NCMPA1 (collectively the Agencies);

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[1] NCEMPA filed a consolidated 2014 REPS compliance report on behalf of the Towns of Apex, Ayden, Belhaven, Benson, Clayton, Edenton, Farmville, Fremont, Hamilton, Hertford, Hobgood, Hookerton, LaGrange, Louisburg, Pikeville, Red Springs, Robersonville, Scotland Neck, Selma, Smithfield, Tarboro, Wake Forest and the Cities of Elizabeth City, Greenville, Kinston, Laurinburg, Lumberton, New Bern, Rocky Mount, Southport, Washington and Wilson. Its filing indicated that Wilson met the REPS compliance requirements of Pinetops, Macclesfield, and Walstonburg.

[2] NCMPA1's members include the Towns of Bostic, Cornelius, Drexel, Granite Falls, Huntersville, Landis, Maiden, Pineville, and the Cities of Albemarle, Cherryville, Gastonia, High Point, Lexington, Lincolnton, Monroe, Morganton, Newton, Shelby and Statesville.

[3] GreenCo filed a consolidated 2014 REPS compliance report on behalf of Albemarle Electric Membership Corporation (EMC), Broad River Electric Cooperative (EC), Brunswick EMC, Cape Hatteras EMC d/b/a Cape Hatteras Electric Cooperative, Carteret-Craven EMC d/b/a Carteret-Craven Electric Cooperative, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood EMC, Jones-Onslow EMC, Lumbee River EMC, Mecklenburg EC, Pee Dee EMC, Piedmont EMC, Pitt & Greene EMC, Randolph EMC, Roanoke EMC d/b/a Roanoke EC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC d/b/a Union Power Cooperative, Wake EMC and the Town of Oak City, whose requirements are included with those of Edgecombe-Martin County EMC.

jointly by Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP); and the Public Staff. On October 19, 2015, the Commission issued an Order Addressing Poultry Compliance Shortfall and Requesting Comments on New Allocation Method in which it: 1) required DEC and DEP to adjust the RECs in their 2014 compliance sub-accounts, 2) required the NC-RETS Administrator to report to the Commission as to the status of those adjustments, and 3) invited parties to provide comments as to alternative methods of allocating the aggregate poultry obligation in the future. The question of alternative allocation methods remains pending before the Commission.

On November 6, 2015, Fayetteville PWC filed a public and confidential version of amendments to its 2014 compliance report.

On December 18, 2015, the Public Staff filed a motion requesting that the date for initial comments be extended to January 8, 2016, and that the date for reply comments be extended to February 5, 2016. On December 21, 2015, the Commission issued an Order Granting Extensions of Time in which it extended the dates as requested by the Public Staff.

On January 8, 2016, the Public Staff filed public and confidential versions of its comments addressing the 2014 REPS compliance reports and compliance plans that had been filed by EnergyUnited, Fayetteville PWC, Fountain, GreenCo, Halifax, NCEMPA, NCMPA1, and TVA. These comments also addressed the electric power suppliers' EM&V for EE measures that they intend to use toward REPS compliance.

On January 12, 2016, Fountain requested that the Commission allow it to adjust the renewable energy certificates (RECs) in its 2014 compliance sub-account because "only 30 percent of the total RECs used for compliance can be hydroelectric RECs," and it needed to "acquire the necessary non-hydro RECs ... to rectify this situation."

On January 22, 2016, TVA filed a letter notifying the Commission that it had worked with NC-RETS to correct an error whereby some RECs had been erroneously classified as having come from an out-of-state facility.

On February 3, 2016, the Public Staff filed supplemental comments.

<u>2014 REPS Compliance</u>

General Statute 62-133.8(c) established a 2014 REPS obligation under which all electric power suppliers are required to meet 3 percent of their 2013 retail sales with renewable energy or savings from EE/DSM. Further, under G.S. 62-133.8(d) the municipal and EMC suppliers are required to meet 0.07 percent of their customers' needs (based on 2013 retail sales) with solar energy resources. As discussed earlier, the aggregate poultry waste set-aside requirement for 2014 was 170,000 MWh and the 2014 swine waste set-aside requirement was delayed until 2015.

In its January 8, 2016 comments, the Public Staff stated that all municipal electricity suppliers and EMCs had met their REPS requirements, with two exceptions.[1] The Public Staff said that Fountain had not submitted enough non-hydro RECs, and that TVA had not met its poultry waste requirement. Both of these deficiencies were subsequently addressed as explained later in this Order. The Public Staff also stated that all of the municipal electricity suppliers and EMCs had kept their incremental costs of REPS compliance below the annual cost caps established by G.S. 62-133.8(h)(4).

Commission Rule R8-67(h)(3) requires each electric power supplier to participate in NC-RETS and to provide data to NC-RETS "to calculate its REPS obligation and to demonstrate its compliance with G.S. 62-133.8." Based on the filed REPS compliance reports, the Public Staff's comments, and the records contained in NC-RETS, the Commission accepts each electric power supplier's 2014 REPS compliance, as discussed below.

<u>EnergyUnited</u>

The Public Staff stated that EnergyUnited's compliance report and NC-RETS sub-account indicate that the power supplier met its REPS requirements for 2014. EnergyUnited's report stated that its 2013 retail sales were 2,359,482 MWh, which, when multiplied by 3 percent, resulted in a 2014 REPS obligation of 70,785 RECs. When multiplied by 0.07 percent, this sales level resulted in an obligation of 1,652 solar RECs. EnergyUnited's report stated that its share of the 2014 poultry waste requirement is 3,012 poultry RECs. EnergyUnited's compliance sub-account in NC-RETS affirms that EnergyUnited met its 2014 REPS obligations, both the general obligation and the set-asides. However the specific mix of renewable resources that EnergyUnited used to achieve compliance is not consistent as between the confidential Appendix 1 of its compliance report, and EnergyUnited's NC-RETS compliance sub-account. Similarly, while the total number of energy efficiency certificates (EECs) that EnergyUnited is using toward its 2014 compliance is consistent as between the confidential Appendix 1 of its report and NC-RETS, those two information sources are inconsistent as to the number of EECs that were generated by each of EnergyUnited's two EE programs. EnergyUnited counted toward its 2014 REPS compliance EECs from two programs, its commercial lighting program and its heat pump rebate program. The Public Staff stated that it agreed with EnergyUnited's EM&V results for these programs. Further, the Public Staff recommended that the Commission approve EnergyUnited's 2014 compliance report, including the EM&V results for the EECs that the power supplier earned in 2014.

The Commission is of the opinion that the discrepancies between EnergyUnited's compliance report filed in this docket and NC-RETS are clerical in nature and immaterial.

[1] The Commission has addressed the 2014 REPS compliance for the State's other electric power suppliers as follows: Dominion North Carolina Power (Dominion), Order Approving REPS and REPS EMF Riders and 2014 REPS Compliance issued December 16, 2015, in Docket No. E-22, Sub 525; Duke Energy Carolinas, LLC (DEC), Order Approving REPS and REPS EMF Riders and 2014 REPS Compliance issued July 30, 2015, in Docket No. E-7. Sub 1074; and Duke Energy Progress, Inc. (DEP), Order Approving REPS and REPS EMF Riders and 2014 REPS Compliance issued November 17, 2015, in Docket No. E-2, Sub 1071. Dominion provided REPS compliance services for the Town of Windsor. DEC provided REPS compliance services for Blue Ridge EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the City of Highlands, the City of Kings Mountain and Rutherford EMC. DEP provided REPS compliance services for the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, the Town of Winterville, and the City of Waynesville.

Therefore, based on EnergyUnited's REPS compliance report, the comments of the Public Staff, and the data in NC-RETS, the Commission finds that EnergyUnited complied with its 2014 REPS obligation, and that the RECs and EECs in EnergyUnited's 2014 compliance sub-account in NC-RETS should be retired.

Fayetteville PWC

Fayetteville PWC's 2014 compliance report and its November 6, 2015 amendment provided details of its 2014 compliance. Its 2013 retail sales were 2,026,104 MWh, which, when multiplied by 3 percent, resulted in a 2014 general REPS obligation of 60,784 RECs. When multiplied by 0.07 percent, this sales level resulted in an obligation of 1,419 solar RECs. Fayetteville PWC's compliance sub-account in NC-RETS is consistent with this information, and contains 60,784 RECs, including 1,419 in-state solar RECs. NC-RETS shows that Fayetteville PWC's share of the aggregate poultry waste set-aside requirement was 2,659 poultry RECs, and that it met that obligation as well.

The Public Staff stated that Fayetteville PWC reported four EE programs: a compact fluorescent light (CFL) distribution program, an LED street lighting pilot program, a high-efficiency audit program, and an HVAC replacement program. The CFL distribution program is the only one for which Fayetteville PWC had provided EM&V data and for which it had banked EECs. For EM&V, it used data from a similar program by Duke Energy Progress, Inc. (DEP), which the Public Staff found to be acceptable. Fayetteville PWC did not use any EECs for REPS compliance in 2014. The Public Staff recommended that the Commission approve Fayetteville's 2014 compliance report, including the EM&V results for the EECs that it banked in 2014.

Therefore, based on Fayetteville PWC's compliance report, as well as the comments of the Public Staff and the records in NC-RETS, the Commission finds that Fayetteville PWC complied with its 2014 REPS obligation, and that the RECs in Fayetteville PWC's 2014 compliance sub-account in NC-RETS should be retired.

Fountain

Fountain's 2014 REPS compliance report stated that its 2013 retail sales were 3,573 MWh, which, when multiplied by 3 percent, resulted in a 2014 REPS obligation of 108 RECs. When multiplied by 0.07 percent, this sales level resulted in an obligation of three solar RECs. NC-RETS shows that Fountain's share of the aggregate poultry waste set-aside requirement was five poultry RECs, and that Fountain met this obligation. In its January 8, 2016 comments, the Public Staff stated that Fountain had used only hydroelectric RECs to comply with its general REPS requirements, and that this contradicted G.S. 62-133.8(c)(2)(c) which states that hydroelectric RECs may only be used to meet 30 percent of a municipal power supplier's general REPS obligations. Subsequently, on January 11, 2016, Fountain requested that the Commission "re-open" its compliance sub-account in NC-RETS in order to replace some hydroelectric RECs with RECs from other renewable energy resources. The Commission's review of Fountain's NC-RETS compliance account shows that these changes have been made, and that Fountain has fully complied with its 2014 REPS obligations.

Therefore, based on Fountain's 2014 REPS compliance report, the Public Staff's comments and the records in NC-RETS, the Commission finds that Fountain complied with its 2014 REPS obligation, and that the RECs in Fountain's 2014 compliance sub-account in NC-RETS should be retired.

GreenCo

GreenCo's 2014 REPS compliance report indicated that the combined 2013 retail sales of its REPS compliance participants were 12,363,411 MWh, which, when multiplied by 3 percent, resulted in a 2014 REPS obligation of 370,904 RECs. When multiplied by 0.07 percent, this sales level resulted in an obligation of 8,656[1] solar RECs. GreenCo's compliance sub-account in NC-RETS is consistent with this information, and contains 370,905 RECs, including 8,655 in-state solar RECs. NC-RETS has calculated GreenCo's share of the aggregate poultry waste set-aside requirement to be 16,220 poultry RECs and shows that GreenCo has complied by placing 16,230 poultry RECs in its 2014 compliance sub-account.

GreenCo's compliance report states that it placed 145,976 EECs in its 2014 retirement sub-account, and this is consistent with the data in NC-RETS. In 2014 GreenCo members offered the following EE programs: Agricultural EE, Commercial EE, Commercial New Construction, Community Efficiency Campaign, Community Efficiency (low income), EnergyStar Appliances, EnergyStar New Home Construction, EnergyStar Lighting, Energy Cost Monitor, Refrigerator/Freezer Turn-in, and Water Heating Efficiency.

GreenCo bases the energy savings for these programs on data and analyses from GDS's 2013 market potential study and other customer-specific reports. The Public Staff agreed with the 2013 study's program assessments. GreenCo's compliance report stated that it does not claim EECs for CFLs that were installed after 2013 because it considers CFLs to now be a baseline technology.

The Public Staff recommended that the Commission approve GreenCo's 2014 report, including the EM&V results for the EECs it earned in 2014.

Based on the foregoing, including the records in NC-RETS, the Commission concludes that GreenCo's member electric power suppliers, along with Mecklenburg, Broad River, and Oak City, met their 2014 REPS obligations, and that the RECs in the GreenCo compliance sub-account in NC-RETS should be retired.

Halifax

Halifax's 2014 REPS compliance report indicated that its 2013 retail sales, when combined with those of Enfield, were 193,834 MWh, which, when multiplied by 3 percent, resulted in a 2014 REPS obligation of 5,815 RECs. When multiplied by 0.07 percent, this sales level resulted in an obligation of 136 solar RECs. Halifax's compliance report stated that its share of the aggregate poultry waste set-aside was 255 RECs. The Public Staff recommended that the Commission approve Halifax's 2014 compliance report "after it [Halifax] puts the proper number

[1] Due to rounding, GreenCo's compliance report over-stated its REPS obligation by one REC.

of in-state poultry waste RECs into its NC-RETS subaccount ....” NC-RETS shows that 191 of the 255 poultry waste RECs are from in-State sources. Halifax’s compliance sub-account in NC-RETS is consistent with its compliance report, and contains 5,815 RECs, including 136 in-state solar RECs. Halifax placed 2,065 EECs into its 2014 compliance sub-account, and in 2014 earned EECs from several programs.

Halifax’s heat pump rebate program provides rebates to encourage the installation of high efficiency heat pump and air conditioning systems. Halifax provided spreadsheets showing the efficiency ratings of the units removed and the new units installed. Using a widely accepted energy savings calculator, Halifax determined the program savings and the Public Staff stated that its calculations are satisfactory.

Halifax has provided free CFLs to its members, but will stop claiming EECs from future installations. Halifax also offers LED street lighting and outdoor lighting programs. The Public Staff agreed with the quantification of the number of recent EECs earned by these programs.

In its renewable energy generation tariff filed in Docket No. EC-33, Sub 64, Halifax offers $60 for a solar REC and $90 for a wind REC. The Public Staff stated that:

> ... these REC prices are significantly higher than current REC prices paid by other suppliers and found in the REC market in general. The reasonableness and prudence of purchasing RECs under this tariff in the future and using these RECs for REPS compliance could become an issue, particularly if Halifax’s compliance costs are approaching its cost cap.

This is the second time that the Public Staff has asserted that Halifax’s tariff pays its customers well above market costs for RECs from solar and wind resources. The Commission notes further that in Halifax’s REPS compliance plan the power supplier expressed concern that a planned expansion by one of its industrial customers would increase Halifax’s REPS obligation by 10 percent without providing additional revenues toward that higher REPS obligation. This is because an industrial customer’s cost cap is $1,000 per year regardless of its energy consumption. Halifax should, therefore, transition to less costly compliance options. While Halifax’s REPS costs are still well below the REPS cost cap, the Commission will nonetheless require Halifax to provide a rationale for these REC prices in its 2015 compliance report.

The Public Staff recommended that the Commission approve Halifax’s 2014 report, including the EM&V results for the EECs it earned in 2014.

Based on Halifax’s compliance report, the Public Staff’s comments, and the records in NC-RETS, the Commission finds that Halifax and Enfield have complied with their 2014 REPS obligations, and that the RECs and EECs in Halifax’s 2014 compliance sub-account in NC-RETS should be retired.

NCEMPA

NCEMPA's 2014 REPS compliance report stated that its 2013 retail sales were 6,924,830 MWh, which, when multiplied by 3 percent, resulted in a 2014 REPS obligation of 207,745 RECs. When multiplied by 0.07 percent, this sales level resulted in an obligation of 4,848 solar RECs. NCEMPA's compliance sub-account in NC-RETS is consistent with this information, and contains 207,745 RECs, including 4,848 solar RECs from in-state sources. NCEMPA stated that its share of the aggregate poultry waste set-aside was 9,071 RECs. However, NC-RETS calculated NCEMPA's poultry waste obligation to be slightly more, 9,085 RECs, and NCEMPA actually provided 9,089.

The Public Staff stated that NCEMPA earned EECs from its EE kit distribution program. The impacts associated with these kits are derived from the installation of CFL bulbs but do not include savings from any other components of the kit. NCEMPA has been relying on EM&V from a 2008 study by DEP as support for the savings associated with the program. The Public Staff had no objection to the estimated savings for this program but believes that more recent EM&V data show that the savings per CFL are smaller than was indicated in the initial studies. While the Public Staff has no objections to NCEMPA's estimated 2014 savings, it recommends that NCEMPA use updated EM&V data for 2015 and beyond.

The Public Staff recommended that the Commission approve NCEMPA's 2014 report, including the EM&V results for the EECs it earned in 2014.

Based on the information filed by NCEMPA and the Public Staff and the records in NC-RETS, the Commission concludes that the NCEMPA municipalities met their 2014 REPS obligations and that it is appropriate to retire the RECs in NCEMPA's 2014 compliance sub-account. The Commission will discuss requirements related to EM&V for CFLs later in this Order.

NCMPA1

NCMPA1's report stated that its 2013 retail sales were 4,855,329 MWh, which, when multiplied by 3 percent, resulted in a 2014 REPS obligation of 145,660 RECs. When multiplied by 0.07 percent, this sales level resulted in an obligation of 3,399 solar RECs. NCMPA1's compliance sub-account in NC-RETS is consistent with this information, and contains 145,660 RECs, including 3,399 solar RECs, of which 2,550 are from in-state sources. NCMPA1 stated that its share of the aggregate poultry waste set-aside obligation is 6,361 poultry RECs. However, NC-RETS calculated a slightly higher obligation of 6,370 poultry RECs, and NCMPA1 actually provided 6,373.

NCMPA1 earned EECs from its EE kit distribution program but did not use any EECs for 2014 REPS compliance. This program is identical to the program offered by NCEMPA. As with NCEMPA, the Public Staff recommended that NCMPA1 use data from a more recent EM&V study for EECs claimed in 2015 and beyond, but has no objection to the estimated savings for this program in 2014.

The Public Staff recommended that the Commission approve NCMPA1's 2014 report, including the EM&V results for the EECs it earned in 2014. The Commission will discuss requirements related to EM&V for CFLs later in this Order.

Based on the foregoing and the information in NC-RETS, the Commission finds that NCMPA1 met its 2014 REPS obligations and concludes that the RECs in NCMPA1's compliance sub-account should be retired.

TVA

TVA's 2014 REPS compliance report indicated that its 2013 retail sales were 586,195 MWh, which, when multiplied by 3 percent, resulted in a 2014 REPS obligation of 17,586 RECs. When multiplied by 0.07 percent, this sales level resulted in an obligation of 411 solar RECs. TVA stated that its share of the aggregate poultry waste set-aside requirement was 777 poultry RECs. This is slightly higher than the obligation as calculated by NC-RETS, which was 769 RECs. TVA's compliance sub-account in NC-RETS shows that it met all of its 2014 obligations. The account contains a total of 17,586 RECs, including 7,136 solar RECs, all of which are from in-state sources. TVA also met its poultry obligation by submitting 777 poultry RECs.

In its January 8, 2016 comments, the Public Staff noted that all of TVA's poultry waste RECs were generated outside of the State, and that the Commission's Order on Dominion's Motion for Further Clarification[1] limits the use of out-of-state RECs to 25 percent of a power supplier's set-aside obligation. The Public Staff stated that it agreed with TVA that the facility from which the RECs were purchased was misclassified in NC-RETS as being from an out-of-state facility and encouraged TVA to pursue correction as quickly as possible. On January 22, 2016, TVA submitted a letter in which it stated that it had resolved the issue. TVA stated that the poultry resource is located in Kentucky and that TVA buys electric power as well as RECs from the facility. Since the power is transmitted over the integrated transmission system to the four TVA power distributors that are North Carolina power suppliers, this power qualifies as being from an in-State resource under G.S. 62-133.8(b)(2)(d). On February 3, 2016, the Public Staff filed supplemental comments in which it agreed with TVA's reasoning and acknowledged that the issue had been resolved. Therefore, the Public Staff recommended that the Commission approve TVA's 2014 report.

Based on the foregoing, including the records in NC-RETS, the Commission concludes that TVA met its 2014 REPS obligations and that the RECs in its 2014 compliance sub-account in NC-RETS should be retired.

REPS Cost Caps

General Statute 62-133.8(h)(3) and (4) limit an electric power supplier's annual REPS spending. For 2014, these spending caps were $12 for each residential customer account, $150 for each commercial customer account, and $1,000 for each industrial customer account. The Public Staff stated that all of the municipal and EMC suppliers had kept their incremental costs below

[1] Issued September 22, 2009, in Docket No. E-100, Sub 113.

these annual cost caps, but noted that some very small electric power suppliers are approaching the cost cap and might have difficulty meeting their REPS obligations while staying below the cap in the future. No party asserted that any of the electric power suppliers spent more on REPS compliance than is authorized by G.S. 62-133.8. Based on the foregoing, the Commission concludes that all of them have complied with the cost caps.

EM&V for CFL Programs

GreenCo and Halifax both stated that they now consider CFLs to be a baseline lighting technology and hence they are no longer claiming energy savings for new CFL distributions. The Public Staff has for two years now expressed concern that the energy savings claimed by NCEMPA and NCMPA1 from CFLs are too high because they are relying on a 2008 Duke Energy Progress study. The Commission has allowed smaller utilities to rely upon the EM&V findings of larger utilities because it would be cost-prohibitive for small electric power suppliers to conduct rigorous EM&V themselves. Given what appears to be widespread adoption of CFLs the Commission will require all electric power suppliers to provide EM&V studies no older than 2015 with their 2015 REPS compliance reports if they intend to claim energy savings from CFLs that were distributed in 2016 or subsequent years.

IT IS, THEREFORE, ORDERED, as follows:

1. That EnergyUnited, Fayetteville PWC, Fountain, GreenCo, Halifax, NCEMPA, NCMPA1, and TVA met their 2014 REPS obligations and that the RECs and EECs in their compliance sub-accounts in NC-RETS shall be retired;

2. That all electric power suppliers that intend to claim energy savings from CFL distributions that occur in 2016 or subsequent years must provide EM&V studies no older than 2015 with their 2015 REPS compliance reports;

3. That Halifax shall include in its 2015 REPS compliance report an explanation for the prices that it pays customers for wind and solar RECs via its renewable energy tariff; and

4. That the Chief Clerk shall serve a copy of this Order on DEC, DEP and Dominion.

ISSUED BY ORDER OF THE COMMISSION.
This the ___29th___ day of March, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Commissioner James G. Patterson did not participate in this decision.

DOCKET NO. SP-100, SUB 31

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition by North Carolina Waste Awareness and Reduction Network for a Declaratory Ruling Regarding Solar Facility Financing Arrangements and Status as a Public Utility	))))	ORDER ISSUING DECLARATORY RULING

BY THE COMMISSION: On June 17, 2015, North Carolina Waste Awareness and Reduction Network (NC WARN), a non-profit corporation, filed a petition requesting that the Commission issue a declaratory ruling that it would not be considered a public utility pursuant to G.S. 62-3(23) and other relevant provisions of Chapter 62, the Public Utilities Act, if it enters into a power purchase agreement (PPA) with Faith Community Church (Church) in Greensboro, North Carolina, to install a 5.2 kW solar photovoltaic (PV) electric generating system on the roof of the Church and to sell the electricity produced by the PV system to the Church, another non-profit entity.[1] NC WARN notes in its petition that a key issue to be resolved by the Commission is whether State law prohibits third parties, such as NC WARN, from installing a PV system and selling the power produced by the system to a non-profit entity. Further, NC WARN notes that it has a history of developing up-front funding mechanisms for solar systems, including providing free solar panels and/or solar hot water heaters to three non-profit organizations in the Triangle area and initiating Solarize NC programs in Durham, Chatham County, the Triad, and western Wake County, primarily for residential owners.

On July 6, 2015, North Carolina Sustainable Energy Association (NCSEA) filed a letter requesting that the Commission review its existing Orders that are related to the issue of third-party sales. NCSEA summarized several Commission Orders that it perceives to be related to third-party sales and the issues presented by NC WARN's petition.

On September 30, 2015, the Commission issued an Order Requesting Comments. In that Order, the Commission found good cause to request that interested persons file initial and reply comments regarding NC WARN's petition. Additionally, the Commission found good cause to make Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (collectively, Duke); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP); and North Carolina Electric Membership Corporation (NCEMC) parties to this docket without requiring them to file petitions to intervene. Finally, the Commission found good cause to request that the parties address the following questions as part of their initial and reply comments:

1. Does the Commission have the express legal authority to allow third-party sales of Commission-regulated electric utility services? If so, please provide a citation to all such legal authority.

[1] On September 18, 2015, NC WARN filed a report of its activities under the PPA. In the report, NC WARN stated that on August 28, 2015, it sent its first invoice to the Church for 1,423 kilowatt-hours (kWh) of electricity at a rate of $0.05 per kWh. The total bill was $76.49, including tax at 7.5%.

2. If the Commission has the authority to allow third-party sales of regulated electric utility service, should the Commission approve such sales by all entities desiring to engage in such sales, or limit third-party sales authority to non-profit organizations?

3. What authority, if any, does the Commission have to regulate the electric rates and other terms of electric service provided by a third-party seller?

4. To the extent that the Commission is without authority to authorize third-party sales or to the extent the Commission's express authorization is required before third-party sales may be initiated, what action should the Commission take in response to NC WARN's sales in this docket?

Petitions to intervene were filed by and granted for ElectriCities of North Carolina, Inc., North Carolina Eastern Municipal Power Agency, and North Carolina Municipal Power Agency Number 1 (collectively, ElectriCities); Carolina Utility Customers Association, Inc. (CUCA); North Carolina Interfaith Power and Light (NCIPL); North Carolina Sustainable Energy Association (NCSEA); and Energy Freedom Coalition of America, LLC (EFCA). The intervention of the Public Staff – North Carolina Utilities Commission is recognized pursuant to G.S. 62-15 and Commission Rule R1-19(e).

On October 30, 2015, initial comments were filed by Duke, NCEMC, ElectriCities, and DNCP (collectively, the Electric Suppliers); NC WARN; NCIPL; EFCA; and the Public Staff. On November 20, 2015, NC WARN, NCSEA, EFCA, NCIPL, and DNCP filed reply comments.

SUMMARY OF PARTIES' COMMENTS

NC WARN

In its petition and initial comments, NC WARN states that it is proposing a funding mechanism, that of monthly payments to NC WARN for electricity generated by a PV system and delivered to an end-use consumer, to overcome one of the most significant barriers to widespread use of solar electric generation. Such a funding mechanism would both allow consumers, such as the Church, to avoid the up-front cost of installing a PV system and create a revenue stream to allow NC WARN to install similar systems for additional consumers. To that end, argues NC WARN, it is not subject to regulation by the Commission for third-party sales of electricity because it "is providing funding, a service, rather than just selling electricity to a church."

Even if it is deemed to be selling electricity and not simply providing a funding service, argues NC WARN, it is not subject to regulation because it is not selling electricity "to or for the public" as provided in the definition of public utility in G.S. 62-3(23)a.1. As NC WARN notes:

The relevant statute defines a public utility:

> a. "Public utility" means a person, whether organized under the laws of this State or under the laws of any other state or country, now or hereafter owning or operating in this State equipment or facilities for:
>
> 1. Producing, generating, transmitting, delivering or furnishing electricity, piped gas, steam or any other like agency for the production of light, heat or power to or for the public for compensation; provided, however, that the term "public utility" shall not include persons who construct or operate an electric generating facility, the primary purpose of which facility is for such person's own use and not for the primary purpose of producing electricity, heat, or steam for sale to or for the public for compensation.

G.S. 62-3(23). If the proposed activities fall within the definition of those of a public utility, "producing electricity … for sale to or for the public for compensation," the entity is required to comply with statutory requirements in the Public Utilities Act, and regulation by the Commission.

NC WARN Comments, p. 4. According to NC WARN, the arrangement that it has entered into with the Church does not cause NC WARN to fall within the definition of a public utility because it is not selling to the public; rather, NC WARN is selling "to a specific non-profit, the Faith Community Church, that it is working with to obtain solar electricity." Id. at 5.

NC WARN, therefore, answers the Commission's first question by arguing that the Commission does have the legal authority to determine that the sale of electricity as described in NC WARN's petition is not a sale to or for the public subject to Commission regulation, citing State ex rel. Utils. Comm'n v. Simpson, 295 N.C. 519, 524, 246 S.E.2d 753 (1978) (Simpson). In Simpson, the North Carolina Supreme Court adopted a flexible definition of "the public" under the Public Utilities Act, requiring the Commission to balance the regulatory circumstances of each case to define "the public" in the utilities context rather than depend on some abstract, formulistic definition of the public. NC WARN Comments, p. 4.

NC WARN discusses two cases in which the Commission applied the flexible approach articulated in Simpson in determining whether the sellers would be subject to Commission jurisdiction as public utilities under the Public Utilities Act. See Order Denying Petition for Declaratory Ruling, In re Request by National Spinning Company, Inc. and Wayne S. Leary, d/b/a Leary's Consultative Services, Docket No. SP-100, Sub 7 (Apr. 22, 1996) (National Spinning); Order on Request for Determination of Public Utility Status, In re Request by Progress Solar Investments, LLC, and Progress Solar Solutions, LLC, Docket No. SP-100, Sub 24 (Nov. 25, 2009) (Progress Solar).

NC WARN asserts that its arrangement in this docket is more like that in Progress Solar, which the Commission found to be permissible, than that in National Spinning because in this case

NC WARN is providing a service, i.e., funding, in addition to selling electricity to the Church. By contrast, in National Spinning, the Commission was not asked to consider whether either of the parties would have been a public utility if some service in addition to the direct sales of electricity had been proposed. According to NC WARN, the existence of this distinction would support a Commission determination that the sale of electricity as described in the petition is not a sale to the public as set forth in G.S. 62-3(23)a.1 and, therefore, is not subject to Commission regulation. In its reply comments, NC WARN stated that the Public Staff, in its analysis of National Spinning, failed to consider the crucial distinction between sales on the customer's side of the meter, as NC WARN proposed in this case, and the sale of excess power from a company like National Spinning to an adjacent manufacturing facility.

Additionally, NC WARN asserts that, on balance, other Simpson factors would support a Commission conclusion that the sale of electricity to the Church is not a sale to the public. Specifically, NC WARN states that such a conclusion is warranted because (1) there is an acute need for some type of funding mechanism to assist the faith community and other limited resource non-profits to avail themselves of the benefits of solar generation; (2) too often, these entities are prevented from benefitting from solar generation due to the high upfront costs that the purchase and installation of these systems entail; (3) it is the current policy of the state of North Carolina to encourage renewable energy, and the proposition NC WARN has advanced would encourage the development of renewable resources; (4) Duke Energy does not have any program, nor has it proposed any such funding program, that would encourage the rooftop installation of PV systems for similar customers; (5) NC WARN is only selling to a single customer; and, (6) eventually, as a result of this funding mechanism, the Church would own the system.

Finally, NC WARN notes the phrase "third-party sales" is not presently defined in the statute. As a result, NC WARN contends that whether the arrangement between NC WARN and the Church would constitute a "third-party sale" as the Commission's question implies is not so clear-cut. NC WARN urges the Commission to adopt the definition proposed in House Bill 245 (HB 245),[1]the Energy Freedom Act, which it states was introduced in the 2015 General Assembly in an effort to clarify what would and would not be permissible when an entity other than an electric utility is selling electricity. House Bill 245 would allow third-party sales, but would limit such sales to facilities "located on the customer's property where such electricity will be consumed," as proposed by NC WARN in this case.

NC WARN further argues that the Commission should follow SZ Enterprises, LLC d/b/a Eagle Point Solar v. Iowa Utils. Board, 850 N.W.2d 441(2014) (Eagle Point Solar), in which the Iowa Supreme Court held that the sale of electricity from a PV facility by Eagle Point Solar to the City of Dubuque pursuant to a similar statutory definition of public utility would not be subject to regulation by the Iowa Utilities Board. Because the circumstances in that case are directly analogous to the circumstances in this case, this Commission should conclude, as did the Iowa Supreme Court, that utilizing a PPA as a financing method for a PV system would not cause an entity to be subject to regulation by the Commission. In so doing, according to NC WARN, the Commission would be in accord with numerous other commissions around the country.

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[1] House Bill 245 was not enacted into law, but remains eligible for consideration in the 2016 Session of the General Assembly. NC WARN incorrectly referred to the proposed bill as Senate Bill 245 in its petition.

In its reply comments, NC WARN observes that the substantive comments by Duke and DNCP focus on the lack of explicit statutory authority in the Public Utilities Act allowing "third-party sales." In NC WARN's opinion, the lack of specific statutory authority is not dispositive. The Commission should apply Simpson to determine if the sales in question are permitted. In conducting this analysis, the Commission should not be overly influenced by the arguments of Duke and DNCP concerning the importance of maintaining the franchise of the utility monopoly, particularly when NC WARN and other parties have offered legitimate, countervailing arguments in opposition.

In answering the remaining questions set forth in the Commission's September 30 Order, NC WARN believes the Commission should allow metered sales from any PV facility, whether or not the seller or purchaser is a non-profit entity. To the extent the third-party seller is not a public utility, the Commission does not have any authority to regulate the rates and terms of service provided. Lastly, NC WARN notes that the Commission could issue an order either authorizing the proposed sale or compelling NC WARN to cease and desist its arrangement with the Church and requiring NC WARN to reimburse the Church for any payments made.

In its reply comments, NC WARN further stated that Duke misrepresented NC WARN's intentions and several statements made by NC WARN. For instance, Duke contends that NC WARN has held itself out as offering its services to all who apply and that NC WARN intends to expand its public utility service. According to NC WARN, neither statement is true. It has only offered this service to the Church, and it is not offering public utility service. Finally, NC WARN requests that the Commission schedule this matter for oral argument.

NCIPL

In its initial and reply comments, NCIPL observes that the up-front cost of installing PV systems present difficulties for many faith congregations. Relying on Simpson and Eagle Point Solar, NCIPL, as does NC WARN, argues that the PPA arrangement proposed by NC WARN is permissible as a financing mechanism to overcome this barrier. NCIPL, therefore, supports the arrangement proposed by NC WARN and would request that the Commission issue a declaratory ruling that the proposed arrangement would not subject NC WARN to regulation as a public utility. In addition, NCIPL seeks clarification that other third-party financing arrangements that supply PV systems on the property of and for use of individual customers would not trigger Commission regulation, regardless of the status of the third-party owner.

In response to the Commission's first question, NCIPL contends that Simpson provides the Commission with the express legal authority to allow third-party sales of electricity from behind-the-meter PV systems that are affixed to the property of a consumer and are for that consumer's use, noting the Supreme Court determined that the definition of "the public" in the Public Utilities Act should be viewed flexibly rather than in abstract or formulistic terms. Once the Simpson factors are considered, it would be improper for the Commission to subject to regulation as public utilities third-party owners of PV systems that are financed with PPAs, as PPAs are merely a vehicle for paying for the installation and use of PV systems. In other words, the primary nature of a business that utilizes a PPA as a method of payment is the installation of PV systems for the use of individual customers and not the provision of electric utility service. The methods that customers use to pay for alternative, self-generating energy sources, when such installations serve on-site energy needs does not necessarily require Commission oversight and regulation.

The factors that would militate against such Commission regulation in this case are that (1) the PPA is merely a financing vehicle for the purchase of the PV system, the terms of which are agreed upon after arms-length negotiation; (2) the PV system itself will only serve a portion of the Church's needs and does not remove the Church from the utility's reach; and, (3) third-party owned PV systems complement rather than supplant existing markets for sale of electricity. Additionally, NCIPL asserts that the Commission should not regulate this transaction because: (1) the transaction as structured is designed to take advantage of certain tax credits to offset the purchase of such systems which are unavailable to religious institutions and other non-profits; (2) allowing PPAs to finance third-party owned PV systems would have little to no effect on those already in place because neither the installers of PV systems that are purchased outright by the consumers nor the consumers who buy such PV systems for their own use are regulated as public utilities; and (3) transactions of this type are consistent with the policy of this State to promote the development of renewable energy.

In its reply comments, NCIPL distinguishes National Spinning based on the differences in scale, timing, and nature of the generating facility, noting that the larger customers involved in that case are much desired and have a more significant impact on the utility than the small PV facility in this case. In addition, the Commission's decision in National Spinning predates relevant public policy provisions enacted by the General Assembly which encourage renewable energy.

NCIPL believes the Commission should follow its decision in Progress Solar here because of the close similarities between the two cases. In its reply comments, NCIPL disagrees with Duke and DNCP, which argue that Progress Solar should not apply because, unlike National Spinning, it did not involve the direct generation or sale of electricity. NCIPL contends that this argument is not persuasive because the definition of public utility encompasses the services being provided, i.e., "facilities for producing … or furnishing electricity or any other like agency for the production of light … to the or for the public for compensation," NCIPL's Reply Comments, p. 11, and is not limited to the production of electricity. In NCIPL's opinion, this decision is important because the Commission applied the Simpson regulatory circumstances and determined that Progress Solar would not be providing electricity or other like agency "to or for the public." Said services were a bargained-for transaction and were consistent with the recently enacted policy encouraging the development of renewable resources.

NCIPL further disagrees in its reply comments with the Public Staff's arguments based on the failure of the General Assembly to pass HB 245. Noting that North Carolina courts have stated that the failure of the legislature to act is "a 'weak reed upon which to lean' and a 'poor beacon to follow' in construing a statute," NCIPL states that the Commission should not be swayed by legislative inaction; rather, the Commission should be guided by the Simpson regulatory circumstances test, existing North Carolina policy, and persuasive legal authorities applying those regulatory circumstances. Although Eagle Point Solar is not binding upon the Commission, NCIPL disagrees with Duke that it is contrary to North Carolina law and urges the Commission to closely review the decision in making its determination in this case.

Lastly, in answering the remaining questions set forth in the Commission's September 30 Order, NCIPL believes that, as both a legal and practical matter, there is no justification for limiting the ability of third-party for-profit entities from installing and operating PV systems that are "purchased" with PPAs. While third-party owners of PV systems would not be subject to Commission regulation and oversight, they would be subject to consumer protection laws and oversight by the Attorney General's Office and the Better Business Bureau. As NCIPL believes the Commission can authorize third-party sales, the Commission should permit NC WARN and the Church to proceed with the PPA for the length of the contract.

EFCA

In its initial comments, EFCA observes that third-party ownership in its many forms has become the dominant model for the growth of rooftop PV facilities across the country. EFCA states that third-party ownership is primarily about advancing customer choice and giving customers the type of options that they enjoy in the consumer market for obtaining products that they use for domestic and personal use.

EFCA notes that many states have addressed the basic question raised by NC WARN's proposal in this case, a number of which concluding that a system serving only one customer and entered into as a result of a private agreement between a customer and a company does not constitute a sale to or for the public. However, as EFCA further notes, not all states that have considered the issue have allowed third-party sales. See, e.g., PW Ventures, Inc. v. Nichols, 533 So. 2d 281 (Fla. 1988) (holding that providing electric service to a single customer constitutes service to the general public). EFCA urges the Commission to be guided by the flexible standard adopted in Simpson rather than the rigid standard it believes was adopted in Florida.

In its reply comments, EFCA observes that the Commission must determine whether the proposal by NC WARN will have a distinctly private characteristic or whether the proposal will have such significant impact on the public that it may be considered clothed in the public interest and appropriate for government intervention. In EFCA's opinion, the facts of this case do not establish a public characteristic for the underlying transaction or satisfy the traditional justification for regulation of NC WARN or any other entity engaged in similar circumstances. According to EFCA, the public's interest in encouraging individual freedom and utilization of demand-side renewable generation substantially outweighs the utilities' interest in limiting the market forces and emerging technologies that give customers greater control over their individual electricity consumption.

EFCA disagrees with DNCP's Simpson analysis, which it believes fails to acknowledge that NC WARN's proposal is qualitatively different than the service offered by a regulated utility in this state and fails to apply the regulatory circumstances test. EFCA agrees with NCIPL, however, that the application of the Simpson regulatory circumstances test leads to the conclusion that the questioned activity is wholly private and does not invoke the public interest concerns necessary to trigger public utility status under Simpson. EFCA also notes that it found NCIPL's discussion of the Iowa Supreme Court discussion in Eagle Point Solar compelling because of the striking similarities between the North Carolina and Iowa laws and the similarity of analysis employed by the Iowa Supreme Court and the Simpson decision.

In response to the Commission's first question, EFCA does not believe the Commission has the authority to allow third-party sales of regulated utility service because, by definition, such sales are outside the jurisdiction of the Commission. The threshold question in this case, then, is not whether Commission-regulated electricity has been sold; rather, it is (1) whether a third-party sale of electricity has occurred in the first place, and (2) if such sale has occurred, whether the sale is to or for the public and, thus, subject to regulation. Pursuant to Simpson, the Commission has express authority to determine whether the Commission has regulatory jurisdiction over NC WARN's activities. If the Commission determines that it has such jurisdiction, i.e., that NC WARN has sold electricity to or for the public, the Commission is limited in its ability to authorize NC WARN to violate the territorial rights of a certificated public utility. If the Commission determines that it does not have such jurisdiction, the Commission should affirm the arrangement and allow it to continue without harassment.

Further, EFCA observes that in framing the questions, the Commission appears to contemplate entities beyond the petitioner in this case. EFCA, therefore, requests that, to the extent that the Commission intends to go beyond the facts in this case and provide broader guidance regarding its policy toward third-party ownership of distributed generation, the Commission should clarify that "third-party ownership" is not synonymous with "third-party sales." According to EFCA, many forms of third-party ownership and financing appear to constitute self-generation and do not implicate a "third-party sale" of electricity.

In answering the remaining questions set forth in the Commission's September 30 Order, EFCA agrees that the Commission should approve third-party sales by any entity if the Commission concludes that a privately dedicated PV facility that is installed pursuant to a retail PPA to serve a single customer is not a facility providing electricity to or for the public for compensation. NC WARN's status as a non-profit entity is not relevant; if the third-party owner is not a public utility, the Commission lacks any legal basis to regulate its rates or service. EFCA expresses no opinion regarding the appropriate action the Commission should take if it finds that NC WARN was required to obtain Commission authorization prior to commencing sales of electricity to an end-use customer in this state. Finally, EFCA requests that the Commission provide an opportunity to present oral argument.

Duke

In its comments, Duke observes that it is ironic that NC WARN has asked the Commission for an exemption from regulation when it is clear that North Carolina law, court precedent, and past Commission orders all prohibit NC WARN's action, i.e., generating and selling electricity to its chosen customer without waiting for the Commission to rule on the legality of its scheme. According to Duke, NC WARN's request must be rejected, and its blatant disregard for the law and the Commission's authority should not be condoned.

In response to the Commission's first question, Duke states that the Commission does not have the legal authority to allow third-party sales of Commission-regulated electric utility service because third-party sales, such as that proposed by NC WARN, are plainly prohibited under North Carolina law and Commission precedent, as the Commission has recently acknowledged. In Docket No. E-100, Sub 90, the Commission was asked by the Southern Environmental Law Center to "clarify that Chapter 62 does not prohibit power purchase agreements between utility customers and non-utility solar installers." The Commission responded definitively concluding that "Chapter 62 of the North Carolina General Statutes prohibits third-party sales of electricity by non-utility solar installers to retail customers." See Order Approving Pilot Programs, In re Investigation of Voluntary Green and Public Benefit Fund Check-Off Programs, Docket No. E 100, Sub 90 (January 27, 2015).

Duke argues that under North Carolina law, only public utilities are permitted to sell electricity to the public for compensation. To do so, such entities must obtain a certificate of public convenience and necessity (CPCN) from the Commission prior to constructing or operating any utility plant or system. The Supreme Court and this Commission have explained that the public policy basis of the CPCN requirement to engage in public utility activities "is the adoption by the General Assembly, of the policy, that nothing else appearing, the public is better served by a regulated monopoly than by competing suppliers of the service. State ex rel. Utils. Comm'n v. Carolina Tel. & Tel. Co., 267 N.C. 257, 271,148 S.E.2d 100, 111 (1966) (Carolina Telephone). This policy is further expressed in the Territorial Assignment Act of 1965.

Duke further argues that NC WARN has constructed a PV generating facility and sold electricity to the Church based on its contention that it is not a public utility because it has confined its sales to a single customer or that it will, in the future, only provide such service to a limited subset of Duke's customers, i.e., self-selected non-profit organizations. The Court rejected this exact argument in Simpson, where a doctor argued that he was not acting as a public utility by providing two-way radio service to a small number of customers in his county medical society. In rejecting this contention, the Court noted that neither the small number of customers nor the fact that his service was only being offered to a small discrete segment of the market would necessarily disqualify his service from being classified as a public utility service. In holding that Simpson had attained public utility status, the Court stated that "one offers service to the 'public' when he holds himself as willing to serve up to the capacity of his facilities without regard to the fact that his service is limited to a specific area and his facilities are limited in capacity." NC WARN has held itself out as willing to serve all who apply up to its capacity and has generated and sold electricity to the customer. It is, therefore, selling to the public for compensation and has obtained public utility status. In doing so, it has violated North Carolina law and ignored the authority of the Commission.

Lastly, Duke notes that NC WARN, in its petition, discusses two Commission decisions, National Spinning and Progress Solar. Duke argues, however, that neither decision supports NC WARN's position. Rather, both decisions demonstrate that NC WARN's request has no merit. In Progress Solar, for example, the proposal specifically provided that "[n]o generation or sale of electricity will occur, and the amount of the payment will not vary based upon the amount of illumination created by the system." Similarly, Eagle Point Solar, which NC WARN cites as support for its position, is irrelevant because it is based upon Iowa law and precedent that is contrary to North Carolina law and precedent.

For the reasons stated in Duke's response to Commission Question No. 1, Duke argues that the Commission does not have legal authority to allow third-party sales of Commission-regulated electric utility service. If the Commission does not have the authority to authorize third-party sales of regulated electric utility service, it stands to reason that the Commission cannot thereafter approve NC WARN's sale of such service to the Church because of its non-profit status or to any other self-selected non-profit organizations.

Duke notes that NC WARN contends that the Commission may approve such sales because the sale to the Church and/or the prospective sale to other such non-profits are not sales to or for the public. This contention was rejected by the Simpson Court, and the Commission should do likewise in this instance; a customer is not exempted from the law or excluded as a member of the using and consuming public simply because it operates as a non-profit organization. If NC WARN were allowed to generate and sell electricity to "non-profit organizations," of which there are many, what would prevent NC WARN or any other entity from attempting to provide utility service to another class of Duke's customers under the guise that that each separate class was not in and of itself "the public." Further, a step in that direction could shift the electric industry from a regulated industry to one that is largely unregulated. A shift of this type and magnitude would be in contravention of the expressed policy of the General Assembly and this Commission that "nothing else appearing, the public is better served by a regulated monopoly than by competing suppliers of the service," Carolina Telephone, 267 N.C. at 271, 148 S.E.2d at 111, and could lead to the slippery slope where unregulated electric suppliers such as NC WARN could "cherry pick" the electric utilities best customers, which the Commission found so concerning in National Spinning.

Finally, Duke argues that to the extent that the third-party seller of electricity is acting as a public utility without obtaining a CPCN, it is subject to the regulatory powers of the Commission as a de facto public utility. State ex rel. Utils. Comm'n v. Mackie, 79 N.C. App. 19, 338 S.E.2d 888 (1986), mod. and aff'd, 318 N.C. 686, 351 S.E.2d 289 (1987). According to Duke, it is clear that NC WARN was aware that the generation and sale of electricity to the Church violated North Carolina law and precedent. Despite this knowledge, NC WARN willfully engaged in this conduct after being warned by the Company that such conduct would be unlawful. It did so without waiting for the Commission to rule on its request that its actions be condoned. It continues to do so at present. The Commission should issue a cease and desist order to NC WARN to prevent NC WARN from continuing to act as a public utility and require NC WARN to refund to the Church any payments that it has received. Further, Duke contends the Commission should assess civil penalties on NC WARN pursuant to the authority granted to it in G.S. 62-310 for NC WARN's willful violations of Chapter 62 and the Commission Rules, orders, and regulations.

NCEMC

In its comments, NCEMC responds to the Commission's questions, stating that no provision in the Public Utilities Act expressly authorizes the Commission to permit third-party sales of Commission-regulated electric utility service. Because the Commission, as an administrative agency, has no regulatory authority except that conferred on it by statute,[1] the Commission has no authority to allow third-party sales where no such express authority exists in the statute. NCEMC notes that it is widely understood that North Carolina policy prohibits third-party power purchase agreements, citing information published by the United States Department of Energy and the Database of State Incentives for Renewables and Efficiency

[1] State ex rel. Utils. Comm'n v. National Merchandising Corp., 288 N.C. 715, 722 (1975) (citing State ex rel. Utils. Comm'n v. Atlantic Coast Line R. Co., 268 N.C. 242, 245 (1966)).

(DSIRE).[1] NCEMC further notes that the Commission has the authority and duty to regulate the facilities used in third-party seller arrangements, but not the rates and terms of service were such service allowed, which it is not. Lastly, NCEMC states that the Commission should issue an order declaring that NC WARN is in violation of the Public Utilities Act and impose such penalties or remedies as it deems appropriate.

ElectriCities

In its comments, ElectriCities observes that NC WARN seeks Commission approval of the power sale arrangement that it has entered into with the Church. In ElectriCities' opinion, this power sale arrangement is not permitted under North Carolina law because NC WARN is to be paid by the Church on a per kilowatt-hour basis based on the amount of electricity used by the Church.

According to ElectriCities, NC WARN contends that it is not a public utility because the sale of its power to the Church is not a sale to or for the public. This contention, however, cannot be squared with NC WARN's strategy to not only sell power to the Church pursuant to its agreement, but also to generate enough revenue pursuant to this arrangement so that it can replicate this arrangement and provide power to a potentially unlimited number of non-profits in the future. The breadth and scope of NC WARN's proposal makes this case fundamentally different from past Commission decisions where the Commission found that the sale of steam or landfill gas by a single purpose entity to a single user would not be a public utility offering service to and for the public.

In response to the Commission's questions, ElectriCities states that the Commission does not have express legal authority to allow third-party sales of Commission-regulated electric service to retail customers, as the Commission itself concluded in Docket No. E-100, Sub 90, regardless of whether the entities engaged in the transaction are for-profit or non-profit. By this request, NC WARN asks the Commission to reverse that conclusion. ElectriCities urges the Commission not to do so.

ElectriCities further argues that NC WARN's attempt to characterize its arrangement with the Church as a "funding service" rather than a sale of electricity should similarly be unavailing. According to ElectriCities, if a bank lent money to the Church so that it could install its own solar panels and generate its own electricity, arguably one could contend that the bank's provision of funding was a "service" which enabled the Church to purchase the system. In the scenario that NC WARN has constructed, however, NC WARN does not lend money to the Church so that the Church can purchase the system and generate its own electricity. Instead, NC WARN will purchase, install, and own a system that it installs on the church's roof and pay for the system that it will own by selling electricity to the Church. Such an arrangement is a classic power sale arrangement which is not permitted by North Carolina law. In that scenario, the Church neither owns nor purchases the system. If the Commission determines that NC WARN is not a public utility, however, the Commission would not be authorized to regulate the rates, terms, or condition of service that NC WARN would provide to its customers absent a legislative grant of authority

[1] "3rd Party Solar PV Power Purchase Agreement (PPA)," DSIRE, March 2016 <http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2014/11/3rd-Party-PPA_032016.pdf>.

permitting it to do so. Finally, in response to what action the Commission should take in this docket, ElectriCities states that the Commission should deny NC WARN's request.

DNCP

In its initial comments, DNCP notes that North Carolina has become a leader in installed solar energy capacity without modifying the State's traditional regulatory model because North Carolina's energy policies have successfully promoted solar energy development while maintaining electric utilities' singular responsibility subject to Commission oversight. Pursuant to these policies, DNCP is increasingly including solar energy as an important component of its long-term resource planning portfolio to serve its customers.

In response to NC WARN's proposal, DNCP notes that the North Carolina Supreme Court interpreted the definition of public utility in the Simpson case, holding that certain regulatory factors should be considered in determining whether certain activities constituted public utility activities subject to regulation by the Commission. In DNCP's opinion, NC WARN's retail sale of electricity cannot be reconciled with the Simpson decision or prior Commission decisions. Because, applying the Simpson factors, NC WARN's retail sale of electricity to the Church constitutes public utility activity, the Commission cannot authorize NC WARN to bypass Duke's exclusive franchise and sell electricity directly to the Church.

DNCP discusses a number of cases in which the Commission has previously applied the Simpson factors and ruled on this issue. For example, in National Spinning, the Commission held that a proposal to allow an entity to sell steam for use in generating electricity would cause that entity to be a public utility subject to regulation by the Commission because the purchasing customer would be able to bypass the certificated utility that has a monopoly franchise for the area. This would allow unregulated electric suppliers to cherry-pick the electric utility's best customers, leaving the utility with stranded investment and costs which would be shifted to other customers. Despite NC WARN's attempts to distinguish this case, there are no significant distinctions between the facts in National Spinning and the facts in this case. DNCP asserts, for instance, that in this case as well as National Spinning the third-party generation owner is proposing to sell electricity to a single end-use customer, the parties structured the transaction to allow the customer to take advantage of a tax credit that would otherwise be unavailable, and, the customer of the generator would continue to purchase a portion of its requirements from Duke and sell any excess power generated at the proposed facility back to Duke. In addition to these factual similarities, the policy considerations are quite similar. DNCP observes that in both instances, the proposals were designed to reduce the costs for a single customer and, ultimately, a whole class of customers as other generation developers and customers seek similar arrangements. While such arrangements may be beneficial to the favored class of customers, such arrangements ultimately could lead to an inequitable shift of costs to other customers who could not install the favored arrangement.

Similarly, the Commission rejected a proposal by a combined heat and power generator to be allowed to provide electricity to its third-party steam customer for free, finding that the seller would have simply recovered its costs through other payments from the buyer. Order on Request for Declaratory Ruling and Notice of Intent to Revoke Registration of New Renewable Energy Facility, In re Application of W.E. Partners 1, LLC, Docket No. SP-729, Sub 1 (Sept. 17, 2012). Lastly, in approving changes to the NC GreenPower program, the Commission rejected a request by the Southern Environmental Law Center that the Commission clarify that the Public Utilities Act does not prohibit PPAs between utility customers and non-utility solar installers, concluding instead "that Chapter 62 of the North Carolina General Statutes prohibits third-party sales of electricity by non-utility solar installers to retail customers." Docket No. E-100, Sub 90. On the other hand, in Progress Solar, the Commission applied the Simpson factors in considering a proposal for the provision of solar-powered lighting systems and concluded that the proposal would not cause either the supplying party or the recipient of such services to be a public utility subject to regulation by the Commission.

In applying the facts in this case to the law as established by these precedents, DNCP concludes that (1) NC WARN is providing electricity to the Church for compensation; (2) the provision of electricity to the Church pursuant to this arrangement constitutes providing electricity to the public for compensation; (3) NC WARN has clearly indicated that the service that it is providing to the Church is meant to be a template so that it can provide such arrangements to other self-selected non-profits; and (4) NC WARN's sale and contemplated expansion of these sales clearly erodes Duke's exclusive franchise, undermines the current regulatory model, and would be inconsistent with the State policy promoting the inherent advantages of regulated public utilities.

In its reply comments, DNCP asserts that (1) the Commission has no authority to adopt HB 245's definition of third-party sales as recommended by NC WARN; (2) the sale of electricity by NC WARN to the Church cannot reasonably be distinguished from the facts and policy considerations at issue in the Commission's 1996 National Spinning Order; and (3) judicial decisions, legislative enactments, and ballot initiatives from other jurisdictions warrant only passing consideration in applying North Carolina's Public Utilities Act to NC WARN's declaratory ruling request.

In response to the Commission's questions, DNCP, therefore, states that the Commission does not have the legal authority to allow third-party sales of Commission-regulated electricity utility service as proposed by NC WARN. Such an arrangement is not allowed under state law. The Public Utilities Act has long established that it is the policy of the state to promote the inherent advantages of regulated public utilities, to promote adequate, reliable and economic utility service, and to foster the continued service of public utilities on a well-planned and coordinated basis. DNCP observes that it is also the policy of this state to require a CPCN before an entity can engage in public utility activities and, nothing else appearing, that the public is better served by a regulated monopoly than by competing suppliers of utility service. This policy is expressed for electric utility service by the Territorial Assignment Act of 1965, which granted exclusive franchise rights to provide retail electric service to customers in North Carolina assigned within the individual utilities' service territories. The Commission has no authority to expand or limit the scope of activities that the General Assembly has legislated shall be regulated as activities of a public utility. Thus, any modification of this policy would be for the legislature, and not the Commission, to determine.

Assuming arguendo that the Commission could allow third-party sales of a regulated utility service, the Commission would not have any authority to distinguish between non-profit and other entities desiring to engage in such sales because the General Assembly has not granted the Commission such authority in the Public Utilities Act. If the Commission determines that third-party sales of electricity does not constitute public utility activity, the Commission would not have any authority to regulate such sales and/or the rates and terms of service of the third party provider, although new construction of electric generating facilities may require Commission certification. Lastly, DNCP states that if the Commission determines that NC WARN has acted as a public utility without first applying for and receiving a certificate to do so, there are a number of actions that the Commission can take, including seeking an injunction against NC WARN for violating Duke's exclusive franchise and imposing fines pursuant to G.S. 62-310 of up to $1,000 per day for violations of the Public Utilities Act.

NCSEA

In response to the Commission's questions, NCSEA agrees in its reply comments with other parties that the Public Utilities Act does not expressly authorize the Commission to allow third-party sales of Commission-regulated electric utility service. In NCSEA's opinion, however, the absence of a specific, express grant of legal authority to allow third-party sales should not end the Commission's examination of its legal authority. Instead, the Commission should go on to examine the extent of its authority in the absence of such express grant and in the absence of an express prohibition on all third-party sales. NCSEA recommends that the Commission review and reconcile each of its previous orders applying the Simpson factors. If, after applying the Simpson factors, the Commission determines that NC WARN's proposal does not present a transaction with "the public," the Commission should not prohibit the transaction. NCSEA further suggests that the transaction may fall within the self-generation exemption set out in G.S. 62-3(23)a.1. Ultimately, NCSEA argues that North Carolina is better off with clean energy and that policymakers should not, without compelling reasons, opt to limit customers' ability to choose clean energy alternatives. Lastly, NCSEA states that the Commission should decline to assess civil penalties against NC WARN because NC WARN's actions did not injure Duke and because, as NCSEA interprets Duke's correspondence with NC WARN, Duke implicitly agreed to NC WARN's actions.

Public Staff

In responding to the Commission's questions in its comments, the Public Staff states that there is no provision in the Public Utilities Act that expressly authorizes the Commission to allow third-party sales of Commission-regulated electric utility services to the public for compensation. Indeed, the Commission's express legal authority to allow resale of Commission regulated electric utility services is limited to the exemption from regulations of campgrounds and marinas pursuant to G.S. 62-3(23)h and the authority granted in G.S. 62-110(h) for lessors of residential buildings or complexes, both of which apply only under specific conditions.[1] Without a specific grant of such authority, the Commission is prohibited from allowing sales of Commission-regulated electric utility services.

In National Spinning, the Commission considered an arrangement whereby National Spinning, an industrial customer, would own a wood gasifier and sell gas to an unrelated third party. The second entity would, in turn, own and operate a high pressure boiler that would use the

[1] A campground or a marina that resells electricity under circumstances or terms other than those prescribed in G.S. 62-3(23)h would be considered a public utility regardless of whether the underlying supplier of the electricity is a Commission-regulated utility. Similarly, the Commission has the authority to allow a lessor to charge for electric service under the circumstances and terms prescribed in G.S. 62-110(h) regardless of whether the underlying supplier of electricity is a Commission-regulated utility.

purchased gas to produce high pressure steam. The steam would then be sold back to National Spinning and used in a turbine owned by National Spinning to produce up to seven megawatts of electricity for National Spinning's on-site use. In support of this arrangement, the parties argued that it was the functional equivalent of self-generation, an exception to the definition of public utility and the certificate requirements in G.S. 62-110. The Commission rejected this argument based on the test set forth in Simpson. In so doing, the Commission expressed a particular concern that if the proposed arrangement was permitted, other customers and suppliers would inevitably pursue similar arrangements and take customers from regulated electric utilities, thereby negatively impacting the rates of remaining residential, commercial, and smaller industrial customers as a result of significant stranded investment. According to the Public Staff, despite the differences in generating capacity of the facilities involved, similar arrangements are precisely the result envisioned by the scenario presented by NC WARN as the test case.

In North Carolina it is well established law that while the requirement of a certificate is not an absolute prohibition of competition between public utilities rendering the same service, the Commission will not grant another certificate authorizing a different, competing public utility to provide service in the same geographic area in the absence of a showing that the utility in the field is not rendering or cannot render the specific service in question. State ex rel. Utils. Comm'n v. Carolina Tel. & Tel. Co., 267 N.C. 257, 148 S.E.2d 100 (1966).

In addition, the Public Staff observes that this matter has been considered by the General Assembly in recent years, but that no legislation has been enacted. For example, Senate Bill 694, Energy Independence & Job Creation in North Carolina, was introduced in April 2011, and the Third Party Sale of Electricity Committee, authorized by the Legislative Research Commission, met twice in 2012 before the legislature returned for its short session. Two years later, Section 27 of S.L. 2014-4, the Energy Modernization Act, directed the State Energy Office to study, among other things, the impact to the electric grid and to the economy of allowing third-party sales of electricity on the State's military installations. Most recently, HB 245, which was introduced in 2015, would exempt certain third-party sales of electricity from on-site renewable energy facilities from certification and Commission regulation. According to the Public Staff, absent enactment of such legislation or a showing that the certificated service provider in the geographic area is not ready, willing, or able to provide electric service, the Commission is without authority to allow a third party to do so.

Finally, the Public Staff states that, since the Commission has no authority to allow third-party sales of Commission-regulated electric service, it should deny the petition and immediately order NC WARN to cease and desist providing and billing for electric service to the Church. The Commission should also encourage NC WARN to honor its commitment made in the PPA and to assist the Church in filing the report of proposed construction with the Commission pursuant to Commission Rule R8-65 and, if the Church so desires, a registration statement pursuant to Commission Rule R8-66.

DISCUSSION AND CONCLUSIONS

I.
NC WARN Identifies A Program For Third Party Sales
To Or For The Public

NC WARN classifies its petition as a "test case" to determine if the up-front costs of solar equipment and installation can be financed through the sale of electricity generated by PV panels. NC WARN cites its history of providing financing to consumers to install PV facilities, but maintains that it is restricted in following this program without an ability to sell to retail customers the power from the facilities it installs. Under the mechanism at issue in this "test case," NC WARN "will bill the church monthly for electricity generated by the [PV] system." NC WARN represents that an adverse ruling would restrict its ability to enter into similar funding mechanisms with other churches and non-profits. From these recitations it is clear that NC WARN seeks approval to engage in a program to facilitate the installation and sale from PV facilities to consumers in addition to the Church up to the limits of its ability to do so. Parties other than NC WARN have intervened seeking a ruling authorizing third party sales well beyond the electric sales NC WARN is making to the Church. Consequently, the Commission has before it a request to determine on a generic basis the extent to which third party sales from PV facilities are permissible under Chapter 62 of the General Statutes and the North Carolina appellate court decisions providing guidance in this area.

No party disputes that NC WARN is furnishing electricity under its program for compensation or that the electricity produced from its PV facilities is not for NC WARN's own use. Therefore, the dispositive issue raised by this request is whether, under G.S. 62-3(23)a.1, the sales under NC WARN's program are sales "to or for the public" based on North Carolina law as it exists today.

II.
Chapter 62 And North Carolina Appellate Court Decisions
Prohibit Unregulated Electric Sales To Or For The Public

The most significant case addressing the issue of "sales to or for the public" is State ex rel. Utils. Comm'n v. Simpson, 295 N.C. 519, 246 S.E.2d 753 (1978). In that case, as an adjunct to his telephone answering service, Simpson offered two-way radio and beeper service to a 55- to 60-member county medical society. The Court determined that Simpson was providing service to the public subject to regulation by the Commission under Chapter 62.

Among its determinations, the Court concluded that there should be a flexible definition of the "public" that focuses on the preservation of the legislatively-mandated regulatory framework:

> "One offers service to the 'public' within the meaning of this statute when he holds himself out as willing to serve all who apply up to the capacity of his facilities. It is immaterial, in this connection, that his service is limited to a specified area and his facilities are limited in capacity. For example, the operator of a single vehicle within a single community may be a common carrier."

Id. at 522, 246 S.E. 2d at 755 (quoting State ex rel. Utils. Comm'n v. Carolina Tel. & Tel. Co., 267 N.C. 257, 268, 148 S.E. 2d 100, 109 (1966)). The Court stated that Carolina Telephone did not foreclose consideration of whether a service offered only to a selected class of persons might also be considered an offering to the public. Among the cases from other jurisdictions cited with approval by the Court were those concluding (1) that a taxi cab company was a common carrier offering its services to the public even though its services were, by contract, limited to patrons of several hotels and a railroad station; and (2) that a bus service operator offering service only to tenants of certain apartments pursuant to contracts with this landlord was providing service to the public. The Court cited these cases for the proposition that services offered to some sub-classification of the general populace had been uniformly held to be offers made to the public. According to the Court, the teaching from these cases from other jurisdictions is:

> What is the "public" in any given case depends rather on the regulatory circumstances of that case. Some of these circumstances are (1) nature of the industry sought to be regulated; (2) type of market served by the industry; (3) the kind of competition that naturally inheres in that market; and (4) effect of non-regulation or exemption from regulation of one or more persons engaged in the industry. The meaning of "public" must in the final analysis be such as will, in the context of the regulatory circumstances, and as already noted by the Court of Appeals, accomplish "the legislature's purpose and comport with its public policy." 32 N.C. App. at 546, 232 S.E. 2d at 873.

Id. at 524, 246 S.E.2d at 756-57.

In concluding that Simpson's service was offered to the public and, therefore, unauthorized, the Court held:

> The radio common carrier industry is therefore a small one whose users fall into definable classes. Were a definition of "public" adopted that allowed prospective offerors of services to approach these separate classes without falling under the statute, the industry could easily shift from a regulated to a largely unregulated one. A service could be operated for doctors or realtors or builders, escape regulation and still capture a substantial portion or even a majority of the market. For example, while Dr. Simpson is offering the service to only ten subscribers, the record indicates there are only 22 radio common carrier subscribers in the whole of Cleveland County. Dr. Simpson is therefore serving over 45 percent of the available market. The end result of the kind of exemption Dr. Simpson argues for could well be that the only subscribers left in the regulated market would be those who fit in no easily definable class. Even if this extreme situation were not reached, unregulated radio services might focus on classes which are easier and more profitable to serve. The result would be to leave burdensome, less profitable service on the regulated portion resulting inevitably in higher prices for the service.

Id. at 525, 246 S.E.2d at 757.

III.
NC WARN's Program Constitutes
Electric Sales To Or For The Public

Based on Simpson and the Commission's previous decisions addressing the issue of service to the public, the Commission determines that the NC WARN program in this case constitutes service to the public and is thus impermissible. Under Chapter 62 and Commission orders implementing the Public Utilities Act, the service area in Greensboro has been assigned exclusively to Duke, and other service areas in North Carolina have been assigned exclusively to other electric suppliers. [1] Setting aside for the moment the differences between the telecommunication service at issue in Simpson and the electric service at issue here and the differences under the statutes relating to the two distinct services, unlike a number of states, North Carolina by statute does not permit retail electric competition. The prohibition is based on the economic principle that provision of public utility service for compensation is a service fixed with a public interest, and competition results in duplication of investment, economic waste and inefficient service, and high rates. Carolina Telephone, 267 N.C. at 271, 148 S.E.2d at 111 ("nothing else appearing, the public is better served by a regulated monopoly than by competing suppliers of the service.")[2] When other states determined that retail competition for electric service was a better model in the 1990s, North Carolina studied this alternative model, but, after witnessing the calamitous experience in California, determined to retain the status quo.[3]

In addition, the General Assembly in G.S. 62-3(23) has identified differences in the provision of electric utility service and telecommunications services at issue in Simpson that circumscribe the phrase "for the public" for electric service moreso than telecommunications service. Subsection 62-3(23)a.1, addressing electric service, includes a significant and limiting proviso to the definition of "to or for the public" that is conspicuously absent from subsection 3(23)a.6, which defines "to the public" for telecommunications service:

> [P]rovided, however, the term "public utility" shall not include persons who construct or operate an electric generating facility, the primary purpose of which facility is for such person's own use and not for the primary purpose of producing electricity … for sale to or for the public for compensation.[4]

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[1] G.S. 62-110.2

[2] Technological and market changes have resulted in legislative alterations in the regulation of telecommunications service subsequent to Simpson and Carolina Telephone. Significantly, those were changes the General Assembly enacted, not this Commission.

[3] See, e.g., NCUC Web Page on Electric Industry Restructuring; US Energy Information Administration – NC Summary; S.L. 1997-40 (Senate Bill 38); RTI October 1998 Report to the Legislative Study Commission; Study Commission on the Future of Electric Service in North Carolina Report to the 1999 General Assembly of North Carolina 2000 Regular Session.

[4] Theoretically, at least, the Commission could have declared Simpson to be a public utility, requiring him to obtain a certificate of public convenience and necessity to operate and regulating his rates and service in competition with the incumbent telecommunications supplier if, for example, the incumbent was unable or unwilling to provide the service Simpson offered. As Duke has the exclusive franchise in Greensboro and is providing electric service, unless NC WARN is free of regulation under Chapter 62, the Commission has no such option here.

This proviso is a clear legislative declaration that the provision of electric service for compensation to a third party, e.g., NC WARN's service to the Church, is service to the public and proscribed as an encroachment upon the certificated utility's exclusive service rights. The North Carolina Court of Appeals has held that a similar limiting proviso should be strictly construed. Shepard v. Bonita Vista Properties L.P., 191 N.C. App. 614, 664 S.E.2d 338 (2008), aff'd, 363 N.C. 252, 675 S.E.2d 332 (2009) (G.S. 62-3(23)(h), exempting campground owners from regulation if they resell electric service to occupants through individual meters with no mark-up, must be strictly construed.)

The fact that NC WARN's "test case" involves a non-profit seller and a non-profit buyer of electric power does not justify a determination that the sale is not to or for the public. This is the type of subclassification addressed and rejected by the Court in Simpson. Also, when the General Assembly wishes to make exceptions in Chapter 62 for non-profit buyers and sellers of electricity, it has done so explicitly. See G.S. 62-3(23)(d) (exempting non-profit organization serving only its members from public utility classification for persons who serve employees or tenants on a metered basis).

The General Assembly has been successful in determining the best policy for the state resulting in consistently low electric rates compared to the nation. This policy is one of providing regulated exclusive service area franchises to a utility to provide electric service. Until the General Assembly amends Chapter 62, it is not the Commission's role to alter the paradigm. Indeed, the 2015 Session of the General Assembly addressed potential legislation that would have authorized in one fashion or another third-party sales,[1] and the General Assembly will reconvene later in 2016 in further deliberations of the 2015 Session, at which time it may further consider any third-party sales bills. Existing law does not give the Commission the authority to permit NC WARN to compete with Duke in its exclusive franchise territory. Only the legislature can act on the policy arguments NC WARN makes in this docket.

As indicated above, NC WARN's request seeks approval of a program introducing third-party sales to an indefinite number of non-profit consumers. Others wish to expand the third-party sales beyond those to non-profit consumers like the Church.[2] The Commission understands that large commercial establishments desire the installation of PV facilities from which to buy for their own use or to sell excess electricity to other businesses presently served by the incumbent regulated providers. If carried to its logical extension, authorization of third-party sales presents the real probability that the public interest will not be well served as this will leave burdensome, less profitable service to the regulated incumbent and result in higher prices to the remaining customers for the service – the harm identified by the Court in Simpson. In exchange for their exclusive right to serve, the incumbent providers have an obligation to provide service to all, irrespective of the cost of doing so, at prices established through the regulatory, not the competitive, process. Third-party providers bear no such responsibility.

[1] House Bill 245

[2] October 30, 2015 Comments of NCIPL; November 20, 2015 Reply Comments of EFCA.

Under the Commission's ruling, consumers like the Church should not be impeded from taking advantage of rooftop PV facilities such as those already installed on its building and on many other structures in North Carolina under the "customer-owned" generation exception in G.S. 62-3(23)a.1. It is unclear why NC WARN seeks to sell electricity to the Church rather than providing financing to the Church to be repaid through the savings NC WARN represents will be achieved from the electricity the PV facilities will generate. Financing PV facilities with savings achieved does not involve making electric sales. NC WARN certainly makes no effort to support its conclusory assertion that sales are necessary for its program.

An effort to justify third-party sales as a financing mechanism removing the sale aspect of the transaction from regulation under Chapter 62 is unavailing. Financing of PV installations and sales of capacity and energy need not be linked. Should savings to the electric consumer result, they can be used to repay over time any loan taken out to defray the upfront construction costs. NC WARN, as it states in its petition, up until its arrangement with the Church, has helped non-profit entities install PV facilities solely through a loan without taking ownership. While NC WARN asserts it needs to combine the financing aspect of its program with a sale of power, it does not explain why sales of power are a necessary feature of its program. Adding the sale feature provides no apparent benefit to NC WARN's program; rather, it only converts a perfectly legal transaction into an unlawful one. Based on NC WARN's logic, an owner/developer of PV facilities that chooses not to borrow funds from a third party, but wishes to retain ownership and sell power to the building owner, would be prohibited from doing so, but an owner/builder that borrows money would not be so prohibited. This false dichotomy highlights the logical fallacy in NC WARN's position.

Most regulated electric utilities borrow funds to construct generating facilities. The borrowings are repaid through the capacity and energy charges in the rates consumers pay. Taken to its logical extreme, Dominion Resources or Southern Company could build a generating facility financed by borrowed funds in Duke's franchised service area in North Carolina and sell power to the public in competition with Duke without a franchise and beyond this Commission's jurisdiction on the theory that the plant was financed by borrowings, not internally generated funds. Financing the construction of generating resources and selling power from them are two distinct functions. Existing law does not prohibit financing of public utility or customer-owned generating facilities, but sales of power to or for the public makes the generator a public utility irrespective of the manner in which the facility is financed.

Nor does the availability of tax credits convert the sale of power from PV facilities into a nonregulated transaction. Should a for-profit entity take part in construction or development of PV facilities, any tax credits available to that entity should be used to reduce the upfront construction costs and, consequently, the price of the installation to the consumer on whose building the PV facilities are installed. In this case, neither NC WARN nor the Church is a for-profit organization. They pay no income taxes and are unable themselves to take advantage of tax credits. From the petition, YES! Solar Solutions[1] appears to be nothing more than a contractor to NC WARN and, nothing else appearing, unable to take advantage of tax credits. If the program is designed to sell the tax credits to one or more other tax-paying partners, the petition makes no reference thereto. As far as the Commission is aware, any existing tax credits are lost if the system is sold.

[1] YES! Solar Solutions is a solar installation company operating in North Carolina.

Consequently, the NC WARN "program" as laid out in the petition is not a prototypical program designed to take advantage of solar tax credits.

IV.
Past Commission Decisions Support A Determination
That NC WARN's Program Constitutes Sales To Or For The Public

The Commission's decisions determining whether a service was being provided to or for the public have been consistent with the requirements of Simpson in that they analyze the regulatory circumstances of each case rather than applying any strict, inelastic standard. While the cases have precedential force, they address discrete installations, and not part of a comprehensive program for which a "test case" was filed. Also, for the most part, the cases did not concern installations that were resisted by an incumbent supplier as a usurpation of its exclusive service rights and an interference with the public service obligations. The Commission's prior decisions are likewise consistent with the Commission's determination in this case that NC WARN's program of selling power from PV facilities to as many building owners as its resources permit constitutes a sale to or for the public.[1] In any case in which the owner of electric generating facilities has sought to sell electricity to consumers otherwise served by the incumbent electric supplier so as to bypass the incumbent, the Commission has determined that the proposed service is to or for the public.

The case most analogous to the instant case is National Spinning. In that case the generator sought to sell electric service to a consumer otherwise served by the incumbent electric utility. Contrary to assertions by NC WARN and others that this case is more closely analogous to Progress Solar, the commodity to be sold by the petitioner in Progress Solar was space lighting, a commodity distinct from the sale of electric service.[2]

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[1] Even if NC WARN's test case was limited to a sale of electricity solely to the Church and not more broadly to other consumers, under Simpson, there would be an unauthorized sale to or for the public as NC WARN would be serving the Church up to the capacity of its facilities.

[2] In National Spinning, Leary built, owned and operated a steam boiler positioned between a biomass gasifier producing gas that heated the boiler and a turbine generating electricity, all of its electrical output used for a textile plant. All of the components of this system (except the boiler) were owned by the textile plant, National Spinning. The Commission rejected a claim that Leary was exempt from regulation as a public utility because the steam boiler was an essential and integral part of the electric generating equipment and was owned by a third party, not National Spinning, the consumer of the electricity. The self-generation exemption, therefore, did not apply. Also, the electricity generated by the generating equipment would displace the incumbent utility which held the exclusive right to serve.

Moreover, NC WARN blatantly mischaracterizes National Spinning, stating:

> In National Spinning, the company wanted to sell excess power to an adjacent manufacturing company and came to the Commission for a declaratory ruling. … [The] Commission … concluded that direct sale of power from one industrial facility to another made the initial industry a public utility.

Petition, p.6. As noted above, National Spinning did not involve the sale of electricity from one industrial facility to another, but the bifurcated ownership of the generating facility's boiler and turbine-generator.

V.
The Iowa Eagle Point Decision
Is Inconsistent With North Carolina Law

Relying on Chapter 62 and Simpson, the Commission declines to authorize third-party sales. In so doing, the Commission finds Eagle Point,[1] a divided 2012 opinion of the Iowa Supreme Court, to be inapposite, non-controlling, and contrary to existing North Carolina law. The Commission must base its decision on Chapter 62 of the North Carolina General Statutes as interpreted by the North Carolina appellate courts. While Chapter 62 exempts only consumer-owned generation from the definition of an electric public utility, the Iowa statute permits the consumer-owned generator to make a limited number of sales to other consumers. Moreover, the Commission is not persuaded that the Iowa court's analysis comports with current law in North Carolina.

In the first place, the power purchase agreement (PPA) at issue before the Iowa Utilities Board under which Eagle Point sold electricity to the City of Dubuque had been converted into a financing/lease transaction under which no sales had occurred by the time the court addressed the case.[2] The North Carolina courts customarily deem cases so altered as moot and, therefore, refuse to address the merits.[3]

Eagle Point was a for-profit enterprise in the business of constructing, installing, interconnecting, and financing PV generating facilities from which to sell electricity on a metered basis to end users. NC WARN primarily is an advocacy group. NC WARN's purposes and functions are multifaceted and change from time to time, but historically, at least, selling PV output has never been listed among them. Indeed, NC WARN must depend on a third party, YES! Solar Solutions, to fulfill most of the functions Eagle Point provides in Iowa. Both NC WARN and the Church are non-profit entities unable to utilize tax credits from installing PV facilities.

Careful review of the Iowa court's rationale in disagreeing with the Iowa Utilities Board leaves the Commission unpersuaded that its decision should be followed. Much is made of the fact that Eagle Point's generating facilities are placed behind the incumbent certificated electric utility's electric meter installed to measure service to the City of Dubuque's building. This makes Eagle Point's sales to the building, so the argument goes, analogous to consumption from customer-owned facilities or to demand response or energy efficiency actions undertaken by the consumer.

[1] SZ Enterprises, LLC v. Iowa Utilities Board, 850 N.W. 2d 441 (2014)

[2] Id. at 466 n.6, 468.

[3] Angell v. Raleigh, 267 N.C. 387, 389-90, 148 S.E.2d 233, 235 (1966) ("'[T]he inherent function of judicial tribunals is to adjudicate genuine controversies between antagonistic litigants with respect to their rights, status, or other legal relations.'" (citation omitted)); J.S.W. v. Lee Cty. Bd of Educ., 167 N.C. App. 101, 104, 604 S.E.2d 336, 337-38 (2004) ("[W]henever, during the course of litigation it develops that the relief sought has been granted or that the questions originally in controversy between the parties are no longer at issue, the case should be dismissed, for courts will not entertain or proceed with a cause merely to determine abstract propositions of law." (citation omitted)); see also Pearson v. Martin, 319 N.C. 449, 451-52, 355 S.E.2d 496, 497-98 (1987).

The Commission finds this analysis incomplete. Were the City of Dubuque to consume power from its own generating facilities, it would not be in the electricity sales business, free to build generating facilities elsewhere in open competition with the incumbent and free to sell the power it did not need to others. Demand response (DR) involves shifting electrical use from on-peak to off-peak periods, under tariffs making such usage shifting economical, saving the necessity for the incumbent to construct central power plant facilities and transmission lines. Energy efficiency (EE) is the permanent reduction in demand or energy use serving a similar purpose. Third-party sales from a PV installation, an intermittent resource with a low capacity factor such as that at issue in Eagle Point, could not be counted upon to replace DR and EE functions. Contrary to the Iowa court's unsupported conclusions, winter peak demand is in the morning before the sun has risen. In the summer, even on clear days, the peak demand occurs well after maximum output of PV facilities, and there is no electrical output at all on cloudy days or when the PV facilities are out of service.

While Eagle Point's generating facilities are behind the incumbent's meter, these facilities are in front of Eagle Point's meter to the City of Dubuque that is used by Eagle Point to measure on a kilowatt-hour basis its sales to the City.

The Iowa court cites the fact that the City's building remains connected to the incumbent's lines and still relies on the incumbent for service as a factor supporting its conclusion that Eagle Point's competitive service should be authorized.[1] In the Commission's view, and in reliance in Simpson, this is a factor supporting the incumbent and the Iowa Utility Board's decision, not the competitive supplier. The incumbent must have generation and transmission capacity available to serve peak demand from the City's building, i.e., when the incumbent's costs are likely to be highest, but many of its sales over which to recover its costs are supplanted by Eagle Point. This increases the costs borne by the incumbent's other customers. The Iowa court's ruling is not limited to the single building at issue. The whole point of the request for the declaratory ruling was to establish precedent where the third-party electric sales could be repeated elsewhere without limit. No one should ignore that the objective of those favoring third-party sales is to limit them to city buildings consuming all the power from the PV facilities or to a non-profit church. The ultimate objective is for large commercial and industrial electric customers to buy electricity from third-party owners or to install large PV facilities for sale to others in addition to their own use.

The Iowa court measures the benefits of the sales from Eagle Point to the City from the perspective of the savings the City will experience.[2] Individual consumers able to bargain among competitors always benefit from and advocate for competition. The holding of Simpson is that the harm proscriptions against competitive electric sales is designed to avoid is the harm to consumers not able to purchase power from third-party suppliers. The dilution of sales from the incumbent means fixed costs must be recovered from those remaining without opportunity to purchase elsewhere.

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[1] Eagle Point, 850 N.W. 2d at 467.

[2] Id.

In applying the various Serv-Yu[1] factors to conclude that Eagle Point is not a public utility, the Iowa court focuses on the "market" subject to competition at issue as the market for installing PV facilities.[2] The Commission determines that this is not the market that should be addressed. The market in determining whether the "public" is being served is the retail market in which electric capacity and energy is bought and sold. The market for buying and selling solar panels is competitive, but that is not the market in which the incumbent electric supplier and those seeking to sell electric service in its exclusive service area compete. The market in which Duke chooses vendors to construct fossil fuel generating facilities is competitive, too, but that competition has nothing to do with whether those competing to sell electric power from those facilities in competition with Duke are selling to the public.

The Iowa court spends substantial analysis on the historical development of electricity production, the benefits of renewable/solar generation, and its perceived changes in the legislative/regulatory context in Iowa and elsewhere in support of its determination that Eagle Point should not be classified as a public utility. The court refers to a number of scholarly publications in support of its conclusions, none of which appear in the record established before the Iowa Utilities Board. Paradoxically, the court dismisses the Iowa Utility Board's expert justifications to the contrary – that to agree with Eagle Point results in cherry picking, a reduction in incumbent sales, and a foisting in costs stranded thereby on remaining customers – out of hand because the court finds no support in the record.[3]

The Commission finds the scholarly publications cited by the Iowa court to present only one side of the debate and to be out of date. The issue of "Value of Solar" has received widespread scholarly analysis. Two sides to the debate exist. Solar advocates maintain that "distributed renewable generation" provides system support, reduces the need for incumbent transmission and distribution facilities, reduces demand on peak, and provides a clean source of power beneficial to the environment. On the other side, advocates maintain that distributed renewable generation results in stranded investment, cannot be dispatched because of its intermittent nature, costs more than alternative sources of power, and must be subsidized by taxpayers and those such as renters who cannot invest in distributed generation.[4] The debate continues. The point is that the Iowa court's discussion is incomplete and one-sided. Consequently, the Commission will not rely on Eagle Point as precedent as NC WARN requests. Issues such as the Value of Solar in the context of authorizing third-party sales should be addressed in the legislative context where such issues can be thoughtfully examined and resolved on a complete record where all interested parties may

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[1] Natural Gas Service Co. v. Serv-Yu Cooperatives, Inc., 70 Ariz. 235, 219 P.2d 324 (1950). Simpson post dates Serv-Yu and makes no reference to the case or the factors it lists. The Simpson factors are not the same as the Serv-Yu factors.

[2] Eagle Point, 850 N.W. 2d at 467.

[3] Id. at 468.

[4] Steve Mitnick, Before the Death Spiral, Public Utilities Fortnightly, Nov. 2015, at 41-44; Edward Cazalet & David MacMillan, Solar at High Noon, Public Utilities Fortnightly, Dec. 2015, at 27; Chris Vlahoplus, John Pang, Paul Quinlan & John Sterling, Community Solar, Public Utilities Fortnightly, Dec. 2015, at 33-36; Charles J. Cicchette and Jon Wellinghoff, Solar Battle Lines, Public Utilities Fortnightly, Dec. 2015, at 18-25; Charles E. Bayless, Piggybacking on the Grid, Public Utilities Fortnightly, July 2015, 39-42; Ashley Brown, Letter to the Editor, Response to Cicchetti and Wellinghoff Re: Net Metering, Public Utilities Fortnightly, at 8-9; Charles Cicchetti, Letter to the Editor, Response to Brown Re Net Metering, Public Utilities Fortnightly, at 8-9.

participate, not in this request for a declaratory ruling based on atypical facts, and where the generator is an advocacy group and the buyer is a non-profit.

VI.
North Carolina Is Not An Outlier
In Its Treatment Of Third Party Sales

NC WARN contends that "North Carolina is one of only four states that does not have a clear policy statement encouraging third-party funding of renewable energy, either through legislation or court order." In the first place, as indicated above, it is not funding, but sales that is the dispositive issue in dispute in this case. NC WARN does not provide the source for this assertion. The Commission, however, takes note, that the United States Department of Energy publishes a map regarding "3rd Party Solar PV Power Purchase Agreement (PPA)" policies of the states, as referenced by NCEMC in its comments.[1] The July 2015 map indicates that third-party solar PV PPAs are "apparently disallowed by state or otherwise restricted by legal barriers" in five states. The key also indicates that the status of the policy regarding the use of third-party solar PV PPAs in twenty states is "unclear or unknown." Thus, the Commission finds that at the time of NC WARN's filing potentially twenty-five states, as opposed to four states, do not have a clear policy statement encouraging third-party funding of renewable energy, either through legislation or court order.[2] Moreover, in North Carolina it is the General Assembly's policy that determines the advisability of third-party solar.

Claims that North Carolina has no policy encouraging the funding of third-party solar are patently inaccurate. In 2007 the General Assembly enacted Senate Bill 3 authorizing North Carolina electric utilities to pay incentives to encourage renewable generation. Solar generation was one of three set-aside requirements established in the law and entitled to priority treatment. For years, North Carolina provided a 35% state tax credit encouraging the installation of renewable generation. These state-sponsored "encouragements" have resulted in North Carolina being one of the leaders in adding renewable generation, a large percentage being solar. Since the beginning of 2007, North Carolina has installed 1,286 MW of solar capacity. The Commission has authorized net metering tariffs under which owners of PV facilities receive credit for power they provide to the utility equal to the price they pay the utility for electricity they consume.

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[1] See "3rd Party Solar PV Power Purchase Agreement," DSIRE, July 2015, available online at http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2015/08/3rd-Party-PPA072015.pdf (last accessed October 13, 2015) (citing N.C.G.S. 62-3(a)(23) for the basis that third-party sales of electricity are "apparently disallowed by state or otherwise restricted by legal barriers").

[2] A current DSIRE map dated April 2016 indicates that eight states apparently disallow or otherwise restrict by legal barriers and that seventeen states the status is unclear or unknown. See"3rd Party Solar PV Power Purchase Agreement," DSIRE, April 2016, available online at http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2015/01/3rd-Party-PPA_0302015.pdf.

VII.
NC WARN Has Violated North Carolina's Prohibition Of Third-Party Sales Subjecting Itself To Sanctions

On August 28, 2015, without obtaining a certificate from the Commission as required by law to provide public utility service, NC WARN billed the Church for sales of electricity for the period June 30, 2015, through August 27, 2015. Despite the fact that it had filed the request for a declaratory ruling on June 17, 2015, in which it acknowledged that its program "may be restricted under North Carolina law," and with knowledge that the General Assembly had before it proposed legislation addressing the possibility of lifting the ban on third-party sales, NC WARN willfully undertook to provide public utility service.

As recently as January 27, 2015, the Commission has stated unequivocally that third-party sales are unlawful in North Carolina:

> The Commission disagrees with [Southern Environmental Law Center] that Chapter 62 allows for power purchase agreements between utility customers and nonutility solar installers. Rather the Commission concludes that Chapter 62 of the North Carolina General Statutes prohibits third-party sales of electricity by non-utility solar installers to retail customers.

<u>In Re Order Approving Pilot Programs</u>, NCUC Docket No. E-100, Sub 90 (January 27, 2015)

NC WARN is represented by counsel and is a frequent participant in Commission proceedings as well as a vocal and persistent critic of Commission orders. NC WARN knows or is presumed to know the law. It is the General Assembly that has provided Duke its exclusive service rights, pursuant to a CPCN issued by this Commission, and NC WARN is not free to violate those rights as it has blatantly undertaken to do. NC WARN has been so bold as to suggest that the State Constitutional prohibition against illegal monopolies and emoluments is inconsistent with Duke's exclusive franchise when decades of North Carolina appellate court opinions not only acknowledge these franchise rights, but repeat that they best protect the interests of the using and consuming public.

As Duke correctly asserts, when NC WARN billed the Church for electric service it acted as a <u>de facto</u>, but not a <u>de jure</u> public utility subject to penalties for violations of the provisions of Chapter 62.[1] Among these penalties is a fine of up to $1,000 per day for each violation. G.S. 62-310.

The Commission concludes that DNCP accurately characterizes NC WARN's actions:

> NC WARN's actions and public statements before and subsequent to the filing of its Declaratory Ruling Request, the unsupported legal arguments used to support NC WARN's Request, and the fact that NC WARN has proceeded to make retail electric sales to [the Church] prior to the Commission ruling on NC WARN's

[1] <u>State ex rel. Utils. Comm'n v. Mackie</u>, 79 N.C. App. 19, 25-31, 338 S.E.2d 888, 893-898 (1986), <u>aff'd as modified</u>, 318 N.C. 686, 351 S.E.2d 289 (1987); <u>State ex rel. Utils. Comm'n v. Buck Island Inc.</u>, 162 N.C. App. 568, 572-579, 592 S.E.2d 244, 247-253 (2004).

> Request, all point to the Declaratory Ruling Request being frivolous and subterfuge in NC WARN's ongoing public campaign against Duke Energy and North Carolina's traditional regulated utility model.

Having so concluded, the Commission, in response to NC WARN's willful conduct, requires NC WARN to refund its charges to the Church and determines to impose upon NC WARN a fine of $200 per day for each day NC WARN has provided and continues to provide electric service to the Church. The Commission would have been justified in fining NC WARN the statutory maximum of $1,000 per day. However, the financing[1] as opposed to the sales features of NC WARN's program are beneficial to Faith Community Church and justify mitigation of the otherwise justifiable penalty. Furthermore, the Commission, as set forth below, has permitted NC WARN to avoid penalties altogether upon compliance with reasonable conditions most of which NC WARN has agreed to comply with in advance in the event of an adverse ruling on the merits. Consequently, the monetary penalty comes into play only upon NC WARN's decision to choose penalties instead of conditions beneficial to Faith Community Church. The Commission requires that the Public Staff audit NC WARN's books of account to determine the extent to which NC WARN has in fact billed the Church, the amount of such billings, and the amount to be refunded. The Public Staff shall file periodic reports of the results of its audit to the Commission until the full amount plus interest is refunded to the Church.

The requirement of the fines, but not the refunds and the Public Staff audit, shall be suspended upon the following conditions:

(1) NC WARN shall refund to the Church with 10% interest[2] all billings it has made to the Church and all further billings until it ceases to so bill.

(2) NC WARN shall file with the Commission a verified representation that it has ceased and desisted and, until further notice of the Commission, will continue to cease and desist any further attempt to provide electric service for compensation to any consumers in North Carolina.

(3) NC WARN shall cease and desist from advertising and promoting any facet of its solar program that contains as a factor the sale of electric power.

(4) NC WARN shall comply with the representation in its petition to donate the solar PV system installed on the Church's building to the Church.

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[1] NC WARN represents "[t]he PPA also clearly states that if it is determined by the NC Utilities Commission, or a court with jurisdiction over the matter, that NC WARN cannot sell the Church the output of the panels, NC WARN is committed to donating the PV system to the Church." June 15, 2015 petition, p. 4. As such, the donation equates to 100% financings of the Church's PV facilities by NC WARN.

[2] G.S. 62-130 (e).

VIII.
Requests for Oral Argument are Denied

Both EFCA and NC WARN requested that the Commission provide the opportunity to present oral argument. Although both parties recognized that the Commission has adequate information to make the declaratory ruling without oral argument, NC WARN states that the Commission would benefit in the understanding of nuanced arguments of the parties and EFCA contends an oral argument would maximize transparency and allow for development of the record. The Commission is not persuaded. As both parties concede, the Commission determines that the issues have been adequately addressed in the parties' written filings and an oral argument is not necessary.

IX.
Summary of Discussion and Conclusions

In summary, the Commission finds and concludes:

1) NC WARN's program constitutes sales "to or for the public" based on current North Carolina law;

2) NC WARN's electric sales to the public (the Church) is impermissible due to the fact that the Church is located within a service area that has been assigned exclusively to Duke;

3) the General Assembly has determined that the public is better served by a regulated monopoly than by competing suppliers of service, and this policy decision by the General Assembly has resulted in consistently low electric rates compared to other parts of the country;

4) the Church has legal ways to finance the installation of solar on its premises, including, among others, financing over a period of time by using electric bill savings to pay for the purchase and installation;

5) Commission precedent supports the Commission's determination and the Iowa Eagle Point decision is not controlling and is contrary to North Carolina law;

6) North Carolina is one of the nation's leaders in adding renewable generation;

7) NC WARN knowingly entered into a contract to sell electricity in a franchised area and sold electricity without prior permission from the Commission subjecting itself to sanctions; and

8) although the Commission determines that penalties should be issued, those penalties shall be waived upon NC WARN's honoring its commitment to refund all billings to the Church and ceasing all future sales.

IT IS, THEREFORE, ORDERED as follows:

1. That NC WARN's petition shall be, and is hereby, denied.

2. That NC WARN's and EFCA's request for oral argument are denied.

3. That NC WARN shall refund its charges to the Church, with a fine of $200 per day for each day that NC WARN has provided and continues to provide electric service to the Church.

4. That the Public Staff shall audit NC WARN's books of account to determine the extent to which NC WARN has in fact billed the Church, the amount of such billings, and the amount to be refunded.

5. That the Public Staff shall file periodic reports of the results of its audit to the Commission until the full amount plus interest is refunded to the Church.

6. The requirement of the fines but not the refunds and the Public Staff audit, however, shall be suspended upon the following conditions:

a. NC WARN shall refund to the Church with 10% interest[1] all billings it has made to the Church and all further billings until it ceases to so bill.

b. NC WARN shall file with the Commission a verified representation that it has ceased and desisted and, until further notice of the Commission, will continue to cease and desist any further attempt to provide electric service for compensation to any consumers in North Carolina.

c. NC WARN shall cease and desist from advertising and promoting any facet of its solar program that contains as a factor the sale of electric power.

d. NC WARN shall comply with the representation in its petition to donate the PV system installed on the Church's building to the Church and assist the Church in filing a new docket to amend the report of proposed construction with the Commission and, if the Church desires, a registration statement pursuant to Commission Rule R8-66.

ISSUED BY ORDER OF THE COMMISSION.
This the _15th_ day of April, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

[1] G.S. 62-130 (e).

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Telecommunications Relay Service (TRS),	)	ORDER APPROVING
Relay North Carolina	)	SELECTION OF CONTRACTOR

BY THE COMMISSION: On December 15, 2015, the Department of Health and Human Services (DHHS) issued a Request for Proposals (RFP) to select a vendor to provide telecommunications relay service to North Carolina citizens. The new contract will be effective from July 1, 2016 to June 30, 2020. Pursuant to G.S. 62-157, DHHS is charged with administering the statewide telecommunications relay service program, including its establishment, operation, and promotion. Pursuant to G.S. 62-157(e) and as part of its administration of the program, DHHS is authorized to contract out provision of this service for four-year periods to one or more service providers, using the State bidding process prescribed in G.S. 143-129. The present contractor is Sprint Communications Company, LP (Sprint). The present contract expires on June 30, 2016.

The Public Staff presented the results of DHHS' process of selecting a contractor for the 2016-2020 time period at the Commission's Regular Staff Conference on April 25, 2016. The Public Staff stated that two companies submitted proposals in response to the RFP, Sprint and Hamilton Telephone Company, d/b/a Hamilton Telecommunications (Hamilton). An evaluation committee reviewed the two proposals. The evaluation committee consisted of Kevin Earp, Coordinator for the Deaf, Division of Vocational Rehabilitation; Thomas Kuszaj, Equipment Distribution Coordinator, Division of Services for the Deaf and Hard of Hearing (DSDHH); Mark Whisenant, ADA Coordinator, Office of Equal Opportunity and Workforce Services, Department of Transportation; and Sandra Trivett, Policy Consultant, Division of Vocational Rehabilitation, Division of Services for the Blind, DSDHH.

In its review, the evaluation committee considered the following: technical merit, qualifications, references, customer service, outreach, advertising program, and costs. The evaluation committee then weighed and scored each bidding vendor's performance with regard to these considerations. When evaluated pursuant to the considerations listed above, Sprint achieved the highest score and as a result, the evaluation committee recommended Sprint as the new contractor to the DHHS Office of Procurement and Contract Services. This recommendation and evaluation summary, the vendor's proposals in response to the RFP, and the individual scores, were reviewed by the DHHS Office of Procurement and Contract Services and a contract specialist at the Information Technology Services (ITS) Statewide Procurement Office. ITS approved the award of the contract to Sprint on April 7, 2016.

Per minute costs of relay calls will decrease for the upcoming contract period, but the monthly recurring charge and the cost of a CapTel call will increase. Specifically, the cost per minute of a relay call will decrease from $0.85 (2012-2016) to $0.00 (2016-2020), and the cost per minute of a CapTel call will increase $0.09, from $1.60 (2012-2016) to $1.69 (2016-2020). The annual sum of the monthly recurring charge will increase by $98,664, from $657,336 per year (2012-2016) to $756,000 per year (2016-2020). This monthly recurring rate will help fund Sprint's TRS outreach into North Carolina's deaf and hard of hearing community and offset the elimination of the per minute charge for relay calls. The DHHS Office of Procurement and Contract Services estimated the total cost of the contract for the four-year period to be $20,904,200. An increase in the TRS monthly surcharge is not expected or foreseen at this time as a result of the new contract.

G.S. 62-157 provides that the Commission has the same power to regulate TRS as it has to regulate any other public utility subject to the provisions of Chapter 62. DHHS has in the past sought the approval of the Commission prior to the selection of the new contractor. The Public Staff has consulted with representatives of DHHS regarding its selection of Sprint as the contractor. Based on these consultations and a review of the RFP documents, the Public Staff recommended that the Commission approve the selection of Sprint as the contractor for relay services in the four-year period beginning July 1, 2016. This approval will not result in any increase in the TRS monthly surcharge at this time.

Based on the foregoing and the recommendation of the Public Staff, the Commission concludes that DHHS's selection of Sprint as the vendor to provide relay services in North Carolina for the four-year period beginning July 1, 2016, and ending June 30, 2020, should be approved.

IT IS, THEREFORE, ORDERED that DHHS's selection of Sprint as the contractor to provide TRS in North Carolina for the four-year period beginning July 1, 2016, is approved.

ISSUED BY ORDER OF THE COMMISSION.
This the ___26th__ day of April, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Chairman Edward S. Finley, Jr., did not participate in this decision.

DOCKET NO. P-100, SUB 133f

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Lifeline and Link Up Services Pursuant to Section 254 of the Telecommunications Act of 1996	)))))))	ORDER REVISING COMMISSION RULE R9-6, EFFECTIVE DECEMBER 1, 2016, REQUIRING UPDATED TARIFFS, ELIMINATING LIFELINE/LINK UP REPORTING REQUIREMENTS, AND DISBANDING THE LIFELINE/LINK UP TASK FORCE

BY THE COMMISSION: On April 27, 2016, the Federal Communications Commission (FCC) released its Third Report and Order, Further Report and Order, and Order on Reconsideration concerning Lifeline and Link Up Modernization (2016 Lifeline Modernization Order[1]). Certain FCC Rule amendments adopted in the Order will become effective on December 1, 2016.

Commission Rule R9-6 – Link-Up Carolina (LUC) Connection Fee Subsidy Program addresses the "Link-Up Carolina" connection fee subsidy program which is better known simply as the Link Up[2] program. The Commission has promulgated revisions and amendments to the Lifeline and Link Up programs by Commission Order in Docket No. P-100, Sub 133f since November 1997.

On September 7, 2016, the Commission issued an Order Requesting Comments and Proposed Revisions to Commission Rule R9-6 (September 7, 2016, Order). The Order noted that, based on the recent revisions by the FCC to the Lifeline program, and the incomplete and outdated status of Commission Rule R9-6, it would be appropriate to request comments and proposals from the Public Staff – North Carolina Utilities Commission (Public Staff) and interested parties on a revised Commission Rule R9-6. The Commission stated in the Order that it intends to revise Commission Rule R9-6 to include both the Lifeline and Link Up programs and to reflect the FCC's April 27, 2016, Lifeline Modernization Order.

Initial comments were filed on September 30, 2016 by BellSouth Telecommunications, LLC d/b/a AT&T North Carolina (AT&T), CenturyLink, and the Public Staff. No party filed any reply comments.

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[1] See *2016 Lifeline and Link Up Reform and Modernization et al*., WC Docket No. 11-42, et al., Third Report and Order, Further Report and Order, and Order on Reconsideration, FCC 16-38 (*2016 Lifeline Modernization Order*).

[2] Pursuant to federal regulations, beginning April 2, 2012, the LUC connection fee subsidy program (also known as Link Up), is only available to residents of Tribal lands subscribing to service from an eligible telecommunications carrier that is receiving high-cost support.

INITIAL COMMENTS

AT&T noted in its comments that its role as a Lifeline services provider has diminished over the past several years, as an increasing number of consumers eligible for Lifeline discounts are electing to take those discounts from service providers other than AT&T. AT&T maintained that, as of year-end 2015, AT&T had fewer than 4,266 Lifeline subscribers in North Carolina, a drop of about 90% since year-end 2008. AT&T stated that that number continues to decline.

AT&T commented that the FCC's 2016 Lifeline Modernization Order trims the list of programs for Lifeline eligibility to SNAP, Medicaid, SSI, and FPHA and added Veterans Pension Benefits. AT&T stated that income based eligibility remains at 135% of the Federal Poverty Guidelines and Tribal program-based eligibility criteria also remain unchanged. AT&T noted that consumers who live on Tribal lands may also qualify for Lifeline through one of the following Tribal federal assistance programs: Bureau of Indian Affairs general assistance; tribally administered Temporary Assistance for Needy Families; Head Start (subject to income threshold requirements); or the Food Distribution Program on Indian Reservations.

AT&T noted that, based on the FCC's revision to the Lifeline program, the Commission's acknowledgement of the incomplete and outdated status of Commission Rule R9-6, and the Commission's intent to revise Commission Rule R9-6 to include both the Lifeline and Link Up programs and reflect the FCC's April 27, 2016, Order, AT&T believes that revising Commission Rule R9-6 to mirror the Federal rules is appropriate. AT&T asserted that such revisions will make the programs more efficient. For example, AT&T stated, aligning federal and state rules will make it easier to verify eligibility and administer the programs, which in turn will help to reduce waste, fraud, and abuse. Therefore, AT&T made the following recommendations:

(1) That the Commission modify North Carolina's Lifeline/Link Up eligibility criteria to incorporate the revised Federal Lifeline eligibility criteria by reference (47 C.F.R. §54.409);

(2) That the effective date of these changes should mirror the effective date for the revised federal eligibility rules[1];

(3) That should the FCC adopt standardized consumer certification, recertification, and one-per-household worksheets for the Lifeline program, then the Commission should also adopt the FCC's standardized application (certification) form for consumers to use in applying for Lifeline discounts, because use of the FCC's standardized Lifeline forms will become mandatory at that point; and

[1] AT&T noted that the effective date for the streamlined federal eligibility criteria is set for the later of December 1, 2016 or 60 days following the federal Office of Management & Budget's approval of the 2016 Lifeline Modernization Order. AT&T stated that, however, the United States Telecom Association has asked the FCC to defer the effective date until the later of December 31, 2017 or 12 months after the Office of Management & Budget's approval. US Telecom Petition for Reconsideration & Clarification, *In the Matter of Lifeline & Link Up Reform & Modernization*, WC Docket No. 09-197, *Connect America Fund*, WC Docket No. 10-90 (filed June 23, 2016).

(4) That the Commission eliminate its semi-annual reporting requirements for Lifeline subscriber count information because that information will be available directly from the Universal Service Administrative Company (USAC)[1].

CenturyLink stated in its comments that it generally believes that the North Carolina rule should mirror the federal rules adopted earlier this year by the FCC whenever possible. CenturyLink maintained that, in addition, in light of the review of Commission Rule R9-6 prompted by the FCC's action, CenturyLink believes the Commission should also move to eliminate the semi-annual Lifeline and Link Up reporting obligations previously approved by the Commission in 2000.

CenturyLink noted that, with respect to amendments to Commission Rule R9-6, CenturyLink agrees with the observations in the Commission's September 7, 2016, Order that the rule in its current form is outdated. CenturyLink maintained that the FCC's changes have created inconsistency between the Federal Lifeline program and many state programs by phasing out support for voice service and changing requirements for eligibility. CenturyLink stated that a main focus of the changes to the Federal Lifeline program is to streamline and ease administration and encourage more provider participation in the Lifeline program. CenturyLink stated that it recognizes that the Commission retains authority over Lifeline and Link Up services in North Carolina regardless of a local exchange carrier's regulatory status (See G.S. 62-133.5(m)). CenturyLink noted that while North Carolina does not provide its own subsidy for Lifeline and Link Up services at this time, CenturyLink asks that any changes made to Commission Rule R9-6 align with the Federal Lifeline program to reduce the potential for customer confusion and to promote efficiency.

CenturyLink maintained that with respect to the current reporting environment, CenturyLink respectfully submits that the semi-annual Lifeline and Link Up report required pursuant to the Commission's April 11, 2000, Order in Docket No. P-100, Sub 133f is no longer necessary. CenturyLink stated that the Task Force Report supporting that Order as well as the Order itself confirm that the reporting requirement was initially adopted as a means to gauge the effectiveness of measures designed to increase participation. CenturyLink asserted that, moreover, state level enrollment data is available from the USAC. CenturyLink maintained that given the availability of state level data, combined with the fact that the purpose of the reporting requirement is no longer relevant, this report should be eliminated.

The Public Staff noted in its comments that the concept of universal service has been a major policy goal of the FCC and this Commission since the mid-1980s. The Public Staff asserted that, on the federal level, the language of the Telecommunications Act of 1996 reflected this goal, and included the requirement that there should be "specific, predictable and sufficient Federal and State mechanisms to preserve and advance universal service." The Public Staff noted that, to that

[1] AT&T noted that the 2016 Lifeline Modernization Order directs USAC, by December 1, 2016, to make available to the public, information regarding the total number of Lifeline subscribers for which a provider seeks support in each state as well as the types of services for which support is being provided. AT&T stated that the Commission will have direct access to all of that information for its review at its convenience.

end, the FCC adopted rules and regulations to implement federal Lifeline and Link Up programs as a means of providing assistance to low-income consumers in receiving telephone service.

The Public Staff further stated that in 1986, the Commission adopted rules and regulations for the incumbent local exchange companies (ILECs) to offer the predecessor to Lifeline service. The Public Staff noted that upon implementation of the Telecommunications Act of 1996, the Commission modified the program, renamed it Lifeline and began offering Link Up service, generally under the same terms and conditions required by the FCC. Thus, the Public Staff asserted, mechanisms were adopted on the federal and state level for providing universal service support to low-income consumers that participate in certain qualifying programs.

The Public Staff maintained that since initiation of the Lifeline and Link Up programs, the FCC and the Commission have made numerous modifications to the program participation, the level of support provided, and the manner in which eligibility is confirmed. The Public Staff noted that most recently on the state level, as a result of Session Law 2013-316 and Session Law 2013-363, the Commission eliminated the state credit on Lifeline eligible consumers' bills as of January 1, 2014. (See *Order Eliminating Requirement for Lifeline Subsidy Funded by the State Income Tax Credit,* issued in Docket No. P-100, Sub 133f on October 28, 2013)

The Public Staff stated that at the federal level, on April 27, 2016, the FCC issued its 2016 Lifeline Modernization Order. The Public Staff noted that certain FCC Rule amendments adopted in the 2016 Lifeline Modernization Order will become effective on December 1, 2016, while others such as determining eligibility using a National Verifier will become effective once the appropriate processes and procedures are put in place.

The Public Staff observed that the Commission's September 7, 2016, Order notes the recent revisions by the FCC to the Lifeline program as well as the incomplete and outdated status of Commission Rule R9-6. The Public Staff noted that the Commission stated in its request for comments its intent to revise Commission Rule R9-6 to reflect both the Lifeline and Link Up programs and the FCC's 2016 Lifeline Modernization Order.

The Public Staff stated that it attached a proposed rule as Appendix A[1] to its comments to reflect the Commission's objectives of incorporating the Lifeline and Link Up programs and the FCC's 2016 Lifeline Modernization Order in the new rule. The Public Staff proposed that the new rule become effective on December 1, 2016, to be consistent with the changes being made to the federal Lifeline and Link Up programs.

The Public Staff maintained that the proposed changes to Commission Rule R9-6 reflect that the Lifeline and Link Up programs are essentially federal programs with limited state input, and also recognize that providing Lifeline and Link Up service is not limited to ILECs. The Public Staff noted that competing local providers (CLPs) may also be designated as eligible telecommunications carriers (ETCs) and thus be obligated to provide Lifeline and Link Up service.

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[1] The Public Staff noted that due to the extensive revisions, it has not provided a marked-up version of the current rule. The Public Staff stated that it believes the current rule should be replaced in its entirety with the Public Staff's proposed rule.

The Public Staff stated that the proposed rule is intended to limit the need for modifications should changes to the Lifeline and Link Up programs be made.

The Public Staff explained that the proposed rule: (1) describes the Lifeline and Link Up programs; (2) explains the obligations of the local exchange companies to provide the programs; (3) sets forth program eligibility requirements; (4) sets forth verification requirements to determine eligibility for consumers; and (5) sets forth the support provided to consumers that are eligible for one or both of the programs.

The Public Staff stated that, in addition to revising Commission Rule R9-6, the Public Staff also recommends that the Commission require the ILECs to modify their local exchange tariffs concerning Lifeline and Link Up program availability. The Public Staff maintained that the ILECs will need to submit tariff revisions to reflect the changes to Lifeline and Link Up programs that become effective on December 1, 2016. The Public Staff stated that it believes that a one-time tariff change to more generally reflect the availability of Lifeline and Link Up services would lessen the administrative burden on the Commission, the Public Staff, and the ILECs and enable the ILECs to implement any potential future Lifeline or Link Up program changes without unduly harming an eligible consumer's ability to obtain these services.

The Public Staff noted that the ILEC tariffs currently contain detailed language regarding, among other things, the amount of support provided and the program eligibility requirements for Lifeline and Link Up. The Public Staff maintained that to prevent the need for future changes, the Public Staff recommends the tariffs be modified to reflect language as provided in Appendix B as attached to the Public Staff's comments.

In addition, the Public Staff stated that it believes the Lifeline/Link Up Task Force can be disbanded. The Public Staff noted that this group was formed to provide periodic reports, make various recommendations to the Commission regarding the Lifeline and Link Up programs, and provide outreach efforts for informing consumers of the availability of the Lifeline and Link Up programs. The Public Staff noted that no new requests have been submitted to the Task Force since October 2013, when the Commission ordered that the monthly bill credit of $3.50 be eliminated pursuant to Session Law 2013-363 and directed the Task Force to monitor the Lifeline program for evidence that State Lifeline support should be reinstituted. The Public Staff stated that it is unaware of the Task Force having met since May 2013. The Public Staff noted that once Commission Rule R9-6 has been revised, the Public Staff does not believe the Task Force will be needed for the foreseeable future. The Public Staff also noted that to the extent future circumstances warrant, the Commission can always reinstate the Task Force.

In summary, the Public Staff recommended that the Commission:

(1) Adopt the revised Commission Rule R9-6 as shown in Appendix A to the Public Staff's comments;

(2) Require ILEC tariffs be revised as shown in Appendix B to the Public Staff's comments; and

(3) Disband the Lifeline/Link Up Task Force.

REPLY COMMENTS

No party filed any reply comments.

DISCUSSION AND CONCLUSIONS

AT&T, CenturyLink, and the Public Staff all agreed in their comments that Commission Rule R9-6 should be modified to mirror the FCC's 2016 Lifeline Modernization Order. The Public Staff was the only party to provide a proposed revised Commission Rule R9-6. The Public Staff's proposed rule describes the Lifeline and Link Up programs, explains the obligations of the local exchange companies to provide the programs, sets forth program eligibility and verification requirements, and notes the support provided to consumers that are eligible for one or both of the programs.

The Commission agrees with the parties in this regard and finds that it is appropriate to revise Commission Rule R9-6 to mirror the FCC's Rules. The Commission adopts the Public Staff's proposed Commission Rule R9-6 with the following minor edits:

- Rule R9-6(a)(1), inserted the phrase "low-income" between "qualifying" and "consumers";

- Rule R9-6(b), moved the phrase "by the Utilities Commission"; and

- Rule R9-6(d), renamed "Verification of eligibility".

Therefore, the Commission finds it appropriate to adopt revised Commission Rule R9-6 as outlined in Appendix A to this Order, effective December 1, 2016.

In addition, the Commission notes that the Public Staff recommended that the Commission require the ILECs to modify their local exchange tariffs, effective December 1, 2016, to reflect the FCC's Lifeline and Link Up changes. The Public Staff provided proposed tariff language, and the Commission finds it appropriate to adopt the Public Staff's proposed tariff language. However, the Commission has made minor edits to the Public Staff's proposed tariff language identical to the changes made to the Public Staff's proposed Commission Rule R9-6. In addition, the Commission has changed the reference to part "(c) above" in part (c) of the Public Staff's proposed tariff language to part "(b) above". The Commission finds that the ILECs shall be required to modify their local exchange tariffs concerning Lifeline and Link Up program availability as outlined in Appendix B as attached to this Order. The effective date for such tariff changes should be December 1, 2016.

Further, AT&T and CenturyLink recommended that the Commission eliminate its semi-annual Lifeline reporting requirement. The Public Staff did not address this recommendation. On April 11, 2000, the Commission issued its Order Requiring Lifeline/Link-Up Participation Reports and Requesting Specific Recommendations From the Task Force in Docket No. P-100, Sub 133f.

In the Order, the Commission required the local service providers to file semi-annual reports, every June 30th and December 31st, setting out the numbers of their Lifeline and Link Up customers. Both AT&T and CenturyLink noted in their comments that state level enrollment data is or will be available by December 1, 2016 from the USAC website. Based upon the comments of the parties, the Commission is persuaded that it is appropriate to eliminate the semi-annual Lifeline/Link Up reporting requirement at this time.

Finally, the Public Staff recommended in its comments that the Commission disband the Lifeline/Link Up Task Force. Neither AT&T nor CenturyLink commented on the Public Staff's recommendation in this regard. The Public Staff noted that the Lifeline/Link Up Task Force was formed to provide periodic reports, make various recommendations to the Commission regarding the Lifeline and Link Up programs, and provide outreach efforts for informing consumers of the availability of the Lifeline and Link Up programs. The Public Staff further noted that no new requests have been submitted to the Task Force since October 2013 and that the Public Staff is unaware of the Task Force having met since May 2013. The Public Staff maintained that it does not believe the Task Force will be needed for the foreseeable future. Based upon the comments filed, the Commission is persuaded that it is appropriate to disband the Lifeline/Link Up Task Force at this time.

IT IS, THEREFORE, ORDERED as follows:

1. That Commission Rule R9-6 is revised as outlined in Appendix A herein, effective December 1, 2016;

2. That the ILECs shall be required to modify their local exchange tariffs concerning Lifeline and Link Up program availability as outlined in Appendix B herein. The effective date for such tariff changes is December 1, 2016;

3. That the Lifeline/Link Up semi-annual reports required by the Commission's April 11, 2000, Order issued in Docket No. P-100, Sub 133f are hereby eliminated; and

4. That the Lifeline/Link Up Task Force is hereby disbanded.

ISSUED BY ORDER OF THE COMMISSION.
This the __27th__ day of October, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

Revised Commission Rule R9-6
Effective December 1, 2016

Rule R9-6. Lifeline and Tribal Link Up Programs

(a) Description of programs.

(1) Lifeline service is a federally administered program providing a monthly discount to qualifying low-income consumers for voice telephone service or broadband service.

(2) Tribal Link Up service is a federally administered program providing a discount to the customary charge for commencing telecommunications service to a qualifying consumer on Tribal lands.

(b) Obligations of local exchange companies.
All local exchange companies designated as eligible telecommunications companies (ETCs) by the Utilities Commission in this State pursuant to Section 254(e) of the Telecommunications Act of 1996 shall provide Lifeline and Link Up services on such terms as are set out in subsection (c), (d), and (e), and in the Orders of the Utilities Commission. All local exchange companies designated as ETCs shall submit such information to the Utilities Commission, the Federal Communications Commission (FCC), and the Universal Service Administrative Company (USAC) as is necessary to fully implement the Lifeline and Link Up programs.

(c) Program eligibility.
In order to be eligible for assistance, a consumer must meet the eligibility requirements as set forth in 47 C.F.R. part 54, subpart E of the FCC's rules.

(d) Verification of eligibility.
The method for verification of the eligibility criteria set forth in (c) above shall be a national eligibility verifier. Until the national eligibility verifier has been established to verify eligibility in North Carolina, the verification method will be self-certification by the recipients of the eligible programs.

(e) Support.
The support provided to consumers through the Lifeline and Link Up programs is set forth in 47 C.F.R. part 54, subpart E of the FCC's rules.

APPENDIX B

Tariff Language to Reflect Lifeline and Link Up Programs Effective December 1, 2016

Lifeline and Tribal Link Up Programs

(a) Description of programs.

(1) Lifeline service is a federally administered program providing a monthly discount to qualifying low-income consumers for voice telephone service or broadband service.

(2) Tribal Link Up service is a federally administered program providing a discount to the customary charge for commencing telecommunications service to a qualifying consumer on Tribal lands.

(b) Program eligibility.
In order to be eligible for assistance, a consumer must meet the eligibility requirements as set forth in Commission Rule R9-6 and 47 C.F.R. part 54, subpart E of the Federal Communications Commission's rules.

(c) Verification of eligibility.
The method for verification of the eligibility criteria set forth in (b) above shall be a national eligibility verifier. Until the national eligibility verifier has been established to verify eligibility in North Carolina, the verification method will be self-certification by the recipients of the eligible programs.

(d) Support.
The monthly recurring and one-time connection discount provided to consumers through the Lifeline and Link Up programs is set forth in 47 C.F.R. part 54, subpart E of the Federal Communications Commission's rules.

DOCKET NO. P-100, SUB 133f

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Lifeline and Link Up Services Pursuant to Section	)	ORDER REVISING EFFECTIVE
254 of the Telecommunications Act of 1996	)	DATE TO DECEMBER 2, 2016

BY THE COMMISSION: On October 27, 2016, the Commission issued its Order Revising Commission Rule R9-6, Effective December 1, 2016, Requiring Updated Tariffs, Eliminating Lifeline/Link Up Reporting Requirements, and Disbanding the Lifeline/Link Up Task Force in this docket.

Initial comments were filed by the parties in this docket on September 30, 2016, and no party filed reply comments on October 14, 2016. BellSouth Telecommunications, LLC d/b/a AT&T North Carolina (AT&T) did note in its initial comments filed on September 30, 2016 that, "[t]he effective date for the streamlined federal eligibility criteria is set for the later of December 1, 2016 or 60 days following the federal Office of Management & Budget's (OMB's) approval of the [2016] Lifeline Modernization Order."

On October 3, 2016, the Federal Communications Commission (FCC) released a Public Notice (DA 16-1133) announcing the effective dates following approval by the OMB of Lifeline rules in the FCC's 2016 Lifeline Modernization Order. The FCC noted that on September 20, 2016, the FCC received OMB approval of modified information collection requirements under the Paperwork Reduction Act of 1995. The FCC stated that the announcement of OMB approval of the rules was published in the Federal Register on October 3, 2016. Therefore, the FCC proclaimed that the FCC rules implicated in the Commission's October 27, 2016 Order will become effective on December 2, 2016.

Based on this information, the Commission finds it appropriate to revise the effective date of Commission Rule R9-6 and the required tariff revisions as outlined in the Commission's October 27, 2016 Order to December 2, 2016.

IT IS, THEREFORE, ORDERED as follows:

1. That Commission Rule R9-6 is revised as outlined in Appendix A of the Commission's October 27, 2016 Order, effective December 2, 2016; and

2. That the incumbent local exchange companies shall be required to modify their local exchange tariffs concerning Lifeline and Link Up program availability as outlined in Appendix B of the Commission's October 27, 2016 Order, with an effective date for such tariff changes of December 2, 2016.

ISSUED BY ORDER OF THE COMMISSION.
This the ___9th___ day of November, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. P-100, SUB 170

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Tariff Filings Made by Local Exchange	)	
Carriers in Compliance with the Federal	)	ORDER GRANTING THE
Communications Commission's Connect	)	PUBLIC STAFF'S MOTION
America Fund Order	)	

BY THE COMMISSION: On May 19, 2016, the Public Staff filed a Motion for Order Requiring Filing of Information Regarding July 1, 2016, Access Rate Changes.

In its Motion, the Public Staff requested that the Commission issue an order requiring filings from certain carriers showing their compliance with the fourth set of intrastate access rate changes mandated by the Federal Communications Commission's November 18, 2011, Universal Service Fund (USF)/ Intercarrier Compensation (ICC) Transformation Order as soon as practicable, but no later than June 10, 2016.

The Public Staff further noted that it has reviewed last year's responses and compiled a list of carriers as reflected in Appendix A to its Motion that the Public Staff believes should make an appropriate filing regarding their 2016 switched access rate changes. The Public Staff stated that, additionally, any carrier that is not listed in Appendix A, but whose status has changed from last year should also be required to make an appropriate filing.

On May 19, 2016, the Commission issued an Order Requesting Comments on the Public Staff's Motion. No party filed initial comments on the Public Staff's Motion.

Based on the record, the Commission finds it appropriate to grant the Public Staff's Motion. Therefore, impacted carriers must make the required filings as soon as practicable, but no later than Friday, June 10, 2016.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _1st_ day of June, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-22, SUB 534

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

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

HEARD: Monday, November 7, 2016, beginning at 1:30 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

For Dominion North Carolina Power:

Mary Lynne Grigg, McGuireWoods LLP, 2600 Two Hanover Square, Raleigh, North Carolina 27601

For the Carolina Industrial Group for Fair Utility Rates I (CIGFUR I)

Adam Olls, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For the Using and Consuming Public:

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

BY THE COMMISSION: On August 5, 2016, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or Company), filed its application for a fuel charge adjustment, along with accompanying testimony and exhibits, pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities (application).[1] The application was accompanied by the testimony and exhibits of Edward J. Anderson, Regulatory Advisor; Ronnie T. Campbell, Supervisor of Accounting for Dominion Generation; Bruce E. Petrie, Manager of Generation System Planning; Tom A. Brookmire,

[1] Pursuant to G.S. 62-133.2(a3), DNCP is not eligible to recover non-fuel (but still fuel-related) costs through the annual rate adjustments authorized pursuant to G.S. 62-133.2, except for certain costs authorized by G.S. 62-133.2(a1)(6), which DNCP did not incur during the test period and is not projected to incur during the rate period. Therefore, throughout this Order, the costs being considered for recovery shall be termed "fuel costs," and the proceeding shall be termed the "fuel charge proceeding."

Manager of Nuclear Fuel Procurement; Gregory A. Workman, Director - Fuels; and Michael S. Hupp, Jr., Director of Power Generation Regulated Operations for Dominion Generation.

On August 16, 2016, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice.

Petitions to intervene were filed by Nucor Steel-Hertford (Nucor) on August 24, 2016, and the Carolina Industrial Group for Fair Utility Rates I (CIGFUR) on August 25, 2016. These petitions were granted by Orders dated August 29, 2016, and September 21, 2016, respectively. The Public Staff's participation and intervention was recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On October 3, 2016, in Docket Nos. E-22, Subs 532 and 534, DNCP filed a Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund, pursuant to G.S. 62-135. In summary, DNCP gave notice of its intent to implement its proposed new base rates and Rider A1-Fuel Cost Decrement Rider (Rider A1), to be effective on November 1, 2016, pending approval of permanent base rates and fuel rates by the Commission.

The Company filed its Affidavit of Publication on October 11, 2016.

On October 12, 2016, the Commission issued an Order Approving Financial Undertaking and an Order Approving Public Notice of Temporary Rates in response to DNCP's Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund.

On October 24, 2016, the Public Staff filed the testimony of Dustin R. Metz, Engineer, Public Staff Electric Division, and the affidavits of Jay B. Lucas, Engineer, Public Staff Electric Division, and Sonja R. Johnson, Staff Accountant, Electric Section, Public Staff Accounting Division.

On October 31, 2016, DNCP and the Public Staff filed a joint motion requesting that the Commission issue an order excusing the appearance of all witnesses at the hearing. The Commission granted the motion by Order dated November 3, 2016.

The matter came on for evidentiary hearing on November 7, 2016, as scheduled. No public witnesses appeared at the hearing. The parties waived cross-examination of all witnesses, and all of their testimony was received into evidence as if given orally from the stand.

Based upon the verified application, the evidence received at the hearing, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. DNCP is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric

power to the public in northeastern North Carolina. DNCP is lawfully before this Commission based on its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the twelve months ended June 30, 2016.

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

4. The per books test period system sales are 80,716,692,000 kilowatt-hours (kWh).

5. The per books test period system generation is 81,751,738 megawatt-hours (MWh), which includes various types of generation as follows:

Generation Types	MWh
Nuclear	27,012,030
Coal	23,160,114
Heavy Oil	333,329
Wood and Natural Gas Steam	1,569,592
Combined Cycle and Combustion Turbine	22,983,898
Solar and Hydro	3,639,498
Net Power Transactions	5,736,921
Less: Energy for Pumping	(2,683,643)

6. The Public Staff completed its review of test year plant performance except for the following outages: 1) Surry Unit 1, July 11-22, 2015; 2) Surry Unit 1, October 13 - November 18, 2015; 3) Surry Unit 2, July 13-22, 2015; and Surry Unit 2, December 4-11, 2015. Should any adjustment be appropriate due to these outages, such adjustments will be made in the experience modification factor (EMF) in the 2017 fuel adjustment proceeding.

7. Other than the outages still under review referenced above, the Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel costs.

8. The nuclear capacity factor appropriate for use in this proceeding is 94.7%, which is the estimated nuclear capacity factor for the 12 months beginning January 1, 2017.

9. The adjusted test period system sales for use in this proceeding are 82,170,519,314 kWh.

10. The adjusted test period system generation for use in this proceeding is 83,272,843 MWh, which is categorized as follows:

Generation Types	MWh
Nuclear	27,763,412
Coal, including wood and natural gas steam	25,063,397
Heavy Oil	337,803
Combined Cycle and Combustion Turbine	23,294,052
Solar and Hydro - Conventional and Pumped Storage	3,636,995
Net Power Transactions	5,860,827
Less: Energy for Pumping	(2,683,643)

11. A marketer percentage serves as a proxy for fuel costs when actual fuel costs associated with power purchases are not available. A marketer percentage of 78% should be applied in this proceeding to appropriately determine the fuel cost of such power purchases.

12. The adjusted test period system fuel expense for use in this proceeding is $1,700,820,000. The reasonable and appropriate prospective system base fuel factor, as approved in Docket No. E-22, Sub 532 (Sub 532), is 2.073 cents per kWh (including the regulatory fee), and the reasonable and appropriate prospective North Carolina retail class-specific base fuel factors, as also approved in Sub 532 and including the regulatory fee, are as follows:

Customer Class	Class-Specific Prospective Factor
Residential	2.095 ¢/kWh
SGS & PA	2.093 ¢/kWh
LGS	2.079 ¢/kWh
Schedule NS	2.014 ¢/kWh
6VP	2.043 ¢/kWh
Outdoor Lighting	2.095 ¢/kWh
Traffic	2.095 ¢/kWh

13. DNCP filed this fuel charge adjustment application in conjunction with its general rate case filed on March 31, 2016, in Sub 532. All prospective components of fuel costs will be included in the base fuel rates that take effect on January 1, 2017. Therefore, DNCP will not have a Rider A in this proceeding.

14. The appropriate North Carolina retail test period jurisdictional fuel expense over collection is $19,992,805, including interest, and the adjusted North Carolina retail jurisdictional test period sales are 4,283,978,006 kWh.

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

Customer Class	EMF Billing Factor
Residential	(0.473) ¢/kWh
SGS & PA	(0.472) ¢/kWh
LGS	(0.469) ¢/kWh
NS	(0.454) ¢/kWh
6VP	(0.461) ¢/kWh

Outdoor Lighting	(0.473) ¢/kWh
Traffic	(0.473) ¢/kWh

16. In Docket No. E-22, Sub 515 (Sub 515), the Commission approved the Company's proposed Rider B2, which mitigated the rate impact of the high fuel costs that occurred during extremely cold weather in January through March 2014 by allowing the costs to be collected in the EMF for the 2015 and 2016 fuel years, without interest. The two-year term of Rider B2 expires at the end of 2016, therefore, the proposed fuel charges that will become effective on January 1, 2017, will not have a Rider B2.

17. The class-specific base fuel components approved in Sub 532 should be adjusted by EMF Rider B decrements for each class as set forth in Finding of Fact No. 15. The final net fuel factors to be billed to DNCP's retail customers during the 2017 fuel charge billing period, including the regulatory fee, are as follows:

Customer Class	Total Net Fuel Factor
Residential	1.622 ¢/kWh
SGS & PA	1.621 ¢/kWh
LGS	1.610 ¢/kWh
Schedule NS	1.560 ¢/kWh
6VP	1.582 ¢/kWh
Outdoor Lighting	1.622 ¢/kWh
Traffic	1.622 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending June 30 as the test period for DNCP. The Company's filing was based on the 12 months ended June 30, 2016.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every ten years and each time the utility's fuel procurement practices change. The Company's current fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, on December 20, 2013.

In his direct testimony, Company witness Workman discussed the Company's fossil fuel procurement practices, including any recent changes to those practices. He explained that commodity markets (natural gas, coal, and crude oil) continue to remain oversupplied and prices have overall remained depressed, with a slight rebound in the spring of 2016. Witness Workman described the Company's fossil fuel procurement practices and explained that the Company continues to follow the same procurement practices it has in the past in accordance with its report filed in Docket No. E-100,Sub 47A.

In regard to natural gas procurement, witness Workman explained that the Company uses a disciplined natural gas procurement plan to ensure a reliable supply of natural gas at competitive prices. He stated that the Company procures natural gas through periodic solicitations and the open market, with day-ahead, monthly, seasonal, and multiyear physical gas supply purchases. Witness Workman also described how the Company uses its portfolio of pipeline transportation and storage contracts, which provide access to multiple natural gas supply points. He also noted the Company's participation in the interstate pipeline capacity release and physical supply markets, as well as pipeline expansion. Witness Workman testified that since DNCP's 2015 fuel charge adjustment proceeding, the natural gas-fired Brunswick County Power Station became operational, adding 1,358 MW of capacity to the Company's generation fleet. Witness Workman also described how the Company price-hedges natural gas using a range of volume targets, which gradually decrease over a three-year period. He noted that the volume of on-peak power hedges have gradually decreased and the Company expects that the volumes will continue to be *de minimis*.

Witness Workman also discussed the Company's coal procurement, which is accomplished primarily through periodic solicitations and secondarily on the open market for short-term or spot needs. This practice allows a layering-in of contracts with staggered terms and blended prices, to ensure a reliable supply of coal and to limit exposure to potential dramatic market price swings and supplier non-performance.

In regard to biomass, witness Workman explained that the Company currently procures the majority of its wood chips and other woody material for its biomass plants via long-term contracts with two suppliers, with the balance supplied through short-term contracts or spot purchases. He noted that the Company purchases its No. 2 fuel oil and No. 6 fuel oil requirements on the spot market and optimizes its inventory, storage, and transportation to ensure reliable supply to its power generating facilities and to mitigate price volatility.

Company witness Brookmire testified that the nuclear fuel market has softened considerably in the past five years, largely due to the earthquake and tsunami in Japan in March 2011. He also noted reductions in demand due to plant closures in Germany and the United States, as well as some reductions in supply, which may have offset some of the downward trend in demand. Witness Brookmire indicated that the spot market price for conversion services has dropped significantly, though long-term prices have remained high. He also noted that the cost for enrichment services appears to have stabilized. Witness Brookmire explained that the general consensus is that fabrication costs will continue to increase. He also pointed out that there may be some short-term price lift on front-end components due to the restart of reactors in Japan and the growth of China's nuclear energy program.

Company witness Brookmire stated that while these changes in market costs have had some impact on the Company's projected near-term costs, the Company's mix of longer-term front-end component contracts has reduced its exposure to the market price escalation and volatility. Witness Brookmire also pointed out that the 18-month refueling schedule for the Company's nuclear plants delays the full effect of any significant changes in a component price. Further, he noted that the Company has some market-based contracts that allow it to take advantage of current lower prices. Witness Brookmire also noted that the Company continues to follow the same nuclear fuel procurement practices as it has in the past, in accordance with its procedures filed in Docket No. E-100, Sub 47A.

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 – 5

The evidence for these findings of fact is contained in the direct testimony and exhibits of DNCP witnesses Anderson and Petrie and the affidavits and exhibits of Public Staff witnesses Johnson and Lucas.

DNCP witness Anderson testified that the Company's per books test period system sales were 80,716,692,000 kWh, and witness Petrie testified that the Company's per books test period system generation was 81,751,738 MWh. Witness Petrie stated that the per books test period system generation is categorized as follows:

Generation Types	MWh
Nuclear	27,012,030
Coal	23,160,114
Heavy Oil	333,329
Wood and Natural Gas Steam	1,569,592
Combined Cycle and Combustion Turbine	22,983,898
Solar and Hydro – Conventional and Pumped	3,639,498
Net Power Transactions	5,736,921
Less Energy for Pumping	(2,683,643)

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence for these findings of fact is contained in the testimony of Company witnesses Petrie and Workman and Public Staff witness Metz.

For purposes of determining the EMF rider, Commission Rule R8-55(k) requires that a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent Generating Availability Report of the North American Electric Reliability Corporation (NERC), appropriately weighted for size and type of plant, or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent five year period available as reflected in the most recent NERC Generating Availability Report, appropriately weighted for size and type of plant. If a utility does not meet either standard, a rebuttable presumption is created that the increased cost of fuel was incurred imprudently and a disallowance may be appropriate. Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events.

Company witness Petrie testified that the Company's four nuclear units operated at a system average capacity factor of 91.8% during the test period, which exceeded the five-year industry weighted average capacity factor of 87.8% for the period 2009-2013 for 800 to 999 megawatt (MW) units, as reported by NERC in its latest Generating Availability Report. He noted that the Company's nuclear units test year performance of 91.8% was better than the Nuclear Energy Institute average for comparable units for the last five years of 90.7%.

Public Staff witness Metz testified that the Company met both of the standards set out in Rule R8-55(k). He calculated an actual system-wide capacity factor for the test year of 92.16% at 100% of unit output for North Anna, and a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year of 93.04%, based upon the Company's percentage ownership of North Anna. Witness Metz referenced a 2010-2014 NERC report, which provided a weighted average capacity factor of 87.22%.

Witness Metz noted that that the Company calculated a billing period aggregate capacity factor of 91.8%, as opposed to the 92.16% capacity factor he calculated. The difference in calculations is due to witness Metz's use of a weighted average that allocates the actual contribution of each individual unit to the total system generation, with the North Anna units at 100% of unit output. However, as the Public Staff does not contest the Company's contention that it has met the standard set by R8-55(k)(a) using either the Public Staff's or the Company's calculation of the system-wide capacity factor or the NERC average net capacity factor, it accepted the Company's filed system-wide capacity factor for purposes of the proceeding. The Public Staff and DNCP have agreed to discuss the use of a weighted average capacity factor in future fuel clause adjustment cases.

Witness Metz also testified that the Public Staff has completed its review of test year plant performance except for the following outages: 1) Surry Unit 1, July 11-22, 2015; 2) Surry Unit 1, October 13 - November 18, 2015; 3) Surry Unit 2, July 13-22, 2015; and Surry Unit 2, December 4-11, 2015. The Public Staff and the Company are still exchanging information and discussing these outages and have agreed that any resulting recommendations will be made in the 2017 fuel adjustment proceeding. Therefore, the Public Staff did not recommend any adjustment related to plant performance in this proceeding.

Based upon the evidence in the record, the Commission concludes, subject to further consideration of the outages still under review by the Public Staff, DNCP managed its baseload plants prudently and efficiently so as to minimize fuel costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

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

Company witness Petrie testified in his direct testimony that for the 12 months ending December 31, 2017, North Anna Unit 1 is projected to operate at a net capacity factor of 90.7%, North Anna Unit 2 is projected to operate at a net capacity factor of 99.7%, Surry Unit 1 is projected to operate at a net capacity factor of 94.0%, and Surry Unit 2 is projected to operate a net capacity factor of 94.3%. For the nuclear fleet, the projected nuclear generation during the upcoming rate year is expected to be slightly higher than the actual generation during the test period. Based on this projection, the Company has normalized expected nuclear generation and fuel expenses in developing the proposed fuel cost rider. DNCP's projected fuel costs are based on a 94.7% nuclear capacity factor, which is what DNCP anticipates for the twelve months from January 1, 2017, through December 31, 2017, the period the new rates will be in effect.

No party presented any testimony contesting DNCP's use of a 94.7% nuclear capacity factor to normalize estimated rate year fuel expenses. Based on the foregoing evidence, the Commission concludes that a projected normalized system nuclear capacity factor of 94.7% is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is contained in the direct testimony of DNCP witness Anderson and the affidavit of Public Staff witness Lucas.

Witness Anderson testified that he was sponsoring the calculation of the adjustment to the Company's system sales for the twelve months ended June 30, 2016, due to changes in usage, weather normalization, and customer growth, in accordance with Commission Rule R8-55(d)(2). The Company's filing further states that the methodology used for the normalization is the same as adopted by the Commission in Docket No. E-22, Sub 479, and as filed in Sub 532. Witness Anderson adjusted total Company sales by 1,453,827,314 kWh. This adjustment is the sum of adjustments for changes in usage, weather normalization, and customer growth. The Public Staff reviewed and accepted these adjustments. No other party offered or elicited testimony on these adjustments.

Based on the foregoing, the Commission concludes that the adjustments for changes in usage, weather normalization, and customer growth are reasonable and appropriate adjustments for use in this proceeding. The adjusted system sales for the twelve months ended June 30, 2016, are 82,170,519,314 kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

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

DNCP witness Petrie presented an adjustment to per book MWh generation for the 12-month period ended June 30, 2016, to incorporate nuclear generation based upon the expected future operating parameters for each unit. Other sources of generation were then normalized, including an adjustment for weather, customer growth, and increased usage. This methodology for normalizing test period generation resulted in an adjusted generation level of 83,272,843 MWh. The Public Staff accepted this adjusted generation level, which includes various types of generation as follows:

Generation Types	MWh
Nuclear	27,763,412
Coal (including wood and natural gas steam)	25,063,397
Heavy Oil	337,803
Combined Cycle and Combustion Turbine	23,294,052
Hydro – Conventional and Pumped Storage	3,636,995
Net Power Transactions	5,860,827
Less Energy for Pumping	(2,683,643)

No other party offered or elicited testimony on the adjusted test period system generation for use in this proceeding. Thus, based on the foregoing, the Commission concludes that the adjusted test period system generation level of 83,272,843 MWh is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact is contained in the direct testimony of DNCP witnesses Campbell and Hupp and the affidavit of Public Staff witness Johnson.

Company witness Campbell explained that for dispatchable non-utility generators (NUGs) that do not provide actual fuel costs, the Company included as fuel cost 85% of the reasonable and prudent energy costs in the EMF calculation (Doswell Complex and Hopewell Cogeneration). Additionally, to the extent a dispatchable NUG provides market-based energy rather than dispatching its facility, the Company included 85% of those reasonable and prudent energy costs in the EMF calculation. He noted that use of the 85% "marketer's percentage" was agreed to between the Company and the Public Staff and approved by the Commission in the Company's 2012 fuel factor proceeding, Docket No. E-22, Sub 485. Company witness Hupp testified regarding the Company's request in this proceeding and in Sub 532 for the approval of a Marketer Percentage of 100%.

Public Staff witness Johnson testified that the Company proposes to recover through the fuel clause all purchased power energy costs subject to economic dispatch, all energy-related (i.e., non-capacity) costs of the dispatchable NUGs that do not provide actual fuel costs, and congestion related costs and Financial Transaction Rights (FTR) revenues, including congestion costs and FTR revenues related to Company-owned generation, as well as total prudently incurred power purchase costs, inclusive of congestion costs. Because a general rate case is pending, she explained that the Company proposes to implement the change in the Marketer Percentage through the base fuel component set in Sub 532 and any applicable incremental or decremental Rider A and Rider B components set in the annual fuel proceedings going forward.

Witness Johnson noted that in Sub 532, the Public Staff and DNCP entered into and filed, on October 3, 2016, an Agreement and Stipulation of Settlement (Stipulation). Paragraph IV A. of the Stipulation resolved the issue of the Marketer Percentage through an agreement to adjust the Company's base fuel and non-fuel expenses to reflect 78% as the Marketer Percentage to remain in effect until the Company's next base rate application (general rate case) or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first. The 78% Marketer Percentage was recommended by Public Staff witness Darlene Peedin in Sub 532 based on data from the 2014 and 2015 State of the Market reports for PJM Interconnection, LLC, and Company data that blended DNCP's internal data with the PJM State of the Market report data for the Dominion Zone.

Based upon the foregoing, the Commission concludes that it is reasonable to apply a 78% fuel-to-energy percentage to DNCP's purchases from suppliers that do not provide the Company with actual fuel costs as the proxy for actual fuel costs associated with such purchases in this proceeding, and that the percentage should be reviewed in the context of DNCP's next general rate case or its 2018 fuel charge adjustment proceeding, whichever occurs first.

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

The evidence for these findings of fact is contained in the direct testimony of Company witnesses Petrie and Anderson, and the affidavit of Public Staff witness Lucas.

Company witness Petrie presented the Company's system fuel expense for the test period and the initially proposed normalized system fuel expense projected for the calendar year 2017 rate period of $1,735,922,773. He testified that he normalized fuel expenses using a methodology approved in previous North Carolina fuel charge adjustment proceedings. More specifically, the expense rates for nuclear, coal, oil, and NUGs were based on the actual 12-month average expense rates incurred during the test period. The expense rate for natural gas was adjusted upward to reflect a forward view of commodity prices, and the NUG expense was also adjusted upward to account for DNCP's proposed increase in the Marketer Percentage and retirements of two contracts. An additional adjustment was made to account for the benefits of a full year of the operation of the Brunswick plant.

Public Staff witness Lucas testified that DNCP filed this fuel proceeding in conjunction with its Sub 532 general rate case. Company witness Anderson testified that in Sub 532, the Company updated the base fuel component for each class to be equal to the system fuel expense rate, adjusted for respective losses, calculated in this case. Therefore, he testified that the Company requests that Fuel Cost Rider A in this case will be set to $0.00000/kWh for all classes.

Public Staff witness Lucas testified that on September 7, 2016, the Public Staff filed the testimony of its witness Darlene Peedin in Sub 532, which included a recommended marketer percentage of 78% to account for the fuel component of purchased power, which was agreed to in the Stipulation. Concurrent with the Stipulation, the Public Staff filed the settlement testimony and exhibits of its witness, Katherine Fernald. Fernald Exhibit 1, Schedule 3-1(t)(1) shows

DNCP's stipulated pro forma total system fuel expense ($1,700,820,000) and system base fuel factor ($0.02070 per kWh, excluding the regulatory fee adjustment factor of 1.0014, and $0.02073 per kWh, including the regulatory fee adjustment factor), based on the stipulated 78% marketer percentage and adjusted test period system sales of 82,170,519 MWh (the same level of system energy sales found appropriate and reasonable for this proceeding in the Evidence and Conclusions for Finding of Fact No. 9).

Public Staff witness Lucas also testified that to account for line losses, DNCP and the Public Staff agree that energy sales must be scaled up to determine the energy generation required to serve customers at the retail level. This increase in energy requirement results in the following customer class-specific North Carolina retail prospective base fuel factors (including the regulatory fee), as set forth on Lucas Exhibit No. 1, Column (7):

Customer Class	Class-Specific Prospective Base Fuel Factor
Residential	2.095 ¢/kWh
SGS & PA	2.093 ¢/kWh
LGS	2.079 ¢/kWh
Schedule NS	2.014 ¢/kWh
6VP	2.043 ¢/kWh
Outdoor Lighting	2.095 ¢/kWh
Traffic	2.095 ¢/kWh

No other party offered or elicited testimony on the adjusted test period system fuel expense for use in this proceeding. In its Order in Sub 532, the Commission approved the marketer percentage, the system base fuel factor, and the North Carolina retail class-specific base fuel factors. Based upon that approval and the evidence presented in this proceeding, the Commission concludes that the appropriate level of fuel expenses to be used to set the prospective, or forward-looking, fuel factor in this proceeding is $1,700,820,000, the appropriate prospective system average base fuel factor (including regulatory fee) is $0.02073 per kWh, and the appropriate class-specific prospective base fuel factors (including regulatory fee) are as set forth on Lucas Exhibit No. 1, Column (7). The Commission further concludes that because the class-specific factors have been incorporated in the base rates approved in Sub 532, Fuel Cost Rider A should be set to $0.00000/kWh for all classes.

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

The evidence supporting these findings of fact is contained in the direct testimony and exhibits of DNCP witnesses Anderson, Campbell, and Petrie and the affidavits of Public Staff witnesses Lucas and Johnson.

Company witness Petrie testified that mild weather, lower commodity prices, and the addition of new and efficient natural gas generation during the test year resulted in an over-recovery of fuel costs. Company witness Campbell testified that the fuel costs allocated to North Carolina jurisdictional customers totaled $84,657,705, while the Company received fuel revenues totaling $102,042,753 during the test year. The difference between the fuel costs and the fuel revenues resulted in an over-recovery of $17,385,048 for the test period. Company witness Anderson testified that this total over recovered fuel expense was adjusted by $1,757,999 to account for interest, for a total net balance of $19,143,047. To determine the EMF (Rider B), Company witness Anderson divided this net balance by the adjusted jurisdictional test period sales of 4,283,978,006 kWh. He then used customer class expansion factors to differentiate the uniform factor by voltage to determine the North Carolina retail jurisdictional voltage differentiated EMF fuel factors at the sales level applicable to each customer class.

Public Staff witness Johnson testified that the Public Staff had reviewed the calculations of the EMF provided by the Company and set forth in the direct testimony and exhibits of Company witnesses Anderson and Campbell. She stated that other than the recommendation discussed below regarding the calculation of interest on the over recovery, the Public Staff has not found any other items in the EMF calculation requiring adjustment in this proceeding.

With regard to the interest calculation, witness Johnson testified that the Company did not calculate interest on the over-recovery in accordance with the Commission's Order in Docket No. E-100, Sub 55, which provides that interest should be calculated from the midpoint of the test period to the midpoint of the EMF refund period. She explained that under the methodology used in that Order, the Public Staff calculated total interest in the amount of $2,607,757, resulting in a net total fuel expense over-recovery amount of $19,992,805 as set forth in Johnson Exhibit 1, Schedule 1. Witness Johnson indicated that the Company had agreed with the Public Staff's calculation of interest. Johnson Exhibit 1, Schedule 2 sets forth the jurisdictional voltage differentiated EMF rate by class (Rider B) that is summarized in Lucas Exhibit 2.

Based upon the evidence, the Commission concludes that the appropriate North Carolina retail test period jurisdictional fuel expense over collection is $19,992,805 (including interest) and that the adjusted North Carolina jurisdictional test period sales appropriate for computing the EMF (Rider B) are 4,283,978,006 kWh.

Company witness Anderson and Public Staff witness Lucas testified regarding Rider B2 approved in Docket No. E-22, Sub 515, to mitigate the rate impact of the high fuel costs that occurred during extremely cold weather in January through March 2014 by allowing the costs to be collected in the EMF for the 2015 and 2016 fuel years, without interest. Company witness Anderson indicated that the Company was requesting that the B2 rates be set to $0.00000/kWh for all classes for purposes of this case and for the 2017 fuel year. The Commission concludes that Rider B2 should be set to $0.00000/kWh for all classes for purposes of this case and for the 2017 fuel year.

The Commission also concludes that the appropriate class-specific EMFs (Rider B) for this proceeding, including interest and the regulatory fee, are as follows:

Customer Class	EMF Billing Factor
Residential	(0.473) ¢/kWh
SGS & PA	(0.472) ¢/kWh
LGS	(0.469) ¢/kWh
Schedule NS	(0.454) ¢/kWh
6VP	(0.461) ¢/kWh
Outdoor Lighting	(0.473) ¢/kWh
Traffic	(0.473) ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is cumulative and is contained in the direct testimony and exhibits of DNCP witnesses Anderson, Petrie, Campbell, Brookmire, Workman, and Hupp, the testimony of Public Staff witness Metz, and the affidavits of Public Staff witnesses Lucas and Johnson.

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

Customer Class	Total Net Fuel Factor
Residential	1.622 ¢/kWh
SGS & PA	1.621 ¢/kWh
LGS	1.610 ¢/kWh
Schedule NS	1.560 ¢/kWh
6VP	1.582 ¢/kWh
Outdoor Lighting	1.622 ¢/kWh
Traffic	1.622 ¢/kWh

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after January 1, 2017, DNCP shall implement a Fuel Cost Rider A of $0.00000/kWh for all classes as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 12 and 13 above;

2. That EMF Rider decrements (Rider B) as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 14 -16 above, shall be instituted and remain in effect for usage from January 1, 2017, through December 31, 2017;

3. That DNCP shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein as soon as practicable; and

4. That DNCP shall work with the Public Staff to prepare a joint proposed Notice to Customers of the rate adjustments ordered by the Commission in Docket Nos. E-22, Subs 532, 534, 535, and 536, and the Company shall file such proposed notice for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of December, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. E-2, SUB 1107

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

HEARD: Tuesday, September 20, 2016, at 9:30 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioner Bryan E. Beatty, Commissioner ToNola D. Brown-Bland, Commissioner Don M. Bailey, Commissioner Jerry C. Dockham, Commissioner James G. Patterson and Commissioner Lyons Gray

APPEARANCES:

For Duke Energy Progress, LLC:

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

and

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolinas Industrial Group for Fair Utility Rates III:

Adam Olls, Bailey & Dixon, L.L.P., 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Peter H. Ledford, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff, North Carolina Utilities Commission, 430 N. Salisbury Street, 4326 MSC, Raleigh, North Carolina 27699-4300

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

BY THE COMMISSION: On June 22, 2016, Duke Energy Progress, LLC (Duke Energy Progress, DEP, or the Company), filed an application pursuant to G.S. 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Kimberly D. McGee, Swati V. Daji, Joseph A. Miller, Jr., T. Preston Gillespie, Jr., and Kenneth D. Church.

Petitions to intervene were filed by the North Carolina Sustainable Energy Association (NCSEA) on June 28, 2016, by Carolina Industrial Group for Fair Utility Rates III (CIGFUR) on June 29, 2016, and by Carolina Utility Customers Association, Inc. (CUCA) on July 14, 2016. The Commission granted CIGFUR's petition to intervene on June 30, 2016, NCSEA's petition to intervene on July 1, 2016, and CUCA's petition to intervene on July 19, 2016. The North Carolina Attorney General's Office filed its notice of intervention on June 27, 2016.

On July 6, 2016, the Commission entered an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that direct testimony of intervenors should be filed on September 2, 2016, that rebuttal testimony should be filed on September 14, 2016, and that a hearing on this matter would be held on September 20, 2016.

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

On September 15, 2016, DEP filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural Order.

On September 1, 2016, DEP filed the supplemental testimony and revised exhibits and workpapers of Kimberly D. McGee, as well as the supplemental testimony of T. Preston Gillespie, Jr.

On September 2, 2016, the Public Staff filed the testimony and exhibit of Darlene P. Peedin and the testimony of Dustin R. Metz.

On September 6, 2016, DEP and the Public Staff filed a joint motion requesting that all witnesses be excused from appearance at the evidentiary hearing. On September 8, 2016, DEP and the Public Staff filed a revised version of the joint motion. On September 12, 2016, the Commission granted the motion, excusing DEP witnesses McGee, Daji, Miller, Gillespie, and Church, and Public Staff witnesses Peedin and Metz from appearing at the evidentiary hearing.

The case came on for hearing as scheduled on September 20, 2016. The prefiled direct and supplemental testimony of DEP's witnesses and the prefiled testimony and exhibits of the Public Staff's witnesses were received into evidence. No other party presented witnesses, and no public witnesses appeared at the hearing.

The Public Staff and DEP filed a joint proposed order on October 18, 2016 and NCSEA filed a post-hearing brief on October 20, 2016.

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

FINDINGS OF FACT

1. Duke Energy Progress is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Progress is lawfully before 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 months ended March 31, 2016 (test period).

3. In its application and direct testimony in this proceeding, DEP requested a total decrease of approximately $235 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEP included Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost under-recoveries and over-recoveries experienced during the test period, with an overall over-recovery of approximately $70 million.

4. The Company's baseload plants were generally managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs. However, it is appropriate to disallow certain replacement power costs associated with an outage in March and April 2015 at Unit 2 of the Brunswick Nuclear Plant, and to defer consideration of two other nuclear plant outages with respect to which certain relevant information is not yet available.

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

6. The Company's merger-related fuel savings for the test period as reported in Schedule 11 of the Company's Monthly Fuel Report are reasonable.

7. The test period per book system sales are 59,035,174 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 67,619,619 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	11,063,013
Natural Gas, Oil and Biomass	22,856,905
Nuclear	27,039,717
Hydro – Conventional	653,098
Solar	50,316
Purchased Power – subject to economic dispatch or curtailment	3,361,080

Other Purchased Power	2,595,490
Total Net Generation (may not add to sum due to rounding)	67,619,619

8. The appropriate nuclear capacity factor for use in this proceeding is 92.1%.

9. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 37,755,070 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	15,866,836
Small General Service	1,938,377
Medium General Service	11,178,626
Large General Service	8,359,294
Lighting	411,938
Total (may not add to sum due to rounding)	37,755,070

10. The projected billing period (December 2016-November 2017) sales for use in this proceeding are 62,219,566 MWh on a system basis and 37,498,100 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	15,669,799
Small General Service	1,803,978
Medium General Service	10,387,456
Large General Service	9,232,995
Lighting	403,873
Total (may not add to sum due to rounding)	37,498,100

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 70,053,661 MWh and is categorized as follows:

Generation Type	MWh
Coal	13,732,386
Gas Combustion Turbine (CT) and Combined Cycle (CC)	20,617,481
Nuclear	28,538,158
Hydro	601,148
Solar	283,514
Purchased Power	6,280,974
Total (may not add to sum due to rounding)	70,053,661

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

A. The coal fuel price is \$30.53/MWh.
B. The gas CT and CC fuel price is \$27.96/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is \$29,395,169.
D. The total nuclear fuel price (including Joint Owners generation) is \$7.01/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is \$233,250,614.
F. System fuel expense recovered through intersystem sales is \$119,188,725.

13. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are \$814,509,590.

14. The over-recovery of \$70,124,061 shown in DEP witness McGee's Exhibit No. 3 should be increased by \$415,531 to reflect the replacement power costs associated with the outage in March and April 2015 at the Brunswick Plant.

15. The Company's appropriate North Carolina retail jurisdictional fuel and fuel-related expense over-collection for purposes of the EMF was \$70,539,593, consisting of over/(under)-recoveries of \$21,699,751; \$5,972,024; \$42,848,746; \$1,172,990 and \$(1,153,918), for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively.

16. The appropriate amount of interest on the Company's fuel and fuel-related cost over-collection for the North Carolina retail jurisdiction is \$11,948,914, consisting of \$3,616,624 for the Residential class, \$995,337 for the Small General Service class, \$7,141,455 for the Medium General Service class, and \$195,498 for the Large General Service class.

17. The decrease in fuel and fuel-related costs from the amounts approved in Docket No. E-2, Sub 1069, should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

18. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 1.993¢/kilowatt-hour (kWh) for the Residential class; 2.088¢/kWh for the Small General Service class; 2.431¢/kWh for the Medium General Service class; 2.253¢/kWh for the Large General Service class; and 0.5960¢/kWh for the Lighting class.

19. The appropriate EMFs established in this proceeding, excluding the regulatory fee, are as follows: (0.137)¢/kWh for the Residential class; (0.308)¢/kWh for the Small General Service class; (0.383)¢/kWh for the Medium General Service class; (0.014)¢/kWh for the Large General Service class; and 0.280¢/kWh for the Lighting class.

20. The appropriate EMF interest decrements established in this proceeding, excluding GRT and the regulatory fee, are as follows: (0.023)¢/kWh for the Residential class; (0.051)¢/kWh

for the Small General Service class; (0.064)¢/kWh for the Medium General Service class; (0.002)¢/kWh for the Large General Service class; and (0.000)¢/kWh for the Lighting class.

21. The total net fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 1.833¢/kWh for the Residential class; 1.729¢/kWh for the Small General Service class; 1.984¢/kWh for the Medium General Service class; 2.237¢/kWh for the Large General Service class; and 0.876¢/kWh for the Lighting class.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending March 31 as the test period for DEP. The Company's filing in this proceeding was based on the 12 months ended March 31, 2016.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the testimony of Company witnesses Gillespie and Miller and the testimony of Public Staff witnesses Peedin and Metz.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Gillespie testified that the Company's four nuclear units operated at a system average capacity factor of 91.02% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 93.98%, exceeded the five-year industry weighted average capacity factor of 88.5% for the period 2010-2014 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Witness Gillespie testified that DEP's nuclear fleet consists of three generating stations and a total of four units. He testified that those four nuclear units operated at an actual system average capacity factor of 91.02% for the test period, which began with the completion of a refueling outage at Brunswick Unit 2 and included three additional refueling outages.

Company witness Gillespie also testified that on July 31, 2015, DEP finalized the purchase of portions of ownership for Brunswick Units 1 and 2, and Harris Unit 1 from North Carolina Eastern Municipal Power Agency. This purchase brought DEP's ownership to 100% of these units and added 493 megawatts (MWs) of reliable, efficient, cost effective, and greenhouse gas emission-free base load generation to DEP's nuclear portfolio.

Company witness Miller testified concerning the performance of DEP's fossil/hydro assets. He stated that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor (EAF), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned maintenance, *i.e*., forced outage time); (2) equivalent forced outage rate (EFOR), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated[1] hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and (3) starting reliability (SR), which represents the percentage of successful starts.

Company witness Miller testified that the DEP fossil/hydro fleet responded to the test period summer and winter peaks with a very strong performance. He testified that Sutton CC's EAF for January and February 2016 was 100%, while the four coal-fired units at Roxboro Station had an EAF of 99.4% for the same time period. The coal-fired fleet EAF during the months of January and February 2016 was 98.7%, and the CC fleet EAF for the same period was 99.4%.

Witness Miller presented the following chart, which shows operation results, as well as results from the most recently published NERC Generating Availability Brochure for the period 2010 through 2014, and is categorized by generator type:

[1] Derated hours are hours the unit operation was less than full capacity.

Generator Type	Measure	Review Period Operational Results	2010-2014 NERC Average	Nbr of Units
Coal-Fired	EAF	83.5%	82.8%	423
	EFOR	3.7%	7.3%	
2015 Summer Peak	Coal-fired EAF	97.1%	n/a	n/a
	Combined Cycle EAF	96.4%	n/a	n/a
Total CC Average	EAF	90.6%	84.4%	179
	EFOR	1.6%	6.3%	
Total CT Average	EAF	92.3%	87.3%	928
	SR	97.5%	97.6%	
Hydro	EAF	80.4%	82.6%	1074

Company witness Miller also testified that the Company, like other utilities across the United States, has experienced a change in the dispatch order for each type of generating facility due to favorable economics resulting from the low pricing of natural gas, which includes the expansion of shale gas. Gas-fired facilities provided 65% of the DEP fossil/hydro generation during the test period.

Public Staff witness Metz testified that the Public Staff reserves the right to continue its review and make a recommendation on the following nuclear forced outage events in next year's fuel adjustment proceeding: 1) the Brunswick Nuclear Plant Unit 1 manual reactor shutdown (SCRAM) for a component failure that occurred on February 7, 2016 and lasted through February 14, 2016; and 2) the Robinson Nuclear Plant Unit 2 low pressure turbine blade repair outage that occurred on November 17, 2015 and lasted through November 28, 2015. Witness Metz stated, however, that in this case the Public Staff does not recommend any adjustment related to the above listed outages. The reason for the carryover, to which the Company has agreed, is that the Company has not completed its final reports related to these outages, and it is still gathering requested information on one of the outages from its vendors for review by the Public Staff.

Public Staff witness Peedin testified that $415,531 in replacement power costs associated with an outage in March and April 2015 at Unit 2 of the Brunswick Nuclear Plant should be disallowed. She stated that in DEP's May 2016 fuel cost review proceeding in South Carolina, the Office of Regulatory Staff (ORS) proposed "an over-recovery adjustment of $73,204 to the Company's base fuel costs to remove an amount for replacement power incurred due to a portion of the outage extension at Brunswick Unit 2." DEP, together with all other parties to the proceeding, entered into a stipulation which incorporated this adjustment. The $73,204 adjustment represented South Carolina's share of the total replacement costs (approximately $600,000) that the ORS contended should not be recovered. Witness Peedin noted that North Carolina's share is $415,531, and DEP has agreed that it will not object to the disallowance of this amount.

Based upon the evidence in the record, the Commission concludes that the disallowance proposed by witness Peedin is appropriate, and it is also appropriate to defer consideration of the November 2015 outage at Unit 2 of the Robinson Plant and the February 2016 shutdown of Unit 1 of the Brunswick Plant, as proposed by witness Metz. Apart from these matters, however, DEP generally managed its baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is contained in Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's revised fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in 2008, and were in effect throughout the 12 months ending March 31, 2016. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses McGee, Daji, Miller, and Church.

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

Company witness Daji described DEP's fossil fuel procurement practices, set forth in Daji 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 Daji, the Company's average delivered coal cost per ton decreased approximately 9%, from $88.77 per ton in the prior test period to $80.74 per ton in the test period. The Company's transportation costs decreased approximately 18%, from $29.34 per ton in the prior test period to $24.02 per ton in the test period.

Witness Daji stated that DEP's current coal burn projection for the billing period is 5.1 million tons compared to 4.8 million tons consumed during the test period. DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: delivered natural gas prices versus the average delivered cost of coal, volatile power prices, and electric demand. Inventory levels were above target at the end of the test period. Future inventory levels are dependent on actual versus projected coal burns and actual coal deliveries based on performance of the railroads. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $76.11 per ton for the billing period compared to $80.74 per ton in the test period.

According to witness Daji, DEP continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price increases and maintaining average fuel costs at or below those seen in the marketplace.

Witness Daji further testified that DEP's current natural gas burn projection for the billing period is approximately 151 MMBtu, which is a decrease from the 176 MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.71 per MMBtu, compared to $2.44 per MMBtu in the test period, resulting in the Company's decreased natural gas consumption projection. Although the price of natural gas is currently projected to increase slightly, gas markets remain in a near historically low price environment which will affect actual burns. Witness Daji also testified that the Company's average price of gas purchased for the test period was $4.10 per MMBtu, compared to $6.03 per MMBtu in the prior test period, representing a decrease of 32%.

G.S. 62-133.2(a1)(3) permits DEP to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Miller testified that the Company's fossil/hydro generation portfolio consists of 9,378 MW of generating capacity, 3,544 MW of which is coal-fired generation across three generating stations and a total of seven units. These units are equipped with emission control equipment, including selective catalytic reduction equipment for removing nitrogen oxides (NOx), flue gas desulfurization equipment for removing sulfur dioxide, and low NOx burners. This inventory of coal-fired assets with emission control equipment employed enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content – providing flexibility for DEP to procure the best cost options for coal supply.

Company witness Miller further testified that overall the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emissions reduction required.

Company witness Church testified as to DEP's nuclear fuel procurement practices, which include 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, and monitoring deliveries against contract commitments. Witness Church explained that 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. He also stated that throughout the industry, the typical initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis, using multi-year contracts.

G.S. 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Daji testified that DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider factors that include, but are not limited to, the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, estimated 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.

In its post-hearing brief, NCSEA states that it does not challenge any costs that DEP seeks to recover in its fuel and fuel-related rider application as unreasonable or imprudent, but wishes to focus the Commission's attention, in this docket and others, on how renewable energy generation can act as a hedge and can effectively help minimize the risk of future rate shocks to ratepayers.

No 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.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony of Company witnesses Daji.

According to witness Daji, through April 2016, the combined merger savings from the Joint Dispatch Agreement and the Companies' fuel procurement activities are $670 million, of which DEP's North Carolina share is $171 million. DEP's and DEC's customers are allocated their share of the combined savings based upon the resource ratios of the combined company. This resource ratio is 39% for DEP and 61% for DEC through April 2016.

Based on the evidence presented by DEP, and noting the absence of evidence presented to the contrary by any other party, the Commission finds and concludes that the Company's merger-related fuel savings for the test period are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

According to the exhibits sponsored by Company witness McGee, the test period per book system sales were 59,035,174 MWh, and test period per book system generation and purchased power amounted to 67,619,619 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (McGee Exhibit 6):

Net Generation Type	MWh
Coal	11,063,013
Natural Gas, Oil and Biomass	22,856,905
Nuclear	27,039,717
Hydro – Conventional	653,098
Solar	50,316
Purchased Power – subject to economic dispatch or curtailment	3,361,080
Other Purchased Power	2,595,490
Total Net Generation (may not add to sum due to rounding)	67,619,619

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party took issue with the portions of witness McGee's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 59,035,174 MWh and system generation and purchased power of 67,619,619 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

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

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. The Company proposed using a 92.1% 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 2016-2017 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 88.5% for the period 2010-2014 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report. Public Staff witness Metz did not dispute the Company's proposed use of a 92.1% capacity factor.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEP system, and the fact that the Public Staff and other parties did not dispute the Company's proposed capacity factor, the Commission concludes that the 92.1% nuclear capacity factor, and its associated generation of 28,538,158 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

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

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

On her Exhibit 4, Company witness McGee set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 37,755,070 MWh, comprised of Residential class sales of 15,866,836 MWh, Small General Service sales of 1,938,377 MWh, Medium General Service sales of 11,178,626 MWh, Large General Service sales 8,359,294 MWh, and Lighting class sales of 411,938 MWh.

Witness McGee used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on McGee Exhibit 2, Schedule 1, is 62,219,566 MWh. The projected level of generation and purchased power used was 70,053,661 MWh (calculated using the 92.1% capacity factor found reasonable and appropriate above), and was broken down by witness McGee as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	13,732,386
Gas Combustion Turbine and Combined Cycle	20,617,481
Nuclear	28,538,158
Hydro	601,148
Solar	283,514
Purchased Power	6,280,974
Total (may not add to sum due to rounding)	70,053,661

As part of her Workpaper 7, Company witness McGee also presented an estimate of the projected billing period North Carolina retail Residential, Small General Service, Medium General Service, Large General Service, and Lighting MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	15,669,799
Small General Service	1,803,978
Medium General Service	10,387,456
Large General Service	9,232,995
Lighting	403,873
Total (may not add to sum due to rounding)	37,498,100

These class totals were used in McGee Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

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

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses McGee and Daji and the testimony of Public Staff witness Metz.

In her Exhibit 2, Schedule 1, Company witness McGee recommended the fuel and fuel-related prices and expenses set forth in Finding of Fact No. 12 above. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff.

In his affidavit, Public Staff witness Metz stated that, based on his review, it appears that the projected fuel and reagent prices set forth in the testimony of DEP witnesses McGee, Daji, and Church, and the supplemental testimony of DEP witnesses McGee and Gillespie, and the prospective components of the total fuel factor, have been calculated in accordance with the requirements of G.S. 62-133.2.

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

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

According to McGee Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $814,509,590. Public Staff witness Metz did not take issue with her calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $814,509,590 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 14-20

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee, the testimony and exhibit of Public Staff witness Peedin, and the testimony of Public Staff witness Metz.

Company witness McGee presented DEP's original fuel and fuel-related expense over-collection and prospective fuel and fuel-related cost factors. Company witness McGee's supplemental testimony sets forth the projected fuel and fuel-related costs, the amount of over/(under) collection for purposes of the EMF, the method for allocating the decrease in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, EMFs and the EMF interest along with revised exhibits and workpapers. Public Staff witness Peedin testified that the Public Staff proposed to disallow the North Carolina retail amount of $415,531 in replacement power costs associated with an outage in March and April 2015 at the Brunswick Plant. She also testified that by recommending this adjustment, the Public Staff takes no position as to the prudence or imprudence of the March and April outage at the Brunswick Plant. The net effect of this adjustment is to increase the originally filed EMF decrement riders. Public Staff witness Peedin testified that DEP's EMF increment/(decrement) riders for each customer class should be approved based on the following over/(under)-recoveries, broken down as set forth in Peedin Exhibit 1, as follows:

N.C. Retail Customer Class	Test Period Over/Under Recovery	Interest
Residential	$21,699,751	$3,616,624
Small General Service	5,972,024	995,337
Medium General Service	42,848,746	7,141,455
Large General Service	1,172,990	195,498
Lighting	(1,153,918)	0
Total	$70,539,593	$11,948,914

(may not add to sum due to rounding)

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

N.C. Retail Customer Class	EMF Increment/ (Decrement) (cents/kWh)	EMF Interest Increment/ (Decrement) cents/kWh)
Residential	(0.137)	(0.023)
Small General Service	(0.308)	(0.051)
Medium General Service	(0.383)	(0.064)
Large General Service	(0.014)	(0.002)
Lighting	0.280	(0.000)

The Commission concludes that the EMF increment/(decrement) billing factors set forth in the testimony and exhibit of Public Staff witness Peedin and the testimony of Public Staff witness Metz are reasonable and appropriate for use in this proceeding.

Company witness McGee calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the decrease in fuel costs from the amounts approved in Docket No. E-2, Sub 1069, should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEP fuel cases approved by this Commission. No party opposed the use of this allocation method. Public Staff witness Metz recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in Public Staff Peedin's testimony.

Based upon the testimony and exhibits in the record, the Commission concludes that DEP's projected fuel and fuel-related cost of $814,509,590 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that the EMF increment/(decrement) riders and the EMF interest decrement rider for each class set forth in the testimony and exhibit of Public Staff witness Peedin and the testimony of Public Staff witness Metz in this proceeding, excluding the regulatory fee, and the Public Staff's prospective fuel and fuel-related cost factors proposed in this proceeding for each of the rate classes, are appropriate. Additionally, the Commission concludes that DEP's decrease in fuel and fuel-related costs from the amounts approved in Docket No. E-2, Sub 1069 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEP's past fuel cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence for this finding of fact is contained in the testimony of Company witness McGee and in the testimony and exhibits of Public Staff witness Peedin and the testimony of Public Staff witness Metz.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF and related EMF interest, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 1.833¢/kWh for the Residential class, 1.729¢/kWh for the Small General Service class, 1.984¢/kWh for the Medium General Service class, 2.237¢/kWh for the Large General Service class, and 0.876¢/kWh for the Lighting class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 1.993¢/kWh, 2.088¢/kWh, 2.431¢/kWh, 2.253¢/kWh, and 0.596¢/kWh, EMF increments/(decrements) of (0.137)¢, (0.308)¢, (0.383)¢, (0.014)¢, and 0.280¢/kWh, and EMF interest decrements of (0.023)¢/kWh, (0.051)¢/kWh, (0.064)¢/kWh, (0.002)¢/kWh and (0.000)¢/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively, all excluding the regulatory fee. The billing factors, both excluding and including the regulatory fee, are shown in Appendix A to this Order.

IT IS, THEREFORE, ORDERED, as follows:

1. That effective for service rendered on and after December 1, 2016, DEP shall adjust the restated base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in Docket No. E-2, Sub 1045, amounting to 3.013¢/kWh for the Residential class, 3.001¢/kWh for the Small General Service class, 2.921¢/kWh for the Medium General Service class, 2.958¢/kWh for the Large General Service class, and 3.655¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to (1.020)¢/kWh, (0.913)¢/kWh, (0.490)¢/kWh, (0.705)¢/kWh and (3.059)¢/kWh, respectively and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of (0.137)¢/kWh for the Residential class, (0.308)¢/kWh for the Small General Service class, (0.383)¢/kWh for the Medium General Service class, (0.014)¢/kWh for the Large General Service class, and 0.280¢/kWh for the Lighting class (excluding the regulatory fee) and EMF interest decrements of (0.023)¢/kWh for the Residential class, (0.051)¢/kWh for the Small General Service class, (0.064)¢/kWh for the Medium General Service class, and (0.002)¢/kWh for the Large General Service class (excluding the regulatory fee). The EMF and EMF interest increments/(decrements) are to remain in effect for service rendered through November 30, 2017;

2. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement the approved rate adjustments ordered by the Commission in Docket Nos. E-2, Subs 1107, 1109, and 1110 as soon as practicable; and

3. That DEP shall work with Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket Nos. E-2, Subs 1107, 1109, and 1110, and the Company shall file the proposed customer notice for approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of November, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

Appendix A

EXCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	3.013	(1.020)	1.993	(0.137)	(0.023)	1.833
Small General Service	3.001	(0.913)	2.088	(0.308)	(0.051)	1.729
Medium General Service	2.921	(0.490)	2.431	(0.383)	(0.064)	1.984
Large General Service	2.958	(0.705)	2.253	(0.014)	(0.002)	2.237
Lighting	3.655	(3.059)	0.596	0.280	-	0.876

INCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	3.017	(1.021)	1.996	(0.137)	(0.023)	1.836
Small General Service	3.005	(0.914)	2.091	(0.308)	(0.051)	1.732
Medium General Service	2.925	(0.491)	2.434	(0.384)	(0.064)	1.986
Large General Service	2.962	(0.706)	2.256	(0.014)	(0.002)	2.240
Lighting	3.660	(3.063)	0.597	0.280	-	0.877

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

DOCKET NO. E-34, SUB 44

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by New River Light & Power	)	ORDER APPROVING
Company for Approval of Purchased Power	)	PURCHASED POWER
Adjustment Factor	)	ADJUSTMENT FACTOR

BY THE COMMISSION: On October 1, 2015, pursuant to the Commission's Order Approving Rate Increase and Annual Procedure issued on December 22, 2010, in Docket No. E-34, Sub 38 (the Sub 38 Order), New River Light and Power Company (New River or the Company) filed a request for an adjustment to its rates and charges for purchased power (the Purchased Power Adjustment or PPA). In this filing, New River presented a preliminary PPA factor of $0.019737 per kilowatt-hour (kWh), excluding the North Carolina regulatory fee (NCRF), or $0.019766 per kWh, including NCRF. The Company stated that this rate was the preliminary calculation of the PPA factor to be included in rates effective February 1, 2016.

On January 12, 2016, New River filed its final proposed PPA factor, including an experience modification factor (EMF) based on total actual purchased power revenues and costs for the period January through December 2015. The PPA factor requested in this filing totals $0.010226 per kWh (excluding NCRF), consisting of two elements: estimated purchased power costs for the period January through December 2016 of $0.009596 per kWh, and an EMF increment of $0.000630 per kWh. New River stated that when calculated to include the NCRF, the PPA factor totals $0.010241 per kWh, which is $0.007826 less than its current PPA factor of $0.018067 per kWh. New River requested that the new rates be approved for all service rendered on or after February 1, 2016.

In its January 12, 2016 filing, New River proposed to revise all of its retail rate schedules, including its outdoor lighting schedules, to incorporate the $0.007826 per kWh decrease in the PPA factor. The Company stated that its proposed PPA factor, if approved by the Commission, would decrease rates for its customers by a range of 8.1% (for residential customers) to 11.4% (for large commercial customers).

The Public Staff presented this matter at the Commission's Regular Staff Conference on January 19, 2016, stating that it had reviewed New River's calculations for the PPA and the proposed decreases in retail rates. Further, the Public Staff stated that it had determined that the proposed PPA and the rate adjustments had been calculated accurately and in a reasonable manner, given the projections of purchased power costs received from Blue Ridge Electric Membership Corporation, and are consistent with previous New River pass through requests approved by the Commission. Furthermore, pursuant to the provision of the Sub 38 Order that each annual PPA factor adjustment should take into consideration, as appropriate, New River's overall level of earnings and return on rate base at that time, the Public Staff stated that it had also conducted a general review of New River's 2014 earnings. This review included consideration of certain pro forma adjustments to normalize and annualize net operating income at December 31, 2014, operating levels and current purchased power costs and revenues, but it was not as detailed as the review that the Public Staff would conduct in a general rate case. The Public Staff stated that based on the results of its review, it was of the opinion that the requested PPA is appropriate and reasonable in that it (a) is based solely on the level of purchased power expense expected to be incurred by New River (including the true-up of the EMF), and (b) when combined with pro forma 2014 results of New River's operations, does not appear to be unreasonable overall.

Based on the foregoing, the Commission concludes that the proposed PPA and the accompanying pass through to New River's customers of the decreased cost of purchased power from New River's wholesale supplier should be approved without public hearing, subject to refund of any amounts subsequently found to be unjust or unreasonable upon protest and hearing, and subject to the requirements set forth in the Ordering Paragraphs below.

IT IS, THEREFORE, ORDERED as follows:

1. That effective with service rendered on and after February 1, 2016, New River is authorized to adjust its base rates to reflect a PPA factor of $0.010226 per kWh (excluding NCRF) and $0.010241 per kWh (including NCRF), resulting in a decrease of $0.007826 per kWh in the PPA factor.

2. That the rates authorized by this Order are subject to refund of any amounts which may subsequently be found unjust or unreasonable after public hearing.

3. That New River shall file copies of its approved rates, as modified herein, within 10 days of the date of this Order.

4. That the Notice to the Public attached as Appendix A be mailed by separate mail or bill insert by New River to all its customers and that said Notice be mailed not later than 7 days after the date of this Order.

5. That the Notice to the Public be published by New River at its own expense in newspapers having general coverage in its North Carolina service area once a week for two consecutive weeks, the first Notice appearing not later than seven days following the date of this Order, and said Notice covering no less than one-quarter of a page.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of January, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX A
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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO THE PUBLIC

DOCKET NO. E-34, SUB 44
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that New River Light and Power Company (New River) has requested the North Carolina Utilities Commission to approve an adjustment to its purchased power adjustment (PPA) factor for service rendered on and after February 1, 2016, to pass through to its customers the decreased cost of purchased power from its wholesale power supplier, Blue Ridge Electric Membership Corporation (BREMCO).

The amount of the decrease to New River's customers resulting from the new PPA factor will be approximately $1.6 million per year, a decrease of approximately 9.0%. The decrease will be applied to New River's customers as a uniform decrease to the kilowatt-hour (kWh) energy charge. The decrement in revenue produced by the decrease will be the same as the reduction in the cost of purchased power from BREMCO, adjusted for the effects of the utility regulatory fee. The proposed decrease of $0.007826 per kWh will result in a decrease in the monthly bill of a residential customer using 1,000 kWh from $96.97 to $89.15. The approximate percentage decreases in customers' bills, by rate schedule, are as follows (actual percentages may differ depending on specific customers' usage amounts):

Residential	8.1%
Schedule G (Commercial)	8.5%
Schedule GL (Large Commercial)	11.4%
Schedule I (Industrial)	10.4%
Schedule A (App. State Univ.)	9.4%

The Commission has concluded that the PPA and pass-through rate adjustment requested by New River are reasonable, in that (a) they are based solely on the level of purchased power expense expected to be incurred by New River, and (b) when combined with pro forma 2014 results of New River's operations, the PPA factor does not appear to be unreasonable overall.

Therefore, the Commission has approved New River's requests without public hearing, subject to refund of any amounts which should subsequently be found to be unjust or unreasonable after any public hearing in this matter that may subsequently be held by the Commission, as described below.

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Page 2 of 2

Persons desiring to intervene in this matter as formal parties of record should file a motion under Commission Rules R1-6, R1-7, and R1-19 not later than 45 days after the date of this notice. Persons desiring to present testimony or evidence at a hearing should so advise the Commission. Persons desiring to send written statements to inform the Commission of their position in the matter should address their statements to the Chief Clerk, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4300. However, such written statements cannot be considered competent evidence unless those persons appear at a public hearing and testify concerning the information contained in their written statements. If a significant number of requests for a public hearing are received within 45 days after the date of this notice, the Commission may schedule a public hearing.

The Public Staff is authorized by statute to represent the using and consuming public in proceedings before the Commission. Written statements to the Public Staff should include any information which the writer wishes to be considered by the Public Staff in its investigation of the matter, and such statements should be addressed to Christopher J. Ayers, Executive Director, Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of January, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-35, SUB 46

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Western Carolina	)	ORDER APPROVING
University for Authority to Recover	)	PURCHASED POWER COST RIDER
Purchased Power Expense	)	

BY THE COMMISSION: On December 11, 2015, in compliance with the Commission's prior orders in Docket No. E-35, Subs 17, 19, and 40, Western Carolina University (WCU) filed an application for a change in its Schedule CP Purchased Power Cost Rider (Rider) to be effective for the twelve monthly billings beginning with the bills rendered in January 2016. This filing included actual purchased power cost and recovery information only for the period January 2015 through November 2015. On January 12, 2016, WCU filed its final rates for the Rider, which incorporated actual purchased power costs and revenues through December 2015.

The net purchased power adjustment factor requested by WCU for use in Schedule CP is an increment of $0.02708 per kWh. This proposed factor would replace the current expiring factor of $0.03890 and would decrease a customer's monthly bill by $11.82 for 1,000 kWh of usage. The requested factor is made up of three elements. The first is an increment of $0.03277 per kWh to recover estimated purchased power costs for the period January 2016 through December 2016. The second element is an Experience Modification Factor (EMF) decrement of ($0.00513) per kWh to refund purchased power costs over-collected during the period January 2015 through December 2015. The third is an EMF interest decrement of ($0.00056) per kWh calculated in conjunction with the over-collection of purchased power costs.

The Public Staff presented this matter at the Commission's Regular Staff Conference on January 19, 2016, and recommended that the proposed Rider increment be approved effective for the twelve monthly bills rendered on and after January 19, 2016, and before January 1, 2017. In support of this recommendation, the Public Staff stated that it had reviewed the calculations and documentation supporting the Rider requested by WCU and found them to be accurate. The Public Staff further stated that the approval of this Rider should be without prejudice to the right of any party to take issue with it in a general rate case.

The Public Staff noted that on November 25, 2015, in Docket No. E-35, Sub 45, WCU filed an application with the Commission for a general rate increase, and that it is possible that the estimated 2016 purchased power component of Schedule CP will need to be revised or eliminated when the rates established in the general rate case take effect. Therefore, the Public Staff recommended that approval of the Rider in this docket be made subject to possible revision as a result of Commission action in the general rate case.

After careful review of WCU's proposal and the recommendation of the Public Staff, the Commission concludes that the adjustment factor increment of $0.02708 per kWh proposed by WCU should be approved. The Commission also concludes that the adjustment factor should be subject to possible revision as a result of Commission action in Docket No. E-35, Sub 45.

IT IS, THEREFORE, ORDERED as follows:

1. That WCU's Schedule CP Purchased Power Cost Rider, which is attached to this Order as Attachment A, is allowed to become effective for the twelve monthly bills rendered on and after January 19, 2016, and before January 1, 2017, subject to possible revision as a result of Commission action in Docket No. E-35, Sub 45.

2. That the Purchased Power Cost Rider is approved without prejudice to the right of any party to take issue with the Rider in a general rate case.

3. That WCU shall give appropriate notice to its retail customers for the Purchased Power Cost Rider by bill insert in the bills issued in January 2016. A copy of this notice shall be filed with the Chief Clerk of the North Carolina Utilities Commission within five working days of the date of this Order.

4. That WCU shall file appropriate rate schedules and riders with the Commission in order to implement the approved purchased power adjustment no later than ten working days from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the _20th_ day of January, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

ATTACHMENT A

WESTERN CAROLINA UNIVERSITY
DOCKET NO. E-35, SUB 46

SCHEDULE "CP"
PURCHASED POWER COST RIDER

Each customer's twelve monthly bills rendered on and after January 19, 2016, for each month between January 19, 2016, and January 1, 2017, shall be adjusted by an incremental charge of $0.02708 per kWh as determined to be appropriate by the North Carolina Utilities Commission.

This rate is determined as follows:

	$/kWh
Factor for estimated purchased power costs for the period January 2016 through December 2016	$0.03277
Experience Modification Factor to reflect actual results for the period January 2015 through December 2015	($0.00513)
Experience Modification Factor Interest to reflect the over-collection of expenses for the period January 2015 through December 2015	($0.00056)
TOTAL RATE	$0.02708

Effective for bills rendered on and after January 19, 2016 and before January 1, 2017.

DOCKET NO. E-2, SUB 1089

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC, for	)	
a Certificate of Public Convenience	)	ORDER GRANTING APPLICATION
and Necessity To Construct a 752 MW Natural	)	IN PART, WITH CONDITIONS, AND
Gas-Fired Electric Generation Facility in	)	DENYING APPLICATION IN PART
Buncombe County Near the	)	
City of Asheville	)	

HEARD: Tuesday, January 26, 2016, at 7:00 p.m., in Courtroom 1A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina; and Monday, February 22, 2016, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham and James G. Patterson

APPEARANCES:

For Duke Energy Progress, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, P. O. Box 1551/NCRH20, Raleigh, North Carolina 27602

For NC WARN and The Climate Times:

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For Columbia Energy, LLC:

Daniel C. Higgins, Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605

For MountainTrue and the Sierra Club:

Gudrun Thompson, Southern Environmental Law Center, 601 W. Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516.

D. J. Gerkin, Southern Environmental Law Center, located at 22 South Pack Square, Suite 700, Asheville, North Carolina 28801

For Grant Millin:

Grant Millin, 48 Riceville Road, B314, Asheville, North Carolina 28805, pro se

For Brad Rouse:

Brad Rouse, 3 Stegall Lane, Asheville, North Carolina 28805, pro se

For the Using and Consuming Public:

Diana Downey and Robert S. Gillam, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On December 16, 2015, Duke Energy Progress, LLC (DEP), filed a letter in the above-captioned docket giving notice of its intent to file an application on or after January 15, 2016, for a certificate of public convenience and necessity (CPCN) to construct a 752 MW natural gas-fired electric generation facility consisting of two new natural gas-fired 280 MW (winter rating) combined cycle (CC) units and a natural gas-fired 192 MW (winter rating) simple cycle combustion turbine (CT) unit, each with fuel back up, in Buncombe County near the City of Asheville. In its letter, DEP states, "The Western Carolinas Modernization Project (Project or WCMP) will enable the early retirement of the 379 MW (winter rating) Asheville 1 and 2 coal units on or before the commercial operation of the new combined cycle units, thereby permanently ceasing operations of all coal-fired units at the site."

The notice of intent was filed by DEP pursuant to Section 1 of the Mountain Energy Act, Session Law 2015-110, which provides:

> Notwithstanding G.S. 62-110.1, the Commission shall provide an expedited decision on an application for a certificate to construct a generating facility that uses natural gas as the primary fuel if the application meets the requirements of this section. A public utility shall provide written notice to the Commission of the date the utility intends to file an application under this section no less than 30 days prior to the submission of the application. When the public utility applies for a certificate as provided in this section, it shall submit to the Commission an estimate of the costs of construction of the gas-fired generating unit in such detail as the Commission may require. G.S. 62-110.1(e) and G.S. 62-82(a) shall not apply to a certificate applied for under this section. The Commission shall hold a single public hearing on the application applied for under this section and require the applicant to publish a single notice of the public hearing in a newspaper of general circulation in Buncombe County. The Commission shall render its decision on an application for a certificate, including any related transmission line located on the site of the new generation facility, within 45 days of the date the application is filed if all of the following apply:
>
> (1) The application for a certificate is for a generating facility to be constructed at the site of the Asheville Steam Electric Generating Plant located in Buncombe County.

(2) The public utility will permanently cease operations of all coal-fired generating units at the site on or before the commercial operation of the generating unit that is the subject of the certificate application.

(3) The new natural gas-fired generating facility has no more than twice the generation capacity as the coal-fired generating units to be retired.

Section 2 of the Mountain Energy Act amends Section 3(b) of the Coal Ash Management Act (CAMA), Session Law 2014-122, by extending the deadline for closing the coal combustion residual (coal ash) surface impoundments at the Asheville Steam Electric Generating Plant (Asheville Plant) by three years if, on or before August 1, 2016, the Commission has issued a CPCN to DEP for a new natural gas-fired facility to replace the coal units at the Asheville Plant, based upon written notice by DEP to the Commission that it will permanently cease operations at the coal units no later than January 31, 2020. In addition, replacement of coal generation with natural gas-fired generation within the deadlines set forth in the Mountain Energy Act exempts impoundments and electric generating facilities located at the Asheville Plant from the prohibitions in CAMA related to storm water discharge and the requirements for conversion to "dry" fly and bottom ash.

On December 18, 2015, the Commission issued an Order Scheduling Public Hearing and Requesting Investigation and Report by the Public Staff. Among other things, in light of the 45-day deadline for making a decision on DEP's application, the Order scheduled the required public hearing on DEP's application for Tuesday, January 26, 2016, at 7:00 p.m. in Asheville. The Commission further found good cause to require the Public Staff to investigate the application and present its findings, conclusions, and recommendations to the Commission at the Commission's Regular Staff Conference on February 22, 2016.

On December 21, 2015, before DEP had filed its application for the CPCN, North Carolina Waste Awareness and Reduction Network and The Climate Times (collectively, NC WARN) filed a motion requesting that the Commission hold an evidentiary hearing for expert witnesses in this docket or, in the alternative, deny DEP's CPCN application as incomplete and insufficient until an evidentiary hearing can be held.

On December 31, 2015, DEP filed a response requesting that the Commission deny NC WARN's motion.

On January 5, 2016, DEP filed an affidavit of publication certifying that DEP caused to be published a notice of the public hearing scheduled for January 26, 2016, in Asheville.

On January 6, 2016, NC WARN filed a reply to DEP's response.

On January 15, 2016, the Commission issued an Order denying NC WARN's motion.

On January 15, 2016, DEP filed a verified application for a CPCN to construct up to 746 MW of natural gas-fired electric generating capacity consisting of two new natural gas-fired 280 MW CC units and a natural gas-fired 186 MW (winter rating) simple cycle CT unit,[1] each with fuel oil back up, and associated transmission in Buncombe County at DEP's Asheville Plant. In addition, DEP requested a waiver of Commission Rule R8-61(a), which requires certain information to be filed 120 days prior to a CPCN application, and a waiver of Rule R8-61(b), which requires the filing of testimony with a CPCN application. The application further notes that the need for the 186 MW CT may be avoided or delayed due to the utilization of other technologies and programs to meet the future peak demand requirements of DEP's customers in the region. The application also includes information about related on-site transmission facilities, DEP's plans to build up to 15 MW of solar generation at the Asheville Plant and plans to invest in a minimum of 5 MW of utility-scale storage pilot in the DEP-Western Region. In addition, DEP notes that the North Carolina Electric Membership Corporation (NCEMC) has an option to purchase 100 MW of the proposed facility, but states that the load required to be served by DEP in the region will be the same regardless of NCEMC's ownership decision.

Attached to the application are four exhibits, portions of which were filed under seal on the grounds that they contain confidential information and are not subject to disclosure pursuant to G.S. 132-1.2. Exhibit 1A is the public version of DEP's 2015 Integrated Resource Plan (IRP). Exhibit 1B is a Statement of Need and contains additional resource planning information required by Commission Rule R8-61(b)(1). Exhibit 2 contains Plant Description, Siting, and Permitting Information. Exhibit 3 contains Cost Information. Exhibit 4 contains Construction Information.

DEP asserts that the application is subject to expedited review under the Mountain Energy Act because it complies with the three factors set forth in the Act for such expedited review: (1) the application is for a CPCN to construct a natural gas-fired generating facility at the Asheville Plant, (2) DEP has proposed to permanently cease operations of its coal-fired units at the Asheville Plant on or before the commercial operation of the Project, and (3) the proposed natural gas-fired generating facility would have no more than twice the generation capacity as the coal-fired units to be retired. In conclusion, DEP requests that the Commission find that the public convenience and necessity requires construction of the two 280 MW CC units and the contingent 186 MW CT unit and issue a CPCN for their construction.

On January 22, 2016, the Commission issued an Order on Procedure for Accepting Comments of the Parties. The Order provided that parties could present a brief opening statement at the January 26, 2016 public hearing, that parties could file written comments on or before February 12, 2016, and that parties would have an opportunity to make oral comments at the Commission's Regular Staff Conference on February 22, 2016.

On January 25, 2016, NC WARN filed a motion to compel DEP to provide additional responses to discovery requests submitted by NC WARN and to make public certain information in DEP's application that was filed as confidential trade secrets.

On January 26, 2016, the public hearing was held in Asheville as scheduled, at which 51 public witness testified.

[1] DEP's December 16, 2015 notice of filing indicated that it was planning to request a 192 MW (winter rating) CT, but reduced the capacity to 186 MW (winter rating) prior to filing the application on January 15, 2016.

On January 29, 2016, the Commission issued an Order granting DEP's request for a waiver of Commission Rule R8-61(a) and (b).

On February 1, 2016, DEP filed Revised Exhibit 1B, Attachment A, Revised Exhibit 3 and Revised Exhibit 4. In its cover letter, DEP stated that it conducted a comprehensive review of the confidential information filed under seal on January 15, 2016, with its CPCN application and removed the confidential designation on much of the information initially designated as a trade secret.

Also on February 1, 2016, DEP filed a response to NC WARN's motion to compel.

On February 4, 2016, the Commission issued an Order denying NC WARN's motion to compel.

Motions to intervene were filed and granted for the following persons and organizations: Grant Millin, Richard Fireman, Brad Rouse, North Carolina Sustainable Energy Association (NCSEA), Sierra Club, MountainTrue, Carolina Utility Customers Association, Inc. (CUCA), Carolina Industrial Group for Fair Utility Rates II (CIGFUR II), NC WARN,[1] and Columbia Energy, LLC (Columbia Energy). The intervention and participation of the Public Staff is recognized and made pursuant to G.S. 62-15.

The Commission has received numerous statements of position from interested persons. All statements of position have been filed as a part of the record in this docket.

On February 9, 2016, comments were filed by Richard Fireman. On February 10, 2016, comments were filed by Brad Rouse and NCSEA. On February 12, 2016, comments were filed by Sierra Club and MountainTrue (collectively, Sierra Club), NC WARN, and Columbia Energy.

On February 17, 2016, the Public Staff filed its agenda item for the Commission's February 22, 2016 Regular Staff Conference to discuss the Public Staff's investigation of DEP's application and its recommendation for Commission action.

On February 19, 2016, NC WARN filed a response to the Public Staff's agenda item and the affidavit of J. David Hughes.

On February 22, 2016, the Public Staff presented the results of its investigation and its recommendation at the Commission's Regular Staff Conference. In addition, Brad Rouse, Columbia Energy, NC WARN, Sierra Club and DEP made statements regarding their positions.

On February 25, 2016, Brad Rouse filed additional comments and DEP filed Reply Comments to Additional Comments of Brad Rouse. On February 26, 2016, Brad Rouse filed 2nd Additional Comments of Brad Rouse and Grant Millin filed a statement. On February 26, 2016, NC WARN filed Additional Comments of NC WARN and the Climate Times.

[1] The Climate Times intervened along with NC WARN and they are collectively referred to as NC WARN in this Order.

On February 29, 2016, the Commission issued a Notice of Decision stating that this full Order with discussion and conclusions regarding all issues would follow.

Based on of the filings, comments, and arguments of the parties and the whole record in this case, the Commission makes the following

FINDINGS OF FACT[1]

1. DEP is a corporation existing under the laws of the State of North Carolina and is engaged in the business of generating, transmitting, distributing and selling electric power to the public in its franchised service territory in North Carolina subject to the jurisdiction of the Commission. DEP serves 160,000 households and businesses in its DEP-Western Region.

2. DEP presently operates two coal-fired electric generating units with a combined generating capacity of approximately 379 MW (winter rating) at its Ashville Plant site in Buncombe County.

3. DEP filed an application for a CPCN to construct up to 746 MW of natural gas-fired electric generating capacity consisting of two new natural gas-fired 280 MW CC units and a natural gas-fired 186 MW (winter rating) simple cycle CT unit, each with fuel oil back up, and associated transmission in Buncombe County at DEP's Asheville Plant. The Commission has jurisdiction over the application.

4. The issuance of the CPCN will enable the early retirement of the two Asheville coal units on or before the commercial operation of the new CC units, thereby permanently ceasing operations of all coal-fired units at the site and reducing CO_2 emissions. The CC units are planned for commercial operation in the fall of 2019. The existing on-site CT units will continue in operation.

5. From a total system perspective, the DEP 2015 IRP identifies the need for an additional 1,152 MW of new resources by 2020 and 5,099 MW by 2030.

6. As load continues to grow, more local generation is required in Asheville to maintain system reliability pursuant to NERC reliability standards.

7. The public convenience and necessity require the construction of new generation, and it is best served by the proposed two 280 MW CC units because the construction of the CC units in the timeframe provided under the Mountain Energy Act will allow DEP to do the following: (1) retire 379 MW of coal capacity at the Asheville Plant, (2) avoid significant capital investments and environmental controls required by CAMA if the coal units at the Asheville Plant remain in operation, (3) avoid construction of 147 MW of fast start CT capacity shown as a resource need in DEP's 2014 IRP, (4) realize cost saving synergies by participating at incremental cost in a new intrastate natural gas pipeline project being constructed by PSNC in Western North Carolina, (5) serve projected energy and demand growth in its western region while maintaining sufficient reserve transmission capacity

[1] If a finding of fact is misidentified herein as a conclusion of law or vice versa, then said item shall be deemed to be that which it should be.

into the region to comply with NERC reliability standards, and (6) achieve system-wide fuel and other cost savings by dispatching generation resources more efficiently.

8. DEP cannot rely upon energy efficiency, demand-side management and renewables to eliminate or delay its need for critical generation capacity in the 2019 timeframe.

9. The critical function, nature and location requirements of the CC units require that DEP operate, maintain and control these resources, and therefore DEP's decision not to evaluate the wholesale market alternative to meet these resource needs was reasonable.

10. Issuing a CPCN for the contingent 186 MW CT unit is not appropriate at the present time.

11. Columbia Energy owns an existing 535 MW cogeneration facility in South Carolina which is a qualified facility under the Public Utilities Regulatory Policies Act of 1978 (PURPA), which may be the subject to a future contested case. The CPCN issued herein is without prejudice to the right of any party to assert its relative rights and obligations under PURPA in any future arbitration or other proceeding relating to the Columbia Energy facility.

12. There were no material facts in dispute that could not be resolved on the basis of the written record.

SUMMARY OF PARTIES' COMMENTS

Public Staff

In its investigation, the Public Staff reviewed DEP's application and exhibits and the supporting documentation that DEP provided in response to data requests. This review included evaluation of the methodology, inputs, and assumptions underlying DEP's statement of need and economic justification for the Project compared to viable alternatives. The Public Staff also had discussions and meetings with DEP representatives and with Intervenors, visited the Asheville Plant, attended the public hearing, and reviewed the customer statements of position and Intervenor comments that had been filed with the Commission.

Based on provisions of the Mountain Energy Act modifying CPCN statutory requirements, the Commission is not required to approve the estimated construction costs of the CC and CT units or to make a finding that construction of the units will be consistent with the Commission's plan for expansion of electric generating capacity. However, in order to grant the CPCN the Commission must find that the public convenience and necessity require, or will require, the construction of the new units. That determination necessarily involves consideration of information related to construction costs and generation planning as well as other factors specific to the Project, all of which have been submitted with the verified application in this case.

By passage of the Mountain Energy Act, the General Assembly has expressed, as a matter of public policy, its desire that the coal units at the Asheville Plant be replaced with natural gas-fired generation. Based on its understanding of the Mountain Energy Act and its investigation of DEP's application, the Public Staff concludes that replacement of the coal units at the Asheville Plant with the CC units proposed by DEP is consistent with the purposes of the Act and that the public convenience and necessity requires the construction of the CC units in the time frame proposed. In particular, DEP's historical and projected load growth in the DEP-Western Region, coupled with the retirement of the Asheville Plant coal units, demonstrate the need for the CC units proposed by DEP. In addition, retiring the Asheville Plant coal units will enable DEP to avoid significant capital investments in environmental controls required by CAMA. Another significant benefit is the opportunity for DEP to participate at incremental cost in a new intrastate pipeline project being constructed by PSNC in Western North Carolina.

Moreover, replacement of the coal units at the Asheville Plant with the CC units will provide benefits to both the DEP-Western Region and the DEP system as a whole by 1) easing transmission constraints, 2) assisting in meeting NERC's reliability standards, 3) improving economic dispatch of generation, and 4) providing system-wide fuel cost savings and potential emissions benefits.

However, DEP's request that the CPCN include the construction of a contingent 186 MW natural gas-fired CT is problematic. Based on current projections, it is likely that additional capacity will be required to meet future demand in the DEP-Western Region, but such additional capacity is not expected to be needed until 2024. Further, that need is contingent on (a) the success of energy efficiency and demand-side management efforts, (b) load growth in the area, and (c) potential lower cost developments that may materialize in the future. In the Public Staff's view, the better course of action at this time is for the Commission to wait and see how load growth develops in the region and whether collaboration between DEP and the Asheville community results in reduced electricity usage and demand. CT capacity takes 24 months to construct. Even assuming that the area's load growth will continue as projected, there is time to wait for potential advances in generation, transmission, and storage technologies that might provide other least cost resource options for DEP to consider.

The Public Staff asserts that DEP's cost estimates and proposed contracting process are consistent with recent additions of CC units in the service areas of DEP and Duke Energy Carolinas, LLC (DEC). However, the Public Staff is not making a recommendation with respect to approval of the final costs associated with the CC units, and it reserves the right to take issue with the treatment of the final costs for ratemaking purposes in a future proceeding.

Based on its investigation and review, the Public Staff recommends that the Commission grant DEP a CPCN for the construction of two 280 MW CC units at DEP's Asheville Plant, with the following conditions:

1. That DEP shall retire its existing coal units at the Asheville Plant no later than the commercial operation date of the CC units;

2. That DEP shall construct and operate the CC units in strict accordance with all applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environmental Quality (DEQ);

3. That DEP shall file with the Commission in this docket a progress report and any revisions in the cost estimates for the CC units on an annual basis, with the first report due no later than one year from the issuance of the Commission's Order;

4. That DEP shall file with the Commission in this docket a progress report annually, including actual accomplishments to date, on its efforts to work with its customers in the DEP-Western Region to reduce peak load growth and on its efforts to site solar and storage capacity in the DEP-Western Region, with the first report due no later than one year from the issuance of the Commission's Order; and

5. That for ratemaking purposes, the issuance of the Commission's Order and the CPCN does not constitute approval of the final costs associated therewith, and that the approval and grant is without prejudice to the right of any party to take issue with the treatment of the final costs for ratemaking purposes in a future proceeding.

Richard Fireman

In his comments, Intervenor Fireman stated that pursuant to G.S. 62-2, the Commission is required to promote harmony between public utilities, their users and the environment, and to promote the development of renewable energy and energy efficiency. The Commission should examine the traditional factors of reliable, adequate and least cost service within the framework of rapidly accelerating climate change. Replacing coal-fired electric generation with natural gas-fired generation is not acceptable because natural gas is a highly potent greenhouse gas. The Commission's decision on DEP's application will have long-term consequences for potential risks to our environment and humans. The risks are too great for making a hurried decision. The Commission should deny DEP's application and proceed with a full evidentiary hearing that will allow expert testimony by DEP and all interested parties.

Brad Rouse

In his comments, Intervenor Rouse stated that the energy and electric utility industries are in a period of rapid change due to two developments. The first is recognition of the need to end the use of fossil fuels because their use is the primary cause of climate change. The second is the technological change that is making renewable energy resources and energy efficiency measures more and more cost effective. Building the large natural gas-fired plant proposed by DEP will subject DEP's ratepayers to the unnecessary risk of a very expensive stranded investment. The Commission should deny DEP's application and require DEP to work with the community to develop renewable energy and energy efficiency options as opposed to building a large natural gas-fired plant.

NCSEA

In its comments, NCSEA stated that pursuant to the public convenience and necessity standard set forth in G.S. 62-110.1(a), the Commission must determine whether there is a need for the generating facilities proposed by DEP, and, if so, whether DEP's proposal will meet the need in a manner consistent with the public policy goals stated in G.S. 62-2. The Commission should examine all of the information and make a determination of the need for the two CC units proposed by DEP. However, the record demonstrates that the 186 MW CT is not needed in the near future and may never be needed. Therefore, the Commission should deny DEP's application to build the CT. Further, the Commission should require DEP to consider several energy efficiency alternatives for implementation in the near future, including residential time-of-use rates, residential smart meters, a smart thermostat demand response program, combined heat and power systems, and small scale solar and battery incentive programs.

Sierra Club

In its comments, Sierra Club stated that the public convenience and necessity standard requires DEP to show that it has considered all reasonable alternatives to building these proposed generating facilities. DEP has failed to meet that burden. Based on findings by consultant Richard S. Hahn, a principal consultant with Daymark Energy Advisors, DEP has not shown that transmission capacity into the Asheville region is constrained, that its projected capacity and reserve requirements are accurate, or that it has considered purchased power, renewable energy and energy efficiency alternatives. DEP can reasonably meet the region's needs with a smaller project, such as two 185 MW CCs and a 100 MW CT. If the Commission grants DEP a CPCN, it should be subject to several conditions, including: (1) require the retirement of coal capacity in addition to the two coal units at the Asheville Plant; (2) require DEP to comply with a specific timeline and reporting requirements to demonstrate its commitment to working towards more renewable energy, energy efficiency and demand response resources; and (3) require DEP to comply with a specific timeline and reporting requirements in meeting its commitment to build 15 MW of solar generation and 5 MW of storage capacity.

NC WARN

In its comments, NC WARN stated that the Commission should deny DEP's application. There are several reasons supporting this conclusion, based on three affidavits and a whitepaper, including: (1) the application does not include sufficient information; (2) the abbreviated decision schedule does not allow the Commission and parties sufficient time to make a well-informed decision; (3) DEP's proposed capacity addition is far larger than is needed; (4) the future supply and price of natural gas is uncertain; and (5) DEP's increased reliance on natural gas-fired generation will contribute to increased environmental harm due to methane leaks. In addition, there are viable alternatives that have not been considered or addressed by DEP, including purchasing hydropower that is available in the western part of North Carolina or other power available in the southeast, and using aluminum wire to "reconductor" DEP's transmission lines to increase their capacity.

Columbia Energy

DEP's application does not meet the public convenience and necessity standard for three reasons. First, DEP did not evaluate the wholesale market as an alternative to building new generation. Columbia Energy noted that it is the owner of a 523 MW generating plant in Gaston, South Carolina, that is a qualifying facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). Therefore, DEP is required to purchase Columbia Energy's energy and capacity at DEP's avoided costs. Columbia Energy stands willing and able to sell the energy and capacity from its QF to DEP at DEP's avoided costs, resulting in a lower cost alternative for meeting the Asheville area's electric needs. Second, DEP's estimated cost of $1.1 billion for construction of the Project is about 60 percent higher than the market cost construction estimate of LS Power Development, LLC, Columbia Energy's parent company. Third, the Commission should deny the CPCN for the 186 MW CT because the public convenience and necessity will not be served by allowing DEP to build generating capacity based on such an uncertain need for it. Finally, if the Commission approves DEP's application, Columbia Energy requests that the Commission include a statement acknowledging DEP's obligation under PURPA to purchase electricity from QFs and stating that the Commission's Order is without prejudice to the assertion of Columbia Energy's rights under PURPA in any future arbitration proceeding.

SUMMARY OF PUBLIC TESTIMONY AND COMMENTS

Between January 15, 2016, and February 25, 2016, 360 members of the public submitted comments to the Commission via e-mail or mail. Of those written comments, 115 were identical, or nearly so, and expressed the following positions: 1) support for closing DEP's coal-fired plant in Asheville; 2) support for replacing that plant with renewable energy rather than an "over-sized gas plant"; 3) support for DEP's proposal to install 15 MW of solar and 5 MW of storage; 4) the belief that DEP has historically over-estimated electricity demand and favored building power plants "which drive profits for its shareholders"; 5) job-creating energy efficiency programs are a viable option; and 6) approval for DEP's proposed third gas unit is premature and would be "betting against the success of the new clean energy partnership it is forming with the City of Asheville and Buncombe County."

The Commission received another 187 statements expressing opposition to DEP's proposal. About half of these expressed opposition to the "fast track" review process created by the Mountain Energy Act. They urged the Commission to slow the CPCN review process down to ensure a thorough review. About a third strongly opposed any gas plant in Asheville and/or wanted DEP's proposal to be scaled back to be as small as possible while maintaining reliability. The major reasons for this opposition were: 1) the plant would contribute to climate change; 2) the plant would directly or indirectly involve natural gas production via hydraulic fracturing, which they asserted causes water pollution, earthquakes, and methane emissions; and 3) any burning of fossil fuels harms the environment. Those who opposed the natural gas-fired units believe solar power and energy efficiency can meet the area's electricity needs, with some also supporting wind power and, to a lesser degree, hydropower. Some stated that these alternatives would create badly needed jobs. Many commenters felt DEP's proposed 15 MW solar installation should be larger and that a CPCN request for that solar facility should have been included in the instant application. Several writers encouraged the Commission to make approval of the pending CPCN contingent on DEP pursuing the solar facility. Similarly, many commenters supported DEP's proposal for 5 MW of battery storage, but thought the Company should build even more.

About a dozen writers asserted that DEP could buy the needed power from other entities. Several people stated that the existing transmission lines could accommodate the needed imports. A few opposed allowing the plant to export power outside of the DEP-Western Region. Several mentioned the option of buying power from Columbia Energy or from unspecified hydropower facilities. About a dozen people expressed concern that natural gas might not always be available, or that its price could increase in the future, raising costs for consumers. A few writers believe that a carbon tax will eventually be enacted, and oppose DEP's natural gas-fired facilities because those taxes would eventually be borne by consumers.

About two dozen writers urged the Commission to require DEP to be more transparent about its energy consumption forecast and the model it uses to forecast energy and peak demand.

Some asserted that DEP has over-estimated its future demand and stated that an independent review of DEP's forecasts is needed.

Among those writers who oppose the natural gas-fired plants, about a dozen expressed support for shutting down the existing coal plant and removing the coal ash.

Twenty-nine writers expressed support for the Project; almost all of them said that they live in the Asheville area. Many stated that they own or work for businesses or Asheville area civic organizations, including: Asheville Area Chamber of Commerce; Asheville Savings Bank; Biltmore Farms; Burlington & Harris, PA; Constangy, Brooks, Smith & Prophet, LLP; Diamond Brand Gear Company; Economic Development Coalition for Asheville-Buncombe County; ECS Carolinas, LLP; First Citizens Bank; GE Aviation; GFoss Consulting, LLC; JB Media Group, LLC; Johnson Price Sprinkle, PA; TD Bank; and Windsor Boutique Hotel.[1]

Those who wrote to support the Project emphasized that natural gas is a cleaner fuel than coal, and that the new facilities would provide reliable, efficient and affordable electricity. They stated that affordable and reliable power is very important for attracting businesses to the area. They acknowledged that Asheville is growing quickly, and half of them specifically supported approval, now, of the contingent peaking unit. On the whole, the supporters expressed support for DEP's efforts to develop renewable energy, but they stated that solar is good "only when the sun shines." One writer expressed concern that development of utility scale solar would require the clearing of many trees. Several stated that DEP's proposed project would create jobs, and several expressed support for removing coal ash from the site. Several supporters acknowledged that there are vocal opponents to the project, but, as one writer stated: "While their voices may be loud, I do not believe that they represent the vast number of customers who will benefit from the plan."

In addition to the written comments summarized above, 51 people testified at the public hearing that the Commission held in Asheville on January 26, 2016: Carolina Arias, Harvard Ayers, Philip Bisesi, Marston Blow, Xavier Boatright, Ken Brame, Rebecca Bringle, Phillip Brown, Rick Burt, Bruce Clarke, Karen Richardson Dunn, Richard Fireman, Sabrey Franks, Avram Friedman, Kelly Gloger, Kendall Hale, Bob Hanna, Scott Hardin-Niery, Beth Henry, Katie Hicks, Ashleigh Hillen, Cathy Holt, Ken Huck, Steve Kaagan, Rowdy Keelor, Jane Laping, Bill Maloney, Kelly Martin, Judy Mattox, Pat Moore, Graydon Nance, Steven Norris, Lewis Patrie, Susan Presson, Steffi Rausch, Brad Rouse, Steve Runholt, Cathy Scott, Rachel Shopper, Mac Swicegood, Randy Talley, Ronald Taylor, Sara Lynch Thomason, Keith Thomson, Mark Threlkeld, Macon Verteskjall, William Vine, Joan Walker, Rich Wasch, Gabrielle White, and Alice Wyndham. Many of these individuals stated that, while they are members of the Sierra Club and/or MountainTrue, they were speaking on their own behalf, and most of them stated that they are DEP customers. Five of these speakers also submitted exhibits into the record.

The public witnesses at the hearing echoed the concerns that were raised in the written public comments described above. Many opposed the plant out of environmental concerns with the natural gas production technology called hydraulic fracturing. Many speakers believe that the proposed facility is too large and that DEP's request to build the peaking plant is pre-mature. Many

[1] Some of the entities represented in these twenty-nine filings represent a larger population. For example, there are approximately 1,719 members in the Asheville Area Chamber of Commerce.

spoke in support of renewable energy and stated that DEP's proposed solar facility should be larger and should have been included in the pending CPCN application. Similarly, many stated a preference for wind power, and several voiced support for hydropower. Some expressed support for DEP's battery storage facility, but asserted that it should have been larger and should have been included in the current CPCN application. A large number of speakers voiced support for energy efficiency and demand response programs. Many expressed support for DEP's closure of the existing coal plant, and several stated support for DEP's cancellation of the Foothills Transmission Line. A few people expressed opposition to the Mountain Energy Act and stated that, due to the Act, there would be no opportunity for DEP's witnesses to be cross-examined. Several asserted that DEP's forecasting methods need review and that its forecasting model should be disclosed. One person asserted that it is inefficient to use natural gas to make electricity and then to use that electricity to heat homes. He asserted that DEP's system wouldn't be peaking in the winter, but "we've been suckered into using electric heat."

The concern most consistently voiced at the public hearing was that of climate change and the belief that methane produced during the natural gas production process, along with emissions from the plant itself, would contribute to global warming. Several speakers cited the recent methane leak from the Porter Ranch, California, natural gas storage facility to emphasize their opposition to natural gas-fired electricity production due to its methane risks. Several speakers mentioned the Clean Power Plan, the United States Environmental Protection Agency (EPA) rules for the reduction of carbon dioxide emissions from existing power plants. They wanted the State to move ahead to comply with these rules and expressed concern that North Carolina has instead challenged the EPA rules in court.

SUMMARY OF PUBLIC STAFF'S RECOMMENDATIONS
AND PARTIES' COMMENTS AT STAFF CONFERENCE

Public Staff's Agenda Item and Comments

The Public Staff presented its findings, conclusions and recommendations to the Commission at the Commission's Regular Staff Conference on February 22, 2016. As set forth in the application, the CC units will consist of two power blocks, each with one CT, one heat recovery steam generator (HRSG), and one steam turbine (ST), which will be designed to operate in a simple cycle configuration if the steam cycle is not available. The power blocks will be sited in the former "1982 Ash Pond" area, which is currently being excavated. One power block will be connected to the Company's existing 230 kV switchyard with a single 230 kV line. Both the ST and the CT will be connected to the single 230 kV line. The other power block will be connected to the existing 115 kV switchyard via two 115 kV lines. The ST will be connected to one 115 kV line, and the CT will be connected to the other 115 kV line. DEP's 2014 IRP calls for continued operation of the Asheville coal units until 2031 with the construction of two fast-start CTs in 2019 to meet reliability requirements in the Company's western region. The contingent CT unit would be sited near the two existing 185 MW (winter rating) CT units at the Asheville facility.

Natural gas for the CC units will be provided by a new intrastate pipeline being constructed by Public Service Company of North Carolina, Inc. (PSNC), pursuant to an agreement for firm transportation redelivery service between PSNC and the Company.

According to the application, DEP serves 160,000 households and businesses in its DEP-Western Region. The Company states that the WCMP will enable the early retirement of the 379 MW (winter rating) Asheville 1 and 2 coal units on or before the commercial operation of the new CC units, thereby permanently ceasing operations of all coal-fired units at the site.[1] The CC units are planned for commercial operation in the fall of 2019. The contingent CT unit would potentially begin commercial operation in 2024 if the current peak demand growth is not sufficiently reduced by the alternative approach discussed in the application. The existing on-site CT units will continue in operation.

As stated in the application, since the year 2000, the annual winter peak loads in the DEP-Western Region have increased at an average rate of 2.5%. Over the next decade, winter peak demand in the DEP-Western Region is projected to outpace that of the rest of the DEP system in North Carolina and South Carolina, and to grow at an annual rate of 1.6%, with a total growth of approximately 17% over the next decade. As a result, the Company's 2014 IRP shows a resource need of 126/147 MW (summer/winter) of fast start CT[2] capacity in the DEP-Western Region. Construction of the CC units will allow for the elimination of this CT capacity as well as the retirement of the 376/379 MW (summer/winter) of coal capacity at the Asheville Plant. Retirement of the coal units at the Asheville Plant in the time frame provided under the Mountain Energy Act (January 31, 2020) will also allow the Company to avoid significant capital investments in environmental controls required by CAMA (i.e., new dry fly ash and bottom ash handling technology and storm water requirements).

A significant additional benefit associated with constructing the CC units in the proposed time frame rather than constructing CC units for commercial operation commencing in 2031, the current projected retirement date of the two coal-fired units at the Asheville Plant, is the opportunity for DEP to participate at incremental cost in a new intrastate natural gas pipeline project being constructed by PSNC in Western North Carolina. Postponement of the Project likely would result in significant future costs associated with incremental capacity upgrades to the pipeline to serve the CC units. The confluence of events involving the extension of natural gas capacity in the region and construction of the CC units in the proposed timeframe produces cost-saving synergies that will benefit ratepayers.

Moreover, replacement of the coal units at the Asheville Plant with the CC units will provide benefits to both the DEP-Western Region and the DEP system as a whole. Currently, at the time of the system peak, all Company-owned resources in the DEP-Western Region are required to meet demand. In addition, even with those resources fully dispatched, the region requires the utilization of imported power via limited transmission options.[3] NERC reliability

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[1] DEP's 2014 IRP calls for continued operation of the Asheville coal units until 2031 with the construction of two fast-start CTs in 2019 to meet reliability requirements in the Company's western region.

[2] Fast start CTs provide greater system reliability and flexibility due to their ability to quickly respond to balancing authority area (BAA) changes in demand or loss of generation. For example, a fast start CT can achieve 100% of its rated output in less than 15 minutes, whereas a coal unit takes several hours before it can produce any power at all after it has been shut down.

[3] In its application, DEP asserts that there is a maximum Total Transmission Import Capability of 750 MW into the DEP-Western Region. Of this total, 198 MW must be held in reserve as Transmission Reliability Margin in the event of the loss of the largest single unit in the BAA, currently Asheville Unit 1. DEP also has 164 MW of import commitments.

standards require mandatory compliance by balancing authority areas (BAAs) to ensure sufficient reserve transmission capacity into the BAA to respond to system disturbances in a timely manner.[1] As load continues to grow, either more generation or more power import capability or both is required to maintain system reliability. The Company's original WCMP proposal to add transmission capacity in the region (the Foothills Transmission Line) together with the construction of a 650 MW CC unit at the Asheville Plant was met with extensive community opposition and has been cancelled. The revised configuration of the CC units reduced the size of the CC capacity as originally proposed and was selected by the Company to optimize existing transmission capacity, while improving the economic dispatch of the generation serving the DEP-Western Region and the entire DEP system. The new CC units are projected to operate at significantly higher capacity factors than the existing coal units, providing system-wide fuel cost savings and potential emission benefits. Thus, the new CC units will provide some room for load growth in the region, provide greater operational flexibility due to their ability to operate as intermediate and peaking units, as needed, in addition to their primary use as baseload, and serve as a resource for the broader DEP system when not fully required to meet demand in the DEP-Western Region.

The CC units will have a total generating capacity of 560 MW compared to the 379 MW of coal that DEP will be retiring. However, given the projected energy and peak demand growth along with the transmission constraints in the DEP-Western Region, the Public Staff asserts the incremental additional generating capacity to be reasonable and necessary to maintain adequate and reliable service in the area both now and in the future and, as stated above, will eliminate the need to construct fast start CT capacity in the near future.

While the Public Staff posits that granting the Company's request for a CPCN for the CC units will accomplish the purpose of the Mountain Energy Act and is otherwise required by the public convenience and necessity, DEP's request that the CPCN include the construction of a contingent 186 MW (winter rating) natural gas-fired CT unit at the Asheville Plant is problematic. Unlike the CC units, which must be in commercial operation in time for the coal units to cease operation by January 31, 2020, the CT unit does not require the expedited decision-making prescribed under the Mountain Energy Act. Based on current projections, it is likely that additional capacity eventually will be required to meet future demand in the DEP-Western Region, but such additional capacity (which takes 24 months to construct) is not expected to be needed until 2024, eight years from now, and that need is contingent on (a) the success of energy efficiency and demand side management efforts, (b) load growth in the area and (c) potential lower cost developments that may materialize in the future. In the Public Staff's view, the better course of action at this time would be for the Commission to wait and see how load growth develops in the region and whether collaboration between the Company and the Asheville community results in reduced electricity usage and demand. Not granting a CPCN for the additional CT unit will allow time for advances in generation, transmission, and storage technologies that may provide other least cost resource options for the Company to consider should load growth continue as projected

DEP uses the remaining 388 MW of import capability into its West BAA to transfer firm capacity and energy from its East BAA into its West BAA. The West BAA has 865 MW of internal generation and a realized peak load of nearly 1,200 MW.

[1] NERC reliability standard TOP-004 requires each transmission operator to operate within certain limits so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe credible single contingency (e.g., loss of the largest generating unit or loss of a major transmission line within the BAA).

without significant reductions in demand as a result of community collaborative efforts with the Company.

In summary, the Public Staff opined that through the passage of the Mountain Energy Act, the General Assembly has expressed, as a matter of public policy, its desire that the coal units at the Asheville Plant be replaced with on-site natural gas-fired generation. The replacement of these units with the CC units proposed by DEP in its application is consistent with the purposes of the Act, and that the public convenience and necessity require the construction of the CC units in the timeframe proposed.

Finally, the Public Staff indicated that although the Commission is not required to approve a cost estimate for the facility under the Mountain Energy Act, the Public Staff did review the Company's cost estimates for the CC units, including the basis of the estimates and process being undertaken to contract with vendors for the units, and determined that the estimates and contracting process, are consistent with recent additions of CC units in the service areas of DEP and DEC. Based on the foregoing, the Public Staff recommended the issuance of an Order granting the requested CPCN only for the CC units with the conditions as outlined in its filing dated February 17, 2016.

Intervenor Comments

Intervenor Rouse agreed with the Public Staff's recommendation to close the coal units at the Asheville Plant, to deny DEP's request for the construction of the contingent CT unit, and for DEP to provide annual reports on its progress in reducing peak load and building solar capacity at the site. Rouse made two additional requests: (1) the Commission should order Duke to work with the customers in Western North Carolina to develop a specific addendum to its biennial IRP, wherein the contents of this IRP should include the preferred strategy to meet future Western North Carolina needs without the contingent CT, including peak load reductions, solar, storage, along with the consideration of wind, hydropower and additional transmission; and (2) the Commission should only approve two 188 MW CC units, the same capacity as the two coal-fired units to be retired, if the CC units are built instead of DEP's requested two 280 MW CC units. Rouse asked the Commission to visualize what the future will be like in 20 to 30 years. He questioned whether the nation will still be using fossil fuels or whether there will be monumental change because "humanity [is] being challenged to use all of its productivity and innovative capacity to rid itself of fossil fuels." He stated if the Commission's vision is continued use of fossil fuels, then the Commission should adopt the Public Staff's recommendation, but if the Commission's prefers innovation, the future is all renewables and the amount of natural gas-fired capacity being built is too great. He stated that the largest unit in Western North Carolina is increasing from 188 MW to 280 MW and that from a NERC compliance standpoint, nothing will be gained.

Columbia Energy indicated that it owns an existing 535 MW cogeneration power plant in South Carolina that is a QF under PURPA. Columbia Energy stated that its interest in this proceeding is in protecting its rights under PURPA. Columbia Energy posited that DEP acknowledged that it did not evaluate the wholesale market for alternatives to meet the resource needs which are described in its application. While PURPA does not mandate rejection of DEP's application in favor of a power purchase agreement with a QF, Columbia Energy stated that it is concerned that DEP may seek to avoid its PURPA obligations, which include the obligation to purchase all capacity made available at the electric utility's avoided cost rates. Columbia Energy is concerned that DEP will cite approval of this project in arguing in a future case that a power purchase agreement for the output of its facility would not avoid capacity costs for the full capacity made available by this QF. Columbia Energy argues that PURPA does not allow DEP to ignore available QF capacity to meet needs for which it would otherwise build new facilities. Columbia Energy acknowledged that the parties' potential dispute will be the focus of another docket. However, Columbia Energy indicated concern because DEP has rejected an offer by Columbia Energy and proposed only a short-term power purchase agreement with an energy-only rate and no proposal for payment for capacity. Lastly, Columbia Energy stated that with DEP's reported future capacity needs, it might be that DEP can simultaneously construct the 560 MW that the Public Staff has recommended and accommodate a power purchase agreement with Columbia. However, until an agreement is signed under PURPA, Columbia Energy argues that output from its facility is a viable alternative to a significant addition of generation to DEP's system.

NC WARN stated that the primary purpose of G.S. 62-110.1 is to regulate the expansion policy of electric utility plants in North Carolina to provide for the public need for electricity without wasteful duplication or over expansion of generating facilities. NC WARN stated that the Mountain Energy Act unrealistically expedites this process. NC WARN argued that a 30-day notice and a 45-day review period does not allow the Commission the opportunity to review the cost of the facility, the alternatives to the facility, the need for the facility, the long term costs, and the natural gas prices. Therefore, NC WARN opined that the Mountain Energy Act is unconstitutional, as applied. NC WARN argued that the lack of opportunity to put on expert witnesses and testimony and the restricted review period of only 45 days results in the Commission not being able to fairly regulate DEP. NC WARN requested that the Commission deny DEP's application without prejudice so that all parties can conduct a full review with all of the procedures set forth in Chapter 62 as opposed to this expedited procedure. Further, NC WARN argued that a lot of information in DEP's application was confidential and that the public did not have a chance to review that confidential information. NC WARN offered Dr. Howarth's comments, stating that he is one of the leading scientists in the world on the impacts of natural gas and its pollutant methane on the global climate. Dr. Howarth states that methane is 80 to 100 times more dangerous than carbon dioxide to the climate, supporting NC WARN's contention that natural gas is not a bridge fuel; rather, it is as potent or as dangerous in some ways as coal. NC WARN provided an affidavit by Mr. Hughes looking at natural gas prices based on his analysis of different natural gas fields. The affidavit indicates that natural gas is at as low a price now as it has been for a long time, but that the Commission should look to the future and that the price will go up significantly. Building this plant will lock DEP into an expensive natural gas future. NC WARN provided an affidavit by Mr. Powers who looked at the need for the plant as opposed to alternatives in a "responsible energy future." NC WARN argued that there is well over 100 MW of dispatchable hydropower that is not part of this plan and that it was offered to DEP as an alternative. NC WARN also suggested that DEP should look to see whether the transmission lines can be reconductored to allow more power to be delivered to Asheville from Columbia Energy or some other plant. NC WARN requested that DEP honor its commitments to build solar in the DEP-Western Region and that the Commission should create tangible goals for energy efficiency and demand side management in the region. Lastly, NC WARN stated that there is no justification for DEP's 17 percent increase in the growth rate for electric usage in the Asheville area. NC WARN indicated that when looking back at previous IRPs back to 2003, DEP's load forecast was many times higher, as much as 4 or 5 times higher, than the actual demand that was subsequently reached.

Sierra Club stated that it strongly supports DEP's decisions to retire the existing 379 MW Asheville coal units in 2020 and to cancel the Foothills Transmission Line Project. However, it has concerns about the amount and type of capacity being requested to replace the capacity of the coal units. Sierra Club indicated it agrees with and joins the Public Staff in asking the Commission to deny Duke's request to certify the contingent 186 MW CT unit, but it respectfully disagrees with the Public Staff's recommendation to grant a CPCN for the two 280 MW CC units. Sierra Club stated that DEP has an incentive to overbuild its system and maximize revenue for its shareholders. Sierra Club posited that our courts have recognized that the purpose of G.S. 62-110.1 and of the public convenience and necessity standard is to prevent costly overbuilding. Sierra Club recognizes that the Commission's regulatory oversight provides an important check on DEP's incentive to overbuild. Sierra Club highlighted five points that Richard Hahn, its consultant, made upon his review of DEP's application. First, DEP failed to give serious consideration to cleaner, potentially cheaper alternatives, such as renewable energy resources, demand response, energy efficiency, and purchased power that could eliminate or reduce the need for this Project. Second, DEP has not demonstrated on the record in this proceeding that DEP-West is a legitimate load pocket due to import constraints. Third, DEP recently increased its planning reserve margin from 14.5 percent to 17 percent based on a study that was not even complete at the time, a change that alone results in an increased capacity need of 355 MW across the DEP system. Fourth, even after the coal units are retired there will be enough capacity available in DEP-West except during times of peak demand, suggesting that if DEP needs new natural gas-fired capacity in DEP-West, it should build peaking units which would cost less, run less, and pollute less than CC units that would be run as intermediate or baseload units. Sierra Club indicated that these four points lead to the conclusion that DEP has not shown that its proposal is required by the public convenience and necessity. Finally, assuming what DEP says about the basis for the proposal to build two CC units, a smaller plant would provide the same level of reliability in DEP-West. Sierra Club indicated that DEP could meet customer needs in DEP-West with two 185 MW CC units in 2020 and one contingent 100 MW CT in 2024 without compromising reliability.

Sierra Club stated that even though the General Assembly might have expressed a policy preference that the coal plants at the Asheville site be replaced with natural gas, the legislature did not prescribe a specific result, and it did not relieve the Commission of its duty to apply the public convenience and necessity standard. Further, if the legislature wanted to mandate a new natural gas-fired plant or a specific plant configuration or size, it certainly knew how to do that. The legislature did not do that. Instead, the General Assembly entrusted this Commission, the regulatory body with expertise in utility resource decisions, to make that decision. Sierra Club asked the Commission to deny the application and allow DEP to reapply with the right size project. Sierra Club argued that DEP itself has said that it takes two to three and a half years to build a new natural gas-fired plant, so Sierra Club argued there is still time to reapply without delaying the retirement of the Asheville coal plant. Alternatively, if the Commission does grant a CPCN based on the pending application, it should only issue a certificate for two 185 MW CC units and should deny the certificate for the contingent CT unit. If the Commission does grant a CPCN for any new natural gas-fired capacity at the Asheville site, it should require DEP to retire additional coal-fired generating capacity corresponding to any incremental capacity certificated over and above the 379 MW of coal capacity being retired at the Asheville site, just as the Commission did with the

Wayne County CC application several years ago under a similar fast track statute.[1] Lastly, Sierra Club requested that the Commission hold Duke to its commitments to invest in clean energy resources in Western North Carolina, including demand response, energy efficiency, solar, and storage.

DEP Response

DEP presented the impetus for DEP's filing requesting a CPCN application for the Project, a summary of the Project, and a response to comments by the Intervenors. DEP stated that the Project provides a unique opportunity to reliably and cost-effectively meet its customer needs while transitioning to a cleaner and smarter energy future. DEP outlined the basics of the Project as set forth in more detail in its 441-page CPCN application filed on January 15, 2016. DEP indicated that the Project will allow it: (1) to retire early the existing 1960s vintage 379 MW coal units at its Asheville Plant; (2) to avoid building 147 MW of fast start CTs in the 2019 timeframe that were included in DEP's 2014 IRP; and (3) to partner with PSNC in its expanded natural gas pipeline to provide much needed natural gas service to Western North Carolina and the Asheville area. DEP will participate in that project at the incremental cost, saving its customers nearly twice what it would cost if Duke paid the full cost to build the pipeline itself. Lastly, DEP indicated that the Project is needed not only for the reliability of the fast-growing, nine county western region, but is also the most cost-effective resource to serve all of DEP's 1.5 million customers in North Carolina and South Carolina.

In response to Intervenor suggestions that DEP focus merely on building a facility of a certain size to "just" meet the reliability needs of the western region, DEP responded that it must plan and build its system with the most cost-effective size of units for its entire customer base because all of DEP's customers will pay for this generation if it is approved.

In response to Intervenor and public concerns about the "fast track process" under the Mountain Energy Act, DEP indicated that the Act, which was signed into law in June of 2015 and passed unanimously by the General Assembly, encourages DEP to retire its existing 1960s coal units and replace them with cleaner, more efficient, and more cost-effective natural gas-fired generation. DEP indicated that despite the expedited process that was required by the General Assembly, DEP has filed a complete CPCN application that includes all of the technical information about the Project, including costs, engineering, need, and benefits of the Project. Every party has had access to that detailed information since January 15, 2016. DEP indicated that portions of only 12 pages out of the 441-page application were filed under seal, and parties agreeing to sign a confidentiality agreement have had access to those pages. NC WARN declined to sign the confidentiality agreement to obtain access to this information.

DEP cautioned the Commission that without the Mountain Energy Act that extends CAMA deadlines and without this Commission's approval of the CPCN for the Project, DEP will be required to invest hundreds of millions of dollars in new environmental controls at the Asheville

[1] Order Granting Certificate of Public Convenience and Necessity Subject to Conditions, In re Application of Progress Energy Carolinas, Inc., Docket No. E-2, Sub 960 (Oct. 22, 2009) (decided under G.S. 62-110.1(h)).

coal plant. In addition, DEP will have to continue to operate the coal units until their projected retirement date of 2031.

DEP summarized the environmental benefits of the retirement of the coal units and replacement with the cleaner, more efficient natural gas-fired units as detailed in its application. DEP indicated that significant emission reductions will result from the retirement of the coal units: NO_x emissions will be reduced by 35 percent, SO_2 emissions will be reduced by 90 to 95 percent, CO_2 emissions will be reduced by 60 percent per megawatt-hour, and all mercury emissions will be eliminated. DEP stated that there are significant benefits from the standpoint of water usage as well. DEP indicated that the current Asheville coal units use once through cooling water. The new combined cycle units will use cooling towers, eliminating all thermal loading to Lake Julian and 97 percent of the water withdrawal from Lake Julian.

In response to those who have argued that there has been insufficient information shown as to need, DEP questioned whether those individuals have either been misled by someone or whether they have not had an opportunity to read the full application filed with the Commission. DEP indicated that the need for the Project is based on an IRP planning basis. DEP argued that the comments filed by many of the Intervenors appear to demonstrate a lack of fundamental understanding as to the difference between capacity and energy, a fundamental lack of understanding as to how load forecasts are prepared and approved by this Commission, as well as a fundamental lack of understanding of how electric systems are planned and maintained for a reliable and least cost basis. As detailed in the CPCN application, DEP indicated that the basis for this need is demonstrated in the 2015 DEP IRP. DEP stated that there exists a specific, unique situation regarding the DEP-Western Region, which DEP contends is an energy island.

DEP cited to the fact that the DEP-Western Region is an attractive place to live, to visit, to retire, and to work, and is the fastest growing region within DEP’s entire service territory. DEP indicated that since 1970, the western region’s electric needs have more than tripled. Since 2000, the annual winter peak has increased an average of 2.5 percent, far outpacing the growth in the rest of DEP’s system. The DEP-Western Region’s peak load forecast is projected to grow at approximately 17 percent over the next 10 years. DEP made clear that it is important to note that the DEP-Western Region is a winter peaking area as opposed to summer peaking, as in the DEP-Eastern Region and in South Carolina. DEP’s decisions and the capacity factors stated are based on meeting a peak winter need in its western region.

The original 2015 IRP for DEP included a single combined cycle unit of 733 MW (winter rating) and the construction of the Foothills Transmission Line, a 45-mile 230 kV transmission line from Asheville to Campobello, South Carolina, a community approximately 10 miles south of Asheville across the state border. DEP indicated that the DEP-Western Region is an energy island in that there is insufficient local generation to meet peak demand and that this region is a net importer of energy. The transmission facilities into DEP-West are significantly constrained so as to limit the import of additional energy. This constraint led DEP to propose the Foothills Transmission Line. DEP outlined that the Foothills Transmission Line was met with significant opposition from its customers in North Carolina and South Carolina. DEP indicated that in the face of that opposition and the real likelihood that there would be litigation and appeals that would delay construction of that line for many years, DEP made the decision to cancel the Foothills Transmission Line in November of 2015, so that DEP could attempt to meet the deadline for retirement of the coal units by January 20, 2020, per the Mountain Energy Act. DEP reconfigured the Project to propose two smaller units in order to maximize the amount of local generation given no new transmission import capability.

DEP noted that even if DEP builds both CC units and the CT unit as part of the Project, the DEP-Western Region will still have insufficient generation to meet its peak load needs and DEP will still rely upon transmission import capability, which is severely limited. DEP referred the Commission to Table 1 of Exhibit 1B to the CPCN application, which shows that even after the Project is built, there will be only 470 MW of usable transmission (or 470 MW of import capability) into the DEP-Western Region. DEP stated that currently that capacity is used to transport purchased power into the region as well as to transfer power from DEP-East to DEP-West. DEP noted that NCEMC has an option to purchase 100 MW of the CC unit. Regardless of whether NCEMC exercises its option and, thus, whether DEP owns 460 MW or 560 MW of the CC units, the load that DEP will have to serve in the western region remains the same.

In responding to comments regarding the capacity factors of the coal units, DEP indicated that DEP operates its system in a least cost manner. DEP indicated that the coal units in Asheville are run out of economic dispatch throughout the year because of the local voltage and reliability needs. DEP, in operating the system in a least cost manner, will, when load conditions enable it, import cheaper energy from the eastern part of the system. Such energy is largely generated in natural gas-fired units, resulting in the lower capacity factors for the coal units.

DEP stressed that its reliability concerns, which are detailed in Attachment A to Exhibit 1B, are real and cannot be ignored as some of the Intervenors would like decision-makers to do. DEP explained that there is a minimum amount of Asheville generation that is required to be online at all times to supply voltage and provide reliable service given planning contingencies. These contingencies include a generator being offline. Also, DEP must review the transmission lines in the area and the impact on them if one or more of those transmission lines is unavailable.

DEP highlighted that since November 2008, DEP has declared four energy emergency alerts (EEA) for DEP-West due to having marginally enough capacity to serve load. Three of these events were EEA Level 2. The next level, EEA Level 3, requires shedding firm load, which is commonly known as rolling blackouts. These events occurred on November 19, 2008, January 4, 2012, January 7, 2014, and February 20, 2015.

DEP stated that the size of the CC units proposed as part of the Project were engineered specifically, based on the criteria to optimally meet the load and reliability requirements given the transmission import constraints and to provide for cost-effective system needs for the benefit of all DEP customers. DEP explained that the Intervenors who argue that the size of the CC units is too large fail to recognize that when there is insufficient load in the western region, those new CC units as part of the Project will be the most efficient and most cost-effective natural gas-fired units on DEP's system and will be used to serve DEP's customers in eastern North Carolina and in DEP's service territory in South Carolina. The result, as the Public Staff noted in their recommendation, means a lowering of costs to all of DEP's customers.

In response to Intervenor concerns regarding whether DEP has shown a need for the CT unit because the CT unit's need could be delayed or eliminated if DEP is successful in collaborating with its community partners to get the community to reduce its peak load demand growth, DEP stated that the need is real and has been shown. DEP argued that even though there is a need for this CT unit, there is the potential to delay or eliminate the need through other measures, such as energy efficiency (EE), demand side management (DSM) and other technologies.

DEP has committed to work with the community to aggressively seek EE, DSM, renewables, and other technologies that could delay or eliminate the need for the CT unit. DEP summarized actions it has engaged in to date as part of its commitment to a cleaner, smarter energy future. As to EE and DSM measures, DEP has been working with Asheville area community leaders to develop a collaborative effort to maximize participation in its existing programs and to develop new programs and services. Some examples include education and training. DEP's head of Integrated Resource Planning recently participated on a panel with NCSEA, MountainTrue, and New Belgium Brewing at an event sponsored by UNC Asheville to discuss utility planning and efforts to reduce peak demand. DEP has begun working with the City of Asheville to set up training for its building and code enforcement personnel so they can promote EE and DSM measures. DEP has also agreed to participate in several upcoming events and provide demonstrations of EE and DSM measures.

DEP indicated that it has also worked aggressively to promote its existing programs. DEP has used a targeted Facebook ad directed at members of the DEP-Western Region to promote its EE programs, and the ads were somewhat successful in signing up new participants. DEP is canvassing door-to-door to promote its EnergyWise load control programs, signing up 53 new participants on the first day. DEP is also in the process of developing a community steering team that will work with the DEP to develop further efforts to promote and market these programs and hopes to have a team in place by the end of March or early April.

DEP indicated that it has applied for community attendance at the Rocky Mountain Institute's electricity accelerator, or eLab where innovative ways of conserving energy and reducing peak load growth will be discussed. The participants in that program include an Asheville City Council member who is also a leader of Intervenor MountainTrue, the Assistant City Manager for the City of Asheville, a Buncombe County Commissioner who is also an executive with FLS Solar, a local environmental advocate, a community organizer, and several Duke Energy employees.

DEP indicated that some Intervenor comments relate to DEP's commitment to renewables. DEP stated that it is committed to pursuing a CPCN for new solar generation in Asheville for a minimum of 15 MW. DEP indicated that the size of the solar facility at the Asheville plant cannot be known until the Asheville coal units are demolished and the 1964 ash basin is excavated. DEP explained that it takes approximately 100 acres for a 15 MW utility-scale solar facility. DEP committed that if the Asheville site configuration does not allow the construction of 15 MW or more of solar generation, it will supplement the on-site solar facility with a combination of rooftop, community, or other utility-scale solar facilities at other locations in the Asheville area. Furthermore, DEP did not include the solar facility in this CPCN application because the Mountain Energy Act, under which the present application is filed, only applies to new generation that is primarily fueled by natural gas.

DEP has also committed to pursue new technologies, including battery storage. DEP indicated that it is one of the larger deployers of battery storage in the United States and owns approximately 15 percent of all battery storage that is interconnected to the grid in the entire country. DEP has committed to pursue a pilot project of a minimum of 5 MW of battery storage at the Asheville site, which will be the largest regulated utility battery project in North Carolina. DEP indicated again that the battery storage project is not fired by natural gas and, therefore, is not included in the Mountain Energy Act's CPCN provisions.

DEP stated that it asked counsel for all of the Intervenors to make a commitment to support a future CPCN application for a CT if the Commission denies the current request for a CPCN for the CT unit and the collaborative efforts are unsuccessful, in delaying or eliminating the need for that CT unit but no parties have made such commitment.

DEP concluded the discussion of need by stating that the public convenience and necessity require construction of the Project based upon the facts presented in its application and its presentation at the Commission's Regular Staff Conference. DEP indicated that it does not have the luxury of single issue focus like some the Intervenors in the present docket. DEP indicated that it must look at all of its customers' needs, which include commercial, industrial, and residential customers. DEP has to consider a broad range of scenarios, including whether natural gas prices are going to increase or whether CO_2 prices or a carbon tax will exist, all of which were modeled through a robust IRP process and detailed in the CPCN application. DEP has an obligation to consider all of those factors and many others in making its decision and submits that the record is clear that the Project is the best solution to meet DEP's customers' needs and allow the transition to a cleaner, smarter energy future.

DEP also responded to the Intervenors' comments made at the Regular Staff Conference. Intervenor Rouse and Sierra Club argued for a smaller CC unit. Rouse suggested a 185 MW CC as opposed to a 280 MW CC unit. DEP responded that a 280 MW CC unit is the most cost-effective means of serving the needs reliably, given the transmission import limitations. Some Intervenors suggested that the units be CT versus CC, and DEP indicated that CTs are more appropriately a peaking resource as opposed to a CC, which is used more for baseload reliability. Further, DEP indicated that smaller-sized units would only meet today's load requirements for 2016 and not for the future load growth. DEP indicated that it must provide for the needs of its customers not just for 2016 but for the future as well.

In response to the arguments of Columbia Energy, DEP agreed that it is a QF, but stated that any issues between DEP and Columbia Energy are matters for another docket to resolve issues surrounding any power purchase agreement (PPA) under PURPA. DEP further opined that the proper Commission to resolve such issues would be the Public Service Commission of South Carolina as the QF is located in South Carolina approximately 170 miles from Asheville. DEP indicated that Columbia Energy first approached DEC in 2015 to ask for some information concerning the Company's avoided cost rates, and that it was only in January 2016 that Columbia Energy first approached DEP. DEP provided Columbia Energy its avoided cost rates in South Carolina because that is where DEP understood the facility would interconnect. DEP indicated it understands now that Columbia Energy is interconnected to the South Carolina Electric & Gas system.

DEP's understanding is that Columbia Energy has submitted a transmission study request into DEP-East in South Carolina, as opposed to Columbia Energy's assertion that there was a firm transmission request pending. DEP further believes that in order to get to DEP-East, Columbia Energy will have to wheel through South Carolina Electric & Gas' transmission system. Thus, the Columbia Energy facility is two wheels away from the DEP-Western Region. Further, DEP's understanding is that Columbia Energy has not yet elected to proceed in response to the avoided cost rates provided by DEP, and there have been no negotiations as to a PPA. DEP argued that if Columbia Energy was contemplating building a new transmission line from south of Columbia to Asheville or obtaining transmission into DEP-West, this option would not meet DEP's reliability needs because the generation is not located in the western region. DEP reiterated that transmission constraints into the western region exist and that voltage requirements require DEP to site the new generation in the Asheville region. DEP argues that if it enters into a PPA with Columbia Energy at some point in the future, this PPA will have no impact on the needs to be served by the Project.

NC WARN questioned the load forecast for the DEP-Western Region and questioned how 17 percent could be a reasonable load forecast. DEP indicated that it answered three sets of data requests from NC WARN. DEP provided all of the details about the load forecast, including all of the equations behind the load forecast and all of the summary statistics. The only information DEP did not provide was the underlying software because DEP has a license from the software owner, Itron. DEP runs the models, and it provided NC WARN with all of the data underlying those model runs. DEP noted that NC WARN makes this exact same argument every year in the IRP docket where these arguments have been repeatedly rejected by the Commission.

DEP indicated that NC WARN has argued that United States Energy Information Administration (EIA) data support its theory of a zero load growth forecast. DEP disagrees and requests that the Commission review the most recent EIA data, which projects a 0.8 percent electric load growth for the entire United States. In looking at the EIA data, it shows annual electric usage growth is projected to be 1 percent per year for the period of 2016 to 2026 for the South Atlantic region, which includes North Carolina. DEP has provided data that show that the DEP-Western Region, which has grown faster from a winter peak standpoint than the rest of the system that DEP serves, has grown an average of 2.5 percent per year since 2000. DEP urged the Commission to note the emergency alert reliability information that DEP discussed earlier, which proves that the load growth and demand growth is real. Finally, DEP provided that in each of the past two winters the DEP-Western Region peak load was nearly 1,200 MW.

DEP briefly indicated that it found NC WARN's concern regarding the confidential portions of the application and lack of full access to information disingenuous when NC WARN has been offered the opportunity to sign a confidentiality agreement and has refused to avail itself of such access. Lastly, DEP noted that NC WARN is inconsistent in criticizing DEP's choice to rely upon natural gas for the Project, but supporting natural gas when it is used by Columbia Energy.

In responding to Sierra Club's argument that DEP failed to show that the transmission import capability into the western region is limited, DEP argued that, given all of the evidence in the detailed CPCN filing, Sierra Club's position is not a credible one. DEP stated that in the affidavit submitted by Sierra Club, Mr. Hahn also argued that any CC unit should be in the 185 MW range. DEP argued that that size unit is going to be very inefficient compared to the

280 MW CC unit that DEP has proposed. Further, a simple cycle CT in that range is going to have a heat rate that is approximately 50 percent higher than the CC units. Thus, DEP stated that while DEP's customers would save money from an upfront capital cost standpoint, the production cost would be significantly higher. Finally, as to Mr. Hahn's analysis in Exhibit C, where he argues that DEP could retire the coal units and rely solely on the existing CT units and the existing hydropower units that DEP has in the western region, DEP states that his argument is basically that DEP should rely on the existing CTs as baseload. DEP argued that relying on CTs for baseload is a very uneconomic choice and that, from an air permitting standpoint, environmental regulators might not allow the CTs to run as baseload.

Many Intervenors questioned the expedited procedure set forth in the Mountain Energy Act. DEP responded stating that DEP has submitted detailed technical information, which has been available to the Public Staff and all parties, and that the confidential portion has been available to all parties that have signed a confidentiality agreement. Further, DEP submits that there is a full and complete record before the Commission. The Public Staff, as did most of the parties in this case, sent multiple data requests to DEP. The Public Staff spent several days in DEP's office reviewing detailed engineering and cost information. DEP indicated that it has not heard any statement from the Public Staff that it was unable to complete its investigation and make a recommendation within the prescribed time.

In response to Commissioner questions, DEP indicated the following:

1. If the application is denied, DEP would not be able to meet the Mountain Energy Act's requirements to obtain a CPCN by August 1, 2016, and the coal unit retirement deadline of January 31, 2020, which would force DEP to continue to run the coal units and make substantial investments in order to meet the original deadlines of CAMA.

2. North Carolina still has the Ridge Law which prohibits wind turbines from being constructed along mountain ridges, where the greatest territorial wind potential exists. Although it could not respond at Staff Conference about the wind potential in the valleys, the potential to use wind energy is part of the comprehensive IRP process, and, to date, wind has not met the reliability and cost-effectiveness test to be part of the short term action plan in the DEP IRP.

3. If DEP is required to enter into a PPA with Columbia Energy, that resource can be used to offset future system needs or other expiring contracts. Paragraph 16 of the application shows that from a total system perspective, the DEP 2015 IRP identifies the need for an additional 1,152 MW of new resources by 2020 and 5,099 MW by 2030.

4. In response to Mr. Hahn's question of import constraints, DEP assumed that what Mr. Hahn concluded is that the tie lines that connect the DEP-Western Region to other systems have a rating of 2,200 megavolt-amperes (MVA), and contrasting that with the 750 MW of import capability that DEP has identified, the numbers just do not add up. Sierra Club's apparent argument that there is at least 2,000 MW of import capability is simply not true. DEP explained that the grid is a complicated interconnected system and that one cannot simply look at the availability in terms of megawatts of transmission line

capacity, add them all together, and determine that the sum of the two numbers is the import capability. DEP provided the following examples in response:

> Hypothetically, if a region had two 1,000 MW transmission lines that provided import capability into that region, the maximum transfer capability would not be 2,000 MW, but 1,000 MW. Likewise, if a region had a 1,000 MW line and 100 MW line, the maximum import capability would be 100 MW because one must assume contingencies under the NERC reliability standards. DEP's balancing authority area, again, is connected through multiple lines at different capacities so the calculation is quite more complex than what's been asserted. [See] Table 1 in partially confidential Exhibit 1B for a description of this. Details providing how the transmission import limitations are determined was provided to MountainTrue and Sierra Club's counsel through discovery requests.

DISCUSSION AND CONCLUSIONS

The Commission's findings in this case are based upon matters of record, and its conclusions are based upon the findings and upon the Commission's assessment of the filings, comments, and arguments of the parties and the applicable law. The Commission is acting in this docket upon a verified application of DEP, comments of the Public Staff and Intervenors, including affidavits, public witness testimony, comments by the public filed with the Commission, and the presentations of the Public Staff, certain Intervenors, and DEP at the Commission's Regular Staff Conference. To the extent applicable, the Commission has followed the procedure it followed in Docket No. E-2, Sub 960 pursuant to G.S. 62-110.1(h) in 2009. The Commission asked the Public Staff to investigate the application and to present its findings, conclusions and recommendations to the Commission. The Public Staff prepared an agenda item at the conclusion of its audit and investigation and presented this matter at the Commission's Regular Staff Conference on Monday, February 22, 2016. The Public Staff stated that in its opinion as a result of its investigation the application meets the requirements of the Mountain Energy Act, comports with the public convenience and necessity, and that the Commission should grant DEP a CPCN for the construction of the two 280 MW CC units at the Asheville Plant.

The Mountain Energy Act prescribes procedures under which the Commission must consider and decide an application for a CPCN to construct an electric generating facility meeting the requirements of the Act. As stated in the Chair Order dated January 15, 2016, the hearing requirements of G.S. 62-110.1(e) and 62-82 do not apply if the application meets the requirements of the Act. The Commission concludes that the application filed by DEP is within the scope of Mountain Energy Act and that based on the record compiled by the Commission, the application, as modified, meets the public convenience and necessity test. Acting pursuant to the Mountain Energy Act, the Commission made a decision on the application within 45 days when it issued a Notice of Decision on February 29, 2016. The issues presented by the parties are fully discussed in this Order.

The first issue to be discussed is whether DEP has shown a need for the Project. Under the Mountain Energy Act, the Commission is not required to approve the estimated construction costs of the CC and CT units or make a finding that construction of the units will be consistent with the

Commission's plan for expansion of electric generating capacity. However, the expedited procedure under the Act did not remove the Commission's requirement to find that the public convenience and necessity require, or will require, the construction of the new units. The Commission, in making this determination, looks to information regarding construction costs and generation planning, which has been provided by DEP in its verified application and as commented upon by the Public Staff and other Intervenors.

Several Intervenors expressed concern over whether DEP is overbuilding generating capacity with its request to build two 280 MW combined cycle natural gas-fired electric generating units and one 186 MW combustion turbine unit at the Asheville Plant. Section 62-110.1 is intended to provide for the orderly expansion of electric generating capacity in order to create a reliable and economical power supply and to avoid the costly overbuilding of generation resources. State ex rel. Utils. Comm'n v. Empire Power Co., 112 N.C. App. 265, 278 (1993), disc. rev. denied, 335 N.C. 564 (1994); State ex rel. Utils. Comm'n v. High Rock Lake Ass'n, 37 N.C. App. 138, 141, disc. rev. denied, 295 N.C. 646 (1978). A public need for a proposed generating facility must be established before a certificate is issued. Empire, 112 N.C. App. at 279-80; High Rock Lake, 37 N.C. App. at 140.

Beyond need, the Commission must also determine if the public convenience and necessity are best served by the generation option being proposed. The standard of public convenience and necessity is relative or elastic, rather than abstract or absolute, and the facts of each case must be considered. State ex rel. Utils. Comm'n v. Casey, 245 N.C. 297, 302 (1957) (emphasis added). Subsections 62-110.1(c)-(f) direct the Commission "to consider the present and future needs for power in the area, the extent, size, mix and location of the utility's plants, arrangements for pooling or purchasing power, and the construction costs of the project before granting a [CPCN] for a new facility." High Rock Lake, 37 N.C. App. at 140-41. As hereinafter discussed, the Commission has considered all of these factors in determining whether the public convenience and necessity are served by DEP's proposal in this docket.

The Commission agrees with the reasoning of DEP, the Public Staff, and a number of the comments from consumers that the replacement of the two coal-fired generating units with the two CC units proposed by DEP in its application is consistent with the purposes of the Mountain Energy Act and that the public convenience and necessity require the construction of the CC units in the timeframe proposed.

Since the year 2000, the annual winter peak loads in the DEP-Western Region have increased at an average rate of 2.5%. Over the next decade, winter peak demand in the DEP-Western Region, based on reasonable assumptions, is projected to outpace that of the rest of the DEP system in North Carolina and South Carolina, and to grow at an annual rate of 1.6%, with a total growth of approximately 17% over the next decade. As a result, as shown in the Company's 2014 IRP, DEP has a resource need of 126/147 MW (summer/winter) of fast start CT capacity in the DEP-Western Region. Construction of the CC units will allow for the elimination of this CT capacity as well as the retirement of the 376/379 MW (summer/winter) of coal-fired generation capacity at the Asheville Plant. Retirement of the coal units at the Asheville Plant in the time frame provided under the Mountain Energy Act (January 31, 2020) will also allow the Company to avoid significant capital investments in environmental controls required by CAMA (i.e., new dry fly ash and bottom ash handling technology and storm water requirements).

A significant benefit associated with constructing the CC units in the proposed time frame rather than constructing CC units for commercial operation commencing in 2031, the current projected retirement date of the two coal-fired units at the Asheville Plant, is the opportunity for DEP to participate at incremental cost in a new intrastate pipeline project being constructed by PSNC in western North Carolina. Postponement of the Project likely would result in significant future costs associated with incremental capacity upgrades to the pipeline to serve the CC units. The confluence of events involving the extension of natural gas capacity in the region and construction of the CC units in the proposed timeframe produces cost-saving synergies that will benefit ratepayers.

Moreover, replacement of the coal units at the Asheville Plant with the CC units will provide benefits to both the DEP-Western Region and the DEP system as a whole. Under NERC standards, at the time of the system peak, all Company-owned resources in the DEP-Western Region are required to meet demand. In addition, even with those resources fully dispatched, the region requires the utilization of imported power via limited transmission options. NERC reliability standards require mandatory compliance by BAAs to ensure sufficient reserve transmission capacity into the BAA to respond to system disturbances in a timely manner. As load continues to grow, either more generation or more power import capability or both is required to maintain system reliability. DEP's original WCMP proposal to add transmission capacity in the region (the Foothills Transmission Line) together with constructing a 650 MW CC unit at the Asheville Plant was met with extensive community opposition and opposition from some of the same interests that now oppose DEP's application to replace the coal plants with natural gas-fired facilities and has been cancelled. The revised configuration of the CC units reduced the size of the CC capacity as originally proposed and was selected by the Company to optimize existing transmission capacity, while improving the economic dispatch of the generation serving the DEP-Western Region and the entire DEP system. While the revised configuration reduces some economies of scale, increased costs are offset in large measure by elimination of the costs of the 230 kV transmission line. The new CC units are projected to operate at significantly higher capacity factors than the existing coal units, providing system-wide fuel cost savings and potential emission benefits. Thus, the new CC units will provide capacity for load growth in the region, provide greater operational flexibility due to their ability to operate as intermediate and peaking units as needed, in addition to their primary use as baseload, and serve as a resource for the broader DEP system when not fully required to meet demand in the DEP-Western Region.

Even though the Commission does not need to make any findings regarding the estimated construction costs because G.S. 62-110.1(e) does not apply, based upon the Public Staff's review of the Company's cost estimates for the CC units, including the basis of the estimates and process being undertaken to contract with vendors for the units, and its determination that the estimates and contracting process are consistent with recent additions of CC units in DEP's and DEC's service areas, the Commission determines that the estimated construction costs are appropriate and may be relied upon in approving the construction project as modified.

The CC units will have a total generating capacity of 560 MW compared to the 379 MW of coal-fired generation that DEP will be retiring. However, given the projected energy and peak demand growth along with the transmission constraints in the DEP-Western Region, the incremental additional generating capacity is reasonable and necessary to maintain adequate and reliable service in the DEP-Western Region both now and in the future and, as stated above, will eliminate the need to construct 147 MW of fast start CT capacity in the near future.

Several Intervenors expressed concern over whether the public convenience and necessity standard had been met under the facts of the present case.

Sierra Club highlighted five points that Richard Hahn, its consultant, made upon his review of DEP's application. First, DEP failed to give serious consideration to cleaner, potentially cheaper alternatives like renewable energy resources, demand response, energy efficiency, and purchased power that could eliminate or reduce the need for this Project. Second, DEP has not demonstrated on the record in this proceeding that DEP-West is a legitimate load pocket due to import constraints. Third, DEP recently increased its planning reserve margin from 14.5 percent to 17 percent based on a study that was not complete at the time, a change that alone results in an increased capacity need of 355 MW across the DEP system. Fourth, even after the coal units are retired there will be enough capacity available in DEP-West except during times of peak demand, suggesting that if DEP needs new natural gas-fired capacity in DEP-West, it should build peaking units, which would cost less, run less, and pollute less than CC units that would be run as intermediate or baseload units. Sierra Club indicated that these four points lead to the conclusion that DEP has not shown that its proposal is required by the public convenience and necessity.

In reliance upon all of the evidence in the detailed CPCN application, and the record as a whole, the Commission determines that Mr. Hahn and the Sierra Club's position is not a credible one. With respect to Mr. Hahn's argument that any CC unit should be sized in the 185 MW range, that size unit is going to be less efficient compared to the 280 MW CC unit that DEP has proposed. As to Mr. Hahn's analysis in Exhibit C of his application, where he argues that DEP could retire the coal units and rely solely on the existing CT units and the existing hydro units that DEP has in the western region, his argument is essentially that DEP should rely on CTs as baseload. Relying on CTs as baseload is an uneconomic choice, and from an air permitting standpoint, the CT unit might not be allowed to run as baseload. Mr. Hahn does not address the issue of compliance with required air permits. Further, a simple cycle CT in that range is going to have a heat rate that is approximately 50 percent higher than the CC units. Thus, while DEP's customers would save money from an upfront capital cost standpoint, the plant's production costs over time would be significantly higher.

In response to Mr. Hahn's question of import constraints, Mr. Hahn seems to be arguing that the tie lines that connect DEP-West to other systems have a rating of 2,200 MVA,[1] and contrasting that with the 750 MW of import capacity that DEP has identified, the numbers fail to add up. Sierra Club thus seems to argue that there is at least 2,000 MW of import capability. As DEP correctly explained, this assumption is incorrect. The grid is a complicated interconnected system and one cannot simply look at the availability in terms of megawatts of transmission lines and add those transmission megawatts and determine that this sum equals the import capability. DEP correctly explained that hypothetically, if a region had two 1,000 MW transmission lines that provided import capability into that region, the maximum transfer capability would not be 2,000 MW, but 1,000 MW. Likewise, if a region had a 1,000 MW line and 100 MW line, the maximum import capability would be 100 MW because one must assume contingencies under the

[1] One megavolt-ampere (MVA) equals one megawatt (MW) with a power factor of 1.0.

NERC reliability standards. The contingency is if one line drops, say the 1,000 MW drops off, then DEP is only left with 100 MW of import capability and that is how DEP determines import capability pursuant to NERC standards. DEP's BAA, again, is connected through multiple lines at different capacities, so the calculation is more complex than Mr. Hahn's assertion, as provided in the description in Table 1 in partially confidential Exhibit 1B. Details providing how the transmission import limitations are determined were provided to MountainTrue and Sierra Club's counsel through discovery requests.

NC WARN also argued against issuance of a CPCN in the present case based upon lack of need. NC WARN stated that there is no justification for DEP's forecasted 17 percent increase in the growth rate for electric usage in the Asheville area. NC WARN indicated that when looking back at previous IRPs back to 2003, DEP's load forecast was many times higher, as much as 4 or 5 times higher, than the actual demand that was subsequently reached.

The Commission notes that DEP answered three sets of data requests from NC WARN regarding this issue. DEP provided to Intervenors, including the Public Staff and NC WARN, all of the details addressing the load forecast, including all of the equations behind the load forecast and all of the summary statistics. The only information DEP did not provide NC WARN was the underlying software because DEP has a license from the software owner, Itron, which precludes distribution. DEP runs the models, and it provided NC WARN and others with all of the data underlying those model runs. DEP noted that NC WARN makes the argument that DEP's load forecasts are inaccurate in the IRP docket every year, and NC WARN does not understand the validity of the load forecast models. The Commission has repeatedly rejected the NC WARN criticisms. The Commission notes that during periods like the 2014 Polar Vortex, not only DEP, but nearly all the electric utilities on the east coast struggled to avoid service disruptions. The Commission determines NC WARN's assertions of excess capacity overly simplistic and lacking credibility. Moreover, even if past forecasts had not accurately predicted the future, this alone does not indicate that current forecasts are suspect. Few predicted the 2007-08 recession.

NC WARN argued that there is well over 100 MW of dispatchable hydropower that is not part of DEP's plan and that it was offered to DEP as an alternative. NC WARN also suggests that DEP should look to see whether the transmission lines can be reconductored to allow more power to be delivered to Asheville from Columbia Energy, another natural gas-fired electric generating plant in South Carolina, or some other plant.

DEP provided satisfactory responses to arguments that the record contains insufficient justification of need. The need for the two 280 MW CC units is based on an IRP planning basis. The comments filed by many of the Intervenors appear to demonstrate a lack of fundamental understanding as to the difference between capacity and energy, a fundamental lack of understanding as to how load forecasts are prepared and approved by this Commission, as well as a fundamental lack of understanding of how electric systems are planned and maintained for a reliable and least cost system. As detailed in the CPCN application, the basis for need is demonstrated in the 2015 DEP IRP. A specific, unique situation exists regarding the DEP-Western Region, which is an energy island. Lastly, the 100 MW of hydropower, as well as wind, is not an available option for DEP or it would have been included as part of DEP's IRP.

The DEP-Western Region is an attractive place to live, to visit, to retire, and to work, and it is the fastest growing region within DEP's entire service territory. According to the United States Census Bureau, North Carolina ranks number nine in numeric increase from July 1, 2014, to July 1, 2015.[1]

DEP-West is an energy island in that there is insufficient local generation to meet peak demand and it is a net importer of energy. The transmission facilities into DEP-West are significantly constrained so as to limit the import of additional energy. This constraint led DEP to propose the Foothills Transmission Line. After intense opposition to the transmission line, DEP reconfigured the Project to propose two smaller units in order to maximize the amount of local generation given no new transmission import capability.

In response to comments regarding the capacity factors of the coal units, DEP operates its system in a least cost manner. The coal units in Asheville are run out of economic dispatch throughout the year because of local voltage and reliability needs. The Commission determines that DEP, in operating the system in a least cost manner, will, when load conditions enable it, import cheaper energy from the eastern part of the system, which is largely natural gas-fired generation, resulting in the lower capacity factors for the existing coal units.

The Commission determines that DEP's reliability concerns detailed in Attachment A to Exhibit 1B to the application are real and cannot be ignored. There is a minimum amount of Asheville generation that is required to be online at all times to supply voltage and provide reliable service given possible contingencies, such as a generator being offline and the impact of also losing transmission lines.

Since November 2008, DEP has declared four energy emergency alerts (EEA) for DEP-West due to having marginally enough capacity to serve load. Three of these events were EEA Level 2. The next level, EEA Level 3, requires shedding firm load, which is commonly known as rolling blackouts. These events occurred on November 19, 2008, January 4, 2012, January 7, 2014, and February 20, 2015.

The size of the CC units proposed as part of the Project was engineered specifically, based on the criteria to optimally meet the load and reliability requirements given the transmission import constraints and to provide a cost-effective system for the benefit of all DEP customers. Intervenors who argue that the CC units are too large fail to recognize that when there is low customer use in the western region, and that those new CC units will be the most efficient and most cost-effective natural gas-fired units on DEP's system and will be used to serve DEP's customers in eastern North Carolina and in DEP's service territory in South Carolina. The result, as the Public Staff noted in its recommendation, means a lowering of costs to all of DEP's customers.

The Commission concludes, based upon the entire record, that the public convenience and necessity require the construction of two 280 MW CC units at the Asheville Plant. The Commission notes that under North Carolina law, the Commission may agree with only the

[1] According to the Economic Development Coalition of Asheville-Buncombe County, the number of homes sold increased 41.8 percent between December 2014 and December 2015, and new residential building permits increased 42.7 percent. Total employment in the Asheville metro area grew by 7.1 percent from 2010-2014.

evidence of one party, no matter the volume of opposing evidence, as long as the record as a whole supports that party's position. See, State ex rel. Utils. Comm'n v. Eddleman, 320 NC 344, 352 (1987). In the present case, viewing the entire record as a whole, sufficient evidence supports the Commission's determination in this matter. The Commission concludes that because of the critical function and need for voltage support through generation in DEP's western region, it was reasonable for DEP to decline to rely upon wholesale purchases and to not place greater reliance on intermittent resources such as wind and solar or to reconductor transmission lines. The Commission has a responsibility to ensure that the utility has the means to provide reliable and affordable electricity, and concludes that it is unwise at the present time for DEP to depend on measures that are outside of DEP's control such as programs that rely on community participation to succeed. DEP knows its system needs more so than any other party. The Commission concludes that DEP properly proposed two 280 MW CC units to further modernize its generation fleet through the replacement and retirement of less efficient 1960s vintage coal-fired units. DEP has shown to the Commission's satisfaction that its customer base is growing and that it needs additional generation resources located in the DEP-Western Region to reliably meet these growing power needs in the 2020 timeframe.

The second related issue is whether the two 280 MW CC units should be reduced to two 185 MW CC units. Several Intervenors, including the Sierra Club and Rouse, argue that constructing two 280 MW CC units to replace the existing 379 MW of coal-fired generation results in an overbuild of facilities. These Intervenors suggest that the Commission should not grant the full capacity requested for these two CC units and should instead require DEP to further investigate and properly size the facilities to meet the current need in Asheville. These Intervenors argue that DEP should instead build two 185 MW CC units and a possible contingent 100 MW CT unit. Sierra Club indicated that a smaller plant would provide the same level of reliability in DEP-West. Rouse questioned whether the current amount of capacity is the minimum amount that is needed.

The Commission determines that those concerns reflect a misunderstanding of transmission limitations as well as least cost system planning. Table 1 of Exhibit 1B to the application shows that even after the Project is built, there will only be 470 MW of usable transmission (or 470 MW import capability) into the DEP-Western Region. Currently, that capacity is used to transport purchased power as well as to transfer power from DEP-East to DEP-West.

DEP cannot merely build facilities of a certain capacity that minimally meets the reliability needs of only the western region. DEP represented and the Commission agrees that it must plan to serve its entire customer base with the most cost-effective fleet of units because all of DEP's customers will pay for this generation, if approved. Furthermore, DEP stated that even if DEP builds both CC units and the CT unit as part of the Project, the DEP-Western Region will still have insufficient generation to meet its projected peak load needs, and DEP will still rely upon transmission import capability, which is severely limited.

When deliberating on a CPCN application, the Commission must determine whether the public convenience and necessity require, or will require, the construction of the proposed facilities. DEP's application shows that due to projected load growth in the area and within the State, the public needs or will need the proposed two 280 MW CC units at the Asheville Plant. Again, the Intervenors ignore the fact that these CC units will be used for baseload capacity within the DEP-Western Region and will also be used to meet DEP's system needs in DEP-East and in South Carolina. From a total system perspective, the DEP 2015 IRP identifies the need for an additional 1,152 MW of new resources by 2020 and 5,099 MW by 2030.

The Commission concludes that the construction of two 280 MW CC units is needed to meet the projected growth in the DEP-Western Region and to meet DEP's total system needs.

The third issue relates to the construction of the 186 MW simple cycle CT unit. Most, if not all of the Intervenors, as well as the Public Staff, opposed the granting of a CPCN at the present time for this unit. The Public Staff indicated that based on current projections, it is likely that additional CT capacity eventually will be required to meet future demand in the DEP-Western Region, but that such additional capacity, which only takes 24 months to construct, is not expected to be needed until 2024. That need is contingent on the level of success of EE and DSM efforts, load growth in the area, and potential lower cost developments that might materialize in the future.

DEP responded that the need is real and has been shown, but that the potential exists to delay or eliminate the need through other measures. According to the application, the contingent CT unit would potentially begin commercial operation in 2024 if the current peak demand growth is not sufficiently reduced by the alternative approach discussed in the application.

The Commission determines that unlike the two CC units, additional time exists to determine whether other measures will remove the need for the CT unit at the Asheville Plant. More time exists because a CT unit takes approximately 24 months to construct and the projected need for the unit is in 2024. Even DEP admits that it may be appropriate to delay or forgo construction of the CT through reliance on EE, DSM, renewables and other technologies. Based upon these facts, at the present time, the Commission concludes that the public convenience and necessity standard has not been met for the requested CT unit. However, this determination is without prejudice to any future filing if the generation capacity is still needed and has not been avoided by EE, DSM, or other load reduction measures undertaken by DEP and the Asheville community.

The next issue relates to DEP's commitment to renewables and load reduction measures. The Sierra Club requested that the Commission hold DEP to its commitments to invest in clean energy resources in Western North Carolina, including demand response, EE, solar, and storage. NC WARN also requested that DEP honor its commitments to build solar in the DEP-Western Region and that the Commission should create tangible goals for EE and DSM in the region. NC WARN further sponsored Dr. Howarth's comments, stating that he is one of the leading scientists in the world on the impacts of natural gas and its pollutant methane on the global climate. Dr. Howarth states that methane is 80 to 100 times as dangerous as carbon dioxide to the climate.

All of the Commissioners who participated in this proceeding attended the public hearing in Asheville on January 26, 2016, and heard first-hand the concerns and perspectives of the people who attended the hearing and provided public witness statements regarding the use of renewables and climate change concerns. In addition, the Commission has reviewed the many public comments that were submitted by mail and by e-mail regarding this matter. As explained elsewhere in this Order, the Commission has determined that the public convenience and necessity require the construction of the two CC units at the Asheville Plant in order to assure continued reliable electric service for DEP's western customers and reliable and affordable electric service for all of DEP's customers on its entire system. It simply is not possible to shut down the existing coal-burning units and assure reliable service through dependence on non-fossil fuel, but intermittent power sources such as solar and wind alone as some speakers advocated. The EPA Clean Power Plan rules promulgated to reduce greenhouse gases and address climate change acknowledges that reliance on natural gas-fired electric generation is an important component in meeting the agency's objectives. The natural gas-fired units will emit substantially lower levels of greenhouse gases than the older, less efficient coal plants they will replace. Refusal to grant DEP's CPCN is to perpetuate reliance on these coal-fired plants. No natural gas presently is extracted in North Carolina where methane may be released, and it is unlikely to be in the near term future. Refusal to grant the CPCN is unlikely to impact in any measurable degree methane emissions from natural gas wells or transmission facilities.

Nonetheless, the Commission heard repeatedly the expressed desire for cleaner energy sources. To that end, the Commission is aware that the North Carolina Department of Environmental Quality (DEQ) identified opportunities for some of the coal-burning power plants that are located in North Carolina to cost-effectively reduce their emissions through a variety of plant upgrades. These opportunities are detailed in the DEQ's proposed "Standards of Performance for Existing Electric Generating Units Under Clean Air Act Section 111(d)," which was published in the North Carolina State Register on November 16, 2015. For DEP, these proposed carbon rules for existing power plants would require upgrades to the Company's four coal-burning units at Roxboro.

On February 9, 2016, the United States Supreme Court issued a stay of the EPA Clean Power Plan rules, and the Commission understands that DEQ's proposed carbon rules for existing power plants are subsequently being held in abeyance pending full judicial review of the EPA regulations. Even so, in light of the public comments, public testimony, and filed comments by Intervenors Firemen and Rouse, the Commission will require DEP to conduct an investigation on retrofitting its Roxboro coal-burning plant pursuant to the DEQ's draft rules cited above. DEP shall include an assessment of the feasibility and cost-effectiveness of conducting the retrofits at Roxboro and shall include this report in the Company's 2016 IRP.

The Commission commends the work that DEP has begun in engaging Asheville community leaders to work collaboratively on load reduction measures. The Commission shall require DEP to continue to update it on these efforts, along with its efforts to site solar and storage in the western region. As to solar and storage, the Commission expects DEP to file as soon as practicable the CPCN to construct at least 15 MW of solar at the Asheville Plant or in the Asheville region. The Commission further urges DEP to move forward in a timely manner with the 5 MW storage project in the Asheville region. To the extent DEP does not do so, the Commission reserves the right on its own motion or on the motion of any interested party to investigate DEP's decision not to move forward with its representations.

The next issue relates to Columbia Energy's concern that DEP may seek to avoid its PURPA obligations, which includes the obligation to purchase all capacity made available at the electric utility's avoided cost rates. Columbia Energy is concerned that DEP will cite approval of this project to argue in a future case that a PPA for the output of its facility would not avoid capacity costs for the full capacity made available by this QF. Columbia Energy acknowledged that the parties' potential dispute will be the focus of another docket. However, Columbia Energy indicated it is concerned because DEP has rejected an offer by Columbia Energy and proposed only a short-term PPA with an energy-only rate and no proposal for payment for capacity.

DEP indicated that if it is required to enter into a PPA with Columbia Energy pursuant to PURPA obligations, that resource can be used to offset DEP's future system needs or other contracts that are expiring. Paragraph 16 of its CPCN application indicates that from a total system perspective, the DEP 2015 IRP identifies the need for an additional 1,152 MW of new resources by 2020 and 5,099 MW by 2030.

DEP indicated that Columbia Energy first approached DEC in 2015 to ask for information about the Company's avoided cost rates. In January 2016, DEP provided Columbia Energy its avoided cost rates in South Carolina because that is where the project would interconnected. Columbia Energy is already interconnected to the South Carolina Electric & Gas system. DEP further indicated that its understanding is that Columbia Energy has submitted a transmission study request to move power into DEP-East in South Carolina, which contrasts with Columbia Energy's assertion that it has a firm transmission request pending. DEP asserts that Columbia Energy has not yet elected to proceed in response to the avoided cost rates provided by DEP and, thus, there have been no negotiations yet as to a PPA. As to suggestions by Intervenors that DEP rely upon the Columbia Energy natural gas-fired project rather than those proposed by DEP at the Asheville Plant site, the transmission constraint issues DEP has confronted make this alternative problematic.

Columbia Energy's concerns relate to a future PPA and avoided cost decisions which seem to be at the preliminary stages and cannot be addressed in this docket. The Commission concludes that such decisions must be made either through negotiations between the parties or in a future Commission proceeding. This decision is without prejudice to such decisions. The Commission urges the parties to work together to resolve any potential future issues in negotiating a PPA.

Lastly, NC WARN stated that the Mountain Energy Act enacted by the General Assembly unrealistically expedites the process for addressing DEP's request. NC WARN argued that a 30-day notice and a 45-day review period do not allow the Commission the opportunity to review the cost of the facility, the alternatives to the facility, the need for the facility, the long term costs, and the natural gas prices. Therefore, NC WARN opined that the Mountain Energy Act is unconstitutional, as applied. NC WARN argued that the lack of opportunity to put on expert witnesses and testimony and the restricted review period of only 45 days results in the Commission not being able to fairly regulate DEP. NC WARN and Mr. Fireman requested that the Commission deny DEP's application without prejudice so that all parties could conduct a "full review" with all of the procedures set forth in Chapter 62, as opposed to this expedited procedure. Further, NC WARN argued that information in DEP's application was confidential and that the public did not have a chance to review that confidential information.

DEP has submitted detailed technical information about the Project, which has been available to the Public Staff and all parties. The confidential portion has been available to all parties that have signed a confidentiality agreement. NC WARN's concern regarding access to the confidential portions of the filing and lack of full access to information could have been rectified. NC WARN was offered the opportunity to sign a confidentiality agreement, and NC WARN refused such access. NC WARN has made its assertions that the withheld information does not constitute trade secrets, and the Commission has rejected them for reasons set forth in its February 4, 2016 Order Denying Motion to Compel in this docket. The Commission has compiled a full and complete record in this case. The Public Staff, and most of the parties in this case, sent DEP multiple data requests. The Public Staff spent several days in DEP's office reviewing detailed engineering and cost information. The Public Staff has made no suggestion that it has been unable to complete its investigation and make a recommendation within the prescribed time. The Public Staff has a statutory responsibility to represent the using and consuming public. To the extent NC WARN purports to represent a greater segment of the public than its 1,000 members, it does so on a self-appointed basis and with guidelines only NC WARN itself imposes.

The Commission determines that sufficient evidence is before it to make a determination in this matter within the time required by the Mountain Energy Act. The Commission concludes that the Public Staff, the entity representing the using and consuming public pursuant to G.S. 62-15, whose duties include reviewing, investigating and making recommendations to the Commission, had sufficient time in this matter to make a recommendation. The Public Staff completed its review and examination and presented its findings and recommendations to the Commission within the time established by the Commission under the Mountain Energy Act for the presentation.

DEP, as a public utility with a franchise to serve in its service area as assigned by this Commission, bears a duty to ensure that reasonable, least cost service is provided with minimal disruption. By statute, parties with a direct interest in the subject matter of Commission proceedings are permitted to intervene and participate. The Public Staff's participation arises as a matter of law. The Public Staff is composed of attorneys, engineers, accountants, and economists with expertise in investigating applications such as DEP's at issue in this docket and making recommendations as to actions the Commission should take. The Public Staff's investigative responsibilities may commence well before a formal application is filed, especially as in this case where the Mountain Energy Act forecasts DEP's request and established an expedited schedule for Commission decision.

Parties other than DEP and the Public Staff, with neither the obligation to serve nor the statutory responsibility to investigate and recommend, may find themselves pressed for time and resources in their participation. Such parties have no responsibility to the State's using and consuming public, statutory or otherwise, but more narrow perspectives or agendas, and may not have resources to dedicate to such investigations. Nevertheless, the Commission is justified in relying on presentations by DEP and the Public Staff, especially when the Public Staff represents that it conducted the investigation necessary to make its recommendation. The Commission need not withhold its order or refuse to comply with statutory deadlines imposed by the legislature because other Intervenors represent that they need more time to investigate and make recommendations.

In this case, the Commission has compiled a record sufficient to comply with the controlling statutes. The Commission has conducted the required public hearing at which over a five-hour nighttime hearing in Asheville the Commission accepted the testimony of more than 50 witnesses. The Commission has accepted, relied upon, and addressed the written comments of expert witnesses tendered by Intervenors. The Commission has accepted and studied DEP's comprehensive application. The Commission continuously monitors and reviews IRP filings. The Commission has accepted the Public Staff's summary of its investigation. The Commission has permitted any Intervenor to argue its position at the February 22, 2016 agenda conference. The Commission has been forced to modify the procedures it would have followed, including those set forth in G.S. 62-82, had not the General Assembly passed the Mountain Energy Act. But in this case, the General Assembly in the Mountain Energy Act expressed its desire that natural gas-fired electric generation facilities be approved for DEP's western region and established procedures and timelines for the Commission to follow, thus modifying the Commission's customary procedure. To comply with the Mountain Energy Act, the Commission compressed the procedural schedule and truncated the process for accepting evidence. The Commission had no choice.[1] The procedures and processes it employed were mandated by provisions of the Mountain Energy Act. Entities and parties dissatisfied by these processes and procedures had opportunity to address provisions of the Mountain Energy Act while the General Assembly deliberated over its provisions. To the extent they failed to do so, efforts to persuade this Commission to disregard the dictates of the Mountain Energy Act are too late and out of place.

Aside from establishing an expedited procedural schedule, the Commission has relied more heavily on paper submissions than on live testimony from the witness stand than the Commission might otherwise have done. Nevertheless, the Commission is an administrative agency with considerable discretion to establish its calendar and procedures. Paper hearings in the administrative agency context, where full documentation establishes a complete record, satisfy due process requirements. As stated by FERC in San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services, 127 FERC ¶ 61,269, 2009 FERC LEXIS 1251 (2009) (citing Town of Norwood v. FERC, 202 F.3d 392, 404 (1st Cir.), cert denied, 531 U.S. 818 (2000); Central Maine Power Co. v. FERC, 252 F.3d 34, 46 (1st Cir. 2001); Lomak Petroleum, Inc. v. FERC, 206 F.3d 1193, 1199 (D.C. Cir. 2000); Conoco Inc. v. FERC, 90 F.3d 536, 543 n.15 (D.C. Cir. 1996); Environmental Action v. FERC, 996 F.2d 401, 413 (D.C. Cir. 1993)):

> 96. Finally, we reject the due process arguments raised by Cal Parties. We note that Cal Parties have twice previously raised these arguments, in their rehearing request of the August 8, 2005 Order and in their Common Comments on Sellers' Cost Filings filed on October 11, 2005. The Commission has already explained twice why a paper hearing with full documentation filed was sufficient to establish a complete record on the cost filings. We again find that Cal Parties fail to raise any persuasive concerns as to the adequacy of the paper hearing process. First, as we have stated above, the Commission has considerable discretion to establish its calendar and procedures. In particular, within the context of administrative law, it is well established that "[t]he term 'hearing' is notoriously malleable." Moreover, in this proceeding, parties have received a form of paper hearing that courts agree is now quite common in utility regulation. As the Commission has previously stated, "[n]ot every factual dispute requires a trial-type hearing. The use of a paper hearing rather than a trial-type evidentiary hearing has been addressed in numerous cases … It is well settled that the Commission may determine disputed facts in a paper hearing."

[1] Commission Rule R1-30 states that the Commission may deviate from its rules where compliance is impossible or impracticable.

> 97. Indeed, the Commission has previously found that a paper hearing is sufficient process to protect parties' rights even when there are material issues of fact raised. As noted in the January 26, 2006, and November 19, 2007 Rehearing Orders, courts have repeatedly held that the Commission is required to provide a trial-type hearing only if the material facts in dispute cannot be resolved on the basis of written submissions in the record. Here, the Commission found that there were no material facts in dispute that could not be resolved on the basis of the written record. Accordingly, the paper hearing constituted adequate due process. A voluminous written record has been amassed in this proceeding. The Commission has considered all the arguments presented by Cal Parties, along with the numerous submissions by all parties in this case. The Commission finds that its procedures have provided parties with more than adequate means to establish a complete record that is sufficient to enable the Commission to achieve just and reasonable results in these proceedings. Accordingly, the Commission again maintains that it will not order trial-type hearings on any of the cost filings.
>
> 98. Moreover, mere allegations by Cal Parties of disputed fact and lack of due process are insufficient to mandate an evidentiary hearing. Such allegations must be supported by an adequate proffer of evidence. Despite Cal Parties' complaints regarding the inadequacy of the period for reviewing and commenting on cost filings, Cal Parties managed to produce literally hundreds of pages of carefully footnoted comments on all cost filings of interest to them. Where Cal Parties challenged the inclusion of specific cost items or a lack of support by an individual filer, we were able to address those challenges on the basis of the voluminous written record amassed in this proceeding. Trial-type evidentiary hearings are not necessary to dispense with purely technical issues, such as the specific categories of information raised by Cal Parties in their comments. Cal Parties failed to show either that the existing written record is insufficient to address any specific disputes or that the administrative process already provided requires additional steps in order to adjudicate fairly the cost filings.
>
> 99. Further, we again reject Cal Parties' request for additional discovery and/or cross-examination of witnesses. The August 8, 2005 Order required each seller submitting a cost filing to include the sworn affidavit of a corporate officer, verifying the accuracy of its submission. As we previously found, the written testimony provided by witnesses by way of sworn affidavits in this proceeding pertained to actual historic operations. In addition, we found that such written testimony was supplied by witnesses whose corporate positions placed them in the best position to explain those historic operations. The Commission maintains that these corporate officers' attestations are sufficient to verify the actual historic cost data. Accordingly, the Commission again maintains that it will not and need not permit additional discovery or cross-examination of witnesses.

(Footnotes omitted.)

Therefore, based upon the foregoing and the record in this proceeding, and based on the conditions contained in the Ordering Paragraphs below, the Commission concludes that construction of the two 280 MW CC units with fuel oil backup and associated transmission at the Asheville Plant is required by the public convenience and necessity and that a CPCN for the two 280 MW CC should be issued. It has been demonstrated that DEP's customer base is growing, that the Company is taking steps to modernize its generation fleet through the retirement of older, less-efficient coal units, and that the Company needs additional generation resources in the DEP-Western Region. The Commission concludes that the CC units will also assist DEP to avoid building 147 MW of fast start CTs in the 2019 timeframe that were included in DEP's 2014 IRP. The Commission concludes that this project is cost-effective for DEP's customers in that it presents a unique opportunity for DEP to partner with PSNC in its expanded natural gas pipeline to provide much needed natural gas service to Western North Carolina and the Asheville area allowing for cost-saving synergies. In order to reliably meet the growing power supply needs of the DEP-Western Region and of the State in the 2020 timeframe, DEP must take steps now to begin construction of the two 280 MW CC units at the Asheville Plant. The Company shall submit annual progress reports during construction pursuant to G.S. 62-110.1(f).

IT IS, THEREFORE, ORDERED as follows:

1. That the application filed in this docket shall be, and the same is hereby, approved and a certificate of public convenience and necessity for the two 280 MW CC natural gas-fired electric generating units, with fuel oil backup, along with the associated transmission facilities, is hereby granted;

2. That the request for a CPCN for the 186 MW CT unit is denied without prejudice to DEP's right to file a future CPCN application;

3. That DEP shall retire its existing Asheville coal units 1 and 2 no later than the commercial operation of the two 280 MW CC units;

4. That DEP shall construct and operate the two 280 MW CC units in strict accordance with all applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environmental Quality;

5. That DEP shall file with the Commission in this docket a progress report and any revisions in cost estimates for these CC units on an annual basis, with the first report due one year from the issuance of this Order;

6. That DEP shall file with the Commission a progress report annually in this docket, and the report shall include actual accomplishments to date on its efforts to work with its customers in the DEP-Western Region to reduce peak load through demand-side management, energy efficiency or other measures, and on DEP's efforts to site solar and storage capacity in the DEP-Western Region, with the first report due one year from the issuance of this order;

7. That DEP shall conduct an investigation on retrofitting its four Roxboro coal-burning power plants as proposed by the North Carolina Department of Environmental Quality in its November 16, 2015 draft rule entitled "Standards of Performance for Existing Electric Generating Units Under Clean Air Act Section 111(d)," and submit a report to the Commission in the Company's 2016 Integrated Resource Plan regarding the feasibility and cost-effectiveness of conducting such retrofits;

8. That for ratemaking purposes, the issuance of this order and CPCN does not constitute approval of the final costs associated therewith, and that the approval and grant is without prejudice to the right of any party to take issue with the treatment of the final costs for ratemaking purposes in a future proceeding; and

9. That the attached Attachment A shall constitute the certificate of public convenience and necessity issued to DEP for the two 280 MW CC natural gas-fired electric generating units to be located at the Asheville Plant in Buncombe County, North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the __28th__ day of March, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Commissioner Lyons Gray did not participate in this decision.

ATTACHMENT A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1089

Duke Energy Progress, LLC
410 South Wilmington Street
Raleigh, North Carolina 27601
is hereby issued this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

for two 280-MW_{AC} combined cycle natural gas-fired electric generating units with fuel oil backup, along with the associated transmission facilities,
to be located at
the Asheville Steam Electric Generating Plant, Asheville,
Buncombe County, North Carolina

subject to all orders, rules, regulations and conditions as are now or may hereafter be lawfully made by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the __28th__ day of March, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

ELECTRIC – FILINGS DUE PER ORDER

DOCKET NO. E-7, SUB 487
DOCKET NO. E-7, SUB 828
DOCKET NO. E-7, SUB 1026

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Duke Energy Carolinas, LLC – Investigation of Existing	)	
Rates and Charges Pursuant to Regulatory Condition	)	ORDER APPROVING
No. 76 as Contained in the Regulatory Conditions	)	EDPR RIDER
Approved by Order Issued March 24, 2006, in Docket	)	
No. E-7, Sub 795	)	

BY THE COMMISSION: On March 24, 2016, Duke Energy Carolinas, LLC (DEC or the Company), filed a proposed Existing DSM Program Costs Adjustment Rider (EDPR) based on the December 31, 2015, legacy demand-side management (DSM) deferral account balance. The Company requested that the EDPR be effective for the period July 1, 2016, through June 30, 2017.

An EDPR was first proposed in Section 11 of the Agreement and Stipulation of Partial Settlement (Stipulation) entered into by the Company and various parties in DEC's general rate case in Docket No. E-7, Sub 828. The Commission approved the Stipulation in its December 20, 2007 Order Approving Stipulation and Deciding Non-Settled Issues (the Sub 828 Order) and has continued to approve the EDPR mechanism in DEC's subsequent general rate cases. The EDPR reflects the inclusion in DEC's approved base rates of a per kilowatt-hour (kWh) amount specifically intended to recover the costs of certain legacy DSM and energy efficiency (EE) programs existing as of the date of the Sub 828 Order. The EDPR is adjusted annually to true up the difference between the applicable base rate amount in effect and the actual cost of the legacy DSM and EE programs during the then most recent calendar year. During calendar year 2015, the applicable base rate amount was 0.0125 cents per kWh (excluding the North Carolina regulatory fee), as reaffirmed pursuant to the Commission's September 24, 2013 Order in general rate case Docket No. E-7, Sub 1026.

In its filing, DEC proposes to replace the existing EDPR decrement rider amount of (0.0040) cents per kWh (excluding the regulatory fee), which was allowed to become effective as of July 1, 2015, pursuant to Commission Order in these dockets, with a new decrement rider amount of (0.0050) cents per kWh (excluding the regulatory fee) effective on and after July 1, 2016. The base existing DSM program cost amount of 0.0125 cents per kWh will remain in place following Commission approval of the new EDPR pursuant to the current filing. Adjusting for the regulatory fee does not result in a change to either the base amount or the rider amount proposed in this proceeding. Therefore, the proposed net change to the EDPR, relative to the currently approved amount, including all rate adders, is the difference between the proposed decrement rider, including the regulatory fee of (0.0050) cents per kWh, and the existing decrement rider, including the regulatory fee of (0.0040) cents per kWh, or a reduction of (0.0010) cents per kWh.

This matter was presented to the Commission at its Regular Staff Conference on June 20, 2016. The Public Staff stated that it had reviewed DEC's calculation of the proposed EDPR, including the supporting workpapers submitted with the filing and information provided by DEC in response to Public Staff data requests. Based on its review, the Public Staff concluded that the proposed rate decrement is reasonable. Therefore, the Public Staff recommended that DEC's proposed EDPR be approved, effective beginning July 1, 2016.

Based on its review of DEC's filing and the recommendation of the Public Staff, the Commission concludes that the proposed EDPR is reasonable and should be approved effective beginning July 1, 2016.

IT IS, THEREFORE, ORDERED that the EDPR proposed by DEC in its filing of March 24, 2016, consisting of a rate decrement of (0.0050) cents per kWh, excluding the regulatory fee [(0.0050) cents per kWh, including the regulatory fee], is approved effective for the period July 1, 2016, through June 30, 2017.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of June, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-7, SUB 1086
DOCKET NO. E-7, SUB 1087

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	ORDER ACCEPTING REGISTRATION
for Registration of New Renewable Energy	)	OF NEW RENEWABLE ENERGY
Facilities	)	FACILITIES

HEARD: Tuesday, November 3, 2015, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham and James G. Patterson

APPEARANCES:

For Duke Energy Carolinas, LLC:

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For North Carolina Pork Council:

Kurt J. Olson, Law Offices of Kurt J. Olson, 3737 Glenwood Avenue, Suite 100, Raleigh, North Carolina 27612

For North Carolina Sustainable Energy Association:

Michael D. Youth, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Optima KV, LLC:

Steven J. Levitas, Attorney at Law, Kilpatrick Townsend & Stockton, LLP, 4208 Six Forks Road, Suite 1400, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Tim R. Dodge, Staff Attorney, Public Staff - North Carolina Utilities Commission, 430 N. Salisbury Street, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 8, 2015, in Docket No. E-7, Sub 1086 and June 9, 2015, in Docket No. E-7, Sub 1087, Duke Energy Carolinas, LLC (DEC), filed registration statements as new renewable energy facilities for its Buck and Dan River combined-cycle generating facilities, respectively. DEC stated that Buck and Dan River "will be combusting directed biogas derived from swine waste and other biomass to generate electricity for DEC's customers." DEC further stated that it "has entered into two contracts to purchase directed biogas produced by a swine waste renewable development company and a poultry processing plant in the Midwest." Finally, DEC noted that the Commission determined that directed biogas is a renewable energy resource in its March 21, 2012 Order on Request for Declaratory Ruling in Docket No. SP-100, Sub 29. On July 9, 2015, DEC filed amendments to the Buck and Dan River registration statements in response to a request by the Public Staff for additional information.

In the Buck and Dan River registration statements, DEC states that it has entered into contracts to purchase directed biogas produced by two waste processers that produce swine waste renewable fuel: High Plains Bioenergy, LLC (High Plains), and Roeslein Alternative Energy of Missouri, LLC (RAE) (collectively, directed biogas suppliers). High Plains will produce biogas by anaerobic digestion of swine waste and other biomass at three covered anaerobic lagoons located in Guymon, Oklahoma. RAE will produce biogas by anaerobic digestion of 100% swine waste produced at nine hog farms in northern Missouri. The biogas produced by both directed biogas suppliers will be cleaned to pipeline quality, metered, injected into the interstate pipeline system, and nominated for use by DEC at Buck and Dan River. DEC states that it will secure contract paths and storage to ship the biogas in the interstate gas pipeline system to Buck and Dan River. DEC states that the Directed Biogas Fuel Producer Attestation form, Attachment 3 to each of the registration statements, will be used monthly by its directed biogas suppliers to: (1) represent, warrant, and attest to the quantity of directed biogas produced, and (2) confirm that all environmental attributes of the biogas being sold and delivered to DEC to be fired at Buck and Dan River remains intact and has not been resold.

The registration statements also include certified attestations that: (1) the facilities are in substantial compliance with all federal and state laws, regulations and rules for the protection of the environment and conservation of natural resources; (2) the facilities will be operated as new renewable energy facilities; (3) DEC will not remarket or otherwise resell any renewable energy certificates sold to an electric power supplier to comply with G.S. 62-133.8; and (4) DEC will consent to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers, the purchase of fuel for the facilities or the generation of electricity at the facilities, and DEC agrees to provide the Public Staff and Commission with access to those books and records wherever they are located, as well as access to the facilities.

Petitions to intervene in both of the above-captioned dockets were granted by the Commission for the North Carolina Pork Council (NCPC); the North Carolina Sustainable Energy Association (NCSEA); GreenCo Solutions Inc.; the North Carolina Farm Bureau; Optima KV, LLC; and North Carolina Eastern Municipal Power Agency and North Carolina Municipal Power Agency Number 1.

On July 24, 2015, the Public Staff filed its recommendation as required by Commission Rule R8-66(e) stating that DEC's registration statements as new renewable energy facilities should be considered to be complete and that Buck and Dan River should be considered new renewable energy facilities. Additionally, the Public Staff stated that it had reviewed DEC's multi-fuel calculations and recommended that they be accepted.

On July 29, 2015, NCPC filed comments and requested a hearing in both of the above-captioned dockets. In summary, NCPC noted that "[t]he directed biogas combusted at Buck and Dan River would be generated primarily from swine waste collected from locations in Oklahoma and Missouri." NCPC stated that the swine waste set-aside requirement is intended to promote in-state goals and objectives and that DEC's proposal "will not advance those goals and in fact, could seriously impede the development of the in-state industry and infra-structure needed for those objectives and goals to be reached." NCPC recited the legislative history of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), in particular, that of the swine waste set-aside requirement, and noted prior Commission Orders stating that the "legislature's intent [for the set-aside requirements was] to foster local economic development and the use of indigenous renewable energy resources." NCPC also acknowledged the Commission's determination in Docket No. SP-100, Sub 29 that directed biogas is a renewable energy resource, but stated that the Commission did not "resolve the question of whether RECs [renewable energy certificates] generated from the directed biogas would be subject to the out-of-state limits." NCPC noted that in Docket SP-100, Sub 29 the Commission stated that "the definition of renewable energy resource is not geographically dependent." NCPC requested that the Commission determine that RECs produced at Buck and Dan River "be deemed out-of-state RECs subject to the limits in [G.S.] 62-133.8(b)(2)e and (c)(2)d beginning in compliance year 2018." NCPC stated that the suggestion to wait until compliance year 2018 "is intended to permit DEC to recoup costs invested to date in the projects and recognizes that in-state sources are unlikely to meet demand in the short term." Alternatively, NCPC requested that the Commission delay acceptance of DEC's registration statements "for 6 to 12 months to allow time for the projects that are now taking form to come to fruition or to a point in development that shows they will commence production in the short-term."

On August 3, 2015, NCSEA filed comments in support of NCPC's requests. NCSEA opined that Buck and Dan River are different from the two directed biogas facilities previously approved by the Commission, stating:

> First, DEC's proposed "new renewable energy facilities" will not address resources or issues indigenous to the State; DEC's facilities will actually impede indigenous resource use and create, rather than resolve, an issue. Second, DEC's proposed "new renewable energy facilities" will not actually foster new development of renewable energy facilities.

On August 18, 2015, RAE filed a letter in support of DEC's registration of Buck and Dan River. In summary, RAE described its project with Murphy-Brown of Missouri, LLC, in which RAE will harvest biogas from swine waste using anaerobic digesters developed by RAE. In addition, RAE stated that this project can be a model for North Carolina and other states to use in developing similar systems.

On August 18, 2015, DEC filed a response to NCPC's comments. In summary, DEC asserted that its registration statements for Buck and Dan River meet the requirements of G.S. 62-133.8 and the Commission's rules for registration as a new renewable energy facility. Further, DEC stated that NCPC's position should be rejected because it would impose on DEC restrictions that are beyond the REPS requirements and would adversely affect DEC's compliance with the REPS. Further, DEC maintained that registration of Buck and Dan River represents an interim step in DEC's ongoing compliance strategy to achieve and maintain full compliance with the REPS. According to DEC, these transactions would allow it to achieve at least partial compliance with the swine waste set-aside requirement while it continues to seek a diversified portfolio of multiple contracts with developers in North Carolina. Finally, DEC stated that it was opposed to NCPC's request for a hearing because there were no factual or legal issues in dispute.

On October 15, 2015, the Commission issued an Order scheduling an oral argument on November 3, 2015, regarding NCPC's request that RECs produced at Buck and Dan River be deemed out-of-state RECs subject to the limits in G.S. 62-133.8(b)(2)e and (c)(2)d. On November 3, 2015, the oral argument was held as scheduled.

On November 6, 2015, RAE filed additional comments in response to three contentions made during the oral argument. In summary, RAE stated that: (1) RAE's project is not being subsidized by federal or state funds or unrecovered costs, (2) the project is on target to be competed in a timely manner, and (3) depending on the success of its project in Missouri, RAE intends to be active in similar projects in North Carolina.

DISCUSSION

Registration as New Renewable Energy Facilities

Pursuant to G.S. 62-133.8(a)(5), a "new renewable energy facility" is a renewable energy facility that was placed into service on or after January 1, 2007. A "renewable energy facility" includes a facility that generates electric power by the use of a "renewable energy resource," G.S. 62-133.8(a)(7), which includes "a biomass resource, including agricultural waste, animal waste," and various other biomass resources. G.S. 62-133.8(a)(5).

In previous orders, the Commission has concluded that biogas derived from the anaerobic digestion of animal waste is a renewable energy resource. See, e.g., Order Accepting Registration of New Renewable Energy Facility, In re Application of Orbit Energy, Inc., Docket No. SP-297, Sub 0 (June 19, 2008); Order Accepting Registration of New Renewable Energy Facility, In re Application of Green Energy Solutions NV, Inc., Docket No. SP-578, Sub 0 (Jan. 20, 2010).

Further, in Docket No. SP-100, Sub 29, the Commission concluded that such biogas, produced outside of North Carolina, injected into the natural gas pipeline, and nominated for use by a natural gas-fueled electric generating facility is a renewable energy resource pursuant to G.S. 62-133.8(a)(5). On March 21, 2012, at the request of Bloom Energy Corporation, the Commission issued a declaratory ruling that such "directed biogas" qualifies as a renewable energy resource where, on a case-by-case basis, a proper showing can be made that the biogas is displacing natural gas and retains all required environmental attributes that make the gas renewable. Order on Request for Declaratory Ruling, In re Request of Bloom Energy Corporation, Docket No. SP-100, Sub 29 (March 21, 2012) (Bloom Order). The Commission stated:

> [B]y purchasing the Directed Biogas and nominating it for delivery to the Facility, an Owner is displacing, or offsetting, conventional natural gas that would have otherwise been injected into the pipeline. The Commission, therefore, concludes that, as long as appropriate attestations are made and records kept regarding the source and amounts of biogas injected into the pipeline and used by the Facility to ensure that no biogas is double-counted, the Directed Biogas would be a renewable energy resource and the resulting electric generation would be eligible to earn RECs that may be used for REPS compliance.

Bloom Order, at 4. In addition, the Commission emphasized that the "definition of renewable energy resource is not geographically dependent" and that issues regarding the production of in-State versus out-of-State RECs are "irrelevant to the question of whether the Directed Biogas is a renewable energy resource." Id. at 5.

Subsequent to the Bloom Order, the Commission approved registration statements for two facilities fueled by directed biogas as eligible for REPS compliance. On December 10, 2012, in Docket No. SP-1642, Sub 1, the Commission approved Apple Inc.'s request to register a 10 MW fuel cell generating facility as a new renewable energy facility. On May 5, 2014, in Docket No. SP-2014, Sub 1, the Commission approved a facility fueled by directed biogas for the production of combined heat and power as a new renewable energy resource.

Applying the plain language of the above statutes, as the Commission has done in the Bloom Order and in subsequent orders, the Commission concludes that DEC has met the requirements of the REPS statute and Commission Rule R8-66 for registration of Buck and Dan River as new renewable energy facilities. Buck was placed into service in 2011; Dan River in 2012. Further, each facility utilizes, at least in part, directed biogas, a renewable energy resource, to generate electricity. The geographic location from which the biogas is sourced is irrelevant to the determination of whether Buck and Dan River are new renewable energy facilities, which only considers the dates on which the facilities began operations and the type of fuel used, at least in part, to generate electricity. In addition, based upon the Public Staff's review and unopposed recommendation, the Commission accepts DEC's multi-fuel calculations.

Use of Renewable Energy Certificates for REPS Compliance

No party disagrees that Buck and Dan River should be registered as new renewable energy facilities or that the biogas used at these facilities to generate electricity is a renewable energy resource. NCPC, however, has urged the Commission to allow the use of electricity derived from out-of-State directed biogas to meet no more than 25% of the REPS swine waste set-aside requirement. G.S. 62-133.8(e).

Pursuant to G.S. 62-133.8(b)(2), an electric public utility such as DEC may comply with the REPS requirements by any one or more of the following:

(a) Generate electricity at a new renewable energy facility;
(b) Use a renewable energy resource at a generating facility, other than waste heat derived from the combustion of a fossil fuel;
(c) Reduce energy consumption through implementation of an energy efficiency measure;
(d) Purchase electricity from a new renewable energy facility, including such a facility located outside North Carolina if the power is delivered to a public utility that provides retail electricity to customers within North Carolina;
(e) Purchase unbundled renewable energy certificates (RECs) derived from a new renewable energy facility, with the use of unbundled RECs derived from out-of-State facilities limited to 25% of the public utility's REPS requirements;
(f) Use banked RECs; or
(g) Electricity demand reduction.

A REC is defined, in pertinent part, as a

> tradable instrument that is equal to one megawatt hour of electricity or equivalent energy supplied by a renewable energy facility, a new renewable energy facility, or reduced by implementation of an energy efficiency measure that is used to track and verify compliance with the requirements of this section as determined by the Commission.

G.S. 62-133.8(a)(6). Thus, the owner of a renewable energy facility earns one REC for every megawatt-hour of energy generated by a renewable energy resource. RECs, however, are not required to be bundled, or sold together with the associated renewable energy, but may also be unbundled and sold separately from the energy. This allows the energy to be sold to a local utility or other purchaser and the REC to be sold to a different, often remote entity.

On September 22, 2009, the Commission issued an Order in Docket No. E-100, Sub 113 in response to a request by Dominion North Carolina Power to clarify the use of unbundled out-of-State RECs purchased to meet the REPS solar, swine waste, and poultry waste set-aside requirements. G.S. 62-133.8(d)-(f). The Commission concluded that allowing the electric power suppliers to use the same compliance methods to meet the REPS general obligation and set-aside requirements best harmonizes the provisions of the REPS. Thus, pursuant to G.S. 62-133.8(b)(2)e and (c)(2)d, unbundled RECs derived from out-of-State renewable and new renewable energy facilities can be used to meet no more than 25% of the solar, swine waste, and poultry waste set-aside requirements.

The NCPC urges the Commission to deem all of the RECs earned by DEC at Buck and Dan River from the use of out-of-State directed biogas to be out-of-State RECs, thus limiting their usage for compliance to not more than 25% of the applicable REPS requirements, including the swine waste set-aside requirement, beginning in compliance year 2018. NCPC contends that the General Assembly included the swine waste set-aside requirement to address the need of North Carolina farmers to utilize swine waste in a way that would eliminate or greatly reduce the environmental impacts presently being experienced in this State. NCPC recounts the history of problems with hog lagoon/spray field treatment systems and the General Assembly's decision in 2007, the same year as the REPS, to make permanent the previously temporary moratorium on lagoon/spray field treatment systems. NCPC maintains that these two actions by the General Assembly signify the legislature's intent to use the swine waste set-aside requirement to help resolve North Carolina's swine waste problem and to promote the expansion of environmentally compatible hog production in North Carolina. NCPC contends that this goal will be severely hampered or defeated if DEC and other electric power suppliers are allowed to use RECs associated with energy derived from directed biogas to fulfill their total swine waste set-aside requirement.

DEC effectively counters NCPC's position by providing a step-by-step analysis of (1) the manner in which DEC intends to earn RECs from directed biogas at Buck and Dan River, and (2) the application of G.S. 62-133.8(a) and (b) in determining the guidelines for earning RECs, in particular in-State versus out-of-State RECs. In addition, DEC states that the General Assembly chose not to place any geographic limits on the source of renewable energy resources. DEC notes that the General Assembly obviously knew how to expressly impose such geographic limits when it intended to do so, citing the 25% limitation on the use of unbundled out-of-State RECs. Moreover, DEC points to some of the practical difficulties that would result if the Commission attempted to define and regulate geographic limits on the renewable energy resources used by electric power suppliers. For example, DEC states that the Commission would be hard pressed to determine whether waste wood used by a renewable energy facility was derived from building projects and timber operations in North Carolina or was trucked in from a bordering state, such as Virginia or South Carolina. The same practical considerations would apply to attempts to track the location at which swine and poultry waste was produced. In addition, DEC submits that it has worked with NCPC and other stakeholders to develop cost-effective swine waste-to-energy facilities in North Carolina and will continue to do so. Lastly, DEC contends that the development of swine waste-to-energy facilities by RAE and High Plains in Missouri and Oklahoma, respectively, will produce new and improved technologies that will help jump-start the development of such projects in North Carolina.

NCPC's public policy argument is compelling. There is little doubt that the General Assembly's main purpose in enacting the swine waste set-aside requirement was to incentivize the utilization of new technologies in North Carolina for environmentally friendly uses of swine waste in the production of electricity. Nevertheless, NCPC's position that the REPS is ambiguous is not persuasive.

The Commission's first task in carrying out the legislature's intent is to interpret the plain meaning of the words of a statute, rule or regulation. See Lenox, Inc. v. Tolson, 353 N.C. 659, 664, 548 S.E.2d 513, 518 (2001). The Commission can consider the legislative history of a statute, particularly when there is ambiguity in the statute. However, the Commission finds no ambiguity in the provisions of G.S. 62-133.8 that are at issue in this docket.

As described above, under G.S. 62-133.8(b)(2), there are numerous methods by which electric public utilities can meet their REPS obligations. The statute is very specific in describing each method separately and in plain language, and it allows an electric public utility to meet its REPS obligations by any one or more of the methods. In the present docket, DEC is planning to meet all or a portion of its swine waste set-aside obligation by generating electricity at two new renewable energy facilities located in North Carolina. This method complies with G.S. 62-133.8(b)(2)a. As the fuel used to generate the electricity is derived from swine waste, the RECs may be used to meet the swine waste set-aside requirement of G.S. 62-133.8(e).

In addition, it is possible that DEC will sell some of the swine waste RECs earned at Buck and Dan River to other electric power suppliers for their own use in meeting the REPS swine waste set-aside requirement. For example, if DEC has more swine waste RECs than it needs, it might sell a portion of the swine waste RECs to Duke Energy Progress, LLC (DEP). In that event, DEP could meet its own REPS swine waste set-aside obligation, or a portion of that obligation, by purchasing unbundled RECs from in-State new renewable energy facilities, as allowed under 62-133.8(b)(2)e. Based on the plain meaning of G.S. 62-133.8(b)(2)a, the swine waste RECs produced at Buck and Dan River would be RECs derived from generating electricity at in-State new renewable energy facilities and, therefore, not subject to the 25% limitation of 62-133.8(b)(2)e and (c)(2)d on unbundled out-of-State RECs.

Lastly, it is clear that NCPC's requested relief is not based on an interpretation of the language of the REPS statute, but on a public policy argument. Otherwise, the limitation urged for the use of the RECs derived from out-of-State directed biogas would be effective for all REPS compliance and not applicable only in compliance years beginning at some future time. The Commission is not persuaded that it should adopt NCPC's policy argument in this case to so distort the plain meaning and intent of the legislature. Rather, the policy argument advocated by NCPC is properly a subject for the legislature which can impose additional limitations, if desired, on the use for REPS compliance of RECs associated with the generation of energy at in-State new renewable energy facilities by out-of-State swine waste-derived directed biogas.

CONCLUSIONS

Based on the registration statements filed by DEC and the record as a whole in these dockets, including the source of fuel stated in the registration statements, the Commission finds good cause to accept registration of Buck and Dan River as new renewable energy facilities. DEC shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year and shall be required to participate in the NC-RETS REC tracking system (http://www.ncrets.org) in order to facilitate the issuance of RECs. Pursuant to Commission Rule R8-67(d)(2), because DEC is using multiple fuels to generate electricity at Buck and Dan River, it shall earn RECs based only upon the energy derived from the renewable energy resources in proportion to the relative energy contents of the fuels used. Consistent with the Commission's January 20, 2010 Order on Motion for Clarification issued in Docket No. E-100 Sub 113, if any organic material other than swine waste is used to produce the directed biogas, only that portion of the electricity generated from the directed biogas that is derived from swine waste is eligible to earn RECs that may be used to meet the REPS swine waste set-aside requirement. Lastly, RECs associated with the renewable energy generated at Buck and Dan River from directed biogas will not be deemed out-of-State RECs subject to the 25% limitation on the use for REPS compliance of unbundled out-of-State RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration statements filed by DEC for Buck and Dan River as new renewable energy facilities shall be, and the same hereby are, accepted.

2. That DEC shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year.

ISSUED BY ORDER OF THE COMMISSION.
This the _11th_ day of March, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-2, SUB 1098
DOCKET NO. E-2, SUB 1099

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC for	)	ORDER ACCEPTING REGISTRATION
Registration of a New Renewable Energy	)	OF NEW RENEWABLE ENERGY
Facilities	)	FACILITIES

BY THE CHAIRMAN: On March 18, 2016, in Docket No. E-2, Subs 1098 and 1099 Duke Energy Progress, LLC (DEP), filed registration statements pursuant to Commission Rule R8-66 for new renewable energy facilities for its Sutton and Lee combined-cycle generating facilities, respectively. DEP stated that it has entered into a contract to purchase directed biogas from Carbon Cycle Energy, LLC, to be produced at a plant to be located in Eastern North Carolina. DEP further stated that under the terms of the contract, Carbon Cycle Energy, LLC, will capture methane derived from swine waste, poultry waste, and biomass; record, meter, and attest to the amount of swine waste, poultry waste, and biomass-derived methane it is producing; and deliver to DEP certificates that attest to the production of the underlying fuel. The biogas will be nominated for use at and transported to the Sutton and Lee combined-cycle generating facilities via interconnection with Piedmont Natural Gas where it will be combusted to generate electricity for DEP's customers.

On May 23, 2016, DEP filed amendments to its registration statements stating that it has also entered into a contract to purchase directed biogas for use at the Sutton and Lee combined-cycle generating facilities from Optima KV, LLC, to be produced at a plant to be located in Duplin County, North Carolina. DEP's description of the terms of the contract with Optima KV, LLC, are nearly identical to that of the contract with Carbon Cycle Energy, LLC, with the exception that Optima KV, LLC, will use only swine waste to produce directed biogas, rather than the mixture of fuel sources described in DEP's filing with regard to its contract with Carbon Cycle Energy, LLC.

The filings include certified attestations that: 1) the facilities will be in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; 2) the facilities will be operated as a new renewable energy facility; 3) DEP will not remarket or otherwise resell any renewable energy certificates (RECs) sold to an electric power supplier to comply with G.S. 62-133.8; and 4) DEP will consent to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers

On July 18, 2016, the Public Staff filed the recommendation required by Commission Rule R8-66(e) stating that DEP's registration statement as a new renewable energy facility should be considered to be complete. The Public Staff further stated that DEP has not yet provided multi-fuel calculations as to the fuel that will be delivered under DEP's contract with Carbon Cycle Energy, LLC. The Public Staff committed to review those calculations and file a letter in these proceedings with a recommendation regarding the calculations. As DEP's contract with Optima KV, LLC, contemplates use of only swine waste as a fuel source, the Public Staff stated that no multi-fuel calculations for the biogas that Optima KV, LLC, will provide to DEP are not required. Finally, the Public Staff recommended that the Commission require that the fuel producer attestations and supporting documentation be available for audit by the Public Staff and that DEP shall notify the Commission within fifteen (15) days of any changes in fuel suppliers. No other party made a filing with respect to these issues.

A "new renewable energy facility" includes a renewable energy facility that was placed into service on or after January 1, 2007. G.S. 62-133.8(a)(5)(a). A "renewable energy facility" includes a facility that generates electric power through the use of a "renewable energy resource." G.S. 62-133.8(a)(7). In its March 11, 2016 Order Accepting Registration of New Renewable Energy Facilities in Docket No. E-2, Subs 1086 and 1087, the Commission concluded that using directed biogas produced from swine waste to generate electricity at the Buck and Dan River combined-cycle facilities met the statutory requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) and Commission Rule R8-66 for registration of new renewable energy facilities. As discussed in that Order, prior orders of the Commission concluded that biogas derived from the anaerobic digestion of animal waste is a renewable energy resource. Further, when that biogas is injected into the natural gas pipeline, nominated for use by a natural gas-fueled electric generating facility, and a proper showing can be made that it is displacing or offsetting conventional natural gas, it is a renewable energy resource pursuant to G.S. 62-133.8(a)(5). In its March 21, 2012 Order on Request for Declaratory Ruling in Docket No. SP-100, Sub 29, the Commission stated:

> [B]y purchasing the Directed Biogas and nominating it for delivery to the Facility, an Owner is displacing, or offsetting, conventional natural gas that would have otherwise been injected into the pipeline. The Commission, therefore, concludes that, as long as appropriate attestations are made and records kept regarding the source and amounts of biogas injected into the pipeline and used by the Facility to ensure that no biogas is double-counted, the Directed Biogas would be a renewable energy resource and the resulting electric generation would be eligible to earn RECs that may be used for REPS compliance.

Consistent with the requirements of those orders, the Commission concludes that DEP has met the requirements of the REPS statute and Commission Rule R8-66 for registration of the Sutton and Lee combined-cycle generating facilities as new renewable energy facilities. The Sutton facility was placed into service on November 27, 2013; the Lee facility was placed into service on January 1, 2013. Each facility will utilize, at least in part, directed biogas, a renewable energy resource, to generate electricity. The Commission will take such further actions as are necessary upon receipt of DEP's multi-fuel calculations and the Public Staff's review.

Based upon the foregoing and the entire record in this proceeding, including the source of fuel stated in the registration statements, the Chairman finds good cause to accept registration of DEP's Sutton and Lee combined-cycle generating facilities as new renewable energy facilities. DEP shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. DEP will be required to participate in the NC-RETS REC tracking system (www.ncrets.org) in order to facilitate the issuance of RECs. Pursuant to Commission Rule R8-67(d)(2), because DEP is using multiple fuels to generate electricity at the Sutton and Lee combined-cycle generating facilities, it shall earn RECs based only upon the energy derived from the renewable energy resources in proportion to the relative energy contents of the fuels used. Consistent with the Commission's January 20, 2010 Order on Motion for Clarification issued in Docket No. E-100 Sub 113, if any organic material other than poultry or swine waste is used to produce the directed biogas, only that portion of the electricity generated from the directed biogas that is derived from poultry waste is eligible to earn RECs that may be used to meet the REPS poultry waste set-aside requirement, and, likewise, only that portion of the electricity generated from the directed biogas that is derived from swine waste is eligible to earn RECs may be used to meet the REPS swine waste set-aside requirement.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration statements filed by DEP for its Sutton and Lee combined-cycle generating facilities as new renewable energy facilities shall be, and the same hereby are, accepted; and

2. That DEP shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year.

ISSUED BY ORDER OF THE COMMISSION.
This the __21st__ day of July, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

ELECTRIC – MERGER

DOCKET NO. E-2, SUB 1095
DOCKET NO. E-7, SUB 1100
DOCKET NO. G-9, SUB 682

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Corporation	)	ORDER APPROVING MERGER
and Piedmont Natural Gas, Inc., to Engage in a	)	SUBJECT TO REGULATORY
Business Combination Transaction	)	CONDITIONS AND CODE OF
and Address Regulatory Conditions and Code of	)	CONDUCT
Conduct	)	

HEARD: On July 18 and 19, 2016, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

For Duke Energy Corporation:

Kodwo Ghartey-Tagoe, Senior Vice President, State and Federal Regulatory Legal Support, 550 S. Tryon Street, Charlotte, North Carolina 28202

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For Piedmont Natural Gas Company, Inc.:

James H. Jeffries IV, Moore & Van Allen PLLC, 100 N. Tryon Street, Suite 4700, Charlotte, North Carolina 28202

For North Carolina Waste Awareness and Reduction Network, Inc., The Climate Times, Inc., and North Carolina Housing Coalition, Inc.:

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For the Public Works Commission of the City of Fayetteville:

James P. West, West Law Offices, PC, 434 Fayetteville Street, Suite 2325, Raleigh, North Carolina 27601

For Carolina Utility Customers Association, Inc.:

> Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For the Environmental Defense Fund:

> Tatjana Vujic, Director, Southeast Clean Energy, 4000 Westchase Boulevard, Suite 510, Raleigh, North Carolina 27607

For the Using and Consuming Public:

> Antoinette R. Wike, Chief Counsel, and Elizabeth D. Culpepper, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On January 15, 2016, pursuant to G.S. 62-111(a), and Commission Rule R1-5, Duke Energy Corporation (Duke Energy) and Piedmont Natural Gas Company, Inc. (Piedmont) (collectively, Applicants), filed an Application, including exhibits, for authorization to: (i) engage in a business combination transaction (transaction or merger); and (ii) revise and apply Duke Energy Carolinas, LLC's (DEC's) and Duke Energy Progress, LLC's (DEP's) Regulatory Conditions and Code of Conduct to Piedmont (Application). The Application included a copy of the Agreement and Plan of Merger between Duke Energy, Forest Subsidiary, Inc. (Forest), and Piedmont (Merger Agreement) as well as a cost-benefit analysis (Cost-Benefit Analysis) and a market power analysis (Market Power Analysis) as required by the Commission's Order Requiring Filing of Analyses, issued November 2, 2000, in Docket No. M-100, Sub 129 (M-100, Sub 129 Order). The Applicants also filed the testimony of Lynn J. Good, Thomas E. Skains, Frank Yoho, Steven K. Young, and James D. Reitzes.

Concurrent with the filing of the Application in this proceeding, Duke Energy also filed a Request of Duke Energy for Expedited Approval of Piedmont Transaction-Related Financing seeking authorization to engage in certain debt and equity transactions necessary to effectuate the proposed business combination.

On January 29, 2016, the Commission issued an order approving Duke Energy's request for approval of transaction-related financing.

On March 2, 2016, the Commission issued its Order Scheduling Hearing, Establishing Procedural Deadlines, and Requiring Public Notice (Scheduling Order). The Scheduling Order, among other things, established a hearing date of July 18, 2016, set prefiled testimony dates, and required the Applicants to give notice to their customers of the hearing on this matter. In addition, the Scheduling Order found and concluded that the Application satisfied the requirements of the M-100, Sub 129 Order.

Petitions to intervene were filed by the Public Works Commission of the City of Fayetteville (FPWC); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); and North Carolina Waste Awareness and Reduction Network, Inc., the

Climate Times, Inc., and the North Carolina Housing Coalition, Inc. (collectively, NC WARN). By various orders, the Commission granted these petitions to intervene. The intervention of the Public Staff – North Carolina Utilities Commission (Public Staff) is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On June 9, 2016, EDF filed the testimony and exhibits of Dianne Munns.

On June 10, 2016, the Public Staff filed an Agreement and Stipulation of Settlement between the Applicants and the Public Staff, which included stipulated Regulatory Conditions and a Code of Conduct, and the supporting testimony of Public Staff witness James G. Hoard.

Also, on June 10, 2016, testimony was filed by NC WARN witnesses Touché Howard and J. David Hughes.

On June 14, 2016, the Applicants filed a Settlement Agreement between the Applicants and CUCA (CUCA Agreement).

On June 16, 2016, the Applicants moved to strike portions of NC WARN witnesses Hughes' and Howard's testimony on the grounds that the testimony was irrelevant and beyond the scope of this docket and moved, in limine, to preclude questioning at the hearing of this matter on the subjects raised by NC WARN witnesses Hughes and Howard. NC WARN responded to this motion in a filing on June 22, 2016.

On June 17, 2016, the Commission issued the Order Allowing Testimony in Response to Settlement Agreements, which called for comments to be filed by July 1, 2016, in response to the Applicants' settlements with the Public Staff and CUCA.

On June 21, 2016, a Settlement Agreement between the Applicants and EDF (EDF Agreement) was filed. The Commission issued an Order on June 23, 2016, allowing comments in response to the EDF Agreement by July 1, 2016.

On June 25, 2016, consistent with the provisions of the EDF Agreement, EDF filed a notice of the withdrawal of the testimony and exhibits of EDF witness Munns.

On June 28, 2016, the Commission issued an Order Granting Motion to Strike and Reserving Decision on Motion in Limine (Motion to Strike Order). In summary, the Motion to Strike Order concluded that the bulk of NC WARN's testimony was not evidence relevant to the facts pertinent to the Commission's decision to approve or deny the proposed merger of Duke and Piedmont. Therefore, the Motion to Strike Order struck the majority of witnesses Howard's and Hughes' testimony. However, the Commission reserved a ruling on the Applicants' Motion in Limine until the expert witness hearing.

On June 28, 2016, NC WARN filed the testimony of Samuel Gunter in response to the settlement between the Applicants and the Public Staff.

On July 1, 2016, the Applicants filed the Supplemental and Rebuttal Testimony of Bruce P. Barkley regarding the settlement agreements reached with the parties in this proceeding.

On July 6, 2016, the Commission issued its Order Regarding Procedure of Public Hearing, which established procedures for the public witness testimony to be received by the Commission at the July 18, 2016 hearing.

On July 14, 2016, pursuant to the Commission's Scheduling Order, the Applicants filed the Joint List and Order of Witnesses with Estimated Times for Cross-Examination for the July 18, 2016 expert witness hearing.

On July 15, 2016, the Applicants filed an Amendment to the Agreement and Stipulation of Settlement between the Applicants and the Public Staff along with the Supplemental Settlement Testimony of Bruce P. Barkley. The Agreement and Stipulation of Settlement between the Applicants and the Public Staff and the Amendment thereto are hereinafter collectively referred to as "the Settlement."

Numerous statements of position from members of the public were received by the Commission and the Public Staff and were filed in these dockets.

The matter came on for hearing on July 18, 2016, as scheduled. At the beginning of the hearing, testimony was received from public witnesses Ruth Zalph, John Wagner, Dr. Steven Norris, Beth Henry, Catherine Chandler, Andrew Hernandez, Clint McSherry, Hope Taylor, Dr. Richard Fireman, Dr. Steve English, and Emily Wilkins. Following the testimony of public witnesses, the pre-filed testimony and exhibits of the following party witnesses were received into evidence:

For the Applicants: Lynn J. Good, Chairman, President and Chief Executive Officer of Duke Energy; Thomas E. Skains, Chairman, President and Chief Executive Officer of Piedmont; Frank Yoho, Senior Vice President and Chief Commercial Officer of Piedmont; Steven K. Young, Executive Vice President and Chief Financial Officer of Duke Energy; James D. Reitzes, a Principal of the Battle Group; and Bruce P. Barkley, Vice President – Regulatory Affairs, Rates and Gas Cost Accounting of Piedmont.

For the Public Staff: James G. Hoard, Director of the Accounting Division of the Public Staff.

For NC WARN: Samuel Gunter, Director of Policy and Advocacy for the North Carolina Housing Coalition.

At the hearing, the Application and exhibits, as well as the settlement agreements between the Applicants and CUCA, EDF, and the Public Staff, including the Amendment thereto filed on July 15, 2016, were entered into the record without objection.

On August 25, 2016, the Applicants and the Public Staff filed a Joint Proposed Order Approving Merger Subject to Regulatory Conditions and Code of Conduct.

On August 25, 2016, FPWC filed a post-hearing Brief.

On August 25, 2016, NC WARN filed a post-hearing Brief, which included a Motion for Reconsideration requesting that the Commission reconsider the Motion to Strike Order.

On August 26, 2016, in Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A and G-9, Sub 682A, the Applicants filed Amended Affiliate Agreements that they intend to use should the proposed merger be approved and consummated.

On August 30, 2016, the Applicants filed a document entitled Supplemental Evidence and Conclusions for Find of Fact No. 36.

On September 1, 2016, the Applicants simultaneously filed a motion for leave to file a response to NC WARN's Motion for Reconsideration along with their response.

On September 7, 2016, the Commission issued an Order granting the Applicants' motion for leave to file a response to NC WARN's Motion for Reconsideration and accepting the Applicants' response for filing.

DECISION ON MOTION IN LIMINE AND CONTINUING OBJECTIONS

In their motion in limine, the Applicants moved to preclude cross-examination by NC WARN's counsel regarding certain issues relating to environmental concerns, gas cost price volatility, methane emissions, and other matters raised in the prefiled testimony of witnesses for NC WARN, which the Commission struck from the record as irrelevant to this proceeding under Rule 402 of the North Carolina Rules of Evidence. The Commission initially reserved ruling on the in limine motion until the hearing. At the hearing, counsel for Applicants renewed the motion and also raised objections to questions by NC WARN's counsel on these topics. The Chairman granted Applicants a continuing objection to these questions but allowed the questions subject to objection. The Public Staff subsequently joined in the Applicants' objection. The Chairman reserved a ruling on the objections in order to give NC WARN the opportunity to establish a nexus between the subject matter of its questions and the factors to be considered in determining whether the proposed merger meets the public convenience and necessity standard.

On August 25, 2016, NC WARN filed a post-hearing Brief. With regard to the relevance of the testimony elicited by NC WARN in cross-examination, NC WARN contends that the purchase of Piedmont by Duke Energy will result in the use of more natural gas by DEC and DEP for the generation of electricity. NC WARN cites the Integrated Resource Plans (IRPs) filed by DEC and DEP in 2015 in Docket No. E-100, Sub 141, stating that the IRPs show DEC's and DEP's plans to significantly increase the number of natural gas-fired plants they use to serve retail electric customers in North Carolina. Therefore, NC WARN argues that evidence concerning methane emissions from natural gas, potential additional safety costs related to natural gas, gas price volatility and potential shortages of natural gas are relevant to the Commission's decision in this proceeding.

On the other hand, the Applicants contend that the evidence elicited by NC WARN on cross-examination of the Applicants' witnesses concerns the same subjects addressed by NC WARN's testimony that was struck by the Commission as irrelevant, and, therefore, should be found to be irrelevant and struck from the record. With regard to the Applicants' objections to NC WARN's cross-examination questions, the subjects covered with Applicants witnesses Good and Skains, who testified together as a panel, were several risk factors addressed in Piedmont's Form 10K filed with the Securities and Exchange Commission. These risk factors included potential gas shortages, possible increases in gas prices, and potential new regulations governing gas producers and pipelines. With respect to DEC and DEP, the main subject was their planned increase in the use of natural gas-fired electric generation facilities. See Transcript (T) Vol. 1, p. 111, line 24 through p. 114, line 14; p. 116, line 17 through p. 121, line 21; p. 122, line 13 through p. 132, line 3; p. 138, line 8 through p. 141, line 21.

The subjects of NC WARN's cross-examination questions to Applicants' witness Yoho were Piedmont's possible increased reliance on shale gas, the adequacy of gas supplies, and forecasts of gas prices. See Transcript Vol. 2, p. 74, line 7 through p. 78, line 3.

Pursuant to Rule 402 of the North Carolina Rules of Evidence, only relevant evidence is admissible. Under Rule 401, "relevant evidence" is defined as

> [e]vidence having any tendency to make the existence of any fact that is of consequence to the determination of the action more probable or less probable than it would be without the evidence.

G.S. 8C-1, Rule 401.

With regard to the admissibility of the above-referenced testimony elicited by NC WARN's cross-examination questions, the issue is whether the testimony has a bearing on "any fact that is of consequence to the determination of the action."

Pursuant to G.S. 62-111(a), the Commission must examine all relevant facets of the proposed merger having a bearing on the public convenience and necessity. In that regard, two of the most important considerations are whether the merger would have an adverse impact on the rates and services provided by the utilities, and whether retail ratepayers would be protected as much as possible from potential costs and risks of the merger. See Order Approving Merger Subject To Regulatory Conditions and Code of Conduct, Docket Nos. E-2, Sub 998 and E-7, Sub 986 (Duke/Progress Merger Order), aff'd, In re Duke Energy Corporation, 232 N.C. App. 573, 755 S.E.2d 382 (2014). Thus, the Commission's emphasis is on the rates, services and protection of North Carolina's ratepayers. Further, in assessing adverse impacts and potential risks of the merger, the Commission necessarily focuses on adverse impacts and potential risks that might be created by the combination of the two companies, not adverse impacts and risks that already exist and may continue to exist irrespective of whether the merger is approved by the Commission.

Duke Energy's acquisition of Piedmont may facilitate Duke Energy's ability to acquire natural gas with added reliability and at marginally lower costs from the interstate pipeline system produced at the widespread sources of gas supply through its platform as owner of Piedmont. This should benefit Duke Energy's consumers through lower prices. However, there is no indication that Duke Energy will build more gas-fired generating facilities or burn more natural gas to generate electricity after its acquisition of Piedmont than it would have without the acquisition. Neither Duke Energy nor Piedmont engages in natural gas extraction through hydro fracturing or other extraction methods. Further, there is no indication that natural gas extracted through hydro fracturing and horizontal directional drilling will be materially affected as a result of Duke Energy's acquisition of Piedmont. Many markets both domestic and foreign exist for the acquisition of low-priced natural gas. Moreover, in the event production of natural gas from shale plays does not materialize as the overwhelming majority of experts in the field expect, Piedmont will bear the responsibility of providing service to its ratepayers just as it did before gas extraction from shale became widespread.

Based on the foregoing and the record, the Commission concludes that the cross-examination testimony referenced above is not evidence of any fact of consequence to the Commission's decision to approve or deny the merger of Duke Energy and Piedmont. NC WARN's cross-examination was permitted conditionally upon NC WARN's representation that NC WARN would establish its relevancy. The Commission determines that NC WARN has failed to do so. Rather, the testimony elicited through cross-examination addresses NC WARN's generic concerns over methane emissions, the potential inadequacy of future natural gas supplies, and the possibility that higher natural gas prices will be passed on to the Applicants' ratepayers. These are concerns of NC WARN that exist today with Duke and Piedmont operating as separate companies. In addition, the subject cross-examination testimony is based on the premise that the merger of Duke and Piedmont will result in an increased use of natural gas by Duke Energy and Piedmont. However, there is no evidence in the record that the merger of Duke Energy and Piedmont will cause an increase in their use of natural gas.

As discussed in the Motion to Strike Order, the risks cited by NC WARN – such as methane emissions, potential natural gas supply shortages and possible cost increases - are risks that DEC, DEP and Piedmont face today and will continue to face irrespective of whether the merger is consummated. For example, as testified to by Applicant witness Young, Duke Energy acquired a 40% interest in the proposed Atlantic Coast Pipeline, a risk that it decided to undertake even before it applied for approval to purchase Piedmont. In addition, as NC WARN notes, DEC's and DEP's 2015 IRPs, filed prior to the merger application, forecast an increased reliance on natural gas-fired generation. However, in order to build such a plant DEC or DEP would have to acquire a certificate of public convenience and necessity (CPCN) from the Commission. There is no application for a CPCN to build gas-fired electric generation in this docket. Likewise, there is no application to pass along increased rates in this docket. In addition, if DEC or DEP files an application for a CPCN to build a new natural gas-fired plant, that will be the docket in which relevant testimony regarding an increased use of natural gas by DEC or DEP will be appropriate.

With respect to Piedmont, a primary reason that it would increase its use of natural gas is to expand its services to new customers. Economic expansion of natural gas service to unserved areas is a public policy of the State of North Carolina. See G.S 62-2(a)(9). However, there is no evidence in the record that the merger, in itself, will increase Piedmont's expansion of natural gas services. Further, there is no request in this docket to approve such an expansion of Piedmont's services, or to pass along increased rates. While Piedmont might also increase its use of natural gas to deliver it to electric generating plants, such delivery is as likely to occur without the proposed merger as with it.

In conclusion, there is no evidence in this proceeding that Duke Energy's purchase of Piedmont, in and of itself, will result in an increased use of natural gas by DEC, DEP, or Piedmont. Thus, the risks of increased methane emissions, potential natural gas supply shortages and possible cost increases are not relevant to the question of whether the merger should be approved by the Commission. As a result, the Commission finds and concludes that NC WARN has failed to establish a nexus between the proposed merger and its concerns regarding methane emissions, potential natural gas supply shortages, and possible gas cost increases. Despite the Chairman's having allowed counsel latitude to elicit on cross-examination a tie between the proposed merger and an increase in the use of gas by the combined company that could be attributed to the combination, counsel never asked questions or elicited answers that established such a tie. Consequently, the above-referenced testimony elicited by NC WARN in its cross-examination of Applicants witnesses Good, Skains and Yoho on those subjects is irrelevant and should be and is struck.

DECISION ON MOTION FOR RECONSIDERATION

Included in NC WARN's post-hearing Brief is a Motion for Reconsideration requesting that the Commission reconsider the Motion to Strike Order. In summary, NC WARN contends that the cross-examination testimony discussed above demonstrates that the merger will create risks of increased methane emissions, potential natural gas supply shortages and potential gas cost increases. Accordingly, NC WARN maintains that the Commission should rescind its Motion to Strike Order and admit the testimony of NC WARN witnesses Howard and Hughes.

Pursuant to G.S. 62-80

> The Commission may at any time upon notice to the public utility and to the other parties of record affected, and after opportunity to be heard as provided in the case of complaints, rescind, alter or amend any order or decision made by it. Any order rescinding, altering or amending a prior order or decision shall, when served upon the public utility affected, have the same effect as is herein provided for original orders or decisions.

The Commission's decision to rescind, alter or amend an order upon reconsideration under G.S. 62-80 is within the Commission's discretion. <u>State ex rel. Utilities Comm'n v. MCI Telecommunications Corp.</u>, 132 N.C. App. 625, 630, 514 S.E.2d 276, 280 (1999). However, the Commission cannot arbitrarily or capriciously rescind, alter or amend a prior order. Rather, there must be some change in circumstances or a misapprehension or disregard of a fact that provides a basis for the Commission to rescind, alter or amend a prior order. <u>State ex rel. Utilities Comm'n v. North Carolina Gas Service</u>, 128 N.C. App. 288, 293-294, 494 S.E.2d 621, 626, <u>rev. denied</u>, 348 N.C. 78, 505 S.E.2d 886 (1998).

The Commission finds and concludes that there has been no change in circumstances or misapprehension or disregard of a fact with respect to its Motion to Strike Order. As discussed above, NC WARN has failed to establish a sufficient nexus between the proposed merger and its concerns regarding methane emissions, potential natural gas supply shortages, and possible gas cost increases. Thus, the testimony of witnesses Howard and Hughes remains as irrelevant as it was when the Commission issued the Motion to Strike Order. As a result, the Commission finds and concludes that NC WARN's Motion for Reconsideration should be denied.

DECISION ON APPLICANTS' REQUEST FOR MERGER APPROVAL

Based on the foregoing, the testimony and exhibits presented at the hearing of this matter, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

I. Jurisdiction

1. Duke Energy is a corporation duly organized and existing under the laws of Delaware and is headquartered in Charlotte, North Carolina. DEC and DEP, wholly-owned subsidiaries of Duke Energy, are limited liability companies organized, existing, and operating under the laws of North Carolina.

2. DEC is engaged in the business of generating, transmitting, distributing, and selling electricity to approximately 2.5 million retail customers in a service area that covers more than 24,000 square miles in portions of central and western North Carolina and western South Carolina. DEC also sells electricity in the wholesale market to various municipal, cooperative, and investor-owned electric utilities.

3. DEP is engaged in the business of generating, transmitting, distributing, and selling electricity to approximately 1.5 million retail customers in a service area that covers more than 34,000 square miles in portions of eastern, central, and western North Carolina and eastern South Carolina. DEP also sells electricity in the wholesale market to various municipal, cooperative and investor-owned electric utilities.

4. DEC and DEP are public utilities under the laws of North Carolina and their respective public utility operations are subject to the jurisdiction of this Commission.

5. Duke Energy also owns two combined electric and natural gas local distribution utilities in Ohio and Kentucky – Duke Energy Ohio, LLC (DEO), and Duke Energy Kentucky, LLC (DEK) – which collectively provide natural gas transportation, distribution, and sales service to approximately 500,000 customers in those states.

6. Duke Energy is also the sole owner of Forest, a North Carolina corporation formed for the purpose of effectuating a business combination transaction with Piedmont.

7. Piedmont is a corporation duly organized, existing, and operating under the laws of North Carolina.

8. Piedmont is engaged in the business of transporting, distributing, and selling natural gas in North Carolina, South Carolina and Tennessee, serving approximately one million retail customers throughout a service territory comprising approximately 39,000 square miles in portions of eastern, central, and western North Carolina, western South Carolina, and the greater Nashville metropolitan area in Tennessee.

9. Piedmont is a public utility under the laws of North Carolina and its public utility operations are subject to the jurisdiction of this Commission.

10. The Applicants are lawfully and properly before this Commission pursuant to G.S. 62-111(a) with respect to the relief sought in the Application and are in compliance with the requirements of the M-100, Sub 129 Order with respect to the filing of a market power analysis and a cost-benefit analysis related to the proposed transaction.

11. The Application, testimony, exhibits, affidavits of publication, and public notices submitted by the Applicants are in compliance with the procedural requirements of the North Carolina General Statutes and the Rules and Regulations of the Commission.

II. The Proposed Transaction

12. The Merger Agreement provides that, at closing, Piedmont will merge with Forest and "New" Piedmont will be the surviving corporation. In conjunction with this combination, Piedmont shareholders will receive $60.00 a share, in cash, for each outstanding share of Piedmont stock. Following the closing of the merger, Piedmont's shareholders will no longer own any interest in Piedmont, and Piedmont will be a wholly-owned subsidiary of Duke Energy.

13. Following the closing of the merger, Duke Energy will add one member from Piedmont's Board of Directors to the Duke Energy Board of Directors, Thomas E. Skains, Piedmont's current Chairman, President, and Chief Executive Officer.

14. Following the closing of the merger, Piedmont will be operated as a fully functional and separate natural gas subsidiary of Duke Energy.

15. Following the closing of the merger, Piedmont will be managed predominantly by members of Piedmont's existing executive management team and will be led by Frank Yoho, Piedmont's current Senior Vice President and Chief Commercial Officer.

16. Following the closing of the merger, management of Duke Energy's existing natural gas properties and investments will be consolidated under the leadership of Mr. Yoho.

17. Following the closing of the merger, Piedmont will continue to operate under its existing name, will continue to maintain its headquarters in Charlotte at its existing offices, and will retain most of its current operational employees.

III. The Settlements

18. In summary, the Applicants' Settlement with the Public Staff includes agreements by the Applicants to forego the recovery of specific costs, including both operational and merger costs; to provide specific amounts of funds for various charitable organizations; to provide a specific amount of funds for workforce development and low income energy assistance; and to apply the existing DEC and DEP Regulatory Conditions and Code of Conduct, with amendments, to Piedmont.

19. In summary, the Applicants' Agreement with CUCA includes a guarantee by DEC and DEP that their North Carolina retail ratepayers will receive an additional $35 million in fuel and fuel-related cost savings under the Joint Dispatch Agreement (JDA) mechanism approved by the Commission in the 2012 merger of Duke Energy and Progress Energy, Inc., in Docket Nos. E-2, Sub 998 and E-7, Sub 986 (Duke/Progress Merger Order).

20. In summary, the Applicants' Agreement with EDF requires DEC and DEP to study the costs and benefits of implementing integrated voltage control systems in their North Carolina operations.

21. After carefully reviewing the Settlement, the CUCA Agreement and the EDF Agreement, the Commission finds and concludes that these three settlement agreements are the product of give-and-take in settlement negotiations among the parties, and are material evidence entitled to be given appropriate weight by the Commission.

IV. Quantifiable Benefits

22. The merger will result in quantifiable economic benefits for the customers of DEC, DEP and Piedmont. The quantifiable benefits provided in the Settlement and described in Findings of Fact Nos. 23 through 29 below are substantial benefits of the merger.

23. The Settlement requires Piedmont to provide its North Carolina customers a total credit of $10 million in merger-related cost savings through a one-time direct bill credit issued to its customers on or before December 31, 2016. The bill credit will be allocated based upon the allocation factors utilized under Piedmont's Integrity Management Rider (IMR) deferred account.

24. The Settlement requires Piedmont to withdraw its pending Application for Approval of Deferred Accounting Treatment of Certain Distribution Integrity Management [Program] Costs (DIMP Deferral Application), filed on March 11, 2016, in Docket No. G-9, Sub 686, in which Piedmont estimated that its costs subject to deferral would be as high as $18.03 million for North Carolina over the next five years, or approximately $3.6 million per year.

25. The Settlement requires a contribution of a total of $7.5 million by DEC, DEP, and Piedmont to the Duke Energy Foundation and the Piedmont Natural Gas Foundation within 12 months following the closing of the merger, with the funds to be used for workforce development and low-income energy assistance in the North Carolina service territories of DEC, DEP and Piedmont.

26. The Settlement requires a continuation of annual community support and charitable contribution initiatives in North Carolina by the Duke Energy Foundation and the Piedmont Natural Gas Foundation for four years from the closing of the merger at annual levels of not less than $9.65 million, $6.375 million, and $1.5 million, for community support and charitable contributions in the North Carolina service territories of DEC, DEP, and Piedmont, respectively.

27. The Settlement requires Piedmont to reduce the interest rate applicable to monies owed to Piedmont by customers for under-recovery of gas costs from the present 10% level to 6.58%.

28. The CUCA Agreement requires DEC and DEP to guarantee that their North Carolina retail customers will receive their allocable shares of an additional $35 million in fuel and fuel-related cost savings under the JDA mechanism approved by the Commission in the Duke/Progress Merger Order.

29. The Cost-Benefit Analysis, provided as Exhibit B with the Application, projects merger-related cost savings of approximately $9.45 million per year for Piedmont ratepayers in future general rate case proceedings.

V. Non-Quantifiable Benefits

30. The merger will result in non-quantifiable economic and non-economic benefits for the customers of DEC, DEP and Piedmont. The non-quantifiable benefits identified in the Cost-Benefit Analysis and testimony, as described in Findings of Fact Nos. 31 through 36 below, are substantial benefits of the merger.

31. The Cost-Benefit Analysis and testimony projects an increase in Piedmont's ability to access on reasonable terms the capital needed to expand services to new customers and meet its obligations under federal pipeline safety requirements.

32. The Cost-Benefit Analysis and testimony projects reductions in the costs of operating Piedmont, DEC, and DEP based on efficiencies to be gained by combining the control and operation of certain aspects of the three utilities.

33. The Cost-Benefit Analysis and testimony concludes that the merger will create enhanced efficiencies in the procurement of natural gas supplies and capacity, including enhanced opportunities for procurement of upstream capacity and supply at favorable prices, as a result of integrated planning and the sharing of corporate best practices between DEC, DEP and Piedmont.

34. The Cost-Benefit Analysis and testimony concludes that the combination of DEC, DEP and Piedmont under the corporate structure of Duke Energy will create a larger, more diversified and economically stable utility holding company with lower aggregate market risk capable of more effectively competing for capital and efficiently developing and expanding natural gas and electric infrastructure and service within North Carolina.

35. The Cost-Benefit Analysis and testimony conclude that the merger will produce more efficient and reliable customer service by Piedmont, DEC, and DEP through the preservation of Piedmont's recognized customer service focus and the opportunity to share best customer practices among Piedmont, DEC and DEP.

36. The Cost-Benefit Analysis and testimony establish that the merger will result in the retention of Piedmont's corporate headquarters and its operational management team, resulting in a strong corporate presence with business operations in North Carolina, which reduces the risk that Piedmont will be a target for acquisition by out-of-state entities.

VI. Potential Costs

37. The merger will result in known and potential costs to North Carolina customers of DEC, DEP and Piedmont. However, the known and potential costs of the merger are eliminated or mitigated to the fullest extent reasonably possible by the Settlement and the continued full regulatory authority of the Commission.

38. The Settlement requires the Applicants to exclude from recovery from customers of DEC, DEP and Piedmont the acquisition premium paid by Duke Energy for the purchase of Piedmont's stock.

39. The Settlement requires the Applicants to exclude from recovery from customers of DEC, DEP and Piedmont the merger-related direct expenses and severance costs.

40. The Settlement limits the recovery of merger-related transition costs from customers of DEC, DEP and Piedmont to capital costs when: (i) the costs result in quantifiable benefits from the incurrence of the costs; (ii) the quantifiable benefits exceed the costs; (iii) the costs are incurred within the first three years after the merger; (iv) the costs relate to qualified capital investments; and (v) the costs are approved for recovery by the Commission.

41. The Settlement excludes from recovery from customers of DEC, DEP and Piedmont all Piedmont long-term incentive plan costs, including performance shares and restricted stock units/shares, that result from the increase in the Piedmont stock price above the $42.22 per share closing price on October 23, 2015, adjusted for changes in the stock price that would have occurred absent the merger.

VII. Potential Risks

42. The merger will result in potential risks to North Carolina customers of DEC, DEP and Piedmont. However, the potential risks of the merger are eliminated or mitigated to the fullest extent reasonably possible by the Settlement, the Regulatory Conditions, the Code of Conduct, and the continued full regulatory authority of the Commission.

A. Potential Risks Addressed by the Settlement

43. The Settlement provides reasonable and adequate assurance that the existing competition between electric and natural gas by DEC, DEP and Piedmont will be preserved.

44. The Settlement provides reasonable and adequate regulatory scrutiny over transactions involving DEC, DEP, or Piedmont with each other or with non-utility affiliates of Duke Energy.

45. The Settlement provides reasonable and adequate protections against the potential for discriminatory behavior in intra-company transactions by DEC, DEP, and Piedmont compared to their similar transactions with third parties.

46. The Settlement provides reasonable and adequate assurance of the continued independent operations of DEC, DEP, and Piedmont, and precludes adverse impacts from the merger on rates and services provided by DEC, DEP and Piedmont.

47. The Settlement provides reasonable and adequate protection to ratepayers by excluding secondary market sales of gas by Piedmont to DEC or DEP from Piedmont's secondary market sharing mechanism.

B. Potential Risks Addressed by the Regulatory Conditions

48. The Regulatory Conditions included in the Settlement are another benefit of the merger to North Carolina retail customers in that they update, clarify, strengthen, and expand the existing Regulatory Conditions and Code of Conduct approved by the Commission in the Duke/Progress Merger Order.

49. The Regulatory Conditions effectively address as much as reasonably possible potential risks and concerns related to financing issues arising from the merger by ensuring that (a) DEC's, DEP's and Piedmont's capital structures and cost of capital are not adversely affected because of their affiliation with Duke Energy, each other, and other affiliates, and (b) DEC, DEP and Piedmont have sufficient access to equity and debt capital at reasonable costs to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their retail customers.

50. The Regulatory Conditions effectively address as much as reasonably possible potential risks and concerns related to corporate governance and ring-fencing issues arising from the merger by ensuring the continued viability of DEC, DEP and Piedmont and insulating and protecting DEC, DEP and Piedmont, and their retail ratepayers from the business and financial risks of Duke Energy and the affiliates within the Duke Energy holding company system, including the protection of utility assets from the liabilities of affiliates.

51. The Regulatory Conditions effectively enable the Commission to exercise its jurisdiction over future business combinations involving Duke Energy or other members of the Duke Energy holding company family following the merger by ensuring that the Commission receives sufficient notice and opportunity to exercise its lawful authority.

52. The Regulatory Conditions effectively address as much as reasonably possible potential risks and concerns related to structure and organization arising from the merger by ensuring that the Commission will receive adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to changes to the structure and organization of Duke Energy, DEC, DEP, Piedmont, and other affiliates, and non-public utility operations as they may affect North Carolina retail ratepayers.

53. The Regulatory Conditions provide appropriate and effective procedures requiring advance notices and other filings arising from the merger, and ensure monitoring of and compliance with their provisions, including the Code of Conduct, by requiring Duke Energy, DEC, DEP, Piedmont and other affiliates to establish and maintain the structures and processes necessary to

fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner.

54. The Regulatory Conditions effectively ensure that DEC, DEP and Piedmont maintain a strong commitment to customer service following the merger.

55. The Regulatory Conditions effectively ensure that DEC's, DEP's and Piedmont's North Carolina retail ratepayers are protected as much as reasonably possible from any adverse effects of any tax sharing agreement and receive an appropriate portion of any income tax benefits associated with services taken by DEC, DEP and Piedmont from an affiliated service company.

56. The Regulatory Conditions effectively protect as much as reasonably possible the Commission’s jurisdiction as a result of the merger, including risks related to agreements and transactions between and among DEC, DEP, Piedmont, and their affiliates; financing transactions involving Duke Energy, DEC, DEP or Piedmont, and any other affiliate; the ownership, use, and disposition of assets by DEC, DEP or Piedmont; participation in the secondary transactions market by DEC, DEP or Piedmont; and filings with federal regulatory agencies. In addition, they insulate DEC's, DEP's and Piedmont's retail ratepayers as much as reasonably possible from any adverse consequences potentially resulting from the merger.

57. The Regulatory Conditions effectively address as much as reasonably possible potential risks and concerns related to the possible adverse impact on the cost of capital of DEC, DEP, and Piedmont from merger-related credit downgrades.

C. Potential Risks Addressed by the Code of Conduct

58. The Code of Conduct, as well as existing regulatory requirements, provides reasonable and adequate regulatory oversight of affiliate contracts and cost allocations.

59. The Code of Conduct provides reasonable and adequate regulatory oversight to ensure that the costs of common goods and services are fairly allocated among affiliates, to protect ratepayers from overcharges by non-regulated affiliates, and to prevent cross-subsidization of non-regulated affiliates by DEC's, DEP's and Piedmont's customers.

60. The Code of Conduct provides reasonable and adequate regulatory oversight to ensure that costs incurred by DEC, DEP and Piedmont are properly incurred, accounted for, and directly charged, assigned, or allocated to their respective North Carolina retail operations.

61. The Code of Conduct provides reasonable and adequate regulatory oversight by providing for appropriate and effective auditing and reporting requirements with respect to affiliate transactions and cost of service for retail ratemaking purposes.

62. The Code of Conduct provides reasonable and adequate regulatory oversight to ensure that the priority of natural gas service provided by Piedmont to DEC and DEP is consistent with Commission established priorities and not unduly discriminatory with respect to third-party gas-fired electric generators.

63. The Code of Conduct provides reasonable and adequate regulatory oversight to ensure that DEC, DEP and Piedmont continue to independently acquire and own their own upstream pipeline capacity and supply contracts based upon the needs of their respective customers.

VIII. Market Power Study

64. The proposed merger will not lead to the concentration or creation of significant additional market power in either Duke Energy, DEC, DEP or Piedmont, will not result in an anti-competitive impact on markets subject to the Commission's jurisdiction, and will not create the potential for self-dealing by and among DEC, DEP and Piedmont.

IX. Public Witness Testimony

65. The public witnesses testified regarding a variety of subjects, including concerns about the size and manageability of Duke Energy, effects of the proposed merger on customer service and rates, methane emissions and climate change.

66. The Commission finds and concludes that portions of the public witness testimony are relevant to the issues presented by the proposed merger, and that such testimony is entitled to significant weight and consideration in the Commission's decision in this matter.

X. Approval of Settlements

67. The Commission finds and concludes in light of the evidence presented that the provisions of the Settlement are just and reasonable to the customers of DEC, DEP and Piedmont, and to all parties to this proceeding, and that the Settlement serves the public interest. Therefore, the Settlement should be approved in its entirety. In addition, it is entitled to substantial weight and consideration in the Commission's decision in this matter.

68. The Commission finds and concludes in light of the evidence presented that the CUCA Agreement is just and reasonable to the customers of DEC, DEP and Piedmont, and to all parties to this proceeding, and that it serves the public interest. Therefore, the CUCA Agreement should be approved in its entirety. In addition, it is entitled to substantial weight and consideration in the Commission's decision in this matter.

69. The Commission finds and concludes in light of the evidence presented that the EDF Agreement is just and reasonable to the customers of DEC, DEP and Piedmont, and to all parties to this proceeding, and that it serves the public interest. Therefore, the EDF Agreement should be approved in its entirety. However, the EDF Agreement is entitled to less weight and consideration than other evidence in the Commission's decision in this matter.

XI. Public Convenience and Necessity

70. The proposed merger, as modified, limited and restricted by the Settlement, the CUCA Agreement and the EDF Agreement, is justified by the public convenience and necessity, serves the public interest, and should be approved pursuant to G.S. 62-111.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-11

The evidence supporting these findings of fact is set forth in the Application, the Merger Agreement, the Market Power Analysis, the Cost-Benefit Analysis, the testimony of Applicants witnesses Good and Skains, and the Commission's records in this and other proceedings. These findings are essentially informational, procedural, and jurisdictional in nature and are not contested by any party.

According to the Application and Merger Agreement, as well as the testimony of witnesses Good and Skains, Duke Energy and Piedmont intend to engage in a transaction pursuant to which Duke Energy will become the owner of Piedmont through the purchase of all the outstanding stock of Piedmont from Piedmont's existing shareholders. There is no dispute that such a transaction requires the approval of this Commission under G.S. 62-111(a) and the Application seeks such approval.

In addition, the M-100, Sub 129 Order requires the Applicants to file both a market power analysis and a cost-benefit analysis in conjunction with an application for Commission approval of the proposed merger. The market power analysis must include a Herfindahl-Hirschman Index (HHI) evaluation of the proposed merger and the cost-benefit analysis must set forth a "comprehensive list of all material areas of expected benefit, detriment, cost and savings over a specified period (e.g., three to five years) following consummation of the merger . . . ." See M-100, Sub 129 Order, p. 7. The purpose of these required filings is to assist the Commission in making the public convenience and necessity determination required under G.S. 62-111(a).

Consistent with the requirements of the M-100, Sub 129 Order, the Application included both a Cost-Benefit Analysis and a Market Power Analysis as Exhibits B and C to the Application. The Market Power Analysis was prepared by the Brattle Group and contains, among other things, an HHI analysis of the relative market power of Duke Energy both before and after the proposed merger as required by the M-100, Sub 129 Order. The Cost-Benefit Analysis enumerates identified costs and benefits associated with the proposed merger transaction. In its Scheduling Order, the Commission found and concluded that "the application satisfies the requirements of the November 2, 2000, Order in Docket No. M-100, Sub 129." Scheduling Order, p. 2. No party challenged Applicants' satisfaction of the M-100, Sub 129 Order requirements.

Finally, a review of the record in this proceeding indicates that the Applicants have complied with all procedural and notice requirements established by the Commission in the Scheduling Order.

The Commission, therefore, finds and concludes that Duke Energy and Piedmont are lawfully before the Commission with respect to the relief sought in the Application and are in compliance with the merger filing requirements established in Docket No. M-100, Sub 129, with respect to the market power and cost-benefit analyses submitted with the Application.

ELECTRIC – MERGER

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-17

The evidence supporting these findings of fact is set forth in the Application, the Merger Agreement, and the testimony of Applicants witnesses Good, Skains, and Yoho, and is uncontested.

Through the Application and supporting testimony, the Applicants described the process for accomplishing the merger and the holding company structure that will exist upon closing.

The Application describes the proposed merger transaction as follows:

a. Forest and Piedmont will merge, with Piedmont being the surviving entity (this surviving entity is referred to herein as New Piedmont);

b. The articles of incorporation and bylaws of New Piedmont will be in the form of the articles of incorporation and bylaws of Forest prior to the Transaction;

c. Immediately following the Transaction closing, the directors of New Piedmont will be those persons that were the directors of Forest immediately prior to the Transaction closing. Subsequent to the Transaction closing, changes to the directors of New Piedmont may be made based upon integration efforts and Duke Energy's entity management conventions;

d. Immediately following the Transaction closing, the officers of New Piedmont will be those persons that were the officers of Piedmont immediately prior to the Transaction closing. Subsequent to the Transaction closing, changes to the officers of New Piedmont may be made based upon integration efforts and Duke Energy's entity management conventions; and

e. New Piedmont will be a direct, wholly-owned subsidiary of Duke Energy.

Application, at Paragraph No. 4.

The Application further indicates that

> upon consummation of the Transaction: (i) each issued and outstanding share of common stock of Piedmont will be converted into and will thereafter represent solely the right to receive an amount in cash; and (ii) each issued and outstanding share of capital stock of Forest will be converted into and become one validly issued, fully paid, and non-assessable share of common stock of New Piedmont. Thus, as a result of the Transaction: (i) Duke Energy (which presently owns all the stock of Forest) will own all the stock of New Piedmont; and (ii) the ownership of stock in Duke Energy will not be impacted.

Application, at Paragraph No. 5.

Finally, the Application indicates that "[u]nder the terms of the Merger Agreement, each share of Piedmont's common stock will be converted into the right to receive $60.00 in cash, without interest and less any applicable taxes." Application, at Paragraph No. 6.

This structure is confirmed by the provisions of the Merger Agreement itself, which is attached to the Application as Exhibit A. This structure is also described in the testimony of Applicants witnesses Good and Skains, and those descriptions are consistent with the Application and Merger Agreement.

The Application provides, in Paragraph No. 21, that "[t]he Transaction will not have a net adverse impact on the rates and services of DEC, DEP and Piedmont."

The Merger Agreement provides, in Section 1.7(c), that Duke Energy "will take all necessary action so that, as soon as practicable after the Effective Time, Parent will expand the size of its board of directors by one seat and appoint a mutually agreeable current member of the Company's Board as a director to serve on Parent's board of directors."

The Application provides that "Duke Energy has agreed, following the Transaction, to expand the size of its board of directors by one seat and has designated Mr. Thomas E. Skains . . . to serve as a director on Duke Energy's Board of Directors." Application, at Paragraph No. 7.

In addition, Applicants witnesses Good and Skains confirmed Mr. Skains' selection to sit on the Duke Energy Board of Directors following the closing of the merger.

The Application provides, in Paragraph No. 8, that "[a]t the closing of the Transaction, Piedmont will become New Piedmont, a wholly-owned subsidiary of Duke Energy that will continue to exist as a separate legal entity. New Piedmont will retain its existing headquarters in Charlotte." Similarly, in Paragraph No. 14, the Application states that "New Piedmont will retain its name and operate as a business unit of Duke Energy and continue to maintain its current headquarters office in Charlotte." In Paragraph No. 16, the Application states that "Mr. Yoho will lead Duke Energy's natural gas operations in the Carolinas, Tennessee, Ohio, and Kentucky and report to Ms. Good. He will be assisted in these efforts by members of Piedmont's existing operational leadership team . . . ." In Paragraph No. 23, the Application provides that "Duke Energy and Piedmont do not anticipate a significant number of involuntary workforce reductions associated with the combination."

The Merger Agreement provides additional evidence on these matters. In Section 1.7(d), the Merger Agreement provides that upon closing, Duke Energy "intends to offer to retain the existing executive operating management team of the Company to manage Parent's and the Company's combined natural gas operations and . . . expects the head of such combined operations to report directly to the Chief Executive Officer of Parent and serve on Parent's Senior Management Committee." In Section 1.7(g) the Merger Agreement provides that upon closing Duke Energy "intends to cause [Piedmont] . . . to maintain the Company brand and continue to operate their business thereunder."

Applicants witness Good testified that "Piedmont will retain its current name, corporate form and headquarters" and that "[f]or the most part, Piedmont's overall operational management team and operational philosophy will be unchanged, which will allow for the continuation and enhancement of the already excellent service that Piedmont provides to North Carolina customers." (T Vol. 1, pp. 75 and 79) Witness Good further testified that "[u]pon closing of the Merger, Frank Yoho . . . will manage Duke Energy's natural gas operations . . . [and] will report directly to me." (T Vol. 1, pp. 79-80) Finally, witness Good testified that the "Carolinas and Tennessee gas LDC operations will continue to be run under the Piedmont Natural Gas brand, and the operations team will be based at Piedmont's current headquarters in Charlotte, North Carolina." (T Vol. 1, p. 80)

Applicants witness Skains testified that his "belief is that Duke Energy intends to operate Piedmont as a separate natural gas subsidiary and combine Duke Energy's existing LDC operations and additional interstate joint venture investments . . . under the leadership of Frank Yoho . . . who has been named by Ms. Good as head of Duke Energy/Piedmont's combined gas operations upon the close of the Merger." (T Vol. 1, p. 94) According to witness Skains, this "will preserve and expand the Piedmont name and 'brand' and allow the Company to maintain and expand its high-performance/customer service focused culture in providing natural gas service to both existing and new customers." (T Vol. 1, p. 94)

Applicants witness Yoho testified that as of the effective date of the merger he "will assume responsibility for Piedmont's operations, as well as Duke Energy's gas LDC operations and the consolidated gas pipeline investments. . . . [and that he] will report directly to Lynn Good . . . ." (T Vol. 2, p. 58) Witness Yoho further testified that "the intent of the parties is that Piedmont will continue as a fully functional operating natural gas subsidiary of Duke Energy following closing . . . [and that] Piedmont will maintain its core management team and strong local presence to ensure the continued provision of safe, reliable and efficient natural gas service in and throughout the service areas in which we currently operate." (T Vol. 2, p. 59) Finally, witness Yoho testified that "after the Merger, Piedmont will continue to provide safe and reliable natural gas service to the public with the same high level of customer service and operational excellence that we currently provide. This service will also continue to be fully regulated by this Commission and the other state public service commissions under whose jurisdiction we operate." (T Vol. 2, p. 61)

Witness Good's testimony, as well as the testimony of witness Skains and witness Yoho, described the proposed merger as "strategic" in nature and not based on "synergies." (T Vol. 1, pp. 75-76, 96, and 162, and Vol. 2, pp. 60-61) As a result, as testified to by witness Yoho, job displacement should be limited.

Based on the foregoing evidence, the Commission finds that the rates and service of DEC, DEP, and Piedmont will remain subject to the same degree of regulatory oversight and control by the Commission as they were before the merger. Additionally, the proposed integration plan will allow Piedmont to continue operating as a fully functional and separate natural gas entity following the close of the merger. Further, the proposed management plan ensures that Piedmont's operations will continue to be managed by individuals with extensive experience in the natural gas distribution industry and the operations of Piedmont.

ELECTRIC – MERGER

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-21

The evidence supporting these findings of fact is set forth in the Application, the Public Staff Settlement, the CUCA Agreement, the EDF Agreement, the testimony of Applicants witness Barkley, and the testimony of Public Staff witness Hoard.

On June 10, 2016, the Public Staff, Duke and Piedmont (Stipulating Parties) filed an Agreement and Stipulation of Settlement (Settlement or Public Staff Settlement) between the Applicants and the Public Staff. The Settlement includes stipulations, revised Regulatory Conditions, and a revised Code of Conduct. The main stipulations included in the Settlement are:

- Piedmont will withdraw its Application for Approval of Deferred Accounting Treatment of Certain Distribution Integrity Management Costs, filed on March 11, 2016, in Docket No. G-9, Sub 686, in which Piedmont estimates that its costs subject to deferral would be as high as $18.03 million for North Carolina over the next five years, or approximately $3.6 million per year.

- Piedmont will commit to credit a total of $10 million to its North Carolina customers as follows: $5 million per year to its North Carolina Integrity Management Deferred Account (IM Deferred Account) in each of the first two years after the merger. However, in the event of a Piedmont general rate case with rates effective no more than two years after the merger, Piedmont will reserve the right to reflect an adjustment in the general rate case that would increase its revenue requirement for a portion of this $10 million in savings and if that is exercised, the Public Staff reserves the right to incorporate the effect of additional merger-related savings in its proposed revenue requirement calculation. On July 15, 2016, the Settlement was amended to provide that Piedmont will credit the full $10 million to its customers by means of a one-time bill credit issued no later than December 31, 2016.

- Beginning January 1, 2017, DEC, DEP and Piedmont will fund The Duke Energy Foundation and Piedmont Natural Gas Foundation for four years after the merger at annual levels of no less than $9.65 million, $6.375 million, and $1.5 million, for community support and charitable contributions in the North Carolina service territories of DEC, DEP and Piedmont, respectively.

- DEC, DEP, and Piedmont will contribute a total of $7.5 million to The Duke Energy Foundation and Piedmont Natural Gas Foundation in support of workforce development and low income energy assistance in the North Carolina service territories of DEC, DEP, and Piedmont as may be agreed upon with the Public Staff, within 12 months after the merger. The contribution will be allocated among the North Carolina service territories of DEC, DEP and Piedmont in proportion to the number of North Carolina jurisdictional customers served by each.

- Direct merger costs will be excluded from DEC's, DEP's, and Piedmont's regulated expenses.

- Severance costs will be excluded from DEC's, DEP's, and Piedmont's cost of service for ratemaking purposes.

- DEC's, DEP's, and Piedmont's respective shares of capital costs associated with achieving merger savings, such as system integration costs, may be requested to be recovered through depreciation or amortization, and inclusion in rate base, as appropriate, provided that such costs are incurred no later than three years after the merger and result in quantifiable cost savings that offset the revenue requirement effect of including the costs in rate base.

- Effects of all Piedmont long-term incentive plan costs above the Piedmont stock price of $42.22 per share closing price on October 23, 2015, adjusted for changes that would have occurred absent the merger, will be excluded from DEC's, DEP's, and Piedmont's regulated expenses and plant accounts.

- Beginning in the month that the merger closes, Piedmont will use the net-of-tax overall rate of return from its last general rate case (6.58%) as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts.

- DEC, DEP and Piedmont will file proposed amended affiliate agreements no later than 30 days prior to close of the merger.

In the Settlement, the Applicants and Public Staff also agreed to a number of changes to the Regulatory Conditions and Code of Conduct approved by the Commission in the Duke/Progress Merger Order[1]. The proposed Regulatory Conditions and Code of Conduct are set forth in Attachment A of the Settlement Agreement. The Stipulating Parties generally made revisions throughout the various sections of the Regulatory Conditions and Code of Conduct to include Piedmont and references to natural gas services and customers, or to explicitly indicate that a specific section does not apply to Piedmont. Section 16 of the Settlement states, in pertinent part, that the agreement "is the product of give-and-take negotiations."

In addition, the Settlement is supported by the testimony of Public Staff witness Hoard and Applicants witness Barkley. In his pre-filed direct testimony, witness Hoard describes the steps taken by the Public Staff in its investigation of the Applicants' proposed merger. He states that the Public Staff organized a task force of accountants, engineers, attorneys and financial analysts who reviewed the Application, Applicants' testimony, Cost-Benefit Analysis and Market Power Study. In addition, witness Hoard states that the Public Staff submitted data requests to the Applicants and reviewed the information obtained in response to the data requests. He also testifies that the Public Staff reviewed merger proxy statements and other documents filed by the Applicants with

[1] Subsequent to the Duke/Progress Merger Order, the Regulatory Conditions were modified by the Commission's Order Approving Revisions to Regulatory Conditions Nos. 7.7 and 7.8 issued March 24, 2015, in Docket Nos. E-7, Subs 986 and 986A, and E-2, Subs 998 and 998A, and Order Approving Transfer of Employees and Amendment to Regulatory Condition [No. 5.3] issued November 25, 2015, in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

the Securities and Exchange Commission, the Federal Trade Commission and the United States Department of Justice.

Further, witness Hoard discusses the public convenience and necessity standard that has been traditionally applied by the Commission in assessing the benefits and risks of a proposed merger. He states that the Settlement evinces the Public Staff's belief that the quantitative benefits provided in the Settlement, along with the Regulatory Conditions, are sufficient to meet the standard.

In his pre-filed supplemental and rebuttal testimony, Applicants witness Barkley describes the investigation by the Public Staff and the negotiations between the Applicants and the Public Staff. Witness Barkley testifies that the Public Staff served the Applicants with more than one hundred data and document requests set forth in fourteen sets of discovery. He states that the discovery process also included multiple and varied informal follow-up requests and discussions. In addition, witness Barkley states that in early May the Applicants and the Public Staff began discussions regarding the parameters of a possible settlement. He testifies that the discussions continued for about five weeks and involved a large number of issues discussed in multiple face-to-face meetings. Witness Barkley further states that the process involved substantial compromise on the issues by the Applicants and Public Staff and resulted in the Settlement filed with the Commission.

As the Settlement has not been adopted by all of the parties to this docket, its acceptance by the Commission is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I the Supreme Court held that

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding.
>
> The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires *only* that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id. at 231-32, 524 S.E.2d at 16 (emphasis added).

The Commission gives substantial weight to the testimony of Public Staff witness Hoard and Applicants witness Barkley regarding the Stipulating Parties' efforts in negotiating the Settlement. Further, the Commission finds and concludes that the Settlement is the product of the give-and-take between the Applicants and the Public Staff during their settlement negotiations in an effort to appropriately balance the costs, benefits and risks of the proposed merger and to protect ratepayers from the risks. As a result, the Settlement is material evidence to be given appropriate weight in this proceeding.

On June 13, 2016, Duke, Piedmont, and the Carolina Utility Customers Association, Inc. (CUCA) entered into a Settlement Agreement (CUCA Agreement). The CUCA Agreement was filed with the Commission on June 14, 2016. Duke, Piedmont, and CUCA resolved all the issues among them. The main stipulation included in the CUCA Agreement is:

> DEC and DEP guarantee that their North Carolina retail customers will receive their allocable shares of an additional $35 million in fuel and fuel-related cost savings achieved by DEC and DEP over and above the amount DEC and DEP are obligated to provide to them pursuant to the Commission Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued June 29, 2012, in Docket Nos. E-2, Sub 998, and E-7, Sub 986 (DEC-DEP Merger Order) and Duke was ordered to guarantee in the December 12, 2012 Order Approving Settlement Agreement and Closing Investigation in Docket No. E-7, Sub 1017. The additional $35 million in fuel and fuel-related costs savings will be achieved on or before December 31, 2017; however, such period shall be further extended by an additional 18 months if the conditions outlined in the Stipulation approved by the DEC-DEP Merger Order occur. The total cumulative amount of guaranteed fuel and fuel-related costs savings from the DEC-DEP merger and this Agreement is $721,800,000.

The CUCA Agreement further states that "the Settling Parties agree to resolve all issues among them regarding the Docket." Further, it states that CUCA agrees to waive cross-examination of the Applicants witnesses and to stipulate their testimony into the record.

On June 20, 2016, Duke, Piedmont, and the Environmental Defense Fund (EDF) entered into a Settlement Agreement (EDF Agreement). The EDF Agreement was filed with the Commission on June 21, 2016. Duke, Piedmont and EDF resolved all the issues among them. The main stipulation in the EDF Agreement states:

> Duke Energy will complete a cost-benefit study for a broad deployment of Integrated Volt-VAR Control in the Duke Energy Carolinas, LLC, territory, similar to the deployment plan that Duke Energy developed for its Duke Energy Indiana territory. Additionally, the Company will perform a cost-benefit analysis for the Duke Energy Progress Distribution System Demand

> Response (DSDR) program to evaluate the expansion of Integrated Volt-VAR Control beyond current peak demand reduction such that Integrated Volt-VAR Control includes conservation voltage reduction and balancing of grid management and customer reliability requirements. Duke Energy will provide the cost-benefit estimates in the October 2018 North Carolina Smart Grid Technology Plan filing.

The EDF Agreement further states that “the Settling Parties agree to resolve all issues among them regarding the Docket.” Further, it states that EDF agrees to withdraw the pre-filed direct testimony of its witness, Diane Munns. In addition, it provides that EDF agrees to waive cross-examination of the Applicants witnesses and to stipulate their testimony into the record.

The testimony of Applicants witness Barkley supports both the CUCA Agreement and the EDF Agreement. Witness Barkley describes the main provisions of the Agreements and states that the Applicants support both Agreements. The Commission gives substantial weight to the testimony of Applicants witness Barkley, and the terms of the CUCA and EDF Agreements whereby CUCA and EDF waive their right to cross-examine the Applicants' witnesses and stipulate to the introduction of their testimony. The Commission concludes that the CUCA Agreement and the EDF Agreement are the product of give-and-take between the Applicants and CUCA and EDF, respectively. Based on the same factors and reasoning discussed above with regard to the Public Staff Settlement, the Commission concludes that the CUCA Agreement and EDF Agreement are material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-29

The evidence supporting these findings of fact is set forth in the Application, the Cost-Benefit Analysis, the Public Staff Settlement, the CUCA Agreement, the testimony of Applicants witnesses Good, Skains, Young, Yoho, and Barkley, the testimony of Public Staff witness Hoard, and the Commission's statutory and inherent supervisory authority over public utilities.

In the Public Staff Settlement, the Applicants and the Public Staff agreed to a number of benefits to be provided to customers of Piedmont, DEC, and DEP upon closing of the merger. These benefits include: (i) accelerated sharing of merger-related cost savings with Piedmont's North Carolina customers in the total amount of $10 million delivered through a one-time direct bill credit issued on or before December 31, 2016; (ii) a four-year commitment to continue annual community support and charitable contribution initiatives in North Carolina by the Applicants, through the Duke Energy Foundation and the Piedmont Natural Gas Foundation, in the aggregate amount of no less than $17.525 million[1] a year; (iii) a contribution to North Carolina workforce development and low-income energy assistance within 12 months of the close of the merger in the amount of $7.5 million; (iv) a reduction in the interest rate applicable to Piedmont under-collected gas costs; and (v) a requirement to refile non-service related affiliate contracts for re-approval by the Commission.

[1] This annual aggregate amount consists of $9.65 million from DEC, $6.375 million from DEP, and $1.5 million from Piedmont.

The Public Staff Settlement requires Piedmont to withdraw its DIMP Deferral Application wherein it seeks Commission authorization to defer Distribution Integrity Management Program Operations and Maintenance costs projected to total $18.03 million over the next five years.

The Public Staff Settlement provides that, beginning with the month in which the merger closes, Piedmont will use the net-of-tax overall rate of return from its last general rate case as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The methods and procedures used by Piedmont for the accrual of interest on the Deferred Gas Cost Accounts will remain unchanged.

The CUCA Settlement guarantees that DEC's and DEP's North Carolina retail customers will receive the benefit of their allocable shares of an additional $35 million in fuel and fuel-related cost savings under the mechanism approved in the Duke/Progress Merger Order.

In the Cost-Benefit Analysis, Exhibit B to the Application, Duke Energy and Piedmont also identified a number of benefits attendant to the proposed merger of these two companies. These benefits include a reduction in annual public company operating costs associated with the merger of at least $9.45 million (Cost-Benefit Analysis at p. 5). Applicants witness Barkley also testified regarding benefits of the settlements with the Public Staff, CUCA, and EDF and supported those settlements.

Finally, Public Staff witness Hoard testified in some detail as to the benefits provided by the Public Staff Settlement discussed above. Witness Hoard's testimony focused on the context and contents of the Public Staff Settlement and the Applicants' support for the Settlement.

Public Staff witness Hoard also described the proposed new Regulatory Conditions and Code of Conduct provisions that address matters related to the affiliate relationship of Piedmont's local distribution gas company operations with the electric utility operations of Duke Energy. These provisions are subsequently discussed in detail.

The Commission has carefully reviewed and considered all of the evidence set forth above describing the known and potential benefits of the proposed merger and finds it to be credible. Many of these benefits have been enhanced and guaranteed as a result of the settlements filed in this proceeding

The Commission notes that many of the quantifiable benefits and concessions by the Applicants are described in terms of minimum commitments and there is reason to believe that actual benefits in several categories may be greater. The most significant example of this is in the area of merger-related cost savings. The Applicants projected in the Cost-Benefit Analysis that such savings would be approximately $9.45 million per year. This annual amount consists of $2.1 million in Board of Director costs; $3 million in CEO compensation; $0.4 million in outside counsel costs; $1 million in outside auditor costs; $0.55 million in transfer agent costs; $2.3 million in insurance costs; and $0.1 million in stock listing fees. However, this amount represents only the immediately quantifiable cost savings resulting from the merger and contains no additional savings projections from the integration process now being conducted by the Applicants. To the extent that this integration process results in additional merger-related cost savings, Piedmont's customers will benefit as those savings are incorporated into updated rates for Piedmont in future general rate case proceedings. In the meantime, Piedmont has agreed to an immediate sharing of a total of $10 million in merger-related cost savings with its ratepayers through a onetime direct bill credit to be made prior to December 31, 2016.

NC WARN witness Gunter, Director of Policy and Advocacy for the North Carolina Housing Coalition, testified with regard to the Applicants' commitment to contribute $7.5 million to North Carolina workforce development and low-income energy assistance within 12 months of the close of the merger. Witness Gunter opined that this commitment is "not nearly sufficient to meet the needs of families who might be harmed by the proposed merger" and is "inadequate." (T Vol. 2, p. 185) Witness Gunter recommended that the Applicants be required to provide "an increased financial commitment to families that would be most vulnerable to cost increases, and that the money be distributed with the advice of an outside non-profit that works directly with low-income families in North Carolina. The amount of the contribution should be established with the goal of providing lower bills for the most vulnerable households." (T Vol. 2, p. 186)

In response to witness Gunter's testimony, the Applicants' presented the rebuttal testimony of Applicants witness Barkley. Witness Barkley noted his disagreement with the apparent assumption of witness Gunter that low-income families will be harmed by the proposed merger. Further, witness Barkley testified that he believes that the merger will have both economic and non-economic benefits for all of Duke Energy's and Piedmont's customers. Witness Barkley also stated that the provisions relating to low-income energy assistance and workforce development, as well as the other economic and non-economic benefits of the Public Staff Settlement, were negotiated with and agreed to by the Public Staff – the agency charged with representing the interests of the using and consuming public, including low-income ratepayers. Finally, witness Barkley pointed out that the alternate proposal of witness Gunter to increase payments to low-income customers is both indeterminate and more properly addressed in separate proceedings before the Commission involving energy efficiency measures.

In its post-hearing Brief, NC WARN repeats the contentions made by witness Gunter with regard to the $7.5 million to be contributed by the Applicants for workforce development and low-income energy assistance. In addition, NC WARN assails the Applicants' commitment to make annual contributions of at least $17.5 million for four years to the Duke Energy Foundation and the Piedmont Natural Gas Foundation as merely a continuation of contribution levels that the Applicants would likely make irrespective of the Settlement.

With respect to witness Gunter's concerns, the Commission does not find his testimony persuasive. First, there is no evidence in this proceeding that costs to Piedmont's, DEC's or DEP's customers will increase as a result of the merger. To the contrary, the substantial evidence before the Commission supports the opposite conclusion – that customers will receive substantial benefits from the proposed merger and that such benefits will be both economic and non-economic in nature. Thus, the main premise underlying witness Gunter's testimony is faulty. Secondly, while the Commission recognizes the burdens and challenges faced by low-income customers, the evidence demonstrates substantial merger benefits to be received by all of Piedmont's, DEC's and

DEP's customers, including low-income customers. As a result, the Commission gives witness Gunter's testimony minimal weight.

With respect to the Applicants' commitment to make annual contributions of at least $17.5 million to the Duke Energy Foundation and Piedmont Natural Gas Foundation for four years, the Commission finds NC WARN's criticism to be unavailing. First, the contributions will total at least $70 million over the next four years. That is a very large commitment. Secondly, NC WARN's position that the Applicants would likely make these contributions irrespective of the Settlement is pure speculation. Undoubtedly, there are a myriad of factors that the Applicants weigh in deciding how much to contribute to these foundations each year. Nevertheless, the Applicants are willing to guarantee at least $70 million in contributions over the next four years. That guarantee should enable the foundations to engage in planning and activities that they might not otherwise have the opportunity to undertake absent the knowledge that they will have $70 million with which to fund such activities. As a result, the Commission concludes that the Applicants' commitment to make annual contributions of at least $17.5 million to the Duke Energy Foundation and Piedmont Natural Gas Foundation for four years is a substantial benefit provided by the Settlement.

The Commission has carefully reviewed the evidence presented regarding economic and non-economic benefits to customers cited by the Applicants and agreed to and set forth in the settlement agreements in this proceeding. Based upon that evidence, and the lack of any significant countervailing evidence, the Commission finds and concludes that the Public Staff Settlement and the CUCA Agreement provide substantial quantifiable benefits to the ratepayers of DEC, DEP and Piedmont.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-36

The evidence supporting these findings of fact is set forth in the Application, the Cost-Benefit Analysis, the testimony of Applicants witnesses Good, Skains, Young, Yoho, and Barkley, Public Staff witness Hoard, and the Commission's statutory and inherent supervisory authority over public utilities.

The Application recites several asserted benefits from the proposed merger. These include: (i) financial benefits resulting from a larger more diversified company; (ii) direct and immediate operational benefits to customers; (iii) enhanced ability of Duke Energy and Piedmont to participate in the growing natural gas sector of the United States economy; (iv) future integration benefits; and (v) maintenance of a strong corporate presence in North Carolina.

In the Application, the Applicants identified a number of projected benefits from the merger. These include the retention of Mr. Yoho to lead Piedmont's and Duke Energy’s combined natural gas operations and investments assisted by the majority of Piedmont’s existing operational management team (Application, at pp. 6 and 9); financial and strategic benefits associated with the incorporation of Piedmont’s utility operations into a larger and more diverse energy company with enhanced access to capital and greater potential for further growth in the natural gas industry (Application, at pp. 8-9); enhanced opportunities for the combined companies to procure gas supplies and capacity at favorable prices, to participate in gas infrastructure expansion projects, and to ensure an adequate, reliable and cost-effective supply of natural gas for DEC and DEP, (Application, at pp. 10-11) which the Commission has previously recognized as a benefit in mergers between electric utilities and gas local distribution companies. See Order Approving Merger and Issuance of Securities, issued July 13, 1999, in Docket Nos. E-2, Sub 740 and G-21, Sub 377. The Application also projects benefits resulting from increased reliability and efficiency in the provision of both electric and natural gas service by the combined companies; no proposed increase in rates or changes to services provided by DEC, DEP and Piedmont resulting from the merger; and the opportunity for cost-savings for Piedmont customers resulting from the merger integration process.

In the Cost-Benefit Analysis, Duke Energy and Piedmont also identified the benefits attendant to the proposed merger, including (i) increased financial strength of the combined company resulting in greater ability of Piedmont to access capital on reasonable terms (Cost-Benefit Analysis, at p. 3); (ii) a reduction in market risk associated with a larger and more diversified utility holding company structure (Cost-Benefit Analysis, at p. 3); (iii) enhanced system efficiency and reliability for DEC and DEP resulting from the consolidation of Piedmont into the Duke Energy corporate structure (Cost-Benefit Analysis, at p. 3); (iv) potential enhancement of gas supply and capacity procurement activities by the combined utilities (Cost-Benefit Analysis, at p. 4); and (v) enhanced ability to facilitate infrastructure expansion for both gas and electric customers.

In addition, Applicants witness Good testified to the following anticipated benefits of the proposed merger: (i) creation of a strong natural gas platform within Duke Energy to promote additional investment in the natural gas industry; (ii) diversification of Duke Energy's business and customer base; (iii) the addition of experienced and well-regarded management over natural gas assets and investments of the combined companies; (iv) enhanced ability to plan for and construct additional natural gas and electric infrastructure projects; (v) increased reliability and efficiency of service to DEC's and DEP's gas-fired generation facilities; (vi) customer benefits resulting from the sharing of best-practices with respect to the provision of customer service; and (vii) the addition of Thomas Skains to the Duke Energy board of directors.

Applicants witness Skains testified regarding benefits to Piedmont and its customers arising from the proposed merger. These included the preservation and potential expansion of the Piedmont brand as a consequence of Duke Energy's stated intent to allow Piedmont to operate as a separate gas subsidiary, and the opportunity for Piedmont to expand its high-performance/customer service focused culture. Witness Skains also indicated his belief that the proposed merger would enhance both growth opportunities for Piedmont and Duke Energy's ability to effectively participate in the growing natural gas sector of the energy economy in the United States.

In addition, Applicants witness Skains testified that he perceived the following benefits from the merger: (i) continued operation of Piedmont as a separate natural gas utility under the leadership of Mr. Yoho, who will have responsibility for Duke Energy/Piedmont's combined natural gas operations and investments; and (ii) enhanced opportunities for both Duke Energy and Piedmont to improve customer service through the sharing of best practices in that area.

Applicants witness Young testified to his belief that the proposed merger would have benefits for the companies and customers. Witness Young specifically identified the following discrete benefits from the transaction: (i) solid investment grade credit ratings for Duke Energy and Piedmont; (ii) enhanced ability to access capital at reasonable rates resulting from a larger corporate entity and access to expanded financing mechanisms (including the Duke Energy money pool); (iii) maintenance of a healthy balance sheet for the combined company; and (iv) stabilization of the companies' long term growth objectives. Witness Young also explained the possible downgrade of Piedmont's credit rating from "A" to "A-" by Standard & Poor's (S&P). In this regard, he explained that it is common practice for S&P to adjust a new subsidiary's credit rating to match that of its corporate parent. Furthermore, to the extent that such a credit rating downgrade occurs, witness Young testified that Regulatory Condition No. 8.2 will protect customers from any negative rate consequences of such a downgrade resulting from the merger.

Applicants witness Yoho testified regarding his belief that the merger will be "seamless" to customers as a result of Duke Energy's express intent to allow Piedmont to continue to be managed by existing Piedmont operational managers. He also testified that the ongoing integration process underway between the companies should result in operational cost savings going forward and enhanced service quality through the sharing of best practices between DEC, DEP and Piedmont, with limited job displacement and without operational disruption from the merger. Witness Yoho also testified regarding his belief that the benefits described in the Cost-Benefit Analysis attached to the Application would be realized by the companies and their respective customers, including reductions in costs to Piedmont's ratepayers as a result of the merger and integration process.

In response to a question during cross-examination, Applicants witness Barkley testified that DEC, DEP and Piedmont will begin looking at and sharing best practices during the integration process. He stated that integration groups will examine the different approaches of the three utilities and try to choose the best practice, or perhaps combine the best aspects of two practices. Witness Barkley cited right-of-way practices and customer call center practices as examples of the areas in which the utilities will look to exact efficiencies.

Public Staff witness Hoard discusses in his testimony the importance of identifying the balance of costs and benefits in merger proceedings. He states that G.S. 62-111(a) provides that no merger or combination affecting any public utility shall be made through acquisition or control by stock purchase or otherwise, except after Commission approval, and that approval will be given if justified by the public convenience and necessity. He testifies that this statute requires that the Commission review all aspects of a proposed merger, including review of all costs and benefits to determine whether the transaction is in the public interest and should be approved. Witness Hoard further states that the Commission has considered factors such as "maintenance of or improvement in service quality, the extent to which costs can be lowered and rates can be maintained or reduced, the extent to which the merger could have anticompetitive effects, the continuation of effective state regulation, and the relationships between and among the various units of the merged firm." (T Vol.3, p. 74) Witness Hoard also testifies that the Commission has historically made sure that ratepayers are held harmless in these types of transactions and are insulated to the highest extent possible from any risks and costs associated with the transaction and that any benefits resulting from the transaction offset any of those potential risks or costs. Public Staff witness Hoard additionally provided testimony regarding the Applicants' Cost-Benefit Analysis. Witness Hoard states that its March 2, 2016 Scheduling Order in this docket, the Commission found and concluded that the application satisfies the requirements of the Commission’s Order in Docket No. M-100, Sub 129, which requires an applicant to file a cost-benefit analysis, among other things. Witness Hoard further testifies regarding the Cost-Benefit Analysis that the Public Staff believes that the quantitative benefits of the merger, together with the agreed upon Regulatory Conditions provided for in the Settlement, are sufficient to meet the public convenience and necessity standard.

With regard to maintaining Piedmont as a North Carolina based business, the Commission views this as a significant benefit of the merger. The possibility that Piedmont could be purchased by an out-of-state holding company is not purely academic. Indeed, witness Skains discusses in his direct testimony an inquiry that he received from a potential purchaser of Piedmont at virtually the same time as the inquiry from Duke Energy.

The Commission has carefully reviewed the evidence presented regarding the non-quantifiable economic and non-economic benefits from the merger to customers of DEC, DEP and Piedmont testified to by the Applicants and finds the evidence to be credible. Based upon that evidence, and the lack of any significant countervailing evidence, the Commission finds and concludes that there are substantial non-quantifiable economic and non-economic benefits to be derived from the merger by the customers of DEC, DEP and Piedmont.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37-41

The evidence supporting these findings of fact is set forth in the Application, the Cost-Benefit Analysis, the Public Staff Settlement, the CUCA Agreement, the testimony of Applicants witnesses Good, Skains, Young, Yoho, and Barkley, the testimony of Public Staff witness Hoard, and the Commission's statutory and inherent supervisory authority.

In the Public Staff Settlement, the Applicants and the Public Staff agreed to a number of benefits to be provided to customers of Piedmont, DEC, and DEP upon closing of the merger. These benefits include the elimination or mitigation of potential costs of the merger from recovery by the three utilities' in their rates.

In particular, the Public Staff Settlement precludes Piedmont’s recovery from ratepayers of direct merger-related expenses and severance costs. The Public Staff Settlement further provides for recoverability of merger-related transition costs only in circumstances involving capital costs associated with achieving merger savings, such as system integration costs and the adoption of best practices, where such costs are incurred no later than three years from the close of the merger and result in quantifiable cost savings that offset the revenue requirement effect of including the costs in rate base. The Settlement also provides that only the net depreciated costs of such system integration projects at the time the request is made may be included, and that no request for deferrals of these costs may be made.

The Public Staff Settlement also holds customers harmless from the effects of all Piedmont's long-term incentive plan (performance shares and restricted stock units/shares) that result from the increase in the Piedmont stock price above the $42.22 per share closing price on October 23, 2015, adjusted for estimated changes in the stock price that would have occurred absent the merger.

Applicants' witness Yoho testified to the protection of ratepayers from costs of the merger through absorption by Duke Energy and Piedmont shareholders of the acquisition premium and transaction costs associated with the merger.

First, the Application and the Cost-Benefit Analysis appended thereto as Exhibit B commits the Applicants not to seek recovery of several categories of merger-related costs of which they would otherwise be entitled to seek recovery. Specifically, the Applicants have expressly waived, in both the Application and Cost-Benefit Analysis, any right to seek recovery of the acquisition premium associated with the merger as well as any transaction fees associated with the merger. See Cost-Benefit Analysis, at p. 7. This commitment is significant inasmuch as the acquisition premium in this merger is approximately $3.4 billion, and the transaction fees identified in the Cost-Benefit Analysis, which include one-time costs associated with the merger transaction, such as investment bankers fees, costs relating to security issuances, legal costs, accounting costs, and other advisory fees are estimated at $125 million. Hence, these commitments by the Applicants serve to insulate ratepayers from the major costs of the merger transaction itself.

Second, in the Public Staff Settlement, the Applicants have contractually precluded the possibility that they may seek recovery of either merger-related direct expenses or severance costs from ratepayers. As defined in Paragraph No. 5 of the Public Staff Settlement, the direct merger costs are "change-in-control payments made to terminated executives, regulatory process costs, and transaction costs, such as investment banker and legal fees for transaction structuring, financial market analysis, and fairness opinions based on formal agreements with investment bankers." The Public Staff Settlement, in Paragraph No. 6, also limits recovery of merger-related transition costs to capital/rate base related integration expenses to the extent they are incurred no later than three years after the merger and result in quantifiable cost savings that offset the revenue requirement impact of including them in rate base. In Paragraph No. 7 of the Public Staff Settlement, the Applicants have agreed to exclude from cost-recovery the impact of the merger premium on Piedmont employee incentive plan and benefit plan costs. These provisions provide significant additional protections for DEC, DEP, and Piedmont ratepayers from the costs and quantifiable risks associated with the merger.

In its post-hearing Brief, NC WARN asserts that the acquisition premium will unduly overcompensate Piedmont's shareholders, and that a portion of the acquisition premium should be received by ratepayers. NC WARN's argument is based on the fact that Piedmont's ratepayers have contributed to building the rate base assets, including goodwill, of Piedmont and should profit from the sale of these assets to Duke Energy.

Duke Energy is not purchasing Piedmont's assets. Rather, Duke Energy is paying an acquisition premium to Piedmont's shareholders for the purchase of Piedmont's stock. Piedmont's assets will remain the property of Piedmont. Further, Piedmont's rate base will remain the same after Duke Energy's acquisition of the Piedmont stock as it was while the stock was in the hands of the Piedmont shareholders. Were this an asset acquisition, Piedmont's rate base in the hands of a new owner would be the lesser of Piedmont's net original cost or the purchase price on the theory that ratepayers should only be responsible for paying rates on the cost of assets financed by the utility's investors. In this case, a stock acquisition, Piedmont's rate base stays the same. Piedmont's ratepayers bear responsibility for paying a return on rate base and a return of the costs financed by investors. However, the risks of ownership in Piedmont's common equity stock and the increase or decrease in the value of that stock continue to reside with the owners of that stock.

NC WARN's witnesses did not provide testimony regarding its position that the Commission should require Duke Energy to pay a portion of the acquisition premium to Piedmont's ratepayers. In addition, NC WARN's post-hearing Brief does not cite any direct authority or precedent in support of its argument, and the Commission is not aware of any such direct authority or precedent. In its Order Determining Regulatory Treatment of Gain on Sale, in Docket No. W-354, Sub 331 (2011), aff'd, State of North Carolina ex rel. Utilities Comm'n v. Carolina Water Service, Inc. of North Carolina, 225 N.C. App. 120, 738 S.E.2d 187 (2013) (CWS Order), the Commission made an exception to its long-standing policy of allocating 100% of a gain or loss to the shareholders of the utility where there is a sale of assets of a regulated water and/or sewer utility. The Commission's policy is based on its goal to incentivize the transfer of water and sewer systems to municipalities where the municipality has annexed the subdivision or area served by the regulated water and sewer utility. See Order Determining Regulatory Treatment of Gain on Sale of Facilities, Docket Nos. W-354, Subs 133 and 134 (1994). However, in the CWS Order the Commission addressed a situation in which the franchise and assets that CWS was using to serve several subdivisions, about 6,200 customers, were being sold to the Charlotte-Mecklenburg Utilities department (CMU). CMU had agreed to pay CWS $19.2 million more than CWS's net investment in the assets being acquired by CMU. In addition, CMU would thereafter serve the 6,200 former CWS customers. Further, the Commission found as a fact that the sale of the assets and the loss of 6,200 customers would have a significant adverse impact on the rates of the remaining customers of CWS, resulting in an increase of 5.8% and 6.0% in their average monthly water and sewer bill, respectively. Based on those facts, the Commission determined that the sale to CMU was in the public interest only if CWS's remaining ratepayers received 17.5% of the $19.2 million gain on sale, about $3.36 million, to protect them from the increase in their rates.

The present case is distinguishable from the CWS case in several respects. First, the CWS case involved a sale of assets not the acquisition of stock. Second, Piedmont's assets will remain the property of Piedmont. Third, Piedmont will continue to use those assets to provide natural gas service to its customers. Fourth, Piedmont's rates will not increase as a result of the merger.

Therefore, the Commission concludes that there is no factual or legal basis for the Commission to adopt NC WARN's position that Duke Energy should be required to pay a portion of the acquisition premium to Piedmont's customers.

The Commission has carefully reviewed and considered all of the evidence set forth above describing the known and potential benefits of the proposed merger and finds it to be credible. The Commission finds and concludes that the commitments in the Public Staff Settlement are significant and effectively mitigate as much as reasonably possible the potential costs of the merger to ratepayers. Further, even if such potential costs are not effectively mitigated by these commitments, the Commission retains full power and authority to address any potential impact from the merger on the ratepayers of DEC, DEP and Piedmont.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42-47

The evidence supporting these findings of fact is set forth in the Application, the Cost-Benefit Analysis, the Public Staff Settlement, the CUCA Agreement, the testimony of Applicants witnesses Good, Skains, Young, Yoho, and Barkley, the testimony of Public Staff witness Hoard, and the Commission's statutory and inherent supervisory authority over electric utilities.

The Application asserts, in Paragraph No. 27, that "DEC, DEP, and New Piedmont will remain subject to full regulation by the Commission. The Merger in no way diminishes the authority of the Commission to regulate service quality and rates of any of these companies. Therefore, effective state regulatory oversight of all three utilities will continue." The Application also states, in Paragraph No. 20, that the merger will enhance customer service and will not have a net adverse impact on the rates and services of DEC, DEP and Piedmont. The stipulated Regulatory Conditions and Code of Conduct also contain provisions designed to ensure that the Commission's regulatory jurisdiction over DEC, DEP, and Piedmont is not diminished as a result of the merger.

According to the direct testimony of Applicants witness Good

> [D]uke Energy would experience compelling strategic benefits that include a diversified energy company that will be well positioned to provide the highest quality service to our customers at just and reasonable rates. This transaction establishes a valuable natural gas infrastructure platform which will provide strong growth opportunities for years to come. Abundant, low-cost natural gas will continue as an increasingly important part of the nation's energy mix as the shift away from coal continues. Duke Energy has been a leader in the coal-to-gas transition during the last decade, and this acquisition further solidifies our leadership for the future.

Witness Good also states that Piedmont will exist as a separate entity and subsidiary of Duke Energy and maintain its separate headquarters in North Carolina. Public Staff witness Hoard also states that Piedmont is expected to retain its current name, corporate form and headquarters.

Public Staff witness Hoard testified that customer rates and services will not be adversely impacted by the proposed merger in light of the Public Staff Settlement and the other commitments of the Applicants in this proceeding. His testimony recites the standard for approval of utility mergers under G.S. 62-111 and Commission precedent, describes, in some detail, the provisions of the Public Staff Settlement that are designed to prevent any adverse consequences to customers, and ultimately recommends approval of the merger subject to the restrictions and requirements of the Public Staff Settlement and the stipulated Regulatory Conditions and Code of Conduct.

As is discussed later in this Order, the Regulatory Conditions and Code of Conduct also provide significant ratepayer protections against potential future cost impacts of the merger by ensuring that DEC, DEP and Piedmont continue to operate independently and competitively, except where greater efficiencies can be gained without negatively impacting customers.

In order to protect the jurisdiction of the Commission against the risk of federal preemption as a result of the merger, the Stipulating Parties agree in Regulatory Condition No. 3.9 (g) (vii) (B) that the Applicants will take all actions to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases, or any other adverse effects of such preemption.

In regards to overall service quality, according to Regulatory Condition Nos. 11.1 and 11.2, DEC, DEP, and Piedmont shall provide superior public utility service and shall maintain the overall reliability of electric services and natural gas services at levels no less than the overall levels it has achieved in the past decade and shall incorporate each other's best practices into its own practices to the extent practicable. According to Regulatory Condition No. 11.9, DEC, DEP, and Piedmont shall each meet annually with the Public Staff to discuss service quality initiatives and results and to discuss potential new tariff programs and services that enable their customers to appropriately manage their energy bills based on the varied needs of their customers.

According to Regulatory Condition No. 15.2, concerning the procedures for determining long-term sources of pipeline capacity and supply, Piedmont shall retain title, ownership, and management of all gas contracts necessary to ensure the provision of reliable natural gas services consistent with Piedmont's best cost gas and capacity procurement methodology.

Finally, the testimony of Public Staff witness Hoard and Applicants witness Barkley supports the conclusion that ratepayers are protected from potentially adverse impacts on rates and costs associated with the merger. Public Staff witness Hoard's testimony discusses each aspect of the Public Staff Settlement as well as changes to the Regulatory Conditions and Code of Conduct and concludes that the merger should be approved subject to the protections afforded customers provided by the Public Staff Settlement.

In his testimony, Applicants witness Barkley describes the Public Staff Settlement and indicates both his agreement with witness Hoard's description of the Settlement as well as the Applicants' support for the Settlement.

The Commission notes that several provisions of the General Statutes also serve to protect customers from potential negative consequences of the proposed merger. These include G.S. 62-130 – Commission supervision over rates; and G.S. 62-139 – prohibition of service at other than Commission approved rates.

In this regard, the Commission notes that the provisions of the Public Utilities Act, Chapter 62 of the General Statutes, provide the Commission with broad supervisory authority over DEC, DEP and Piedmont, including the authority to establish (and modify if necessary) the rates, terms, and conditions of service for these entities. As such, and given the absence of any proposal by any of these companies to actually change rates or services in these dockets - other than the proposal to credit Piedmont ratepayers with a one-time $10 million bill credit, which is an immediate benefit to those ratepayers - the Commission finds no evidence that the merger will increase rates, or diminish services, or that the Commission's jurisdiction over DEC, DEP or Piedmont as regulated public utilities will be adversely impacted in any way. Additionally, any currently unknown risks to customers arising out of the proposed merger are sufficiently mitigated through the terms contained in the Public Staff Settlement, including the Regulatory Conditions and Code of Conduct, and the Commission's continuing exercise of jurisdiction over Piedmont, DEC and DEP.

In response to questions on cross-examination, Applicants witness Barkley testified that Piedmont is confident that the merger, in and of itself, will not cause an increase in Piedmont's rates. He elaborated by explaining that the bulk of the costs of the merger have been specifically excluded from Piedmont's rates pursuant to the terms of the Settlement. Further, he cited the Settlement restrictions on Piedmont's recovery of certain integration costs, such as information technology upgrades, noting that the Settlement prohibits cost recovery from ratepayers unless there are corresponding savings in at least the same amount.

With respect to continued competition between the electric services provided by DEC and DEP and the gas services provided by Piedmont, some of the public witnesses expressed concerns about maintaining that competition. For example, witnesses Ruth Zalph stated:

> [t]his merger would stifle both the spirit and the reality of marketplace competition. When you have a number of companies and they all want a piece of the pie, you have competition and you have innovation. This might advance new technologies in the harnessing and delivery of cleaner, non-toxic and sustainable energy that can reduce global warming and save our planet. (T Vol. 1, pp. 18-19)

In addition, Steve English testified that, "Eliminating competition and doubling down on burning more fossil fuels is a fool's errand." (T Vol. 1, p. 58)

Neither of those witnesses acknowledged the measures in the Settlement and Code of Conduct that address the need to preserve competition.

However, the Commission shares these concerns and notes that they are addressed in the proposed Code of Conduct. Section III.H of the Code of Conduct states that

> DEC, DEP and Piedmont shall continue to compete against all energy providers, including each other, to serve those retail customer energy needs that can be legally and profitably served by both electricity and natural gas. The competition between DEC or DEP and Piedmont shall be at a level that is no less than that which existed prior to the Merger.
>
> Further, Section III.H lists minimum standards as follow:
>
> 1. Piedmont will make all reasonable efforts to extend the availability of natural gas to as many new customers as possible.
>
> 2. In determining where and when to extend the availability of natural gas, Piedmont will at a minimum apply the same standards and criteria that it applied prior to the Merger.

3. In determining where and when to extend the availability of natural gas, Piedmont will make decisions in accordance with the best interests of Piedmont, rather than the best interest of DEC or DEP.

4. To the extent that either the natural gas industry or the electricity industry is further restructured, DEC, DEP and Piedmont will undertake to maintain the full level of competition intended by this Code of Conduct subject to the right of DEC, DEP, Piedmont or the Public Staff to seek relief from or modifications to this requirement from the Commission.

In response to a question on cross-examination, Applicants witness Good confirmed that Duke Energy is prepared to maintain Piedmont's residential and commercial customer addition rate. In addition, she agreed that combined heat and power, and direct use by residential and commercial customers were all potential considerations. She further stated that

> [w]e have seen an increasing interest on the part of some of our industrial customers and direct gas products because of the cost-competitive nature of natural gas at this point. So every direction we look we see additional customer interest. (T Vol. 1, p. 158)

In its post-hearing Brief, NC WARN contends that the merger will potentially eliminate the competition between electricity and natural gas in Piedmont's service area overlapping DEC's and DEP's service areas. However, the Commission is not persuaded that the merger will reduce such competition. As previously discussed herein, the Code of Conduct provisions on continued competition between Piedmont, DEC and DEP, and the Commission's continuing regulatory authority over the three utilities provide reasonable assurances that they will continue to compete with each other to provide gas and electric service to their customers in the same manner that they have performed prior to the merger.

The Commission finds that the provisions in the Settlement, the Code of Conduct and the testimony of the witnesses provide reasonable and adequate assurance that the existing competition between electric and natural gas by DEC, DEP and Piedmont will be preserved.

With respect to the potential for favoritism or discrimination by DEC, DEP and Piedmont, G.S. 62-140 prohibits public utilities from making or granting any person an unreasonable preference or advantage in the rates and services offered by the utility. In addition, Section III.D of the Code of Conduct deals with “Transfers of Goods and Services, Transfer Pricing, and Cost Allocation.” That section prohibits cross subsidies, and requires all costs incurred by affiliate personnel for or on behalf of Duke Energy or any affiliate or the Nonpublic Utility Operations to be charged to the entity responsible for the costs. Further, it includes explicit conditions as a general guideline to the transfer prices charged for goods and services.

In response to a cross-examination question with regard to interstate pipeline and storage capacity, Applicants witness Skains stated:

> [t]he FERC does have non-discriminatory rules and regulations which apply to offerings of existing pipeline capacity in the wholesale market. And, as I understand the regulatory conditions agreed to as a part of this merger settlement, the Companies have agreed to maintain separate capacity and supply portfolios for the gas utility versus the electric utilities. (T Vol. 1, p. 156)

The Commission finds that G.S. 62-140, the Settlement and the Commission's continuing regulatory authority over DEC, DEP and Piedmont provides reasonable and adequate protections against the potential for discriminatory behavior in intra-company transactions by DEC, DEP, and Piedmont compared to their similar transactions with third parties.

With regard to secondary market transactions, Code of Conduct Section III.D.3.(g) states

> All of the margins, also referred to as net compensation, received by Piedmont on secondary market sales to DEC and DEP shall be recorded in Piedmont's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins on secondary market sales by Piedmont to DEC and DEP shall be included in the secondary market transactions subject to the sharing mechanism on secondary market transactions approved by the Commission in its Order Approving Stipulation, dated December 22, 1995, in Docket No. G-100, Sub 67. The sharing percentage on secondary market sales shall not be considered in determining the prudence of such transactions.

In response to a cross-examination question about whether that provision would give Piedmont an incentive to engage in secondary market transactions with unaffiliated parties rather than with DEC and DEP, Public Staff witness Hoard testified that Piedmont should not profit from sales to DEC and DEP. He did add that there have not been many transactions between Piedmont and DEC and DEP.

The Commission has carefully reviewed and considered all of the evidence set forth above describing the known and potential risks of the proposed merger and finds it to be credible.

Based on the foregoing, the Commission finds and concludes that the proposed merger poses no risk of any real or potential adverse impact on the rates and services provided by DEC, DEP, and Piedmont to their customers. Further, the Commission finds and concludes that other potential risks of the merger to ratepayers have been effectively mitigated by the commitments of the Applicants in the Application, the Cost-Benefit Analysis, and the testimony of Applicants witnesses, as well as the Public Staff Settlement, including the Regulatory Conditions and Code of Conduct. Further, even if such risks were not effectively mitigated by these commitments, the Commission retains full power and authority to address any potential impact from the merger on the ratepayers of DEC, DEP and Piedmont.

ELECTRIC – MERGER

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 48-57

The evidence supporting these findings of fact is set forth in the Application, the Public Staff Settlement, the testimony of Applicants witnesses Good, Skains, Young, Yoho, and Barkley, the testimony of Public Staff witness Hoard, and the Commission's statutory and inherent supervisory authority.

Under G.S. 62-30, the Commission has general power and authority to supervise and control public utilities. G.S. 62-32 grants the Commission supervisory power over public utility rates and service, including the power to compel reasonable service and set reasonable rates. As noted above, Paragraph No. 27 of the Application provides that "DEC, DEP, and New Piedmont will remain subject to full regulation by the Commission. The Merger in no way diminishes the authority of the Commission to regulate service quality and rates of any of these companies. Therefore, effective state regulatory oversight of all three utilities will continue." This continuing and undiminished regulatory oversight will serve to protect ratepayers from any adverse consequences of the merger.

Separate and apart from the Commission's inherent and continuing supervisory function, there is substantial evidence in this proceeding that ratepayers are and will be protected as much as possible from potential costs and risks of the merger.

In the Public Staff Settlement, Applicants and the Public Staff agreed to a number of benefits to be provided to customers of Piedmont, DEC, and DEP upon closing of the merger. These benefits include adoption of revised Regulatory Conditions and a Code of Conduct which ensure that the ongoing operations of DEC, DEP, and Piedmont will be independent, transparent, non-discriminatory, and consistent with the interests of their customers, as well as effective oversight by the Commission and the Public Staff.

Further, the Regulatory Conditions also provide numerous protections and restrictions governing the ongoing operations of DEC, DEP, and Piedmont. As discussed more fully below, these safeguards include a number of provisions designed to (i) preserve the Commission's jurisdiction over the regulated utilities (Regulatory Conditions, Section III); (ii) establish intra-company financing requirements and separate accounting for each utility (Regulatory Conditions, Sections VII and VIII); (iii) ensure ongoing review of the operation of DEC, DEP and Piedmont under a holding company structure (Regulatory Conditions, Section VIII); (iv) provide the Commission with advance notice of proposed business combinations and mergers, and advance notice of changes in the structure and organization of Duke Energy, DEC, DEP, and Piedmont, (Regulatory Conditions, Section IX and X); (v) ensure continuing levels of service quality for the respective customers of DEC, DEP, and Piedmont (Regulatory Conditions, Section XI); (vi) ensure that DEC's, DEP's and Piedmont's North Carolina retail ratepayers do not bear any additional tax costs as a result of the merger and that they receive an appropriate share of any tax benefits associated with the service company affiliates (Regulatory Conditions, Section XI); and (vii) ensure that Duke Energy, DEC, DEP, Piedmont, and all other affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent and effective manner (Regulatory

Conditions, Section XIV); and, (viii) preserve the integrity of utility specific acquisitions of upstream supply and capacity (Regulatory Conditions, Section XV).

The purpose of Section III of the Regulatory Conditions is to protect the Commission's jurisdiction from the risk of federal preemption. This section includes Regulatory Condition No. 3.1 that requires DEC, DEP and Piedmont to incorporate certain provisions into their affiliate agreements, and to refrain from asserting federal preemption claims regarding the Commission's retail ratemaking and regulatory accounting authority. Further, it requires DEC, DEP and Piedmont to file advance notice, including a copy of the proposed affiliate agreement, with the Commission prior to filing the agreement with FERC. The advance notice triggers certain procedures that allow the Commission, Public Staff and other interested parties the opportunity to review the agreement and address concerns about its potential for resulting in preemption issues.

Regulatory Condition No. 3.3 stipulates that DEC, DEP and Piedmont will own and control the assets used to serve their respective retail customers. Further, if DEC, DEP or Piedmont intends to transfer an asset having a gross book value in excess of $10 million, they are required to provide the Commission with at least 30 days advance notice of the proposed transfer.

The Commission finds and concludes, that the Regulatory Conditions effectively address as much as reasonably possible the concerns related to potential loss of or reduction in the Commission's jurisdiction arising from the merger.

The purposes of Section VII of the Regulatory Conditions are to ensure that (a) DEC’s, DEP's and Piedmont's capital structure and cost of capital are not adversely affected through their affiliation with Duke Energy, each other, and other affiliates, and (b) that DEC, DEP and Piedmont have access to sufficient equity and debt capital at reasonable costs so as to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their customers.

The Commission finds and concludes, that the Regulatory Conditions effectively address as much as reasonably possible the concerns related to potential financing issues arising from the merger. In particular, the Commission finds and concludes that the Regulatory Conditions effectively ensure as much as reasonably possible that (a) DEC’s, DEP's and Piedmont's capital structures and cost of capital are adversely affected because of their affiliation with Duke Energy, each other, and other affiliates, and (b) that DEC, DEP and Piedmont have sufficient access to equity and debt capital at a reasonable cost to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their customers.

Section VIII of the Regulatory Conditions addresses the risks and concerns related to corporate governance and ring-fencing issues arising from the merger. These Regulatory Conditions are intended to ensure the continued viability of DEC, DEP and Piedmont and to insulate and protect DEC, DEP and Piedmont, and their North Carolina retail ratepayers from the business and financial risks of Duke Energy and the affiliates within the Duke Energy holding company system, including the protection of utility assets from liabilities of affiliates.

"Ring-fencing" can be defined as the legal walling off of certain assets or liabilities within a corporate system, including the creation of a new subsidiary to protect (i.e., ring-fence) specific assets from creditors. Ring-fencing measures are used to insulate a regulated utility from the potentially riskier activities of unregulated affiliates. From a debt rating agency perspective, ring-fencing mechanisms are techniques used to isolate the credit risks of one company within an affiliated group from the risks of other companies within that group. Concurrent use of numerous ring-fencing measures, including regulatory, financial, structural, and operational restrictions, is considered to be the most effective way to separate risk.

The Settlement, which includes the Regulatory Conditions, requires the Applicants to implement the techniques of corporate governance and ring-fencing set forth in Section VIII of the Regulatory Conditions. For example, Regulatory Condition No. 8.1 requires DEC, DEP and Piedmont to manage their respective businesses so as to maintain an investment grade debt rating on all of their rated debt issuances with all of the debt rating agencies. If the debt rating of either DEC, DEP or Piedmont falls to the lowest level still considered investment grade at the time, a written notice by DEC, DEP or Piedmont must be filed with the Commission and provided to the Public Staff within five days, along with an explanation as to why the downgrade occurred. Furthermore, within 45 days of such notice, DEC, DEP or Piedmont are required to provide the Commission and the Public Staff with a specific plan for maintaining, improving and returning its debt rating to investment grade. The Commission, after notice and hearing, may then take whatever action it deems necessary, consistent with North Carolina law, to protect the interests of DEC's, DEP's or Piedmont's North Carolina retail ratepayers in the continuation of adequate and reliable service at just and reasonable rates. Another example is Regulatory Condition No. 8.2, which limits DEC's, DEP's and Piedmont's cumulative distributions paid to Duke Energy subsequent to the merger to (a) the amount of retained earnings on the day prior to the closure of the merger, plus (b) any future earnings recorded by DEC, DEP and Piedmont subsequent to the merger. In addition, Regulatory Condition 8.2 also holds DEC's, DEP's and Piedmont's customers harmless, through DEC's, DEP's and Piedmont's next general rate cases, against any potential increase in costs associated with a debt downgrade attributable to the merger.

The Commission, therefore, finds and concludes that the Regulatory Conditions effectively address as much as reasonably possible potential risks and concerns related to corporate governance and ring-fencing issues arising from the merger by ensuring the continued viability of DEC, DEP and Piedmont, and insulating and protecting DEC, DEP, Piedmont, and their retail ratepayers from the business and financial risks of Duke Energy and the affiliates within the Duke Energy holding company system, including the protection of utility assets from the liabilities of affiliates.

The purpose of Section IX of the Regulatory Conditions is to ensure that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Duke Energy, DEC, DEP, Piedmont, other affiliates, or the non-public utility operation. Regulatory Condition No. 9.1 provides for Commission approval of future proposed mergers by DEC, DEP or Piedmont. Regulatory Condition No. 9.2 requires that advance notification be filed with the Commission at least 90 days prior to the proposed closing date for the proposed merger, acquisition, or other business combination that is believed not to have an effect on DEC's, DEP's or Piedmont's rates or service, but which involves Duke Energy, other affiliates, or the non-public utility operations and which has a transaction value exceeding $1.5 billion. Any interested party may file comments within 45 days of the filing of the advance notification, and, if timely comments are filed, the Public Staff is required to place the matter on a Commission Staff Conference agenda and recommend how the Commission should proceed. This condition further provides that, if the Commission determines that the merger, acquisition, or other business combination requires approval, an order shall be issued requiring the filing of an application, and no closing can occur until and unless the Commission approves the proposed merger, acquisition, or business combination.

The Commission, therefore, finds and concludes that the Regulatory Conditions will effectively enable the Commission to exercise its jurisdiction over business combinations involving Duke Energy or other members of the Duke Energy holding company structure following the merger by ensuring that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Duke Energy, DEC, DEP, Piedmont, other affiliates, or the nonpublic utility operations of DEC, DEP and Piedmont.

The Regulatory Conditions in Section X are intended to ensure that the Commission receives adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to changes to the structure and organization of Duke Energy, DEC, DEP, Piedmont, and other affiliates, and nonpublic utility operations of DEC, DEP and Piedmont as they may affect North Carolina retail ratepayers.

Regulatory Condition No. 10.1 provides that DEC, DEP and Piedmont are required to file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, employees, rights, obligations, assets; or liabilities from DEC, DEP or Piedmont to Duke Energy Business Services, LLC (DEBS), Duke Energy, another affiliate, or a nonpublic utility operation that (a) involves services, functions, departments, employees, rights, obligations, assets; or liabilities other than those of a governance or corporate nature that traditionally have been provided by a service company, or (b) potentially would have a significant effect on DEC's, DEP's or Piedmont’s public utility operations.

Regulatory Condition No. 10.2 provides that, upon request, DEC, DEP and Piedmont shall meet and consult with, and provide requested relevant data to, the Public Staff regarding plans for significant changes in DEC's, DEP's, Piedmont’s or Duke Energy's organization, structure and activities; the expected or potential impact of such changes on DEC's, DEP's or Piedmont’s retail rates, operations and service; and proposals for assuring that such plans do not adversely affect DEC’s, DEP's or Piedmont’s retail customers. To the extent that proposed significant changes are planned for the organization, structure, or activities of an affiliate or nonpublic utility operation and such proposed changes are likely to have an adverse impact on DEC’s, DEP's or Piedmont’s retail customers, then DEC’s, DEP's and Piedmont’s plans and proposals for assuring that those plans do not adversely affect those customers must be included in these meetings. DEC, DEP and Piedmont shall inform the Public Staff promptly of any such events and changes.

The Commission finds and concludes that the Regulatory Conditions effectively address risks and concerns related to structure and organization arising from the merger as much as reasonably possible by ensuring that the Commission will receive adequate notice of, and an opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Duke Energy, DEC, DEP, Piedmont, and other affiliates, and nonpublic utility operations of DEC, DEP and Piedmont as they may affect North Carolina retail ratepayers.

The Applicants state in the application that the proposed merger in no way diminishes the Commission's authority to regulate the service quality of Piedmont. Section XI of the Regulatory Conditions attached to the Stipulation contains ten separate provisions that are intended to ensure that Piedmont continues to implement and further their commitment to providing superior utility service by meeting recognized service quality indices and implementing the best practices of each other and their utility affiliates to the extent reasonably practicable. As applicable to Piedmont, these provisions include overall service quality, best practices, right-of-way maintenance expenditures and clearance practices, customer access to service representatives and other services, call center operations, customer surveys, and regular meetings with the Public Staff on matters related to service quality.

In addition, Applicant witness Yoho testified that Piedmont is committed to continuing to maintain a high level of reliable and quality service to its customers after the merger.

The Commission finds and concludes that the Commission's continuing regulatory authority and procedures and the Regulatory Conditions will effectively ensure that Piedmont maintains a strong commitment to customer service after the merger.

Section XII of the Regulatory Conditions is intended to ensure that DEC's, DEP's and Piedmont's North Carolina retail ratepayers do not bear any additional tax costs as a result of the merger and that they receive an appropriate share of any tax benefits associated with the service company affiliates, as defined in Section I of the Regulatory Conditions.

Regulatory Condition No. 12.1 provides that under any tax sharing agreement DEC, DEP and Piedmont will not seek to recover from their North Carolina retail ratepayers any tax cost that exceeds DEC's, DEP's or Piedmont's tax liability calculated as if DEC, DEP and Piedmont were stand-alone taxable entities for tax purposes.

Regulatory Condition No. 12.2 provides that the appropriate portion of any income tax benefits associated with DEBS will accrue to the North Carolina retail operations of DEC, DEP and Piedmont for regulatory accounting, reporting, and ratemaking purposes.

The Commission finds and concludes that Regulatory Condition Nos. 12.1 and 12.2 will effectively ensure as much as reasonably possible that DEC's, DEP's and Piedmont's North Carolina retail ratepayers (a) are protected from any adverse effects of a tax sharing agreement, and (b) will receive an appropriate portion of income tax benefits associated with DEBS.

Section XIII of the Regulatory Conditions provides procedures for the implementation of conditions requiring advance notices and other filings arising from the merger. In particular, Regulatory Condition No. 13.1 provides detailed procedures and designated Sub dockets for filings pursuant to the Regulatory Conditions that are not subject to the advance notice provisions of Regulatory Condition No. 13.2. This Regulatory Condition provides that filings related to (a) affiliate matters required by Regulatory Condition Nos. 5.4, 5.5, 5.6, 5.7, and 5.23 and the filing permitted by Regulatory Condition No. 5.3 shall be made by DEC, DEP and Piedmont in Sub 986A and Sub 998A, respectively; (b) financings required by Regulatory Condition No. 7.6, and the filings required by Regulatory Condition Nos. 8.5, 8.6, 8.9, 8.10 and 8.11 shall be made by DEC, DEP and Piedmont in Sub 986B and Sub 998B, respectively; (c) compliance filings required by Regulatory Condition Nos. 3.1(d) and 14.4 and filings required by Sections III.A.2(l), III.A.3(e), (f), and (g), III.D.5, and III.D.8 of the Code of Conduct shall be made in Sub 986C and Sub 998C; (d) the independent audits required by Regulatory Condition No. 5.8 shall be made in Sub 986D; and (e) orders and filings with the FERC, as required by Regulatory Condition Nos. 3.1(d), 3.11 and 5.13 shall be made by DEC, DEP and Piedmont in Sub 986E and Sub 998E, respectively.

Regulatory Condition No. 13.2 provides that advance notices filed pursuant to Regulatory Condition Nos. 3.1(c), 3.3(b), 3.7(c), 3.10(c), 4.2, 5.3, 8.8, and 10.1 shall be assigned a new, separate Sub docket and imposes detailed requirements and procedures for processing such notices.

The Commission, therefore, finds and concludes that Section XIII of the Regulatory Conditions provides appropriate and effective procedures for the implementation of conditions requiring advance notices and other filings arising from the merger.

The purpose of Section XIV of the Regulatory Conditions is to ensure that Duke Energy, DEC, DEP, Piedmont, and all other affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent and effective manner.

Regulatory Condition No. 14.1 requires Duke Energy, DEC, DEP, Piedmont and all other affiliates to devote sufficient resources to the creation, monitoring and ongoing improvement of effective internal compliance programs to ensure compliance with the Regulatory Conditions and the Code of Conduct. It further requires them to take a proactive approach toward correcting any violations and reporting them to the Commission, including the implementation of systems and protocols for monitoring, identifying, and correcting possible violations, a management culture that encourages compliance among all personnel, and the tools and training sufficient to enable employees to comply with Commission requirements.

Regulatory Condition No. 14.2 requires DEC, DEP and Piedmont to designate a chief compliance officer who will be responsible for compliance with the Regulatory Conditions and Code of Conduct. This person's name and contact information must be posted on DEC's, DEP's and Piedmont's Internet Website. Regulatory Condition No. 14.3 requires that annual training be provided by DEC, DEP and Piedmont on the requirements and standards contained within the Regulatory Conditions and Code of Conduct to all of their employees, including service company employees, whose duties in any way may be affected by such requirements and standards.

Regulatory Condition No. 14.4 states that if DEC, DEP or Piedmont discover that a violation of the requirements or standards contained within the Regulatory Conditions and Code of Conduct has occurred, then they are required to file a statement with the Commission describing the circumstances leading to that violation and the mitigating and other steps taken to address the current or any future potential violation.

The Commission, therefore, finds and concludes that the Regulatory Conditions will effectively ensure monitoring and compliance with the Regulatory Conditions and the Code of Conduct by requiring Duke Energy, DEC, DEP, Piedmont, and all other affiliates to establish and maintain the structures and processes necessary to fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent and effective manner. With regard to Findings of Fact Nos. 48-57, the Regulatory Conditions provide the protections noted in each such finding of fact. These protections include risks related to agreements and transactions between and among DEC, DEP, Piedmont and their affiliates; corporate governance and ring-fencing; financing transactions involving Duke Energy, DEC, DEP or Piedmont, and any other affiliate; the ownership, use, and disposition of assets by DEC, DEP or Piedmont; participation in the secondary transactions market by DEC, DEP and Piedmont; the jurisdiction of the Commission; and filings with federal regulatory agencies. No party has offered evidence contesting these provisions of the Regulatory Conditions or the testimony of the witnesses in support thereof. As a result, the Commission determines that the evidence is sufficient to support these findings of fact and need not be repeated here.

Finally, the purpose of Regulatory Condition XV is to preserve the integrity of utility specific acquisitions of upstream supply and capacity. Section 15.1 requires DEC, DEP and Piedmont to determine the appropriate sources for their interstate pipeline capacity and supply on the basis of the benefits and costs to their respective customers. Section 15.2 specifies that Piedmont shall retain ownership and control of all gas contracts necessary to maintain reliable service to Piedmont's customers consistent with its best cost gas and capacity procurement methodology.

The Commission, therefore, finds and concludes that these Regulatory Conditions will effectively ensure the continuation of DEC's DEP's and Piedmont's current practices for determining their long-term sources of interstate pipeline capacity and supply.

With regard to all of the Regulatory Conditions approved herein, the Regulatory Conditions are essentially identical to those approved by the Commission in the 2006 merger of Duke Energy and Cinergy Corporation and the 2012 merger of Duke Energy and Progress Energy, Inc. Indeed, in response to questions on cross-examination, Applicants witness Barkley testified that many, if not all, of the Regulatory Conditions are the product of negotiations by various utilities with the Public Staff in prior merger proceedings. Witness Barkley also agreed that for the most part the Regulatory Conditions were adopted to provide protection to the utilities' ratepayers. Thus, the Commission and the Public Staff have 10 years of experience with the application and enforcement of these Regulatory Conditions. The Commission has found them to be effective in protecting ratepayers as much as reasonably possible from the real and potential risks of those mergers. The Commission is, therefore, confident in the ongoing strength of the Regulatory Conditions and their ability to protect Piedmont's ratepayers as much as reasonably possible from the real and potential risks of Piedmont's merger with Duke Energy.

In its post-hearing Brief, NC WARN discusses Carolina Power & Light Company's (CP&L's) prior purchase and sale of North Carolina Natural Gas Company (NCNG), and Duke Energy's prior purchase and sale of Westcoast Energy (Westcoast). NC WARN asserts that Duke Energy might likewise buy Piedmont and sell it a few years later. However, in response to questions on cross-examination, Applicants witness Good explained that Duke Energy's decision to divest Westcoast was based on less convergence in electricity and natural gas by 2006 than had been anticipated. She testified, however, that current changes in market conditions occasioned by shale gas, early retirement of coal plants, and environmental measures such as the Clean Power Plan have resulted in more convergence of electricity and gas.

With regard to NCNG, NC WARN attempted through cross-examination to present some evidence as to the circumstances surrounding CP&L's purchase and sale of NCNG. However, as NC WARN acknowledges in its Brief, those transactions occurred in 1999 and 2002, respectively. This was long before Duke Energy acquired CP&L (now DEP) in 2012. Therefore, NC WARN's argument has no merit.

In addition, the Commission finds and concludes that witness Good's testimony regarding Duke Energy's divestiture of Westcoast is credible and a reasonable explanation for that transaction. As a result, NC WARN's argument has no merit.

Based on the testimony provided by Public Staff witness Hoard and for the reasons discussed above, the Commission concludes that the Regulatory Conditions safeguard customers as much as reasonably possible from potential adverse impacts of the merger on rates, services and other aspects of the public utility operations of DEC, DEP and Piedmont. Further, even if such adverse impacts are not effectively mitigated by these commitments, the Commission retains full power and authority to address any potential impact from the merger on the ratepayers of DEC, DEP, and Piedmont.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 58-63

The evidence supporting these findings of fact is set forth in the Application, the Public Staff Settlement, including the Regulatory Conditions and Code of Conduct, the testimony of Public Staff witness Hoard, and the Commission's statutory authority over public utilities.

With the merger Application, the Companies filed proposed revisions to the existing DEC/DEP regulatory conditions.[1] Among the proposed changes is a revised Code of Conduct. Applicants proposed that the Code would govern the relationships, activities and transactions between and among the public utility operations of DEC, DEP, and Piedmont, as well as Duke Energy, other affiliates, and the nonpublic utility operations of DEC, DEP and Piedmont.

Public Staff witness Hoard testified that the Code of Conduct, together with the Regulatory Conditions, were developed in order to allocate the cost of goods and services among affiliates in a

[1] The current DEC/DEP Regulatory Conditions were modified by the Commission’s Order Approving Revisions to Regulatory Conditions Nos. 7.7 *and* 7.8 issued March 24, 2015, in Docket Nos. E-7, Subs 986 and 986A, and E-2, Subs 998 and 998A, and Order Approving Transfer of Employees and Amendment to Regulatory Condition [No. 5.3] issued November 25, 2015, in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

fair manner, protect ratepayers from overcharges paid by a regulated utility to a non-regulated affiliate, and to prevent cross-subsidization of a non-regulated affiliate by a regulated utility. He testified further that DEC and DEP have developed a cost allocation manual to allocate the costs of common goods and services from Duke Energy's services company to the affiliates, and between or among its utilities. As filed with the Application, the Code of Conduct is organized into seven sections. The Public Staff Settlement would add an eighth section to address competition between gas and electricity.

Section A of the Code discusses Independence and Information Sharing. This section requires Duke Energy, DEC, PEC, Piedmont and other affiliates to operate independently of each other, and sets guidelines and restrictions on the exchange of customer information and confidential systems operation information[1]. The Applicants propose to amend this provision to acknowledge that the Commission has allowed Duke Energy's regulated utilities to purchase services from its own shared services affiliate, Duke Energy Business Services, LLC (DEBS). The merging utilities propose to add a provision stating that they may disclose customer information to state or federal regulatory agencies or courts "to the extent the state or federal regulatory agency or court requires the disclosure and requests the disclosure in writing or by electronic means." This provision is codified as A.2.(f)(iii) in the version of the Code that was agreed to as part of the Settlement with the Public Staff.

The Public Staff Settlement adds new language such that DEC and DEP may provide Customer Information to their respective Nonpublic Utility Operations under the same terms and conditions that apply to the provision of such information to non-affiliates. Customers must authorize the disclosure of their information to third parties. The Settlement version of the Code provides that:

> DEC and DEP may disclose Customer Information to their Nonpublic Utility Operations with Customer consent to the extent necessary for the Nonpublic Utility Operations to provide goods and services to DEC and DEP and upon the written agreement of the Nonpublic Utility Operations to protect the confidentiality of such Customer Information. [Code provision III.2(f)(ii)]

The Commission notes that Piedmont was not included in provision lll.A.2.(d), which requires DEC and DEP to post on their websites some of the Code's provisions that address disclosure of customer information between DEC, DEP and their Nonpublic Utility Operations. This was likely an inadvertent error. In addition, the posting requirement applies to some, but not all, of the disclosure provisions, and it excludes the exceptions that are listed in lll.A.2.(f). The Commission believes that full disclosure of all of the provisions is appropriate and thus will require provision lll.A.2.(d) to be further revised as follows:

> Section lll.A.2~~(a), 2.(b), and 2.(c)~~ shall be permanently posted on DEC's, ~~and~~ DEP's and Piedmont's website(s).

[1] Confidential Systems Operation Information (CSOI) includes DEC and DEP nonpublic information concerning electric generation, transmission, distribution or sales. The merging companies would add to the CSOI definition "information that pertains to Natural Gas Services provided by Piedmont, including but not limited to information concerning transportation, storage, distribution, gas supply, or other similar information."

Section B of the Code addresses "Nondiscrimination." It prohibits the Applicants from giving any preference in pricing or service priority to an affiliate, or requiring the purchase of any goods or services in return for receiving electric service. The version of the Code that was submitted pursuant to the Settlement with the Public Staff adds two provisions to this section of the Code. New provision 10 states that "unless otherwise directed by order [of] the Commission, electric generation shall not receive a priority of use from Piedmont that would supersede or diminish Piedmont's provision of service to its human needs firm residential and commercial customers." New provision 11 provides that Piedmont shall file an annual report with the Commission summarizing all requests for natural gas services made by a non-utility generator, Piedmont's response to the request, and the status of the inquiry.

Section C of the Code addresses "Marketing." It allows joint sales and joint advertising by Duke Energy affiliates subject to restrictions imposed by the Commission, but requires the three utilities to make any such joint marketing opportunities available to third parties. This section of the Code also prohibits the use by an affiliate of the utilities' names and logos unless disclaimers accompany such use. The disclaimers clarify that the utilities/affiliates are separate companies and that the Commission does not regulate Duke Energy.

Section D of the Code address "Transfers of Goods and Services, Transfer Pricing and Cost Allocation." This section sets guidelines for the pricing of goods and services exchanged between affiliates. Provision D.3.(d) allows DEC, DEP and Piedmont to transfer untariffed non-power, non-generation and non-fuel goods to each other or to other Duke Energy affiliates, and to receive transfers of such goods and services from affiliates, at the supplier's "fully distributed cost."[1] The Applicants proposed to add a new provision (e) to specify that "for gas supply transactions, transportation transactions, or both, between DEC and Piedmont or DEP and Piedmont, Piedmont shall provide service to DEC or DEP at the same price and terms that are made available to other similarly situated shippers." In the version of the Code of Conduct that was stipulated among the Applicants and the Public Staff, provision (e) was amended to read:

> All Piedmont deliveries to DEC and DEP pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric) [sic] generation, size of load, profile of load (daily, monthly, seasonal, annual), location on Piedmont's system, and costs to serve and rates. Piedmont shall maintain records in sufficient detail to demonstrate compliance with this requirement.

In addition, the Settlement version of the Code of Conduct contains new provisions (f) and (g) that read:

[1] "Fully Distributed Cost" is defined to include all direct and indirect costs, including overheads, and capital costs, incurred in providing goods and services. The definition provides that the cost of capital from the supplying utility's most recent general rate case shall be used to calculate the fully distributed cost of a good or service.

> (f) All gas supply transactions, interstate transportation and storage transactions, and combinations of these transactions, between DEC or DEP and Piedmont shall be at the fair market value for similar transactions between non-affiliated third parties. DEC, DEP, and Piedmont shall maintain records, such as published market price indices, in sufficient detail to demonstrate compliance with this requirement.
>
> (g) All of the margins, also referred to as net compensation, received by Piedmont on secondary market sales to DEC and DEP shall be recorded in Piedmont's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins ... shall be included in the secondary market transactions subject to the sharing mechanism ... approved by the Commission in its Order Approving Stipulation, dated December 22, 1985, in Docket No. G-100, Sub 67.[1]

Provision D.4 and D.6 provide that charges for shared services and all permitted transactions among the affiliates shall be allocated to the affiliated utilities in accordance with cost allocation manuals that are filed with the Commission.

Provision D.5 provides that Duke Energy's affiliated utilities may "capture economies-of-scale in joint purchases of goods and services" as well as coal and natural gas if the joint purchases result in cost savings for customers. The Applicants propose a new provision in this section so that joint purchases of electricity or ancillary services can be made pursuant "to a Commission-approved contract or service agreement."

Provision D.8 provides that trade secrets shall not be transferred from the three North Carolina utilities to Duke Energy or other affiliates without just compensation and notice to the Commission. Pursuant to the Code, trade secrets may be transferred among the three North Carolina utilities without advance notice. However, Provision D.9 provides that DEC, DEP and Piedmont shall receive compensation from Duke Energy or other affiliates for intangible benefits, if appropriate.

Section E, "Regulatory Oversight," reiterates that G.S. 62-153 will continue to apply to all transactions between DEC, DEP, Piedmont, Duke Energy and other affiliates. This statute requires all public utilities to file with the Commission any contract with any affiliate, and the Commission may disapprove such a contract if it is found to be unjust or unreasonable. Further, the books and records of the Applicants and their affiliates will be open for examination by the Commission or the Public Staff. The Applicants propose to add a new provision E(3) which provides that DEC or DEP shall file a report with their annual fuel cost recovery rider demonstrating that any gas services purchased from Piedmont (except those provided under Commission-approved contracts) were prudent and reasonably priced.

[1] In the Matter of Accounting for Secondary Market Transactions By Natural Gas Local Distribution Companies.

Section F is entitled "Utility Billing Format" and provides that if customers receive bills for a variety of services such bills shall clearly separate the electric service charges from the gas service charges. In addition, the bill shall clearly state that a customer's failure to pay for one utility service will not cause termination of their other utility service.

Section G of the Code provides a "Complaint Procedure" for resolving complaints that arise due to the relationship of the three utilities with Duke Energy and other affiliates.

The Settlement with the Public Staff would add a new Section H entitled "Natural Gas/Electricity Competition." In part, it states as follows:

> DEC, DEP and Piedmont shall continue to compete against all energy providers, including each other, to serve those retail customer energy needs that can be legally and profitably served by both electricity and natural gas. The competition between DEC or DEP and Piedmont shall be at a level that is no less than that which existed prior to the Merger. Without limitation as to the full range of potential competitive activity, DEC, DEP and Piedmont shall maintain the following minimum standards:

Further, as fully discussed earlier, Section III.H. includes specific provisions that require Piedmont to make all reasonable efforts to extend the availability of natural gas to as many new customers as possible, at a minimum applying the same standards and criteria as it applied before the merger. Moreover, in determining where and when to extend natural gas service, Piedmont will be required to make decisions in accordance with the best interests of Piedmont, rather than the best interests of DEC or DEP.

In the Public Staff Settlement, the Applicants and the Public Staff agreed that the Regulatory Conditions, including the Code of Conduct, represent commitments by the Applicants as a precondition of approval by the Commission of the Application for merger. The stipulated version of these documents, as described above, were attached to the Public Staff Settlement with a statement that they are intended to be incorporated into any order by the Commission approving the merger.

The Commission has reviewed the Regulatory Conditions, including the Code of Conduct, and finds and concludes that they are significant commitments by the Applicants to provide ongoing protection to ratepayers from possible costs and risks of the proposed merger.

Also applicable is G.S. 62-138, the requirement to obtain Commission approval over service contracts; G.S. 62-140, the prohibition against discrimination; and, as discussed previously, G.S. 62-153, which requires the Applicants to file affiliated contracts and to obtain approval for affiliated service contracts. Each of these statutory provisions either prohibits or mandates utility conduct for the purpose of assuring that rates charged to customers for utility services are just and reasonable.

The Commission has carefully reviewed and considered all of the evidence set forth above and finds it to be credible.

In its post-hearing Brief, NC WARN contends that the provisions of the Regulatory Conditions and Code of Conduct governing affiliate transactions are vague and without enforcement mechanisms. In particular, NC WARN questions how the Commission will determine the "fair market value" of natural gas sold by Piedmont to DEC and DEP. It asserts that the competitiveness of the natural gas market will become a vague notion when there are only two main large local distribution companies (LDCs) in North Carolina, and Duke Energy owns one of them.

The Commission notes that the Code of Conduct defines "market value" as "The price at which property, goods, or services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts." See Code of Conduct, Sec. I, at 2. This is a very standard definition of market value, one that the courts and the Commission have worked with for many years. In addition, it appears that NC WARN has a misconception as to how the market for natural gas operates and the choices that electric generating plants have in acquiring gas. Although DEC and DEP will need the services of Piedmont and Public Service of North Carolina, Inc. (PSNC) to transport their gas, DEC and DEP can purchase their gas from any source they choose. Moreover, there are many marketers and sellers operating in the natural gas sales market. Thus, the Commission will not be restricted to the gas prices being charged by Piedmont and PSNC if the Commission needs to determine what the market value of a quantity of gas was at the time that it was sold by Piedmont to DEC or DEP. With respect to the enforcement mechanism, pursuant to G.S. 62-153, the Commission can use its authority to disapprove any proposed affiliate contract that it determines to be unjust or unreasonable. As a result, NC WARN's arguments have no merit.

No party has offered evidence contesting the provisions of the Code of Conduct or the testimony of the witnesses in support thereof, other than the previously discussed concerns expressed by NC WARN, and those of FPWC with regard to Code of Conduct Section III.D.3.(e). FPWC's concerns are addressed later in this Order. As a result, the Commission determines that there is substantial credible evidence to support the findings of fact regarding the Code of Conduct.

Further, the Code of Conduct is essentially identical to the Code approved by the Commission in the 2006 merger of Duke Energy and Cinergy Corporation and the 2012 merger of Duke Energy and Progress Energy, Inc. Thus, the Commission and the Public Staff have 10 years of experience with the application and enforcement of the Code of Conduct. The Commission has found the Code of Conduct to be effective in protecting ratepayers as much as reasonably possible from the real and potential risks of those mergers. The Commission is, therefore, confident in the ongoing strength of the Code of Conduct and its ability to protect Piedmont's ratepayers as much as reasonably possible from the real and potential risks of Piedmont's merger with Duke Energy.

Based on the foregoing, the Commission finds and concludes that potential risks of the merger to ratepayers have been effectively mitigated as much as reasonably possible by the commitments of the Applicants in the Application, as well as the testimony of Applicants witnesses and the Public Staff Settlement, including the Regulatory Conditions and Code of Conduct. Further, even if such risks are not effectively mitigated by these commitments, the Commission retains full power and authority to address any potential impact from the merger on the ratepayers of DEC, DEP, and Piedmont.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 64

The evidence supporting this finding of fact is contained in the Market Power Analysis, the testimony of Applicants witnesses Reitzes and Barkley, the testimony of Public Staff witness Hoard, and the Public Staff Settlement, including the stipulated Regulatory Conditions and Code of Conduct, and the Commission's statutory and inherent regulatory authority over public utilities.

In the M-100, Sub 129 Order, the Commission required natural gas and electric utilities proposing to engage in a merger to file a market power analysis with their merger approval petitions. The purpose of this requirement was to allow the Commission to evaluate the impact of the proposed merger on competitive and regulated markets and to assess whether any potential anticompetitive effects might flow from the proposed merger transaction.

Some of the public witness testimony and consumer statements of position filed in this proceeding reflect concerns about the possibility of enhanced “monopoly” market power resulting from the proposed merger and the potential for self-dealing or anticompetitive behavior by the merged companies.

The Commission has carefully reviewed the record in this proceeding related to these issues and finds no substantial evidence that would support the conclusion that the proposed merger will result in materially increased market or monopoly power, particularly when viewed in the light of the restrictions and requirements set forth in the stipulated Regulatory Conditions and Code of Conduct.

In this regard, the Commission has reviewed the HHI study performed by the Brattle Group, which indicates only a slightly increased concentration in market power of the combined Duke Energy entities as a result of the merger. Market Power Analysis, Technical Appendix B, Table 4. Further, the Market Power Analysis found that “Duke and Piedmont lack both the ability and the incentive to raise prices or restrict output as a result of the Transaction, due to economic and regulatory conditions in the electric and gas markets in North Carolina. . . [and] that the Transaction raises no basis for competitive concerns” with regard to the three areas studied, which were “(i) ‘inter-fuel’ competition between gas and electricity as alternative sources of energy; (ii) ownership of gas transmission rights by each of the merging parties and any potential effect of the Transaction on the price of released gas transportation capacity and/or delivered gas in North Carolina; and (iii) the potential effects of the Transaction on third-party generation.” Market Power Analysis at p. 1. These findings are supported, as the Brattle Group notes, by the Federal Trade Commission’s early termination of its 30-day preliminary antitrust review of this merger. Market Power Analysis at p. 1. Significantly, the Market Power Analysis constitutes the only substantive evidence in the record of this proceeding on the issue of market or monopoly power, and the Commission finds the analysis contained in the Market Power Analysis credible and convincing.

With respect to the slightly different and more speculative concern voiced by some public witnesses (or consumer statements of position) to the effect that the merger will result in a “mega-monopoly,” the Commission notes that each of DEC, DEP and Piedmont is currently a monopoly provider of utility services operating within its exclusive service area. This model for the provision of electric and natural gas service by public utilities is the long-standing norm both in North

Carolina and nationally and is premised on the notion that the capital intensive nature of providing public utility services makes a regulated monopoly the preferred form of service rather than competing providers operating in a free market with a risk of duplicative costs and higher rates. In this case, the status of DEC, DEP, and Piedmont as separate and distinct regulated monopoly providers of utility services will not change as a result of the merger. The most that can be said is that the family of Duke Energy subsidiary utilities will increase in size as a result of the merger, but there is no evidence that this will translate into enhanced power to charge higher rates or force customers to accept lower standards of service – both of which are entirely within the jurisdictional authority of this Commission to regulate. In short, the manner in which DEC, DEP, and Piedmont provide service to the public – at least insofar as it relates to the exercise of "monopoly" service rights and regulation by this Commission – will not change as a result of the merger.

With respect to the possibility of self-dealing or anti-competitive conduct by and among DEC, DEP, and Piedmont after the merger, that risk is effectively mitigated by the stipulated Regulatory Conditions and Code of Conduct attached to the Public Staff Settlement and by the ongoing authority of this Commission over the rates, terms, and conditions of service offered by each of these utilities. In this regard, the Commission notes that the stipulated Regulatory Conditions and Code of Conduct are updated versions of documents approved in prior merger proceedings involving Duke Energy, DEC, and DEP, and, for the most part, simply add Piedmont to the commitments made by the merging entities and adjust the provisions thereof to account for the addition of a natural gas distribution company to the Duke Energy family of regulated utilities. The Commission's experience with these conditions and Code of Conduct provisions is that they have functioned effectively to protect ratepayers in prior Duke Energy merger transactions, and the Commission is confident they will operate just as effectively in this instance.

The Regulatory Conditions and Code of Conduct, as set forth in the Public Staff Settlement and as explained by Public Staff witness Hoard in his testimony, address several areas in which self-dealing or anticompetitive behavior by DEC, DEP, and Piedmont could arise. First, the affiliated transaction rules set forth in the stipulated Regulatory Conditions and Code of Conduct are designed to "(1) fairly allocate the cost of common goods and services among affiliates, (2) protect the ratepayers of utilities from overcharges by non-regulated affiliates, and (3) prevent cross-subsidization of non-regulated affiliates by utility affiliates." (T Vol. 3, pp. 83-84) In addition, provisions have been added to the stipulated Regulatory Conditions and Code of Conduct to address priority of natural gas services to electric generation facilities in order to protect natural gas customers, separation of gas and electric operations, potential discrimination against gas-fired non-utility generators, the provision of services/sales of natural gas to DEC and DEP by Piedmont, and the preservation of competition between Piedmont as a natural gas provider and DEC/DEP as electric providers. According to witness Hoard, the Public Staff believes that these provisions appropriately address concerns raised by the proposed merger. At the hearing of this matter, counsel for FPWC asked several witnesses about the potential for future discrimination against FPWC by Piedmont in the provision of natural gas transportation services which could impact its ability to compete in the wholesale generation market.[1] As the Commission understands it, FPWC is currently served under an interruptible transportation service special contract arrangement which was agreed to by FPWC and North Carolina Natural Gas (predecessor to Piedmont) and has no current issues with service under that contract. It is also the Commission's understanding that

[1] FPWC presented no witness, however.

FPWC's Butler Warner generation facilities are currently dispatched by DEP under a tolling agreement that extends until at least 2019. Market Power Analysis, Table 10. FPWC's concern appears to be that at some future point in time, as a consequence of the merger, Piedmont could be incentivized to unduly discriminate against FPWC in the provision of natural gas transportation service.

The Commission has fully considered this potential risk of the merger but notes that FPWC does not assert, and the evidence does not support, current discriminatory treatment by Piedmont as to FPWC. Further, the following mitigating factors would provide protection to FPWC if it were to find itself competing with DEC or DEP in the wholesale generation market at some point in the future. First, as has been noted previously, the Commission has full jurisdiction and supervisory authority over the rates, terms, and conditions of service provided by Piedmont, including any service provided to FPWC. As such, any proposed rate for natural gas sales or transportation service to be provided to FPWC would be subject to the direct scrutiny and review of the Commission and the Public Staff. Second, under the provisions of G.S. 62-140(a):

> No public utility shall, as to rates or services, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage. No public utility shall establish or maintain any unreasonable difference as to rates or services either as between localities or as between classes of service.

62-140(a) (2015).

Third, under Section III.B.1. of the stipulated Code of Conduct attached to the Public Staff Settlement, Piedmont and its employees are prohibited from unduly discriminating against non-affiliated entities in the provision of utility services. Each of these factors mitigates against the likelihood that FPWC's concerns will be manifested.

At the hearing and in its prior Motion to Compel, FPWC raised the issue of whether its facilities would be considered to be "similarly situated"[1] with those of DEC or DEP. This issue was addressed at the hearing by reference to Section III.D.3.(e) of the stipulated Code of Conduct, which does not use the term "similarly situated" and provides as follows:

> All Piedmont deliveries to DEC and DEP pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric generation), size of load, profile of load (daily, monthly, seasonal, annual), location on Piedmont's system, and costs to serve and rates.

[1] Section III.D3(e) of the proposed Code of Conduct filed as Exhibit D to the Application provides:

> For gas supply transactions, transportation transactions, or both, between DEC and Piedmont or DEP and Piedmont, Piedmont shall provide service to DEC or DEP at the same price and terms that are made available to other similarly situated shippers.

> Piedmont shall maintain records in sufficient detail to demonstrate compliance with this requirement.

FPWC, however, raised the further issue of whether it would be considered a "Shipper," which the Code of Conduct defines as "[a] Non-affiliated Gas Market, a municipal gas customer, or an end user of gas. FPWC then raised the issue of whether the Butler- Warner facilities would be considered to have characteristics comparable to those of DEC and DEP.

On August 25, 2016, FPWC filed a post-hearing Brief. In summary, FPWC contends that after the proposed merger with Duke Energy, DEC, DEP and Piedmont will have a financial incentive to discriminate against FPWC in favor of DEP and DEC because such discrimination will allow DEP and DEC to succeed in competing with FPWC in the wholesale electric market. According to FPWC, the discrimination will be effectuated by increasing the gas delivery costs of FPWC's gas-fired generation in relation to the costs charged to DEP and DEC. FPWC notes that the Applicants have revised Code of Conduct Section III.D.3(e), but FPWC submits that the revised version is deficient for four primary reasons: (1) The standard is applicable to Shippers rather than generating units of Shippers; (2) even with the articulation of several "factors," the legal standard set forth in the Code of Conduct is overly vague; (3) since the negotiated rate agreement with each shipper and any supporting documents are filed confidentially, shippers have no knowledge of the negotiated rates made available to other shippers; and (4) reliance on the Code of Conduct (or, in the alternative, G.S. 62-140) to prevent undue discrimination will shift the burden of proof to FPWC or any other shipper that may receive unfair treatment by Piedmont. See State ex rel. Utilities Comm. v. Edmisten, 314 N.C. 122, 151, 333 S.E.2d 453, 471 (1985), vacated Nantahala Power & Light Co. v. Thornburg, 477 U.S. 902, 106 S.Ct. 3268, 91 L.Ed.2d 559 (1986).

In addition, FPWC asserts that witness Reitzes' conclusions about the risk of anti-competitive conduct are both: (1) inadequate because he failed to assess the potential anti-competitive impact of the merger when the Butler-Warner facility is no longer subject to a "Duke tolling agreement," which is scheduled to occur in a few years according to his own report; and (2) inaccurate because he ignored the fact that Butler-Warner's combined cycle capacity is capable of serving as an intermediate generating unit rather than peaking unit, which therefore provides a material incentive to increase the cost of gas delivered to FPWC's Butler-Warner facility.

Therefore, FPWC contends that Section III.D.3(e) of the Code of Conduct should be modified (1) by clarifying the definition of "Shipper" to allow the determination of comparability and discrimination to be made at the generating unit level for the Shippers and the Applicants; (2) to require Piedmont to utilize a uniform model to develop negotiated rates; and (3) to require Piedmont to prepare a comprehensive narrative report and quantification for each negotiated rate for which Commission approval is sought.

FPWC contends that the foregoing modifications would provide a viable enforcement mechanism if: (1) Piedmont is required to certify to the Commission whether the uniform model was used to set negotiated rates rather than simply maintain confidential supporting documentation; and (2) before any negotiated rate is approved, the Public Staff is required to certify to the Commission that the Public Staff has reviewed the Piedmont report and supporting information and confirmed the use of the uniform model and the same rate of return on common equity and the validity of the incremental cost inputs and their derivation and the output of the model. If Piedmont and the Public Staff publicly file the requisite certifications, FPWC believes it would be reasonable to impose the burden of proof on a shipper that wishes to challenge a negotiated rate as inconsistent with Section III.D.3(e) or unduly discriminatory pursuant to G.S. 62-140. However, if Piedmont deviates from the use of the uniform model or the derivation of incremental costs, or the Public Staff fails to provide the requisite comprehensive certification, FPWC or another shipper should be entitled to bring an action challenging the proposed negotiated rates as prohibited by the Code of Conduct or G.S. 62-140 in which Piedmont should bear the burden of proving that the negotiated rate is not unduly discriminatory.

With regard to FPWC's proposal that the definition of Shipper be modified, questions were raised by FPWC as to whether the Code of Conduct's provisions would be applicable just to FPWC as the Shipper, or whether an FPWC generating plant, such as the Butler-Warner facility, would be protected by Section III.D.3(e). Applicants witness Barkley made clear that "Shipper" under the Code of Conduct, does apply to a generating unit. Therefore, the Code of Conduct would apply to negotiated rates provided to a FPWC generating unit compared to those provided to DEC and DEP, and differences in rates would have to be supported. Therefore, the Commission finds that no modification of the definition is necessary to address FPWC's concerns.

The FPWC's second request was to require Piedmont to utilize a uniform model to develop negotiated rates. Applicants witness Barkley testified that a negotiated rate, "would be based on a cost of service base model," (T Vol. 3, p. 26) He discussed generally the factors that Piedmont considers in the model that it uses to establish a negotiated rate. He also discussed factors that could cause costs to vary between customers, including both costs and load characteristics. Witness Barkley testified that Piedmont's evaluation of a negotiated rate for an individual customer was a "mini version of what happens in a general rate case," with Piedmont seeking to earn a return on investment after recovering costs that the customer causes Piedmont to incur. He agreed that Piedmont's model is, "common to all negotiated rate agreements, but the inputs are specific to the customer or the generating station," adding, "It's a consistent process, but two dissimilar customers would have very dissimilar inputs." (T Vol. 3, p. 30) FPWC was not explicit in what it meant by a "uniform model," or how such a model would differ from the cost of service model that witness Barkley testified that Piedmont uses. The Commission finds that Piedmont's use of a cost of service model as described by witness Barkley is appropriate to fairly determine a negotiated rate.

Witness Barkley was asked how a customer would know that it was being discriminated against. He responded that

> the customer is not going to be given all the details on another customer's arrangement because then the entire process is open to the entire world and the confidential discussions you had with that counterparty can't be shared with the customer that you're representing in your question. (T Vol. 3, p. 32)

Witness Barkley added that a customer, "will have to obtain the best deal that it can get for itself using its negotiating abilities, and then if it feels like it's being discriminated against, it's going to have to raise it, I believe, here at this Commission." (T Vol. 3, p. 32) The Commission notes that any future dispute in this regard would be subject to an examination of the factors set forth in the Code of Conduct, the Public Staff's review of a proposed service contract, and the

Commission's ultimate scrutiny in a complaint proceeding. The Commission is confident that its complaint authority and procedures are adequate to address future discrimination claims, if and when they are asserted by FPWC and other shippers. As a result, the Commission declines to revise its procedures and burden of proof guidelines in the manner requested by FPWC. With regard to FPWC's request for a narrative report, witness Barkley testified that, while Piedmont did not produce a report, it would maintain the documentation to support the rate for the duration of the contract, and that documentation would be subject to review by the Public Staff and approval by the Commission. Whether a formal report is produced, or Piedmont simply maintains documentation, the Commission expects Piedmont to be able to fully explain and support the derivation of negotiated rates.

The Commission has carefully reviewed and considered all of the evidence set forth above describing the potential of the proposed merger to result in increased market or monopoly power and finds it to be credible.

Based on the foregoing evidence, the Commission concludes that the proposed merger will not result in materially increased market or monopoly power to the detriment of customers. The Commission's conclusion is further supported by the restrictions and requirements set forth in the Regulatory Conditions and Code of Conduct designed to deter and prohibit self-dealing and anti-competitive behavior as well as the Commission's continuing regulatory jurisdiction over Piedmont, DEC and DEP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65-66

The evidence supporting these findings of fact is set forth in the Application, the Cost-Benefit Analysis, the Public Staff Settlement, the CUCA Agreement, the testimony of public witnesses, the testimony of Applicants witnesses Good, Skains, Young, Yoho, and Barkley, the testimony of Public Staff witness Hoard, and the Commission's statutory and inherent supervisory authority.

The following is a summary of the testimony provided by each of the public witnesses in this docket.

Ruth Zalph, from Chapel Hill, testified regarding her concerns for additional gas plants that Duke would need to build; that the spirit and reality of marketplace competition would be stifled; the impact on our environment, and the creation of a mega-monopoly with tremendous power benefiting only Duke and its shareholders. She would not like to see this merger go forward.

John Wagner, from Pittsboro, expressed concerns regarding Duke becoming an even larger monopoly of electrical energy; the impact that eminent domain will have on some citizens; and that fossil fuels threaten global climate disruptions. He would like for the Commission to rule against this merger.

Dr. Steven Norris, from Fairview, testified that not only is it the law, but the responsibility of the Commission to operate in the public interest. He stated that seven years ago climate change was not as bad as it is today. Carbon emissions have increased and continue to rise, and greenhouse gases largely due to methane being released from fracking have increased, all of which are causing out of control climate change.

Beth Henry, from Charlotte, testified that the Commission's three-prong test is not met by the merger. The merger does not result in sufficient benefits to offset the potential costs and risks. She testified that our climate is getting hotter and more extreme and Duke should not be allowed to double down on dangerous fossil fuels. Due to Duke's size and financial status, giving them more power by approving the merger risks severe harm to North Carolinians.

Catherine Chandler, from Durham, testified that the citizens of North Carolina are already held accountable for uncontrolled decisions and expenses of a runaway monopoly. The public of North Carolina needs the Commission to represent it and not indebt us to two monopolies with the merger of Duke and Piedmont. Consideration should be given to the state's environmental, economic health, and long-term future.

Andrew Hernandez, from Cary, testified that the merging of two enormous monopolies in such a radically streamlined fashion is unheard of. His concern is when the well runs dry, fracking is ushered out as obsolete, pipes leak and maintenance is required, or in the next 10 years when the actual greenhouse gas is being emitted through methane and affects the coast, who is paying for the externality cost of all these different developments.

Clint McSherry, from Durham, testified that he had no intentions to attack Duke or Piedmont for attempting to act in their own best interest, increased profits. He does feel it is borderline negligent of the future of the people of this state, himself as a recent college graduate fighting for his own future, for children and future children; that it is foolish in a sense, negligent in a sense and perhaps even irrational to move forward with a merger that we know will only result in billions of dollars spent furthering a dying industry.

Hope Taylor, from Stem, testified that she objects to the merger as it would intensify the profitability of Duke in an unjustified way and accelerate the construction of gas pipelines, thwart investment in transition to cleaner, more cost-effective and more job creating renewable energies and efficiency. She testified that future pipeline construction, especially in Eastern North Carolina, would have disproportionate impacts on lower income communities, some of them long-time residents, the elderly, people of color including African Americans, Native Americans and the Latino population.

Richard Fireman, from Mars Hill, testified that when the merger is approved by the Commission, Duke Energy will derive most of its profit from building out a natural gas infrastructure that will help feed our state and planet to dangerous and inhospitable levels destroying the society to which human culture is ill adapted. He stated that the Public Staff has failed its mandate to protect the public welfare for both current ratepayers and future generations.

Dr. Steven Sanborn English, from Charlotte, testified that of all the many devastations that earth has suffered, the biggest causes are poor land use and the burning of fossil fuels. For the sake of future generations, the Commission should say no to this merger.

Emily Wilkins, from Durham, testified that maybe other natural sources of energy might be used that are less polluting.

The Commission is cognizant of the risks expressed by public witnesses regarding the size of Duke Energy and the challenges that its increased size creates for the Commission in its duty to regulate the public utility subsidiaries of Duke Energy. In particular, Duke Energy's increased size makes it more difficult for the Commission and Public Staff to audit and regulate affiliate transactions, cost allocations and financial arrangements. As a result, the Commission gives significant weight to the public witness testimony regarding these concerns.

However, to the extent that the public witnesses' concerns about monopolies revolve around the monopoly status of DEC, DEP and Piedmont, North Carolina has long chosen to serve the electricity and natural gas needs of its residents by authorizing regulated monopoly public utilities to provide those services. The merger of Piedmont with Duke Energy will not change anything about that public policy.

In addition, as previously discussed with regard to NC WARN's testimony, the risks cited by several of the public witnesses – such as methane emissions, climate change and potential gas shortages - are risks that DEC, DEP and Piedmont face today and will continue to face irrespective of whether the merger is consummated. Thus, the testimony regarding these risks is not relevant to the provisions of G.S. 62-111 at issue in this case and, therefore, is not entitled to be given any weight.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 67-69

The evidence supporting these findings of fact is set forth in the Application, the Cost-Benefit Analysis, the Public Staff Settlement, the CUCA Agreement, the EDF Agreement, the testimony of Applicants witnesses Good, Skains, Young, Yoho, and Barkley, the testimony of Public Staff witness Hoard, the Commission's statutory and inherent supervisory authority, and the entire record in this proceeding.

As fully discussed in Findings of Fact and Conclusions Nos. 18-28 and 37-47, the provisions of the Settlement are the product of the give-and-take of settlement negotiations between the Applicants and the Public Staff. As a result, the Settlement reflects the fact that the Applicants agreed to certain provisions that advanced the Public Staff's interests and the Public Staff agreed to other provisions that advanced the Applicants' interests. The end result is that the Settlement strikes a fair balance between the interests of the Applicants and their customers.

In his pre-filed supplemental and rebuttal testimony, Applicants witness Barkley testified that the Settlement provides additional economic benefits and certainty beyond that identified by the Applicants in the Application. Further, he states that the Settlement provides non-economic benefits as part of the Regulatory Conditions and Code of Conduct.

In response to questions on cross-examination, Applicants witness Barkley testified that the settlement negotiations between the Applicants and Public Staff involved numerous face-to-face meetings held in the Wells Conference Room in the Dobbs Building.[1] Witness Barkley testified that the negotiations were extensive because the parties had very divergent views. He stated that the Public Staff negotiators were tough negotiators, they were effective, and conducted themselves with a great deal of integrity. In addition, witness Barkley testified that he would not find it appropriate to characterize the Settlement as a "backroom deal." Further, he stated that the Commission did not have any involvement in the negotiations between the Applicants and the Public Staff, and that the parties did not inform the Commission on any aspect of the negotiations until the Settlement was filed with the Commission on June 10, 2016.

Many of the benefits to be derived from the merger have been established as a result of the settlements filed in this proceeding. Indeed, many of the requirements of the settlement agreements are requirements that the Commission does not have the authority to impose on Duke Energy, DEC, DEP or Piedmont under the Public Utilities Act. For example, the Commission could not require Piedmont to withdraw its application for deferral of integrity management costs, which costs might total $18.03 million for North Carolina over the next five years. Further, the Commission could not require Piedmont to give its customers a $10 million one-time bill credit by the end of 2016. In addition, the Commission could not require the Applicants to make substantial donations to The Duke Energy Foundation and Piedmont Natural Gas Foundation for four years after the merger, and a substantial contribution to workforce development and low-income energy assistance.

Although no other intervenors joined the Settlement, the only party that expressed opposition to the Settlement is NC WARN. The Commission addressed NC WARN witness Gunter's testimony regarding the funds committed by the Settlement for workforce development and low-income energy assistance in an earlier section of this Order. In addition, the Commission struck the substantive portions of the testimony of NC WARN's witnesses Howard and Hughes as irrelevant to the provisions of G.S. 62-111 at issue in this case, and struck NC WARN's cross-examination on the same subjects for the same reason.

In its post-hearing Brief, NC WARN contends that the Settlement contains a number of provisions that are vague or unreasonable, and lack enforcement mechanisms. First, NC WARN argues that "Duke Energy promises to guarantee North Carolina retail customers will receive their allocable shares of $650 million in total projected fuel and fuel-related cost savings." See NC WARN's Brief, at 19. However, there is no guarantee of $650 million in fuel savings in the Settlement. Rather, the CUCA Agreement guarantees an additional $35 million in fuel savings over and above the fuel savings guaranteed in the Duke/Progress Merger Order. In addition, NC WARN contends that there is no mechanism for calculating fuel savings and ensuring that they are received by ratepayers. This argument has no merit. Applicants witness Barkley testified that for purposes of the CUCA Agreement the amount of fuel savings achieved by DEC and DEP will be measured using the same methodology arising from the JDA and the Duke/Progress Merger Order, as approved by the Commission. In addition, he testified that the mechanism has been used for approximately four years.

[1] The Commission notes that the Dobbs Building, with the Wells Conference Room located on the fifth floor, is a public building used by North Carolina government agencies, including the Public Staff.

NC WARN also complains that Paragraph No.12 of the Settlement stipulates, in essence, that the terms of the Settlement satisfy the requirements for meeting the public convenience and necessity standard under G.S. 62-111, and should not, by itself, provide the basis for such a conclusion. The Commission agrees and has given the conclusory statement in Paragraph No. 12 of the Settlement no weight.

Further, NC WARN asserts that the Commission should not endorse the "take it or leave it" provision in Paragraph No. 16 of the Settlement. The Commission agrees and has given the statement in Paragraph No. 16 of the Settlement no weight. Indeed, the Commission does not feel the least constrained by such a provision, and has demonstrated that by adding conditions of its own, or rejecting proposed provisions, in prior proceedings. See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, Docket No. E-7, Sub 795 (2006); and Order Granting General Rate Increase, Docket No. E-7, Sub 989 (2012).

Public witness Fireman's testimony centered on the environmental consequences of what he asserted would be an increase in the use of natural gas by DEC, DEP and Piedmont. In this context, he maintained that the Public Staff failed its mandate to protect the public welfare for both current ratepayers and future generations. Tangentially, this could be construed as questioning the efficacy of the Settlement and the effort of the Public Staff. However, as the Commission has previously concluded, there is no evidence that the merger will cause DEC, DEP or Piedmont to increase their use of natural gas. In addition, the Commission gives significant weight to the benefits and risk protections included in the Settlement, as well as witness Barkley's testimony that the Public Staff was thorough and effective in its role as ratepayer advocate.

The Commission finds and concludes that the Settlement is a reasoned and balanced resolution of the matters that might otherwise be in dispute between the Stipulating Parties in this docket. Further, the Settlement is just and reasonable to all parties in light of the evidence presented and serves the public interest. Therefore, the Commission approves the Settlement in its entirety, with the minor modifications to Code of Conduct Sec. III.A.2.(d) noted earlier herein. Further, based on the substantial ratepayer benefits and protections provided by the Settlement, the Commission concludes that the Settlement is material evidence that is entitled to substantial weight.

With regard to the CUCA Agreement, it too secures a benefit for ratepayers that the Commission does not have the authority to require DEC and DEP to provide, that being a guarantee to their customers that they will receive an additional $35 million in fuel savings. Further, in response to questions during cross-examination, Applicants witness Barkley testified that the merger will not result in quantified fuel cost savings for DEC and DEP. He stated that the guarantee is not linked to any merger efficiencies. As previously noted, witness Barkley also testified that the amount of fuel savings achieved by DEC and DEP will be measured using the same methodology arising from the JDA and the Duke/Progress Merger Order.

To be clear, DEC's and DEP's customers are entitled to all fuel savings that result from the co-ordination of DEC's and DEP's electric generating facilities under the JDA. Further, they are entitled to the guaranteed level of savings approved in the Duke/Progress Merger Order. However, the CUCA Agreement adds $35 million to that guaranteed amount.

The Commission finds the CUCA Agreement to be a reasoned and balanced resolution that avoids litigation of matters that might otherwise be in dispute between the Applicants and CUCA. Further, the Commission notes the absence of any testimony challenging the benefits provided by the CUCA Agreement. Therefore, the Commission finds and concludes that the CUCA Agreement is just and reasonable to all parties in light of the evidence presented and serves the public interest. As a result, the Commission approves the Agreement in its entirety. Further, based on the substantial ratepayer benefits provided by the Agreement, the Commission concludes that the CUCA Agreement is material evidence that is entitled to substantial weight.

With regard to the EDF Agreement, it requires DEC and DEP to conduct studies of the effectiveness of Integrated Volt Var technology on certain of their operations. These studies will contribute to the potential for both DEC and DEP to utilize voltage reduction technology to reduce peak and non-peak demand on their respective systems, which could potentially reduce costs to customers and emissions associated with peak demand generation, and delay or avoid construction of future generation facilities.

However, unlike the Public Staff Settlement and the CUCA Agreement, the EDF Agreement does not require anything of DEC and DEP beyond that which the Commission can require. Indeed, as referenced in the EDF Agreement, DEP already has in operation a voltage reduction program, Distribution System Demand Response (DSDR) that DEP uses to reduce demand during peak times. The DSDR program was approved by the Commission in June 2009 in Docket No. E-2, Sub 926. Further, in Docket No. E-100, Sub 141, the Commission's ongoing investigation regarding smart grid technology plans, DEC discusses its Integrated Voltage/Volt-Ampere Reactive Control (IVVC) Pre-Scale Deployment pilot project. DEC describes the IVVC as an advanced distribution management system that can reduce system demand by optimizing voltage and reactive power across the distribution grid. DEC states that it is demonstrating the IVVC at seven substations. Further, in the Commission's November 5, 2015 Order Approving Smart Grid Technology Plans, in Ordering Paragraph No. 4, the Commission directed “That DEC, DEP and Dominion shall include in their 2016 SMGTs [Smart Grid Technology Plans] a discussion of the variety of technologies for controlling voltage on the distribution grid as discussed in this Order.” Thus, DEP and DEC already have a significant level of voltage reduction programs in operation.

The Commission finds the EDF Agreement to be a reasoned and balanced resolution that avoids litigation of matters that might otherwise be in dispute between DEC, DEP and EDF. Further, the Commission notes the absence of any testimony challenging the benefits provided by the EDF Agreement. Therefore, the Commission finds and concludes that the EDF Agreement is just and reasonable to all parties in light of the evidence presented and serves the public interest. As a result, the Commission approves the Agreement in its entirety and accepts it as material evidence in this proceeding. However, the Commission also concludes that the EDF Agreement has little to do with merger savings and ratepayer protection from merger risks. Therefore, based on the limited ratepayer benefits provided by the Agreement, the Commission concludes that the EDF Agreement is entitled to less weight and consideration than other evidence.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

The evidence supporting this finding of fact is contained in the Application, the Public Staff Settlement, the Regulatory Conditions and Code of Conduct, the testimony of Applicants witness Yoho and Public Staff witness Hoard, and the Commission's supervisory authority under Chapter 62 of the General Statutes over the rates, terms and conditions of service provided to the public by DEC, DEP and Piedmont. The Commission has carefully reviewed and considered all of the evidence set forth above describing the known and potential benefits of the proposed merger and finds it to be credible.

The legal standard applicable to this proceeding is set forth in G.S. 62-111(a) and requires the Commission to determine whether the proposed merger is "justified by the public convenience and necessity." Upon such finding, the statute instructs that approval of the proposed merger "shall be given."

In prior merger proceedings the Commission has established a three-part test for determining whether a proposed utility merger is justified by the public convenience and necessity. That test is (1) whether the merger would have an adverse impact on the rates and services provided by the merging utilities; (2) whether ratepayers would be protected as much as possible from potential costs and risks of the merger; and (3) whether the merger would result in sufficient benefits to offset potential costs and risks. See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Duke/Progress Merger Order), issued June 29, 2012, in Docket Nos. E-2, Sub 998 and E-7, Sub 986, aff'd, In re Duke Energy Corp., 232 N.C. App. 573, 755 S.E.2d 382 (2014). These questions are related to one another and together establish a reasoned framework upon which utility mergers may be evaluated. In making these assessments, the Commission has also examined factors such as whether service quality will be maintained or improved, the extent to which costs can be lowered and rates can be maintained or reduced, and whether effective regulation of the merging utilities will be maintained. See Order Approving Merger and Issuance of Securities, issued April 22, 1997, in Docket No. E-7, Sub 596.

The Commission has made findings of fact regarding the substantial economic and non-economic benefits to be received by ratepayers as a result of the merger. In addition, the Commission notes the absence of any proposal to change rates, terms, or conditions of service for any customer of DEC, DEP, or Piedmont in conjunction with or as a direct result of the proposed merger. This is confirmed in the testimony of Applicants witness Yoho that "the Merger will not cause an increase to customer rates because Piedmont will not be seeking rate relief for the Merger transaction costs," and that "there will be no adverse rate or operational consequence to our customers as a result of this Merger." (T Vol. 2, p. 60) It is also confirmed by Paragraph No. 21 of the Application, which provides that the merger "will not have a net adverse impact on the rates and services of DEC, DEP and Piedmont." Finally, the Cost-Benefit Analysis filed with the Application indicates that ratepayers will not be charged for merger costs such as the acquisition premium and transaction fees, which, instead, will be absorbed by Duke Energy and Piedmont.

Further, the Commission has made findings of fact that there are a significant number of additional actual and potential benefits that will accrue to the State of North Carolina, to DEC, DEP, and Piedmont, and most importantly, to the ratepayers of DEC, DEP and Piedmont as a result of the proposed merger of Piedmont with Duke Energy. These benefits more than offset any potential risks or costs attendant to the proposed merger, which are amply mitigated in any event by the Applicants' commitments concerning absorption of merger costs and acquisition premiums and by the restrictions imposed on the Applicants' conduct by the Public Staff Settlement, the Regulatory Conditions and Code of Conduct, and by this Commission's continuing jurisdiction and authority over the rates, terms and conditions of service provided by DEC, DEP and Piedmont. On balance, the Commission concludes that the merger will have no adverse impact on the rates and services provided by DEC, DEP and Piedmont to their North Carolina ratepayers and that the known and potential benefits of the merger are sufficient to offset the potential costs and risks.

In addition, the Commission has made findings of fact that the Regulatory Conditions, Code of Conduct and other provisions of the Settlement, as approved herein, will protect DEC's, DEP's and Piedmont's North Carolina retail ratepayers as much as reasonably possible from known and potential costs and risks of the merger.

Therefore, the Commission concludes that the proposed merger of Duke Energy and Piedmont is justified by the public convenience and necessity, serves the public interest, and should be approved pursuant to G.S. 62-111.

CONCLUSION

Based on the Commission's findings of fact and the whole record, the Commission concludes that the Applicants' commitments in their testimony, the Public Staff Settlement, the Regulatory Conditions and Code of Conduct, and the CUCA Agreement are sufficient to ensure that: (1) the merger will have no adverse impact on the rates and services provided by DEC, DEP, and Piedmont to their North Carolina ratepayers; (2) DEC's, DEP's, and Piedmont's ratepayers are protected as much as reasonably possible from potential costs and risks resulting from the merger; and (3) the known and potential benefits of the merger are sufficient to offset the potential costs and risks. Therefore, the Commission concludes that the proposed business combination between Duke Energy and Piedmont is justified by the public convenience and necessity and serves the public interest.

Accordingly, the Commission finds good cause to approve the proposed merger between Duke Energy and Piedmont subject to all of the terms, conditions, and provisions of this Order, and, further, provided that Duke Energy and Piedmont file a statement in these dockets notifying the Commission that they accept and agree to all the terms, conditions and provisions of this Order, as well as the Regulatory Conditions and Code of Conduct.

IT IS, THEREFORE, ORDERED as follows:

1. That the application of Duke Energy and Piedmont pursuant to G.S. 62-111(a) to engage in a business combination transaction shall be, and is hereby, approved subject to compliance with the provisions of this Order, the Public Staff Settlement, the CUCA Agreement, the EDF Agreement, and the Regulatory Conditions and Code of Conduct attached hereto and incorporated herein, with the minor modifications to Code of Conduct, Sec. III.A.2.(d) noted earlier herein.

2. That subject to the merger being consummated and the Regulatory Conditions and Code of Conduct approved herein becoming effective, the Regulatory Conditions and Code of Conduct approved by the Commission in the Duke/Progress Merger Order shall be nullified.

3. That upon closing of the merger, Piedmont shall withdraw its DIMP Deferral Application.

4. That Piedmont shall credit $10 million to its North Carolina customers through a one-time bill credit to be completed by December 31, 2016. The bill credit shall be allocated to the rate schedules using the apportionment percentages set forth in Piedmont's Integrity Management Rider (Appendix E of Piedmont's North Carolina Service Regulations). Within 30 days after the bill credit is completed, Piedmont shall file a report with the Commission detailing the amount of the bill credit. In the event of a Piedmont general rate case with rates effective no more than two years from the merger close, Piedmont shall retain the right to reflect an adjustment in the general rate case that would increase its revenue requirement for a portion of the $10 million in savings that Piedmont credited to its North Carolina customers. Should Piedmont exercise its right to reflect such an adjustment, the Public Staff shall retain the right to incorporate the effect of additional merger-related savings in its proposed revenue requirement calculation.

5. That beginning January 1, 2017, DEC, DEP and Piedmont shall fund The Duke Energy Foundation and Piedmont Natural Gas Foundation for four years from the close of the merger at annual levels of no less than $9.65 million, $6.375 million, and $1.5 million, for community support and charitable contributions in the North Carolina service territories of DEC, DEP and Piedmont, respectively.

6. That in support of The Duke Energy Foundation's and Piedmont Natural Gas Foundation's North Carolina workforce development and low-income energy assistance in the North Carolina service territories of DEC, DEP, and Piedmont as may be agreed upon with the Public Staff, within twelve months of the close of the merger, DEC, DEP, and Piedmont shall contribute a total of $7.5 million to The Duke Energy Foundation and Piedmont Natural Gas Foundation. The $7.5 million shall be allocated among the North Carolina service territories of DEC, DEP, and Piedmont in proportion to the number of North Carolina jurisdictional customers served by each.

7. That merger and merger-related costs shall be treated as follows:

(a) Direct expenses associated with costs to achieve the merger, including change-in-control payments made to terminated executives, regulatory process costs, and transaction costs, such as investment banker and legal fees for transaction structuring, financial market analysis, and fairness opinions based on formal agreements with investment bankers, shall be excluded from the regulated expenses of Piedmont, DEC, and DEP for North Carolina

Utilities Commission financial reporting and ratemaking purposes. Piedmont, DEC, and DEP shall file a summary report of their final accounting for merger-related direct expenses within 60 days after the close of the merger, and supplemental reports within 60 days after each quarter, as necessary.

(b) DEC, DEP, and Piedmont may request recovery through depreciation or amortization, and inclusion in rate base, as appropriate and in accordance with normal ratemaking practices, their respective shares of capital costs associated with achieving merger savings, such as system integration costs and the adoption of best practices, including information technology, provided that such costs are incurred no later than three years from the close of the merger and result in quantifiable cost savings that offset the revenue requirement effect of including the costs in rate base. Only the net depreciated costs of such system integration projects at the time the request is made may be included, and no request for deferrals of these costs may be made.

(c) DEC's, DEP's, and Piedmont's merger-related severance costs shall be excluded from DEC's, DEP's, and Piedmont's cost of service for ratemaking purposes.

(d) Piedmont, DEC, and DEP shall exclude from their regulated expense and plant accounts the effects of all Piedmont long-term incentive plan (performance shares and restricted stock units/shares) costs that result from the increase in the Piedmont stock price above the $42.22 per share closing price on October 23, 2015, adjusted for changes in the stock price that would have occurred absent the merger. The adjusted stock prices shall be based upon percentage changes in the average stock price experienced by a peer group of twelve natural gas utilities.

8. That effective upon the close of the merger, Piedmont shall begin utilizing a revised NCUC GS-1 Earnings Surveillance Report format that is similar to the format of the ES-1 Earnings Surveillance Report that is submitted to the Commission by the electric utilities.

9. That beginning with the month in which the merger closes, Piedmont shall use the net-of-tax overall rate of return from its last general rate case as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The methods and procedures used by Piedmont for the accrual of interest on the Deferred Gas Cost Accounts shall remain unchanged.

10. That within 180 days after the close of the merger, Piedmont shall begin to implement procedures to ensure that project unitization and plant retirements are finalized within 180 days of project completion. Piedmont shall file semi-annual status reports with the Commission detailing its progress in implementing these practices, with the first report due twelve months from the close of the merger.

11. That DEC's and DEP's North Carolina retail ratepayers shall be guaranteed receipt of their allocable shares of an additional $35 million in fuel and fuel-related cost savings under the mechanism implemented in the Duke/Progress Merger Order.

12. That DEC and DEP shall conduct Integrated Volt Var studies as provided by the EDF Agreement.

13. That the Applicants are authorized to take such other and further actions as are reasonable and necessary to consummate the merger transaction set forth in the Merger Agreement subject to the terms hereof.

14. That the Applicants are precluded from recovering from their respective ratepayers any portion of the goodwill or acquisition premium associated with the acquisition of Piedmont by Duke Energy.

15. That Applicants shall file a written notice in this docket within ten (10) days of the consummation of the merger approved herein.

16. That the following cross-examination questions by NC WARN to witnesses Good, Skains and Yoho and the witnesses' testimony in response thereto shall be, and are hereby, stricken from the record: Transcript, Vol. 1, p. 111, line 24 through p. 114, line 14; p. 116, line 17 through p. 121, line 21; p. 122, line 13 through p. 132, line 3; p. 138, line 8 through p. 141, line 21; and Transcript Vol. 2, p. 74, line 7 through p. 78, line 3.

17. That NC WARN's Motion for Reconsideration of the Commission's Motion to Strike Order shall be, and is hereby, denied.

18. That these dockets shall remain open pending the filing by the Applicants of notice of the closing of the merger, and other actions by the Commission that may be required.

ISSUED BY ORDER OF THE COMMISSION.
This the __29th__ day of September, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

DOCKET NO. E-2, SUB 1095
DOCKET NO. E-7, SUB 1100
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REGULATORY CONDITIONS AND CODE OF CONDUCT

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REGULATORY CONDITIONS

These Regulatory Conditions set forth commitments made by Duke Energy Corporation (Duke Energy) and its public utility subsidiaries, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Piedmont Natural Gas Company, Inc. (Piedmont), as a precondition of approval of the application by Duke Energy and Piedmont pursuant to G.S. 62-111(a) for authority to engage in their proposed business combination transaction. These Regulatory Conditions, which become effective only upon closing of the Merger, shall apply jointly and severally to Duke Energy, DEC, DEP, and Piedmont, and shall be interpreted in the manner that most effectively fulfills the Commission's purposes as set forth in the preamble to Section II of these Regulatory Conditions.

SECTION I
DEFINITIONS

For the purposes of these Regulatory Conditions, capitalized terms shall have the meanings set forth below. If a capitalized term is not defined below, it shall have the meaning provided elsewhere in this document or as commonly used in the electric or natural gas utility industry.

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of these Regulatory Conditions, Duke Energy and each business entity so controlled by it are considered to be Affiliates of DEC, DEP, and Piedmont, and DEC, DEP, and Piedmont are considered to be Affiliates of each other.

Affiliate Contract: (a) Any contract or agreement between or among DEC, DEP, and Piedmont or between or among DEC, DEP, or Piedmont and any other Affiliate or proposed Affiliate, and (b) any contract or agreement between such other Affiliate or proposed Affiliate and another Affiliate that is related to the same subject matter and is reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service. Such contracts and agreements include, but are not limited to, service, operating, interchange, pooling, wholesale power sales agreements and agreements involving financings and asset transfers and sales, and the Joint Dispatch Agreement.

Catawba Joint Owners: The North Carolina Electric Membership Corporation, North Carolina Municipal Power Agency No. 1, and Piedmont Municipal Power Agency. For purposes of these Regulatory Conditions, DEC is not included in the definition of Catawba Joint Owners.

Code of Conduct: The minimum guidelines and rules approved by the Commission that govern the relationships, activities, and transactions between and among the public utility operations of DEC, DEP, and Piedmont, Duke Energy, the other Affiliates of DEC, DEP, and Piedmont, and the Nonpublic Utility Operations of DEC, DEP, and Piedmont, as those guidelines and rules may be amended by the Commission from time to time.

Commission: The North Carolina Utilities Commission.

Customer: Any retail electric customer of DEC or DEP in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of Piedmont located in North Carolina.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP or Piedmont, singly or in any combination.

ELECTRIC – MERGER

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

DEP: Duke Energy Progress. LLC, the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the DEP's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC, DEP, and Piedmont, and any successor company.

Effect on DEC's, DEP's, or Piedmont's Rates or Service: When used with reference to the consequences to DEC, DEP, or Piedmont of actions or transactions involving an Affiliate or Nonpublic Utility Operation, this phrase has the same meaning that it has when the Commission interprets G.S. 62-3(23)(c) with respect to the affiliation covered therein.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Federal Law: Any federal statute or legislation, or any regulation, order, decision, rule or requirement promulgated or issued by an agency or department of the federal government.

FERC: The Federal Energy Regulatory Commission.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good or service supplied by or from DEC, DEP, or Piedmont, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding, (b) for each good or service supplied to DEC, DEP, or Piedmont, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good or service supplied by or from DEC, DEP, or Piedmont to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's, DEP's, or Piedmont's most recent general rate case proceeding, as applicable.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission in Docket Nos. E-7, Sub 986, and E-2, Sub 998, on June 22, 2011, and as amended and refiled on June 12, 2012.

ELECTRIC – MERGER

Market Value: The price at which property, goods, or services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Piedmont.

Native Load Priority: Power supply service being provided or electricity otherwise being sold with a priority of service equivalent to that planned for and provided by DEC or DEP to their respective Retail Native Load Customers.

Natural Gas Services: Commission-regulated natural gas sales and natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering and billing, and standby service.

Non-Native Load Sales: DEC's or DEP's sales of energy at wholesale, not including transactions between DEC and DEP pursuant to the JDA and not including service to customers served at Native Load Priority.

Nonpublic Utility Operations: All business operations engaged in by DEC, DEP, or Piedmont involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS, other than a Utility Affiliate, DEC, DEP, or Piedmont.

Piedmont: Piedmont Natural Gas Company, Inc., the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of DEP and is a subsidiary of Duke Energy, and any successors.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

PUHCA 2005: The Public Utility Holding Company Act of 2005.

Purchased Power Resources: Purchases of energy by DEC or DEP at wholesale from sellers other than each other, the contract terms for which are one year or longer.

Retail Native Load Customers: The captive retail Customers of DEC and DEP in North Carolina for which DEC and DEP have the obligation under North Carolina law to engage in long-term planning and to supply all Electric Services, including installing or contracting for capacity, if needed, to reliably meet their electricity needs.

Retained Earnings: The retained earnings currently required to be listed on page 112, line 11, of the pre-Merger DEC FERC Form 1, the pre-Merger DEP FERC Form 1, and page 112, line 11 of the pre-Merger Piedmont FERC Form 2.

Shared Services: The services that meet the requirements of these Regulatory Conditions and that the Commission has explicitly authorized DEC, DEP, and Piedmont to take from DEBS pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and these Regulatory Conditions.

Utility Affiliates: The regulated public utility operations of Duke Energy Indiana, LLC (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), Florida Power Corporation, d/b/a Duke Energy Florida, LLC (DEF), and Duke Energy Ohio, Inc. (Duke Ohio).

SECTION II
AUTHORITY, SCOPE, AND EFFECT

These Regulatory Conditions are based on the general power and authority granted to the Commission in Chapter 62 of the North Carolina General Statutes to control and supervise the public utilities of the State. The Regulatory Conditions (a) constitute specific exercises of the Commission's authority, (b) provide mechanisms that enable the Commission to determine in advance the extent of its authority and jurisdiction over proposed activities of, and transactions involving, DEC, DEP, Piedmont, Duke Energy, other Affiliates or Nonpublic Utility Operations, and (c) protect the Commission's jurisdiction from federal preemption and its effects. The purpose of these Regulatory Conditions is to ensure that DEC's and DEP's Retail Native Load Customers and Piedmont's Customers (a) are protected from any known adverse effects from the Merger, (b) are protected as much as possible from potential costs and risks resulting from the Merger, and (c) receive sufficient known and expected benefits to offset any potential costs and risks resulting from the Merger. These Regulatory Conditions are not intended to impose legal obligations on entities in which Duke Energy does not directly or indirectly have a controlling voting interest, or to affect any rights of any party to participate in subsequent proceedings.

2.1 Waiver of Certain Federal Rights. Pursuant to these conditions, DEC, DEP, Piedmont, Duke Energy, and other Affiliates waive certain of their federal rights as specified in these Regulatory Conditions, but do not otherwise agree that the Commission has authority other than as provided for in Chapter 62.

2.2 Limited Right to Challenge Commission Orders. Other than as provided for, or explicitly prohibited, in these conditions, Duke Energy, DEC, DEP, Piedmont, and other Affiliates retain the right to challenge the lawfulness of any Commission order issued pursuant to or relating to these Regulatory Conditions on the basis that such order exceeds the Commission's statutory authority under North Carolina law or the other grounds listed in G.S. 62-94(b).

2.3 Waiver Request. DEC, DEP, Piedmont, Duke Energy, and other Affiliates may seek a waiver of any aspect of these Regulatory Conditions in a particular case or circumstance for good cause shown by filing a such request with the Commission.

SECTION III
PROTECTION FROM PREEMPTION

The following Regulatory Conditions are intended to protect the jurisdiction of the Commission against the risk of federal preemption as a result of the Merger, including risks related to agreements and transactions between and among DEC, DEP, Piedmont, and any of their Affiliates; financing transactions involving Duke Energy, DEC, DEP, or Piedmont, and any other Affiliate; the ownership, use, and disposition of assets by DEC, DEP, or Piedmont; participation in the wholesale market by DEC or DEP; and filings with federal regulatory agencies.

3.1 Transactions between DEC, DEP, Piedmont, and Other Affiliates; Affiliate Contract Provisions; Advance Notice of Affiliate Contracts to be Filed with the FERC; Annual Certification.

(a) DEC, DEP, and Piedmont shall not engage in any transactions with Affiliates or proposed Affiliates without first filing the proposed contracts or agreements memorializing such transactions pursuant to G.S. 62-153 and taking such actions and obtaining from the Commission such determinations and authorizations as may be required under North Carolina law. DEC, DEP, or Piedmont, as applicable, shall submit each proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract to the Public Staff for informal review at least 15 days before filing it with the Commission. If DEC, DEP, or Piedmont and the Public Staff agree within the 15-day period that the proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract does not require any action by the Commission, DEC, DEP, or Piedmont may proceed to execute the agreement subject to later disapproval and voidance by the Commission pursuant to G.S. 62-153(a). Otherwise, the proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract shall not be executed until the agreement has been filed and payment of compensation has been approved by the Commission pursuant to G.S. 62-153(b). No formal advance notice pursuant to Regulatory Condition 13.2 is required for such agreements unless the agreements are to be filed with the FERC, in which case subsection (c) applies.

(b) All Affiliate Contracts to which DEC, DEP, or Piedmont is a party shall contain the following provisions:

(i) DEC's, DEP’s, or Piedmont’s participation in the agreement is voluntary, DEC, DEP, or Piedmont is not obligated to take or provide services or make any purchases or sales pursuant the agreement, and DEC, DEP, or Piedmont may elect to discontinue its participation in the agreement at its election after giving any required notice;

(ii) DEC, DEP, or Piedmont may not make or incur a charge under the agreement except in accordance with North Carolina law and the rules, regulations and orders of the Commission promulgated thereunder;

(iii) DEC, DEP, or Piedmont may not seek to reflect in rates any (A) costs incurred under the agreement exceeding the amount allowed by the Commission or (B) revenue level earned under the agreement less than the amount imputed by the Commission; and

(iv) DEC, DEP, or Piedmont shall not assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of another entity's assertions, that the Commission's authority to assign, allocate, impute, make pro-forma adjustments to, or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is, in whole or in part, (A) preempted by Federal Law or (B) not within the Commission's power, authority or jurisdiction; DEC, DEP, and Piedmont will bear the full risk of any preemptive effects of Federal Law with respect to the agreement.

(c) To enable the Commission to determine and exercise its lawful authority and jurisdiction over a proposed Affiliate Contract or amendment to an existing Affiliate Contract that involves costs that will be assigned to DEC, DEP, or Piedmont and that is required or intended to be filed with the FERC, the following procedures shall apply:

(i) DEC DEP, or Piedmont shall file advance notice and a copy of the proposed Affiliate Contract, a contract with a proposed Affiliate, or an amendment to an existing Affiliate Contract with the Commission at least 30 days prior to a filing with the FERC. All Affiliate Contracts, contracts with a proposed Affiliate, or amendments to existing Affiliate Contracts filed with the advance notice under Regulatory Condition 3.1(c) shall be unexecuted at the time of filing and remain unexecuted for the duration of the advance notice period. If, consistent with Regulatory Condition 13.2(h), the Commission extends the advance notice period, the Affiliate Contract, contract with a Proposed Affiliate, or amendments to existing Affiliate Contracts shall remain unexecuted until the Commission issues an order on the advance notice or the extension of the advance notice period expires without a Commission order, procedural or substantive, being issued. A copy shall be provided to the Public Staff at the time of the filing. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

(ii) If an objection to DEC, DEP, or Piedmont proceeding with the filing with the FERC is filed pursuant this Regulatory Condition, the proposed filing shall not be executed and made with the FERC until the Commission issues an order resolving the objection.

(iii) Filings of advance notices and copies of proposed Affiliate Contracts, a contract with a proposed Affiliate, and amendments to existing Affiliate Contracts pursuant to this subsection shall be in addition to filings required by G.S. 62-153, and the burden of proof as to those filings shall be as provided by statute.

(d) DEC, DEP, and Piedmont shall each certify in a filing with the Commission that (i) it has not made any filing with the FERC or any other federal regulatory agency inconsistent with the foregoing and (ii) Duke Energy, any other Affiliate and any Nonpublic Utility Operation has not made any such filing. Such certification shall be repeated annually on the anniversary of the first certification.

(e) In the event the FERC or any other federal regulatory agency requires modification of a proposed Affiliate Contract to omit any of the provisions of Regulatory Condition 3.1(b) as a condition of acceptance or approval by that agency, DEC, DEP or Piedmont shall remain bound by those provisions for state regulatory purposes.

3.2 Financing Transactions Involving DEC, DEP, Piedmont, Duke Energy, or Other Affiliates.

(a) With respect to any financing transaction between or among DEC, DEP, or Piedmont and Duke Energy or any one or more other Affiliates, any contract memorializing such transaction shall expressly provide that DEC, DEP, or Piedmont shall not enter into any such financing transaction except in accordance with North Carolina law and the rules, regulations and orders of the Commission promulgated thereunder; and

(b) With respect to any financing transaction (i) between or among any of the Affiliates if such contracts are reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, or (ii) between or among DEC, DEP, and Piedmont or between DEC, DEP, or Piedmont and any other Affiliate, any contract memorializing such transaction shall expressly provide that DEC, DEP, or Piedmont shall not include the effects of any capital structure or debt or equity costs associated with such financing transaction in its North Carolina retail cost of service or rates except as allowed by the Commission.

3.3 Ownership and Control of Assets Used by DEC, DEP, and Piedmont to Supply Electric Power or Natural Gas Services to North Carolina Customers; Transfer of Ownership or Control.

(a) DEC, DEP, and Piedmont shall own and control all assets or portions of assets used for the generation, transmission, and distribution of electric power or the transmission, storage, or distribution of natural gas to their respective Customers (with the exception of assets solely used to provide power purchased by DEC or DEP at wholesale).

(b) With respect to the transfer by DEC, DEP, or Piedmont to any entity, affiliated or not, of the control of, operational responsibility for, or ownership of generation, transmission, or distribution assets with a gross book value in excess of ten million dollars ($10 million), DEC, DEP, or Piedmont shall provide written notice to the Commission at least 30 days in advance of the proposed transfer. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

(c) Any contract memorializing such a transfer shall include the following language:

(i) DEC, DEP, or Piedmont may not commit to or carry out the transfer except in accordance with applicable law, and the rules, regulations and orders of the Commission promulgated thereunder; and

(ii) DEC, DEP, or Piedmont may not include in its North Carolina cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the Commission in accordance with North Carolina law.

(d) Any application filed with the FERC in connection with any transfer of control, operational responsibility, or ownership that involves or potentially affects DEC, DEP, or Piedmont shall include the language set forth in subdivisions (c)(i) and (ii), above.

3.4 Purchases and Sales of Electricity and Natural Gas between DEC, DEP, Piedmont, and Duke Energy, Other Affiliates, or Nonpublic Utility Operations. Subject to additional restrictions set forth in the Code of Conduct, neither DEC, DEP, nor Piedmont shall purchase electricity (or related ancillary services) or natural gas from Duke Energy, another Affiliate, or a Nonpublic Utility Operation under circumstances where the total all-in costs, including generation, transmission, ancillary costs, distribution, taxes and fees, and delivery point costs, incurred (whether directly or through allocation), based on information known, anticipated, or reasonably available at the time of purchase, exceed fair Market Value for comparable service, nor shall DEC, DEP, or Piedmont sell electricity (or related ancillary services) or natural gas to Duke Energy, another Affiliate, or a Nonpublic Utility Operation for less than fair Market Value; provided, however, that such restrictions shall not apply to emergency transactions.

This condition shall not apply to transactions between DEC and DEP that are governed by the JDA.

3.5 Least Cost Integrated Resource Planning and Resource Adequacy. This Regulatory Condition does not apply to Piedmont. DEC and DEP shall retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law. DEC and DEP shall determine the appropriate self-built or purchased power resources to be used to provide future generating capacity and energy to their respective Retail Native Load Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources to those Retail Native Load Customers.

3.6 Priority of Service.

(a) This Regulatory Condition does not apply to Piedmont.

(b) The planning and joint dispatch of DEC's system generation and Purchased Power Resources shall ensure that DEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. DEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

(c) The planning and joint dispatch of DEP's system generation and Purchase Power Resources shall ensure that DEP's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. DEP shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

3.7 Wholesale Power Contracts Granting Native Load Priority.

(a) This Regulatory Condition does not apply to Piedmont.

(b) DEC is not required to file an advance notice with the Commission or receive its approval prior to entering into wholesale power contracts that grant Native Load Priority to the following historically served customers: the City of Concord, North Carolina; the City of Kings Mountain, North Carolina; the Town of Dallas, North Carolina; the Town of Forest City, North Carolina; Lockhart Power Company; the Public Works Commission of the Town of Due West, South Carolina; the Town of Prosperity, South Carolina; the City of Greenwood, South Carolina; the Town of Highlands; North Carolina; Western Carolina University (WCU); the electric membership cooperatives (EMCs) within DEC's control area; North Carolina Municipal Power Agency No. 1; Piedmont Municipal Power Agency; New River Light & Power Company; and the South Carolina distribution cooperatives historically served by Saluda River Electric Cooperative, Inc., and currently served by Central Electric Power Cooperative, Inc. (which are Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc., and York Electric Cooperative, Inc.). Subject to the conditions set out in Regulatory Condition 3.8, the retail native loads of these historically served wholesale customers shall be considered DEC's Retail Native Load Customers for purposes of Regulatory Conditions 3.5, 3.6, and 4.5; provided, however, that this subsection applies only to the same types of supplemental load and backstand requirements services that were historically provided to the Catawba Joint Owners under the Catawba Interconnection Agreements between DEC and the Catawba Joint Owners prior to 2001, which, for the North Carolina Electric Membership Corporation, only includes the EMCs within DEC's control area.

(c) DEP is not required to file an advance notice with the Commission or receive its approval prior to entering into wholesale power contracts that grant Native Load Priority to the Public Works Commission of the City of Fayetteville, North Carolina; the Town of Waynesville, North Carolina; the City of Camden, South Carolina; the French Broad Electric Membership Corporation; the North Carolina Eastern Municipal Power Agency; the electric membership cooperatives (EMCs) within DEP’s control area, whether served through the North Carolina Electric Membership Corporation (NCEMC) or individually; the Town of Black Creek, North Carolina; the Town of Lucama, North Carolina; the Town of Stantonsburg, North Carolina; the Town of Sharpsburg, North Carolina; and the Town of Winterville, North Carolina. Subject to the conditions set out in Regulatory Condition 3.8, the retail native loads of these historically served wholesale customers shall be considered DEP’s Retail Native Load Customers for purposes of Regulatory Conditions 3.5, 3.6, and 4.5.

(d) Before either DEC or DEP executes any contract that grants Native Load Priority to a wholesale customer (other than as set forth in subdivisions (a) and (b) above) or to one or more retail customers of another entity, it must provide the Commission with at least 30 days' written advance notice of its intent to grant Native Load Priority and to treat the retail native load of a proposed wholesale customer as if it were DEC's or DEP’s retail native load pursuant to Regulatory Conditions 3.5, 3.6, and 4.5. The provisions set forth in Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

3.8 Additional Provisions Regarding Wholesale Contracts Entered into by DEC or DEP as Sellers.

(a) This Regulatory Condition does not apply to Piedmont.

(b) The Commission retains the right to assign, allocate, impute, and make pro-forma adjustments with respect to the revenues and costs associated with both DEC's or DEP's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes.

(c) Entry into wholesale contracts that grant Native Load Priority or otherwise obligate DEC or DEP to construct generating facilities or make commitments to purchase capacity and energy to meet those contractual commitments constitutes acceptance by DEC, DEP, Duke Energy, and other Affiliates or Nonpublic Utility Operations thereof of the risks that investments in generating facilities or commitments to purchase capacity and energy to meet such contractual commitments and maintain an adequate reserve margin throughout the term of such contracts may become uneconomic sunk costs that are not recoverable from DEC's or DEP's respective Retail Native Load Customers. In a future Commission retail proceeding in which cost recovery is at issue, neither DEC nor DEP shall claim that it does not bear this risk, and both DEC and DEP shall acknowledge that the Commission retains full authority under Chapter 62 to disallow such costs as not used and useful and to allocate, impute, or assign such costs away from Retail Native Load Customers. For purposes of this condition, capacity will be considered used and useful and not excess capacity to the extent the Commission determines such capacity is needed by DEC or DEP to meet the expected peak loads of DEC's or DEP's respective Retail Native Load Customers in the near term future plus a reserve margin comparable to that currently being used or otherwise considered appropriate by the Commission. Neither DEC, DEP, Duke Energy, nor any other Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that the Commission is preempted from taking the actions contemplated in this subsection.

(d) Neither DEC, nor DEP, nor Duke Energy, nor other Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that (i) transactions entered into pursuant to DEC's or DEP's cost- or market-based rate authority or (ii) the filing with, or acceptance for filing by, the FERC of any wholesale power contract to which either is a party establishes or implies a cost allocation methodology that is binding on the Commission, requires the pass-through of any costs or revenues under the filed rate doctrine, or preempts the Commission's authority to assign, allocate, impute, make pro-forma adjustments to, or disallow the revenues and costs associated with, DEC's or DEP's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes.

(e) Neither DEC, nor DEP, nor Duke Energy, nor other Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that the exercise of authority by the Commission to assign, allocate, impute, make pro-forma adjustments to, or disallow the costs and revenues associated with DEC's or DEP's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes in itself constitutes an undue burden on interstate commerce or otherwise violates the Commerce Clause of the United States Constitution. DEC and DEP, however, retain the right to argue that a specific exercise of authority by the Commission violates the Commerce Clause based upon specific evidence of undue interference with interstate commerce.

(f) Except as provided in the foregoing conditions, DEC and DEP retain the right to challenge the lawfulness of any order issued by the Commission in connection with the assignment, allocation, imputation, pro-forma adjustments to, or disallowances of the revenues and costs associated with DEC's or DEP's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes on any other grounds, including but not limited to the right outlined in G.S. 62-94(b).

3.9 Other Protections.

(a) DEC, DEP, Piedmont, Duke Energy, another Affiliate, and a Nonpublic Utility Operation shall not assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that approval by the FERC of market-based rates, transfers of generating facilities, or any matter that involves Affiliates in any way preempts the Commission's authority to determine the reasonableness or prudence of DEC's, DEP's, or Piedmont's decisions with respect to supply-side resources, demand-side management, or any other aspect of resource adequacy.

(b) No agreement shall be entered into, nor shall any filing be made with the FERC, by or on behalf of DEC or DEP, that (i) commits DEC or DEP to, or involves either of them in, joint planning, coordination, dispatch or operation of generation, transmission, or distribution facilities with each other or with one or more other Affiliates, or (ii) otherwise alters DEC's or DEP's obligations with respect to these Regulatory Conditions, absent explicit approval of the Commission.

(c) DEC, DEP, Duke Energy, the other Affiliates, and the Nonpublic Utility Operations shall file notice with the Commission at least 30 days prior to filing with the FERC any agreement, tariff, or other document or any proposed amendments, modifications, or supplements to any such document that has the potential to (i) affect DEC's or DEP's retail cost of service for system power supply resources or transmission system; (ii) reduce the Commission's jurisdiction with respect to transmission planning or any other aspect of the

Commission's planning authority; (iii) be interpreted as involving DEC or DEP in joint planning, coordination, dispatch, or operation of generation or transmission facilities with one or more Affiliates; or (iv) otherwise have an Effect on DEC's or DEP's Rates or Service. The provisions set forth in Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition; provided, however, that, to the extent the filing with the FERC is not to be made by DEC or DEP, the advance notice procedures shall be for the purpose of a determination by the Commission as to whether the filing is reasonably likely to have an Effect on DEC's or DEP's Rates or Service.

(d) Any contract or filing regarding DEC's or DEP's membership in or withdrawal from an RTO or comparable entity must be contingent upon state regulatory approval. This Regulatory Condition does not apply to Piedmont.

(e) DEC, DEP, and Piedmont shall obtain Commission approval before DEBS is sold, transferred, merged with any other entities, has any ownership interest therein changed, or otherwise changed so that a change of control could occur. This requirement does not apply to any movement of DEBS within the Duke Energy holding company system that does not constitute a change of control.

(f) DEC, DEP, and Piedmont may participate in joint comments and other joint filings with Affiliates only when such participation fully complies with both the letter and the spirit of the Regulatory Conditions. Any filing made by DEBS on behalf of DEC, DEP, or Piedmont must clearly identify DEBS as an agent of DEC, DEP, or Piedmont for purposes of making the filing.

(g) Neither DEC, DEP, Piedmont, Duke Energy, another Affiliate, nor a Nonpublic Utility Operation shall make any assertion or argument either on its own initiative or in support of any other entity's assertions in any forum – whether judicial, administrative, federal, state, or otherwise – with respect to any contract, transaction, or other matter in which DEC, DEP, or Piedmont is involved or proposes to be involved or any contract, transaction, or matter involving or proposed to involve Duke Energy, any other Affiliate, or any Nonpublic Utility Operation that may have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, that any of the following actions by the Commission are preempted, in whole or in part, by Federal Law or exceed the Commission's power, authority or jurisdiction under North Carolina law:

(i) reviewing the reasonableness of any Affiliate commitment entered into or proposed to be entered into by DEC, DEP, or Piedmont, or disallowing the costs of, or imputing revenues related to such commitment to, DEC, DEP, or Piedmont;

(ii) exercising its authority over financings or setting rates based on the capital structure, corporate structure, debt costs, or equity costs that it finds to be appropriate for retail ratemaking purposes;

(iii) reviewing the reasonableness of any commitment entered into or proposed to be entered into by DEC, DEP, or Piedmont to transfer an asset;

(iv) mandating, approving, or otherwise regulating a transfer of assets;

(v) scrutinizing and establishing the value of any asset transfers for the purpose of determining the rates for services rendered to DEC's or DEP's Retail Native Load Customers or Piedmont's Customers; or

(vi) exercising any other lawful authority it may have.

Should any other entity so assert, neither DEC, DEP, Piedmont, Duke Energy, other Affiliates, nor the Nonpublic Utility Operations shall support any such assertion and shall, promptly upon learning of such assertion, advise and consult with the Commission and the Public Staff regarding such assertion.

(vii) DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall (A) bear the full risk of any preemptive effects of Federal Law with respect to any contract, transaction, or commitment entered into or made or proposed to be entered into or made by DEC, DEP, or Piedmont, or which may otherwise affect DEC's, DEP's, or Piedmont's operations, service, or rates and (B) shall take all actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases or any other adverse effects of such preemption. Such actions include, but are not limited to, filing with and making reasonable efforts to obtain approval from the FERC or other applicable federal entity of such commitments as the Commission deems reasonably necessary to prevent such preemptive effects.

3.10 FERC Filings and Orders. In addition to the filing requirements of Commission Rule R8-27 and all other applicable statutes and rules, DEC and DEP shall, on a quarterly basis, file with the Commission the following: (a) a list of all active dockets at the FERC, including a sufficient description to identify the type of proceeding, in which DEC, DEP, Duke Energy, or DEBS is a party, with new information in each quarterly filing tracked; and (b) a list of the periodic reports filed by DEC, DEP, Duke Energy, or DEBS with the FERC, including sufficient information to identify the subject matter of each report and how each report can be accessed. These filings shall be made in Docket Nos. E-7, Sub 1100E, and E-2, Sub 1095E, as appropriate, and updated regularly. In addition, DEC and DEP shall serve on the Public Staff all filed cost-based and market-based wholesale agreements and amendments; all filings related to their Joint Open Access Transmission Tariff; interconnection agreements and amendments; and any other filings made with the FERC, to the extent these other filings are reasonably likely to have an Effect on DEC's or DEP's Rates or Service. This Regulatory Condition does not apply to Piedmont, as relevant FERC-related information is required to be filed with the Commission in annual gas cost prudence reviews.

SECTION IV
JOINT DISPATCH

The Regulatory Conditions in Section IV do not apply to Piedmont. They are intended to prevent the jurisdiction and authority of the Commission from being preempted as a result of the JDA, to ensure that DEC's and DEP's Retail Native Load Customers receive adequate benefits from the JDA, and to ensure that both joint dispatch costs and the sharing of cost savings can be appropriately audited. The Regulatory Conditions set forth in Section III and the Regulatory Conditions in Section V to the extent they are relevant to Affiliate Contracts also apply to the JDA.

4.1 Conditional Approval and Notification Requirement. DEC and DEP acknowledge that the Commission's approval of the merger between Duke Energy and Progress Energy, and the transfer of dispatch control from DEP to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA, control area or transmission system, (c) joint planning or joint development of generation or transmission, (d) DEC or DEP to construct generation or transmission facilities for the benefit of the other, (e) the transfer of any rights to generation or transmission facilities from DEC or DEP to the other, or (f) any equalization of DEC's and DEP's production costs or rates. If, at any time, DEC, DEP or any other Affiliate learns that any of the foregoing interpretations are being considered, in whatever forum, they shall promptly notify and consult with the Commission and the Public Staff regarding appropriate action.

4.2 Advance Notice Required. To the extent that DEC and DEP desire to engage in any of items (a) through (f) listed in Regulatory Condition 4.1, above, DEC and DEP shall file advance notice with the Commission at least 30 days prior to taking any action to amend the JDA or a successor document or to enter into a separate agreement. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

4.3 Function in DEC or DEP. The joint dispatch function, as provided in the JDA or in a successor document, shall be performed by employees of either DEC or DEP.

4.4 No Limitation on Obligations. DEC and DEP acknowledge that nothing in the JDA or any successor document is intended to alter DEC's and DEP's public utility obligations under North Carolina law or to provide for joint dispatch in a fashion that is inconsistent with those obligations, including, without limitation, the following: (a) DEC's obligation to plan for and provide least cost electric service to its Retail Native Load Customers and DEP's obligation to plan for and provide least cost electric service to its Retail Native Load Customers; (b) DEC's obligation to serve its Retail Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales; and (c) DEP's obligation to serve its Retail Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales.

4.5 Protection of Retail Native Load Customers. All joint dispatch and other activities pursuant to the JDA or successor document shall be performed in such a manner as to (a) ensure the reliable fulfillment of DEC's and DEP's respective service obligations to their Retail Native Load Customers, (b) fulfill each utility's obligation to serve its own Retail Native Load Customers with its lowest cost generation; and (c) minimize the total costs incurred by DEC and DEP to fulfill their respective obligations to their Retail Native Load Customers. In no event shall any Non-Native Load Sales be made if, based upon information known, anticipated, or reasonably available at the time a sale is made, any such sale results in higher fuel and fuel-related costs or non-fuel O&M costs, on a replacement cost basis, than would otherwise have been incurred unless the revenues credited from each such sale more than offset the higher costs.

4.6 Treatment of Costs and Savings. DEC's and DEP's respective fuel and fuel-related costs and non-fuel O&M costs, and the treatment of savings for retail ratemaking purposes, shall be calculated as provided in the JDA, unless explicitly changed by order of the Commission.

4.7 Required Records. DEC and DEP shall keep records related to the JDA or any successor document as prescribed by the Commission and in such detail as may be necessary to enable the Commission and the Public Staff to audit both the actual joint dispatch costs and the sharing of cost savings.

4.8 Auditing of Negative Margins. DEC and DEP also shall keep records that provide such detail as may be necessary to enable the Commission and the Public Staff to audit the circumstances that cause any negative margin on a Non-Native Load Sale or a negative transfer payment made pursuant to Section 7.5(a)(ii) of the JDA.

4.9 Protection of Commission's Authority. Neither DEC, DEP, nor any Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that any aspect of the JDA or successor document is intended to diminish or alter the jurisdiction or authority of the Commission over DEC or DEP, including, among other things, the jurisdiction and authority of the Commission to do the following: (a) establish the retail rates on a bundled basis for DEC or DEP, (b) to impose regulatory accounting and reporting requirements, (c) impose service quality standards, (d) require DEC and DEP to engage separately in least cost integrated resource planning, and (e) issue certificates of public convenience and necessity for new generating and transmission resources.

4.10 Preventive Action Required. DEC, DEP, Duke Energy, and other Affiliates shall take all necessary actions to prevent the generating facilities owned or controlled by DEC or DEP from being considered by the FERC to be (a) part, or all, of a power pool, (b) sufficiently integrated to be one integrated system, or (c) otherwise fully subject to the FERC's jurisdiction, as the result of DEC's and DEP's participation in the JDA or any successor document.

4.11 Modification and Termination. DEC and DEP shall modify or terminate the JDA if at any time following consummation of the Merger the Commission finds, after notice and opportunity to be heard, that the JDA does not produce overall cost savings for, or is otherwise not in the best interests of, the North Carolina ratepayers of both DEC and DEP.

4.12 Hold Harmless Commitment. DEC and DEP shall take all actions as may be reasonably appropriate and necessary to hold North Carolina retail ratepayers harmless from any adverse rate impacts related to the JDA, including any trapped costs resulting from actions taken or required by the FERC with respect to the JDA.

SECTION V
TREATMENT OF AFFILIATE COSTS AND RATEMAKING

The following Regulatory Conditions are intended to ensure that the costs incurred by DEC, DEP, and Piedmont are properly incurred, accounted for, and directly charged, directly assigned, or allocated to their respective North Carolina retail operations and that only costs that produce benefits for DEC's and DEP's respective Retail Native Load Customers and Piedmont's Customers are included in DEC's, DEP's, and Piedmont's North Carolina cost of service for ratemaking purposes. The procedures set forth in Regulatory Condition 13.2 do not apply to an advance notice filed pursuant to this section.

5.1 Access to Books and Records. In accordance with North Carolina law, the Commission and the Public Staff shall continue to have access to the books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations.

5.2 Procurement or Provision of Goods and Services by DEC, DEP, or Piedmont from or to Affiliates or Nonpublic Utility Operations. Except as to transactions between and among DEC, DEP, and Piedmont pursuant to filed and approved service agreements and lists of services, and subject to additional provisions set forth in the Code of Conduct, DEC, DEP, and Piedmont shall take the following actions in connection with procuring goods and services for their respective utility operations from Affiliates or Nonpublic Utility Operations and providing goods and services to Affiliates or Nonpublic Utility Operations:

(a) DEC, DEP, and Piedmont each shall seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services, and shall have the burden of proving that any and all goods and services procured from their Utility Affiliates, Non-Utility Affiliates, and Nonpublic Utility Operations have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market, which shall include a showing that comparable goods or services could not have been procured at a lower price from qualified non-Affiliate sources or that DEC, DEP, or Piedmont could not have provided the services or goods for itself on the same basis at a lower cost. To this end, no less than every four years DEC, DEP, and Piedmont shall perform comprehensive non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services they receive from a Utility Affiliate, DEBS, another Non-Utility Affiliate, and a Nonpublic Utility

Operation, including periodic testing of services being provided internally or obtained individually through outside providers. To the extent the Commission approves the procurement or provision of goods and services between or among DEC, DEP, Piedmont, and the Utility Affiliates, those goods and services may be provided at the supplier's Fully Distributed Cost.

(b) To the extent they are allowed to provide such goods and services, DEC, DEP, and Piedmont shall have the burden of proving that all goods and services provided by any one of them to Duke Energy, a Non-Utility Affiliate, any other Affiliate, or a Nonpublic Utility Operation have been provided on the terms and conditions comparable to the most favorable terms and conditions reasonably available in the market, which shall include a showing that such goods or services have been provided at the higher of cost or market price. To this end, no less than every four years DEC, DEP, and Piedmont shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services provided by either of them to a Utility Affiliate, DEBS, another Non-Utility Affiliate, any other Affiliate, and a Nonpublic Utility Operation.

(c) The periodic assessments required by subdivisions (a) and (b) of this subsection may take into consideration qualitative as well as quantitative factors. To the extent that comparable goods or services provided to DEC, DEP or Piedmont, or by DEC, DEP or Piedmont are not commercially available, this Regulatory Condition shall not apply.

5.3 Location of Core Utility Functions.

(a) This Regulatory Condition does not apply to Piedmont.

(b) Core utility functions are those functions related to Electric Services. The employees performing these core utility functions will be DEC or DEP employees and not service company employees of DEBS. Core utility functions do not include services of a governance or corporate type nature that have been traditionally provided by a service company, the specific services listed on the service company agreement services list for DEC and DEP filed with the Commission pursuant to Regulatory Condition 5.4(a), and roles that provide oversight to the enterprise and are not jurisdiction-specific (Excluded Functions).

(c) All core utility functions employees charging 50% or more of their time to DEC and DEP (separately or combined) should be in the payroll company of either DEC or DEP and not on the payroll of an Affiliate such as DEBS. If it is not readily determinable that a particular function is related to the provision of Electric Services or is an Excluded Function, the appropriate payroll company decision will be governed by whether 50% or more of the affected group or individual employee's time is charged to DEC or DEP.

(d) DEC and DEP shall annually review core utility function employees charging more than 50% of their time to DEC and DEP (separately or combined) over a six-month period from January 1 to June 30. If DEC and DEP determine that an employee performing a core utility function is direct charging 50% or more of his or her time to DEC or DEP, that employee should be transferred to DEC or DEP (if not already on the DEC or DEP payroll). Conversely, if a DEC or DEP employee is charging less than 50% of his or her time to DEC or DEP (separately or combined), and the employee is not otherwise charging the larger portion of their time to DEC or DEP, that employee should not be on the payroll of DEC or DEP.

(e) DEC and DEP shall annually file, at least 90 days prior to January 1, a report containing the results of the annual review and advance notice of any transfers from DEC to DEP to another entity based on direct charging results (Employee Payroll Transfer Report). New organizations and reorganizations will be reflected in the Employee Payroll Transfer Reports.

(f) If an employee transfer from DEC or DEP occurs during the middle of the year, and that transfer involves the transfer of a core utility function to the service company, the provisions of Regulatory Condition 10.1 will apply.

(g) DEC and DEP may file a list of employees at the higher levels of management (not including those levels of management that report directly to the Chief Executive Officer for Duke Energy) for their core utility functions that they propose to be DEBS employees in their annual filing.

5.4 Service Agreements and Lists of Services.

(a) DEC, DEP, and Piedmont shall file pursuant to G.S. 62-153 final proposed service agreements that authorize the provision and receipt of non-power goods or services between and among DEC, DEP, Piedmont, their Affiliates or Nonpublic Utility Operations, the list(s) of goods and services that DEC, DEP, and Piedmont each intend to take from DEBS, the list(s) of goods and services DEC, DEP, and Piedmont intend to take from each other and the Utility Affiliates, and the basis for the determination of such list(s) and the elections of such services. All such lists that involve payment of fees or other compensation by DEC, DEP, or Piedmont shall require acceptance and authorization by the Commission, and shall be subject to any other Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) DEC, DEP, and Piedmont shall take goods and services from an Affiliate only in accordance with the filed service agreements and approved list(s) of services. DEC, DEP, and Piedmont shall file notice with the Commission in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-6, Sub 682A, respectively, at least 15 days prior to making any proposed changes to the service agreements or to the lists of services.

5.5 Charges for and Allocations of the Costs of Affiliate Transactions. To the maximum extent practicable, all costs of Affiliate transactions shall be directly charged. When not practicable, such costs shall be assigned in proportion to the direct charges. If such costs are of a nature that direct charging and direct assignment are not practicable, they shall be allocated in accordance with Commission-approved allocation methods. The following additional provisions shall apply:

(a) DEC, DEP, and Piedmont shall keep on file with the Commission a cost allocation manual (CAM) with respect to goods or services provided by DEC, DEP, or Piedmont, any Utility Affiliate, DEBS, any other Non-Utility Affiliate, Duke Energy, any other Affiliates, or any Nonpublic Utility Operation to DEC, DEP, or Piedmont. Piedmont will adopt DEC's and DEP's CAM.

(b) The CAM shall describe how all directly charged, direct assignment, and other costs for each provider of goods and services will be charged between and among DEC, DEP, Piedmont, their Utility Affiliates, Non-Utility Affiliates, Duke Energy, any other Affiliates, and the Nonpublic Utility Operations, and shall include a detailed review of the common costs to be allocated and the allocation factors to be used.

(c) The CAM shall be updated annually, and the revised CAM shall be filed with the Commission no later than March 31 of the year that the CAM is to be in effect. DEC, DEP, and Piedmont shall review the appropriateness of the allocation bases every two years, and the results of such review shall be filed with the Commission. Interim changes shall be made to the CAM, if and when necessary, and shall be filed with the Commission, in accordance with Regulatory Condition 5.6.

(d) No changes shall be made to the procedures for direct charging, direct assigning, or allocating the costs of Affiliate transactions or to the method of accounting for such transactions associated with goods and services (including Shared Services provided by DEBS) provided to or by Duke Energy, other Affiliates, and the Nonpublic Utility Operations until DEC, DEP, or Piedmont has given 15 days' notice to the Commission of the proposed changes, in accordance with Regulatory Condition 5.6.

5.6 Procedures Regarding Interim Changes to the CAM or Lists of Goods and Services for which 15 Days' Notice Is Required. With respect to interim changes to the CAM or changes to lists of goods and services, for which the 15 day notice to the Commission is required, the following procedures shall apply: the Public Staff shall file a response and make a recommendation as to how the Commission should proceed before the end of the notice period. If the Commission has not issued an order within 30 days of the end of the notice period, DEC, DEP, or Piedmont may proceed with the changes but shall be subject to any fully adjudicated Commission order on the matter. The provisions of Regulatory Condition 13.2 do not apply to advance notices filed pursuant to Regulatory Condition 5.5(c) and (d). Such advance notices shall be filed in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A.

5.7 Annual Reports of Affiliate Transactions. DEC, DEP, and Piedmont shall file annual reports of affiliated transactions with the Commission in a format to be prescribed by the Commission in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A. The report shall be filed on or before May 30 of each year, for activity through December 31 of the preceding year. DEC, DEP, Piedmont, and other parties may propose changes to the required affiliated transaction reporting requirements and submit them to the Commission for approval, also in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A.

5.8 Third-party Independent Audits of Affiliate Transactions.

(a) No less often than every two years, a third-party independent audit shall be conducted related to the affiliate transactions undertaken pursuant to Affiliate agreements filed in accordance with Regulatory Condition 5.4 and of DEC's, DEP's, and Piedmont's compliance with all conditions approved by the Commission concerning Affiliate transactions, including the propriety of the transfer pricing of goods and services between or among DEC, DEP, Piedmont, other Affiliates, and all of the Nonpublic Utility Operations.

(i) The first audit shall begin two years from the date of the close of the Merger. It shall include whether DEC's, DEP's, and Piedmont's transactions, services, and other Affiliate dealings pursuant to the regulated utility-to-regulated utility service agreement and any other utility to utility agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC, DEP, and Piedmont have operated in accordance with those conditions and Code of Conduct.

(ii) The second audit shall begin two years from the date of the Commission's order on the independent auditor's final report on the first audit or, if no such order is issued, two years from the date of such final report. It shall include whether DEC's, DEP's, and Piedmont's transactions, services, and other Affiliate dealings pursuant to the Service Company Utility Service Agreement and other Affiliate transactions other than transactions undertaken pursuant to regulated utility to regulated utility service agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC, DEP, and Piedmont have operated in accordance with those conditions and Code of Conduct.

(iii) Thereafter, independent audits shall occur every two years from the date of the Commission's order on the immediately preceding auditor's final report or, if no such order is issued, two years from the date of such final report. The subject matter of these audits shall alternate between the subject matters for the first and second independent audits. DEC, DEP, and Piedmont may request a change in the frequency of the audit reports in future years, subject to approval by the Commission.

(b) The following further requirements apply:

(i) The independent auditor shall have sufficient access to the books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and all of the Nonpublic Utility Operations to perform the audits.

(ii) For each audit, the Public Staff shall propose one or more independent auditor(s). DEC, DEP, Piedmont, and other parties shall have an opportunity to comment and propose additional auditors. Selection of the independent auditor shall be made by the Commission. Any party proposing an independent auditor shall file such auditor's audit proposal with the Commission.

(iii) The independent auditor shall be supervised in its duties by the Public Staff, and the auditor's reports shall be filed with the Commission.

5.9 Ongoing Review by Commission.

(a) The services rendered by DEC, DEP, and Piedmont to their Affiliates and Nonpublic Utility Operations and the services received by DEC, DEP, or Piedmont from their Affiliates and Nonpublic Utility Operations pursuant to the filed service agreements, the costs and benefits assigned or allocated in connection with such services, and the determination or calculation of the bases and factors utilized to assign or allocate such costs and benefits, as well as DEC's, DEP's, and Piedmont's compliance with the Commission-approved Code of Conduct and all Regulatory Conditions, shall remain subject to ongoing review. These agreements shall be subject to any Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) The service agreements, the CAM(s) and the assignments and allocations of costs pursuant thereto, the biannual allocation factor reviews required by Regulatory Condition 5.5(c), the list(s) and the goods and services provided pursuant thereto, and any changes to these documents shall be subject to ongoing Commission review, and Commission action if appropriate.

5.10 Future Orders. For the purposes of North Carolina retail accounting, reporting, and ratemaking, the Commission may, after appropriate notice and opportunity to be heard, issue future orders relating to DEC's, DEP's, or Piedmont's cost of service as the Commission may determine are necessary to ensure that DEC's, DEP's, and Piedmont's operations and transactions with their Affiliates and Nonpublic Utility Operations are consistent with the Regulatory Conditions and Code of Conduct, and with any other applicable decisions of the Commission.

5.11 Review by the FERC. Notwithstanding any of the provisions contained in these Regulatory Conditions, to the extent the allocations adopted by the Commission when compared to the allocations adopted by the other State commissions with ratemaking authority as to a Utility Affiliate of DEC, DEP, or Piedmont result in significant trapped costs related to "non-power goods or administrative or management services provided by an associate company organized specifically for the purpose of providing such goods or services to any public utility in the same holding company system," including DEC, DEP, and Piedmont, DEC, DEP, or Piedmont may request pursuant to Section 1275(b) of Subtitle F in Title XII of PUHCA 2005 that the FERC "review and authorize the allocation of the costs for such goods and services to the extent relevant to that associate company." Such review and authorization shall have whatever effect it is determined to have under the law. The quoted language in this Regulatory Condition is taken directly from Section 1275(b) of Subtitle F in Title XII of PUHCA 2005. The terms "associate company" and "holding company system" are defined in Sections 1262(2) and 1262(9), respectively, of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

5.12 Biannual Review of Certain Transactions by Internal Auditors. Transactions between DEC, DEP, or Piedmont and Duke Energy, other Affiliates, or the Nonpublic Utility Operations, transactions between or among DEC, DEP, and Piedmont, and other transactions between or among Affiliates if such transactions are reasonably likely to have a significant Effect on DEC's, DEP's, or Piedmont's Rates or Service, shall be reviewed at least biannually by Duke Energy's internal auditors. To the extent external audits of the transactions are conducted, DEC, DEP, and Piedmont shall make available such audits for review by the Public Staff and the Commission. DEC, DEP, and Piedmont also shall make available for review by the Public Staff and the Commission all workpapers relating to internal audits and all other internal audit workpapers, if any, related to affiliate transactions, and shall not oppose Public Staff and Commission requests to review relevant external audit workpapers. The requirement to make internal audit workpapers available for review is subject to the assertion of the attorney-client privilege by attorneys for DEC, DEP, and Piedmont. Any dispute as to whether the privilege applies in a particular instance shall be resolved by the Commission in accordance with its regulations and North Carolina law, including the rules of the North Carolina State Bar.

5.13 Notice of Service Company and Non-Utility Affiliates FERC Audits. At such time as DEC, DEP, Piedmont, Duke Energy, or DEBS receives notice from the FERC related to an audit of any Affiliate of DEC, DEP, or Piedmont, DEC, DEP, or Piedmont shall promptly file a notice the Commission that such an audit will be commencing. Any initial report of the FERC's audit team shall be provided to the Public Staff, and any final report shall be filed with the Commission in Docket Nos. E-7, Sub 1100E, E-2, Sub 1095E, and G-9, Sub 682E, respectively.

5.14 Acquisition Adjustment. Any acquisition adjustment that results from the Merger shall be excluded from DEC's, DEP's, and Piedmont's utility accounts and treated for regulatory accounting, reporting, and ratemaking purposes so that it does not affect DEC's or DEP's North Carolina retail rates and charges for Electric Services or Piedmont's North Carolina rates and charges for Natural Gas Services.

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5.15 Non-Consummation of Merger. If the Merger is not consummated, neither the cost, nor the receipt, of any termination payment between Duke Energy and Piedmont shall be allocated to DEC, DEP, or Piedmont or recorded on their books. DEC's, DEP's, or Piedmont's Customers shall not otherwise bear any direct expenses or costs associated with a failed merger.

5.16 Protection from Commitments to Wholesale Customers.

(a) This Regulatory Condition does not apply to Piedmont.

(b) For North Carolina retail electric cost of service/ratemaking purposes, DEC's and DEP's respective electric system costs shall be assigned or allocated between and among retail and wholesale jurisdictions based on reasonable and appropriate cost causation principles. For cost of service/ratemaking purposes, North Carolina retail ratepayers shall be held harmless from any cost assignment or allocation of costs resulting from agreements between DEC and the Catawba Joint Owners, and between either DEC or DEP and any of their wholesale customers.

(c) To the extent commitments to DEC's or DEP's wholesale customers relating to the 2012 merger of Duke Energy and Progress Energy are made by or imposed upon DEC or DEP, the effects of which (i) decrease the bulk power revenues that are assigned or allocated to DEC's or DEP's North Carolina retail operations or credited to DEC's or DEP's jurisdictional fuel expenses, (ii) increase DEC's or DEP's North Carolina retail cost of service, or (iii) increase DEC's or DEP's North Carolina retail fuel costs under reasonable cost assignment and allocation practices approved or allowed by the Commission, those effects shall not be recognized for North Carolina retail cost of service or ratemaking purposes.

(d) To the extent that commitments are made by or imposed upon DEC, DEP, Duke Energy, another Affiliate, or a Nonpublic Utility Operation relating to the Merger, either through an offer, a settlement, or as a result of a regulatory order, the effects of which serve to increase the North Carolina retail cost of service or North Carolina retail fuel costs under reasonable cost allocation practices, the effects of these commitments shall not be recognized for North Carolina retail ratemaking purposes.

5.17 Joint Owner-Specific Issues. Assignment or allocation of costs to the North Carolina retail jurisdiction shall not be adversely affected by the manner and amount of recovery of electric system costs from the Catawba Joint Owners as a result of agreements between DEC and the Catawba Joint Owners. This Regulatory Condition does not apply to Piedmont.

5.18 Inclusion of Cost Savings in Future Rate Proceedings. Neither DEC, DEP, Piedmont, Duke Energy, any other Affiliate, nor a Nonpublic Utility Operation shall assert that any interested party is prohibited from seeking the inclusion in future rate proceedings of cost savings that may be realized as a result of any business combination transaction impacting DEC, DEP, and Piedmont.

5.19 Reporting of Costs to Achieve. The North Carolina portion of costs to achieve any business combination transaction savings shall be reflected in DEC's and DEP's North Carolina ES-1 Reports and Piedmont's North Carolina GS-1 Report, as recorded on their books and records under generally accepted accounting principles. DEC, DEP, and Piedmont shall include as a footnote in their ES-1 and GS-1 Reports, as applicable, the Merger-related costs to achieve that were expensed during the relevant period.

5.20 Accounting for Costs to Achieve Related to Historical Events Involving DEP. All costs of Carolina Power and Light Company's merger with North Carolina Natural Gas Company, the Formation of Progress Energy, and Progress Energy's merger with Florida Progress Corporation shall be excluded from DEP's utility accounts, and all direct or indirect corporate cost increases, if any, attributable to those three events shall be excluded from utility costs for all purposes that affect DEP's regulated retail rates and charges. For purposes of this condition, the term "corporate cost increases" means costs in excess of the level DEP would have (a) incurred using prudent business judgment, or (b) had allocated to it, had these transactions not occurred. "Corporate cost increases" also includes any payments made under change-of-control agreements, salary continuation agreements, and other severance- or personnel-type arrangements that are reasonably attributable to these transactions. This Regulatory Condition does not apply to DEC and Piedmont.

5.21 Liabilities of Cinergy Corp. and Florida Progress Corporation.

(a) DEC's and DEP's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all liabilities of Cinergy Corp. and its subsidiaries, including those incurred prior to and after Duke Energy's acquisition of Cinergy Corp. in 2006. These liabilities include, but are not limited to, those associated with the following: (i) manufactured gas plant sites, (ii) asbestos claims, (iii) environmental compliance, (iv) pensions and other employee benefits, (v) decommissioning costs, and (vi) taxes.

(b) DEC's and DEP's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all liabilities of Florida Progress Corporation and its subsidiaries, including those incurred prior to and after Progress Energy's acquisition of Florida Progress Corporation in 2000. These liabilities include, but are not limited to, those associated with the following: (i) any outages at and repairs of Crystal River 3, (ii) manufactured gas plant sites, (iii) asbestos claims, (iv) environmental compliance, (v) pensions and other employee benefits, (vi) decommissioning costs, and (vii) taxes.

(c) DEC's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all current and prospective liabilities of DEP, and DEP's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all current and prospective liabilities of DEC.

5.22 Hold Harmless Commitment. DEC, DEP, Piedmont, Duke Energy, the other Affiliates, and all of the Nonpublic Utility Operations shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina Customers harmless from the effects of the Merger, including rate increases or foregone opportunities for rate decreases, and other effects otherwise adversely impacting Customers.

5.23 Cost of Service Manuals. Within six months after the closing date of the Merger, DEC and DEP shall each file with the Commission revisions to its electric cost of service manual to reflect any changes to the cost of service determination process made necessary by the Merger, any subsequent alterations in the organizational structure of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations, or other circumstances that necessitate such changes. These filings shall be made in Docket Nos. E-7, Sub 1100A, and E-2, Sub 1095A, respectively. This Regulatory Condition does not apply to Piedmont.

5.24 Direct Charging and Positive Time Reporting for Piedmont. For purposes of distributing the costs of services provided between and among Affiliates, Piedmont will use direct charging and positive time reporting to at least the same extent as DEC and DEP.

5.25 Piedmont Corporate Cost Allocations Among State Jurisdictions. Piedmont will notify the Commission and Public Staff of any plans to modify its corporate cost allocation procedures at least 90 days prior to implementation of the change.

5.26 Allocation of Fully-distributed Costs to Piedmont's Nonpublic Utility Operations. Piedmont shall direct charge or allocate fully distributed costs to its Nonpublic Utility Operations. The fully distributed costs shall include an overhead component for the cost of shared services provided to these non-regulated businesses and equity investments by Piedmont corporate, DEC, DEP, and DEBS employees.

SECTION VI
CODE OF CONDUCT

These Regulatory Conditions include a Code of Conduct in Appendix A. The Code of Conduct governs the relationships, activities and transactions between or among the public utility operations of DEC, DEP, Piedmont, Duke Energy, the Affiliates of DEC, DEP, and Piedmont, and the Nonpublic Utility Operations of DEC, DEP, and Piedmont.

6.1 Obligation to Comply with Code of Conduct. DEC, DEP, Piedmont, Duke Energy, the other Affiliates, and the Nonpublic Utility Operations shall be bound by the terms of the Code of Conduct set forth in Appendix A and as it may subsequently be amended

SECTION VII
FINANCINGS

The following Regulatory Conditions are intended to ensure (a) that DEC's, DEP's, and Piedmont's capital structures and cost of capital are not adversely affected through their affiliation with Duke Energy, each other, and other Affiliates and (b) that DEC, DEP, and Piedmont have sufficient access to equity and debt capital at a reasonable cost to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their Customers.

These conditions do not supersede any orders or directives of the Commission regarding specific securities issuances by DEC, DEP, Piedmont, or Duke Energy. The approval of the Merger by the Commission does not restrict the Commission's right to review, and by order to adjust, DEC's, DEP's, or Piedmont's cost of capital for ratemaking purposes for the effect(s) of the securities-related transactions associated with the Merger.

7.1 Accounting for Equity Investment in Holding Company Subsidiaries. Duke Energy shall maintain its books and records so that any net equity investment in Cinergy Corp. and Progress Energy, their subsidiaries, or their successors, by Duke Energy or any Affiliates can be identified and made available on an ongoing basis. This information shall be provided to the Public Staff upon its request.

7.2 Accounting for Capital Structure Components and Cost Rates. Duke Energy , DEC, DEP, and Piedmont shall keep their respective accounting books and records in a manner that will allow all capital structure components and cost rates of the cost of capital to be identified easily and clearly for each entity on a separate basis. This information shall be provided to the Public Staff upon its request.

7.3 Accounting for Equity Investment in DEC, DEP, and Piedmont. DEC, DEP, and Piedmont shall keep their respective accounting books and records so that the amount of Duke Energy's equity investment in DEC, DEP, and Piedmont can be identified and made available upon request on an ongoing basis. This information shall be provided to the Public Staff upon request.

7.4 Reporting of Capital Contributions. As part of their Commission ES-1 and GS-1 Reports, DEC, DEP, and Piedmont shall include a schedule of any capital contribution(s) received from Duke Energy in the applicable calendar quarter.

7.5 Identification of Long-term Debt Issued by DEC, DEP, or Piedmont. DEC, DEP, and Piedmont shall each identify as clearly as possible long-term debt (of more than one year's duration) that they issue in connection with their regulated utility operations and capital requirements or to replace existing debt.

7.6 Procedures Regarding Proposed Financings.

(a) For all types of financings for which DEC, DEP, or Piedmont (or their subsidiaries) are the issuers of the respective securities, DEC, DEP, or Piedmont (or their subsidiaries) shall request approval from the Commission to the extent required by G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16. Generally, the format of these filings should be consistent with past practices. A "shelf registration" approach (similar to Docket No. E-7, Sub 727) may be requested.

(b) For all types of financings by Duke Energy, other than short-term debt as described in G.S. 62-167, the following shall apply:

(i) On or before January 15 of each year, Duke Energy shall file with the Commission and serve on the Public Staff an advance confidential plan of all securities issuances that it anticipates to occur during that calendar year. The annual confidential plan shall include a description of all financings that Duke Energy reasonably believes may occur during the applicable calendar year. A description for each financing shall include the best estimates of the following: type of security; estimate of cost rate (e.g., interest rate for debt); amount of proceeds; brief description of the purpose/reason for issue; and amount of proceeds, if any, that may flow to DEC, DEP, or Piedmont.

(ii) If at any time material changes to the financing plans included in the filed plan appear likely, Duke Energy shall file a revised 30-day advance confidential plan that specifically addresses such changes with the Commission and serve such notice on the Public Staff.

(iii) At the time of the confidential plan filings identified above, Duke Energy shall also file a non-confidential notice that states that a confidential plan has been filed in compliance with this Regulatory Condition 7.6(b).

(iv) Duke Energy may proceed with equity issuances upon the filing of the confidential plan. However, actual debt issuances shall not occur until 30 days after the advance confidential plan or revised plans are filed. In the event it is not feasible for Duke Energy to file a revised advance confidential plan for a material change 30 days in advance, such plan shall be filed by a date that allows adequate time for review or a debt issuance shall be delayed to allow such review. Prior to the Commission's action on the confidential plan for the year in which the plan is filed, Duke Energy may issue securities authorized under the previous year's plan to the extent such securities were not issued during the previous year.

(v) Within 15 days after the filing of an advance confidential plan or revised plan, the Public Staff shall file a confidential report with the Commission with respect to whether any debt issuances require approval pursuant to G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16 and shall recommend that the Commission issue an order deciding how to proceed. Duke Energy shall have seven days in which to respond to the report. If the Commission determines that any debt issuance requires approval, the Commission shall issue an order requiring the filing of an application and no such issuance shall occur until the Commission approves the application. If the Commission determines that no debt issuance requires approval, the Commission shall issue an order so ruling. At the end of the notice period, Duke Energy may proceed with the debt issuance, but shall be subject to any fully adjudicated Commission order on the matter; provided, however, that nothing herein shall affect the applicability of G.S. 62-170 or other similar provision to such securities or obligations.

(vi) On or before April 15 of each year, Duke Energy shall file with the Commission a report on all financings that were executed for the previous calendar year. The actual reports should include the same information as required above for the advance plans plus the actual issuance costs.

(c) If a filing with the Securities and Exchange Commission or other federal agency will be made in connection with a securities issuance, the notice shall describe such filing(s) and indicate the approximate date on which it would occur.

(d) Securities issuances or financings that are associated with a merger, acquisition, or other business combination shall be filed in conjunction with the information requirements and deadlines stated in Regulatory Conditions 9.1 and 9.2, and this Condition 7.6 shall not apply to such securities issuances or financings.

7.7 Money Pool Agreement. Subject to the limitations imposed in Regulatory Condition 8.5, DEC, DEP, and Piedmont may borrow through Duke Energy's "Utility Money Pool Agreement" (Utility MPA), provided as follows: (a) participation in the Utility MPA is limited to the parties to the Utility MPA filed with the Commission on December 1, 2011, in Docket Nos. E-7, Sub 986A, and E-2, Sub 998A, plus Piedmont and with the exception of the Progress Energy Service Company; and (b) the Utility MPA continues to provide that no loans through the Utility MPA will be made to, and no borrowings through the Utility MPA will be made by, Duke Energy, Progress Energy, and Cinergy Corp.

7.8 Borrowing Arrangements. Subject to the limitations imposed in Regulatory Condition 8.5, DEC, DEP, and Piedmont may borrow short-term funds through one or more joint external debt or credit arrangements (a Credit Facility), provided that the following conditions are met:

(a) No borrowing by DEC, DEP, or Piedmont under a Credit Facility shall exceed one year in duration, absent Commission approval;

(b) No Credit Facility shall include, as a borrower, any party other than Duke Energy, DEC, DEP, Duke Indiana, Duke Kentucky, DEF, Duke Ohio, and Piedmont; and

(c) DEC's, DEP's, and Piedmont's participation in any Credit Facility shall in no way cause either of them to guarantee, assume liability for, or provide collateral for any debt or credit other than its own.

7.9 Long-Term Debt Fund Restrictions. DEC, DEP, and Piedmont shall acquire their respective long-term debt funds through the financial markets, and shall neither borrow from, nor lend to, on a long-term basis, Duke Energy or any of the other Affiliates. To the extent that either DEC, DEP, or Piedmont borrows on short-term or long-term bases in the financial markets and is able to obtain a debt rating, its debt shall be rated under its own name.

SECTION VIII
CORPORATE GOVERNANCE/RING FENCING

The following Regulatory Conditions are intended to ensure the continued viability of DEC, DEP, and Piedmont and to insulate and protect DEC, DEP, and their Retail Native Load Customers and Piedmont and its Customers from the business and financial risks of Duke Energy and the Affiliates within the Duke Energy holding company system, including the protection of utility assets from liabilities of Affiliates.

8.1 Investment Grade Debt Rating. DEC, DEP, and Piedmont shall manage their respective businesses so as to maintain an investment grade debt rating on all of their rated debt issuances with all of the debt rating agencies on all of their rated debt issuances. If DEC's, DEP's, or Piedmont's debt rating falls to the lowest level still considered investment grade at the time, DEC, DEP, or Piedmont shall file written notice to the Commission and the Public Staff within five (5) days of such change and an explanation as to why the downgrade occurred. Within 45 days of such notice, DEC, DEP, or Piedmont shall provide the Commission and the Public Staff with a specific plan for maintaining and improving its debt rating. The Commission, after notice and hearing, may then take whatever action it deems necessary consistent with North Carolina law to protect the interests of DEC's or DEP's Retail Native Load Customers and Piedmont's Customers in the continuation of adequate and reliable service at just and reasonable rates.

8.2 Protection Against Debt Downgrade. To the extent the cost rates of any of DEC's, DEP's, or Piedmont's long-term debt (more than one year) or short-term debt (one year or less) are or have been adversely affected through a ratings downgrade attributable to the Merger, a replacement cost rate to remove the effect shall be used for all purposes affecting any of DEC's North Carolina retail rates and charges, DEP's North Carolina retail rates and charges, and Piedmont's North Carolina rates and charges. This replacement cost rate shall be applicable to all financings, refundings, and refinancings taking place following the change in ratings. This procedure shall be effective through DEC's, DEP's and Piedmont's next respective general rate cases. As part of DEC's, DEP's and Piedmont's next respective general rate cases, any future procedure relating to a replacement cost calculation will be determined. This Regulatory Condition does not indicate a preference for a specific debt rating or preferred stock rating for DEC, DEP, or Piedmont on current or prospective bases.

8.3 Distributions from DEC, DEP, and Piedmont to Holding Company. DEC, DEP, and Piedmont shall limit cumulative distributions paid to Duke Energy subsequent to the Merger to (a) the amount of Retained Earnings on the day prior to the closure of the Merger, plus (b) any future earnings recorded by DEC, DEP, and Piedmont subsequent to the Merger.

8.4 Debt Ratio Restrictions. To the extent any of Duke Energy's external debt or credit arrangements contain covenants restricting the ratio of debt to total capitalization on a consolidated basis to a maximum percentage of debt, Duke Energy shall ensure that the capital structures of both DEC, DEP, and Piedmont individually meet those restrictions.

8.5 Limitation on Continued Participation in Utility Money Pool Agreement and Other Joint Debt and Credit Arrangements with Affiliates. DEC, DEP, and Piedmont may participate in the Utility MPA and any other authorized joint debt or credit arrangement as provided in Regulatory Conditions 7.7 and 7.8 only to the extent such participation is beneficial to DEC's and DEP's respective Retail Native Load Customers and Piedmont's Customers and does not negatively affect DEC's, DEP's, or Piedmont's ability to continue to provide adequate and reliable service at just and reasonable rates.

8.6 Notice of Level of Non-Utility Investment by Holding Company System. In order to enable the Commission to determine whether the cumulative investment by Duke Energy in assets, ventures, or entities other than regulated utilities is reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service so as to warrant Commission action (pursuant to Regulatory Condition 8.8 or other applicable authority) to protect DEC's or DEP's Retail Native Load Customers or Piedmont's Customers, Duke Energy shall notify the Commission within 90 days following the end of any fiscal year for which Duke Energy reports to the Securities and Exchange Commission assets in its operations other than regulated utilities that are in excess of 22% of its consolidated total assets. The following procedures shall apply to such a notice:

(a) Any interested party may file comments within 45 days of the filing of Duke Energy's notice.

(b) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall make a recommendation as to how the Commission should proceed. If the Commission determines that the percentage of total assets invested in Duke Energy's its operations other than regulated utilities is reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service so as to warrant action by the Commission to protect DEC's and DEP's Retail Native Load Customers and Piedmont's Customers, the Commission shall issue an order setting the matter for further consideration. If the Commission determines that the percentage threshold being exceeded does not warrant action by the Commission, the Commission shall issue an order so ruling.

8.7 Notice by Holding Company of Certain Investments. Duke Energy shall file a notice with the Commission subsequent to Board approval and as soon as practicable following any public announcement of any investment in a regulated utility or a non-regulated business that represents five (5) percent or more of Duke Energy's book capitalization.

8.8 Ongoing Review of Effect of Holding Company Structure. The operation of DEC, DEP, and Piedmont under a holding company structure shall continue to be subject to Commission review. To the extent the Commission has authority under North Carolina law, it may order modifications to the structure or operations of Duke Energy, DEBS, another Affiliate, or a Nonpublic Utility Operation, and may take whatever action it deems necessary in the interest of Retail Native Load Customers and Piedmont's Customers to protect the economic viability of DEC, DEP, and Piedmont, including the protection of DEC's, DEP's, and Piedmont's public utility assets from liabilities of Affiliates.

8.9 Investment by DEC, DEP, or Piedmont in Non-regulated Utility Assets and Non-utility Business Ventures. Neither DEC, DEP, nor Piedmont shall invest in a non-regulated utility asset or any non-utility business venture exceeding $50 million in purchase price or gross book value to DEC, DEP, or Piedmont unless it provides 30 days' advance notice. Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition. Purchases of assets, including land that will be held with a definite plan for future use in providing Electric Services in DEC's or DEP's franchise area or Natural Gas Services in Piedmont's franchise area, shall be excluded from this advance notice requirement.

8.10 Investment by Holding Company in Exempt Wholesale Generators. By April 15 of each year, Duke Energy shall provide to the Commission and the Public Staff a report summarizing Duke Energy's investment in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs) in relation to its level of consolidated retained earnings and consolidated total capitalization at the end of the preceding year. Exempt wholesale generator and foreign utility company are defined in Section 1262(6) of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

8.11 Notice by DEC, DEP, or Piedmont of Default or Bankruptcy of Affiliate. If an Affiliate of DEC, DEP, or Piedmont experiences a default on an obligation that is material to Duke Energy or files for bankruptcy, and such bankruptcy is material to Duke Energy, DEC, DEP, or Piedmont shall notify the Commission in advance, if possible, or as soon as possible, but not later than ten days from such event.

8.12 Annual Report on Corporate Governance. No later than March 31 of each year, DEC, DEP, and Piedmont shall file a report including the following:

(a) A complete, detailed organizational chart (i) identifying DEC, DEP, Piedmont, and each Duke Energy financial reporting segment, and (ii) stating the business purpose of each Duke Energy financial reporting segment. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

(b) A list of all Duke Energy financial reporting segment that are considered to constitute non-regulated investments and a statement of each segment's total capitalization and the percentage it represents of Duke Energy's non-regulated investments and total investments. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

(c) An assessment of the risks that each unregulated Duke Energy financial reporting segment could pose to DEC, DEP, or Piedmont based upon current business activities of those affiliates and any contemplated significant changes to those activities.

(d) A description of DEC's, DEP's, Piedmont's and each significant Affiliate's actual capital structure. In addition, describe Duke Energy's, DEC's, DEP's, and Piedmont's respective capital structures and plans for achieving such goals.

(e) A list of all protective measures (other than those provided for by the Regulatory Conditions adopted in Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682) in effect between DEC, DEP, Piedmont, and any of their Affiliates, and a description of the goal of each measure and how it achieves that goal, such as mitigation of DEC's, DEP's, and Piedmont's exposure in the event of a bankruptcy proceeding involving any Affiliate(s).

(f) A list of corporate executive officers and other key personnel that are shared between DEC, DEP, Piedmont, and any Affiliate, along with a description of each person's position(s) with, and duties and responsibilities to each entity.

(g) A calculation of Duke Energy's total book and market capitalization as of December 31 of the preceding year for common equity, preferred stock, and debt.

SECTION IX
FUTURE MERGERS AND ACQUISITIONS

The following Regulatory Conditions are intended to ensure that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Duke Energy, DEC, DEP, Piedmont, other Affiliates, or the Nonpublic Utility Operations. The advance notice provisions set forth in Regulatory Condition 13.2 do not apply to these conditions.

9.1 Mergers and Acquisitions by or Affecting DEC, DEP, or Piedmont. For any proposed merger, acquisition, or other business combination by DEC, DEP, or Piedmont that would have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, DEC, DEP, or Piedmont shall file in a new Sub docket an application for approval pursuant to G S. 62-111(a) at least 180 days before the proposed closing date for such merger, acquisition, or other business combination.

9.2 Mergers and Acquisitions Believed Not to Have an Effect on DEC's, DEP's, or Piedmont's Rates or Service. For any proposed merger, acquisition, or other business combination that is believed not to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, but which involves Duke Energy, other Affiliates, or the Nonpublic Utility Operations and which has a transaction value exceeding $1.5 billion, the following shall apply:

(a) Advance notification shall be filed with the Commission in a new Sub docket by the merging entities at least 90 days prior to the proposed closing date for such proposed merger, acquisition or other business combination. The advance notification is intended to provide the Commission an opportunity to determine whether the proposed merger, acquisition, or other business combination is reasonably likely to affect DEC, DEP, or Piedmont so as to require approval pursuant to G S. 62-111(a). The notification shall contain sufficient information to enable the Commission to make such a determination. If the Commission determines that such approval is required, the 180-day advance filing requirement in Regulatory Condition 9.1 shall not apply.

(b) Any interested party may file comments within 45 days of the filing of the advance notification.

(c) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall recommend that the Commission issue an order deciding how to proceed. If the Commission determines that the merger, acquisition, or other business combination requires approval pursuant to G.S. 62-111(a), the Commission shall issue an order requiring the filing of an application, and no closing can occur until and unless the Commission approves the proposed merger, acquisition, or business combination. If the Commission determines that the merger, acquisition, or other business combination does not require approval pursuant to G.S. 62-111(a), the Commission shall issue an order so ruling. At the end of the notice period, if no order has been issued, Duke Energy, any other Affiliate, or the Nonpublic Utility Operation may proceed with the merger, acquisition, or other business combination but shall be subject to any fully-adjudicated Commission order on the matter.

SECTION X
STRUCTURE/ORGANIZATION

The following Regulatory Conditions are intended to ensure that the Commission receives adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Duke Energy, DEC, DEP, Piedmont, and other Affiliates, and Nonpublic Utility operations as they may affect Customers.

10.1 Transfer of Services, Functions, Departments, Rights, Assets, or Liabilities. DEC, DEP, and Piedmont shall file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, rights, obligations, assets, or liabilities from DEC, DEP, or Piedmont to DEBS that (a) involves services, functions, departments, rights, obligations, assets, or liabilities other than those of a governance or corporate type nature that traditionally have been provided by a service company or (b) potentially would have a significant effect on DEC's, DEP's, or Piedmont's public utility operations. The provisions of Regulatory Condition 13.2 apply to an advance notice filed pursuant to this Regulatory Condition.

10.2 Notice and Consultation with Public Staff Regarding Proposed Structural and Organizational Changes. Upon request, DEC, DEP, and Piedmont shall meet and consult with, and provide requested relevant data to, the Public Staff regarding plans for significant changes in DEC's, DEP's, Piedmont's or Duke Energy's organization, structure (including RTO developments), and activities; the expected or potential impact of such changes on Customer rates, operations and service; and proposals for assuring that such plans do not adversely affect DEC's or DEP's Retail Native Load Customers or Piedmont's Customers. To the extent that proposed significant changes are planned for the organization, structure, or activities of an Affiliate or Nonpublic Utility Operation and such proposed changes are likely to have an adverse impact on DEC's, DEP's, or Piedmont's Customers, then DEC's, DEP's, and Piedmont's plans and proposals for assuring that those plans do not adversely affect their Customers must be included in these meetings. DEC, DEP, and Piedmont shall inform the Public Staff promptly of any such events and changes.

SECTION XI
SERVICE QUALITY

The following Regulatory Conditions are intended to ensure that DEC, DEP, and Piedmont continue to implement and further their commitment to providing superior public utility service by meeting recognized service quality indices and implementing the best practices of each other and their Utility Affiliates, to the extent reasonably practicable.

11.1 Overall Service Quality. Upon consummation of the Merger, DEC, DEP, and Piedmont each shall continue their commitment to providing superior public utility service and shall maintain the overall reliability of Electric Services and Natural Gas Services at levels no less than the overall levels it has achieved in the past decade.

11.2 Best Practices. DEC, DEP, and Piedmont shall make every reasonable effort to incorporate each other's best practices into its own practices to the extent practicable.

11.3 Quarterly Reliability Reports. DEC and DEP shall each provide quarterly service reliability reports to the Public Staff on the following measures: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

11.4 Notice of NERC Audit. This Regulatory Condition does not apply to Piedmont. At such time as either DEC or DEP receives notice that the North American Electric Reliability Corporation (NERC) or the SERC Reliability Corporation will be conducting a non-routine compliance audit with respect to DEC's or DEP's compliance with mandatory reliability standards, DEC or DEP shall notify the Public Staff.

11.5 Right-of-Way Maintenance Expenditures (DEC and DEP). DEC and DEP shall budget and expend sufficient funds to trim and maintain their lower voltage line rights-of-way and their distribution rights-of-way in a manner consistent with their internal right-of-way clearance practices and Commission Rule R8-26. In addition, DEC and DEP shall track annually, on a major category basis, departmental or division budget requests, approved budgets and actual expenditures for right-of-way maintenance.

11.6 Right-of-Way Maintenance Expenditures (Piedmont). Piedmont shall budget and expend sufficient funds to maintain its pipeline rights-of-way so as to allow ready access by personnel and vehicles for the purpose of responding to pipeline damage, conducting leak and corrosion surveys, performing maintenance activities, and ensuring system integrity, safety, and reliability.

11.7 Right-of-Way Clearance Practices (DEC and DEP). DEC and DEP shall each provide a copy of their internal right-of-way clearance practices to the Public Staff, and shall promptly notify the Public Staff of any significant changes or modifications to the practices or maintenance schedules.

11.8 Right-of-Way Clearance Practices (Piedmont). Piedmont shall provide a copy of its Operating and Maintenance Manual to the Public Staff and shall promptly notify the Public Staff in writing of any substantive changes to Section 9, "Right-of-Way Management Program."

11.9 Meetings with Public Staff.

(a) DEC, DEP, and Piedmont shall each meet annually with the Public Staff to discuss service quality initiatives and results, including (i) ways to monitor and improve service quality, (ii) right-of-way maintenance practices, budgets, and actual expenditures, and (iii) plans that could have an effect on customer service, such as changes to call center operations.

(b) DEC, DEP, and Piedmont shall each meet with the Public Staff at least annually to discuss potential new tariffs, programs, and services that enable its customers to appropriately manage their energy bills based on the varied needs of their customers.

11.10 Customer Access to Service Representatives and Other Services. DEC, DEP, and Piedmont shall continue to have knowledgeable and experienced customer service representatives available 24 hours a day to respond to service outage calls and during normal business hours to handle all types of customer inquiries. DEC, DEP, and Piedmont shall also maintain up-to-date and user-friendly online services and automated telephone service 24 hours a day to perform routine customer interactions and to provide general billing and customer information.

11.11 Customer Surveys. DEC, DEP, and Piedmont shall continue to survey their customers regarding their satisfaction with public utility service and shall incorporate this information into their processes, programs, and services.

SECTION XII
TAX MATTERS

The following Regulatory Conditions are intended to ensure that DEC's, DEP's, and Piedmont's North Carolina Customers do not bear any additional tax costs as a result of the Merger and receive an appropriate share of any tax benefits associated with the service company Affiliates.

12.1 Costs under Tax Sharing Agreements. Under any tax sharing agreement, DEC, DEP, and Piedmont shall not seek to recover from North Carolina Customers any tax costs that exceed DEC's, DEP's, or Piedmont's tax liability calculated as if it were a stand-alone, taxable entity for tax purposes.

12.2 Tax Benefits Associated with Service Companies. The appropriate portion of any income tax benefits associated with DEBS shall accrue to the North Carolina retail operations of DEC, DEP, and Piedmont, respectively, for regulatory accounting, reporting, and ratemaking purposes.

SECTION XIII
PROCEDURES

The following Regulatory Conditions are intended to apply to all filings made pursuant to these Regulatory Conditions unless otherwise expressly provided by, Commission order, rule, or statute.

13.1 Filings that Do Not Involve Advance Notice. Regulatory Condition filings that are not subject to Regulatory Condition 13.2 shall be made in sub dockets of Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682, as follows:

(a) Filings related to affiliate matters required by Regulatory Conditions 5.4, 5.5, 5.6, 5.7, and 5.23 and the filing permitted by Regulatory Condition 5.3 shall be made by DEC, DEP, and Piedmont in Subs 1100A, 1095A, and 682A, respectively;

(b) Filings related to financings required by Regulatory Condition 7.6, and the filings required by Regulatory Conditions 8.6, 8.7, 8.10, 8.11 and 8.12 shall be made by DEC, DEP, and Piedmont in Subs 1100B, 1095B, and 682B, respectively;

(c) Files related to compliance as required by Regulatory Conditions 3.1(d) and 14.4 and filings required by Sections III.A.2(k), III.A.3(e), (f), and (g), III.D.5, and III.D.8 of the Code of Conduct shall be made by DEC, DEP, and Piedmont in Subs 1100C, 1095C, and 682C, respectively;

(d) Filings related to the independent audits required by Regulatory Condition 5.8 shall be made in Subs 1100D, 1095D, and 682D, respectively; and

(e) Filings related to orders and filings with the FERC, as required by Regulatory Condition 3.1(d), 3.10 and 5.13 shall be made by DEC, DEP, and Piedmont in Subs 1100E, 1095E, and 682E, respectively.

13.2 Advance Notice Filings. Advance notices filed pursuant to Regulatory Conditions 3.1(c), 3.3(b), 3.7(c), 3.9(c), 4.2, 5.3, 8.9, and 10.1 shall be assigned a new, separate Sub docket. Such a filing shall identify the condition and notice period involved and state whether other regulatory approvals are required and shall be in the format of a pleading, with a caption, a title, allegations of the activities to be undertaken, and a verification. Advance notices may be filed under seal if necessary. The following additional procedures apply:

(a) Advance notices of activities to be undertaken shall not be filed until sufficient details have been decided upon to allow for meaningful discovery as to the proposed activities.

(b) The Chief Clerk shall distribute a copy of advance notice filings to each Commissioner and to appropriate members of the Commission Staff and Public Staff.

(c) DEC, DEC, or Piedmont shall serve such advance notices on each party to Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682, respectively, that has filed a request to receive them with the Commission within 30 days of the issuance of an order approving the Merger in this docket. These parties may participate in the advance notice proceedings without petitioning to intervene. Other interested persons shall be required to follow the Commission's usual intervention procedures.

(d) To effectuate this Regulatory Condition, DEC, DEP, or Piedmont shall serve pertinent information on all parties at the time it serves the advance notice. During the advance notice period, a free exchange of information is encouraged, and parties may request additional relevant information. If DEC, DEP, or Piedmont objects to a discovery request, DEC, DEP, or Piedmont and the requesting party shall try to resolve the matter. If the parties are unable to resolve the matter, DEC, DEP, or Piedmont may file a motion for a protective order with the Commission.

(e) The Public Staff shall investigate and file a response with the Commission no later than 15 days before the notice period expires. Any other interested party may also file a response or objection within 15 days before the notice period expires. DEC, DEP, or Piedmont may file a reply to the response(s).

(f) The basis for any objection to the activities to be undertaken shall be stated with specificity. The objection shall allege grounds for a hearing, if such is desired.

(g) If neither the Public Staff nor any other party files an objection to the activities within 15 days before the notice period expires, no Commission order shall be issued, and the Sub docket in which the advance notice was filed may be closed.

(h) If the Public Staff or any other party files a timely objection to the activities to be undertaken by DEC, DEP, or Piedmont, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than two weeks after the objection is filed, and shall recommend that the Commission issue an order deciding how to proceed as to the objection. The Commission reserves the right to extend an advance notice period by order should the Commission need additional time to deliberate or investigate any issue. At the end of the notice period, if no objection has been filed by the Public Staff and no order, whether procedural or substantive, has been issued, DEC, DEP, Piedmont, Duke Energy, any other Affiliate, or the Nonpublic Utility Operation may execute the proposed agreement, proceed with the activity to be undertaken, or both, but shall be subject to any fully-adjudicated Commission order on the matter.

(i) If the Commission schedules a hearing on an objection, the party filing the objection shall bear the burden of proof at the hearing.

(j) The precedential effect of advance notice proceedings, like most issues of res judicata, will be decided on a fact-specific basis.

(k) If some other Commission filing or Commission approval is required by statute, notice pursuant to a Regulatory Condition alone does not satisfy the statutory requirement.

SECTION XIV
COMPLIANCE WITH CONDITIONS AND CODE OF CONDUCT

The following Regulatory Conditions are intended to ensure that Duke Energy, DEC, DEP, Piedmont, and all other Affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in all of the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner.

14.1 Ensuring Compliance with Regulatory Conditions and Code of Conduct. Duke Energy, DEC, DEP, Piedmont, and all other Affiliates shall devote sufficient resources into the creation, monitoring, and ongoing improvement of effective internal compliance programs to ensure compliance with all Regulatory Conditions and the DEC/DEP/Piedmont Code of Conduct, and shall take a proactive approach toward correcting any violations and reporting them to the Commission. This effort shall include the implementation of systems and protocols for monitoring, identifying, and correcting possible violations, a management culture that encourages compliance among all personnel, and the tools and training sufficient to enable employees to comply with Commission requirements.

14.2 Designation of Chief Compliance Officer. DEC, DEP, and Piedmont shall designate a chief compliance officer who will be responsible for compliance with the Regulatory Conditions and Code of Conduct. This person's name and contact information must be posted on DEC's, DEP's, and Piedmont's Internet Websites.

14.3 Annual Training. DEC, DEP, and Piedmont shall provide annual training on the requirements and standards contained within the Regulatory Conditions and Code of Conduct to all of their employees (including service company employees) whose duties in any way may be affected by such requirements and standards. New employees must receive such training within the first 60 days of their employment. Each employee who has taken the training must certify electronically or in writing that s/he has completed the training.

14.4 Report of Violations. If DEC, DEP, or Piedmont discover that a violation of their requirements or standards contained within the Regulatory Conditions and Code of Conduct has occurred then DEC, DEP, or Piedmont shall file a statement with the Commission in Docket Nos. E-7, Sub 1100C, E-2, Sub 1095C, and G-9, Sub 682C, respectively, describing the circumstances leading to that violation of DEC's, DEP's, or Piedmont's requirements or standards, as contained within the Regulatory Conditions and Code of Conduct, and the mitigating and other steps taken to address the current or any future potential violation.

ELECTRIC – MERGER

SECTION XV
PROCEDURES FOR DETERMINING LONG-TERM SOURCES OF PIPELINE CAPACITY AND SUPPLY

The following Regulatory Conditions are intended to ensure the continued practices of DEC, DEP, and Piedmont for determining long-term sources of pipeline capacity and supply.

15.1 Cost-benefit Analysis. The appropriate source(s) for the interstate pipeline capacity and supply shall be determined by DEC and DEP on the basis of the benefits and costs of such source(s) specific to their respective electric customers. The appropriate source(s) for the interstate pipeline capacity and supply shall be determined by Piedmont on the basis of the specific benefits and costs of such source(s) specific to its natural gas customers, including electric power generating customers.

15.2 Ownership and Control of Contracts. Piedmont shall retain title, ownership, and management of all gas contracts necessary to ensure the provision of reliable Natural Gas Services consistent with Piedmont's best cost gas and capacity procurement methodology.

CODE OF CONDUCT
GOVERNING THE RELATIONSHIPS, ACTIVITIES, AND TRANSACTIONS BETWEEN AND AMONG THE PUBLIC UTILITY OPERATIONS OF DEC, THE PUBLIC UTILITY OPERATIONS OF DEP, THE PUBLIC UTILITY OPERATIONS OF PIEDMONT, DUKE ENERGY CORPORATION, OTHER AFFILIATES, AND THE NONPUBLIC UTILITY OPERATIONS OF DEC, DEP, AND PIEDMONT

I. DEFINITIONS

For the purposes of this Code of Conduct, the terms listed below shall have the following definitions:

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of this Code of Conduct, Duke Energy and any business entity controlled by it are considered to be Affiliates of DEC, DEP, and Piedmont, and DEC, DEP, and Piedmont are considered to be Affiliates of each other.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information or CSOI: Nonpublic information that pertains to Electric Services provided by DEC or DEP, including but not limited to information concerning electric generation, transmission, distribution, or sales, and nonpublic information that pertains to Natural Gas Services provided by Piedmont, including but not limited to information concerning transportation, storage, distribution, gas supply, or other similar information.

ELECTRIC – MERGER

Customer: Any retail electric customer of DEC or DEP in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of Piedmont located in North Carolina.

Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC, DEP, or Piedmont in connection with the supplying of Electric Services or Natural Gas Services to that Customer or group of Customers.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, or Piedmont, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

DEP: Duke Energy Progress. LLC, the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the DEP's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC, DEP, and Piedmont, and any successor company.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by DEC or DEP from sources other than DEC or DEP for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good or service supplied by DEC, DEP, or Piedmont, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding; (b) for each good or service supplied to DEC, DEP, or Piedmont, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good or service supplied by DEC, DEP, or Piedmont to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's, DEP's, or Piedmont's most recent general rate case proceeding, as applicable.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission in Docket Nos. E-7, Sub 986, and E-2, Sub 998, on June 22, 2011, and as amended and refiled on June 12, 2012.

Market Value: The price at which property, goods, or services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Piedmont.

Natural Gas Services: Commission-regulated natural gas sales and natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering and billing, and standby service.

Non-affiliated Gas Marketer: An entity, not affiliated with DEC, DEP, or Piedmont, engaged in the unregulated sale, arrangement, brokering or management of gas supply, pipeline capacity, or gas storage.

Nonpublic Utility Operations: All business operations engaged in by DEC, DEP, or Piedmont involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS, other than a Utility Affiliate, DEC, DEP, or Piedmont.

Personnel: An employee or other representative of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

Piedmont: Piedmont Natural Gas Company, Inc., the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of DEP and is a subsidiary of Duke Energy, and any successors.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, or subsequent orders of the Commission and that the Commission has explicitly authorized DEC, DEP, and Piedmont to take from DEBS pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

Shipper: A Non-affiliated Gas Marketer, a municipal gas customer, or an end-user of gas.

Utility Affiliates: The regulated public utility operations of Duke Energy Indiana, LLC (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), Florida Power Corporation, d/b/a Progress Energy Florida, LLC (DEF), and Duke Energy Ohio, Inc. (Duke Ohio).

II. GENERAL

This Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, transactions, and activities involving the public utility operations of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, and Piedmont, to the extent such relationships, activities, and transactions affect the public utility operations of DEC, DEP, and Piedmont in their respective service areas. DEC, DEP, Piedmont, and the other Affiliates are bound by this Code of Conduct pursuant to Regulatory Condition 6.1 approved by the Commission in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682. This Code of Conduct is subject to modification by the Commission as the public interest may require, including, but not limited to, addressing changes in the organizational structure of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry or natural gas industry; or other changes that warrant modification of this Code.

DEC, DEP, or Piedmont may seek a waiver of any aspect of this Code of Conduct by filing a request with the Commission showing that circumstances in a particular case justify such a waiver.

Ill. STANDARDS OF CONDUCT

A. Independence and Information Sharing

1. Separation - DEC, DEP, Piedmont, Duke Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable; however, to the extent that the Commission has approved or accepted a service company-to-utility or utility-to-utility service agreement or list, DEC, DEP, Piedmont, Duke Energy, and the other Affiliates may operate as described in the agreement or list on file at the Commission. DEC, DEP, Piedmont, Duke Energy, and each of the other Affiliates shall maintain separate books and records. Each of DEC's, DEP's, and Piedmont's Nonpublic Utility Operations shall maintain separate records from those of

DEC's, DEP's, and Piedmont's public utility operations to ensure appropriate cost allocations and any arm's-length-transaction requirements.

2. Disclosure of Customer Information:

(a) Upon request, and subject to the restrictions and conditions contained herein, DEC, DEP, and Piedmont may provide Customer Information to Duke Energy or another Affiliate under the same terms and conditions that apply to the provision of such information to non-Affiliates. In addition, DEC and DEP may provide Customer Information to their respective Nonpublic Utility Operations under the same terms and conditions that apply to the provision of such information to non-Affiliates.

(b) Except as provided in Section III.A.2.(f), Customer Information shall not be disclosed to any Affiliate or non-affiliated third party without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates of DEC, DEP, and Piedmont or to DEC's or DEP's Nonpublic Utility Operations may be obtained by means of written, electronic, or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A; provided, however, that DEC, DEP, and Piedmont retain such authorization for verification purposes for as long as the authorization remains in effect. Written, electronic, or recorded verbal authorization or consent for the disclosure of Piedmont's Customer Information to Piedmont's Nonpublic Utility Operations is not required.

(c) If the Customer allows or directs DEC, DEP, or Piedmont to provide Customer Information to Duke Energy, another Affiliate, or to DEC's or DEP's Nonpublic Utility Operations, then DEC, DEP, or Piedmont shall ask if the Customer would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs DEC, DEP, or Piedmont to provide the Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

(d) Section III.A.2.shall be permanently posted on DEC's, DEP's and Piedmont's website(s).

(e) No DEC, DEP, or Piedmont employee who is transferred to Duke Energy or another Affiliate shall be permitted to copy or otherwise compile any Customer Information for use by such entity except as authorized by the Customer pursuant to a signed Data Disclosure Authorization. DEC, DEP, and Piedmont shall not transfer any employee to Duke Energy or another Affiliate for the purpose of disclosing or providing Customer Information to such entity.

(f) Notwithstanding the prohibitions in this Section III.A.2.:

(i) DEC, DEP, and Piedmont may disclose Customer Information to DEBS, any other Affiliate, or a non-affiliated third party without Customer consent to the extent necessary for the Affiliate or non-affiliated third party to provide goods or services to DEC, DEP, or Piedmont and upon the written agreement of the other Affiliate or non-affiliated third-party to protect the confidentiality of such Customer Information. To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(ii) DEC and DEP may disclose Customer Information to their Nonpublic Utility Operations without Customer consent to the extent necessary for the Nonpublic Utility Operations to provide goods and services to DEC or DEP and upon the written agreement of the Nonpublic Utility Operations to protect the confidentiality of such Customer Information.

(iii) DEC, DEP, and Piedmont may disclose Customer Information to a state or federal regulatory agency or court of competent jurisdiction if required in writing to do so by the agency or court.

(g) DEC, DEP, and Piedmont shall take appropriate steps to store Customer Information in such a manner as to limit access to those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) DEC, DEP, and Piedmont shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

(i) No DEBS employee may use Customer Information to market or sell any product or service to DEC's, DEP's, or Piedmont's Customers, except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by DEC, DEP, or Piedmont.

(j) DEBS employees with access to Customer Information must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the Customer Information by employees of DEBS that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC and DEP.

(k) Should any inappropriate disclosure of DEC, DEP, or Piedmont Customer Information occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission describing the circumstances of the disclosure, the Customer information disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

3. The disclosure of Confidential Systems Operation Information of DEC, DEP, and Piedmont shall be governed as follows:

(a) Such CSOI shall not be disclosed by DEC, DEP, or Piedmont to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required under the following circumstances:

(i) The CSOI is provided to employees of DEC or DEP for the purpose of implementing, and operating pursuant to, the JDA in accordance with the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

(ii) The CSOI is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements.

(iii) A state or federal regulatory agency or court of competent jurisdiction over the disclosure of the CSOI requires the disclosure.

(iv) The CSOI is provided to employees of DEBS pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153.

(v) The CSOI is provided to employees of DEC's, DEP's, or Piedmont's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service.

(vi) The CSOI is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of CSOI to be disclosed.

(vii) Disclosure is otherwise essential to enable DEC or DEP to provide Electric Services to their Customers or for Piedmont to provide Natural Gas Services to its Customers.

(viii) Disclosure of the CSOI is necessary for compliance with the Sarbanes-Oxley Act of 2002.

(b) Any CSOI disclosed pursuant Section III.A.3.(a)(i)-(viii) shall be disclosed only to employees that need the CSOI for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such CSOI must be prohibited from acting as conduits to pass the CSOI to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such CSOI.

(c) For disclosures pursuant to Section III.A.3.(a)(vii) and (viii), DEC, DEP, and Piedmont shall include in their annual affiliated transaction reports the following information:

(i) The types of CSOI disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed;

(ii) The reasons for the disclosure; and

(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process.

To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

(d) DEC, DEP, Piedmont, and DEBS employees with access to CSOI must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the CSOI by employees that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC, DEP, and Piedmont.

(e) Should the handling or disclosure of CSOI by DEBS, or another Affiliate or Nonpublic Utility Operation, or its respective employees, result in (i) a violation of DEC's or DEP’s FERC Statement of Policy and Code of Conduct (FERC Code), 18 CFR 358 - Standards of Conduct for Transmission Providers (Transmission Standards), or any other relevant FERC standards or codes of conduct, (ii) the posting of such data on an Open Access Same-Time Information System (OASIS) or other Internet website, or (iii) other public disclosure of the data, DEC or DEP shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, and E-2, Sub 1095C, respectively, describing the circumstances leading to such violation, posting, or other public disclosure describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the steps taken to mitigate the effects of the current and prevent any future potential violation, posting, or other public disclosure.

(f) Should any inappropriate disclosure of CSOI occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, E-2, Sub 1095C, or G-9, Sub 682C, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

(g) Unless publicly noticed and generally available, should the FERC Code, the Transmission Standards, or any other relevant FERC standards or codes of conduct be eliminated, amended, superseded, or otherwise replaced, DEC and DEP shall file a letter with the Commission in Docket Nos. E-7, Sub 1100E, and E-2, Sub 1095E, describing such action within 60 days of the action, along with a copy of any amended or replacement document.

B. Nondiscrimination

1. DEC's, DEP's, and Piedmont's employees and representatives shall not unduly discriminate against non-Affiliated entities.

2. In responding to requests for Electric Services, Natural Gas Services, or both, DEC, DEP, and Piedmont shall not provide any preference to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, or to any customers of such an entity, as compared to non-Affiliates or their customers. Moreover, neither DEC, DEP, Piedmont, Duke Energy, nor any other Affiliates shall represent to any person or entity that Duke Energy, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. DEC, DEP, and Piedmont shall apply the provisions of their respective tariffs equally to Duke Energy, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. DEC, DEP, and Piedmont shall process all similar requests for Electric Services, Natural Gas Services, or both, in the same timely manner, whether requested on behalf of Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

5. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Duke Energy or another Affiliate speaks on behalf of DEC, DEP, or Piedmont; provided however, that this prohibition shall not apply to employees of DEBS providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no personnel or representatives of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of DEC's or DEP's regulated public utility operations.

6. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services or

Natural Gas Services exists as the result of that party dealing with Duke Energy, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. DEC, DEP, and Piedmont shall not condition or otherwise tie the provision or terms of any Electric Services or Natural Gas Services to the purchasing of any goods or services from, or the engagement in business of any kind with, Duke Energy, another Affiliate, or a Nonpublic Utility Operation.

> 8. When any employee or representative of DEC or DEP receives a request for information from or provides information to a Customer about goods or services available from Duke Energy, another Affiliate, or a Nonpublic Utility Operation, the employee or representative shall advise the Customer that such goods or services may also be available from non-Affiliated suppliers.
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> 9. Disclosure of Customer Information to Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2. of this Code of Conduct.

10. Unless otherwise directed by order of the Commission, electric generation shall not receive a priority of use from Piedmont that would supersede or diminish Piedmont's provision of service to its human needs firm residential and commercial customers.

11. Piedmont shall file an annual report with the Commission summarizing all requests or inquiries for Natural Gas Services made by a non-utility generator, Piedmont's response to the request, and the status of the inquiry.

C. Marketing

1. The public utility operations of DEC, DEP, and Piedmont may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with their Affiliates and with their Nonpublic Utility Operations, subject to compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. DEC, DEP, and Piedmont shall not otherwise engage in such joint activities without making such opportunities available to comparable third parties.

2. Neither Duke Energy nor any of the other Affiliates shall use the names or logos of DEC, DEP, or Piedmont in any communications without the following disclaimer:

(a) "[Duke Energy Corporation/Affiliate) is not the same company as [DEC/DEP/Piedmont], and [Duke Energy Corporation/Affiliate) has separate management and separate employees";

(b) "[Duke Energy Corporation/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission";

(c) "Purchasers of products or services from [Duke Energy Corporation/Affiliate] will receive no preference or special treatment from [DEC/DEP/Piedmont]"; and

(d) "A customer does not have to buy products or services from [Duke Energy Corporation/Affiliate] in order to continue to receive the same safe and reliable electric service from [DEC/DEP] or natural gas service from Piedmont."

3. Nonpublic Utility Operations may not use the names or logos of DEC, DEP, or Piedmont in communications without the following disclaimer:

"[Name of product or service being offered by Nonpublic Utility Operation] is not part of the regulated services offered by [DEC/DEP/Piedmont] and is not in any way sanctioned by the North Carolina Utilities Commission."

4. In addition, DEC's and DEP's Nonpublic Utility Operations may not use the names or logos of DEC or DEP in any communications without the following disclaimers:

(a) "Purchasers of [name of product or service being offered by Nonpublic Utility Operation] from [Nonpublic Utility Operation] will receive no preference or special treatment from [DEC/DEP]"; and

(b) "A customer does not have to buy this product or service from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from [DEC/DEP]."

The required disclaimers in this Section III.C.4. must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D. Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-subsidies involving DEC, DEP, or Piedmont and Duke Energy, other Affiliates, or the Nonpublic Utility Operations are prohibited.

2. All costs incurred by personnel or representatives of DEC, DEP, or Piedmont for or on behalf of Duke Energy, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. The following conditions shall apply as a general guideline to the transfer prices charged for goods and services, including the use or transfer of personnel, exchanged between and among DEC, DEP, or Piedmont, and Duke Energy, the other Non-Utility Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect DEC's, DEP's, or Piedmont's operations or costs of utility service:

(a) Except as otherwise provided for in this Section III.D., for untariffed goods and services provided by DEC, DEP, or Piedmont to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer price paid to DEC, DEP, or Piedmont shall be set at the higher of Market Value or DEC's, DEP's, or Piedmont's Fully Distributed Cost.

(b) Except as otherwise provided for in this Section III.D., for goods and services provided, directly or indirectly, by Duke Energy, a Non-Utility Affiliate other than DEBS, or a Nonpublic Utility Operation to DEC, DEP, or Piedmont, the transfer price(s) charged by Duke Energy, the Non-Utility Affiliate, and the Nonpublic Utility Operation to DEC, DEP, or Piedmont shall be set at the lower of Market Value or Duke Energy's, the Non-Utility Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If DEC, DEP, or Piedmont do not engage in competitive solicitation and instead obtain the goods or services from Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, DEC, DEP, and Piedmont shall implement adequate processes to comply with this Code provision and related Regulatory Conditions and ensure that in each case DEC's, DEP's, and Piedmont's Customers receive service at the lowest reasonable cost, unless otherwise directed by order of the Commission. For goods and services provided by DEBS to DEC, DEP, Piedmont, and Utility Affiliates, the transfer price charged shall be set at DEBS' Fully Distributed Cost.

(c) Tariffed goods and services provided by DEC, DEP, and Piedmont to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services or Natural Gas Services under the applicable tariff.

(d) With the exception of gas supply transactions, transportation transactions, or both, between DEC and Piedmont or DEP and Piedmont, untariffed non-power, non-generation, or non-fuel goods and services provided by DEC, DEP, or Piedmont to DEC, DEP, Piedmont, or the Utility Affiliates or by the Utility Affiliates to DEC, DEP, or Piedmont, shall be transferred at the supplier's Fully Distributed Cost, unless otherwise directed by order of the Commission.

(e) All Piedmont deliveries to DEC and DEP pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric generation), size of load, profile of load (daily, monthly, seasonal, annual), location on Piedmont's system, and costs to serve and rates. Piedmont shall maintain records in sufficient detail to demonstrate compliance with this requirement.

(f) All gas supply transactions, interstate transportation and storage transactions, and combinations of these transactions, between DEC or DEP and Piedmont shall be at the fair market value for similar transactions between non-affiliated third parties. DEC, DEP, and Piedmont shall maintain records, such as published market price indices, in sufficient detail to demonstrate compliance with this requirement.

(g) All of the margins, also referred to as net compensation, received by Piedmont on secondary market sales to DEC and DEP shall be recorded in Piedmont's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins on secondary market sales by Piedmont to DEC and DEP shall be included in the secondary market transactions subject to the sharing mechanism on secondary market transactions approved by the Commission in its Order Approving Stipulation, dated December 22, 1995, in Docket No. G-100, Sub 67. The sharing percentage on secondary market sales shall not be considered in determining the prudence of such transactions.

4. To the extent that DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from DEBS (or its successor), these Shared Services may be jointly provided to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by DEC, DEP, and Piedmont is cost beneficial on a service-by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to DEC, DEP, and Piedmont. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual filed with the Commission pursuant to Regulatory Condition 5.5, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies-of-scale in joint purchases of goods and services (excluding the purchase of electricity or ancillary services intended for resale unless such purchase is made pursuant to a Commission-approved contract or service agreement), if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies-of-scale in joint purchases of coal and natural gas, if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion of the purchases and shall be reported in DEC's, DEP's, and Piedmont's affiliated transaction reports filed with the Commission.

6. All permitted transactions between DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manual required to be filed with the Commission pursuant to Regulatory Condition 5.5 and with Affiliate agreements accepted by the Commission or otherwise processed in accordance with North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Costs that DEC, DEP, and Piedmont incur in assembling, compiling, preparing, or furnishing requested Customer Information or CSOI for or to Duke Energy, other Affiliates, Nonpublic Utility Operations, or non-Affiliates (other than the Customer or the Customer's designated representative or agent) shall be recovered from the requesting party pursuant to Section III.D.3. of this Code of Conduct.

8. Any technology or trade secrets developed, obtained, or held by DEC, DEP, or Piedmont in the conduct of regulated operations shall not be transferred to Duke Energy, another Affiliate, or a Nonpublic Utility Operation without just compensation and the filing of 60-days prior notification to the Commission. DEC, DEP, and Piedmont are not required to provide advance notice for such transfers to each other and may request a waiver of this requirement from the Commission with respect to such transfers to Duke Energy, a Utility Affiliate, a Non-Utility Affiliate, or a Nonpublic Utility Operation. In no case, however, shall the notice period requested be less than 20 business days.

9. DEC, DEP, and Piedmont shall receive compensation from Duke Energy, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. The requirements regarding affiliate transactions set forth in G.S. 62-153 shall continue to apply to all transactions between DEC, DEP, Piedmont, Duke Energy, and the other Affiliates.

2. The books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 2-51.

3. If Piedmont supplies any Natural Gas Services, with the exception of Natural Gas Services provided pursuant to Commission-approved contracts or service agreements, used by either DEC or DEP to generate electricity, DEC or DEP, as applicable, shall file a report with the Commission in its annual fuel and fuel-related cost recovery case demonstrating that the purchase was prudent and the price was reasonable.

4. To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Duke Energy, an Affiliate, or a Nonpublic Utility Operation to supply DEC, DEP, or Piedmont with Natural Gas Services or other Fuel and Purchased Power Supply Services used by DEC or DEP to provide Electric Services to Customers, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are supplied, DEC or DEP, as applicable, shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

F. Utility Billing Format

To the extent any bill issued by DEC, DEP, Piedmont, Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes charges to Customers for

Electric Services or Natural Gas Services and non-Electric Services, non-Natural Gas Services, or any combination of such services, from Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party, the charges for Electric Services and Natural Gas Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language stating that the Customer's Electric Services and Natural Gas Services will not be terminated for failure to pay for any other services billed.

G. Complaint Procedure

1. DEC, DEP, and Piedmont shall establish procedures to resolve potential complaints that arise due to the relationship of DEC, DEP, and Piedmont with Duke Energy, the other Affiliates, and the Nonpublic Utility Operations. The complaint procedures shall provide for the following:

(a) Verbal and written complaints shall be referred to a designated representative of DEC, DEP, or Piedmont.

(b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.

(c) DEC, DEP, or Piedmont shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.

(d) DEC, DEP, and Piedmont shall each maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege) by the Commission, its staff, or the Public Staff.

2. Notwithstanding the provisions of Section III.G.1., any complaints received through Duke Energy's EthicsLine (or successor), which is a confidential mechanism available to the employees of the Duke Energy holding company system, shall be handled in accordance with procedures established for the EthicsLine.

3. These complaint procedures do not affect a complainant's right to file a formal complaint with the Commission or otherwise communicate with the Commission or the Public Staff regarding a complaint.

H. Natural Gas/Electricity Competition

DEC, DEP and Piedmont shall continue to compete against all energy providers, including each other, to serve those retail customer energy needs that can be legally and profitably served by both electricity and natural gas. The competition between DEC or DEP and Piedmont shall be at a level that is no less than that which existed prior to the Merger. Without limitation as to the full range of potential competitive activity, DEC, DEP and Piedmont shall maintain the following minimum standards:

ELECTRIC – MERGER

1. Piedmont will make all reasonable efforts to extend the availability of natural gas to as many new customers as possible.

2. In determining where and when to extend the availability of natural gas, Piedmont will at a minimum apply the same standards and criteria that it applied prior to the Merger.

3. In determining where and when to extend the availability of natural gas, Piedmont will make decisions in accordance with the best interests of Piedmont, rather than the best interest of DEC or DEP.

4. To the extent that either the natural gas industry or the electricity industry is further restructured, DEC, DEP, and Piedmont will undertake to maintain the full level of competition intended by this Code of Conduct subject to the right of DEC, DEP, Piedmont or the Public Staff to seek relief from or modifications to this requirement by the Commission.

CODE OF CONDUCT
ATTACHMENT A

DEC/DEP/PIEDMONT CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

For Disclosure to Affiliates:

DEC's/DEP's/Piedmont's Affiliates offer products and services that are separate from the regulated services provided by DEC/DEP/Piedmont. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP/Piedmont to provide any data associated with the Customer account(s) residing in any DEC/DEP/Piedmont files, systems or databases **[or specify specific types of data]** to the following Affiliate(s) __________________. DEC/DEP/Piedmont will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

For Disclosure to Nonpublic Utility Operations:

DEC/DEP offers optional, market-based products and services that are separate from the regulated services provided by DEC/DEP. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP to use any data associated with the Customer account(s) residing in any DEC/DEP files, systems or databases **[or specify types of data]** for the purpose of offering and providing energy-related products or services to the Customer. DEC/DEP will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

DOCKET NO. E-7, SUB 986D

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Third-Party Independent Audits of Affiliate Transactions Pursuant to Regulatory Condition No. 5.8	)))	ORDER ON AUDIT RECOMMENDATIONS

BY THE COMMISSION: As part of its approval of the merger of Duke Energy Corporation (Duke Energy) and Progress Energy, Inc. (Progress), in 2012 (Merger), the Commission required independent third-party audits of the affiliate transactions of Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP)[1] (collectively, the Companies) no less often than every two years. Regulatory Condition No. 5.8, as approved in the Commission's Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued June 29, 2012, in Docket Nos. E-7, Sub 986, and E-2, Sub 998 (Merger Order), provides in pertinent part:

> (a) No less often than every two years, a third-party independent audit shall be conducted related to the affiliate transactions undertaken pursuant to Affiliate agreements filed in accordance with Regulatory Condition 5.4 and of DEC's and [DEP's] compliance with all conditions approved by the Commission concerning Affiliate transactions, including the propriety of the transfer pricing of goods and services between and/or among DEC, [DEP], other Affiliates, and all of the Nonpublic Utility Operations.
>
> (i) The first audit following the close of the transaction shall begin two years from the date of close and shall include whether DEC and [DEP] have adopted systems, policies, CAMs, and other processes to ensure compliance with all of the conditions related to Affiliate dealings and the Code of Conduct and have operated in accordance with those conditions and Code of Conduct.

On August 8, 2014, pursuant to subsection (b) of Regulatory Condition No. 5.8, the Public Staff proposed that Vantage Energy Consulting, LLC (Vantage), be chosen as the third-party, independent auditor for the first audit of certain affiliate matters involving DEC and DEP.

On August 18, 2014, the Commission issued an Order Allowing Comments Regarding Selection of an Independent Auditor, allowing other parties the opportunity to file comments and propose additional auditors by August 29, 2014. No comments were filed.

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[1] On April 29, 2013, Duke Energy Corporation notified the Commission of the change in the legal name of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., to Duke Energy Progress, Inc. On July 1, 2015, notification was provided to the Commission that Duke Energy Progress, Inc. planned to convert from a corporation to a limited liability company effective August 1, 2015. The conversion occurred as planned and the name of the entity is Duke Energy Progress, LLC (DEP). Throughout this Order, the abbreviation "PEC" has been replaced with "DEP," as appropriate, to recognize these changes.

On September 4, 2014, the Commission issued an Order Selecting Auditor, selecting Vantage as the third-party, independent auditor and requested that the Public Staff file a proposed schedule for the audit, including the filing of the auditor's final report.

On October 1, 2014, the Public Staff filed a proposed schedule for the audit, which the Commission approved on October 10, 2014, setting a deadline of March 17, 2015 for the auditor's final report.

The Public Staff filed motions for extensions of time to file the Vantage audit report on March 17, 2015, and March 26, 2015, both of which were granted by Commission Orders dated March 18, 2015, and March 27, 2015, respectively.

On March 31, 2015, the Public Staff filed the Final Report on the Affiliate Audit of DEC and DEP by Vantage (Audit Report).

On April 23, 2015, the Commission issued its Order Requesting Proposed Procedural Schedule, requiring DEC, DEP and the Public Staff (collectively, the Parties) to file a proposed procedural schedule that provides an opportunity for DEC, DEP, the Public Staff and Vantage to discuss the recommendations in the audit report, reach agreement where possible on the audit report recommendations; for DEC, DEP and the Public Staff to file a statement, or separate statements, detailing their points of agreement and disagreement; for all interested parties to file comments on the audit report recommendations and the statements filed by DEC, DEP, and the Public Staff; and for all parties to file proposed orders.

On May 6, 2015, the Parties filed a Joint Motion for Procedural Schedule. On May 18, 2015, the Commission issued its Order on Procedural Schedule.

On June 19, 2015, and July 8, 2015, the Parties filed Joint Motions for Extensions of Time, which were granted by the Commission on June 19, 2015, and July 10, 2015.

On August 3, 2015, the Parties filed a joint statement regarding the Audit Report (Joint Statement).

No other party intervened in this docket or filed comments on the Audit Report or Joint Statement.

On October 2, 2015, the Parties filed a joint proposed order.

VANTAGE AUDIT RECOMMENDATIONS

The Audit Report provides the results of the first independent, third-party audit conducted pursuant to Regulatory Condition No. 5.8 and contains 24 recommendations. The remainder of this Order presents Vantage's audit recommendations grouped by the headings under which they appeared in the Audit Report, with the exception of RECOMMENDATION NO. VII-R3. Each recommendation or group of recommendations is followed by a summary of the record related to such recommendation or group of recommendations and the Commission's conclusions with respect to each recommendation or group of recommendations.

CHAPTER III – AFFILIATE GOODS AND SERVICES PRICING

1. RECOMMENDATION NO. III-R1 – DEC and DEP should be required to develop a process for identifying those services that have an open market competitor and perform comprehensive assessments of the competiveness of such services as required by Regulatory Condition No. 5.2.

RECOMMENDATION NO. III-R2 – DEC and DEP should be required to perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods acquired and provided by DEC and DEP as required by Regulatory Condition No. 5.2.

> **Joint Statement:** Regulatory Condition No. 5.2 provides in pertinent part that: *[e]xcept as to transactions between DEC and [DEP] pursuant to filed and approved service agreements and lists of services* . . . DEC and [DEP] shall seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services . . . . To this end, no less than every four years DEC and [DEP] shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services they receive from a Utility Affiliate, DEBS [Duke Energy Business Services LLC] . . . , another Non-Utility Affiliate, and a Nonpublic Utility Operation, including periodic testing of services being provided internally or obtained individually through outside providers.
>
> . . . DEC and [DEP] shall have the burden of proving that all goods and services provided by either of them to Duke Energy, a Non-Utility Affiliate, any other Affiliate, or a Nonpublic Utility Operation have been provided on the terms and conditions comparable to the most favorable terms and conditions reasonably available in the market, which shall include a showing that such goods or services have been provided at the higher of cost or market price. To this end, no less than every four years DEC and [DEP] shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services provided by either of them to a Utility Affiliate, DEBS . . . , another Non-Utility Affiliate, any other Affiliate, and a Nonpublic Utility Operation.

(Emphasis added).

The Companies agree that they are required to conduct market competitiveness studies for their transactions with DEBS and other affiliates, although Regulatory Condition No. 5.2 exempts affiliate transactions between DEC and DEP from this requirement. Identifying those services that have an open market competitor and performing a comprehensive assessment of the competitiveness of such services presents some difficulties, however. Prior to the Merger between Duke Energy and Progress, Duke Energy engaged Ernst and Young LLP (EY) to perform a Market and Cost Allocation study of the services provided by DEBS and Duke Energy Shared Services (together, Service Company) to DEC for the period ending December 31, 2008 (EY Study). According to the EY Study:

> [f]or the majority of Services, we noted that the level of activities provided by the Service Company for each Service could not be easily replicated by one vendor, as part of the standard services offered by the vendor. Additionally, without obtaining detailed pricing information from vendors which aligned to the Services provided by the Service Company, market comparables were not readily available. The consensus of the project team . . . was that this sort of solicitation for information from third parties would not be appropriate for a number of reasons, as outlined in the report.

EY Study at page 1.

In light of the above, DEC and DEP are presently exploring the process by which they would identify the services that have an open market competitor and to evaluate the competitiveness of those services. It may be that the market/cost study contemplated by Regulatory Condition No. 5.2 would address that issue.

The Public Staff, DEC, and DEP continue to discuss this concern, as well as the scope of the comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs of services acquired and provided by DEC and DEP as required by Regulatory Condition No. 5.2. With regards specifically to goods, DEC and DEP agree with the recommendation and will develop a process to document market competitiveness for affiliate asset transfers.

Commission Conclusion: Based on the foregoing and taking into account the Parties' efforts at resolving these issues, the Commission concludes that the Parties are addressing the concerns articulated in Audit Report RECOMMENDATION NOS. III-R1 and III-R2 and shall continue to discuss this matter. The Commission notes that the comprehensive, non-solicitation based assessments required by Regulatory Condition No. 5.2 are due later this year.

2. RECOMMENDATION NO. III-R3 – The Internal Audit Department should conduct internal audits of DEP rate schedule for properties owned or occupied by affiliates similar to those conducted for DEC.

Joint Statement: DEC and DEP agree with this recommendation and have indicated to the Public Staff that they will comply with it.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies' agreement to comply with Audit Report RECOMMENDATION NO. III-R3 resolves the concerns articulated therein. The Companies shall file a statement notifying the Commission that this internal audit is complete within three months from the date of this Order.

CHAPTER IV – LOCATION OF CORE UTILITY FUNCTIONS

3. RECOMMENDATION NO. IV-R1 – Duke Energy should complete the process currently underway to clarify how to determine whether new or future functions should be designated as core utility functions or as carve outs to the core utility functions and then an agreed upon process for future questions should be developed.

Joint Statement: After meeting with the Public Staff to discuss this issue, DEC and DEP have provided the Public Staff with a written proposal to (1) clarify how new or future functions should be designated as core utility functions, and (2) develop a process to guide future actions under Regulatory Condition Nos. 5.3 and 10.2. The Public Staff, DEC, and DEP continue to discuss this issue.

Commission Conclusion: On September 16, 2015, the Commission issued an Order Requesting Comments regarding a notice and application filed by the Companies in Docket Nos. E-2, Sub 998 and E-7, Sub 986, in which the Companies requested that the Commission amend Regulatory Condition Nos. 5.3 and 10.1. On November 25, 2015, the Commission issued an Order Approving Transfer of Employees and Amendment to Regulatory Condition that accepted the Companies' proposed amendments. The Commission concludes that the concerns articulated in Audit Report RECOMMENDATION NO. IV-R1 have been resolved by the November 25, 2015 Order in that proceeding.

CHAPTER V – COMPLIANCE WITH FILED SERVICE AGREEMENTS FOR GOODS AND SERVICES

4. RECOMMENDATION NO. V-R1 – A formalized procedure should be established for the purpose of making necessary modifications, clarifications or corrections to the service agreements and lists of services.

RECOMMENDATION NO. V-R2 – DEC and DEP should carefully review and edit, and, as necessary, update the affiliate agreements and clearly label all attachments, appendices, and exhibits for submittal to the Commission within three months from the date the Commission issues an Order on this audit.

Joint Statement: DEC and DEP agree with the need to develop and implement a formal process to review and update the service agreements and file them with the state commissions. The Companies have developed an internal process that will account for the multiple jurisdictions that the affiliate agreements involve. As part of that process, which is underway, the Companies will update the affiliate agreements as necessary. The Companies respectfully reserve the right to request additional time beyond the three-month period after the Commission's Order to complete this task. Although the Companies are working diligently to execute the process to prepare amendments to the affiliate agreements as necessary in North Carolina, the amendments potentially impact the four regulated public utility affiliates and five other state jurisdictions, and the Companies may need additional time to ensure that all changes are agreed to by the impacted jurisdictions.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies' agreement to comply with Audit Report RECOMMENDATION NOS. V-R1 and V-R2 resolves the concerns articulated therein. The Companies shall file a statement notifying the Commission that a formal procedure has been established and that the review to update the affiliate agreements has been completed within three months from the date of this Order.

5. RECOMMENDATION NO. V-R3 – Costs charged against Service Requests should be monitored and the disposition of any overages recorded.

Joint Statement: DEC and DEP respectfully disagree with this recommendation. Service Requests (alternatively referred to as Service Request Forms) are forms that are used to internally monitor affiliate requests for services. They are not used for any accounting purpose; instead they are used to initiate, track and monitor affiliate requests for services. Significantly, the Service Requests indicate the affiliates involved, the requested services to be provided, confirmation that the provision of services does not have an adverse impact on the supplying utility's own operations, and a *forecasted* cost of those services. Other than the forecasted cost of the services, the information on the Service Request Form is used to do an internal check to ensure that requested services conform to existing service agreements and services lists, and the Code of Conduct. The forecasted cost of the services is not used for any accounting purposes, but instead to give an idea of the scope of the provision of services so that those reviewing the requests are aware that there is a budgetary impact to receiving services from another utility.

Because there are no cost caps imposed on the goods and services provided for and received by DEC and DEP, there is no "overage" on an affiliate transaction. All of DEC's and DEP's affiliate transactions are subject to review by the Public Staff or the Commission and, as part of that review, the *actual* amounts, instead of predicted amounts, of affiliate charges may be reviewed.[1]

After discussions with the Companies, the Public Staff agrees that the Companies should not be required to implement Recommendation No. V-R3 concerning the monitoring of costs charged against Service Requests.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies shall not be required to implement Audit Report RECOMMENDATION NO. V-R3 concerning the monitoring of costs charged against Service Requests.

CHAPTER VI – DIRECT CHARGING, ASSIGNMENT, AND COST ALLOCATION

6. RECOMMENDATION NO. VI-R1 – The annual filing date for the CAM should be changed to November 15 for the CAM going into effect for the following year.

RECOMMENDATION NO. VI-R2 – The descriptions regarding cost allocation methods and cost categories should be updated to ensure that language in the CAM and service agreements are consistent and up-to-date.

RECOMMENDATION NO. VI-R3 – Reporting on the appropriateness of cost allocation factors should be enhanced.

Joint Statement: These recommendations pertain to DEC's and DEP's compliance with Regulatory Condition Nos. 5.5 and 5.6.

[1] Regulatory Condition No. 5.8 provides that DEC's and DEP's affiliate transactions are subject to ongoing Commission review.

DEC, DEP, and the Public Staff have discussed changing the filing date to November 15 for the cost allocation manual (CAM) going into effect for the following year. In these conversations, DEC and DEP raised the concern that if the filing date for the CAM was changed to November 15 for the CAM going into effect the following year, DEC or DEP would not have the data necessary to complete it at the time of filing because it takes most of the calendar year to compile the necessary data for filing. Under those circumstances, DEC and DEP are concerned that they would be filing updates and revisions to the CAM in the following year, resulting in a piecemeal, rather than comprehensive, CAM filing. The Companies also cited Regulatory Condition No. 5.6, which requires that interim changes shall be made to the CAM, if and when necessary, and shall be filed with the Commission. Thus, both the Commission and the Public Staff are notified, in advance, of any revisions. Therefore, DEC and DEP requested, and the Public Staff agreed, to maintain the current Regulatory Condition No. 5.5(c), which requires the CAM to be updated annually and be filed no later than March 31 of the year that the CAM is to be in effect and to maintain Regulatory Condition No. 5.6, which requires advance notice for interim changes to the CAM.

DEC and DEP also agree that they will update the CAM to conform to the affiliate service agreements as part of their efforts to update the affiliate service agreements, as discussed above.

DEC and DEP also agree to enhance their reporting on the appropriateness of cost allocation factors.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies shall not be required to implement Audit Report RECOMMENDATION NO. VI-R1 regarding the annual filing date of the CAM. The Commission further concludes that the Companies' agreement to comply with Audit Report RECOMMENDATION NOS. VI-R2 and VI-R3 resolves the concerns articulated therein. The Companies shall file a statement notifying the Commission that the CAM has been updated and conforms to the affiliate service agreements within three months from the date of this Order.

7. RECOMMENDATION NO. VI-R4 – Direct charging in all service functions should continue to increase through continued analysis of work requirements and the correlation between allocation and work functions should be increased by finding allocation factors with better correlation to activity than the "three factor formula."

Joint Statement: DEC and DEP will coordinate with the implementation of Recommendation No. VI-R3, as part of an improved process for updates and filing of changes to the Service Agreements. There are service function areas where the Companies are able to continue to identify allocation factors with better correlation to activities than the three-factor formula. There are governance functions, however, where no better correlation exists, and, in those cases, the Companies will continue to use the three-factor formula.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies are addressing the concerns articulated in Audit Report RECOMMENDATION NO. VI-R4.

8. RECOMMENDATION NO. VI-R5 – Improvements should be made in practices related to insufficient documentation of labor charging and inadequate processes to access, report, monitor, and communicate compliance with time submission requirements on an expedited basis, as recommended by the Internal Audit Staff.

Joint Statement: The Companies agree with this recommendation and intend to comply with their own internal audit staff's recommendation.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies' agreement to comply with Audit Report RECOMMENDATION NO. VI-R5 resolves the concerns articulated therein. The Companies shall file a statement generally describing the improvements in such practices within three months from the date of this Order.

9. RECOMMENDATION NO. VI-R6 – A procedure should be implemented for notifying the Commission of changes in sub-allocation factors in order to fully comply with Regulatory Condition No. 5.5(d).

Joint Statement: Regulatory Condition No. 5.5(d) provides that "[n]o changes shall be made to the procedures for direct charging, direct assigning, or allocating the costs of Affiliate transactions or to the method of accounting for such transactions associated with goods and services (including Shared Services provided by DEBS or PESC) . . ." without giving 15 days advance notice to the Commission of the proposed changes in accordance to Regulatory Condition No. 5.6. The Companies expressed some concern with this recommendation to the Public Staff because, during the course of the year, the business will have projects or work processes requiring a new allocation step for an approved service using an approved allocation method that does not include certain entities in Duke Energy. An example would be a Marketing and Customer Relations Service only being provided to Midwest entities, necessitating a new allocation based on number of customers only in the Midwest. Both the Service Function Description and the Allocation Method are included in the Service Agreements and CAM on file with the Commission. Therefore, the Companies do not believe that advance notice of these circumstances is required under Regulatory Condition No. 5.5, as they have not changed the procedures or the method of allocating such costs for a given service. If the Companies were to use an allocation method not approved for a given service then, at that time, the Companies believe they are required to provide advance notice.

The Public Staff observes that the "sub-allocation factor" issue results from implementation of a new project or work process by an affiliate that is allocated to other affiliates using an allocation factor that is derived from a subset of the data used to compute the factors for an existing allocation method. For example, pursuant to Section H of the CAM, the number of customers ratio is reflected as the appropriate method used to allocate costs from DEBS related to the "design and administration of sales and demand-side management programs" function. The number of Midwest electric customers is a sub-allocation factor (allocation pool), based on the number of customers ratio allocation method, that the Companies have used for purposes of allocating the costs related to "design and administration of sales and demand-side management programs" that benefit the Midwest electric operations. The Public Staff agrees that advance notice of a change of a sub-allocation factor, as illustrated above, is not required under Regulatory Condition No. 5.5.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies shall not be required to implement Audit Report RECOMMENDATION NO. VI-R6.

10. RECOMMENDATION NO. VI-R7 – A summary schedule of direct and allocated labor charges for DEC and DEP should be included in the annual reports of affiliate transactions.

RECOMMENDATION NO. VI-R8 – Summary descriptions of significant components of transfers between DEC, DEP, and their utility affiliates should be included in the annual reports of affiliate transactions.

RECOMMENDATION NO. VII-R3 – Changes to the format of the annual reports on affiliate transactions should be finalized.

Joint Statement: DEC and DEP have recently engaged in discussions with the Public Staff about improving the format and content of the annual reports of affiliate transactions. The Companies are generally agreeable to the above recommendations; however, they request additional discussion on the threshold of what should be included in the summary schedules and descriptions recommended above, as well as what qualifies as a "significant" component of an affiliate transfer between DEC, DEP, and their utility affiliates. DEC and DEP agree to continue discussions with the Public Staff on enhancing the annual affiliate transaction report.

Commission Conclusion: On September 15, 2015, the Companies filed a revised Annual Report of Affiliate Transactions for 2014, which reflects agreement of the Companies and the Public Staff regarding report format. The Commission concludes that the Parties have effectively addressed the concerns articulated in Audit Report RECOMMENDATION NOS. VI-R7, VI-R8, and VII-R3.

CHAPTER VII – REPORTING AND REVIEW REQUIREMENTS[1]

11. RECOMMENDATION NO. VII-R1 – Compliance with Regulatory Condition 5.12 should be strengthened by including transactions between DEBS and the Operating Companies in the universe of affiliate transactions from which samples are selected and, if applicable, cost allocation percentages should be tested as part of the internal audit of affiliate transactions.

Joint Statement: Regulatory Condition No. 5.12 provides, in pertinent part:

> Transactions between DEC or [DEP] and Duke Energy, other Affiliates, or the Nonpublic Utility Operations, transactions between DEC and [DEP], and other transactions between or among Affiliates if such transactions are reasonably likely to have a significant Effect on DEC's or [DEP's] Rates or Service, shall be reviewed at least biannually by Duke Energy Corporation's internal auditors.

[1] RECOMMENDATION NO. VII-R3 was previously addressed in this Joint Statement.

The Companies agree to include transactions between DEBS and the Operating Companies in the universe of affiliate transactions going forward to strengthen compliance with Regulatory Condition No. 5.12.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies' agreement to comply with Audit Report RECOMMENDATION NO. VII-R1 resolves the concerns articulated therein.

12. RECOMMENDATION NO. VII-R2 – The Corporate Audit Staff's planned schedule of internal audits should include a comprehensive audit of the cost allocation methodologies used by the Operating Companies and the Service Company.

Joint Statement: The Companies agree with the recommendation.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies' agreement to comply with Audit Report RECOMMENDATION NO. VII-R2 resolves the concerns articulated therein.

CHAPTER VIII – COMPLIANCE WITH COMMITMENTS

13. RECOMMENDATION NO. VIII-R1 – A central location should be established as a digital repository for the supporting documentation of the compliance-related OpenPages task.

Joint Statement: OpenPages plays a vital role in ensuring DEC and DEP continue to comply with the Regulatory Conditions, Code of Conduct, Service Agreements, and Commission orders. OpenPages operates more broadly than North Carolina regulatory requirements as it also tracks federal requirements, National Electric Reliability Corporation requirements and data privacy issues. OpenPages operates by regularly tracking and requesting that the affected personnel attest that they have complied with the pertinent requirement or that they are familiar with the Regulatory Conditions involved. In some cases, the attestation requires the assignee to save any supporting documentation that will explain how they complied, which is to be provided upon request. The Companies disagree with the requirement that they revise OpenPages to establish a central repository for supporting documentation showing completion of OpenPages tasks. Supporting documentation showing completion of an OpenPages task, for example, would include DEC's semi-annual report on the transition to direct charging and positive time reporting, required to be filed at the Commission for the two years following the Merger. OpenPages requires the attorney that filed the report to affirm in OpenPages that the reports have been filed as required. It does not require, however, that the attorney then upload the report to a centralized database as proof.

Compliance with OpenPages tasks may be verified without the uploading and storage of a publicly-filed document, and the Companies disagree with this recommendation for the following reasons. First, supporting documentation for the numerous OpenPages requirements includes highly sensitive and confidential documents. OpenPages is designed to ensure compliance with certain regulatory requirements; it is not designed as a secure repository for confidential documents. Creating a repository for such confidential documents would require additional and costly enhancements to the cyber-security of OpenPages.

Second, employees in the Companies' State Regulatory Compliance Department can confirm that supporting documentation exists at any time, but uploading every document is time-consuming and cumbersome. OpenPages is designed to operate to remind users of requirements and to have them attest that they have completed the requirement in a "user-friendly" way that fosters ease for users.

Third, the Companies note that Vantage did not identify any Regulatory Conditions or other merger-related compliance requirements that were attested to but were not actually complied with, once the supporting documentation was reviewed. The Companies are aware that obtaining and providing all supporting documentation to Vantage for its review took some time; however, this was the first external audit focusing on OpenPages, and the Companies had never had to gather supporting documentation for external review that quickly before. Lessons learned from this first audit will result in DEC and DEP being better prepared to gather the supporting documentation for auditors' review in the future. For the foregoing reasons, DEC and DEP respectfully disagree with this recommendation.

The Public Staff agrees that establishing a central location as a digital repository for the supporting documentation may not be necessary if the Companies can establish a procedure to ensure that the Companies can obtain and provide any supporting documentation requested by the Public Staff or a third-party auditor in a timely manner. Therefore, the Public Staff recommends that the Companies establish such a procedure and file it with the Commission within two months from the date the Commission issues an Order on the audit. The Public Staff reserves the right to revisit the issue of a central repository if the Companies are unable to provide requested supporting documentation in a timely manner in the future. The Companies agree with the Public Staff's recommendation.

Commission Conclusion: Based on the foregoing and taking into account the Parties' efforts at resolving this issue, the Commission concludes that the Parties are addressing the concerns articulated in Audit Report RECOMMENDATION NO. VIII-R1. The Companies shall establish a procedure to ensure that the Companies can obtain and provide any supporting documentation showing completion of OpenPages tasks requested by the Public Staff or a third-party auditor in a timely manner and shall provide the new procedure to the Public Staff. The Companies shall file a statement notifying the Commission that such a procedure has been established and whether the procedure is acceptable to the Public Staff within three months from the date of this Order.

14. RECOMMENDATION NO. VIII-R2 – The OpenPages task listing should be modified by adding an additional field that identifies the specific Regulatory Condition or other regulatory requirement to which the task is related.

Joint Statement: OpenPages is a web-based tool that is essentially a series of related forms that feed a single database. Currently, the series of forms that support a Regulatory Condition or other regulatory requirement include:

- Requirement – this is the verbatim Regulatory Condition or other regulatory requirement directly from the Merger Order. On this form, there is a citation that specifically states the source of the requirement. For example, the requirement named CoC_R01 has a citation that states: "Code of Conduct; Docket No. E-2, Sub 998; Docket No. E-7, Sub 986; A. Independence and Information Sharing".

- Task(s) – these forms are directly related to each requirement as a parent-child relationship in the database and the web tool. The tasks are presented to the assignee to explain how and what the assignee must perform to stay compliant with the requirement. There may be multiple tasks and thus multiple assignees. The combination of the multiple tasks make up the full compliance program for the given requirement.

The Companies believe that because of the method in which the data was extracted from OpenPages for the purpose of responding to the audit data requests, that the parent-child relationship was lost when spreadsheets at the requirement level were provided separately from the spreadsheets at the task level. This raw data extraction made it confusing for Vantage to compile the citations. To add a data element on each task that duplicates the citation, which is currently on each requirement, would require thousands of duplications of a data element that currently exists and is easily accessible in OpenPages by the assignee. Instead of duplicating data, the Companies propose to make OpenPages more efficient and effective in subsequent audits by building an OpenPages report that will have the necessary data extracted into a single spreadsheet so that no data elements are isolated and thus out of context.

The Public Staff agrees that modifying the OpenPages task listing to include an additional field that would identify the Regulatory Condition or other regulatory requirement to which the task is related may not be necessary if the Companies can build a report to extract the data from OpenPages such that the Regulatory Condition or other regulatory requirement associated with each task is identified. The Public Staff recommends that the Companies build this report within two months from the date the Commission issues an Order on the audit. The Public Staff reserves the right to revisit this recommendation in the future if the Companies are unable to build a report that successfully extracts the necessary information into a single spreadsheet. The Companies agree with the Public Staff's recommendation.

Commission Conclusion: Based on the foregoing and taking into account the Parties' efforts at resolving this issue, the Commission concludes that the Parties are addressing the concerns articulated in Audit Report RECOMMENDATION NO. VIII-R2. The Commission concludes that modifying the OpenPages task listing to include an additional field that would identify the Regulatory Condition or other regulatory requirement to which the task is related may not be necessary if the Companies can build a report to extract the data from OpenPages such that the Regulatory Condition or other regulatory requirement associated with each task is identified. The Companies shall build the report and provide it to the Public Staff and file a statement notifying the Commission that it has built such a report and whether the report is acceptable to the Public Staff within three months from the date of this Order.

15. RECOMMENDATION NO. VIII-R3 – Compliance training courses should be updated in a manner that is not only informative but interesting and timely.

Joint Statement: The Companies agree and are working toward making the recommended improvements in their compliance training materials.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies' agreement to comply with Audit Report RECOMMENDATION NO. VIII-R3 resolves the concerns articulated therein. The Companies shall make the recommended improvements in their compliance training materials and file a statement notifying the Commission that the recommended improvements have been made within three months from the date this Order.

16. RECOMMENDATION NO. VIII-R4 – Inquiries from employees about compliance matters and concerns should be tracked and used as the basis for developing examples and scenarios for subsequent training courses, and greater use should be made of focus groups.

Joint Statement: The Companies agree with this recommendation. The Companies in general, and the State Regulatory Compliance Department in particular, have worked hard to foster a "culture of compliance" that encourages identification of, and inquiries about, compliance issues. To that end, inquiries specifically requesting legal advice should remain subject to the attorney-client privilege, as appropriate, so that tracking compliance questions and concerns under this recommendation does not chill employees' inquiries about compliance issues.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies' agreement to comply with Audit Report RECOMMENDATION NO. VIII-R4 resolves the concerns articulated therein.

17. RECOMMENDATION NO. VIII-R5 – The quality and effectiveness of training programs should be validated and format or content should be modified if necessary.

Joint Statement: This recommendation is based on an Audit Report finding that the Companies' training courses are not validated by professional test writers or Industrial Psychologists to assure that they are effective and meet their objectives.[1] Although neither the finding nor the recommendation describes the standards of effectiveness, the Companies agree to measure the quality and effectiveness of training materials through the use of focus group sessions, follow-up surveys, test questions and real scenario based education materials. The input from these methods will be considered for development of training materials.

[1] Audit Report, Finding VIII-F9, p. 117.

Commission Conclusion: Based on the foregoing, the Commission concludes that the Companies' agreement to comply with Audit Report RECOMMENDATION NO. VIII-R5 resolves the concerns articulated therein. The Companies shall measure the quality and effectiveness of training materials through the use of focus group sessions, follow-up surveys, test questions and real scenario based education materials, and consider the input from these methods for development of training materials and file a statement notifying the Commission that these tasks have been completed within three months from the date of this Order.

CHAPTER X – RESPONSE TO LIBERTY RECOMMENDATIONS AND COMMISSION ORDER

18. RECOMMENDATION NO. X-R1 – DEC should be ordered to complete the market analysis related to NorthSouth that was specified in the Liberty Audit and report the results to the Public Staff and the next auditor.

Joint Statement: NorthSouth provides DEC property, liability, and automobile insurance coverage. To comply with the Liberty Audit recommendations, NorthSouth provided the Public Staff additional information on its market analysis of property, liability and automobile insurance coverage that would be provided by non-affiliated third parties. The information provided was intended to show that the cost for such coverage from non-affiliated third parties would have exceeded the amount charged by NorthSouth.

As discussed previously, under Regulatory Condition No. 5.2, the Companies are to conduct market competitiveness studies in 2016 of any goods and services they receive from Non-Utility Affiliates, which will include any goods and services provided by NorthSouth. The Public Staff has reviewed the information provided by DEC, DEP and NorthSouth. After discussions on its content, the Companies and the Public Staff agree that, in the very near future, they will discuss further the scope and contents of the market studies related to NorthSouth's services for inclusion in the 2016 market competitiveness studies required by Regulatory Condition No. 5.2.

Commission Conclusion: Based on the foregoing and taking into account the Parties' efforts at resolving these issues, the Commission concludes that the Parties are addressing the concerns articulated in Audit Report RECOMMENDATION NO. X-R1 and should continue to discuss this matter and include the outcome of their discussions regarding the scope and contents of the market studies related to NorthSouth's services in the 2016 market competitiveness studies required by Regulatory Condition No. 5.2.

IT IS, THEREFORE, ORDERED that the Companies shall perform the actions they have agreed to undertake and otherwise comply with this Order as set out and discussed herein.

ISSUED BY ORDER OF THE COMMISSION.
This the __29th__ day of __March________, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-64, SUB 1
DOCKET NO. G-51, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request for Exemption from Prohibition	)	ORDER APPROVING MASTER
of Master Metering by The Cypress of Raleigh,	)	METERING EXEMPTION
LLC, Wake County, North Carolina	)	

BY THE COMMISSION: On July 7, 2016, The Cypress of Raleigh, LLC (Applicant) filed a request in the above-captioned dockets for an exemption from the master metering prohibition established in G.S. 143-151.42. In order to promote energy conservation, the statute provides that it shall be unlawful for new residential buildings to be served by a master meter for electric or natural gas service. However, the statute includes several exceptions to the master metering prohibition, one of which is homes for the elderly.

In summary, the Applicant states that it is expanding its home for the elderly at 8801 Cypress Lakes Drive, Raleigh, Wake County, North Carolina, by building a new building containing 57 residential units. Further, the Applicant states that all portions of the development will be for residents who are 62 years of age or older. The Applicant also attached a copy of the Membership Agreement that it will use, which will be a part of the Purchase and Sale Agreement entered into with residents.

On July 25, 2016, the Public Staff filed a letter stating that it has reviewed the Applicant's request for an exemption from the master metering prohibition set forth in G.S. 143-151.42 and recommends that the Commission grant the request.

Based on the foregoing and the record, the Commission finds good cause to grant the request of The Cypress of Raleigh, LLC, to be exempt from the master metering prohibition of G.S. 143-151.42.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the __27th__ day of July, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

ELECTRIC – RATE INCREASE

DOCKET NO. E-22, SUB 532

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric & Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)	ORDER APPROVING RATE INCREASE AND COST DEFERRALS AND REVISING PJM REGULATORY CONDITIONS

HEARD: Wednesday, August 17, 2016, at 7:00 p.m., Halifax County Historic Courthouse, 10 N. King Street, Halifax, North Carolina

Tuesday, September 13, 2016, at 7:00 p.m., Pasquotank County Courthouse, 206 E. Main Street, Courtroom C, Elizabeth City, North Carolina

Wednesday, September 14, 2016, at 7:00 p.m., Commissioner's Meeting Room, Dare County Administration Building, 954 Marshall Collins Drive, Manteo, North Carolina

Wednesday, September 21, 2016, at 7:00 p.m., Martin County Courthouse, 305 E. Main Street, Williamston, North Carolina

Tuesday and Wednesday, October 4 and 5, 2016, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

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BY THE COMMISSION: On March 1, 2016, pursuant to Commission Rule R1-17(a), Virginia Electric and Power Company (VEPCO), d/b/a in North Carolina as Dominion North Carolina Power (DNCP or the Company), filed notice of its intent to file a general rate case application. On the same date, DNCP filed a letter informing the Commission of the Company's intention to propose accounting adjustments to include an appropriate level of amortization of deferred post-in-service costs associated with the Company's Warren County Power Station (Warren County CC) in its rate case revenue requirement.

On March 4, 2016, DNCP filed a Response in Opposition to a motion filed on February 25, 2016, by Nucor in Docket No. E-22, Sub 479, to impose on DNCP additional jurisdictional allocation study filing requirements. On March 7, 2016, CIGFUR I filed a letter stating its position on Nucor's February 25, 2016 motion. On March 17, 2016, the Commission issued an Order denying Nucor's motion and granting alternative relief. In compliance with Paragraph 4 of the Commission's March 17, 2016 Order, DNCP filed a Single CP Cost of Service Study on May 31, 2016.

On March 31, 2016, the Company filed its Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina (Application), along with a Rate Case Information Report Commission Form E-1 (Form E-1),[1] and the direct testimony and exhibits of J. Kevin Curtis, Vice President - Technical Solutions; Mark D. Mitchell, Vice President – Generation Construction; James R. Chapman, Senior Vice President - Mergers & Acquisitions and Treasurer; Robert B. Hevert, Managing Partner of Sussex Economic Advisors, LLC; Paul M. McLeod, Regulatory Advisor - Regulatory Accounting Group; Bruce E. Petrie, Manager - Generation System Planning; Michael S. Hupp, Jr., Director - Power Generation Regulated Operations; Glenn A. Pierce,[2] Manager – Regulation; and Paul B. Haynes, Director - Regulation. The Company also filed requests for authority to use certain deferred accounts to implement a levelization methodology for its nuclear unit and refueling maintenance outage expenses, as well as relief from the conditions imposed by the Commission in its April 19, 2005 Order approving DNCP's integration into PJM Interconnection, Inc. (PJM), in Docket No. E-22, Sub 418 (PJM Order).

Petitions to intervene were filed by CIGFUR I on March 7, 2016, Nucor on April 4, 2016, NCSEA on April 5, 2016, and CUCA on August 1, 2016. Notice of intervention was filed by the Attorney General on June 13, 2016.

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[1] An erratum to DNCP's Form E-1 was filed on July 13, 2016, redacting confidential information from the original.

[2] Witness Pierce's direct testimony was subsequently adopted by witness Haynes.

The Commission subsequently entered Orders granting the petitions to intervene of CIGFUR I, NCSEA, Nucor, and CUCA. The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19. The Attorney General's intervention is recognized pursuant to G.S. 62-20.

On April 20, 2016, Nucor filed a motion requesting *pro hac vice* admission before the Commission for Damon E. Xenopoulos. On June 3, 2016, DNCP filed a motion requesting *pro hac vice* admission before the Commission for Joseph K. Reid, III. Orders allowing these motions for limited practice before the Commission were issued on April 26, 2016, and June 7, 2016, respectively.

On April 26, 2016, the Commission issued an Order Establishing General Rate Case and Suspending Rates. On May 10, 2016, the Commission issued an Order Scheduling Hearings and Requiring Public Notice.

On May 2, 2016, DNCP filed an Application for an Accounting Order to Defer Certain Capital and Operating Costs Associated with Brunswick County Power Station Addition in Docket No. E-22, Sub 533. On May 3, 2016, the Company filed a Motion for Reconsideration of the Commission's March 29, 2016 Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility in Docket No. E-22, Sub 519.

On May 17, 2016, the Commission issued an Order Consolidating Dockets, which consolidated this general rate case with DNCP's pending petition for deferral accounting authority to defer post-in-service costs associated with commercial operation of the Brunswick County Power Station (Brunswick County CC) in Docket No. E-22, Sub 533, and the Company's motion for reconsideration in Docket No. E-22, Sub 519, of the Commission's Order denying the Company's request to defer post-in-service costs associated with commercial operation of the Warren County CC.

On July 8, 2016, DNCP submitted a supplemental filing pertaining to the Company's request for relief from the conditions imposed by the PJM Order, supported by the supplemental direct testimony of Michael S. Hupp, Jr. and James R. Bailey, Manager – Planning and Strategic Initiatives – Electric Transmission Department.

On August 12, 2016, DNCP filed the supplemental direct testimony and exhibits of James R. Chapman, Deanna R. Kesler, Regulatory Consultant in Demand Side Planning – Integrated Resource Planning, Bruce E. Petrie, Paul M. McLeod, and Paul B. Haynes, as well as applicable updated NCUC Form E-1 information report items.

On September 7, 2016, the Public Staff filed the direct testimony and exhibits of Jack L. Floyd, Engineer, Electric Division; John R. Hinton, Director, Economic Research Division; Michael C. Maness, Assistant Director, Accounting Division; James S. McLawhorn, Director, Electric Division; Jay B. Lucas, Engineer, Electric Division; Dustin R. Metz, Engineer, Electric Division; Katherine A. Fernald, Assistant Director, Accounting Division; and Darlene P. Peedin, Supervisor, Electric Section, Accounting Division. On the same day, Nucor filed the direct testimony of J. Randall Woolridge, Professor of Finance and University Fellow at Pennsylvania State University; Lane Kollen, Vice President and Principal, Kennedy and Associates; Jacob M.

Thomas, Senior Project Manager, GDS Associates, Inc.; and witness Dennis W. Goins, Economic Consultant, Potomac Management Group.

On September 7, 2016, CUCA filed a motion requesting a one-day extension of time for it and the other intervenors to file their testimony and exhibits. The Commission issued an Order allowing CUCA's motion on September 8, 2016.

On September 8, 2016, CUCA filed the direct testimony of Kevin O'Donnell, President of Nova Energy Consultants, Inc.; CIGFUR I filed the direct testimony of Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates, Inc.; and Nucor filed the supplemental direct testimony of witness Goins.

On September 26, 2016, DNCP filed the rebuttal testimony and exhibits of J. Kevin Curtis, Mark D. Mitchell, James R. Chapman, Robert B. Hevert, Paul M. McLeod, Mark C. Stevens, Director of Regulatory Accounting, James I. Warren, member of the law firm of Miller & Chevalier Chartered, Michael S. Hupp, Jr., and Paul B. Haynes.

On September 28, 2016, DNCP filed a list of witnesses, the order of witnesses, and estimated time for cross-examination of the witnesses.

On October 3, 2016, the Public Staff filed a notice of settlement in principle. In addition, the Public Staff filed a motion to delay the hearing of expert testimony. The Public Staff requested that the Commission convene the hearing as scheduled on October 4, 2016, at 9:30 a.m., to receive public witness testimony, but delay the start of the testimony by expert witnesses until 1:30 p.m. that afternoon.

Also, on October 3, 2016, DNCP, the Public Staff, and CIGFUR I (Stipulating Parties) entered into and filed an Agreement and Stipulation of Settlement (Stipulation). In addition, DNCP and the Public Staff filed a joint motion to excuse witnesses.

In support of the Stipulation, on October 3, 2016, DNCP filed the testimony and exhibits of J. Kevin Curtis, Robert B. Hevert, and Paul B. Haynes, and the joint testimony of Mark C. Stevens and Paul M. McLeod; and the Public Staff filed the testimony and exhibits of Katherine A. Fernald and John R. Hinton.

On October 4, 2016, Nucor filed a motion to postpone the hearing of expert testimony for 14 calendar days following the filing of the final version of the Stipulation and the additional expert witness testimony, if any. In summary, Nucor asserted that it needed additional time to prepare for the hearing due to the Stipulation recently filed by DNCP, the Public Staff and CIGFUR I.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Halifax:	Belinda Joyner, Tony Burnette, Larry Abram, Dean Knight, Janice Bellamy, Regina Moffett, and Betty Bennett
Elizabeth City:	Peter Bishop

Manteo:	Robert Woodard, Walter L. Overman, Dwight Wheless, Robert C. Edwards, Manny Medeiros, and Judy Williams
Williamston:	Martha McDonald, John McDonald, Tawilda Bryant, Rhett B. White, Ronnie Smith, John Liddick, Linda Gibson, Samantha Komar, Louise Simmons, Jerry McCrary, Glenda Barnes, and Reginald Williams, Jr.
Raleigh:	No public witnesses appeared.

On October 3, 2016, DNCP filed a Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund, pursuant to G.S. 62-135.

The matter came on for hearing on October 4, 2016, at 9:30 a.m. After determining that there were no public witnesses who desired to testify, the Chairman heard the parties' arguments on the Public Staff's motion to delay the start of the expert witness testimony until 1:30 p.m. that afternoon, and Nucor's motion to postpone the hearing for 14 calendar days. The Chairman ruled that the hearing of expert testimony would commence at 1:30 p.m., on October 4, 2016. Further, the Chairman ruled that the concerns of Nucor and other parties about needing more time to prepare direct testimony and cross-examination regarding the Stipulation would be addressed by rearranging the order of witnesses and other accommodations, if such accommodations became reasonably necessary during the hearing. Thus, the Public Staff's motion was granted, and Nucor's motion was denied, but Nucor's and the other parties' concerns about needing additional time to prepare were resolved.

The expert witness hearing began at 1:30 p.m., on October 4, 2016, and was concluded on October 5, 2016. DNCP presented the testimony of witnesses Curtis, Chapman, Mitchell, Hevert, McLeod, Stevens, Warren, Hupp, and Haynes. The testimony and exhibits of DNCP witnesses Kesler, Bailey, and Petrie were stipulated into the record. Nucor presented the testimony of witness Woolridge. The testimony and exhibits of Nucor witnesses Kollen, Thomas, and Goins were stipulated into the record. CUCA presented the testimony of witness O’Donnell. The testimony of witness Phillips was withdrawn by CIGFUR I.

The Public Staff presented the testimony of witnesses Maness, Fernald, Floyd, and McLawhorn. The testimony and exhibits of Public Staff witnesses Lucas, Peedin, Metz, and Hinton were stipulated into the record.

The pre-filed testimony of those witnesses who testified at the expert witness hearing, as well as all other witnesses filing testimony in this docket, except for CIGFUR I witness Nicholas Phillips, Jr., was copied into the record as if given orally from the stand, and their pre-filed exhibits were admitted into evidence.

On October 11, 2016, the Commission issued a notice of mailing of transcript and ordered that the parties submit briefs and/or proposed orders by November 10, 2016. On November 4, 2016, the Attorney General moved that the date by which briefs and proposed orders must be filed be extended until November 15, 2016. The motion was granted by Order issued November 8, 2016.

On November 15, 2016, the Attorney General requested a second extension to November 16, 2016. The motion was granted on November 15, 2016.

On October 12, 2016, the Commission issued an Order Approving Financial Undertaking and an Order Approving Public Notice of Temporary Rates in response to DNCP's Motion for Approval of Undertaking and Notice to Implement Temporary Rates, Subject to Refund.

On October 18, 2016, in response to a request by the Commission during the hearing, DNCP filed additional information regarding its weatherization and other energy assistance programs.

On November 15, 2016, DNCP and the Public Staff filed a late-filed exhibit, as requested by the Commission, comparing the regulatory conditions in the PJM Order with the commitments made by DNCP in the present docket.

Also on November 15, 2016, NCSEA filed a post-hearing Brief.

On November 16, 2016, CUCA filed its Proposed Findings and Brief, and Nucor and the Attorney General's Office filed post-hearing Briefs. In addition, DNCP, the Public Staff and CIGFUR I filed a Joint Proposed Order.

On December 2, 2016, the Public Staff filed a letter on behalf of the Stipulating Parties requesting that the Commission accept revisions to two paragraphs of their Joint Proposed Order regarding Nucor's motion to postpone the expert witness hearing for 14 calendar days.

On December 9, 2016, DNCP filed for informational purposes a letter of December 8, 2016, from DNCP to Nucor regarding the continuation of services to Nucor under the parties' existing contract and Schedule NS.

On December 13, 2016, DNCP and NCSEA filed a letter informing the Commission of an agreement reached between them regarding DNCP's time-of-use rate offerings.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence at the hearings, the Stipulation, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

<u>Jurisdiction</u>

1. Virginia Electric and Power Company (VEPCO) is duly organized as a public utility operating under the laws of the State of North Carolina as Dominion North Carolina Power (DNCP or Company) and is subject to the jurisdiction of the North Carolina Utilities Commission. DNCP is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public in North Carolina for compensation. DNCP is an unincorporated division of VEPCO and has its office and principal place of business in Richmond, Virginia. VEPCO is a wholly owned subsidiary of Dominion Resources, Inc. (DRI).

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including DNCP, under Chapter 62 of the General Statutes of North Carolina.

3. DNCP is lawfully before the Commission based upon its application for a general increase in its retail rates pursuant to G.S. 62-133, 62-133.2, 62-134, and 62-135 and Commission Rule R1-17.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2015, adjusted for certain known changes in revenue, expenses, and rate base through June 30, 2016.

The Application

5. In summary, by its general rate case Application, supporting testimony and exhibits filed on March 31, 2016, in this docket, DNCP sought an increase in its non-fuel base rates and charges to its North Carolina retail customers of $51,073,000, along with other relief, including cost deferrals and changes to its rate design and regulatory conditions. The Application was based upon a requested rate of return on common equity (ROE) of 10.50%, an embedded long-term debt cost of 4.889%, and DNCP's actual capital structure of 53.36% common equity and 46.64% long-term debt, as of December 31, 2015.

The Stipulation

6. On October 3, 2016, the Public Staff filed a Notice of Settlement in Principle with DNCP and CIGFUR I. On October 3, 2016, the Stipulating Parties entered into and filed the Stipulation resolving all of the issues in this proceeding among the Stipulating Parties.

7. After carefully reviewing the Stipulation, the Commission finds that the Stipulation is the product of give-and-take in settlement negotiations among the Stipulating Parties, and is material evidence entitled to be given appropriate weight by the Commission.

Revenue Requirement and Adjustments to Cost of Service

8. The Stipulation, as reflected on Settlement Exhibits I and II, provides for a stipulated increase in the revenue requirement of $25,790,000, consisting of an increase of $34,732,000 in non-fuel revenues and a decrease of $8,942,000 in base fuel revenues. The Stipulation provides for $375,722,000 of operating revenues, $299,084,000 of operating revenue deductions, and $1,040,035,000 of original cost rate base for use in establishing base rates in this proceeding.

9. The costs of rate base and operating revenue deductions reflected in and underlying the Stipulation, as well as the level of operating revenues under present rates, were prudently and reasonably incurred. These rate base costs and operating expenses are necessary for DNCP to meet its obligation to provide safe, adequate, and reliable electric service.

10. The Stipulation provides for certain accounting adjustments, which are set forth in detail at Settlement Exhibit II. The Stipulating Parties agree that settlement regarding those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The accounting adjustments outlined in Settlement Exhibit II are just and reasonable to all parties in light of all the evidence presented.

11. For purposes of this proceeding, the Stipulation removes certain site separation costs associated with development of the proposed North Anna Nuclear Station Unit 3 from the stipulated revenue requirement, and additionally provides that consideration of the recovery of such costs is reserved for a future proceeding. The Stipulation's treatment of the North Anna Unit 3 site separation costs is appropriate, just and reasonable to all parties in this case.

EDIT Refund

12. The Stipulation provides that the appropriate level of excess deferred income taxes (EDIT) to be refunded to customers in this case is $15,708,000 (on a pre-income-tax basis), which includes EDIT associated with the January 1, 2017, reduction in the North Carolina corporate state income tax rate from 4% to 3%.

13. DNCP shall implement a decrement rider, Rider EDIT, to refund EDIT to customers over a two-year period on a levelized basis, with a return. As reflected on Settlement Exhibit IV, the appropriate amount to be credited to customers is a total of $16,816,000, which should be credited to customers via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11. The ratemaking treatment of the EDIT regulatory liability set forth in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Implementation of Session Law 2015-6 (House Bill 41)

14. Pursuant to Section 2.4.(a) of House Bill 41 (HB 41), the Commission must adjust the rate for the sale of electricity, piped natural gas, and water and wastewater service to reflect all tax changes enacted in Session Law 2013-316 (HB 998). Under G.S. 105-130.3C, as enacted in HB 998, an automatic reduction in the State corporate income tax rate from 4% to 3% will become effective for the taxable year beginning on or after January 1, 2017, because certain net General Fund tax collection levels were met for the State's fiscal year 2015-2016. The base non-fuel rate revenue requirement in the Stipulation reflects the 3% North Carolina state income tax (SIT) rate effective for the taxable year beginning on or after January 1, 2017.

Nuclear Refueling and Outage Expense Levelization Accounting

15. Section VII of the Stipulation provides that the Company may use levelization accounting for nuclear refueling costs, as described in the testimony of Public Staff witness Fernald and Fernald Exhibit 3. The levelization accounting treatment of the nuclear refueling costs set forth in the Stipulation is just, reasonable and appropriate.

Coal Combustion Residuals (CCR) Costs

16. DNCP's actions through June 30, 2016, in addressing CCR remediation have been prudent, and its CCR costs incurred through June 30, 2016, are reasonable.

17. Section VIII of the Stipulation provides for the Company's deferral and recovery of CCR expenditures incurred through June 30, 2016, and that such costs be amortized over a five-year period. Section VIII of the Stipulation also provides that by virtue of the Commission's approval in this proceeding of a mechanism to provide for recovery of CCR expenditures incurred through June 30, 2016, DNCP has continuing authority pursuant to the Commission's August 6, 2004 Order in Docket No. E-22, Sub 420, to implement asset retirement obligation (ARO) accounting and to defer additional CCR expenditures for consideration for recovery in a future rate case, without prejudice to the right of any party to take issue with the amount or the treatment of any deferral of ARO costs in a future rate case or other appropriate proceeding.

18. The ratemaking treatment of the CCR costs set forth in the Stipulation, as well as the other provisions of the Stipulation regarding CCR costs, are just and reasonable to all parties in light of all the evidence presented.

Regulatory Assets

19. Section XI of the Stipulation provides for deferral accounting treatment and recovery over a three-year period on a levelized basis of deferred post-in-service costs for the Warren County CC and Brunswick County CC.

20. Section XI of the Stipulation also provides for deferral accounting treatment and recovery of the Chesapeake Energy Center (CEC) impairment and closure cost regulatory assets, as proposed by DNCP witness McLeod and further modified by Public Staff witness Fernald.

21. The Stipulation also provides for deferral accounting treatment and recovery of certain regulatory assets and liabilities expiring in 2017 as proposed by Public Staff witness Fernald, which is set forth in Section XI of the Stipulation.

22. The Stipulating Parties agreed to, and by the Stipulation requested Commission approval of, deferral accounting treatment as proposed by Company witness McLeod of costs associated with the beyond design basis studies mandated by the Nuclear Regulatory Commission (NRC) for North Carolina jurisdictional purposes. Through the Stipulation, the Company committed to comply with Commission Rule R8-27(a)(2) prior to establishing any regulatory assets and liabilities for North Carolina jurisdictional purposes in the future.

23. For the present case, the deferral and recovery of the deferred costs presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Accounting for Deferred Costs

24. The Company is authorized to receive a specific amount of revenue for each of the several deferred costs approved by this Order. If the Company receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

Accounting and Reporting Recommendations

25. Section XIII of the Stipulation provides for certain accounting and reporting commitments by the Company, as recommended by the Public Staff and agreed to by the Company. As a result of the Stipulation, the Company will notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure. Additionally, the Public Staff's accounting recommendations concerning the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) and the service company charges will be addressed by DNCP and the Public Staff in Docket Nos. E-22, Subs 476 and 477. Further, the Company agreed in the Stipulation to provide the Public Staff, within 90 days of the date of the Stipulation, with a presentation regarding its accounting practices for non-nuclear asset retirement obligation costs.

Base Fuel Factor

26. The Stipulation provides for a total decrease in DNCP's annual base fuel revenues of $8.942 million from its North Carolina retail electric operations, based on a base fuel factor of 2.073 cents per kilowatt-hour (kWh) (including regulatory fee), which is just and reasonable to all parties in light of all the evidence presented.

27. The base fuel factor should be differentiated between customer classes as provided on Company Rebuttal Exhibit PBH-1, Schedule 9, Page 2.

28. The Stipulation also provides for an adjustment to the Company's base fuel and non-fuel expenses to reflect 78% as a proxy for the fuel cost component of energy purchases for which the actual fuel cost is unknown (Marketer Percentage), with the remaining 22% of the cost of energy purchases being recovered by DNCP in base rates. This represents a reduction from the Company's current Marketer Percentage of 85%. The 78% Marketer Percentage agreed to in the Stipulation is reasonable and appropriate for use in this proceeding. The 78% Marketer Percentage shall remain in effect until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

Capital Structure, Cost of Capital, and Overall Rate of Return

29. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the 51.75% common equity and 48.25% long-term debt, as set forth at Section II.B of

the Stipulation, is a just, reasonable, and appropriate capital structure for DNCP in this general rate case.

30. DNCP's June 30, 2016, actual long-term debt cost of 4.650% is appropriate for use in this proceeding.

31. Based on the expert witness evidence, the public witness evidence, and the Stipulation, the rate of return on common equity that the Company should be allowed the opportunity to earn is 9.90% as set forth at Section II.B of the Stipulation. This rate of return on common equity is just, reasonable, and appropriate for DNCP in this general rate case.

32. Based on the expert witness evidence, the public witness evidence and the Stipulation, the overall rate of return that the Company should be allowed the opportunity to earn on the Company's invested capital, including its costs of equity and long-term debt, is 7.367%, as set forth at Section II.B of the Stipulation. This overall rate of return is just, reasonable, and appropriate for use in this general rate case.

33. The authorized levels of overall rate of return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of G.S. 62-133, and are fair to DNCP's customers generally and in light of the impact of changing economic conditions.

34. With respect to the foregoing ultimate findings on the appropriate overall rate of return on rate base and allowed rate of return on common equity for use in this proceeding, the Commission relies on the following more specific findings of fact:

a. DNCP's currently authorized overall rate of return on rate base and allowed rate of return on common equity are 7.80% and 10.20% respectively.[1]

b. DNCP's current base rates became effective on November 1, 2012, and have been in effect since that date.

c. In its Application, DNCP sought approval for rates based on an overall rate of return on rate base of 7.88% and an allowed rate of return on common equity of 10.50%.

d. In the Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.367% and an allowed rate of return on common equity of 9.90%.

e. From January 2013 through September 2016, the average authorized ROE for vertically integrated electric utilities was 9.87%. Of the 77 cases decided during that period, 35 included authorized returns of 9.90% or higher. The Commission is not specifically relying on past rate of return on equity determinations authorized for other utilities in determining DNCP's cost of equity and ROE in this case; however, it is appropriate to note such past determinations as a

[1] Virginia Electric & Power Co., Docket No. E-22, Sub 479, Order Granting General Rate Increase, (Dec. 21, 2012) (2012 Rate Order), Order on Remand (July 23, 2015) (2015 Remand Order).

check or as corroboration of the Commission's decision regarding the cost of equity demonstrated by the evidence in the present proceeding.

f. The stipulated overall rate of return on rate base of 7.367% and allowed rate of return on common equity of 9.90% are supported by credible, competent, material, and substantial evidence.

g. The 9.90% rate of return on equity falls between the 10.5% ROE initially requested by the Company and the ROEs recommended by ROE witnesses for Nucor and CUCA (9.0% and 8.6%) and the Public Staff (9.3% before supporting the settlement ROE of 9.90%) in this case.

h. It is appropriate to give substantial weight to the high end of the range of results from Public Staff witness Hinton's updated comparable earnings analysis, where the three highest ROE results - 10.0%, 9.9% and 9.7% - average 9.867%.

i. It is also appropriate to give substantial weight to an average of a combination of the updated analytical results of DNCP witness Hevert. The average of his high growth rate multi-stage Discounted Cash Flow (DCF) results, his Capital Asset Pricing Model (CAPM) Value Line market risk premium results, and his bond yield plus risk premium results, is 9.86%.

j. It is not appropriate to approve the single number recommendation of any of the ROE witnesses in this case, nor any one analytical method. Rather, a 9.90% ROE represents a reasonable middle ground, avoiding the extremes reflected in the recommendation of the Company witness on the one end and the recommendations of intervenor witnesses on the other end. A 9.90% ROE is supported by witness Hinton's comparable earnings results. It is also supported by the averaging of witness Hevert's high growth rate multi-stage DCF results, CAPM Value Line market risk premium results, and bond yield plus risk premium results.

k. Substantial expert evidence presented in this matter, uncontroverted by other expert testimony on the subject, indicates that the overall economic climate in North Carolina (as well as nationally) continues to improve. This evidence includes data and projections from reliable sources indicating that in the few months before the hearing in this matter: (1) unemployment rates were declining; (2) real gross domestic product growth was continuing; (3) median household income was growing; and (4) residential electricity costs remain well below the national average. In DNCP's service territory specifically, such data show that: (1) economic conditions remain difficult for many people; (2) but recent changes in economic conditions have been positive, as unemployment has fallen considerably in the last several years and per capita income has been growing.

l. During four public hearings held in Halifax, Manteo, Elizabeth City, and Williamston, the Commission heard testimony regarding economic conditions and the potential impact of DNCP's proposed rate increase on the Company's customers. No public witnesses appeared at the hearing held in Raleigh. Of the 120,000 DNCP retail customers in North Carolina, 26 public witnesses testified at the hearings, many of whom testified that the rate increase was not affordable to many customers, including senior citizens, persons on fixed incomes, persons with disabilities, the unemployed and underemployed, and the poor. The Commission has considered this public witness testimony in its deliberations in setting just and reasonable rates for DNCP, including its determination that a 9.90% ROE and a 51.75% equity component of the stipulated capital structure are reasonable.

m. The rate increase approved in this case, which includes the approved ROE and capital structure, will be difficult for some of DNCP's customers to pay, in particular the Company's low-income customers.

n. The 9.90% rate of return on equity takes into account the impact of changing economic conditions on consumers. The authorized revenue amount available to pay a return on equity is lower for DNCP because the Stipulation reduced downward DNCP's requested revenue requirement, and this reduction is intertwined with the decision on rate of return on equity in that it affects the earnings available to investors and the rates customers will pay.

o. No party submitted evidence showing that any regulatory commission applies increments or decrements to the return on equity to account for economic conditions or customer ability to pay.

p. DNCP has made significant capital investments since its last rate case in 2012, much of which relates to its efforts to add new baseload combined cycle generating capacity to its fleet and to expand and strengthen its transmission and distribution infrastructure in northeastern North Carolina and throughout its system. All of these investments further the mission of ensuring reliability, operational excellence, and efficient electric service for DNCP's customers. The Company plans to make additional significant capital investments in the future.

q. Continuous safe, adequate, and reliable electric service by DNCP is essential to the well-being of the people, businesses, institutions, and economy of North Carolina, and access to capital at reasonable rates is critical to DNCP's ability to fund its ongoing capital investment requirements and DNCP's provision of safe, reliable, and cost effective electric service.

r. The 9.90% ROE and the ratemaking capital structure consisting of 51.75% common equity approved by the Commission in this case result in a cost of capital that will enable DNCP by sound management to produce a fair return for its shareholders, and is just, reasonable, and fair to DNCP's customers considering the impact of changing economic conditions on those customers. The resulting cost of capital is as low as reasonably possible and appropriately balances DNCP's need to obtain financing and maintain a strong credit rating with its customers' need to pay the lowest possible rates.

s. The potential difficulties that DNCP's low-income customers will experience in paying DNCP's increased rates will be somewhat mitigated by the $400,000 of shareholder funds that the Company will contribute to assist low-income customers.

Revenue Increase

35. The Stipulation provides for an increase in DNCP's annual electric sales revenues from its North Carolina retail electric operations of $34.732 million. With the stipulated decrease in annual base fuel revenues of $8.942 million, there is a net overall revenue increase of $25.790 million from its North Carolina retail electric operations. The increase in annual non-fuel

base rates to be paid by DNCP's North Carolina retail customers is just and reasonable to all parties in light of all the evidence presented.

EnergyShare Contribution

36. Section XV of the Stipulation provides that the Company will make a one-time $400,000 shareholder contribution to the North Carolina EnergyShare program that provides energy assistance to customers in need in the Company's North Carolina service territory. This $400,000 will be an additional contribution in 2017 on top of the Company's usual annual contribution of about $360,000. This shareholder contribution represents an additional rate mitigation measure that could not have been ordered by the Commission without agreement by the Company. This provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Cost of Service Allocation Methodology

37. The Stipulation provides for the use of the Summer-Winter Peak and Average (SWPA) methodology to allocate the Company's cost of service to the North Carolina jurisdiction and among the customer classes in this case. The Stipulating Parties agreed that use of the SWPA methodology for allocation between jurisdictions and among customer classes shall not be a precedent for, and may be contested in, future general rate case proceedings. The Stipulating Parties further agree that the Company's proposed adjustment to DNCP's recorded summer and winter peaks to recognize the peak demand contributions of non-utility generators (NUGs) interconnected to the Company's distribution system is appropriate and reasonable. The SWPA cost of service methodology, as adjusted by DNCP to account for the peak demand contribution of distribution-connected NUGs, is appropriate for determining the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility for purposes of this case.

38. DNCP's adjustment to the peak component of SWPA appropriately recognizes the impact non-utility generators have on DNCP's utility system and is appropriate for use in this proceeding.

39. The SWPA cost of service methodology, as adjusted by DNCP, has been used in this Order to determine the appropriate levels of rate base, revenues, and expenses for North Carolina retail service.

40. DNCP's continued use of the SWPA methodology in this proceeding properly assigns production plant costs to all customer classes, including the Schedule NS Class in recognition of its significant use of the Company's generation throughout the year.

41. It is not reasonable nor necessary at this time to require the Company to re-evaluate the issues addressed in the 1994 fuel study filed in Docket No. E-22, Sub 333, as raised by Nucor.

Rate Design

42. For purposes of apportioning and assigning the approved increase in base non-fuel and base fuel revenues between the North Carolina customer classes in this proceeding, the apportionment and rate design principles presented by Company witness Haynes in his direct and rebuttal testimony, as modified in Section V of the Stipulation, are reasonable, appropriate, and nondiscriminatory. The Stipulation further provides that in developing rates based upon the foregoing class apportionment, the Company agrees to recover 100% of the stipulated revenue increase through the energy and demand components of rates and not to increase the basic customer charge component of rates.

Schedule 6L

43. The new Rate Schedule 6L, as amended in Company Rebuttal Exhibit PBH-1, Schedule 12 to eliminate the NAICS "Manufacturing" classification as part of the qualification for this rate schedule, is reasonable, nondiscriminatory, and should be approved.

Utilities International Model (UI Model)

44. The Stipulation provides that DNCP will work with its cost of service model vendor to determine whether an application can be produced that would enable an intervenor or the Public Staff to perform certain cost of service model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings. DNCP should work with its vendor, Utilities International, to assess reasonable additional cost of service model functionalities that can be produced in an Excel spreadsheet-based format. DNCP should be prepared prior to filing its next general rate case to release the Excel product to intervenors as requested.

LED Schedule

45. The Stipulation provides that the Company shall develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of the Commission's final order in this proceeding. This provision of the Stipulation is reasonable and appropriate.

Time-Differentiated Rates

46. DNCP currently does not offer a Real Time Pricing (RTP) rate for its service territory in North Carolina. It is reasonable to expect the Company to propose a pilot or experimental RTP rate offering no later than July 1, 2017.

47. The number of DNCP residential customers receiving service on either of the time-of-use rates offered by DNCP in North Carolina is approximately 0.3%. In 2008, the Commission encouraged utilities to increase the utilization of time-differentiated rates. However, the percentage of DNCP's residential customers participating is smaller now than it was in 2007. Therefore, DNCP should be required to provide a written summary of its time-of-use rates, and its RTP rates,

when developed, to each residential customer presently being served and to be served in the future by a smart meter. Further, the Commission approves the terms of the agreement filed herein by DNCP and NCSEA on December 13, 2016.

Terms and Conditions

48. The Stipulation provides that DNCP's Terms and Conditions should be revised as set forth in Item 39 of the Company's Form E-1 filed with its supplemental direct testimony on August 12, 2016. The rate designs, rate schedules, and service regulations proposed by the Company are reasonable, as filed, except as specifically addressed in the Stipulation and this Order.

Quality of Service

49. The overall quality of electric service provided by DNCP is good.

PJM Conditions

50. It is appropriate to relieve the Company from compliance with most, but not all, of the conditions that were imposed by the Commission's April 19, 2005 Order Approving Transfer Subject to Conditions issued in Docket No. E-22, Sub 418. The Company shall continue to file with its annual fuel clause adjustment filing the information required by Paragraph 5 of the November 10, 2004 Joint Offer of Settlement between DNCP and PJM. The Independent Market Monitor (IMM) for PJM shall continue to annually file the information required by Paragraph 6 of that same Joint Offer of Settlement. DNCP committed in the Stipulation to comply with the representations and commitments made in its July 8, 2016 Supplemental Filing with respect to certain obligations, and that provision of the Stipulation is just and reasonable. Further, it is appropriate to require the Company to file as a compliance filing in this case a comprehensive document entitled "Code of Conduct" that shall include all representations and commitments to which the Company will be bound, consistent with this Order.

Acceptance of the Stipulation

51. Based upon all of the evidence in the record, including consideration of the public witness testimony and the record evidence from parties who have not agreed with the Stipulation, the provisions of the Stipulation are just and reasonable to the customers of DNCP and to all parties to this proceeding, and serve the public interest. Therefore, the Stipulation should be approved in its entirety. In addition, the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

Just and Reasonable Rates

52. The base non-fuel and base fuel revenues approved herein are just and reasonable to the customers of DNCP, to DNCP, and to all parties to this proceeding, and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact and conclusions is contained in the verified Application and Form E-1 of DNCP, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party. In addition, the Commission finds and concludes that the Company's use of a test period of the 12 months ended December 31, 2015, with appropriate adjustments through June 30, 2016, comports with the requirements of G.S. 62-133 and Commission Rule R1-17, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact and these conclusions is contained in DNCP's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

On March 1, 2016, pursuant to Commission Rule R1-17(a), DNCP filed notice of its intent to file a general rate case application. On the same date, DNCP filed a letter informing the Commission of the Company's intention to propose accounting adjustments to include an appropriate level of amortization of deferred post-in-service costs associated with the Company's Warren County Power Station (Warren County CC) in its rate case revenue requirement.

On March 31, 2016, DNCP filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $ 51,073,000 in its annual electric sales revenues from its North Carolina retail electric operations. The Application is based on a requested rate of return on common equity (ROE) of 10.50%, an overall rate of return of 7.88%, an embedded long-term debt cost of 4.889%, and DNCP's actual capital structure of 53.36% common equity and 46.64% long-term debt, as of December 31, 2015. Further, the Application states that DNCP's 2015 ROE was 5.06%, and its overall rate of return was 4.98%.

The Company's last general rate case was in 2012 in Docket No. E-22, Sub 479. By Order issued on December 21, 2012, the Commission approved an increase in DNCP's base non-fuel revenues of $36,438,000, and a decrease of $14,484,000 in its base fuel revenues. DNCP's current authorized ROE is 10.2%, its authorized overall rate of return is 7.8%, and its authorized capital structure for ratemaking purposes is 51% common equity, 1.5% preferred stock and 47.5% long-term debt.

In its present Application, the Company proposed to implement the non-fuel base rate increase on a temporary basis subject to refund effective on November 1, 2016, along with an accelerated implementation of its new lower base fuel rate – to be filed in August 2016 – as part of any temporary rates (subject to refund) proposed to become effective November 1, 2016. The Company also proposed a methodology for returning certain excess accumulated deferred income taxes (EDIT) to customers through a decrement rider, Rider EDIT, over a two–year period; sought authority to use certain deferred accounts to implement a levelization methodology on its books for its nuclear unit refueling and maintenance outage expenses; and requested an adjustment of the Marketer Percentage to 100%. Further, DNCP requested the deferral of several costs that it had incurred. Finally, DNCP requested relief from the regulatory conditions imposed in the PJM Order.

In its supplemental testimony filed on August 12, 2016, DNCP updated the increase sought in its non-fuel base rates and charges to its North Carolina retail customers to $47.8 million. Upon making certain adjustments, DNCP updated the increase sought to $46.8 million in rebuttal testimony filed on September 26, 2016.

The Commission finds and concludes that DNCP's Application satisfies the requirements of G.S. 62-133, et seq., and Commission Rule R1-17. Further, DNCP is a public utility within the meaning of G.S. 62-3(23). Therefore, pursuant to G.S. 62-30, et seq., the Commission has jurisdiction to consider and decide DNCP's Application for a rate increase and other relief.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence supporting these findings of fact and conclusions is contained in the testimony of DNCP's witnesses Curtis, Haynes, Hevert, McLeod and Stevens, Public Staff witness Hinton, the provisions of the Stipulation, and the entire record in this proceeding.

On October 3, 2016, DNCP, the Public Staff and CIGFUR I (Stipulating Parties) filed a Stipulation resolving all of the issues among the Stipulating Parties. The Stipulation is based on the same test period as the Company's Application. In summary, the Stipulation provides:

- A $34.7 million increase in DNCP's annual non-fuel base revenues;
- A $8.9 million decrease in DNCP's annual fuel base revenues;
- A 2-year Excess Deferred Income Taxes decrement rider (Rider EDIT) returning to ratepayers excess deferred income taxes in the amount of approximately $15.7 million beginning November 1, 2016;
- An overall base rate increase for all customer classes of approximately 7.47%, excluding the effect of any 2017 Fuel Factor Riders and the Rider EDIT decrement;
- An increase to residential customers' bills for 2017 limited to 0.08%, taking into account the effect of the base rate increase, overall fuel decrease, the Company's proposed 2017 Fuel Factor Riders, and the Rider EDIT decrement;
- A rate of return on equity of 9.90% and an overall rate of return on rate base of 7.367%;
- A capital structure for ratemaking purposes consisting of 51.75% equity and 48.25% long-term debt;
- An embedded cost of debt of 4.650%;
- A 5-year amortization of costs associated with coal combustion residual expenditures incurred through June 30, 2016;

- Withdrawal from this case of DNCP's request to recover site separation costs associated with the proposed North Anna 3 nuclear plant. Consideration of the recovery of any such costs would be reserved for a future proceeding;

- Allocation of the Company's cost of service based on the Summer/Winter Peak and Average (SWPA) method;

- A one-time $400,000 shareholder contribution by DNCP to the EnergyShare program that provides energy assistance to customers in need in the Company’s North Carolina service territory;

- Deferral of the post-in-service costs of the Warren County CC and Brunswick County CC generating facilities;

- Deferral of the Chesapeake Energy Center (CEC) impairment and closure costs; and

- Subject to certain clarifications and conditions, release of DNCP from further compliance with the regulatory conditions imposed by the Commission in its Order Approving Transfer Subject to Conditions, Docket No. E-22, Sub 418 (April 19, 2005), approving DNCP's participation in PJM.

In his testimony in support of the Stipulation, filed on October 3, 2016, DNCP witness Curtis stated that the Company was able to reach a settlement with the Public Staff after extensive discovery conducted by the Public Staff and other intervenors. Witness Curtis further testified that the Stipulation is the product of give-and-take negotiations between the Company and the Public Staff. He testified that through extensive discussions and negotiations with the Public Staff, the Company and Public Staff were able to strike the balance between reasonable rates for customers and the Company's need to attract capital in order to continue providing safe and reliable service. In addition, witness Curtis testified that the Company understands that the Commission must set just and reasonable rates, including the authorized ROE, in a way that balances the economic conditions facing DNCP’s customers with the Company’s need to attract capital in order to continue providing safe and reliable service. He testified that the Stipulation mitigates the impact on DNCP’s customers of the rate relief provided to the Company through, for example, the agreed-upon cost of service adjustments, the reduced overall revenue requirement, the decreased base fuel factor, and the refund of excess deferred income taxes through decrement Rider EDIT. Witness Curtis also noted that the Stipulation provides significant benefits that could not otherwise be ordered by the Commission, including the accelerated refund of the current fuel over-recovery through decrement Rider A1, and the Company’s agreement to make a $400,000 contribution of shareholder funds to the North Carolina EnergyShare program, to provide energy assistance to customers in need in DNCP’s North Carolina service area.

Company witness Hevert filed testimony on October 3, 2016, in support of the Stipulation. He testified that although the ROE agreed upon in the Stipulation is below the lower end of his recommended range (i.e. 10.25%), he recognizes that the Stipulation represents the give-and-take regarding multiple issues that would otherwise be contested.

Company witnesses Stevens and McLeod filed joint testimony on October 3, 2016, in support of the Stipulation. They testified that subsequent to the filing of the Company's Application, DNCP, the Public Staff and other intervenors engaged in substantial discovery, and that the parties filed testimony asserting their positions, with DNCP also filing rebuttal testimony responding to the other parties' positions. Witnesses Stevens and McLeod further testified that after lengthy negotiations the Company and Public Staff arrived at a settlement of all of the issues between them. Witnesses Stevens and McLeod also noted that DNCP negotiated in good faith with other parties, and was able to reach a settlement with CIGFUR I. In addition, witnesses Stevens and McLeod stated that the Stipulation is the result of give-and-take negotiations in which each party made substantial compromises on certain issues in order to gain compromises from the other party on other issues, and that the Stipulating Parties believe the results reached are fair to the Company and its customers. Finally, they noted that the Stipulation resolves all issues among the Stipulating Parties without the necessity of contentious litigation.

DNCP witness Haynes also filed testimony on October 3, 2016, in support of the Stipulation. Witness Haynes testified that he believes the Stipulation constitutes a just and reasonable approach to establishing DNCP's cost of service, apportioning the costs among the customer classes, and designing the Company's rates and charges. Moreover, he testified that the Stipulation represents a compromise between differing interests in a number of respects, including CIGFUR I’s support of the Company’s proposed SWPA cost allocation methodology, and CIGFUR I’s withdrawal of its request that an additional portion of the rate increase be allocated to the NS Class.

Public Staff witness Hinton also filed testimony in support of the Stipulation on October 3, 2016. Witness Hinton testified that the Public Staff and DNCP have fundamentally different views of the current market conditions and cost of capital, and that neither party persuaded the other to change its views. He testified that the Public Staff and DNCP nonetheless found a way to bridge their differences and to reach agreement on a proposed ROE and capital structure. Witness Hinton further stated that the stipulated ROE of 9.90% and equity ratio of 51.75% came about as a result of various compromises on other issues by both DNCP and the Public Staff. In addition, Public Staff witness Fernald testified to her belief that the Stipulation is in the public interest.

The Stipulation has not been adopted by all of the parties to this docket. Therefore, the Commission’s determination of whether to accept or reject the Stipulation is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I, the Supreme Court held that

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding.

> The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id., at 231-32, 524 S.E.2d at 16 (emphasis added).

The Commission gives substantial weight to the testimony of DNCP witnesses Curtis, Haynes, McLeod and Stevens describing the Stipulating Parties' efforts in negotiating the Stipulation. Further, the Commission gives significant weight to the settlement testimony of Public Staff witnesses Fernald and Hinton, which in their discussion of the benefits that the Stipulation will provide to customers and their testimony describing the compromise reflected in the Stipulation's terms indicate the Public Staff's commitment to fully represent the using and consuming public. In addition, the Commission gives some weight to the fact that the settlement was not reached until October 3, 2016, the day before the expert witness hearing began. Prior to that date, DNCP, the Public Staff and CIGFUR I pre-filed the testimony of their experts setting forth their litigation positions on the issues. That indicates to the Commission that the Stipulating Parties were fully prepared to litigate the contested issues in the event that a settlement was not reached.

As a result, the Commission finds and concludes that the Stipulation is the product of the give-and-take among the Stipulating Parties during their settlement negotiations in an effort to appropriately balance DNCP's need for increased revenues and its customers' needs to receive safe, adequate, and reliable electric service at the lowest possible rates. In addition, the Commission finds and concludes that the Stipulation was entered into by the Stipulating Parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket among the Stipulating Parties. As a result, the Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-11

The evidence supporting these findings of fact and conclusions is contained in DNCP's verified Application, the direct, supplemental and rebuttal testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

ELECTRIC – RATE INCREASE

Rate Base

Per Settlement Exhibit I of the Stipulation, the amount of original cost rate base is $1,040,035,000. A breakdown of the components of the original cost rate base is as follows (000's omitted):

Line No.	Item	After Rate Increase
1	Electric plant in service	$1,947,252
2	Accumulated depreciation and amortization	(716,858)
3	Net electric plant in service (L1 + L2)	1,230,394
4	Materials and supplies	44,916
5	Cash working capital	18,476
6	Other additions	19,607
7	Other deductions	(17,434)
8	Customer deposits	(5,126)
9	Accumulated deferred income taxes	(250,799)
10	Rounding	1
11	Total original cost rate base (Sum of L3 thru L10)	$1,040,035

Discussion of Certain items included in Rate Base

North Anna 3 Site Separation Costs

The Company's Application included certain North Anna Power Station "site separation" plant investments in DNCP's rate base for ratemaking purposes.

Public Staff witness Metz testified that the North Anna Power Station consists of two nuclear reactors, North Anna Units 1 and 2, that are in-service, as well as a potential site for a third nuclear reactor, known as North Anna 3, for which DNCP has not sought a certificate of public convenience and necessity from the Virginia State Corporation Commission (SCC), a determination of need from this Commission pursuant to G.S. 62-110.6, or approval from this Commission of its decision to incur project development costs pursuant to G.S. 62-110.7. In the Company's most recent integrated resource plan (IRP) in Docket No. E-100, Sub 147, DNCP indicates that it is engaged in development efforts in regard to North Anna 3 and is currently pursuing a Combined Operating License from the NRC, which is expected next year.

Witness Metz testified that the Company has included in its cost of service certain capital investment and related expenses associated with site preparation activities for North Anna 3. Site activities for North Anna 3 have involved removing existing structures/buildings that support North Anna Units 1 and 2, and then relocating them outside of the proposed construction zone of North Anna 3.

Witness Metz cited Company witness Mitchell's testimony in SCC Case No. PUE-2015-00027 that stated, "[t]he services supported by each of these assets will be used by the operating Units 1 and 2 as well as Unit 3 if the Company proceeds with construction. However, but for the development of North Anna 3, the development of these assets would not have been needed." Further, in rebuttal in that same case, witness Mitchell stated: "I highlight that but for the development of North Anna 3, these preconstruction site separation activities would not have been needed." Public Staff witness Metz asserted that these costs should be assigned to North Anna 3 and thus removed from DNCP's cost of service in this proceeding.

Similarly, Nucor witness Kollen testified that the site separation costs are solely related to North Anna 3, and not North Anna 1 and 2; therefore, these costs should be removed from rate base and depreciation expense in this proceeding. Witness Kollen additionally testified that in the Company's most recent biennial review, the Virginia SCC removed the North Anna 3 costs from rate base and operating expense that it was not required to include pursuant to Virginia state law (70% of new nuclear construction costs incurred between July 1, 2007, and December 31, 2013).

In rebuttal, Company witness Mitchell provided a brief history of North Anna Units 1 and 2 and explained the decision making process to move forward with North Anna 3 development as part of the Company's resource planning strategy. Witness Mitchell explained that North Anna Units 1 and 2 are benefiting from the new buildings and how these common facilities would eventually support a third nuclear unit at the site. The new facilities, including warehouses, paint shops, welding areas, and vehicle repair shops, are now in service supporting the operating North Anna station, including Units 1 and 2. Witness Mitchell disputed Public Staff witness Metz's characterization of the activities in question as "site preparation activities for North Anna 3" rather than "site separation activities" needed for North Anna, testifying that the new support buildings and infrastructure are needed today in order to continue the safe and reliable operations of North Anna Units 1 and 2. Witness Mitchell testified that this limited universe of costs are site "separation" investments that are now in service and being used to support operations at North Anna Units 1 and 2.

Company witness Stevens disagreed with Public Staff witness Metz's and Nucor witness Kollen's claim that the North Anna site separation costs are solely related to North Anna 3, not to North Anna Units 1 and 2. While the future development of an additional nuclear unit was the driver of the overall project, witness Stevens explained that the site separation assets are common assets that are used and useful assets today at North Anna. Witness Stevens asserted that the Company's accounting for the site separation assets is also consistent with the FERC USOA. As such, he insisted that the site separation assets – which are now in-service and are used and useful today – should not be recorded in construction work in progress (CWIP), but appropriately recorded in plant-in-service.

In his rebuttal testimony, witness Stevens testified that the Virginia SCC did not remove North Anna 3 rate base and operating expenses in the Company's most recent biennial review in Virginia – it included the recovery of 70% of "all costs" related to North Anna 3 as a period expense in the Company's earnings test results for fiscal year 2014. Specifically, he testified that the Virginia legislature has provided explicit direction to the Virginia SCC through Va. Code § 56-585.1 regarding the manner in which VEPCO, operating in Virginia as Dominion Virginia Power, shall be authorized to recover the costs of new generating facilities (including recovery of CWIP) and other utility plant. DNCP witness Stevens asserted that the Virginia cost recovery statute should have no bearing on DNCP's recovery of the North Carolina portion of site separation costs under the North Carolina Public Utilities Act. According to witness Stevens, prudently incurred investments in plant-in-service that are used and useful today to serve the Company's North Carolina customers are recoverable under the North Carolina Public Utilities Act.

Witness Stevens asserted in his rebuttal testimony that Nucor witness Kollen's calculation of its adjustment to remove the site separation costs was overstated. According to DNCP witness Stevens, witness Kollen imputed depreciation expense for the assets rather than evaluating the actual depreciation expense reflected in the cost of service. Witness Stevens further testified that Nucor witness Kollen also failed to adjust for accumulated deferred income taxes associated with the site separation assets, thereby incorrectly reducing rate base.

For purposes of this proceeding, the Stipulation provides that certain site separation costs associated with development of the proposed North Anna Nuclear Station Unit 3 be removed from the stipulated revenue requirement, and that consideration of the recovery of such costs shall be reserved for a future proceeding. Based on this proceeding and the entire record as a whole, the Commission finds and concludes that the Stipulation's treatment of the North Anna Unit 3 site separation costs is appropriate, just and reasonable in this case.

Cash Working Capital (CWC)

In his direct testimony, Company witness McLeod testified that the CWC requirement is based on a lead/lag study prepared based on calendar year 2013 data. According to witness McLeod, the CWC calculation for regulatory purposes is consistent with DNCP's lead/lag study methodology described in the Company's Reply Comments filed in Docket No. M-100, Sub 137, and meets the requirements identified in the Commission's March 21, 2016 Order Clarifying Order on Lead-Lag Study Procedure.

Public Staff witness Fernald identified and proposed a number of adjustments and corrections to the Company's calculation of CWC in her testimony. Additionally, the Public Staff adjusted CWC under present rates to reflect all of the Public Staff's adjustments, in accordance with the Commission's Order in Docket No. M-100, Sub 137.

Nucor witness Kollen testified that the Company's CWC calculation includes the following non-cash expenses: depreciation and amortization expense; deferred federal and state income tax expense, and income available for common. Witness Kollen argued that these non-cash expenses are typically excluded in the lead-lag calculation for that reason, and recommended that the Commission exclude these non-cash expenses from the lead/lag calculation.

As reflected in the rebuttal testimony of Company witness McLeod, DNCP reviewed Public Staff witness Fernald's testimony and exhibits and accepted each of the revisions to the Company's lead-lag study and allowance for CWC, as adjusted by witness Fernald, with the exception of the current state income tax expense lead days. Company witness McLeod testified that the Company disagreed with the Public Staff's correction to the current income tax expense lead days because the Company's expense lead days are based on all current tax payments during the year. Witness McLeod explained that the Company does not necessarily agree with the Public Staff's other revisions to the expense lead and revenue lag days, but has accepted the changes for purposes of this proceeding due to their minor impact on the overall base non-fuel rate revenue requirement.

In his rebuttal testimony, Company witness Stevens disputed Nucor witness Kollen's recommendation to exclude certain non-cash items from the determination of CWC. Witness Stevens explained that the Company's treatment of these items is consistent with the Company's prior practices and this Commission's prior treatment of lead-lag studies and CWC. According to witness Stevens, the Commission had previously addressed the same issue also raised by Nucor in Docket No. M-100, Sub 137, and the Commission overruled Nucor's position. Witness Stevens recommended that the Commission reject Nucor's adjustment to exclude these expenses from the lead-lag calculation.

The Commission notes that the allowance for CWC in the Stipulation includes an expense lead for current income taxes based on the statutory filing deadlines as proposed by Public Staff witness Fernald. The Commission finds and concludes that for the present case the CWC allowance presented in the Stipulation and agreed to by DNCP and the Public Staff is just and reasonable to all parties in light of all the evidence presented. With respect to Nucor witness Kollen's recommendation regarding certain non-cash items, Nucor has not presented any new evidence to dissuade the Commission from its findings and conclusions addressing inclusion of non-cash items in CWC, as set forth in its May 15, 2015, Order Ruling on Lead-Lag Study Procedure, in Docket M-100, Sub 137. Therefore, the Commission rejects Nucor's position regarding the exclusion of certain non-cash items in the calculation of CWC.

Accumulated Deferred Income Taxes Due to Bonus Depreciation on Brunswick County CC

In its supplemental filing, DNCP updated its rate base as of June 30, 2016. DNCP witnesses testified that this calculation also incorporated both the investment and the accumulated deferred income taxes (ADIT) associated with the recently completed Brunswick County CC. Embedded in the ADIT calculation is the impact of bonus depreciation as recorded on the Company's books and records as of June 30, 2016.

Nucor witness Kollen testified that the Company calculated ADIT due to first year bonus depreciation for the Brunswick County CC and included only six months as a subtraction from rate base. According to witness Kollen, bonus depreciation is taken when the asset is placed in service for tax purposes and the entirety of the ADIT is available at June 30, 2016, not just half (or six months) as reflected in the Company's filing. Witness Kollen contended that the Company chose to allocate the bonus depreciation equally over the months in calendar year 2016 in the filing; however, this understates the ADIT available from bonus depreciation at June 30, 2016. Witness Kollen recommended that the Commission reflect the full federal ADIT from bonus depreciation at June 30, 2016.

In response to Nucor witness Kollen, in his rebuttal testimony Company witness Warren discussed the history of bonus depreciation, and explained that bonus depreciation is conceptually no different from other forms of accelerated depreciation; it represents an incentive provided by the government for stimulating capital investment. Witness Warren testified that by allowing businesses to claim accelerated depreciation, Congress essentially causes the government to extend interest-free loans to those enterprises. These loans, according to witness Warren, produce incremental cash (*i.e.*, a reduction in the amount of tax otherwise payable), which are presently available to the utility, but will have to be paid back to the government over time. He further testified that the repayment of such loans is effected by filing future tax returns. Witness Warren explained that the outstanding loan balance is reflected as an ADIT credit, which is properly reflected as a reduction to rate base. In this way, ratepayers receive the entire benefit of the interest-free feature of the loan.

DNCP witness Warren testified that the nature of the disagreement between the Company and witness Kollen is over how much of the ADIT benefit of the Company's 2016 bonus depreciation should be recognized when computing its rate base as of June 30, 2016. The Company contends that it should recognize a half year's worth of the benefit. Witness Kollen contends that it should recognize 100% of the benefit. Witness Warren explained that on DNCP's accounting records, it spreads the benefits of accelerated tax depreciation ratably over the entire year in which the accelerated depreciation is claimed. He stated that this methodology is not one that it applied only to the Brunswick County CC facility or used only for purposes of calculating ADIT in this proceeding. In fact, as of June 30, 2016, the Company's accounting records reflect 50% of the benefit of the bonus depreciation (as well as of the "regular" accelerated tax depreciation on the non-deducted cost) it will claim on its 2016 tax return relating to Brunswick County CC facility. Thus, the ADIT the Company has recognized for purposes of this proceeding conforms to the ADIT it has recognized for all other purposes. Witness Warren further testified that witness Kollen's proposal recognizes an ADIT amount for purposes of the Company's rate base calculation that does not appear on its books and records.

Witness Warren testified that witness Kollen's assertion that the bonus depreciation deduction is taken when the asset is placed in service is both inaccurate and irrelevant. The Brunswick County CC bonus depreciation deduction will not be taken until DNCP files its 2016 federal income tax return in the second half of 2017. According to witness Warren, the critical issue is when the cost-free capital produced by the Company's ability to claim bonus depreciation with respect to the Brunswick County CC facility becomes available to the Company. According to witness Warren, witness Kollen incorrectly presumes that this occurs when the facility is placed in service.

Witness Warren explained that the Company acquires the cost-free capital produced by accelerated depreciation on the facility by reducing its estimated tax payments. As a tax year progresses, corporations are required to make four estimated tax payments so that they pay their tax liability during the year – not when they file their tax return. The amount of the quarterly estimated tax payments, according to Witness Warren, is equal to the lesser of: (1) one-fourth of the tax liability for the year; or (2) an amount calculated by annualizing the taxable income generated during the period. In terms of alternative (1) above, one-fourth of the impact of any bonus depreciation claimed during the year will reduce each of the four estimated tax payments. Thus, the effect of bonus depreciation is spread ratably throughout the year. Therefore, under alternative (1), the ADIT recorded on the Company's books and records as of June 30, 2016, accurately reflects the cost-free capital in its possession. Witness Warren contended that witness Kollen's proposed adjustment imputes a quantity of cost-free capital that, in fact, did not exist as of June 30, 2016.

Witness Warren explained that under alternative (2) above, the applicable tax regulation, Treasury Regulation §1.6655-2(f)(3)(iv), dictates how depreciation must be handled when a taxpayer annualizes its taxable income. It provides that, in determining taxable income for any annualization period, a proportionate amount of the taxpayer's estimated annual depreciation is taken into account. Thus, the benefit of the bonus depreciation actually claimed during the first period is spread over all four periods. Therefore, under alternative (2), the ADIT recorded on the Company's books and records as of June 30, 2016, accurately reflects the cost-free capital in its possession. Witness Warren contended that witness Kollen's proposed adjustment would again impute a quantity of cost-free capital that did not exist as of June 30, 2016.

Further, witness Warren testified that witness Kollen's proposal also creates a conflict with the tax depreciation normalization rules (Normalization Rules). The Normalization Rules are established by §168(i)(9) of the Internal Revenue Code of 1986, as amended, and Treas. Reg. §1.167(l)-1. They are quite complex, but prescribe: (1) how to implement the required tax benefit deferral (*i.e.*, normalization); (2) what can be done with the deferred tax benefit once it is deferred; and (3) under what circumstances the deferred tax benefit can be reversed. Witness Warren explained that accelerated depreciation was enacted by Congress to promote investment by businesses (including utilities) in plant and equipment. However, Congress was concerned that, in the case of a regulated utility whose rates are set by reference to its costs (one of which is tax expense), these incentives could be extracted from the utility and flowed directly to its customers through the rate-setting process, and the benefits would be stripped from the utilities and converted into consumption subsidies for utility customers who did not necessarily use the money to make plant investments. According to witness Warren, this was not Congress' intent, and it included in the tax law a set of rules to prevent this from happening – the Normalization Rules.

Witness Warren further explained that because the Normalization Rules permit rate base to be reduced by the cost-free capital produced by claiming accelerated depreciation, the benefits of accelerated depreciation that those rules intend to preserve can be passed through to ratepayers by ratemaking that presumes the existence of an excessive quantity of cost-free capital. DNCP witness Warren testified that the Normalization Rules therefore impose a limit on the amount of depreciation-related ADIT by which rate base can be reduced. Witness Warren contended that the limitation that is relevant to witness Kollen's proposed adjustment is the one contained in Treasury

Regulations §1.167(l)-1(h)(6) entitled "Exclusion of normalization reserve from rate base." Treasury Regulations Section §1.167(l)-1(h)(6)(i) states, in pertinent part:

> [A] taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied…exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking.

This regulation requires that rate base not be reduced by an ADIT balance unless that balance has been included in the utility's cost of service. Witness Warren testified that the additional six months of ADIT that witness Kollen proposes to factor into the Company's rate base computation has not been included in the Company's cost of service. Witness Warren asserted that only the amount that has been reflected on the Company's accounting records – the amount that it has used in its rate base computation – has been included in cost of service.

Witness Warren testified that as a condition for claiming accelerated tax depreciation (including bonus depreciation) on any of its depreciable assets, a utility must use a normalization method of accounting. Thus, the penalty for a violation in this proceeding would not be confined to the Brunswick County CC facility, but would extend to all of the Company's North Carolina depreciable assets. Witness Warren explained that the penalty for violating the Normalization Rules is draconian. By no longer being able to claim accelerated depreciation, a non-compliant utility would not generate any additional interest-free, governmental loans. Moreover, witness Warren stated that all governmental loans outstanding as of the date of the violation would have to be paid back a good deal more rapidly than would otherwise have been the case. The inability to claim accelerated tax depreciation would result in a significant reduction in the quantity of cost-free loans such depreciation deductions produce. Company witness Warren attested that this would manifest itself in the form of a dramatically reduced ADIT balance. Since the Company's ADIT balance offsets the rate base upon which a return must be allowed, diminished ADIT balances will produce a higher rate base and, consequently, higher rates than had the normalization violation not occurred.

The Stipulation reflects ADIT from bonus depreciation for the Brunswick County CC as of June 30, 2016, as a reduction to rate base as proposed by the Company.

Based upon the evidence presented by Company witness Warren, the Commission concludes that witness Kollen's proposal to reflect the full federal ADIT from bonus depreciation for the Brunswick County CC as a reduction to rate base as of June 30, 2016, is unreasonable and inappropriate. The Commission agrees with Company witness Warren that DNCP acquires the cost-free capital produced by accelerated depreciation on the facility by reducing its estimated tax payments made over the course of the tax year. As of June 30, 2016, the Company had only acquired half of this benefit, which DNCP has appropriately reflected as a reduction to rate base. The Commission, therefore, finds and concludes that the ADIT reflected in the Stipulation associated with the Brunswick County CC bonus depreciation is just and reasonable to all parties in light of all the evidence presented.

Operating Expenses

Operating Expenses per the Stipulation are $299,084,000. A breakdown of the operating expenses allowed in this proceeding is as follows:[1]

Line No.	Item	Amount (000's omitted)
1	Electric operating expenses:	
2	Operations and maintenance:	
3	Fuel clause expenses	$90,686
4	Other operations and maintenance expenses	98,989
5	Depreciation and amortization	60,047
6	Gain / loss on disposition of property	309
7	Taxes other than income taxes	15,233
8	Income taxes	33,820
9	Total electric operating expenses (Sum of L3 thru L8)	$299,084

Discussion of Certain items included in Operating Expenses

Uncollectible Expense

In its Application, DNCP proposed a normalization adjustment to uncollectible expense based on an historical average uncollectible expense rate for the five-year period of 2011-2015. Public Staff witness Fernald presented testimony stating that in 2014, the Company changed its write-off and collection policies for customers with medical certifications. According to witness Fernald, prior to that time, although these customers existed, the Company did not include them in its determination of the reserve for uncollectibles. She further testified that in 2014, DNCP began including customers with medical certifications in its calculation of the reserve, and to implement this policy change the Company recorded a $12.1 million credit accounting adjustment, on a total system level, to its reserve for uncollectibles account, with a charge to uncollectible expense, in order to establish an initial reserve for these customers. Witness Fernald testified that data from 2014 and prior years should not be used to determine an ongoing level of uncollectibles, since data from those years cannot validly be compared with 2015 data. Accordingly, witness Fernald stated that she calculated uncollectibles based on 2015 data, reflecting the Company's current policy of establishing a reserve for customers with medical certificates. Witness Fernald noted that the uncollectibles rate utilized by the Public Staff was 0.4814% as compared to the Company's 0.5549% rate.

Company witness McLeod testified that the Company's adjustment based on a five-year historical average expense rate methodology was consistent with the methodology approved by the Commission in the 2012 rate case, Docket No. E-22, Sub 479 (2012 Rate Case), as well as the

[1] Chart omits 000's.

Company's prior 2010 rate case, Docket No. E-22, Sub 459 (2010 Rate Case). Witness McLeod noted that the methodology approved in the 2012 Rate Case, which the Company followed in its Application, was first proposed by Public Staff witness Fernald in that proceeding. Witness McLeod argued that a change in accounting policy should not negate the use of an historical average since the purpose of using a historic average is to recognize the volatile nature of the expense - capturing both the highs and lows – and include a "normal" level that the Company will incur over a reasonable period of time. He asserted that normalization adjustments are designed to smooth out volatility in interim years including changes in accounting policy.

The Stipulation provides for an adjustment to uncollectible expenses based on 2015 data as proposed by witness Fernald. The Commission finds and concludes that for the present case the accounting adjustment is just and reasonable to all parties in light of the agreement between the Company and the Public Staff in the Stipulation and all the evidence presented.

Major Storm Restoration Expense

The Company proposed a normalization adjustment to non-labor and overtime major storm restoration expenses based on an historical average of costs during the five-year period of 2011-2015. Company witness McLeod testified that this adjustment is appropriate for ratemaking purposes given the unpredictable nature of storm activity, which can cause a material level of expense in a short period of time.

Public Staff witness Fernald proposed to normalize major storm expense based on the average storm costs for the last 10 years, instead of the last five years as proposed by the Company. Witness Fernald testified that the use of a 10-year average is consistent with the normalization of storm costs in the recent rate cases for Duke Energy Carolinas in Docket No. E-7, Subs 909, 989, and 1026, and for Duke Energy Progress in Docket No. E-2, Sub 1023. In addition, due to the unpredictability of both the frequency and cost of major storms, she contended that a 10-year average is more appropriate for use in determining a normalized level. Witness Fernald further recommended that since the Company has a normalized level of storm costs included in rates in this case, costs for future storms should not be deferred nor amortized.

Nucor witness Kollen testified that the data indicates that there is no "normal" storm damage expense and that a "normalized" expense is highly dependent on the number of years used for that purpose, as there are significant differences from year to year. Witness Kollen recommended that the Commission implement storm damage reserve accounting for ratemaking purposes and calculate the storm damage expense using the three most recent years of expense. According to Witness Kollen, this proposal would allow for the tracking of storm damage costs and the recovery of storm damage expenses on a dollar-for-dollar basis with the net over/under recovery position as a component of rate base. Witness Kollen further testified that any storm costs more or less than the expense accrual, under this scenario, would be tracked in the reserve and he suggested that the Commission could periodically adjust the storm damage expense to target a zero reserve balance over time.

In rebuttal testimony, witness McLeod testified that the Public Staff's reliance on a 10-year average understates the normal level of storm expenses that can be expected to occur going-forward. Witness McLeod asserted that the Public Staff's reliance on 10 years of data also fails to take into account operational changes that have occurred over that period of time.

In rebuttal testimony, Company witness Stevens recommended that the Commission reject Nucor witness Kollen's proposal to establish a ratemaking mechanism for tracking DNCP's storm costs. Witness Stevens contended that the methodology presented by Company witness McLeod is reasonable, and that witness Kollen's storm damage tracker goes beyond any known Commission precedent.

The Stipulation provides for an adjustment to major storm restoration expenses based on data during the period January 1, 2010 to June 30, 2016, in effect, including a levelized storm restoration expense level less than the five-year average recommended by the Company and greater than the level proposed by Public Staff. The Commission finds and concludes that for the present case this stipulated level of storm expense is reasonable and appropriate and is just and reasonable to all parties in light of all the evidence presented. The Commission also finds that Nucor witness Kollen's recommendation for the Commission to order a storm cost tracker should not be implemented in light of the Commission's preceding determination to include storm restoration expense in the cost of service.

Annual Incentive Plan Expense

In the Company's Application, Company witness McLeod explained that the annual incentive plan (AIP) represents at-risk compensation paid out to Company employees only upon meeting certain operational and financial goals during the plan year. During 2015, not all of the operational and financial goals of the Company were achieved, and, as a result, less than 100% of at-risk compensation was paid to employees. Witness McLeod proposed in his direct testimony an accounting adjustment that provides for 100% of the plan target based on employees meeting all operational and financial goals during the year.

Public Staff witness Fernald testified that she agreed that incentive pay, such as DNCP's AIP, represents a part of employees' overall compensation. However, witness Fernald explained that the actual amounts paid to employees under the AIP could vary widely. AIP payout percentages in the last five years have ranged from a 20% payout during the test year to 100% payouts in 2013 and 2014. Witness Fernald recommended that the three-year average of the payout percentage, amounting to 73.33%, be used to determine the amount of AIP expense for this proceeding.

Nucor witness Kollen recommended that the ratemaking level of AIP expense should be limited to the lesser of: (a) the expense incurred in the test year, if the Company's actual payout was less than 100% of target; or (b) 100% of target, if its payout exceeded 100% of target. Witness Kollen contended that the concept underlying the AIP is that employees are paid for performance and that a portion of their payroll is at risk and the Commission should not require customers to pay for performance that the Company did not achieve. Witness Kollen proposed to reduce the Company's adjustment from 100%, as proposed, down to 20% to reflect the actual test year payout.

Company witness McLeod testified in rebuttal that the methodology used by the Company in this case is consistent with the methodology approved by the Commission in 2012 Rate Case. Witness McLeod requested that the Commission again allow the Company to incorporate AIP expense at the 100% target payout percentage and to continue to incentivize high employee performance for the benefit of DNCP's customers. Witness McLeod asserted that Nucor witness Kollen's ratemaking adjustment for AIP expense was asymmetric. Witness McLeod testified that the AIP payout percentage during the test year was the single lowest payout in at least the past eight years.

The Stipulation provides for a normalized level of AIP expense based on the three-year average of the payout percentage of 73.33% as proposed by witness Fernald. The record shows that the Company's AIP payout percentage is, on average, well above the 20% payout percentage recommended by witness Kollen. Therefore, the Commission finds and concludes that for the present case the level of AIP expense presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Employee Severance Program Costs

In the Company's supplemental filing, witness McLeod proposed to include a normalized level of employee severance program costs for ratemaking purposes based on the average severance program costs during the years 1994 through 2016. The normalized annual level of severance costs was determined by dividing the average severance program costs by 4.4 years, the average frequency of severance programs as determined by the Company.

Public Staff witness Fernald explained that in the 2012 Rate Case, an ongoing level of severance program costs was included in rates based on the actual costs of the Company's 2010 employee severance program, which at that time was its latest corporate-wide severance program. Witness Fernald discussed DNCP's most recent employee severance program, the Organizational Design Initiative (ODI), which was announced during the first quarter of 2016. Witness Fernald recommended that the level of employee severance program costs for ratemaking purposes in this proceeding be based upon the actual cost of the most recent corporate-wide severance program, amortized over five years. These costs are lower than the employee severance costs allowed in the 2012 rate case, according to witness Fernald, but this reflects the fact that the costs of ODI, and the savings it generated for ratepayers, were lower than those of the Company's previous programs.

Nucor witness Kollen testified that the scope and frequency of prior employee severance has varied considerably, and thus there is no "normal" employee severance program cost. According to witness Kollen, the Company's change in methodology from its initial filing to its update filing demonstrates how the "normalized" expense can be affected by the selection of the programs to be included, the scope and cost of the programs, and the frequency of the programs. It also demonstrates, according to witness Kollen, that one event can significantly affect the average cost, amortization period, and amortization expense.

Witness Kollen recommended that the Commission reject the approach proposed by the Company. Instead, he recommended that the Commission establish a policy that allows the

Company to defer the costs of major severance programs, subject to a reasonableness test showing savings in excess of costs, and then amortize and recover those costs over a reasonable period coincident with reflecting the savings in rates, including a return on the unamortized costs. In this case, witness Kollen proposed that the Commission authorize the Company to defer the costs of the ODI, include the costs in rate base, and amortize the costs over a 10-year period, which is equivalent to the longest interval without a severance program in the last 27 years.

In rebuttal testimony, Company witness McLeod explained that in the 2012 Rate Case, the Commission concluded the normalized level of employee severance program costs should reflect "actual historical operating experience" and "should be recovered at a level consistent with DNCP's historical practice.…" According to witness McLeod, the Public Staff and Nucor are calculating the going level of severance program costs based solely on ODI, which is by far the least cost program in the past 22 years.

DNCP witness Stevens, in his rebuttal testimony, disputed Nucor witness Kollen's recommendation for the Commission to establish a deferral accounting approach to employee severance program costs. Stevens contended that the deferral mechanism approach suggested by Nucor does not meet the standard or threshold the Commission sets for establishing regulatory assets. According to witness Stevens, the matter is really a debate about the appropriate level of expense to reflect in the cost of service for ratemaking purposes.

The Stipulation provides for a normalized level of employee severance program costs based on the cost of ODI over a five-year period, as recommended by the Public Staff. The Commission finds and concludes that for the present case the accounting adjustment presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented. This approach is consistent with the methodology approved by the Commission in the Company's most recent rate case, which provided for an ongoing level of employee severance program costs and is consistent with DNCP's historical practice of instituting such programs. The Commission in not persuaded by witness Kollen's recommendation to establish a deferral accounting practice for severance costs to be amortized over a protracted period of time. Therefore, the Commission concludes that Nucor witness Kollen's recommendation should be rejected.

Section 199 – Domestic Production Activities Deduction

In supplemental testimony, Company witness McLeod defined the Section 199 – Domestic Production Activities Deduction (Section 199 Deduction or DPAD) as a federal incentive pursuant to Internal Revenue Code §199, which is a permanent benefit available for the generation of electricity – *i.e.,* a federal incentive to manufacture certain goods in the United States. The deduction is equal to 9% of the Company's taxable income attributable to the generation of electricity. Witness McLeod proposed a ratemaking Section 199 Deduction based on a five-year average for the years 2011-2015, on a stand-alone basis for DNCP.

Public Staff witness Fernald explained that the Section 199 Deduction is a tax credit that can be taken by DNCP on the taxable income associated with generation of electricity. A major factor in the computation of taxable income, according to witness Fernald, is the amount of tax depreciation, including bonus depreciation, taken by the Company. Witness Fernald stated that the more bonus depreciation taken, the greater the tax deduction for depreciation expense, and the lower the taxable income. Witness Fernald further explained that the amount of bonus depreciation that could be taken was different in 2011 than what could be taken in 2012 through 2015. In 2011, under the then-current tax laws 100% of the cost of newly acquired property could be deducted as bonus depreciation; however, beginning January 1, 2012, the bonus depreciation deduction decreased to 50% of the cost of the property, where it is set to remain until December 31, 2017. After that it is set to decrease to 40% for 2018, and then to 30% for 2019. Public Staff witness Fernald additionally testified that due to the 100% bonus depreciation deduction in 2011, the Company experienced a net operating loss for that year and was thus unable to utilize the Section 199 Deduction for that tax year. Based on all the above information, witness Fernald concluded that 2011 should not be included in calculating the average Section 199 Deduction, and instead recommended that the Section 199 Deduction be calculated based on the average of the four years from 2012 through 2015, the years for which bonus depreciation was at the current rate of 50%.

Nucor witness Kollen discussed the calculation of the retention factor and claimed the Company failed to include the DPAD in the retention factor (applicable to the increase in taxable income resulting from the rate increase). Witness Kollen testified that the Section 199 Deduction was calculated as 9% of the utility's production taxable income subject to various potential limitations. In the ratemaking process, according to witness Kollen, the test year income tax expense included in the revenue requirement was calculated in two steps. The first step calculates the income tax expense included in operating income and in the operating income deficiency before the rate increase. This calculation includes the Section 199 Deduction on production taxable income, including the effects of any limitations. The second step calculates the income tax expense on the rate increase resulting from the claimed operating income deficiency. The operating income deficiency was grossed up for income taxes and other revenue related expenses through the retention factor to calculate the revenue deficiency or rate increase. Witness Kollen testified that in this second step, the income tax expense on the rate increase was included in the rate increase itself. According to witness Kollen, the calculation assumes that the entirety of the rate increase is subject to income taxes and should reflect all related deductions, including the Section 199 Deduction, and the Section 199 Deduction is fully available without any limitation because the limitations are already embedded into the calculation of the operating income deficiency. Witness Kollen proposed to revise the Section 199 Deduction stating that the federal income tax rate should be reduced by the 9% Section 199 Deduction times the ratio of the production rate base to the sum of the production, transmission, and distribution rate base before it is reflected in the calculation of the retention factor.

In rebuttal testimony, Company witness McLeod explained that Public Staff witness Fernald changed the allocation factor used by the Company for the SIT expense Section 199 Deduction from the Net Book Income factor to the production allocation factor (Factor 1). According to witness McLeod, this is inconsistent with witness Fernald's recommendation to allocate all income tax expense based on the Net Book Income factor.

Witness McLeod concluded that the five-year average Section 199 Deduction produces a reasonable result that should be utilized for ratemaking purposes.

Company witness Warren testified in rebuttal that tax law permits a business to claim a Section 199 Deduction equal to 9% of the lesser of: (1) certain qualified net income (referred to as QPAI); (2) the taxpayer's taxable income; or (3) 50% of the W-2 wages associated with the production of the QPAI. To qualify as QPAI, according to witness Warren, the net income has to be derived from specified activities associated with manufacturing, and the generation of electricity is an eligible activity. Witness Warren asserted that Nucor witness Kollen's proposal was inappropriate because it assumes the DPAD is fully available without any limitation. Witness Warren explained that the DPAD is limited; it is only available for QPAI. Moreover, witness Warren testified that it is limited by taxable income and by 50% of W-2 wages and, therefore, cannot be presumed to be "fully available." Witness Warren contended that witness Kollen's approach implicitly presumes that additional revenue will produce additional QPAI in the same amount and that there will be no taxable income or W-2 wage limitation on the DPAD computation. Unlike other tax deductions, witness Warren explained that the amount of the DPAD is a function of the interaction of a number of variables, and presuming that additional revenues will necessarily produce additional DPAD is overly simplistic.

Witness Warren explained that the Financial Accounting Standards Board (FASB) analyzed and characterized the DPAD in 2004, soon after the enactment of the tax law provision that established the DPAD, and considered how to properly reflect the DPAD for financial reporting purposes. Witness Warren testified that the FASB made a determination that the Section 199 Deduction should not be treated as an adjustment to the income tax rate, but instead, it should be treated as a "special deduction," which is recognized only in the year in which it is deductible on the tax return. The reason for this conclusion was that the DPAD is contingent upon the future performance of specific activities, including the level of wages. Witness Warren contended that the FASB's conclusion is consistent with his recommendation to exclude the DPAD from the retention factor.

Company witness Stevens contended that Nucor witness Kollen double counted the Section 199 Deduction by incorporating his own adjustment, while also leaving in the Company's standalone regulatory accounting adjustment for the Section 199 Deduction in the revenue requirement. According to witness Stevens, witness Kollen also misapplied his own methodology by applying the change in the retention factor to the Company's entire North Carolina jurisdictional rate base. The proper ratemaking exercise, according to witness Stevens, is to derive a Section 199 Deduction effect only for the additional revenue required to produce the targeted return on equity. Stevens testified that Nucor witness Kollen overstated the impact of the proposed retention factor by $1.5 million. Witness Stevens also testified that other electric utilities under the jurisdiction of the Commission do not utilize a retention factor that is comprised of a Section 199 Deduction, and witness Kollen's proposal represents a significant deviation from past regulatory practice for electric utilities in North Carolina and would lead to inaccurate results. Witness Stevens recommended that the Commission reject witness Kollen's proposal.

The Stipulation provides for a normalized level Section 199 Deduction based on an historical average for the four years 2012-2015 as recommended by Public Staff witness Fernald.

Based on the foregoing, the Commission finds and concludes that Nucor witness Kollen's proposal to include the Section 199 Deduction as a component of the retention factor is inappropriate. The Commission does not find the evidence presented by Nucor witness Kollen convincing, nor does it agree that the incremental revenue increase approved in this case would produce an additional Section 199 Deduction tax benefit. The Commission agrees with the testimony of Company witness Warren that the Section 199 Deduction is more appropriately characterized in the current proceeding as a special deduction, subject to taxable income and wage limitations. Thus, the Commission finds and concludes that it is inappropriate to include the Section 199 Deduction as a component of the retention factor for purposes of determining revenue requirement. Further, the Commission finds and concludes that for the present case the accounting adjustment presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Income Tax Expense Allocation

Public Staff witness Fernald testified that the Company allocated income tax expense as follows:

> (1) The Company allocated current and deferred SIT expense to North Carolina retail based on the net book income.
>
> (2) The Company allocated the deferred federal income tax (FIT) expense (i.e., the federal income tax expense associated with revenues and expense items that are recognized in different periods for tax purposes due to timing differences) based on the nature of the timing differences.
>
> (3) The Company allocated the current federal income tax expense based on federal taxable income.

Witness Fernald contended that the income tax expense included in the cost of service for ratemaking should be the amount of income tax expense based on book taxable income, regardless of whether for tax purposes the Company will pay that tax now or later due to timing differences. Therefore, witness Fernald stated, the more appropriate allocation factor for income tax expense is the net book income factor. As such, Public Staff witness Fernald proposed an adjustment to allocate all income tax expense based on net book income.

In rebuttal testimony, Company witness McLeod testified that Schedule 6 (Current Income Tax) and Schedule 7 (Deferred Income Tax) of the Company's cost of service study (COSS) in NCUC Form E-1, Item 45a include detailed calculations of current and deferred FIT expense on both a system level and North Carolina jurisdictional basis. Witness McLeod explained that Schedule 6 contains computations of taxable income for the test period based on the level of operating revenue and expense as determined in the Company's other COSS schedules and an allocation of the various book/tax timing differences, and deferred taxes are allocated among the Company's four jurisdictions in COSS Schedule 7 based on the underlying book/tax timing difference, which corresponds with Schedule 6. Witness McLeod noted that this methodology is consistent with the methodology approved in both of DNCP's most recent rate cases - the 2010 Rate Case and the 2012 Rate Case. Witness McLeod noted that although the Public Staff's audit did not reveal any inherent flaws in the Company's methodology, the Public Staff recommended a complete departure from the methodology proposed by the Company.

Witness McLeod explained that the Company allocates SIT expense to the North Carolina jurisdiction based on the Net Book Income factor because the Company does not have the same level of detail for SIT expense during the test year as it did for FIT expense. Witness McLeod asserted that under these circumstances, it is appropriate to make simplifying assumptions in order to produce a reasonable result for ratemaking purposes. Witness McLeod explained that the Company does, however, have detailed information regarding the book/tax timing differences for FIT expense, and as a result, the methodology in the COSS produces a more accurate and precise allocation of FIT expense than the Public Staff's approach.

According to Company witness McLeod, there are two primary reasons why the methodology in COSS produces a more precise allocation of FIT expense than the Net Book Income factor. First, witness McLeod testified that the Net Book Income factor does not account for all of the permanent differences between book income and taxable income, which causes the Company's effective tax rate to deviate from the statutory rate and will cause the effective tax rate to be different between the Company's jurisdictions. The second item that will cause the Net Book Income factor to not properly reflect North Carolina's appropriate allocable portion of FIT expense, according to witness McLeod, is income tax credits. Witness McLeod argued that since income tax credits are not included in the calculation of the Net Book Income factor, the Public Staff's proposed methodology overrides the allocator designated in the COSS and replaces it with the Net Book Income factor resulting in an inappropriate shift of tax benefits between the jurisdictions. In concluding his testimony, witness McLeod recommended that the Commission allocate FIT expense based on the methodology in the Company's cost of service study since this provides a more precise determination of North Carolina jurisdictional FIT expense.

The Stipulation allocates FIT expense based on the methodology in the Company's cost of service study, as recommended by Company witness McLeod. The Commission finds and concludes that for the present case, the accounting adjustment is just and reasonable to all parties in light of all the evidence presented.

<u>Non-Fuel Variable O&M Expense Displacement</u>

Public Staff witness Maness testified that DNCP made pro forma adjustments to include in the cost of service the full costs of the Brunswick County CC, which began commercial operation on April 25, 2016, including adding incremental non-fuel variable operating and maintenance (O&M) expenses to reflect a full year of operation. With the addition of the Brunswick County CC, witness Maness testified that other plants in DNCP's fleet will operate less frequently, and thus incur fewer non-fuel variable O&M expenses. Therefore, witness Maness asserted, the Public Staff proposed to adjust non-fuel variable O&M expenses to prevent the inclusion in cost of service of more than an annual level of these types of expenses. Otherwise, operating revenue deductions would include both (1) a general annualized and normalized level of variable expenses and (2) the incremental variable expenses related to specific new generation facilities.

In his rebuttal testimony, Company witness McLeod testified that the Company agrees with certain aspects of witness Maness' adjustment for purposes of this case. Specifically, the Company agrees that the addition of the Brunswick County CC will result in some level of purchased power energy savings recovered through base non-fuel rates, and thus proposed in its rebuttal testimony a purchased energy savings adjustment to reduce purchased energy costs proportionate to a pro forma level of the Brunswick County CC generation. However, witness McLeod testified that the Company disagrees with the portion of the adjustment pertaining to energy-related expenses not adjusted elsewhere for growth. Witness McLeod explained that the adjustment is premised on the fact that the Company has included a fully annualized level of Brunswick County CC operating expenses, which was the Company's intent. However, upon further evaluation, the Company determined that its initial adjustment to annualize the Brunswick County CC O&M expense did not include a provision for maintenance outage expenses, which will result in a significant level of cost when incurred. Furthermore, witness McLeod testified that witness Maness' displacement adjustment also does not account for these maintenance outages as the adjustment assumes that the Brunswick County CC will operate for 12 full months. According to witness McLeod, the Public Staff's displacement adjustment, if accepted in full, would understate the level of energy-related expenses necessary to serve the end-of-period customers at the normalized level of generation.

In rebuttal testimony, witness McLeod proposed a new accounting adjustment that reflects an annualized level of purchased energy savings in base non-fuel rates as a result of the Brunswick County CC commencing commercial operation. Witness McLeod recommended that the Commission reject Public Staff witness Maness' displacement adjustment, and incorporate witness McLeod's adjustment that reflects an annualized level of purchased power energy savings for the Brunswick County CC.

The Stipulation reflects an annualized level of purchased power energy savings for the Brunswick County CC as proposed by Company witness McLeod. At the hearing, Public Staff witness Maness testified that while not necessarily agreeing with all aspects of the calculation of this adjustment, the Public Staff accepted it in the Stipulation for purposes of this proceeding only.

Based on the testimony of Public Staff witness Maness and DNCP witness McLeod, and the Stipulation, the Commission finds and concludes that the O&M displacement adjustment, as agreed to in the Stipulation, is just and reasonable to all parties in light of all the evidence presented and should be accepted for purposes of this proceeding.

Depreciation Rates for Warren County CC and Brunswick County CC

Nucor witness Kollen testified that for depreciation expense and rates reflected in the revenue requirement for Warren County CC and Brunswick County CC, the Company used the per books depreciation expense for June 2016, after several adjustments detailed in its workpapers, and annualized the adjusted depreciation expense. According to witness Kollen, the depreciation rates for the per books depreciation expense were provided to the Company by witness John Spanos, a consultant with Gannett Fleming, in a single page letter. The letter included no additional support, analyses, or workpapers, all of which typically are provided in conjunction with an actual depreciation study performed by an expert. The letter states that the depreciation rates "are based on a 36-year life span, interim survivor curves and future interim net salvage percents where applicable. Each of these parameters is established with the general understanding of the new facility and the estimates of comparable Dominion facilities." Witness Kollen stated that the letter provides the proposed interim survivor curve, net salvage rates, and annual depreciation accrual rates for each plant account.

Witness Kollen testified that the Commission should not simply accept the Company's proposed depreciation expense and rates for these units. Witness Kollen contended that there is no support for the parameters used by witness Spanos other than general references to other units owned and operated by the Company. Witness Kollen asserted that he had reviewed the relevant pages from the Company's most recent depreciation studies, and found that the survivor curves and net salvage parameters proposed by witness Spanos did not match any of the Company's other units. He also found that there was a range of life spans for the Company's other CC units from 34 years to 45 years.

In support of his position, witness Kollen testified that one of witness Spanos' colleagues, Ned W. Allis, recommended a 40-year life span for new combined cycle units in a pending Florida Power & Light Company (FPL) proceeding, a change from the 35-year life span that witness Allis recommended in the prior FPL proceeding for new combined cycle units. With that evidence, witness Kollen recommended a 40-year life span for the Warren County CC and Brunswick County CC. Nucor witness Kollen testified that this is the midpoint of the range for the Company's other combined cycle units and is the same life span recommended by witness Allis. Witness Kollen further recommended that the Commission ignore projected interim retirements and net salvage in this proceeding since these units are new and have almost no history of interim retirements or net salvage. Witness Kollen argued that these parameters should be introduced and supported by competent evidence in the Company's next depreciation study.

In response to Nucor witness Kollen's proposal, Company witness Stevens explained in rebuttal that the Company's depreciation consultant provided specific guidance on appropriate depreciation accruals based on informed judgment for Warren County CC and Brunswick County CC. Witness Stevens stated that expert opinion directs that a 36-year useful life for Warren County CC and Brunswick County CC is appropriate given the operating characteristics of these combined cycle units, reviews of Company practice and outlook as they relate to Company operation and retirement, experience of similar existing units within DNCP's generation fleet, and current practice in the electric industry.

DNCP witness Stevens further testified that electric utilities do not experience the exact same performance of a generation facility across the U.S. The expected useful life of a given unit is specific to each utility based on the operating performance of similar units within its owned fleet, the maintenance performance of those units, as well as the expected dispatch characteristics of those units. Witness Stevens contended that a Florida utility's natural gas combined-cycle facility would likely have a different set of operating parameters and conditions and impact on equipment than a natural gas combined-cycle facility constructed by the Company in Virginia.

Witness Stevens also explained that DNCP owns no other combined cycle units with a useful life greater than 36 years. The natural gas combined cycle facilities at Bellemeade, Rosemary, Gordonsville, Chesterfield Unit 7, Chesterfield Unit 8, Possum Point Unit 6, and Bear Garden all have a useful life of 36 years as determined by the Company's depreciation consultant. Witness Stevens noted that this depreciation study was filed with the Commission on April 1, 2013, in Docket No. E-22, Sub 493. Therefore, based on the facts presented, he rejected witness Kollen's testimony that a 40-year life span is the midpoint of the range for the Company's other combined cycle units as inaccurate.

With respect to Nucor witness Kollen's recommendation that the Commission ignore interim cost of removal and net salvage into its depreciation accrual rates for Warren County CC and Brunswick County CC in this proceeding, witness Stevens testified that this practice would be contrary to Generally Accepted Accounting Principles and the FERC USOA.

Witness Stevens further recommended that the Commission reject Nucor's proposed adjustment to the depreciation accruals for Warren County CC and Brunswick County CC.

The Stipulation reflects depreciation expense for the Warren County CC and Brunswick County CC based on the depreciation accrual rates proposed by DNCP.

Based upon the evidence presented in this proceeding, the Commission finds and concludes that the depreciation accrual rates proposed by DNCP for the Warren County CC and Brunswick County CC are appropriate and should be utilized for ratemaking purposes in this case. The Commission concludes that the evidence presented by DNCP supports a useful life of 36 years for these facilities as reasonable for ratemaking purposes until the Company performs another depreciation study. The Commission concludes that Nucor witness Kollen's recommendation to ignore interim cost of removal and net salvage is unsubstantiated and witness Stevens' testimony that witness Kollen's proposal would be contrary to Generally Accepted Accounting Principles and the FERC USOA has not been challenged. Accordingly, the Commission finds and concludes that this recommendation should not be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

The evidence supporting these findings of fact and conclusions is contained in the verified Application, the testimony and exhibits of Company witnesses McLeod, Haynes, and Stevens and Public Staff witnesses Fernald and Floyd, and the Stipulation.

In the Company's Application, Company witness McLeod testified that HB 998 was signed into law on July 23, 2013. According to witness McLeod, prior to the passage of HB 998, the North Carolina SIT rate was 6.9%, and HB 998 made the following changes to the NC SIT Rate:

- Reduced to 6% effective January 1, 2014;
- Reduced to 5% effective January 1, 2015; and
- Reduced to 4% effective January 1, 2016, assuming certain triggering events occurred, as set forth in the legislation.

Witness McLeod explained that after the passage of HB 998, the accumulated deferred North Carolina SIT balance was overstated based on the legislative changes to the statutory corporate tax rate, or in other words, contained "excess" deferred income taxes (EDIT). In its Order Establishing Procedure for Implementation of Session Law 2015-6 in Docket No. M-100, Sub 138 issued on September 11, 2015, the Commission ordered DNCP to hold the EDIT in a regulatory liability account to be refunded to ratepayers in the context of DNCP's next general rate case proceeding. Witness McLeod testified that the Company is proposing a methodology in this case for crediting the North Carolina jurisdictional portion of the EDIT to customers as this is the first general rate case since the Company established the EDIT regulatory liability.

Company witness McLeod proposed to refund the EDIT to customers through a decrement rider over a two-year period (Rider EDIT). This mechanism, according to witness McLeod, provides transparency as the credit is differentiated from the base rate cost of service. Additionally, excluding the credit from the base rate cost of service will defer the need for a subsequent base rate case after the credit is fully amortized. Witness McLeod testified that this approach returns the credit to customers in an efficient and timely manner, and is equitable to both the Company and customers.

Witness McLeod proposed to include capital savings associated with the regulatory liability until the liability is fully returned to customers. According to witness McLeod, the capital savings decline as the regulatory liability is credited to customers over the two-year period; therefore, the revenue requirement during the first year is greater than the revenue requirement in the second year. Witness McLeod discussed the Company's methodology for determining the North Carolina jurisdictional EDIT to be refunded to customers based on a retrospective analysis of the methodologies approved by the Commission for allocating deferred North Carolina SIT expense in DNCP's previous base rate cases.

With respect to the level of SIT expense included the base non-fuel revenue requirement, witness McLeod proposed an accounting adjustment to reduce NC SIT expense for ratemaking purposes based on an apportioned NC SIT rate that includes a 4% statutory rate.

In direct testimony, Company witness Haynes proposed to allocate the Rider EDIT credits to customer classes based upon North Carolina rate revenue for 2015. Witness Haynes developed a decrement rate based upon actual 2015 kWh sales to be applied to each customer's 2015 sales. The total credit amount for each customer will be amortized over 12 months and provided through a monthly bill credit.

Public Staff witness Fernald testified regarding the history of HB 998, noting that it also added a new section, G.S. 105-130.3C, to the General Statutes concerning possible future rate reduction triggers. On August 4, 2016, the North Carolina Department of Revenue announced that pursuant to G.S. 105-130.3C, the corporate tax rate for tax years beginning on or after January 1, 2017, will be reduced from 4% to 3%. Witness Fernald testified that there are no restrictions on how EDIT should be refunded to ratepayers, and explained that the Public Staff believes that the manner in which EDIT should be refunded to ratepayers, including the period over which the EDIT is amortized, should be determined on a case-by-case basis in each utility's next general rate case. In this particular case, witness Fernald explained, in addition to the need for EDIT collected from past ratepayers to be returned to future ratepayers, there are several deferrals, which represent costs incurred to provide service to past ratepayers that will now be recovered from future ratepayers.

In this case, Public Staff witness Fernald proposed an EDIT regulatory liability of $15,708,000, which included the additional EDIT related to the decrease in the tax rate from 4% to 3% that was announced on August 4, 2016. She identified several regulatory assets and liabilities whose amortizations end in 2017, and proposed re-amortizing the unamortized balances for these assets and liabilities, since these amortizations will end in 2017 and will not continue on an ongoing basis. The total deferred costs and unamortized balances for regulatory assets and liabilities with amortizations ending in 2017 to be recovered from North Carolina ratepayers in this proceeding, as recommended by Public Staff witness Fernald in her testimony, are as follows:

Deferred Costs	Total Cost to be Recovered from NC Ratepayers
Warren County CC Deferral	$10,204,000
Brunswick County CC Deferral	2,957,000
Chesapeak Closure Costs	1,504,000
North Branch Net Proceeds/Costs	175,000
Unamortized Balances	
Unamortized Desighn Basic Costs - Surry	39,000
NUG Buyout Costs - Atlantic	104,000
NUG Buyout Costs - Mecklenburg	481,000
Bear Garden Deferral	593,000
DOE Settlement	(565,000)
Total per Public Staff	$15,492,000

Public Staff witness Fernald testified that both the EDIT liability and the deferred costs and unamortized balances listed above represent revenues collected or costs incurred in providing service to past ratepayers that will now be returned to or recovered from future ratepayers. Consequently, witness Fernald recommended that, instead of a decrement rider as proposed by the Company, the refund of the EDIT liability should be treated in the same manner as the recovery of these deferred costs and unamortized balances based on the circumstances in this proceeding. Therefore, witness Fernald recommended that both the EDIT liability and the deferred costs and unamortized balances listed above be included in the cost of service through a levelized amortization. Since the difference between the impact on rates of amortizing the EDIT liability and the deferrals and unamortized balances over three years and the impact of amortizing them over five years is not substantial, witness Fernald recommended that the levelized amortization of the EDIT liability and deferred costs and unamortized balances listed above be amortized over a three-year period using the after-tax rate of return recommended by the Public Staff in this proceeding.

With respect to the level of SIT expense included the base non-fuel revenue requirement, Public Staff witness Fernald proposed accounting adjustments to reflect the reduction in the North Carolina corporate tax rate from 4% to 3% effective for taxable income on or after January 1, 2017.

Public Staff witness Floyd testified that he recommended the Commission reject DNCP's proposed Rider EDIT. Witness Floyd stated that the Public Staff is concerned that although the EDIT was collected from customers over many years, that it will only be repaid to those who were customers during 2015. Witness Floyd testified that he believed witness Fernald's approach to the EDIT credit to be best as it returns the EDIT to all customers and removes the need for a Rider.

In rebuttal testimony, Company witness Stevens testified that a decrement rider provides greater precision in order to demonstrate to multiple constituents – the Commission, North Carolina customers, and the North Carolina General Assembly – that the amount to be refunded did in fact get refunded. Witness Stevens testified that a decrement rider provides greater transparency on the EDIT refund to North Carolina customers. DNCP's decrement rider approach, according to witness Stevens, is preferable because it credits the EDIT back to North Carolina customers more quickly in two years compared to the Public Staff's recommended three years.

Company witness McLeod accepted the total EDIT regulatory liability of $15,708,000 presented by Public Staff witness Fernald. Witness McLeod also accepted the Public Staff's recommendation to calculate the EDIT regulatory liability amortization on a levelized basis using an annuity factor. These changes were reflected in the Rider EDIT credit amounts presented in witness McLeod's rebuttal schedules and exhibits. Witness McLeod also accepted witness Fernald's accounting adjustments to reduce the level of NC SIT expense in the base non-fuel revenue requirement to reflect the reduction in the NC corporate tax rate from 4% to 3% effective for taxable income on or after January 1, 2017.

With respect to Rider EDIT, Company witness Haynes proposed that after Year 1, any over or under-recovery of the credit amount should be deferred and added (or subtracted) as appropriate from the Year 2 credit amount. Such amount should be allocated based upon the annualized revenue in witness Haynes' rebuttal exhibits. Witness Haynes proposed that prior to the tenth month from the effective date of the Year 2 rider, DNCP will provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of Year 2. For any deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff will work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect.

The Stipulation provides that the appropriate level of EDIT to be refunded to customers in this case is $15,708,000 (on a pre-tax basis), which includes EDIT associated with the January 1, 2017, reduction in the North Carolina corporate state income tax rate from 4% to 3%. DNCP shall implement a decrement rider, Rider EDIT, as described in the rebuttal testimony of Company witnesses McLeod and Haynes, to refund EDIT to customers over a two-year period on a levelized basis, with a return. As shown on Settlement Exhibit IV, the appropriate amount to be credited to customers is $16,816,000, which should be credited to customers via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11.[1]

Further, pursuant to Section 2.4.(a) of Session Law 2015-6, the Commission must adjust the rate for the sale of electricity, piped natural gas, and water and wastewater service to reflect all of the tax changes as enacted in HB 998. Under G.S. 105-130.3C, as enacted in HB 998, an automatic reduction in the State corporate income tax rate from 4% to 3% will become effective for the taxable year beginning on or after January 1, 2017, because certain net General Fund tax collection levels were met for the State's fiscal year 2015-2016. The base non-fuel rate revenue requirement in the Stipulation appropriately reflects the 3% NC SIT rate effective for the taxable year beginning on or after January 1, 2017.

The Commission finds and concludes that for the present case the ratemaking treatment of the EDIT regulatory liability presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented. The Commission also finds and concludes that the base non-fuel rate revenue requirement in the Stipulation reflects the 3% NC SIT rate effective for the taxable year beginning on or after January 1, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact and these conclusions is contained in the verified Application, the Stipulation, the testimony and exhibits of the DNCP and Public Staff witnesses, and the entire record in this proceeding.

In the Company's Application, Company witness McLeod requested Commission approval of a levelization methodology on its books and records for its nuclear refueling and maintenance outage expenses. Witness McLeod testified that DNCP operates four nuclear units: two units at Surry and two units at North Anna. The Company utilizes a "3/3/2" planning practice for scheduling nuclear outages, meaning the Company performs three outages in two successive years, then two outages every third year.

According to witness McLeod, the Company incurs substantial outage costs during the refueling outages, and absent the levelization accounting treatment on its books and records, DNCP experiences and will continue to experience significant variability in its annual operating costs which causes the cost of service for one year to appear inconsistent with a previous year. DNCP requested approval of a levelization methodology in order to minimize this variability and to better match the refueling outage expenses with the period over which the benefit is realized. Witness McLeod stated that this request for accounting authority is not intended to modify the Company's existing approach to levelizing nuclear outage expenses for ratemaking purposes. Witness McLeod noted that the Commission approved similar accounting treatment in the most

[1] On October 19, 2016, the Company filed proposed Rider EDIT to be implemented on November 1, 2016. The Rider EDIT rates for each customer class are identified on pages 129 and 260 of the Company's October 19 filing, and the supporting workpapers are included on page 291.

recent general rate case proceedings for Progress Energy Carolinas, now Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC).[1]

Witness McLeod testified that under this accounting methodology, costs incurred during the three months leading up to an outage, costs incurred during the typical two-month outage period, and trailing costs incurred during the three months after an outage are deferred to a regulatory asset account. The deferrals are amortized over the period of the operating cycle between scheduled refueling for the unit, not to exceed 18 months. Amortization begins the month following completion of the outage and adjustments are made for trailing costs.

Public Staff witness Fernald testified that the Company implemented deferral and amortization of nuclear refueling outage costs on its books in April 2014 pursuant to Virginia legislation. Prior to this change, the Company expensed nuclear refueling outage costs in the month that the costs were incurred. According to witness Fernald, the Company has accounted for nuclear refueling outage costs since April 2014 as follows:

> (1) The costs related to nuclear refueling outages are recorded to the appropriate O&M expense account as incurred, as was done in the past.
>
> (2) A credit is recorded to FERC Account 407.4 – Regulatory Asset Deferral O&M for the costs being deferred. When this credit is netted against the amount charged to O&M expense, the costs being deferred are in effect removed from the cost of service. The Company decided that costs eligible for deferral include incremental costs incurred three months prior to the outage, during the outage, and three months after the outage. Specific details regarding the types of incremental costs eligible for deferral are provided in Fernald Exhibit 3.
>
> (3) The deferred costs are then amortized over the refueling cycle, not to exceed 18 months, and the amortization expense for the costs is recorded to FERC Account 407.3.

Witness Fernald explained that in prior rate cases, pro forma adjustments have been made to normalize nuclear refueling outage costs for DNCP. With levelized accounting, the costs reflected in the Company's financial statements will be consistent with the ratemaking treatment of the costs, according to witness Fernald. In future rate proceedings, the test period amounts produced by this levelized accounting method will be the starting point in determining normal nuclear refueling outage expenses, subject to appropriate ratemaking adjustments.

Witness Fernald testified that DNCP's nuclear refueling outage deferral window for nuclear refueling outage costs is a longer period of time than that used by DEC and DEP. Witness Fernald testified that the accounting procedures established by DNCP are used for regulatory purposes in Virginia, and the Public Staff does not believe that the difference in the nuclear refueling outage deferral window necessitates the time and effort required to maintain a different accounting treatment for North Carolina. Public Staff witness Fernald emphasized that the amounts

[1] Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013), Finding of Fact No. 31, and Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sept. 24, 2013), Finding of Fact No. 36.

to be recovered for nuclear refueling outage costs are always subject to review in North Carolina rate cases.

Witness Fernald recommended approval of the Company's levelized accounting treatment with the following conditions:

> (1) The regulatory asset associated with the nuclear refueling outage deferral accounting will not be included in rate base in rate cases. The Company has made an adjustment in this proceeding to remove the nuclear refueling outage deferral balance in regulatory assets from rate base.
>
> (2) Under the Virginia legislation, the amortization period is to be no more than 18 months. The amortization period should be consistent with the refueling cycle of the nuclear units, which currently is 18 months. If DNCP changes the frequency of the refueling cycle for any of its nuclear units in the future, the amortization period for the deferral accounting should be changed to reflect the change in the refueling cycle.

Nucor witness Kollen testified that the change in accounting would result in a one-time reduction in maintenance expense. The Company's proposal will delay the nuclear outage expense for accounting purposes by approximately 18 months to reflect the fact that the costs will be deferred when incurred and then amortized to expense over the period between outages instead of being expensed when incurred. According to witness Kollen, if this accounting is authorized by the Commission, the Company's nuclear outage expense will be reduced when each of the next four outages occur, in other words, there will be a one-time savings in O&M expense. Witness Kollen contended that the Company would retain the one-time savings if the Commission does not direct the Company to defer and amortize the savings as a reduction to expense for ratemaking purposes.

Witness Kollen proposed that the Commission adopt the change in accounting for ratemaking purposes, subject to a deferral and amortization of the one-time savings in expense.

In rebuttal testimony, Company witness Stevens testified that Nucor witness Kollen mischaracterized the financial impacts of implementing the nuclear outage levelization accounting methodology on DNCP's books and records. Witness Stevens argued that the new accounting methodology did not change the cost of nuclear outages. Operating expense in the period was reduced when this accounting methodology was first implemented. However, this was not a "one-time savings," but instead a timing difference resulting from implementation of a new accounting methodology.

Witness Stevens argued that witness Kollen's proposal to establish a regulatory liability for nuclear outage expenses is inappropriate as nuclear outage costs are a component of the base non-fuel rate cost of service, and the Company is not recovering these costs dollar for dollar. According to witness Stevens, an analysis demonstrates that the incurred costs in the past few years are greater than the normalized level of nuclear outage costs approved by the Commission in its 2012 Rate Case. The Company incurred system level average costs for this period of $83.680 million compared to the system level costs included in base rates of $78.163 million. Therefore, witness Stevens concluded that there are no one-time savings or windfalls as suggested by witness Kollen.

The Stipulation provides that the Company may use levelized accounting for nuclear refueling costs, as described in the testimony of Public Staff witness Fernald.

The Commission concurs with DNCP and the Public Staff that implementing this nuclear levelization accounting methodology should have no ratemaking implications, contrary to the proposal set forth by witness Kollen. Accordingly, the Commission finds and concludes that Nucor witness Kollen's proposal to establish a regulatory liability for purported one-time savings associated with establishment of the nuclear outage levelization accounting methodology is inappropriate. The implementation of a new accounting methodology for nuclear outage costs does not change the underlying nature and amount of nuclear outage costs incurred by the Company. The Commission further finds and concludes that DNCP's request to implement levelization accounting for nuclear outage and refueling expenses, as set forth in the Stipulation, is hereby granted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-18

The evidence supporting these findings of fact and conclusions is contained in the verified Application, the testimony and exhibits of Company witnesses Curtis, Hevert, Mitchell and McLeod, Nucor witness Kollen, and Public Staff witness Maness, the Stipulation, and the entire record in this proceeding.

DNCP witness Curtis testified that DNCP's coal combustion residual (CCR) expenditures are the result of efforts by DNCP to comply with the United States Environmental Protection Agency's (EPA's) Standards for Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments (CCR Final Rule), which became effective for DNCP on April 7, 2015.

DNCP witness Mitchell testified that the Virginia Department of Environmental Quality incorporated the CCR Final Rule into its solid waste management regulations in December 2015. He stated that DNCP is developing comprehensive closure and storage plans for the CCR impoundments located at DNCP's operating and non-operating coal plants. Witness Mitchell discussed the Company's plans to close or retrofit the ash ponds and landfills at Chesapeake, Yorktown, Chesterfield, Clover, Mt. Storm, Bremo, and Possum Point Power coal-fired generating stations. He testified that the pond and landfill closures or retrofits are in response to the CCR Final Rule regulating the management of CCR stored in ash ponds and landfills. Witness Mitchell explained that the CCR Final Rule establishes environmental compliance requirements for the disposal of CCR, and provides specifications for construction and closure of CCR ponds and landfills. In addition, witness Mitchell testified that these new regulations also impose higher requirements in the areas of structural integrity standards, public disclosure, location restrictions, inspection, groundwater monitoring and cleanup for existing and new CCR ponds and landfills.

In direct testimony, Company witness McLeod testified that the enactment of the CCR Final Rule created a legal obligation to retrofit or close all inactive and existing ash ponds over a certain period, as well as to perform required monitoring, corrective action, and post-closure care activities as necessary. Witness McLeod explained that the Company recognized ARO liabilities of $385.7 million on a total system basis during the test year for financial reporting purposes in accordance with Accounting Standard Codification (ASC) 410-20 (formerly Statement of Financial Accounting Standard No. 143) related to future ash pond and landfill closure costs.

Witness McLeod testified that the Company eliminates all the effects of ARO accounting pursuant to ASC 410-20 from the cost of service, including the AROs associated with the CCR Rule, in accordance with the Commission's directives in Docket No. E-22, Sub 420. Witness McLeod proposed to defer the actual North Carolina jurisdictional CCR-related cash expenditures incurred through the update period in this case (June 30, 2016) to be amortized over a three-year period commencing with rates approved in this case effective November 1, 2016.

DNCP witness McLeod further testified that the CCR Final Rule requires DNCP to close or retrofit all of its active and inactive coal ash ponds and landfills. He stated that DNCP has eight generating facilities where coal ash remediation must be performed. In his direct testimony, witness McLeod testified that DNCP spent $37.5 million during the test period and anticipated spending an additional $63.8 million through June 2016. He testified that DNCP proposes to defer its portion of the expenditures over a three-year period.

In his supplemental testimony, witness McLeod adjusted the updated January 2015 through June 2016 CCR costs to a total of $84.4 million. He testified that DNCP proposes to establish a regulatory asset in the amount of $4.3 million, North Carolina's allocable share of the CCR costs to date, and to amortize this amount over a three-year period beginning with the effective date of the rates set in this proceeding.

Public Staff witness Maness testified that the Public Staff generally agrees with the concept proposed by the Company of deferring and amortizing the costs incurred through June 30, 2016, over a multi-year period, but does not necessarily agree that this treatment is automatically mandated by the August 6, 2004, Order Allowing Utilization of Certain Accounts in Docket No. E-22, Sub 420 (2004 ARO Order). Witness Maness also disagreed with the Company's proposed three-year amortization period and instead proposed a 10-year amortization. According to witness Maness, the majority of the costs underlying the ARO liability, and thus current and future expenditures, are related to generating assets that have already been retired or are financially impaired and are soon to be retired. He testified that for costs of significant size related to retired or abandoned plants, the Public Staff in recent years has consistently recommended an amortization or levelization period of 10 years, and this period has been approved by the Commission.

In addition, Public Staff witness Maness testified regarding some of the specific CCR work being performed by DNCP, as described by DNCP in response to data requests. Witness Maness stated that four of the DNCP coal-fired facilities are closed, or have been converted to natural gas-fired facilities. At the closed facilities, remediation is taking three different forms: (1) cap and close method; (2) a clean and close method in which the coal ash is moved to an on-site pond that is being capped and closed, and the original impoundment is closed; or (3) the clean and close method, except the original impoundment is used for a new purpose. With regard to operating coal facilities, witness Maness stated that DNCP's work at this point is mainly project planning and engineering.

Witness Maness testified that the Public Staff investigated DNCP's CCR remediation efforts and found that the efforts and costs were prudent and reasonable. He stated that DNCP incurred $84.4 million in cash expenditures for CCR remediation from January 2015 through June 2016. He also provided DNCP's projected CCR costs during the next several years. That amount was filed by DNCP under seal as a confidential trade secret. Witness Maness testified that DNCP has recorded this amount, adjusted to its current fair value, as an ARO. The present amount of the ARO recorded on DNCP's financial statements is $326 million. As these costs are incurred and deferred into a regulatory asset account, that amount will be deducted from the ARO.

With respect to the ongoing deferral of CCR expenditures, witness Maness indicated that the Company plans to defer North Carolina jurisdictional CCR cash expenditures for review by the Commission in future base rate proceedings, and subsequent recovery through base non-fuel rates approved in such proceedings. Witness Maness contended, however, that it was clear from the language of the 2004 ARO Order that the Commission intended that the authorization granted by the Order would have no impact on the ratemaking treatment to be determined by the Commission. He stated that although the 2004 ARO Order could be read as applying to all AROs, it should be noted that at the time of its issuance, the only significant ARO in existence was the one established for nuclear decommissioning. At that time, the Commission already had in place a long-standing, comprehensive mechanism to provide for the tracking and recovery of nuclear decommissioning costs. Witness Maness testified that the purpose of the 2004 ARO Order was to maintain Company accounting to match the Commission’s longstanding accounting and ratemaking treatment of those costs, consistent with the statement in the ARO Order that “the intent and outcome of the deferral process shall be to continue the Commission’s currently existing accounting and ratemaking practices.” However, in the case of CCR expenditures, witness Maness testified that the Commission has not yet decided what the long-standing accounting and regulatory treatment of those costs should be. Therefore, in the absence of any action by the Commission in this case, witness Maness stated that continuing “the Commission’s currently existing accounting and ratemaking practices,” as the 2004 ARO Order requires, would most likely mean that the CCR expenditures through June 30, 2016, and afterwards, would simply be written off to expense in the year incurred. Witness Maness testified that because no prior Commission treatment of CCR costs has been determined, the Company could not simply unilaterally presume that its proposed ratemaking deferral is authorized. Nonetheless, witness Maness testified that in this proceeding the Public Staff has investigated the CCR expenditures that the Company has proposed to defer and amortize, and has determined that the costs were reasonable and prudently incurred. Therefore, the Public Staff recommended the establishment of a regulatory asset for those expenditures.

Given the above, witness Maness made several recommendations regarding ongoing CCR deferrals:

> (1) That the Company be allowed to defer additional CCR expenditures through calendar year 2018, without prejudice to the right of any party to take issue with the special accounting treatment in a regulatory proceeding.
>
> (2) That the Commission note in its order in this proceeding that it is not making any conclusions regarding the prudence and reasonableness of the Company’s overall CCR plan, or regarding any specific expenditures other than the ones it has approved for recovery in this case.
>
> (3) That the annual amortization expense approved for recovery in this proceeding continue to be credited as an offset to any future deferrals recorded by the Company, up until the time rates approved in the Company’s next general rate case go into

effect. Additionally, any other appropriate credits related to CCR expenditures, such as recoveries from third parties or governmental authorities, should be recorded as an offset to any future deferrals.

(4) That the Company be required to file an annual report with the Commission, on the same date it files its annual FERC Form 1 report, detailing the CCR deferrals recorded in the previous calendar year as well as the annual amortization offset and any other offsets recorded.

(5) That because CCR costs are being incurred due to the nature of the coal burned to produce energy over the years, the energy allocation factor be used to determine the North Carolina retail revenue requirement.

Moreover, Public Staff witness Maness testified that, during its investigation in this proceeding the Public Staff became aware that the Company has been or is involved in several legal disputes with various parties regarding its CCR compliance activities or the state of its CCR facilities. Additionally, witness Maness explained that the Company remains subject to possible state and federal findings of non-compliance with applicable statutes and regulations. Witness Maness indicated that the Public Staff has not become aware of any significant costs that have been incurred to date as a result of these disputes. Nevertheless, the Public Staff recommended that the Commission include in its order in this proceeding, in association with any approval of future deferral, a finding that any costs resulting from fines, penalties, other imprudent or unreasonable activities, or corrective actions to address those activities, are not allowable for deferral or recoverable for ratemaking purposes, and that legal costs incurred or settlements reached in resolution of disputes will be subject to close scrutiny to make sure that they are reasonable and appropriate for recovery from ratepayers.

Nucor witness Kollen testified that a three-year amortization period is unduly and unnecessarily short. Witness Kollen explained that a reasonable amortization period for the inactive and retired plants is 10 years, and a reasonable amortization period for the operating plants is the remaining life of each plant. The remaining service lives for the operating plants, according to witness Kollen, range from six to 35 years. Witness Kollen estimated an approximate amortization period based on the remaining service lives of 20 years. For the combined CCR costs of DNCP's retired and operating plants, witness Kollen proposed a 15-year amortization period for all CCR deferrals. Nucor reiterated this position in its post-hearing Brief.

In rebuttal testimony, Company witness Stevens argued that a lengthy recovery period for regulatory assets does not serve the best interests of DNCP's North Carolina customers or the Company. Since the Company is afforded a return on the unamortized balance for ratemaking purposes, witness Stevens argued that a longer amortization period costs customers more in the long run, while delaying the Company's recovery of actually incurred costs in the short run. Witness Stevens contended that delaying recovery of these actually incurred costs produces greater rate instability, and the Company's position strikes a reasonable balance of establishing rates that send accurate price signals to North Carolina customers, while recognizing the appropriate level of cost of service. The Company's proposed non-fuel base revenue increase in this proceeding, according to Stevens, is almost completely offset by a 2017 fuel factor reduction and decrement rider to refund EDIT with the total overall change in North Carolina retail rates approximating 0.2%. Witness Stevens noted that for many customer classes, their bills would reflect an overall decrease in rates on January 1, 2017.

With respect to Nucor witness Kollen's proposal to amortize CCR expenditures over 15 years, witness Stevens explained that the Company anticipates significant additional CCR expenditures subsequent to June 30, 2016, and a short duration for the amortization of this first wave of CCR expenditures is more appropriate. Witness Stevens contended that the Company's position aligns well with the fuel factor reduction and the significant EDIT refund, and setting an appropriate amortization level for this first wave of CCR expenditures allows for greater rate stability when addressing the need to recover additional phases of ongoing CCR compliance in future rate filings.

With respect to Public Staff witness Maness' proposal to amortize CCR expenditures over 10 years, witness Stevens argued that the comparison of the CCR expenditures to the abandonment or impairment and early retirement of a generating facility is neither reasonable nor accurate. Witness Stevens testified that the abandonment or impairment and retirement of a generating facility is a one-time, non-recurring event, while CCR expenditures are recurring and are environmental compliance and remediation costs, not abandoned plant, that will need to be recognized in future rate filings. According to witness Stevens, the Public Staff's proposal will likely result in overlapping vintages of CCR expenditure regulatory asset amortizations in future rate cases. To the contrary, witness Stevens explained that under the Company's proposal, the regulatory asset from the instant proceeding will conclude and be replaced by the next regulatory asset in the next general rate case, allowing for a more smooth transition from one case to the next, and more importantly, achieving greater rate stability for customers.

With respect to witness Maness' discussion regarding the Company's proposed ratemaking treatment of CCR expenditures, Company witness McLeod explained in his rebuttal testimony that the Company has set forth a ratemaking methodology for CCR expenditures in this case, and the Public Staff and other parties have the opportunity to respond. Witness McLeod testified that no one is disputing that the Commission will ultimately rule on the Company's proposed ratemaking methodology for CCR expenditures.

In addition, witness McLeod testified that the Company already requested and the Commission has already granted deferral authority for CCR expenditures in the 2004 ARO Order, and it is not necessary for the Company to request deferral authority from the Commission again for ARO costs beyond 2018 as recommended by Public Staff witness Maness. With respect to witness Maness' recommendation for the Commission to note in its order in this proceeding that it is not making any conclusions regarding the prudence or reasonableness of the Company's overall CCR plan, or regarding specific expenditures other than the ones it has approved for recovery in this case, witness McLeod argued that it is not necessary for the Commission to address future CCR expenditures in this proceeding. Further, witness McLeod disagreed with witness Maness' recommendation for the annual amortization expense approved for recovery in this proceeding continue to be credited as an offset to any future deferral recorded by the Company, up until the time rates approved in the Company's next general rate case go into effect, stating that the Company is not recovering these costs dollar for dollar, they are simply part of the total base non-fuel rate cost of service. Witness McLeod stated that it would be no more appropriate to grant witness Maness' proposal for these costs than it would for any other cost in the base non-fuel cost of service. Witness McLeod also contended that it is not necessary or appropriate for the Commission to address the future ratemaking treatment of fines, penalties, or other litigation costs in this case.

Finally, witness McLeod indicated that the Company accepted the Public Staff's adjustment to calculate the CCR expenditures regulatory asset by the energy factor.

The Stipulation includes the following provisions with respect to CCR costs:

(1) Amortization periods – CCR expenditures incurred through June 30, 2016, should be amortized over a five-year period. Notwithstanding this agreement, the Stipulating Parties further agree that the appropriate amortization period for future CCR expenditures shall be determined on a case-by-case basis.

(2) Deferral of future CCR expenditures – By virtue of the Commission's approval in this proceeding of a mechanism to provide for recovery of CCR expenditures incurred through June 30, 2016, the Company has authority pursuant to the August 6, 2004, Order in Docket No. E-22, Sub 420, to defer additional CCR expenditures, without prejudice to the right of any party to take issue with the amount or the treatment of any deferral of ARO costs in a rate case or other appropriate proceeding.

(3) Continuing amortization and deferral of CCR expenditures – The Company and the Public Staff reserve their rights in the Company's next general rate case to argue to the Commission (a) how the unamortized balance of deferred CCR expenditures incurred by the Company prior to June 30, 2016, and the related amortization expense should be addressed; and (b) how reasonable and prudent CCR expenditures incurred by the Company after June 30, 2016, should be recovered in rates.

(4) Overall prudence of CCR Plan – The Public Staff's agreement in this proceeding to the deferral and amortization of CCR expenditures incurred through June 30, 2016, shall not be construed as a recommendation that the Commission reach any conclusions regarding the prudence and reasonableness of the Company's overall CCR plan, or regarding any specific expenditures other than the ones to be recovered in this case.

(5) Reporting - The Company shall file with the Commission, on the same date it files its quarterly ES-1 report, a report detailing 1) the CCR deferrals recorded in the reporting period, and 2) regulatory accounting entries pursuant to the August 6, 2004, Order in Docket No. E-22, Sub 420, with regard to any costs other than nuclear decommissioning costs or CCR costs, recorded in the reporting period.

(6) That DNCP agrees to provide the Public Staff, within 90 days of the date of the Stipulation, with a presentation regarding its accounting practices for non-nuclear asset retirement obligation costs.

At the hearing, witness Maness testified that the Stipulating Parties had reached agreement as to the CCR issues set forth in his testimony. He also stated that the Company and Public Staff agreed that it was not necessary for the Commission to make any findings regarding the possible future treatment of fines, penalties, or other litigation costs in this proceeding.

Further, witness Maness testified that the Public Staff's general impression is that DNCP's CCR repository facilities "were constructed and operated in a similar manner to facilities in various areas in the country." (T Vol. 8, at p. 361) In addition, witness Maness elaborated on the Public Staff's investigation of DNCP's CCR remediation efforts. He testified that the effort thus far has been engineering studies for work to be performed at the various sites, and beginning the closure of existing impoundments, such as dewatering of CCRs and water treatment. Witness Maness further testified that the Public Staff's Engineering Division reviewed invoices for the CCR work performed by DNCP and did not find any of the costs to be unreasonable.

On November 16, 2016, the Attorney General's Office (AGO) filed a post-hearing Brief. The AGO takes the position that the proposed recovery of coal ash expenditures unfairly burdens consumers and should be rejected by the Commission. The AGO notes that the Commission must set rates that are fair to the ratepayers and utility, pursuant to G.S. 62-133(a), and that the burden of proof is on the utility, under G.S. 62-75. The AGO further states that the Commission should consider, among other things, whether the CCR costs incurred are reasonable and prudent, and that this determination is detailed and fact specific, especially in the context of complicated cost recovery for environment-related clean-up costs. In addition, the AGO states that DNCP's CCR costs are projected to increase significantly over the next two or three years.

Moreover, the AGO contends that DNCP's CCR expenditures do not relate to operations that are used and useful for DNCP's current customers because they are for the disposal of CCRs that were produced over decades at plants that no longer generate electricity. Further, the AGO maintains that DNCP's proposal to include the unamortized balance of CCR costs in DNCP's rate base and earn a return on the unamortized balance is not a fair or lawful burden to impose on ratepayers, and is contrary to the holding in <u>State ex rel. Utilities Comm'n. v. Carolina Water Service</u>, 335 N.C. 493, 439 S.E.2d 127 (1994).

In addition, the AGO asserts that DNCP failed to provide detailed evidence about whether the CCR remediation costs it seeks to recover are reasonable and prudent, and that the Public Staff's analysis was insufficient. According to the AGO, DNCP appears to simply rely on compliance with the CCR Final Rule to justify its recovery of costs. The AGO also points out that DNCP has been sued for alleged violations of CCR environmental regulations.

Discussion and Decision

<u>Prudence and Reasonableness</u>

In the Coal Ash Management Act of 2014, the General Assembly included a moratorium prohibiting the Commission from allowing CCR clean-up costs in a utility's base rates. The moratorium was in effect until January 15, 2015. However, that section also states that "Nothing in this section prohibits the utility from seeking, nor prohibits the Commission from authorizing under its existing authority, a deferral for costs related to coal ash combustion residual surface impoundments." G.S. 62-133.13.

DNCP, like many electric utilities in the United States, has for decades generated electricity by burning coal. During those decades, the widely accepted reasonable and prudent method for handling CCRs has been to place them in coal ash landfills or ponds (repositories). At the hearing in this docket, in response to questions by the Commission, DNCP witness Stevens testified that when the EPA issued its draft CCR Rule in December 2014, DNCP first began addressing the fact that its CCRs could not remain stored in their existing repositories in perpetuity. Further, as discussed above, in his direct testimony, DNCP witness McLeod testified that the CCR Final Rule requires DNCP to close or retrofit all of its active and inactive CCR repositories. He further testified that DNCP spent $37.5 million during the test year and anticipated spending an additional $63.8 million through June 2016. He later filed supplemental testimony adjusting the updated January 2015 through June 2016 CCR costs to a total of $84.4 million.

Public Staff witness Maness testified that the Public Staff's general impression is that DNCP constructed and operated its CCR repositories in a manner that is similar to CCR facilities in various areas of the United States. He stated that four of the eight DNCP coal-fired facilities are closed, or have been converted to natural gas-fired facilities. At the closed facilities, DNCP is using three methods in its effort to comply with the CCR Final Rule: (1) cap and close method; (2) a clean and close method in which the coal ash is moved to an on-site pond that is being capped and closed, and the original repository is closed; or (3) the clean and close method, except the original repository is used for a new purpose. He described the efforts as engineering work at various facilities, and the beginning of closure work at some facilities, including dewatering of the ash ponds and water treatment. Witness Maness also testified that the Public Staff Engineering Division reviewed the invoices for the CCR work that has been performed by DNCP thus far, and that the Public Staff did not find that any of DNCP's CCR costs were unreasonable. Witness Maness testified that the Public Staff found that DNCP's efforts and costs expended were prudent and reasonable.

Based on the allocation methodology agreed upon in the Stipulation, DNCP's allocable share of the CCR costs is $4,417,000. The Stipulating Parties agreed to DNCP's requested deferral of these costs and an amortization period of five years.

The Commission finds the CCR testimony of DNCP witnesses Stevens and McLeod and Public Staff witness Maness to be credible and to constitute substantial evidence that DNCP's actions in planning and beginning the work for permanent CCR repositories have been prudent, and that the CCR remediation costs incurred thus far by DNCP are reasonable. In particular, the Commission gives substantial weight to Public Staff witness Maness's testimony describing the Public Staff's investigation of DNCP's CCR remediation efforts. Witness Maness testified in some detail regarding the three CCR remediation options being employed by DNCP. He also testified that the Public Staff found that DNCP's CCR remediation efforts and costs were prudent and reasonable.

The AGO takes issue with the probative value of the DNCP and Public Staff evidence in support of CCR remediation costs recovery, not with the absence of such evidence. As outlined in detail above, the record contains substantial, unrebutted evidence from DNCP and Public Staff witnesses that DNCP's CCR remediation expenditures at issue were reasonable and prudent. The AGO has offered no witness or other probative evidence that DNCP's incurrence of CCR remediation costs were imprudent or unreasonable. No witness offered evidence that the costs should not be recovered. The only material dispute among the witnesses was over the appropriate amortization period for deferred remediation costs.

The AGO contends that DNCP's CCR activities have not produced property that is used and useful for DNCP's ratepayers. The Commission does not agree and determines that the used and useful argument misses the point. The AGO's argument is based on the fact that some of the coal-fired generating plants producing CCRs were no longer in service or were converted to gas-fired generation or some of the coal ash repositories had been closed before the test year. The Commission finds the AGO's logic misplaced. Due to federal and state environmental regulations, and in an attempt to remediate potential environmental degradation, DNCP incurred expense in the test year as extended. The fact that some of the coal-fired plants from which the CCRs had been removed were no longer in service or that the repositories in which the CCRS were stored had been closed and no longer receiving CCRs is beside the point. The issue is not recovery of costs of closed plants or costs of storing CCRs in repositories over past periods. The issue is recovery of remediation costs incurred in the test year as extended. In addition, a number of the electric generating plants from which CCRs are being and have been produced and the repositories are still in operation and have not been taken off line or closed.

Moreover, the current CCR repositories are and have served their purpose of storing CCRs for many years. In that respect, they have been used and useful for DNCP's ratepayers. However, pursuant to the CCR Final Rule, DNCP must incur expenses to the existing repositories for environmental remediation. As a result, the required solution for the CCR remediation serves the public policy of encouraging and promoting harmony between public utilities, their users and the environment. See G.S. 62-2(a)(5). Based on the testimony of witnesses Stevens, McLeod, and Maness, DNCP is responding to the CCR Final Rule requirements in a responsible and prudent manner. The result of DNCP's efforts should be the expenditure of funds to establish permanent CCR storage repositories. Like the existing CCR repositories, these permanent storage repositories will be used and useful for DNCP's ratepayers.

Further, the Supreme Court's decision in Carolina Water Service, cited by the AGO, does not support a denial of rate base treatment for the deferred and unamortized test year costs of CCR remediation. In Carolina Water Service, the Commission allowed the utility to include in the utility's rate base the unamortized portion of net costs still on the books at time of retirement not charged off in the test year for its Mt. Carmel wastewater treatment plant, even though the plant was not operating at the end of the test year and would never again be in service. The Commission's rationale was that the Mt. Carmel wastewater treatment plant unrecovered net costs should be treated as an extraordinary property retirement, with the deferred and unamortized costs included in the utility's rate base. The Supreme Court reversed that portion of the Commission's Order. The Court stated:

> [C]osts for abandoned property may be recovered as operating expenses through amortization, but a return on the investment may not be recovered by including the unamortized portion of the property in rate base.

Carolina Water Service, 335 N.C., at 508, 439 S.E.2d, at 142.

The issue in Carolina Water Service was whether to include in rate base the unamortized, unrecovered costs of a wastewater treatment plant that had been placed in service many years ago at which time the costs of the plant were incurred but with respect to plant that had been permanently retired. As addressed above, the costs at issue in this case are test year remediation costs, not unamortized costs of abandoned plants. Whatever costs DNCP incurred in past years in coal-fired generating plants already removed from service or costs incurred in the past to store CCRs in repositories now closed are not costs DNCP seeks to recover as DNCP's CCR remediation costs.

If, hypothetically, the Court had determined that costs Carolina Water Service had incurred in the test year to remediate potential environmental degradation from a discontinued wastewater treatment plant could be amortized but that the unamortized costs could not be included in rate base, perhaps such precedent would support the AGO's position; however, such costs are not those the Court addressed.

Although four of the coal-fired generating plants that are the sites of DNCP's CCR remediation efforts are no longer generating electricity, DNCP is not seeking to defer undepreciated costs of these plants or inclusion of unamortized costs in rate base as part of its CCR cost recovery request. Also, the existing CCR repositories at these sites cannot be abandoned by DNCP. Unlike the abandoned Mt. Carmel wastewater treatment plant in Carolina Water Service, the existing CCR repositories continue to be used and useful for storing CCRs, and will continue to be used and useful until DNCP moves the CCRs to a permanent repository, or takes the necessary steps to cap and close the existing repository.

The Commission's determination for allowing a portion of test year CCR costs to be recovered in this case is beneficial to DNCP, and the decision to amortize a large percentage of these test year CCR costs over a five-year period is a benefit to the ratepayer. The Commission likewise finds reasonable the provisions of the Stipulation allowing a return on the unamortized balance over the five-year period to be fair to the Company. Further, the Commission deems appropriate the establishment of a regulatory asset through which future CCR costs are accounted for, and thereby potentially departing from the general rule of matching future annual costs with revenues in the same period. In this fashion, the Company will have the opportunity to seek cost recovery for this unexpected and extraordinary cost expended in response to the CCR Final Rule which has required DNCP to store CCRs in a manner different from that in which the CCRs were being stored prior to 2015. The cost of complying with federal and state CCR remediation requirements was a risk that was unknown to the Company prior to 2015. Absent deferral, failure to recover those future costs could materially impact the Company's earnings. The Company's actions and testimony, and the testimony of Public Staff witness Maness, provide justification for the Commission's decisions. No witness testified against the effort to treat future CCR remediation costs as a regulatory asset for deferral and consideration in a future rate case. Based upon the entire evidence of record, the present Stipulation to allow the test year CCR costs to be recovered in this case by amortization over a five-year period with the unamortized balance to earn a return and the authorization to treat future CCR costs incurred through 2018 as a regulatory asset (which is the mechanism to facilitate the deferral of future CCR costs) is proper and in the public interest under the facts and circumstances of this case.

Conclusions on CCR Cost Deferral

Based on the foregoing and the record, the Commission finds and concludes that DNCP shall be allowed to defer the costs of its remediation of coal combustion residuals through June 30, 2016, and shall be allowed to amortize those deferred costs over a period of five years. The Company submitted substantial evidence that its costs incurred to comply with federal and state law regarding disposal of CCRs were prudently and reasonably incurred. No other party presented conflicting direct evidence on prudence or reasonableness of these costs. However, the Commission's approval of DNCP's CCR cost deferral is based on the particular facts and circumstances presented in this docket and, therefore, is not precedent for the treatment of CCR costs in any future proceedings.

In addition, the Commission finds and concludes that the treatment of CCR costs incurred by DNCP after June 30, 2016, shall be reviewed in a future rate case, subject to the provisions of the Stipulation regarding future amortization periods, deferral of future CCR expenditures, continuing amortization and deferral of CCR expenditures, and any other arguments or positions presented by the Company, the Public Staff, or another party at that time. Further, the Commission's determination in this case shall not be construed as determining the prudence and reasonableness of the Company's overall CCR plan, or the prudence and reasonableness of any specific CCR expenditures other than the ones deferred and authorized to be recovered in this case.

Finally, the Commission finds reasonable the provisions of the Stipulation regarding the agreement of DNCP to make a presentation to the Public Staff regarding its accounting practices for non-nuclear asset retirement obligation costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-23

The evidence supporting these findings of fact and conclusions is contained in the filings and Orders in Docket Nos. E-22, Sub 519, and Sub 533, the Company's verified Application, the direct and rebuttal testimony and exhibits of Company witnesses McLeod and Stevens, the testimony of Public Staff witness Fernald and Nucor witness Kollen, the Stipulation, and the entire record in this proceeding.

Warren County CC and Brunswick County CC Deferrals

The Company's initial Application proposed to amortize the deferred costs, including a return on investment, associated with the Warren County CC requested in the Company's petition in Docket No. E-22, Sub 519. [1] As explained by Company witness McLeod, DNCP requested to

[1] The Commission previously addressed the deferral costs related to the Warren County CC. On January 30, 2015, DNCP filed an application for an accounting order in Docket No. E-22, Sub 519 (Sub 519 docket) requesting that it be allowed to defer certain costs associated with its Warren County CC generating facility that was placed in service in December 2014. After comments by the parties and an oral argument held on June 15, 2015, the Commission issued an Order Denying Deferral Accounting for Warren County CC on March 29, 2016. DNCP filed for

defer the incremental costs incurred from the time the assets were placed into service (December 2014) until the time they are reflected in the base non-fuel rates, and that these cost be amortized over a three-year period, with the unamortized balance, net of ADIT, included in rate base.

The initial Application also proposed to amortize the deferred costs, including a return on investment, associated with the Brunswick County CC requested in the Sub 533 docket, from the time the assets were placed into service (April 2016) until the time they are reflected in base non-fuel rates, and that these costs be amortized over a three-year period.

Public Staff witness Fernald testified that DNCP filed additional evidence concerning the Sub 519 docket. She stated that had DNCP filed this additional evidence concerning its December 2014 ES-1 information as part of its original deferral application, the Public Staff's position on the original deferral request would have changed. Witness Fernald further testified that while the Public Staff does not agree with all of the Company's additional adjustments to the December 2014 ES-1 included in its Motion for Reconsideration, the Public Staff would have agreed with the Company's proposed adjustment to apply the 2014 cost of service study factors to the December 2014 ES-1. Witness Fernald stated that with this adjustment, the ROE would have been materially below the Company's authorized ROE, and the Public Staff would not have opposed the Company's deferral request based on earnings. Therefore, Public Staff witness Fernald recommended that the Warren County CC deferral costs of $10,204,000 for North Carolina retail be recovered from ratepayers in this proceeding through a levelized amortization over a three-year period.

Nucor witness Kollen recommended that the Commission deny DNCP's proposed regulatory deferrals associated with the Warren County CC and Brunswick County CC. With respect to the Warren County CC deferral, witness Kollen discussed the Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility issued on March 29, 2016, in Docket No. E-22, Sub 519, in which the Commission denied the Company's deferral request. Witness Kollen noted the Commission subsequently agreed to rehearing on the issue in the instant proceeding.

According to witness Kollen, the Company's requests sought deferral of costs only through June 30, 2016. He argued that since that date now has passed, an accounting order issued after June 30, 2016, necessarily would authorize retroactive ratemaking.

Nucor witness Kollen noted that the Company did not seek to return to customers savings from the ODI implemented earlier in 2016. The Company proposes to recover increases in its costs

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reconsideration regarding the deferral of the Warren County CC on March 3, 2016 (Motion for Reconsideration). On May 17, 2016, the Commission issued an Order consolidating the Motion for reconsideration for the Warren County CC deferral with the general rate case application filed in this docket. The Order also consolidated the Deferral Request for the Brunswick County CC, which was filed in Docket No. E-22 Sub 533 (Sub 533 docket) into the general rate case docket as well.

(i.e. the Warren County CC deferral request), while at the same time retain reductions in its costs. These proposals, according to witness Kollen, are inconsistent and inequitable.

Additionally, witness Kollen testified that any deferrals authorized for 2015 cannot and will not be recorded in 2015 and will not affect the Company's earnings in 2015, as the Company's accounting books now are closed and final for 2015. He stated that the ROE effect of the Brunswick County CC costs is approximately 0.08%, all else being equal, or approximately two months of the effect of Warren County CC. This is not material, according to witness Kollen, even if the Company is not earning its authorized return and does not meet this basic test applied by the Commission in the Warren County CC and other deferral proceedings. Nucor witness Kollen, therefore, recommended that the Commission reject the Company's request to defer and amortize these post-commercial operation costs.

In the event that the Commission authorizes deferral of these costs, witness Kollen recommended that the Commission levelize or annuitize the revenue requirement effect over a 10-year amortization period to include a return on and recovery of the regulatory asset. He testified that the post-commercial operation costs are analogous to "start-up costs" that could be amortized over the life of the unit. Witness Kollen argued that the Company's proposed three-year amortization period is unduly short and unnecessarily increases the revenue requirement compared to a longer amortization period.

In rebuttal testimony, Company witness Stevens testified that it is important for the Commission to fully assess a utility's request for deferral accounting with the evidence on the financial condition and earned return of the utility in question, as well as the impact that an extraordinary event has on that earned return and financial condition. In response to witness Kollen's testimony regarding the Commission's prior denial of the Warren County CC deferral request, witness Stevens contended that the extensive and detailed evidence presented in the Company's May 3, 2016, Motion for Reconsideration, filed in Docket No. E-22, Sub 519, demonstrates that DNCP's earned return for the 2015 test year was 5.99%. Witness Stevens testified that the financial impact of placing the Warren County CC in service is also significant and meets the Commission's well-established standard for deferral authorization, especially given the substantial fuel savings derived from the operation of the generation asset for the benefit of North Carolina customers, including Nucor, on a timely and current basis. With respect to witness Kollen's assertion that the effect of the Brunswick County CC deferral request only amounts to eight basis (.08%) points ROE, witness Stevens referenced the evidence in the Company's Application for Dominion North Carolina Power for an Accounting Order for the Brunswick County CC (Docket No. E-22, Sub 533), asserting that there was a 31 basis points net detrimental impact to the Company's annualized earned return under existing tariffs. This was benchmarked against the Company's fully adjusted test period North Carolina jurisdictional ROE of 5.06%, when all components for regulatory accounting purposes are properly taken into account.

With respect to Nucor witness Kollen's comparison of the Warren County CC and Brunswick County CC deferrals with a proposed deferral associated with the savings from ODI, witness Stevens testified that the Company has reflected a full going-level of ODI savings in the base non-fuel revenue requirement in this proceeding. Witness Stevens explained that it has been this Commission's practice to approve accounting deferrals sparingly based on its well-established standard of whether a significant and unusual or extraordinary event has occurred that has materially impacted a utility's earnings and overall financial condition. The ODI program was a narrow severance program targeted at certain management layers in the organization – it would not qualify as an issue ripe for deferral given its relatively small impact. Witness Stevens stated that in the Commission's recent denial of the Public Staff's request for deferral accounting associated with a modest increase in annualized revenues resulting from the Company's January 1, 2015, extension of the agreement for electric service with Nucor (Docket No. E-22, Sub 517), the Commission noted that deferral is only warranted where an event affecting the utility's costs or revenues is unusual or extraordinary because changes in revenues, expenses, and investments happen routinely between the time a utility's rates are fixed by the Commission and the time of the next rate case and routine changes alone do not result in a change in the balance of revenues, expenses, and investments struck by the Commission's last rate Order. According to witness Stevens, the ODI program savings are not extraordinary and of such material financial significance to warrant deferral accounting consideration.

With respect to Nucor witness Kollen's proposed 10-year recovery period for the Warren County CC and Brunswick County CC deferrals, witness Stevens argued against such an extended period for the same reasons he generally disagrees with extended recovery periods for other regulatory assets in this proceeding. According to witness Stevens, North Carolina customers have also been receiving substantial fuel expense savings on a timely and current basis through the fuel factor as a direct result of the Warren County CC and Brunswick County CC investments, and it is not appropriate to substantially delay the recovery of the costs incurred that resulted in the fuel savings. Witness Stevens contended that the Commission has generally authorized a shorter time period for the amortization of deferrals associated with new major generation facilities placed into service by North Carolina electric utilities, and DNCP is not aware of the Commission using a 10 year recovery period in recent cases. Witness Stevens added that the Public Staff has agreed with the Company's proposed three-year amortization period in this case.

The Stipulation provides for deferral accounting treatment and recovery of deferred post-in-service costs for both the Warren County CC and the Brunswick County CC. The Stipulation provides that the deferred costs will be recovered over a three-year period on a levelized basis.

The issue before the Commission in this case is one of cost deferral, a recognized practice allowing recovery of unusual expenses arising from extraordinary circumstances or events; and its use, which the Commission has historically employed sparingly, does not constitute impermissible retroactive ratemaking. The Commission has established relatively clear guideposts and standards over the years for determining when a petition for deferral is appropriate. This is especially the case in the context of major new generating facilities that also create material fuel cost savings that are flowed through to ratepayers through lower fuel rates. Based upon the evidence now before the Commission, the Commission finds that DNCP has made the requisite showing that the Warren County CC and Brunswick County CC costs in question had a material impact on the Company's financial condition. As shown in the Company's Motion for Reconsideration in Docket No. E-22, Sub 519, the Company's verified Application in this case, and the testimony of Public Staff witness Fernald, the Commission also recognizes that DNCP's earnings were well below its authorized cost of equity of 10.2% when both the Warren County CC and Brunswick County CC were placed in service. Much of the evidence presented by the Company in this case, relating to its earnings at the time the Warren County CC went into service, was not presented as evidence before the Commission at the time the Commission issued its initial order of March 29, 2016, in Docket No. E-22, Sub 519, denying the Company's request for deferral of the post-in-service costs of the Warren County CC.

In consideration of the foregoing, the Commission finds and concludes that DNCP's requests to defer post-in-service costs of the Warren County CC and the Brunswick County CC should be and are hereby granted. The Commission further finds that the evidence in the record does not support Nucor witness Kollen's view that the ODI program savings are sufficiently extraordinary and of such material financial significance to warrant deferral accounting consideration. The Commission finds and concludes that for the present case deferral and recovery of the Warren County CC and Brunswick County CC deferred post-in-service costs presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Regulatory Assets and Liabilities with Amortization Ending in 2017

Public Staff witness Fernald identified the following regulatory assets and liabilities that will be fully amortized in 2017:

Regulatory Asset or Liability	Amortization Ends On
Unrecovered design basis costs – Surry	May 31, 2017
NUG buyout costs – Atlantic	May 31, 2017
DOE settlement	June 30, 2017
Bear Garden deferral	October 31, 2017
NUG buyout costs – Mecklenburg	October 31, 2017

Witness Fernald recommended that the unamortized balances of these regulatory assets and liabilities as of October 31, 2016 (the date the Company proposed to implement the provisional rates in this proceeding), be re-amortized over three years using a levelized amortization, consistent with her recommended treatment of the EDIT liability and deferred costs.

Company witness McLeod discussed several concerns with Public Staff witness Fernald's proposal. First, witness McLeod testified that the amortization periods for these regulatory deferrals were established by the Commission in prior cases based on the specific facts and circumstances in those cases. Second, the Public Staff's adjustment, according to witness McLeod, would result in an adjustment to rates in this case based on events scheduled beyond the close of the hearing date in this proceeding. Witness McLeod also contended that it is not appropriate to convert to a levelization approach for the treatment of regulatory assets and liabilities midstream, as this will result in either an over- or under-recovery of carrying costs on the deferral balance over the life of the asset.

The Stipulation amortizes the unamortized balances of these regulatory assets and liabilities as of October 31, 2016, based on the date the provisional rates were expected to be implemented in this proceeding, over three years using a levelized amortization, as proposed by

Public Staff witness Fernald. The Commission finds and concludes that for the present case the stipulated treatment of these unamortized balances is just and reasonable to all parties in light of all the evidence presented.

Beyond Design Basis Study Regulatory Assets

Public Staff witness Fernald testified that the Company has included in other additions in this proceeding two regulatory assets related to costs incurred to perform studies at the Surry and North Anna nuclear plants as required by the Nuclear Regulatory Commission (NRC) as a result of the disaster at the Fukushima nuclear plant following an earthquake and tsunami in Japan. Witness Fernald proposed to exclude these two regulatory assets from rate base and instead include the expenses related to these NRC studies incurred in 2015 in O&M expenses in this proceeding. Witness Fernald noted that the Company did not file a request with the Commission to defer the cost of these studies. Public Staff witness Fernald commented that the Commission previously stated in prior DNCP rate case orders that it does not consider a deferral period, an amortization period, or a window for filing a deferral request to be open-ended.

In rebuttal testimony, Company witness McLeod argued that DNCP's accounting methodology for the beyond design basis study costs is consistent with the treatment of design basis documentation costs incurred in the late 1980s and early 1990s. Witness McLeod explained that at that time, the Company requested and received guidance from the FERC for design basis documentation costs incurred, and that the FERC instructed the Company to record the costs to FERC Account 182.2 (regulatory asset account), and that these costs have been included in the Company's cost of service studies in North Carolina for over two decades.

Witness McLeod testified that since these costs were mandated by the NRC, and the Company deferred them to FERC Account 182.2 in accordance with FERC's instructions, it would be improper to account for them as other O&M expenses as recommended by the Public Staff. Witness McLeod represented that the Company will make diligent efforts to seek the Commission's approval on a timelier basis in the future.

The Stipulation provides for deferral accounting treatment of the beyond design basis study costs mandated by the NRC as proposed by Company witness McLeod. The Stipulation also provides that the Company will comply with Commission Rule R8-27(a)(2) prior to establishing any regulatory assets and liabilities for North Carolina jurisdictional purposes in the future. The Commission hereby approves deferral accounting treatment for the beyond design basis study costs *nunc pro tunc* as of July 2012, which is the date the Company began deferring these costs. The Commission finds and concludes that recovery of the beyond design documentation study costs as presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented.

Chesapeake Decommissioning and Closure Costs Regulatory Asset

In its Application, DNCP proposed to include any decommissioning and closure costs incurred at Chesapeake and to amortize such deferred costs as of June 30, 2016, across a three-year recovery period.

Nucor witness Kollen testified that the Company deferred the costs for dismantling and other site costs for Chesapeake, but did not offset those costs by the savings in O&M expense, other operating expenses, and depreciation expense. According to witness Kollen, these expenses were included in the revenue requirement in the 2012 Rate Case, and the Company will continue to collect these expenses through the revenue requirement until rates are reset at the conclusion of this proceeding, even though they no longer are incurred. Witness Kollen asserted that Nucor had requested that the Company quantify the savings since the retirement of the plant, and the Company did not do so and simply responded that the proposed regulatory asset does not include any offsets for avoided operating expenses after the facility was retired.

Witness Kollen recommended that the Commission deny the Company's request for recovery of the deferral unless DNCP can demonstrate that the costs exceed the savings until rates are reset in this proceeding. Alternatively, if the Company provides an appropriate quantification of the savings from the avoided operating expenses (realized since closure of the plant in late 2014), then the Commission should calculate the revenue requirement on the deferred cost net of the savings on a levelized basis using a 10-year amortization period.

In response to Nucor witness Kollen, Company witness Stevens noted there were no operating O&M or depreciation expenses associated with Chesapeake in the Company's 2015 test year cost of service study. The only O&M expenses are those related to closure costs incurred in the 2015 test year. Witness Stevens contended that the cost avoidance of retiring Chesapeake Units 1-4 should also be reflected in Nucor's evaluation. In the 2012 Rate Case, the Company presented information that demonstrated that to comply with the Mercury Air Toxics Standard rules it was expected that Chesapeake Units 1-4 would all require Dry Flue-Gas Desulfurization equipment by 2015. In addition, witness Stevens testified that these units would require other new environmental equipment to comply with other expected environmental rules such as CSAPR, Ozone Standard Review, NAAQS, and 316(b). Witness Stevens presented an analysis showing the net present value cost increase in lieu of retirement totaled over $190 million for these four coal units.

Witness Stevens additionally testified that the purported savings on O&M and depreciation expenses previously incurred at Chesapeake did not create a windfall for the Company that can now retroactively be captured, as Nucor witness Kollen contends. Witness Stevens contended that no further adjustments are necessary because the environmental cost avoidance well exceeded the assumed savings and certainly caused no over-recovery of DNCP's cost of service during this period.

With respect to Nucor witness Kollen's proposed 10-year recovery period for the Chesapeake decommissioning and closure cost deferral, witness Stevens argued against such an extended period for the same reasons he generally disagreed with extended recovery periods for regulatory assets. Witness Stevens noted that the Public Staff agreed with the Company's proposed three-year amortization period and that this is also consistent with prior Commission treatment of regulatory assets.

The Stipulation provides for deferral accounting treatment of the Chesapeake closure costs regulatory asset and recovery over a three-year period on a levelized basis. The Commission does not findNucor's reasoning persuasive and, therefore it declines to adopt Nucor's recommendations in this matter. Rather, the Commission agrees with the deferral treatment as specified in the Stipulation. The Commission finds and concludes that recovery of the Chesapeake closure costs as presented in the Stipulation is just and reasonable to all parties in light of all the evidence presented and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding of fact and these conclusions is contained in the testimony of Public Staff witness Maness and DNCP witness McLeod.

Public Staff witness Maness addressed the question of how revenues received by DNCP for CCR cost deferrals after the approved amortization period should be treated. Witness Maness testified that DNCP appears to interpret prior Commission orders to allow CCR cost deferral to continue automatically after the approved amortization period and for an indefinite period into the future. He stated that the Public Staff disagrees with DNCP's interpretation and recommends that the Commission allow deferral to continue through 2018, subject to prudency and reasonableness reviews, and subject to a credit of the approved CCR expense to future deferrals until DNCP's next general rate case.

In his rebuttal testimony, DNCP witness McLeod disagreed with the Public Staff's recommendation that the annual amortization cost should continue to be credited to DNCP’s deferred CCR costs until the Company’s next general rate case. Witness McLeod opined that the deferred CCR costs should be treated as any other cost of service expense being recovered in the Company’s non-fuel base rates.

The Commission does not agree with DNCP's position on this issue. A deferred cost is not the same as the other cost of service expenses recovered in the Company’s non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company’s next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company. In addition, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DNCP continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission, that does not mean that DNCP is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company’s next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact and these conclusions is contained in the testimony of Public Staff witness Fernald, the rebuttal testimony of Company witness Stevens, the Stipulation, and the entire record of this proceeding.

In her testimony, Public Staff witness Fernald made three accounting recommendations. The first recommendation related to the Yorktown Plant. Witness Fernald urged that upon the closure of the Yorktown plant, should DNCP plan to amortize Yorktown's net book value and closure costs (other than those relating to the closure of coal ash ponds, for North Carolina ratemaking purposes), that DNCP should notify the Commission of the closure and also provide the Commission with an estimate of the net book value and closure costs.

Witness Fernald's second recommendation related to the FERC USOA. She stated that under Commission Rule R8-27, the FERC USOA is prescribed for all electric utilities under the jurisdiction of the Commission. Witness Fernald noted that DNCP does not maintain its accounting system based on the FERC USOA, but instead uses a different system of accounts, which it refers to as natural accounts. Public Staff witness Fernald explained that in order to comply with the Commission's requirements and produce its financials and reports based on the FERC USOA, DNCP maintains a module to convert its natural account postings to FERC accounts.

Witness Fernald testified that the FERC USOA identifies and categorizes costs in a manner that is consistent with ratemaking and identifies costs that are of particular interest to regulators. If a company does not maintain its accounting system based on the FERC USOA, it must still be able to produce records based on the FERC USOA, to a level such that an audit trail is maintained. Witness Fernald noted that during the Public Staff's investigation, there were several instances where costs could not be audited based on the FERC USOA. Based on that, Public Staff witness Fernald recommended that the Company maintain its accounting records in a manner such that it is able to produce records based on the FERC USOA – including allocations from its affiliates such as the service company charges discussed below – so that an audit trail is maintained and fluctuations based on the FERC USOA can be explained. Witness Fernald further recommended that the Company file the procedures and processes that it will implement to improve the transparency between the FERC accounts and the natural accounts with the Commission within 90 days after issuance of the Order in this proceeding.

Witness Fernald's third recommendation related to service company charges. Each month, when DNCP is billed by its affiliated service company, Dominion Resources Services, Inc. (DRS), for (1) services performed by DRS personnel and (2) third-party bills paid by DRS and allocated to DNCP, the expenses allocated to DNCP are initially mapped to FERC Account 923 - Outside Services Employed. Witness Fernald explained that the Company has an automated program that then takes the amounts billed by DRS to DNCP each month and reclassifies items to different accounts as may be appropriate.

Witness Fernald testified that during the Public Staff's investigation, DNCP was unable to provide the specific transactions billed by DRS to DNCP by FERC account. The Company's accounting records should be maintained such that the details of the transactions billed by DRS to

DNCP, including the amounts allocated for third-party bills by vendor and the FERC account to which they are charged, is available. Finally, witness Fernald recommended that the Company file the procedures and processes that it will implement to comply with this recommendation with the Commission within 90 days after the date of the Order in this proceeding.

With respect to the Public Staff's accounting recommendation regarding the Yorktown Plant, Company witness Stevens avowed that the Company would notify the Commission when the Yorktown closure occurs and provide an estimate of the undepreciated value of Yorktown at the time of closure and the estimated level of costs to be incurred for closure.

With respect to the Public Staff's second recommendation pertaining to the FERC USOA, Company witness Stevens indicated that the Public Staff applied no materiality threshold when making such statements and that the Company views its accounting practices as reasonable and appropriate.

In response to the Public Staff's generalized comment about improving transparency between FERC accounts and natural accounts, Company witness Stevens attested that the Company filed its Application for a revised Services Agreement between DRS and DNCP with the Commission on September 23, 2016. Witness Stevens reiterated the Company's commitment to provide the Public Staff with information in Docket Nos. E-22, Subs 476, 477, and 482, which will help to address the Public Staff's issues and concerns.

The Stipulation includes the following provisions addressing Public Staff witness Fernald's accounting recommendations:

> (1) The Company will notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure.
>
> (2) The Public Staff's accounting recommendations concerning the FERC USOA and the service company charges will be addressed in Docket Nos. E-22, Subs 476, 477, and 482.

The Commission finds and concludes that the three accounting recommendations as detailed by Public Staff witness Fernald and agreed to by the Company in the Stipulation are appropriate and should be accepted. The Commission further finds and concludes that provisions set forth in the Stipulation as agreed to between the Company, the Public Staff and CIGFUR I are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-28

The evidence supporting these findings of fact and conclusions is contained in the Application, the direct testimony and exhibits of Company witnesses Petrie, Haynes and Hupp, the supplemental testimony and exhibits of Company witnesses Petrie and Haynes, the testimony and exhibits of Public Staff witnesses Peedin and Lucas, the Stipulation, and the entire record in this proceeding.

In his direct testimony, witness Petrie presented an estimate of DNCP's adjusted system fuel expense for the period July 1, 2015 – June 30, 2016, of $1.689 billion, which was used by witness Haynes to estimate the anticipated reduction in the fuel factor rate. He also estimated the deferred fuel balance as of June 30, 2016, and described DNCP's forecasted fuel expense recoveries for the second half of 2016. In his supplemental testimony, witness Petrie presented an updated adjusted total system fuel expense for the 12-month period ending June 30, 2016, of $1.74 billion, as shown in the Company's August 5, 2016 fuel factor adjustment filing in Docket No. E-22, Sub 534. He noted that this total adjusted amount was calculated based on the 100% Marketer Percentage proposed by witness Hupp in his direct testimony. Witness Petrie also testified that the Company's projected fuel over-recovery at the end of December 2016, assuming an interim rate change on November 1, 2016, was approximately $3.9 million.

In his direct testimony, Company witness Haynes used a placeholder base fuel rate based on the fuel factor approved in the Company's 2015 fuel adjustment case, Docket No. E-22, Sub 526. In his supplemental testimony, witness Haynes used the updated adjusted total system fuel expense presented by witness Petrie to calculate an average base fuel factor of $0.02116/kWh, a reduction from the current base fuel factor of $0.02427/kWh. He also used the revised Rider A rate of zero consistent with the Company's 2016 fuel adjustment filing. He further testified to the Company's reintroduction of Rider A1 on November 1, 2016, for the purpose of accelerating the return of DNCP's fuel over-recovery to its customers in conjunction with placing the proposed updated non-fuel and base fuel rates into effect on a temporary basis on that date. He explained that implementation of Rider A1 will lower the estimated over-recovery balance as of December 31, 2016, and reduce further the impact of the proposed base rate increase.

In his direct testimony, Company witness Hupp presented the Company's recommendation that the Marketer Percentage applicable to DNCP be increased from 85%, as it was established in the Company's 2012 Rate Case and used in DNCP's 2015 fuel factor case, Docket No. E-22, Sub 526, to 100%. He testified that this increase would result in a more appropriate treatment of purchased power costs, because it would permit DNCP to recover all of its prudently incurred purchased power costs through fuel rates. He explained that, when DNCP purchases rather than self-generates power, it does so in order to minimize the cost incurred to meet its customers' energy requirements. As a result, the resulting cost of DNCP's market energy purchases will likely be less than the variable marginal cost of running one of the Company's own generators to meet the energy need. Witness Hupp also testified that the Company believes that any prudently incurred power purchases made to serve customers' energy requirements should be fully allowable through fuel. He stated that the variable costs of running one of the Company's generators largely represent allowable fuel costs deemed recoverable by the Commission in the Company's fuel factor cases. Therefore, witness Hupp stated, purchases of energy deemed to be less expensive than this marginal and allowable cost of fuel for fleet operations should – when shown to be prudently incurred – also be fully allowable through fuel with no impacts to base rates. He testified that this would better align the Company's recoverable fuel-related expenses with its actual costs.

Witness Hupp noted that the Company's request for relief of the PJM Order conditions, addressed below with regard to Finding of Fact No. 50, removes the barrier that the Commission identified in its order in DNCP's 2014 fuel clause adjustment proceeding as preventing the

Commission from using the discretion provided at subsection (f) to permit DNCP to recover 100% of its purchased power costs through fuel, including deemed congestion related costs.

Public Staff witness Peedin testified that with respect to purchased power, DNCP is entitled under G.S. 62-133.2(a3) to recover only "the fuel cost component, as may be modified by the Commission, of electric power purchases identified in subdivision (4) of subsection (a1)," and the fuel cost component of other purchased power, through the prospective fuel factor and the EMF. She testified that the Public Staff interprets the phrase "fuel cost component, as modified by the Commission" to mean that, in DNCP's case, the fuel cost component of purchases subject to economic dispatch must be determined by the Commission when the actual cost is not known, and that the Commission may modify the method for making that determination as appropriate. She stated that allowing DNCP to recover all of the energy costs of purchased power through a Marketer Percentage of 100% appears to read this phrase out of the statute and implies that the energy costs consist solely of fuel costs. She opined that is not the case, stating that a significant portion of energy costs consist of non-fuel variable operation and maintenance expenses.

Witness Peedin recommended that the Commission adopt a Marketer Percentage of 78% to be used as a proxy for the fuel cost component of purchases for which the actual fuel cost is unknown. She stated that both methods used by the Public Staff to determine this Marketer Percentage were proposed by DNCP in its 2008 fuel proceeding, Docket No. E-22, Sub 451, as an alternative to the off-system sales method then used by DEC and DEP. Witness Peedin described the first methodology as a review of data from the 2014 and 2015 PJM State of the Market reports, which identified each fuel component of the cost of energy used to set the energy market price. She stated that according to these reports, the fuel components of energy cost for years 2014 and 2015 were both 73.90%. She described the second methodology as a review of data provided by DNCP that blended the Company's internal data with PJM State of the Market report data for the DOM Zone. She stated that the average of the 2014 and 2015 values under the two methods was 78%. Based on her recommended Marketer Percentage of 78%, witness Peedin further recommended an adjustment to DNCP's non-fuel purchased power energy expense so that 22% of that expense would flow through base rates as purchased energy costs. This resulted in an adjustment to increase the base non-fuel rates by $2.261 million and decrease fuel rates by the same amount.

The Stipulation provides for a base fuel factor of $ 0.02073/kWh, as differentiated between customer classes, as shown on Company Rebuttal Exhibit PBH-1, Schedule 9. The Stipulation also provides that the appropriate EMF to be included in DNCP's updated annual fuel factor for the 2017 rate year shall be determined by Commission order in the Company's 2016 fuel case, Docket No. E-22, Sub 534.

The Stipulation also provides for a Marketer Percentage of 78%, to remain in place until the Company's next base rate application or its 2018 fuel factor application, whichever occurs first.

No party opposed the stipulated base fuel factor or the stipulated Marketer Percentage or conducted cross-examination on these issues at the hearing.

Based on all of the evidence in this proceeding, the Commission finds and concludes that the stipulated base fuel factor of $0.02073/kWh is just and reasonable for DNCP in this case. The

Commission also concludes that a marketer percentage of 78%, to be applied to appropriately determine the fuel cost component of energy purchased for which the fuel cost is unknown, should continue to be used until the Company's next base rate application or the Company's 2018 application to adjust its annual fuel factor, whichever occurs first.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact and these conclusions is contained in the Application, the direct, supplemental, and rebuttal testimony and exhibits of Company witness Chapman, the direct and settlement testimony and exhibits of Public Staff witness Hinton, the direct testimony and exhibits of Nucor witness Woolridge and CUCA witness O'Donnell, the Stipulation and the hearing testimony of witness Chapman.

In the Application, and as explained by DNCP witness Chapman in his direct testimony, the Company proposed a capital structure reflecting long-term debt of 46.641% and common equity of 53.359%. Witness Chapman, who is Senior Vice President – Mergers and Acquisitions and Treasurer for the Company, testified that the appropriate capital structure for use in this case was the Company's actual capital structure as of December 31, 2015. He discussed the Company's significant capital needs going forward, and explained how the Company plans to finance those capital needs, based on a balance of debt and common equity that DNCP believes will support the Company's credit ratings going forward, and continue to enable the Company to access a number of markets, under a wide range of economic environments, on reasonable terms and conditions. He stated that this market access is critical to fund the ongoing infrastructure capital expenditure program that will be necessary to meet the Company's public service obligations in North Carolina and throughout its system. In his supplemental testimony, witness Chapman updated the Company's proposed capital structure to its actual structure as of June 30, 2016, which reflected a long-term debt component of 46.080% and an equity component of 53.920%. Based on the Company's proposed cost rates for long-term debt and common equity, witness Chapman's proposed capital structure produced an overall weighted-average cost of capital of 7.803%.

Public Staff witness Hinton initially filed testimony stating that the Company's proposed common equity ratio produces an overall return on rate base greater than necessary to maintain credit quality and continue to attract capital. Witness Hinton noted that DRI's announced acquisition of Questar Corporation (Questar) led to an S&P credit downgrade for DRI and its subsidiaries, including VEPCO, from A- to BBB+. He noted that the credit rating reports indicate that VEPCO's regulated operations have lower business risk than DRI's unregulated businesses. He opined that the Questar acquisition may contribute to an already high debt ratio for DRI. He also noted that it is too early to tell whether recent actions, in particular the Questar acquisition, pose a risk that will increase the cost of capital.

Witness Hinton referred to DRI's confidential target capital structure for the Company as support for his position on capital structure. In addition, he noted that although the Company's average equity ratio from November 2009 to March 2016 was 54.01%, in contrast the common equity ratio averaged 49.97% for the six-year period prior to November 2009. He referenced testimony submitted in a Virginia State Corporation Commission proceeding regarding the Company operating with an equity ratio at the upper end of its target range, and opined that the increase in the equity ratio in recent years is not necessary for reasonable financing or justified in terms of its impact on Company customers. He also stated that DRI has a much higher debt ratio and lower equity ratio than the Company, and asserted that the Company's ratepayers were being asked to pay a high equity ratio to help offset DRI's high debt ratio. Finally, he stated his concern about the effect of added earnings from Virginia's return on equity incentives on the Company's capital structure. Witness Hinton concluded by recommending a capital structure consisting of 50.96% common equity and 49.04% long-term debt. Witness Hinton based his recommended capital structure on data from Regulatory Research and Associates, Inc., on recently commission approved equity ratios for other vertically integrated electric utilities with comparable Standard & Poor (S&P) bond ratings between BBB+ and A-. He accepted the Company's proposed long-term debt cost rate of 4.645%.

Nucor witness Woolridge testified that DNCP's proposed capital structure includes more equity and less debt than other electric utilities, does not include short-term debt, which amounts to almost 10% of its capitalization as of December 31, 2015, and includes much less equity than the capitalization of DNCP's parent DRI. He testified that the median common equity ratios of his and witness Hevert's proxy groups are 47.1% and 48.2%, respectively, and that DNCP's proposed capitalization includes more equity and less financial risk than these averages. Witness Woolridge, like Public Staff witness Hinton, noted concerns with the use of double leverage where the regulated utility subsidiary finances equity with the use of debt raised through the parent company. Witness Woolridge also compared DNCP's capitalization as of December 31, 2015, comprised of 9.81% short term debt, 41.20% long term debt, and 48.99% common equity, to that of DRI, comprised of 13.03% short term debt, 56.61% long-term debt, and 30.36% common equity. He noted that he used utility holding companies in his proxy group because their common stock is traded in the markets, and their financial risk and equity ratios are thus relevant for comparison rather than those of operating utilities. He testified that a high equity ratio will have a downward impact on a utility's financial risk, and that the ROE should be adjusted to account for that. He stated that based on these factors he proposed a capital structure consisting of 50% long-term debt and 50% common equity. He asserted that this capital structure is more in line with the average common equity ratios approved by state regulatory commissions in electric utility rate cases in 2015 and 2016 than the Company's proposed structure. Witness Woodridge adopted the Company's proposed long-term debt cost rate of 4.65%.

CUCA witness O'Donnell testified that DNCP's proposed capital structure is not comparable to the average common equity ratio of companies in witness Hevert's comparable group nor similar to the average equity ratio granted by state regulators for electric utilities in 2015 and to-date in 2016. He stated that the average common equity ratio for witness Hevert's comparable group is 50.1%. He stated further that the average common equity ratio granted to electric utilities by regulators across the United States in 2015 was 48.86% and to-date in 2016 is 43.67%. He noted that, in 2016, excluding limited issue rider cases, there have been only five rate case decisions and two of those were made in states that use non-investor sources of capital in the regulatory capital structures. Witness O'Donnell's calculation of the common equity ratio for those two companies was 49.47%. He noted further that DRI's common equity ratio as of December 31, 2015 was 34.9%. He concluded that DNCP's requested capital structure is not representative of capital structures of utility holding companies or of operating companies. He recommended a capital structure consisting of 50% common equity and 50% long-term debt, with a weighted debt cost rate of 4.89%. He justified this recommendation as being well above the DRI equity ratio, approximately equal to the equity ratio of witness Hevert's comparable group, and slightly above the average equity ratio granted to electric utilities by state regulators across the country in 2016.

In his rebuttal testimony, witness Chapman testified that the capital structures recommended by witness Hinton (50.96% common equity, 49.04% long-term debt), Witness Woolridge and witness O'Donnell (both 50% common equity, 50% long-term debt) were not reasonable, as they ignored the Company's actual capital structure as of June 30, 2016, as well as DNCP's actual capital structure at year-end of the each of the previous three years. He stated that the actual capital structure is the relevant structure for this case because it is the structure that supports DNCP's target credit ratings, which in turn allows DNCP to attract debt investment at an attractive cost basis. He noted that the equity component of DNCP's actual capital structure as of June 30, 2016 is in line with the equity component of the Company's year-end capital structure for the previous three years as well as to the forecasted capital structure as of December 31, 2016. He disagreed with these witnesses' reliance, without further justification, on proxy groups for their capital structure recommendations, due to the difficulty of determining a truly comparable capital structure within a proxy group of peer utilities that operate in different regulatory jurisdictions.

With regard to these witnesses' comparison of the Company's proposed capital structure to that of DRI, witness Chapman stated that development of the Company's financing plan is done with the objective of maintaining the current credit ratings of the Company, not those of DRI. He stated that a similar but separate analysis is undertaken at the DRI level, which accounts for financing needs of other, non-VEPCO subsidiaries in addition to the Company. He testified that claims that the DRI capital structure is relevant for purposes of this case are unfounded, and that VEPCO ratepayers are not being singled out and asked to pay more to offset DRI's higher debt ratio. He explained that all of DRI's subsidiaries support the parent company's debt capital structure.

Witness Chapman also addressed the impact of DRI's acquisition of Questar on VEPCO's cost of capital, stating that S&P's downgrade of the entire Dominion family due to the acquisition announcement had no discernible impact on VEPCO's cost of debt. He also stated that this one "consolidated" or "family" credit rating change should not adversely impact VEPCO's cost of debt, noting the unchanged "indicator" rating for VEPCO that S&P published along with its downgraded consolidated rating. Finally, in response to arguments concerning the increase in DNCP's common equity ratio in recent years, he stated that the higher equity component that the Company has experienced since 2009 supports using the capital structure that the Company proposed in this proceeding. He stated that the actual equity ratio is appropriate as it offsets the construction risk that an equity investor would experience during a period of heavy capital spending such as the one the Company is currently undertaking. Finally, he explained that witness Hinton's concern regarding Virginia's return on equity incentives is overstated, because it has a negligible impact on DNCP's retained earnings account, and because witness Hinton did not recognize other recent events that had a significant downward impact on the Company's retained earnings.

Following settlement negotiations between DNCP, the Public Staff, and CIGFUR I, as reflected in Section II.B of the Stipulation, the Stipulating Parties proposed a capital structure of 51.75% common equity and 48.25% long-term debt. The Stipulating Parties agreed to use 4.650%

for the cost of long-term debt, based on a correction that was presented in witness Chapman's rebuttal testimony and that was not challenged by any party.

In his stipulation testimony, witness Hinton testified that the capital structure reflected in the Stipulation represents a compromise by both parties in an effort to reach agreement. He accepted the change in the long-term debt cost rate from the originally proposed debt cost rate. He noted that the stipulated 51.75% equity ratio is 217 basis points lower than the Company's request, 125 basis points lower than currently authorized for DEC and DEP, 79 basis points higher than his earlier recommendation, and 75 basis points higher than the Commission-authorized equity ratio in the last two DNCP rate cases. He stated that he believes the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by over $12 million. He also noted the $400,000 to be paid by DNCP shareholders to assist low-income customers.

At the hearing in this case, witness Chapman noted as part of his summary of his testimony that, while the equity component of the stipulated capital structure is below that reflected in the Company's actual capital structure as of June 30, 2016, his opinion is that the stipulated capital structure and overall weighted average return will still allow the Company to access capital markets on reasonable terms in order to secure the capital required to make the significant investments DNCP is planning and will, therefore, benefit the Company's North Carolina customers. No party cross-examined witness Chapman at the hearing.

In its post-hearing Brief, CUCA contends that the Commission should adopt witness O'Donnell's recommendation of a 50% equity and 50% debt capital structure. Similarly, the Attorney General's Office (AGO) states that the evidence supports a capital structure that uses an equity ratio of 50% or less. To support its argument, the AGO largely relies on the testimony of witness Woolridge concerning the median equity ratio of his proxy risk group, the median equity of witness Hevert's proxy group, and the lower equity ratio of DNCP's parent company, DRI, including short-term debt. Nucor's post-hearing Brief, likewise, proposes a capital structure consisting of 50% common equity and 50% long-term debt, relying on the testimonies of witnesses Hinton, Woolridge, and O'Donnell concerning the average equity ratios of various proxy groups and the average of equity ratios approved in electric rate cases by state commissions over various periods of time. The Commission concludes that such comparisons may be relevant and of some interest, but are entitled to minimal weight in determining the appropriate capital structure for DNCP for ratemaking purposes. Instead, the Commission gives substantial weight to the rebuttal testimony of DNCP witness Chapman. He testified that it is difficult to determine a truly comparable capital structure for a proxy group of utilities that operate in different regulatory jurisdictions because not all regulatory jurisdictions define capital structure in the same manner. Some jurisdictions include and/or exclude different balance sheet items, such as short-term debt, income tax items, customer deposits, etc. For example, he contended that the average equity ratio of witness Hinton's peer group is 51.89% when calculated in a manner consistent with DNCP's proposed capital structure in this case. In addition, as noted above, witness Woolridge's proxy group used utility holding companies while DNCP is a subsidiary operating company. Finally, also important is that the mean, median, and range of equity ratios vary for different proxy groups and, therefore, the witnesses use their own discretion in arriving at their recommended capital structures after considering such comparisons.

With regard to comparisons to DRI's capital structure, witness Chapman testified that DNCPs financing plan is developed with the objective of maintaining the current credit ratings of DNCP, not those of DRI. He stated that a similar but separate analysis is undertaken at the DRI level, which accounts for financing needs of DRI's other subsidiaries, in addition to DNCP. Witness Chapman stated that all of DRI's subsidiaries support the parent company's debt capital structure.

The Commission must consider all of the evidence and exercise its independent judgment in determining the appropriate capital structure for DNCP in the context of setting DNCP's rates. The Commission gives substantial weight to Company witness Chapman's testimony regarding the Company's effort to find the appropriate balance between equity and debt financing. As witness Chapman noted, witness Woolridge and witness O'Donnell rely primarily on the averages of their respective proxy groups without providing any further rationale in support of their recommended capitalization ratios.

The Commission is also persuaded by the fact, as noted in the stipulation testimony of Public Staff witness Hinton, that the stipulated 51.75% equity ratio is 217 basis points lower than the Company's request, 125 basis points lower than currently authorized for DEC and DEP, 79 basis points higher than his earlier recommendation, and 75 basis points higher than the Commission-authorized equity ratio in the last two DNCP rate cases. The Commission places substantial weight as well on witness Hinton's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement that, if approved, will reduce the Company's proposed rate increase by over $12 million.

The Commission accords substantial weight to the stipulation testimony of witness Hinton, and finds that an equity ratio of 51.75% represents an appropriate reduction from the Company's actual ratio, for purposes of reducing the amount of higher cost equity financing to be borne by ratepayers in this case. Based upon the evidence described above and the record in this docket as a whole, the Commission finds and concludes that the stipulated capital structure and costs of long-term are fair and reasonable, and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-34

The evidence supporting these findings of fact and conclusions is contained in the Application, the direct, rebuttal, and stipulation testimony and exhibits of Company witnesses Curtis and Hevert, the pre-filed direct and settlement testimony and exhibits of Public Staff witness Hinton, the pre-filed direct testimony and exhibits of Nucor witness Woolridge and CUCA witness O'Donnell, the Stipulation, and the hearing testimony.

Based upon the evidence and legal analysis set forth below, the Commission concludes, based on its own independent analysis, that the stipulated rate of return on common equity of 9.90% proposed in the Stipulation in this proceeding and the resulting stipulated overall rate of return on rate base of 7.367% are just, reasonable, and fair to the Company, its shareholders and its customers and that such rates of return are fully consistent with the requirements of North Carolina law governing the establishment of public utility rates of overall return and returns on common equity.

Summary of the Evidence on Return

DNCP's existing allowed rate of return on common equity, established by the Commission in 2012 in Docket No. E-22, Sub 479, is 10.2%.[1] Its existing approved overall rate of return on rate base is 7.80%.[2] In its Application, DNCP proposed that the allowed rate of return on common equity in this proceeding be established at 10.5%. This proposed rate of return on common equity, in conjunction with the other elements of the Company's proposed capital structure, resulted in a proposed overall rate of return on rate base for the Company of 7.88%. Based on the capital structure updated to June 30, 2016, the 10.5% ROE recommended by witness Hevert, and a cost of long-term debt revised to 4.650% in witness Chapman's rebuttal testimony, the Company's final proposal for the overall rate of return was 7.805% prior to the Stipulation.

DNCP's original rate of return request was supported by the direct testimony and exhibits of DNCP witnesses Curtis and Hevert. Witness Curtis, who is Vice President – Technical Solutions for Virginia Electric and Power Company, testified to the significant capital investment needs facing the Company. He stated that in order to attract the capital needed to meet these substantial future capital needs, the Company must achieve an adequate authorized ROE in this proceeding, and that the 10.5% ROE proposed by DNCP will allow the Company to attract capital on reasonable terms in the still-volatile and highly competitive capital markets. He explained that the ability to attract capital on favorable terms is important to DNCP's ability to maintain its current credit ratings and, ultimately, minimize the cost of capital for customers. An adequate return also ensures DNCP's ability to commit capital to future construction projects to provide safe, reliable, and cost-effective electric service to North Carolina customers without eroding the Company's shareholders' interests. In witness Curtis' supplemental testimony, he stated that as of June 30, 2016, the Company's fully-adjusted earned rate of return on equity capital for the update period was only 5.50%, far below the Company's currently-authorized 10.2%.

Witness Hevert served as DNCP's primary cost of equity witness. Witness Hevert filed direct testimony and nine exhibits in support of DNCP's request for a 10.5% return on equity. He explained that the cost of equity is the return that investors require to make an equity investment in a company, that it should reflect the return that investors require in light of the subject company's risks and the returns available on comparable investments, and that it differs from the cost of debt because it is neither directly observable nor a contractual obligation.

Witness Hevert's direct testimony and exhibits document the specific analyses he conducted in support of DNCP's rate filing and provide a detailed description of the results of his analyses and resulting cost of equity recommendations. He applied the Constant Growth and

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[1] See 2012 Rate Order; 2015 Remand Order.

[2] Id.

Multi-Stage forms of the DCF model, the CAPM, and the Bond Yield Plus Risk Premium approach to develop his ROE recommendation.

Witness Hevert testified that a return that is adequate to attract capital on reasonable terms enables the utility to provide service while maintaining its financial integrity, and that the utility's return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. He stated that the Commission's decision should result in providing DNCP with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He discussed the need to select a group of proxy companies to determine the cost of equity, and how he selected the proxy group for this case.

According to witness Hevert, the results of his Constant Growth DCF analysis produced a range of 8.33% to 10.01% ROE, the results of his Multi-Stage DCF analysis were a range of 9.40% to 10.09%, and the results of his Multi-Stage DCF analysis that used the current proxy group P/E ratio to calculate the terminal value was a range of 9.34% to 10.91%. The results of witness Hevert's CAPM analysis showed a range of 8.69% to 11.64%. The results of his Bond Yield Risk Premium analysis indicated an ROE range from 10.04% to 10.47%. In his rebuttal testimony, witness Hevert updated his results to show an ROE range of 8.14% to 9.32% for his Constant Growth DCF analysis, a range of 8.85% to 9.97% for his Multi-Stage DCF analysis, a range of 8.87% to 11.22% for his CAPM analysis, and a range of 10.02% to 10.38% for his Bond Yield Risk Premium analysis. Based on his analyses, witness Hevert concluded that a rate of return on common equity in the range of 10.25% to 10.75% represents the range of equity investors' required ROE for investment in integrated electric utilities in today's capital markets. Within that range, he recommended an ROE for DNCP of 10.5% in both his direct and rebuttal testimony.

Witness Hevert explained that his ROE recommendation also took into consideration several additional factors, including (1) DNCP's planned investment program, (2) the risks associated with environmental regulations, (3) the regulatory environment in which DNCP operates, (4) flotation costs, and (5) the increased uncertainty in the capital markets. With regard to the regulatory environment, he noted that North Carolina is generally considered to be a constructive regulatory jurisdiction, and that authorized ROEs tend to be correlated with the degree of regulatory supportiveness (utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns). He did not, however, make any specific adjustment to his ROE estimates for the effect of these factors.

Witness Hevert also considered the economic conditions in North Carolina in arriving at his ROE recommendation. He noted that the rate of unemployment has fallen substantially in North Carolina and the U.S. generally since late 2009 and early 2010, with December 2015 rates of 5.60% in the State. He noted that since the Company's last general rate filing in March 2012, unemployment in the counties served by DNCP has fallen by over 4 percentage points. He explained further that while at its peak in 2009 into early 2010, the unemployment rate in those counties reached 13.41% (1.41 percentage points higher than the statewide average), by December 2015 it had fallen to approximately 7.30% (1.80 percentage points higher than the statewide average). He summarized that although it remains higher than the national and State averages, it has fallen considerably since its peak in early 2010. Witness Hevert also noted that since 2013, the

State has consistently exceeded the national rate for real gross domestic product growth, and that since 2009, median household income in North Carolina has grown at a somewhat faster annual rate than the national median income. In addition, total personal income, disposable income, personal consumption, and wages and salaries were generally on an increasing trend. Finally, he noted that since 2005, residential electricity costs in North Carolina remain approximately 13% below the national average. Based on all of these factors, witness Hevert opined that North Carolina and the counties contained within DNCP's service area continue to steadily emerge from the economic downturn that prevailed during the Company's previous rate case, and have experienced significant economic improvement during the last several years that is projected to continue. In his opinion, DNCP's proposed ROE is fair and reasonable to DNCP, its shareholders and its customers, in light of the impact of changing economic conditions on DNCP's customers.

Witness Hevert also addressed the capital market environment, and testified that the current market is one in which it is important to consider a broad range of data and models when determining the cost of equity.

Witness Chapman stated that granting the Company an authorized return of 10.5% on common equity will allow DNCP to compete in the capital markets and to raise equity and debt at reasonable rates. He testified that authorizing the Company's requested return on common equity will allow DNCP to carry out its responsibility to provide reliable services at affordable cost and is fundamental to the Company's ability to maintain a strong credit profile, and that the ability to access capital markets on reasonable terms will reduce DNCP's borrowing cost for the benefit of the customers.

Public Staff witness Hinton testified that current economic conditions are characterized by continued low inflation rates and the reduction in long-term interest rates, particularly the decrease in treasury yields since December 2012 (the time of the DNCP's last general rate case). He further opined that continued low inflation rates have led to lower expected returns in the equity markets, which he supported by recent articles denoting that investors should expect lower rates of return. Witness Hinton used the DCF model, the Regression Analysis of Allowed Returns on Equity for electric utilities, and the Comparable Earnings method as his primary methods for determining the appropriate cost of common equity. He also used the CAPM as a check on those primary methods. For his DCF and comparable earnings analyses, witness Hinton estimated DNCP's cost of equity capital by reference to a group of proxy companies. The results of his analyses were a range of 8.30% to 9.30% for the DCF method, a single estimate of 9.49% for the Regression Analysis, and a range of 9.00% to 9.80% for the Comparable Earnings method. Corrections submitted in his settlement testimony changed his DCF range to 8.40% to 9.40%, and his Comparable Earnings range to 9.03% to 9.87%, but did not change his recommended ROE for DNCP. The result of his CAPM analysis was an estimated ROE of 8.00%, which witness Hinton used as a secondary check on his other results. Witness Hinton also performed tests for the reasonableness of his recommendation: (1) his recommended capital structure and cost rates for debt and equity yielded a pre-tax interest coverage ratio of 4.3 times, and (2) for other electric utilities he identified the average approved rate of return on equity as 9.52% in the first six months of 2016 and 9.60% for all of 2015, excluding Virginia cases that added incentive points to the cost of capital in certain cases. He concluded that a reasonable range of DNCP's cost of equity is between 8.80% and 9.80%, and recommended an ROE for this case of 9.30%. Witness Hinton also recommended an overall cost of capital of 7.02%.

Witness Hinton also testified with regard to changing economic conditions noting that North Carolina Department of Commerce and Bureau of Economic Analysis data show relatively faster growth in per capita income for DNCP's service area compared to the State as a whole, for the 2000 through 2015 period. He noted that the unemployment rate for counties in the Company's service area has fallen from 10.4% in April 2013 to 6.7% as of April 2016. He concluded that while this part of the State has a relatively poor economy, these data indicate that economic conditions facing DNCP ratepayers as a whole have been improving since DNCP's last rate case.

Witness Hinton also critiqued witness Hevert's exclusive use of earnings per share forecasts to estimate the growth component of the DCF. He questioned as unrealistic the use of a 13.65% expected investment return on the S&P 500 in witness Hevert's CAPM analysis. He also questioned witness Hevert's argument that the Company's business risks deserve special consideration. Witness Hinton testified against any risk adjustment due to the Company's projected level of capital expenditures, its level of coal generation, and compliance with the Clean Power Plan, which he believed were risks already factored into return requirements by investors and did not deserve any special recognition or consideration.

Nucor witness Woolridge recommended an ROE of 8.60%, which is near the upper end of the range based on his DCF and CAPM analyses. He applied the constant growth version of the DCF method and the CAPM methods to a proxy group of publicly held electric utilities. He relied primarily on his DCF analysis, as he believes it provides the best measure of public utility equity cost rates. Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness Hevert's proxy groups is in the 7.90% to 8.75% range. He acknowledged that his recommendation is below the average authorized ROEs for electric utility companies.

Witness Woolridge also offered a critique of witness Hevert's ROE recommendation. He asserted with regard to capital market conditions that the forecasts of higher interest rates that witness Hevert used his CAPM and Risk premium analysis are incorrect. He questioned the inputs to witness Hevert's DCF analysis, in particular, his exclusive use of earnings per share forecasts; he disagreed with the low weight that witness Hevert gave his constant-growth DCF results; and he disagreed with witness Hevert's claim that high price-earnings (P/E) ratios can lead to low DCF results. He stated that the projected interest rates and market or equity risk premiums in witness Hevert's CAPM and risk premium approaches are excessive and not reflective of current and prospective market fundamentals. Finally, he disagreed with witness Hevert's inclusion of a flotation cost adjustment to the ROE.

CUCA witness O'Donnell did not conduct his own DCF or other method of determining the appropriate ROE in this case, citing the late entry to the case by CUCA. Rather, he revised the values included in witness Hevert's analyses to correct errors he perceived in those analyses, and, based on those adjustments, recommended an ROE of 9.0% out of a range of 8.50% to 9.50% and, together with his recommended capital structure discussed above, an overall cost of capital of 6.94%. Witness O'Donnell disagreed with the long-term growth rate witness Hevert used for his multi-stage DCF analysis, and with witness Hevert's testimony that, when constant growth DCF results are below the past returns authorized by regulators the validity of the constant growth DCF model is questionable. Witness O'Donnell also disagreed with witness Hevert's explanation of why it is reasonable to focus on different methodologies given the differences in financial markets over time. Witness O'Donnell opined that the expected market return that witness Hevert used for his CAPM and risk premium analyses is not reasonable, and asserted that the Company's requested ROE in this case is related to, but inconsistent with, its pension expense request. He also referenced a September 2, 2015 Order by the Missouri Public Service Commission where that commission found that witness Hevert's CAPM and Risk Premium model resulted in inflated results and his constant growth and multi-stage DCF models are based on excessively high growth rates. Witness O'Donnell presented a graph of allowed ROEs by state regulators across the country over the past 15 years and he noted that in 2016 no electric utility has been granted an ROE in excess of 10%.

In his rebuttal testimony, witness Hevert addressed witness Hinton's analyses with respect primarily to the issues of composition and selection of the proxy group, the growth rates and dividend yields applied in the constant growth DCF model, the application of the Regression Model of Allowed Returns, the reasonableness of the Comparable Earnings method, the application of the CAPM, the relevance of flotation costs in determining the Company's cost of equity, and the business risk of DNCP relative to the proxy group.

Witness Hevert also addressed witness Woolridge's testimony, and explained why the results of witness Woolridge's analyses are not reasonable estimates of the Company's cost of equity. Witness Hevert explained how several aspects of witness Woolridge's DCF analyses and conclusions are not compatible with market conditions and are inconsistent with the practical interpretation of the models' results. Witness Hevert also showed that the growth rates that witness Woolridge asserts are overstated by historical standards represent approximately the 50^{th} to 51^{st} percentile of the actual capital appreciation rates observed from 1926 to 2015. He noted that from January 2014 through September 16, 2016, no utility commission had authorized a return as low as 8.60%, which is Witness Woolridge's recommendation in this case. He also noted Witness Woolridge's recognition that his recommendation is below the average for authorized ROEs for electric utilities, and that the lowest authorized ROE for a vertically integrated electric utility since January 2014 was 70 basis points above witness Woolridge's 8.60%. Witness Hevert also disagreed with witness Woolridge's assertions regarding market/book ratios and the cost of equity and provided updated data in support of that position. Finally, he testified in response to witness Woolridge's proxy group selection and expanded on his position regarding flotation costs.

In his rebuttal to witness O'Donnell's testimony, witness Hevert reiterated that all models are subject to limiting assumptions that may not be valid under certain market conditions, and that it is important to consider the results of multiple methods when estimating the cost of equity. He stated that this position is consistent with the Hope and Bluefield findings that it is the analytical result, as opposed to the methodology, that controls in arriving at ROE determinations. He stated further that a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results in light of the specific case at hand. He explained that capital market conditions influence the application and interpretation of ROE models, because the cost of equity is not directly observable and must be estimated using analytical techniques that rely on market-based data to quantify investor expectations and requirements. Specifically with regard to the constant-growth DCF model, witness Hevert explained that he gave the results of that model less weight in this case for two reasons. First, while one of the limiting assumptions of this model is that the P/E ratio will remain constant over time, the proxy group average P/E ratio had recently been trading at an unusual level relative to the overall market's P/E ratio, and since the date of the analysis he presented in direct testimony had been quite unstable. Second, constant-growth DCF model results recently have been well below the returns authorized for other vertically integrated electric utilities. Witness Hevert also addressed each of witness O'Donnell's contentions regarding the consistency of witness Hevert's ROE analysis as compared to his past analyses, and testified that those contentions are misplaced and should be given little weight.

Witness Hevert also testified that witness O'Donnell provided no testimony as to the reasonableness of the multi-stage DCF model or its application in this proceeding other than with respect to the long-term growth rate, and testified further as to the reasonableness of that rate. Witness Hevert also addressed witness O'Donnell's contentions as to the expected market return and other aspects of his CAPM and risk premium analyses. With respect to witness O'Donnell's contentions regarding the Company's pension fund's expected returns, witness Hevert testified that pension funding expectations should not be viewed as a measure of investors' required return, as the two are developed in separate manners and are used for different purposes.

Finally, in his rebuttal witness Hevert updated his analysis of economic conditions in North Carolina and DNCP's service area and testified that it continues to be his view that on balance, economic data regarding North Carolina and the U.S. do not alter his cost of equity estimates, or his recommendations, one way or the other. He also noted the importance of keeping in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. He stated that, given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in ROE estimates.

As reflected in Section II.B of the Stipulation, the Stipulating Parties agreed to an ROE of 9.90%. In the same Section, the Stipulating Parties also agreed that DNCP should be allowed to earn an overall rate of return on its rate base of 7.367%.

The overall return on rate base and the proposed allowed rate of return on common equity set forth in the Stipulation were supported by the stipulation testimony of DNCP witnesses Curtis and Hevert and Public Staff witness Hinton, and the hearing testimony of witness Hevert.

Witness Curtis testified that the Stipulation, including the stipulated 9.90% ROE, successfully strikes the balance of the Company's need for rate relief with the impact of that rate relief on customers.

Witness Hevert testified that although the stipulated ROE is somewhat below the lower bound of his recommended range (10.25%), he recognizes that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple, otherwise contested issues. He stated his understanding that the Company has determined that the Stipulation terms, taken as a whole, are such that it will be able to raise the external capital required to continue the investments required to provide safe and reliable service when needed at reasonable cost rates, and he appreciates and respects that determination. While his position remains that a range of 10.25% to 10.75% would represent a reasonable and appropriate measure of DNCP's cost of equity in a fully litigated proceeding, he stated that he recognizes the benefits associated with the decision to enter into the Stipulation and as such it is his view that the 9.90% stipulated ROE is a reasonable resolution of an otherwise-contested issue. Witness Hevert also testified that North Carolina falls in the top one-third of jurisdictions in terms of being a constructive regulatory jurisdiction according to RRA, and reiterated the importance of the perception of constructive regulatory environment to ratings agencies. He stated that the stipulated ROE is a reasonable outcome based on its being within three basis points of the average return of 9.87% (and seven basis points of the median) authorized for vertically integrated electric utilities from 2013 through 2016. He also stated that of the 77 cases decided during that period, 35 included authorized returns of 9.90% or higher. He also noted that the stipulated ROE falls 21 basis points below the average (and 30 basis points below the median) authorized ROE during the 2013-2016 time period for jurisdictions that are comparable to North Carolina's constructive regulatory environment and that from that perspective, the stipulated ROE is a somewhat conservative measure of the Company's cost of equity. Finally, witness Hevert testified that on balance, the impact of changing economic conditions data discussed in his direct and rebuttal testimony do not alter his ROE estimates or recommendation, and also do not alter his support of the Company's decision to agree to the stipulated ROE.

Witness Hinton supported the Stipulation as it relates to the cost of equity capital to be used in setting rates in this case, and made several changes and corrections to his direct testimony that did not alter his pre-settlement 9.3% ROE recommendation. He observed that the stipulated 9.90% ROE is higher than his recommended range of 8.80% to 9.80%, and lower than the Company's recommended range of 10.25% to 10.75%. He testified that the 9.90% represents a reasonable middle ground between the Public Staff and DNCP rather than acceptance of a particular analytical model. He also testified that the agreements on ROE and capital structure discussed above could only occur in the context of various compromises by both parties on other issues. Finally, he testified that he believes a 9.90% ROE accounts for the impact on customers when viewed in the context of the overall settlement. He stated that, first, the settlement as a whole is reasonable with regard to the ultimate impact on customers, which is the impact on their monthly bills. Second, he noted that the impact of changing economic conditions in the DNCP service territory is difficult to adequately quantify, as there exist both economic improvement and economic problems. Third, he noted that the one-time payment of $400,000 to assist DNCP's low-income customers in North Carolina, which will come from earnings that would otherwise go to shareholders, will help mitigate the rate increase for the customers who have the greatest need and feel the impact of economic conditions most severely. Witness Hinton concluded that because the contribution could not lawfully be ordered by the Commission in the absence of Company agreement, it therefore provides a response to the impact of economic conditions on customers that could only exist with a settlement agreement, which adds to the reasonableness of the agreed-upon ROE.

At the hearing, witness Hevert testified in response to questions from counsel for CUCA and the Attorney General with regard to the 13.45% Bloomberg estimated market return he used in his CAPM analysis, which as he explained in his rebuttal testimony reflects return expected by analysts covering the companies that compose the S&P 500 Index. It does not represent the return for utilities, but is the expected market return from which the risk-free rate of return is subtracted to find the Market Risk Premium. The Market Risk Premium is then multiplied by the Beta coefficient, which represents a given utility's risk relative to the market. At the hearing, witness

Hevert stated that 13.45% is well within that range considering an average historical market return of 12%, and the historical variation in returns of about 20%. In response to questioning from CUCA counsel as to whether his recommended ROE would be higher or lower if he had used the same approaches to his methodologies in this case as in previous cases, witness Hevert explained that it makes sense to apply different weights to the approaches as the markets change, because one model's assumptions no longer become as relevant to the market circumstances as they had been.

In response to questioning by the Attorney General, witness Hevert testified to the recent volatility in the utility sector, as exemplified by the variance in stock prices used as an input to his constant growth DCF analysis. In response to questions from counsel for Nucor, witness Hevert testified that looking at annual averages of returns may indicate a distorted view of trends in returns, since there may be years with fewer cases, or years with cases from jurisdictions that tend to authorize lower returns, rather than looking at individual cases.

On redirect questioning, witness Hevert reiterated that state regulatory commissions generally do not base rate of return decisions on evidence provided by a single witness, and that often state commissions like the Commission have authorized returns lower than his recommendation and higher than intervenor recommendations. He confirmed that the stipulated ROE of 9.90% is slightly below the lower end of his recommended range, and slightly above the higher end of Public Staff witness Hinton's recommended range. He stated the only instance he can recall of a commission authorizing an ROE comparable to the 9.0% and 8.6% ROEs recommended by Nucor and CUCA was in Hawaii, and that that case involved a reduction to the authorized ROE to account for system inefficiencies.

Public Witness Testimony

The public witness testimony heard by the Commission is summarized below.

Belinda Joyner of Garysburg in Northampton County, testifying on behalf of Concerned Citizens of Northampton County, stated that elderly customers on fixed income and retired State employees have to make purchasing decisions based on their limited income whether to buy groceries, medicine, and other items. She testified that without power these customers cannot cook, wash, nor otherwise function, and that a 17% increase in rates is unfair.

Tony Burnette, President of the Northampton County NAACP, is a caregiver for her elderly mother. She testified that a 17% increase would be detrimental to elderly customers and that elderly customers are often at home all day, and would likely use more than the 1000 kilowatts (kW), the monthly usage of an average customer.

Larry Abram of Tillery in Halifax County agreed with other witnesses regarding the difficulty elderly customers would have paying their bills.

Dean Knight of Halifax testified that his cotton gin business has electric bills of about $150,000 per month for three months of the year, and he must pay for improvements to his equipment within his budget, rather than by raising his rates.

Janice Bellamy of Whitakers in Edgecombe and Nash Counties testified to the difficulty she and others on fixed incomes have in paying their bills, such as water and electric bills.

Regina Moffett of Whitakers, advocating for seniors, stated that the proposed rate increase would impact the entire local community and that higher bills would result in decreased church contributions. She also testified that when she became a Dominion customer, she saw a "great decrease" in her electric bill.

Betty Bennett of Garysburg testified that a 17% increase in electricity rates was too high.

Peter Bishop, the Director of Economic Development for Currituck County, testified on behalf of the Currituck County Board of Commissioners. He testified with respect to DNCP witness Hevert's testimony that while North Carolina "and this region" have improved significantly since the recession, the counties within DNCP's service area have not fared well. He stated that the Company could have made a better argument with regard to economic conditions in the area and presented several statistics related to unemployment, poverty rate, median household income, net loss of population, and new businesses showing that the counties within DNCP's service area are worse off than other counties in the State. Mr. Bishop also recommended that the Commission exercise caution when making determinations regarding recovery of coal ash costs, as this is a developing issue, and stated that the best approach may be to wait and see how coal ash cost recovery is handled in the federal courts before setting precedent for this State.

Robert Woodard, Chairman of the Dare County Board of Commissioners, testified in support of the Dare County Board of Commissioners' resolution that was filed on July 19, 2016, in this proceeding. He also testified that the Board's position is that any rate increase would place an undue hardship on Dare County's citizens.

Walter Overman, Vice Chairman of the Dare County Board of Commissioners, testified that Dare County's population has not seen a 17% or even a 6% increase in wages since DNCP's last rate case. He testified that lower-wage residents would be hit especially hard in an area with a high cost of living. He asked that the rate increase be denied.

Dwight Wheless of Columbia in Tyrrell County testified in support of the Columbia Town Board of Aldermen's resolution in opposition to the proposed rate increase. He testified that Tyrrell County has the second lowest per capita income in the State and its citizens would be most hurt by an increase in the cost of electricity. He also testified that Columbia has not experienced any recovery and that its residents are already challenged by constant increases in the cost of food and pharmaceuticals.

Robert Edwards of Nags Head in Dare County testified that the requested rate increase should not be granted. He testified that inflation has remained near zero in recent years and that if the Company made wise and prudent investments, those alone should have improved productivity and reduced costs so that customer rates should actually be lowered. He testified that DNCP should hedge fuel cost fluctuations with long-term purchase agreements and that customers should not be exposed to fuel cost increases. He testified that the proposed increase for residential customers as compared to large users is unfair, and that the requested rate of return on equity is too high.

ELECTRIC – RATE INCREASE

Manny Madeiros of Kitty Hawk in Dare County testified that DNCP's retail electric rates should not reflect the cost of renewable energy production.

Judy Williams of Manteo in Dare County testified that she and others are living on fixed incomes and even a 7% increase in rates is too high.

Martha MacDonald of Williamston in Martin County testified that the rate increase would have a direct negative impact on seniors, most of whom have Social Security as their sole income, averaging $1300 a month. She testified that Martin County is a Tier 1 County, and that seniors are often forced to choose between paying their electric or water bills or buying food or medicine. She also testified that some residents cannot afford detached homes with insulation and are paying high bills for electricity in mobile homes. She testified that DNCP does a good job restoring power when there are outages.

John MacDonald of Williamston testified that he and many customers in the area are on fixed incomes and cannot afford the proposed rate increase.

Tawilda Bryant of Jamesville in Martin County testified in support of Ms. MacDonald's testimony on the impact of the proposed rate increase on seniors.

Rhett White, the Town Manager of Columbia in Tyrrell County, testified that the Town has struggled in the past to absorb electric rate increases and fuel charge adjustments without increasing local property taxes. He testified that Columbia could not withstand an increase of even 5.9% without an increase of 2 cents per $100 in the Town's tax rate. He testified that many of Columbia's elderly residents are on fixed incomes, sometimes living on the minimum Social Security check of $750 per month. He testified that a typical widowed resident living in a home valued at $75,000 would have to pay another $15 in annual taxes to cover the Town's increased power bills, in addition to the more than $84 that she will pay for her own residential power bill. He also testified that the increase to the County's own power bills would result in increased county taxes for that same resident. He stated that the proposed rate increase would negatively affect the Town's businesses and industry, and that the recent recession is not over in rural Columbia and Tyrrell County. He testified that wages are lower than elsewhere in northeastern North Carolina, unemployment is much higher than throughout the State, poverty rates are high, median household incomes remain the lowest in the region, and out-migration of young residents in search of jobs continues. He testified that the economic climate in Columbia is very different from that described by DNCP witness Hevert, and that the Town is made up mostly of low-income, working residents in a Tier 1 County.

Ronnie Smith, the Chair of the County Commissioners of Martin County, testified that many people in the area cannot afford the proposed increase, and that even small increases impact residents on fixed incomes.

John Liddick of Williamston testified that during the cold winter weather in the past, residents have said they could not afford their electric bills.

Linda Gibson of Williamston testified that most seniors are on fixed incomes of $600 or $700 per month, and that once they pay one or two bills, they have just enough left to buy food.

She testified that most jobs in Martin County pay minimum wage or just a bit more and even young people have trouble making ends meet. She also testified in support of DNCP's good service in terms of restoring power after outages.

Samantha Komar of Williamston testified that she is a veteran and on a fixed income. She testified that the median income in the town is $15,000 per year and that residents already often have to choose between paying their electric and water bills or for food and medication.

Louise Simmons of Jamesville testified that she would not be able to pay any more on her electric bill.

Jerry McCrary, the Mayor of Parmele, Martin County, testified that Parmele has about 300 citizens, the majority of whom are seniors. He also testified that the proposed rate increase would harm these residents who already have to choose between buying food, medicine, and paying their bills.

Glenda Barnes of Parmele testified that the proposed 17% increase is too high.

Reginald William Ross, Jr. of Williamston testified that many of the local residents are seniors on fixed income making difficult choices about buying food or medicine.

Legal Standards Applicable to Rate of Return Findings by the Commission

The Commission's analysis of and decision on rate of return on rate base and allowed rate of return on common equity in this case is governed by the United States Supreme Court's Hope and Bluefield decisions,[1] the requirements of G.S. 62-133, and the North Carolina Supreme Court decisions interpreting and applying each of the foregoing to rate of return decisions by the Commission.

In Bluefield, the US Supreme Court established the basic framework for rate of return regulation of public utilities. On this subject, the Court held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; . . . [t]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

[1] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope); Bluefield Waterworks & Improvement Co. v. Public Service Commission, 262 U.S. 679 (1923) (Bluefield).

Bluefield, 262 U.S. at 692-93. In the subsequent Hope decision, the Court expanded on its analysis by stating:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock…. By that standard the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Hope, 320 U.S. at 603.

The Commission has looked to the Hope and Bluefield standards as guidance for setting rates. In Docket No. E-7, Sub 1026, the Commission noted that:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in *Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va*., 262 U.S. 679 (1923) (*Bluefield*), and *Fed. Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) (*Hope*): To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope.

Id., at 7.

The Commission must balance the interests of investors and customers in setting the rate of return on equity. As the Commission has stated, "the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[1] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum

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[1] Docket No. E-7, Sub 1026, Order Granting General Rate Increase, (Sept. 24, 2013) at 24; see also Docket No. G-9, Sub 631, Order Approving Partial Rate Increase and Allowing Integrity Management Rider, (Dec. 17, 2013), at 26 (noting North Carolina Supreme Court's determination that the provisions of G.S. 62-133 "effectively require the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States, those of the State Constitution, Art. I, § 19, being the same in this respect"); 2015 Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.").

amount needed to meet the Hope and Bluefield comparable risk, capital attraction, and financial integrity standards.

In addition, the Supreme Court has held that "although the Commission must make findings of fact with respect to the impact of changing economic conditions upon consumers," it is not required to "'quantify' the influence of this factor upon the final ROE determination."[1] The Commission echoed this distinction in the 2015 Remand Order as well, stating that it is "not required to isolate and quantify the effect of changing economic conditions on consumers in order to determine the appropriate rate of return on equity."[2]

The Supreme Court has also, however, made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[3] In Cooper II, which addressed an appeal of the Commission's order on DNCP's previous base rate application, the Supreme Court directed the Commission on remand to "make additional findings of fact concerning the impact of changing economic conditions on customers."[4] The Commission made such additional findings of fact in its Order on Remand.[5]

Finally, when a settlement agreement has not been adopted by all of the parties to a case, its acceptance by the Commission is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I, the Supreme Court held that

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and

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[1] State ex rel. Utilities Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014). In this case the court affirmed the Commission's Order on Remand, issued October 23, 2013, in Docket No. E-7, Sub 989, at pages 34-35, where the Commission pointed out that "adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property. This is in accord with the 'end result' test of Hope. This the Commission has done." See also State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 745-46, 767 S.E.2d 305, 308 (2015).

[2] DNCP Remand Order at 26.

[3] State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635, 642 (2014) (Cooper II), See also State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541 (2013) (Cooper I).

[4] Cooper II, 758 S.E.2d at 643.

[5] DNCP Remand Order at 4-10.

> makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement did not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires *only* that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id., at 231-32, 524 S.E.2d at 16. (emphasis added).

With these legal principles in mind, the Commission now turns to the analysis of the evidence in this proceeding relating to a determination of the appropriate overall rate of return on rate base and allowed return on common equity for use in this proceeding.

Analysis of the Evidence

In order to reach an appropriate independent conclusion regarding return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. Cooper I, 366 N.C. at 492-493; CUCA I, 348 N.C. at 460-467*;* CUCA II, 351 N.C. at 229-230.

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the approved rate of return on equity for a public utility. Cooper, 366 N.C. at 491, 739 S.E.2d at 548. There is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers. However, the impact on customers of changing economic conditions is embedded in the return on equity expert witnesses' analyses. The Commission noted this at page 38 of its 2012 Rate Order: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return."

The evidence in this proceeding related to the determination of an overall rate of return on rate base and allowed rate of return on common equity is provided in the testimony of the public witnesses, the testimony and exhibits of DNCP's witness Hevert (and, in support of witness Hevert's recommendations, in the testimony of DNCP witnesses Curtis and Chapman), and the testimony and exhibits of Public Staff witness Hinton, Nucor witness Woolridge, and CUCA witness O'Donnell, and the Stipulation.

Witness Hevert used four different analytical methods, each with multiple variations, to estimate the cost of equity capital for DNCP. He ran a constant growth DCF method with 30-day, 90-day and 180-day low, mean, and high averages for each of his proxy companies, which as updated in his rebuttal testimony resulted in a rate of return on equity range of 8.14% to 9.32%. The range for his updated multi-stage DCF analysis is 8.85% to 9.97%. The range for his updated CAPM analysis is 8.87% to 11.22%, and the range for his updated bond yield plus risk premium analysis is 10.02% to 10.38%. The range between the highest number produced by the four methodologies, 11.22%, and the lowest number, 8.14%, encompasses the stipulated rate of return on equity of 9.90%. Further, the average of witness Hevert's updated analytical results, using the DCF mean growth rate results, is 9.45% (where the CAPM is based on the Bloomberg market risk premium) to 9.58% (where the CAPM is based on the Value Line market risk premium). However, witness Hevert testified that the constant growth DCF results "are difficult to reconcile with observable, prevailing market conditions," and likely reflect increases in utility stock prices that are a temporary overvaluation.

The Commission gives significant weight to witness Hevert's testimony that constant growth DCF results should be viewed with caution in current market conditions. While current stock prices are an observable fact, whether overvalued or not, an underlying assumption of the constant growth DCF is that the price to earnings ratio (P/E) remains constant. However, as noted by witness Hervert, utility sector P/E ratios have increased to the point that they have exceeded both their long-term average and the market P/E. In addition, constant growth DCF results are below authorized returns.

As a result, the Commission finds it reasonable in the current economic circumstances to give no weight to the constant growth DCF results, and to give substantial weight to an averaging of the high growth rate multi-stage DCF, the Value Line-based market risk premium CAPM, and the bond yield plus risk premium results, which indicates a 9.86% ROE. The result of this averaging, being only four basis points below the stipulated 9.90% ROE, is strongly supportive of the stipulated ROE, particularly in light of the Supreme Court's decision in State ex rel. Utils. Comm'n v. General Telephone Co., 285 N.C. 671, 681, 208 S.E.2d 681, 670 (1974) (a "zone of reasonableness extending over a few hundredths of one percent" exists within which the Commission may appropriately exercise its discretion in choosing a proper rate of return on equity).

In addition, the Commission gives substantial weight to witness Hevert's stipulation testimony in support of the stipulated 9.90% ROE. He testified that although the stipulated ROE is somewhat below the lower bound of his recommended range (i.e., 10.25%), he recognized that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple issues that would otherwise be contested by the Stipulating Parties. In addition, he relied on DNCP's determination that the terms of the Stipulation, taken as a whole, are such that DNCP will be able to raise the capital required to continue the investments required to provide safe and reliable service, and that it will be able to do so when needed and at a reasonable cost rates. The Commission notes that the approved ROE is just one of many factors that affect the earnings available to pay a return to equity investors, and therefore it is essential to assess the reasonableness of the ROE in the context of all the issues that affect earnings.

The Commission agrees with witness Hevert's testimony that although the stipulated ROE falls within the range of analytical results presented in his direct and rebuttal testimony, current capital market conditions are such that the models used to estimate the cost of equity continue to produce a wide range of sometimes conflicting estimates. Indeed, all the cost of capital witnesses used multiple analytical models, with wide-ranging results.

The Commission also gives substantial weight to witness Hevert's testimony that it is important to keep in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. Given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in the analytical estimates of the ROE. The Commission further finds credible witness Hevert's testimony that, on balance, economic data regarding North Carolina and the United States do not alter the cost of equity estimates one way or the other.

The Commission additionally gives substantial weight to the stipulation testimony of Company witness Curtis that the concessions the Company has made through the Stipulation reasonably balance its customers' interest in receiving the lowest rate impact while also meeting DNCP's need to recover the substantial investments that it has made in order to continue to comply with regulatory requirements and safely provide high quality electric service.

Based on the testimony of DNCP witnesses Hevert and Curtis, the 9.90% stipulated ROE, in the context of the settlement as a whole, will be sufficient to meet the requirements of investors in capital markets. The corresponding question is whether a 9.90% ROE imposes no more burden on DNCP customers than is necessary for the Company to provide reliable electric service. In this regard, the Commission gives substantial weight to Public Staff witness Hinton's settlement testimony that the stipulated 9.90% ROE represents a reasonable middle ground between the Public Staff and DNCP, higher than his recommended range of 8.80% to 9.80%, and lower than the Company's recommended range of 10.25% to 10.75%.

The Commission also gives weight to witness Hinton's direct and settlement testimony in its focus on the impact on customers from multiple perspectives. In particular, he testified regarding: (1) data showing improvement in economic conditions, notably unemployment and per capita income, for the population within DNCP's service territory; (2) the benefit customers will receive from lower rates as a result of a negotiated settlement that will reduce the Company's proposed rate increase by over $12 million – a result that eliminates uncertainty regarding the chance that a higher rate increase could have been approved in a fully-contested proceeding; and (3) the $400,000 to be paid by shareholders to assist low-income customers who are the most impacted by a rate increase.

Witness Hinton's direct (pre-settlement) testimony employed three primary analytical methods: a constant growth DCF, a regression analysis of allowed ROEs, and the comparable earnings method. The Commission finds the high end of his comparable earnings results to be probative and compelling in the circumstances of this case. As witness Hinton noted, the comparable earnings method is well-suited to the Hope legal standard of authorizing a utility ROE that allows investors to earn a return comparable to returns available on alternative investments with similar risk. As a result, the Commission gives substantial weight to the high end of the range of results from witness Hinton's updated comparable earnings analysis, where the three highest ROE results – 10.0%, 9.9% and 9.7% - average 9.867%. The Commission considers such substantial weight appropriate in the present circumstances where there is a wide range of analytical results, all with strengths and weaknesses. Thus, it is reasonable to rely more heavily on results that support a middle ground among the analyses of the competing witnesses.

Nucor witness Woolridge acknowledged that his recommendation of an ROE of 8.60% out of a range of 7.90% to 8.75% is below the average authorized ROEs for electric utility companies. The Commission notes witness Hevert's rebuttal testimony that the lowest authorized ROE for a vertically integrated electric utility since January 2014 was 70 basis points above witness Woolridge's 8.60% recommendation. The Commission cannot blindly follow ROE results allowed by other commissions, but must determine the appropriate ROE based upon the evidence and particular circumstances of each case. However, the Commission believes that the ROE trends and decisions by other regulatory authorities deserve some weight, as they provide a check or additional perspective on the case-specific circumstances. In addition, DNCP must compete with utilities in other jurisdictions for capital from investors. In this regard, the Commission finds persuasive witness Hevert's testimony at the hearing that North Carolina is generally viewed by the credit ratings agencies to be a supportive jurisdiction, and that an ROE of 9.90% is consistent with the returns recently awarded to utilities in similarly constructive jurisdictions. The Commission has not relied on this evidence to arrive at its ROE decision. Instead, the Commission has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding. That check allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions. In addition, the Commission finds persuasive witness Hevert's responses to witness Woolridge and counsel for Nucor regarding the use of annual averages of the inputs to the DCF analysis and other inputs to his analyses. The Commission gives weight to witness Hevert's rebuttals to witness Woolridge's testimony as discussed above and the check on witness Woolridge's recommended ROE provided by the comparison to other similar jurisdictions. The Commission concludes that witness Woolridge's result of 8.6% ROE is outside the bounds of reasonableness – there is no credible evidence showing that the cost of equity for DNCP has decreased by 160 basis points since the Company's last rate case - and would put the Company at a significant disadvantage in competitive capital markets when attempting to raise capital needed to fund its operations.

The Commission gives little weight to witness O'Donnell's ROE testimony. The Commission find persuasive witness Hevert's responses to witness O'Donnell's' arguments regarding the long-term growth rate and other inputs to his analyses, particularly witness Hevert's discussion regarding the distinction between ROE and pension returns. The Commission agrees with witness Hevert that in light of the Hope case ruling that it is the end result that is the primary consideration in ROE determinations. In this case, witness O'Donnell's end result of a 9.0% ROE, at 120 basis points lower than the last authorized ROE for DNCP, overstates the decline in investors' required return, and therefore is outside the bounds of reasonableness and would put the Company at a significant disadvantage in raising capital needed to fund its operations. Witness O'Donnell provided no testimony as to the reasonableness of the multi-stage DCF model or its application in this proceeding other than with respect to the long-term growth rate.

Counsel for Nucor, CUCA and the Attorney General questioned witness Hevert about various aspects of his analyses; however, their cross-examination did not establish a persuasive basis for an ROE lower than 9.90%. The stipulated 9.90% ROE is itself 60 basis points lower than the 10.5% ROE recommendation resulting from witness Hevert's analysis. The stipulated

9.90% ROE is further corroborated by witness Hevert's hearing testimony that in only one case that he can recall has a commission authorized an ROE comparable to the 9.0% and 8.6% ROEs recommended by Nucor and CUCA, and but for a decrement applied in that case for unrelated reasons, the ROE in that instance would have been 9.5%. Again, while the Commission has not relied on this evidence to arrive at its ROE decision, it has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding that allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions. Overall, the Commission finds the settlement testimony of witness Hevert and witness Hinton to be credible, substantial, and probative evidence that supports approval of a 9.90% rate of return on common equity for DNCP in this proceeding.

As discussed above, numerous customers provided testimony at the public hearings as to the impact that any rate increase would have, especially on those customers in DNCP's service area who are on fixed incomes. The Commission acknowledges and accepts as true the proposition that some percentage of DNCP's customers, particularly those living on fixed incomes, are economically vulnerable and may struggle to pay an increase in DNCP's rates granted in this docket. The Commission gives substantial weight to the public witness testimony as it undertakes to balance the interests of DNCP's customers with the Company's need to obtain financing on reasonable terms for the continuation of reliable electric service.

Conclusions on Return

The Commission has the obligation to reach its own independent conclusion as to whether the Stipulation is just and reasonable, fair to customers, the Company and its shareholders in light of changing economic conditions, and otherwise sufficient to satisfy the requirements of G.S. 62-133. In sum, the Commission finds and concludes for purposes of this case and after thoroughly and independently reviewing all of the evidence that an authorized ROE of 9.90% is just and reasonable based on all of the evidence presented.

The Commission understands that rate increases are not favored by ratepayers and that some portion of any utility's customer base will find it difficult to pay their utility bills from time to time. The Commission further acknowledges that it is the Commission's primary responsibility to protect the interests of utility customers in setting rates for public utilities by complying with the legal principles discussed earlier in this Order. It is also the Commission's responsibility to abide by the constitutional requirements of the Hope and Bluefield cases as reflected in the provisions of G.S. 62-133 and to balance the interests of customers and the regulated utilities.

The Commission finds and concludes, for the reasons set forth herein, that the ROE recommendations of witnesses Woolridge and O'Donnell are to be afforded little weight. The Commission concludes that their analyses would produce a significant risk that the Company could not obtain equity financing on reasonable terms. The Commission further concludes that a 9.90% ROE is reasonable based in part on probative, credible evidence from witness Hevert and witness Hinton. In particular, rather than accept any one approach of any single witness, the Commission has independently determined that the combination of witness Hevert's updated analytical results, as well as witness Hinton's updated comparable earnings results, are supportive of an ROE of 9.90%. The 9.90% ROE is also supported by the Stipulation and the accompanying testimony of DNCP and Public Staff witnesses as to its reasonableness. Finally, as discussed below in more detail, the Commission concludes that a 9.90% ROE is reasonable and appropriate in light of the numerous other adjustments that affect earnings available to investors. Such adjustments include reductions in the Company's requested rate base, reductions in its requested operating expenses, an approved capital structure that imputes a lower equity ratio than the Company's actual capital structure, and a $400,000 shareholder contribution to assist low-income customers. Along with these adjustments, the impact of changing economic conditions on DNCP's customers has been taken into account in determining the approved ROE.

Consumers pay rates, a charge in cents per kilowatt-hour for the electric energy they consume. They do not pay a rate of return on equity. To the extent that the Commission makes downward adjustments to rate base, reduces the approved common equity component of capital structure, disallows test year expenses or increases pro forma test year revenues, the Commission reduces the rates consumers pay during the future period rates will be in effect. However, the utility's investors' compensation for the provision of service to consumers takes the form of return on investment. To the extent the Commission makes adjustments to reduce the overall cost of service, the Commission reduces the rates consumers otherwise must pay irrespective of its determination of rate of return on equity expressed as a percentage, in this case 9.90%. To the extent these adjustments reflect current economic conditions, and consumers' ability to pay, these adjustments reduce not only consumers' rates but also the return on equity, expressed in terms of dollars that investors actually earn. This is also in accord with the end result test of Hope.

In the present case, DNCP's initial Application requested a $51.073 million increase in DNCP's annual North Carolina revenues. That revenue increase would require an overall rate increase of 20.90%. In addition, DNCP requested a 10.5% rate of return on common equity, a 7.88% overall return on a rate base of $1.067 billion, and a capital structure that included 53.359% common equity. In the Company's supplemental and rebuttal cases, it revised its requested revenue increase to $46.8 million and its overall return to 7.805%. These are the "big picture" numbers in the case. However, the crucial details of DNCP's general rate Application, as in all general rate cases, are in the hundreds of line items in the NCUC Form E-1 that detail the Company's cost of service. The details of DNCP's Application, including the cost of service line items, are reviewed by the Public Staff and by other intervenors. The Public Staff typically recommends numerous adjustments to the utility's cost of service items, some adjustments increasing an item and some adjustments decreasing another item. These adjustments are presented by the Public Staff in its testimony, or, as in the present docket, in a settlement agreement with the utility.

In the present docket, the Public Staff's adjustments are shown in Settlement Exhibit II of the Stipulation. There are about 20 adjustments, some up and some down. However, the end result of all the adjustments is a reduction in DNCP's revenue requirement from the $46.752 million requested in the Company's rebuttal case to the stipulated amount of $34.732 million. Thus, the numerous adjustments made by the Public Staff, and approved herein by the Commission, reduce the total annual base revenues to be received by DNCP from ratepayers by $12.020 million, including a reduction of approximately $5.235 million resulting from a decrease in the rate of return to be paid to equity investors.[1] Although the ROE downward adjustment produces a direct reduction in the authorized rate of return on investment financed by equity investors, the numerous other downward adjustments reflected on Settlement Exhibit II further reduce the dollars the investors actually have the opportunity to receive. For example, the authorized 51.75% equity ratio in the capital structure, which is a regulatory reduction from the Company's actual equity ratio of 53.92%, reduces revenues available for earnings by another $2.849 million. Thus, while the equity investor's cost was calculated under the terms of the Stipulation by applying a rate of return on equity of 9.90%, instead of the 10.5% requested in the Application, this is only one of many approved adjustments that reduces ratepayer responsibility and equity investor reward.

This is not to say that the Commission accepts the stipulated 9.90% rate of return on equity merely because it is lower than the 10.5% requested by DNCP. Indeed, the Commission has weighed the evidence of the expert ROE witnesses, and in finding some of that evidence to be highly probative and other parts of that evidence as entitled to little weight, has independently found support in the analytical results for a 9.90% ROE. In addition, the Commission concludes that each of the approximately 20 adjustments made by the Public Staff, and accepted herein by the Commission, reflects the fact that ratemaking, and the impact of rates on consumers, must be viewed as an integrated process where the ratemaking end result is what directly affects customers. The Commission's acceptance of the foregoing ratemaking adjustments, including the 9.90% rate of return on equity, reflects the Commission's application of its subjective, expert judgment under the Public Utilities Act that the end result is in compliance with the Commission's responsibility to establish rates as low as reasonably possible without transgressing constitutional constraints.

Solely focusing on the authorized rate of return on equity in assessing the impact of the Commission's decision on consumers' ability to pay in the current economic environment would fail to give a true and accurate picture of the issues presented to the Commission for decision and the totality of the Commission's order. Such an analysis would also be inconsistent with Hope and the CUCA cases. For example, when the Commission approves a reduction in the investment (rate base) against which the authorized 9.90% rate of return on equity is multiplied to produce the dollars in return on equity investment, the financial impact is a reduction in the rates paid by ratepayers and a reduction in the amount received by equity investors, the same result as if the Commission had instead reduced the 9.90% rate of return on equity. In the present case, the Stipulation included a reduction of $4.903 million in authorized rate base, and therefore, a substantial reduction in revenues available to pay earnings to shareholders, compared to the Company's position in its rebuttal testimony.[2]

As previously noted from the Hope decision, it is the "end result" of the Commission's order that must be examined in determining whether the order produces just and reasonable rates. Consistent with that requirement, the Commission has incorporated into its analysis all of the myriad factors that make up DNCP's revenue requirement, including the rate of return on equity and the impact of the Commission's decision regarding the consumers' ability to pay in the current economic environment. With respect to customers' ability to pay, an important adjunct to the

[1] See Settlement Exhibit II.

[2] See Fernald Exhibit 1, Schedule 2, Revised (filed with the settlement testimony of Public Staff witness Fernald).

9.90% ROE is the $400,000 shareholder contribution to assist low-income customers, notwithstanding the significant improvement in economic conditions in DNCP's service territory since the Company's last rate case. Based on the impact on customers, the requirements of investors in capital markets, and the total effect of the Stipulation with its numerous reductions to the Company's proposed revenue requirement, the Commission concludes that a 9.90% rate of return on equity produces just and reasonable rates for DNCP and for its ratepayers. Any further reduction in the authorized rate of return on equity is not justified by any evidence that the Commission has found to be credible and probative in its fact finding role.

In separate post-hearing briefs, the AGO and Nucor emphasized the generally lower results produced by the Constant Growth DCF analyses of all the witnesses. They argue that either the implementation, or interpretation of results, by witnesses Hinton and Hevert in their Mutli-Growth DCF, Comparable Earning, Risk Premium, or CAPM analyses are flawed and excessive. The AGO, which presented no witness, recommends an ROE of less than 9.0%, and Nucor recommends an ROE of 8.6% consistent with the testimony of witness Woolridge.

In its post-hearing Brief, CUCA contends that the stipulated ROE of 9.90% is too high because it represents a "split the baby" approach between the ROE proposed by Public Staff witness Hinton and the ROE proposed by DNCP witness Hevert. Further, CUCA maintains that each of the analytical models used by witness Hevert is seriously flawed, as discussed by CUCA witness O'Donnell in his testimony.

After consideration of the entire record and for the reasons stated herein, the Commission is not persuaded by the AGO or Nucor that the 9.9% ROE in the Stipulation is excessive. The Commission points out that each of the witnesses to this proceeding use considerable judgement or discretion in deciding which ROE estimation method or model to use and present into evidence, or even withhold. In addition, each ROE witness used discretion in deciding what inputs to use within each method, the interpretation of the results of each method, and how the results of each method were weighted in determining the ROE to recommend on behalf of their employer or client. The Commission is uniquely situated and legally charged with using its impartial judgement to determine the ROE using applicable legal standards. The Commission has used its impartial judgment as necessary and appropriate to evaluate and weigh the evidence in reaching its conclusions and findings relevant to the ROE issue as set forth in this Order.

After a careful review of all the evidence in this case, and adhering to the requirements of the above cited legal precedents, the Commission finds that the overall rate of return on rate base and the allowed rate of return on common equity, as well as the resulting customer rates provided for under the Stipulation, are just and reasonable, fair to both DNCP and its customers, appropriate for use in this proceeding, and should be approved. The rate increase approved herein, as well as the rates of return underlying such rates, are just, reasonable and fair to customers considering the impact of changing economic conditions, and are required in order to allow DNCP, by sound management, to produce a fair return for its shareholders, maintain its facilities and provide services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and existing investors.

The Commission notes further that its approval of an ROE at the level of 9.90% - or for that matter, at any level - is not a guarantee to the Company that it will earn a return on its common equity at that level. As noted above, on June 30, 2016, the Company's fully-adjusted earned rate of return on equity capital for the update period was only 5.50%, far below the Company's currently authorized 10.2%. Rather, as North Carolina law requires, setting the ROE at this level merely affords DNCP the opportunity to achieve such a return. See G.S. 62-133(b)(4). The Commission believes, based upon all the evidence presented, that the ROE provided for here will indeed afford the Company the opportunity to earn a reasonable and sufficient return for its shareholders while at the same time producing rates that are fair to its customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

The evidence supporting this finding of fact and these conclusions is contained in the Application and Form E-1 of DNCP, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

In the Application and direct testimony and exhibits, DNCP provided evidence supporting an increase of $51.073 million, or approximately 20.90%, in its annual non-fuel revenues from its North Carolina retail electric operations. On August 12, 2016, the Company filed supplemental direct testimony and exhibits updating several cost of service adjustments. These updated adjustments decreased the Company's revenue requirement by $3.3 million, for a revised increase in North Carolina retail revenue of $47.8 million, which was reduced again in the Company's rebuttal case filed on September 26, 2016 to $46.8 million.

On September 7, 2016, the Public Staff filed the direct testimony of witness Fernald, presenting her recommended accounting and ratemaking adjustments to the Company's proposed revenue requirement. Accounting for these adjustments, she recommended an increase in the Company's annual base non-fuel operating revenue of $19,755,000. Nucor filed testimony of witness Kollen, who also made recommendations for accounting adjustments.

On September 26, 2016, the Company filed the rebuttal testimony of witness Stevens, which responded to the various accounting adjustments and recommendations of witness Fernald and witness Kollen.

On October 3, 2016, the Company, the Public Staff and CIGFUR I entered into and filed the Stipulation. Pursuant to the Stipulation, the Company, the Public Staff and CIGFUR I agreed upon an increase to DNCP's annual non-fuel revenue from its North Carolina retail electric operations of $34.732 million or 14.25% and a decrease in annual base fuel revenues of $8.942 million.

Also on October 3, 2016, the Company filed the joint testimony of witness Stevens and witness McLeod in support of the stipulated revenue increase. These witnesses testified in support of the accounting and ratemaking adjustments agreed upon in the Stipulation. They also testified that the Stipulation is the result of negotiations between the Stipulating Parties who, collectively, represent both residential and industrial customer interests impacted by this case. Also on

October 3, 2016, the Public Staff filed testimony of witness Fernald recommending and supporting the stipulated adjustments to the Company's requested revenue increase.

Based upon the evidence recited above and the cumulative testimony and evidence supporting the individual components of the stipulated revenue increase discussed throughout this Order, the Commission finds, in the exercise of its independent judgment, that the stipulated net revenue increase of $25.70 million for North Carolina retail electric operations in this case is just, reasonable, and appropriate for use in this proceeding.

The following schedules summarize the gross revenue and the rate of return that the Company should have a reasonable opportunity to achieve based on the determinations made herein. These schedules, illustrating the Company's gross revenue requirement, incorporate the findings and conclusions made by the Commission in this Order. As reflected in Schedule I, and as impacted by the other findings in this Order, DNCP is authorized to increase its annual level of gross revenues by $25.790 million, reflecting an increase of $34.732 million in base non-fuel revenues (including late payment fees and other revenues) and a decrease of $8.942 million in base fuel revenues.

SCHEDULE I
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF OPERATING INCOME
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric sales revenues	$242,718	$34,310	$277,028
Base fuel revenues	99,755	(8,942)	90,813
Late payment fees	1,292	92	1,384
Other revenues	6,167	330	6,497
Total operating revenues	349,932	25,790	375,722
Fuel expenses	90,686	0	90,686
Other O&M expenses	98,829	160	98,989
Depr. and amort. expense	60,047	0	60,047
Gain / loss on disp. of property	309	0	309
Taxes other than income	15,233	0	15,233
Income taxes	23,891	9,929	33,820
Total operating expenses	288,995	10,089	299,084
Net operating income before adj.	60,937	15,701	76,638
Interest on customer deposits	(19)	0	(19)
Interest on tax deficiencies	(1)	0	(1)
Net operating income for return	$ 60,917	$15,701	$ 76,618

SCHEDULE II
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF RATE BASE AND RATE OF RETURN
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric plant in service	$1,947,252	$ 0	$1,947,252
Accumulated depr. and amort.	(716,858)	0	(716,858)
Net electric plant in service	1,230,394	0	1,230,394
Materials and supplies	44,916	0	44,916
Cash working capital	16,406	2,070	18,476
Other additions	19,607	0	19,607
Other deductions	(17,434)	0	(17,434)
Customer deposits	(5,126)	0	(5,126)
Acc. deferred income taxes	(250,799)	0	(250,799)
Rounding	1	0	1
Total original cost rate base	$1,037,965	$ 2,070	$1,040,035
Rate of Return	5.87%		7.37%

SCHEDULE III
DOMINION NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 532
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the 12 Months Ended December 31, 2015
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
		Present Rates – Original Cost Rate Base		
Long-Term Debt	48.25%	$ 500,818	4.650%	$23,288
Common equity	51.75%	537,147	7.010%	37,629
Total	100.00%	$1,037,965		$60,917

	Approved Rates – Original Cost Rate Base			
Long-Term Debt	48.25%	$ 501,817	4.650%	$23,334
Common equity	51.75%	538,218	9.900%	53,284
Total	100.00%	$1,040,035		$76,618

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence for this finding of fact and these conclusions is contained in the Stipulation, the testimony of DNCP witness Stevens and Public Staff witness Fernald, and the entire record in this proceeding.

Section XV of the Stipulation provides that the Company will make a one-time $400,000 shareholder contribution over and above its usual contribution to its North Carolina EnergyShare program, which provides energy assistance to customers in need in the Company's North Carolina service territory, by March 30, 2017. At the hearing, the Company notified the Commission that it would commit to making this contribution no later than early January, 2017, so that the funds would be available for the winter heating season. Company witness Stevens testified that the Company's usual annual EnergyShare expenditure in North Carolina was approximately $360,000, so the amount agreed upon in the Stipulation would effectively double the amount of shareholder contribution to low-income heating assistance.

The Commission notes that the $400,000 shareholder contribution to low-income energy assistance is a feature of the settlement between the Company, the Public Staff and CIGFUR I that could not have been ordered by the Commission without the agreement of the Company. The Commission finds and concludes that this provision of the Stipulation is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37-41

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application and exhibits, the Stipulation, and the testimony of Company witnesses Pierce (as adopted by Haynes), and Haynes, Public Staff witness Floyd, Nucor witness Goins, and CUCA witness O'Donnell, and the entire record before the Commission in this proceeding.

Cost of Service Methodology – The Company's Application, as supported by witness Haynes, used the SWPA cost of service methodology to allocate production and transmission plant costs for both the North Carolina jurisdiction and the North Carolina retail customer classes. The SWPA method recognizes two components of providing service to customers - peak demand and average demand - when determining the responsibility for costs of production and transmission plant and related expenses. The peak demand component takes into account the hour when the load on the system is highest during both the summer months and the winter months. The average demand component recognizes that there is a load incurred by the system over the course of all hours during the year. The average demand is determined based upon the total energy provided to the customers during the year divided by the total number of hours in the year. The average component is then weighted by the system load factor, and the peak component is weighted by one minus the system load factor. The load factor is calculated by taking the Company's actually experienced average demand divided by its actually experienced peak demand during the test year.

Witness Haynes explained that DNCP developed and presented in its Form E-1, Item 45, the "per books," annualized, and "fully-adjusted" jurisdictional and customer class cost of service studies (COSS) based on the SWPA allocation method for the 12-months test year ended December 31, 2015.[1] In developing the SWPA COSS, the Company also made an adjustment to the Company's recorded summer and winter peaks to recognize and add back the kW generated by non-utility generators (NUGs) interconnected to DNCP's distribution system that are not included in those values. This NUG adjustment addresses a "mismatch" between the peak and the average components of the SWPA, as the kWh generated by distribution-interconnected NUGs were included in the average demand component of the SWPA but not in the summer and winter peak component. The NUG adjustment was calculated by determining the actual kW generated by distribution-interconnected NUGs at the time of the summer and winter peaks in both DNCP's Virginia and North Carolina service territories, and then adding these "state" values to each jurisdiction's respective recorded summer and winter peaks to arrive at the adjusted level. DNCP's fully adjusted SWPA COSS produced a North Carolina jurisdictional allocation factor of 5.1166%.

Company witness Haynes testified that the objective of jurisdictional and customer class cost of service studies is to determine the allocation of a share of the system's revenues, expenses, and plant related to providing service across multiple jurisdictions. Certain items can be assigned directly to the jurisdiction and classes based on the utility's records, but other items are not directly assignable and must be allocated. Witness Haynes stated that in this proceeding, the Company allocated its production and transmission plant and expenses using the SWPA cost of service methodology. He noted that the Commission has approved DNCP's use of the SWPA method in five other general rate case proceedings for the Company, dating back to 1983, including the 2012 Rate Case.

Company witness Haynes testified that the SWPA allocation method is consistent with the manner in which DNCP plans and operates its system. Specifically, the "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks while the average component recognizes the type of generation serving customers' energy needs year-round.

Company witness Haynes also emphasized that use of a single peak or other peak-only methodology could allow certain customer classes that have zero demand during the peak hour(s) of the year to fully avoid responsibility for production plant costs. Witness Haynes explained that a common example is that streetlights normally do not operate during peak hours. Company witness Haynes also highlighted the NS Class as another example unique to DNCP's North Carolina jurisdictional load. Witness Haynes explained that Nucor, the only customer in the NS Class, has an average annual demand throughout the year of approximately 100 megawatts (MW), while Nucor's average of its summer (June 2015) and winter (February 2015) coincident

[1] At the request of CIGFUR I and Nucor in discovery, and in response to the Commission's March 17, 2016 Order Denying Motion and Granting Alternative Relief, DNCP also developed and filed with the Commission a per books single coincident peak (1CP) COSS on May 31, 2016. The DNCP 1CP COSS is designed using only the single highest system peak during the test year, and produced a per books North Carolina jurisdictional allocation factor of 5.2354%.

peak demands is approximately 42 MW. Witness Haynes explained that without recognizing an average component in the cost allocation, this customer class would “pay” for only 42 MW and escape cost responsibility for an average of 58 MW for the rest of the year (i.e., the average demand of 100 MW less the allocated demand of 42 MW). Witness Haynes explained that by recognizing both the energy needed to serve load at the peak hour, as well as energy consumed throughout the year, the SWPA method allocates some portion of these system costs to all customers, including those customers that can reduce their peak demand and those that may not place a demand on the system during the respective summer and winter peak hour. Such customers still use and receive the benefit of the Company’s investments in production assets by paying lower energy costs, specifically fuel costs, during all other hours.

Public Staff witness Floyd agreed with the Company’s use of the SWPA cost of service methodology in this proceeding because it appropriately allocates the Company’s production plant costs in a way that most accurately reflects the Company’s generation planning and operation. He testified that unlike other methodologies that allocate all of the production plant costs based on a single coincident peak or on a series of monthly peaks, the SWPA methodology recognizes that a portion of plant costs, particularly for base load generation, is incurred to meet annual energy requirements throughout the year and not solely to meet peak demand at a particular time. Witness Floyd also addressed the NUG adjustment to SWPA, stating that the Public Staff agrees with DNCP’s adjustment as appropriately recognizing the impact that distribution connected NUGs have on DNCP’s system.

Nucor witness Goins recommended that the Commission reject DNCP’s use of the SWPA method and, instead, order DNCP to use the Summer-Winter Coincident Peak (S/W CP) method. Witness Goins developed and filed a fully adjusted S/W CP COSS that incorporated the cost-of-capital and ratemaking adjustments proposed by Nucor witnesses Woolridge and Kollen, respectively.

Witness Goins suggested that the use of the SWPA method is unreasonable because the SWPA methodology is used in almost none of the regulatory jurisdictions with which he was familiar. He further argued that the SWPA method is flawed for a number of reasons and ultimately allocates a greater portion of DNCP’s cost of service to Nucor and other high load factor customers. Specifically, witness Goins argued that Nucor’s load is totally interruptible and, therefore, should be excluded when deriving the SWPA allocation factors. Witness Goins contended that in failing to properly recognize Nucor’s interruptible load, the Company overstated the cost to serve Schedule NS and understated the rate of return for Schedule NS. Finally, witness Goins argued that the use of SWPA harms Nucor and other high load factor customers who would be assigned lower levels of fixed production costs under a peak-only methodology.

Nucor witness Goins testified that should the Commission continue to find the SWPA method appropriate for use in this proceeding, the Commission should reject the system load factor weighting methodology used by DNCP and, instead, use a weighting that allocates a greater percentage of production costs based using peak demand and a lesser percentage based upon the average energy-based demand component. Specifically, witness Goins suggested that DNCP’s system load factor weighting is heavily biased towards energy and suggested that the Commission could mitigate the bias by establishing weighting for the peak demand component at 75% or greater and the average demand component at 25% or less.

CUCA witness O'Donnell's arguments in support of the 1CP methodology were similar to those of witness Goins in support of S/W CP. Witness O'Donnell suggested that 1 CP best depicts how DNCP dispatches its plant to meet peak load. He further argued that he opposed SWPA because it sends the message to industrial consumers to use less energy and for residential and small consumers to use more energy, which will hurt manufacturing and economic development in Eastern North Carolina and, in time, raise rates to the residential and small commercial consumers when industrial consumers that cannot afford the higher rates move their operations elsewhere or simply close altogether.

In rebuttal, Company witness Haynes extensively addressed and rebutted the cost of service arguments of witness Goins on behalf of Nucor and witness O'Donnell on behalf of CUCA. Witness Haynes explained that the SWPA method reasonably and appropriately recognizes the two components of providing service to customers, peak demand, and average demand, and is consistent with the manner in which the Company's planning department plans for and meets DNCP's system needs, taking into consideration the need to meet both peak demands and the need to provide resources that can be operated to serve customers throughout the year. The "Summer and Winter" peak component recognizes the total level of generation resources necessary to serve the system peaks, while the average component recognizes the dispatch of different types of generation providing the system with low cost energy year-round. Witness Haynes pointed to the Company's recent additions of the intermediate/baseload gas-fired combined cycle 1,342 MW Warren County CC and the 1,358 MW Brunswick County CC (as well as the Company's historical investments in its baseload nuclear fleet) as production-related plant operated throughout the year to provide baseload energy to the Company's customers.

Witness Haynes responded to Nucor witness Goins' suggestion that SWPA is a rarely used methodology by explaining that there are numerous other jurisdictions, including the Company's Virginia jurisdiction, that include an "average" (energy) component in the development of production allocation factors. The Company operating in Virginia as Dominion Virginia Power has used the Average & Excess (A&E) cost allocation method in every Virginia rate proceeding dating back to 1972. Witness Haynes also testified that the SWPA and A&E methods have the benefit of also being relatively consistent (both include energy components) and, further, that preserving historical continuity in the method used to allocate costs will also avoid significant shifts in allocated costs to a given class between one rate case and the next.

In addressing the peak-only S/W CP and 1CP methods advocated by witnesses Goins and O'Donnell, witness Haynes explained that these methodologies are unreasonable and inappropriate for DNCP because their reliance on the single coincident peak hour or only the two hours of DNCP's summer and winter peaks is inconsistent with the way DNCP plans and operates its system to both meet the system peaks as well as to deliver low cost energy throughout the year. In addition to the new Warren County and Brunswick County Power Station investments, described above, witness Haynes also specifically pointed to the remaining $4.7 billion of nuclear plant in service at the end of 2015, which still represents approximately 30% of DNCP's total production plant investment. Witness Haynes also presented concerns that use of S/W CP would produce unreasonable results in other areas of DNCP's COSS, such as production plant O&M expenses.

Witness Haynes also presented a number of analyses showing that moving from a SWPA methodology to the S/W CP methodology would cause a significant shift of DNCP's cost of service between the classes and would shift recovery of production costs away from Nucor and other high load factor customers and to the residential class. For example, witness Haynes' analysis in his Rebuttal Table 4 showed that the NS Class rate of return increased from approximately 2% under the SWPA method to approximately 18% under Witness Goins' S/W CP method. Witness Haynes' Rebuttal Table 5 presented the shift in class rate of return indices (RORI) between SWPA and S/W CP, with the Schedule NS Class increasing from 0.40 under SWPA to 2.79 under the S/W CP method (an increase of over 597.5 %), while the residential class fell from a RORI 0.97 under the SWPA method to 0.65 under witness Goins' S/W CP method. Witness Haynes also noted that under the fully adjusted cost of service presented by witness Goins, the residential class would receive a $24.8 million increase to achieve the overall jurisdiction S/W CP ROR.

Witness Haynes explained that witness O'Donnell's 1CP method is unreasonable for the same reasons as the peak only S/W CP method. Witness Haynes testified that 1CP also fails to take into consideration both the summer and winter peaks as DNCP is forecasted to remain a summer peaking utility, but recently experienced all-time system peaks during the winter in 2014 as well as during the 2015 test year. Finally, witness Haynes testified that use of the 1CP method would also increase cost responsibility for the North Carolina jurisdiction, while lowering the rate of return for the jurisdiction, and would also significantly shift costs to the residential class compared to the SWPA method.

Witness Haynes also explained that DNCP's continued use of the test year system load factor is a reasonable, reliable, and consistent method for establishing the weighting of the peak and average components of the SWPA COS methodology. Contrary to witness Goins' view, the Company's use of the system load factor is not arbitrary, but is based on DNCP's actual verified usage of the Company's generation capacity throughout the course of the test year relative to installed capacity. Witness Haynes testified that witness Goins' recommendation to weight the peak demand at 75% and the average demand at 25% is both arbitrary and results oriented as it would have the effect of increasing the residential class' percent of system responsibility for production costs by 13.8% and decreasing the cost responsibility allocated to Nucor by 35.2%.

Finally, witness Haynes argued that the Commission's recent decision in Duke Energy Progress' 2013 rate case adopting a 1CP method for that utility, should not have bearing on the Commission's determination of the appropriate allocation methodology for DNCP. Witness Haynes pointed out that the Commission explained in its Order in the Duke Energy Progress 2013 rate case that cost allocation does not lend itself to a "one size fits all approach."[1] Witness Haynes also emphasized that the use of S/W CP or another peak only method is potentially more significant for DNCP than other utilities due to the Company's obligation to serve a "one-customer industrial

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[1] Application of Progress Energy Carolinas, Inc., Docket No. E-2, Sub 1023, Order Granting General Rate Increase, at 98 (May 30, 2013).

class" – Schedule NS – which used approximately 19% (863,206,000) of the 4,568,385,000 jurisdictional kWh during the test year but can also significantly reduce its demand on the peak.

Under cross-examination by CUCA, witness Haynes accepted that adopting a peak-only methodology such as S/W CP or 1CP would allocate a significantly lower amount of cost responsibility to large high load factor customers, but argued that these methodologies would also cause a shift in cost responsibility to the residential and other non-industrial rate classes. He testified that using only one or two hours of the year to determine cost responsibility is not consistent with the way DNCP plans and operates its generation plants, nor is it fair from a cost allocation perspective, especially considering smaller general service and residential customers. During cross-examination by Nucor's counsel, witness Haynes disagreed with witness Goins' alternative weighting of the SWPA demand and energy components at 75% demand and 25% energy, explaining that his rebuttal Schedule 1 analysis showed that this modified weighting would make residential cost responsibility go up by 13.8%, while Nucor would receive a minus 35.2% shift in cost responsibility and the 6VP class would have a negative 28.9% shift in responsibility under this weighting. On redirect, witness Haynes identified other jurisdictions that use average components in allocating production costs but stated that the Company had not completed an exhaustive assessment of every jurisdiction and utility in the country. He also testified that while it is up to the Commission to determine the weightings in SWPA, the Commission has previously determined that the use of the system load factor was an appropriate way to weight the average demand component, and one minus that system load factor was an appropriate way to weight the peak demand component.

In its post-hearing Brief, CUCA contends that use of the SWPA methodology, as opposed to the 1CP, results in a rate design that sets higher rates than required for large industrial customers. Further, CUCA notes that the Commission has approved the use of 1CP for Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC.

The Commission finds and concludes that DNCP has carried its burden of proof to show that the SWPA methodology is the most appropriate cost of service methodology to use in this proceeding to assign cost responsibility for production plant to the North Carolina jurisdiction and the Company's customer classes. On this issue, the Commission gives substantial weight to the testimony of Company witness Haynes and Public Staff witness Floyd. The cost of service methodology employed in establishing an electric utility's general rates should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class's peak demands and overall energy consumption. Company witness Haynes testified extensively that the Company's investment in generating plant, including the recently placed in service Warren County CC and Brunswick County CC, are designed to meet the Company's system peaks and to deliver low cost energy throughout the year. Witness Haynes explained that the SWPA methodology appropriately recognizes that DNCP's system planning is designed to meet both the Company's peak and average system demands and energy needs of customers throughout the year. Both Company witness Haynes and Public Staff witness Floyd testified that the SWPA method appropriately matches allocation of production plant with DNCP's generation planning and operations. The Commission finds that, for purposes of this proceeding, the SWPA cost of service methodology properly recognizes the manner in which DNCP plans and operates its generating plants to provide utility service to customers in North Carolina.

The Commission also recognizes and reaffirms its prior determination in the Duke Energy Progress 2013 rate case that cost allocation does not lend itself to a "one size fits all approach."[1] Based on the facts in this case, a methodology that does not properly consider the effect of overall energy consumption, but focuses mainly on peak responsibility would not properly represent the way in which the Company plans for and provides its utility service and the way customers use that service.

The Commission is not persuaded that either the S/W CP methodology or the 1CP methodology is appropriate for the Company in this proceeding. Company witness Haynes and Nucor witness Goins provided calculations to compare the rates of return associated with the cost of service methodologies they advocated. The disparity between allocation factors for peak demand-related factors and energy-related factors is apparent for each methodology, with the SWPA resulting in the most equitable sharing of the rate of return among DNCP's customer classes in this case.

In Nucor's Brief, Nucor reiterated witness Goins' testimony that (1) the Commission should abandon the SWPA methodology, (2) the Commission should adopt the S/W CP methodology, and (3) if the Commission decides to adopt SWPA, it should address two flaws/biases inherent in DNCP's SWPA cost studies. The two flaws alleged by Nucor are (1) energy use is given too much weight, 56%, because peak demand is the primary driver of DNCP's need for additional capacity, and (2) DNCP's use of SWPA creates an asymmetry in DNCP's assignment of fixed production cost responsibility and its average cost recovery of fuel costs.

With regard to increasing the weight assigned to peak demand, Nucor recommends giving a 25% weight to the average demand component and a 75% weight to the peak demand component. In support of this recommendation, Nucor cites the decisions of the Michigan Public Service Commission in two 2015 dockets, one involving DTE Electric Company (Case No. U-17689, Opinion and Order dated June 30, 2015), and the other Consumers Energy Company (Case No. U-17688, Opinion and Order dated June 30, 2015) (collectively, Consumers). Pursuant to Michigan statutory provisions, a 50-25-25 (50% peak demand, 25% on-peak energy use, 25% total energy use) cost allocation method is mandated, unless a party shows that an alternative method would better ensure that rates are equal to cost of service. The purpose of the Consumers proceeding was to determine whether a change in the energy/demand ratios mandated by the statute was warranted. Consumers Energy proposed a 4CP 100-0-0 methodology, whereby costs would be allocated based 100% on peak demand. However, the PSC Staff recommended a 75-0-25 methodology, which the PSC ultimately adopted. The PSC cited extensive evidence on the appropriate allocation formula, stating

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[1] Id.

> [T]he Commission therefore finds that the Staff's proposal to modify the production cost allocation method from 50-25-25 to 75-0-25 is well supported, better ensures rates are equal to cost of service, and should therefore be approved.

Id., at p. 17.

The Commission is not persuaded on the present record that the Michigan PSC's approach advocated by Nucor should be adopted for DNCP. For reasons perhaps unique to Michigan, the legislature has mandated that the Michigan PSC use a 50-25-25 cost allocation ratio, unless a better methodology is shown. In contrast, DNCP established its 56%-46% ratio based on DNCP's system load factor test-year data. That process is a more direct and accurate approach than the "one size fits all" ratio mandated in Michigan's statute. In addition, Nucor did not support its 25%-75% allocation weighting proposal with sufficient analyses of DNCP's system operating characteristics.

As a result, the Commission is not convinced that Nucor witness Goins' proposal to reject the Company's use of the system load factor and to adopt Nucor's alternative proposal to establish weighting for the peak demand component at 75% or greater and the average demand component at 25% or less is reasonable or appropriate in this proceeding. Nucor's rationale for this modified SWPA method is that reweighting SWPA to shift significantly greater emphasis to the peak demand component would mitigate the "numerous flaws" that Nucor finds in the SWPA method. Because the Commission finds that the SWPA method is not unreasonable or flawed, the Commission does not find Nucor's argument persuasive. Further, based on the evidence of record in this case, the Commission finds that the system load factor is not arbitrary, but is reasonably based on DNCP's actual verified usage of its Company's generation capacity throughout the course of the test year relative to installed capacity. Nucor's request that the Commission select weighting with a peak demand component of 75% or greater and the average demand component at 25% or less would be unreasonable and, indeed, arbitrary as it is not tied to any objective measurement of DNCP's system operations.

Based on the Stipulation and the testimony on the record, the Commission also finds that including the distribution-interconnected NUG generation in the average portion of the SWPA, but not including this NUG generation in the Company's recorded summer and winter peaks creates a mismatch between the peak and average components of the Company's SWPA COSS. The Commission concludes that the Company's adjustment to the summer and winter peaks to recognize the NUG generation at the distribution level appropriately recognizes the impact the NUGs have on DNCP's utility system and should be approved.

Finally, it is also notable that CIGFUR I joined in the Stipulation with DNCP and the Public Staff supporting the SWPA methodology as reasonable and appropriate in this proceeding. Although CIGFUR I has historically opposed the use of a production plant allocation methodology based on jurisdiction and customer class energy usage, it is not unreasonable for the Stipulating Parties to have agreed, as part of their overall settlement of all contested issues, that the allocation of production plant based on the SWPA methodology is reasonable for purposes of this proceeding. As the Commission has noted, that is part of the give-and-take of settlement negotiations.

Therefore, based upon consideration of the Stipulation in its entirety, the Commission gives the Stipulation substantial weight in resolving the cost allocation methodology issue.

Based on the evidence in this proceeding, including the Stipulation, the Commission finds and concludes that the greater weight of the evidence shows that the SWPA cost of service methodology provides the most appropriate methodology to assign fixed production costs by incorporating DNCP's seasonal peak demands at the two single hours they occur and by incorporating the total energy consumed by the jurisdiction and customer classes over all the other hours of the year. In addition, the Commission finds good cause to require that the Company should continue to file a cost of service study using the SWPA methodology annually with the Commission.

Further, the Commission emphasizes the importance of properly allocating costs between jurisdictions, and specifically in this case between Virginia and North Carolina, and between customer classes. In that regard, the Commission takes note of Company witness Haynes rebuttal testimony that "The Company has used the A&E cost allocation method in every Virginia rate proceeding dating back to 1972. The 'average' portion of the A&E method is similar to the 'average' portion of the SWPA method." (T Vol. 7, at p. 193) However, even though the "average" portion of the A&E method is similar to the "average" portion of the SWPA method, the Commission finds good cause to require the Company to file an A&E cost allocation methodology in its next North Carolina general rate case, in addition to the methodology proposed by the Company.

Finally, the Commission notes that there is ample opportunity under Commission rules for thorough consideration of all issues related to cost of service in a general rate case. Interested parties may intervene, conduct discovery and present evidence in accordance with the rules of practice and procedure established by the Commission.

Treatment of Nucor in the Company's Cost of Service

The Company's SWPA cost of service study (Form E-1, Item 45) followed the same approach for the Schedule NS customer class (NS Class), as well as all other classes, used in the cost of service studies filed and approved in DNCP's two most recent general rate cases, Docket No. E-22, Sub 479 in 2012 and Docket No. E-22, Sub 459 in 2010. Specifically, as described by Company witness Haynes, the Company used both a summer and winter peak demand for the NS Class that reflected Nucor's measured demand and recognized the interruptible nature of Nucor's arc furnace pursuant to the confidential terms and conditions of the Company's contract with Nucor, the only customer in the NS Class. The 43 MW of peak demand assigned to the NS Class represents the average of the winter and summer peaks of the NS Class at the time of the test year system winter and summer peaks. These peak demands were used to develop the production plant and transmission related demand allocation factors. The Company also used Nucor's actual test year energy consumption of 863,206,000 kWh to develop the average component of SWPA.

In addition to his alternative COSS recommendations, addressed above, Nucor witness Goins argued that Nucor's total load is "non-firm" or interruptible pursuant to the Company's contract with Nucor for electric service and recommended that the Commission reject DNCP's treatment of Nucor's interruptible load in its cost of service study. Witness Goins disagreed with DNCP's characterization that Nucor's load continues to be partially interruptible under the Nucor agreement and argued that rates for service to fully interruptible customers should not recover any fixed production costs.

Witness Goins asserted that because Nucor's load is interruptible, it is not responsible (except by administrative fiat) for DNCP's fixed production costs. He concluded that service to Nucor's interruptible load occurs only when excess capacity used to serve firm load is available. Witness Goins further argued that DNCP's SWPA method allocates fixed production costs to Nucor almost exclusively based on Nucor's energy use. In contrast, about 60% of fixed production costs allocated to North Carolina customers in DNCP's cost studies is allocated on the basis of energy. Witness Goins recommended that if the Commission adopts DNCP's SWPA method, then the Commission should also replace DNCP's system load factor weighting scheme with peak demand component weights equal to or greater than 75% and average demand component weights of 25% or less, and further require DNCP to: (1) investigate the SWPA's asymmetrical allocation problem, including the preparation and filing for review of a detailed analysis of the problem similar to the analysis the Commission ordered in Docket No. E-22 Sub 333 (1994 Fuel Study); and (2) require DNCP in future jurisdictional and class cost studies to exclude Nucor's interruptible load in developing allocation factors for fixed production costs.

In rebuttal, Company witness Haynes explained the Company's reasoning for characterizing the Nucor agreement as partially interruptible as well as for the Company's treatment of Nucor in DNCP's COSS. Witness Haynes stated that Nucor's total load is only subject to interruption during system emergencies, when all other customers' load is also subject to interruption. Witness Haynes testified that the confidential terms of the Nucor agreement only allow for curtailment of Nucor's arc furnace load during very limited hours and, in certain of those hours, allow Nucor to buy through the curtailment at a higher price. Witness Haynes stated that the Company reads and applies the Nucor agreement to require Nucor's non-furnace load to be treated as "firm" and supplied with firm power throughout the year. Company witness Haynes also testified that he reviewed Nucor's actual loads since DNCP's 2012 Rate Case and confirmed that Nucor's non-furnace load has not been interrupted for emergency situations during at least that period.

Based on his understanding of the terms of the Nucor agreement as well as DNCP's implementation of the agreement since at least 2012, witness Haynes stated that DNCP's SWPA method properly takes into account Nucor's interruptibility, while also recognizing the demands Nucor places on the system and the energy consumed by Nucor. Nucor's average Summer/Winter coincident peak demand was approximately 43,192 kW during the test year, which represented the non-furnace load that the Company maintains is load that was actually served during the summer and winter peak hours. With regard to the average demand component, the Company has an obligation to serve Nucor each hour of the year and such a requirement is measured by the energy consumed. If Nucor is interrupted in any hour, then the energy consumption for that hour would reflect the interruption. Nucor actually consumed approximately 19% (863,206,000) of the 4,568,385,000 jurisdictional kWh during the test year. Witness Haynes asserted that the average demand component should reflect Nucor's actual use of the dispatch of the system generation and purchased power – just as is the case for all other customers.

Witness Haynes also performed an analysis detailing how recognizing Nucor's curtailed demand in developing the allocation methodology provides a significant and properly recognized financial benefit to Nucor as well as a lower overall allocation of system costs to the North Carolina jurisdiction. He asserted that the Company's SWPA allocation factors were calculated in a reasonable manner – consistent with the principles approved in DNCP's 2012 Rate Case – that appropriately recognizes the value of Nucor's interruptibility to the system and does not overstate cost nor understate returns for the North Carolina jurisdiction and its customer classes. Cost responsibility has been properly and fairly determined based on requirements placed on the system – by Nucor and all other customer classes – on the summer and winter peak days and throughout the year.

Witness Haynes also explained that the Commission is reviewing the same curtailment provisions that it reviewed in 2012 when it determined that the Company's SWPA method properly recognized Nucor's interruptible load under the Nucor agreement.

In response to Nucor's recommendation that the Commission require DNCP to exclude 100% of Nucor's load as interruptible in developing allocation factors for fixed production costs in future jurisdictional and class COSS, witness Haynes explained that this recommendation is inappropriate and, in effect, would treat the Schedule NS Class as if it did not exist. Witness Haynes explained that such an approach would be inconsistent with the manner in which DNCP has provided service to Nucor since the 2002 amendment to the Nucor agreement, when Nucor requested to transition from marginal cost of fuel and no assigned production plant to average cost of fuel for all system production resources. Haynes explained that if a customer once paid marginal cost and a small margin contributed toward production plant and related costs and now pays a more "certain" average fuel cost, then it should also be responsible for production plant costs – similar to all other customers.

Witness Haynes also reiterated that the provisions of the operative Nucor agreement giving Nucor the benefit of average fuel today are identical to the provisions of the Nucor agreement the Commission reviewed in 2012, when the Commission stated on page 30 of its Order as follows:

> The Commission also notes that the 2002 amendment to the Nucor contract to change the pricing structure was made at the request of Nucor. Nucor sought certainty in its pricing arrangements. Nucor therefore opted for a pricing arrangement that was based on the average fuel costs of the system, rather than the marginal cost pricing structure it had been receiving since the inception of the contract. ***The Commission agrees with the Company that under such an arrangement Nucor elected to receive the benefit of average fuel costs, and in doing so it also should be responsible for a share of the fixed production costs required to produce those same average fuel costs.*** The Commission further notes that the Nucor contract filed in the 2010 general rate case, Docket No. E-22, Sub 459, and in this proceeding no longer contains the language relieving the Company of any responsibility to provide for capacity to serve Nucor. (Emphasis added.)

In opposition to witness Goins' recommendation that Nucor be treated as 100% interruptible in future cost of service studies, witness Haynes concluded that Nucor actually consumes energy produced by DNCP equivalent to the energy needs of 71,000 residential households and because the NS Class is using production plant, it should contribute to fixed costs.

Based on the entire record in this proceeding, including the Stipulation, the Commission is persuaded that the Company has treated the NS Class and Nucor appropriately in its cost of service study and that no additional recognition of the benefits associated with the Nucor contract should be made in this proceeding.[1]

The facts and evidence in this proceeding show that the Company has consistently followed the same approach in this case of recognizing the benefits of Nucor's interruptibility – to both Nucor and the North Carolina jurisdiction – consistent with DNCP's approach in the Company's past two general rate case proceedings. Further, the record in this case is undisputed that the curtailment provisions in the Nucor agreement have not been modified since last reviewed by the Commission in 2012. The Commission again concurs with the Company, Nucor, and Public Staff witnesses that the system, and the NS Class in particular, benefits from only recognizing Nucor's non-arc furnace load in calculating the peak load of the NS Class in the cost of service. Nucor's contract with the Company provides Nucor with flexibility in deciding how and when it consumes energy for the vast majority of hours in the year. Outside of the relatively few hours the Company can contractually request Nucor to curtail its arc furnace load, Nucor is free to buy through all other requests at a fixed price arrangement. The Company's testimony that Nucor's non-furnace load has not been interrupted since at least 2012 is also undisputed. Accordingly, based upon the facts and evidence presented in this case, the Commission does not find Nucor's arguments that the Nucor agreement is totally interruptible to be persuasive nor does the Commission find that Nucor should be treated differently than other customer classes and relieved of paying for its allocated share of DNCP's investment in production plant.

The Commission also again notes that the 2002 amendment to the Nucor contract to change the pricing structure was made at the request of Nucor. Nucor sought certainty in its pricing arrangements. Nucor therefore opted for a pricing arrangement that was based on the average fuel costs of the system, rather than the marginal cost pricing structure it had been receiving prior to 2002. The Commission agrees with the Company that under its current contractual arrangement Nucor has elected to receive the benefit of average fuel costs, and in doing so, it also should be responsible for a share of the fixed production costs required to produce those same average fuel costs. The Commission further notes that the Nucor contract, most recently approved by the Commission in Docket No. E-22, Sub 517, no longer contains the language relieving the Company of any responsibility to provide for capacity to serve Nucor as was the case of the Nucor contract prior to 2010. As the Commission describes below, the Nucor contract provides Nucor the right to continue to receive this partially interruptible service or to work with DNCP to move to another generally available rate schedule.

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[1] In arriving at this conclusion, the Commission takes judicial notice of its most recent general rate case order for DNCP, issued on December 21, 2012 in Docket No. E-22, Sub 479. Specifically, the Commission recognizes its findings and conclusions regarding the interruptibility provisions of the Nucor Agreement and Schedule NS in that proceeding, which were ultimately affirmed on appeal by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635 (2014).

Based on the same reasons that service to Nucor should not be treated as 100% interruptible in developing the North Carolina cost of service used in setting just and reasonable rates in this case, the Commission finds and concludes that it would similarly be unreasonable and inappropriate to direct DNCP to make this assumption in future cost of service study filings with the Commission, unless the contract with Nucor is significantly altered such that it supports that position.

Fuel Study

In his testimony, Nucor witness Goins asserted that use of the SWPA methodology creates a mismatch in allocating fixed production costs and variable fuel costs. He stated that because high load factor customers are allocated a disproportionate share of DNCP's fixed production costs, they should also be allocated a disproportionate share of cheaper energy costs associated with the higher cost capacity. Instead, DNCP allocated average fuel costs on the basis of class loss-adjusted energy use. In other words, higher load factor classes get the higher baseload plant costs, but not the corresponding savings from lower baseload fuel costs. Witness Goins noted that in the 1994 Fuel Study, DNCP concluded that traditional average fuel cost recovery is not symmetrical with the way the LGS class is allocated production-related cost under the SWPA method. He recommended that the Commission require DNCP to prepare and file a detailed analysis similar to the analysis undertaken in the 1994 Fuel Study.

Witness Haynes testified in opposition to witness Goins' recommendation that DNCP be required to develop a new analysis similar to the 1994 Fuel Study. He explained that all customers, including residential and large industrial, benefit when the utility's system of available generating resources is operated such that the units with the lowest possible variable cost (mostly fuel) are dispatched to serve customer loads not just in the summer and winter peak hours, but in all hours of the year. This lowers fuel expenses recovered through the fuel clause. The capability to lower fuel expenses throughout the course of the year by system dispatch is accomplished by having available resources to efficiently serve utility loads during all hours and not only during the summer and winter peak hours. If all classes of customers are effectively paying "average fuel cost," then all customers are getting the benefit of the integrated system operation of the full range of generation resources from high capital cost/low operating cost generation to low capital cost/high operating cost generation.

Witness Haynes further testified that the SWPA method produces reasonable results by considering two seasonal peaks and the average demand and appropriately weighting both. DNCP's system load factor is approximately 56%, so the peak demand component is weighted at 44% in calculating the final total allocation factor. Witness Haynes stated that with this 44% weighting of the average of the winter and summer peaks and the ability of high load factor classes in North Carolina to reduce load during peak hours, such customers can reduce, and do reduce, their responsibility for fixed production costs. Witness Haynes testified that this a fair and reasonable approach to determining responsibility for fixed costs while paying average fuel. Witness Haynes therefore testified that there was no reasonable basis for the Commission to require the Company to "re-do" the 1994 Fuel Study.

Witness Haynes also testified during the hearing that DNCP has developed new industrial rate designs since 1994, such as Schedules NS and 6VP that allow high load factor classes in North Carolina to reduce load during peak hours, which has the effect of reducing these customer classes' responsibility for fixed production costs under the Company's SWPA method.

In Nucor's Brief, Nucor reiterated witness Goins' testimony that DNCP's use of SWPA creates an asymmetry in DNCP's assignment of fixed production cost responsibility and its average cost recovery of fuel costs. Witness Goins testified that because higher load factor customers are allocated a disproportionate share of DNCP's fixed production costs (including the higher cost of intermediate and baseload generating plants) under the SWPA methodology, they also should be allocated a disproportionate share of cheaper energy costs associated with the higher cost capacity. According to witness Goins, fixed production costs and variable fuel costs are not allocated symmetrically in DNCP's cost studies.

However, the Commission gives significant weight to the rebuttal testimony of DNCP witness Haynes. He testified that all customers, including residential and large industrial customers, benefit by DNCP's method of dispatching its generating resources such that the units with the lowest possible variable cost (mostly fuel) are dispatched to serve customer loads not just in the summer and winter peak hours but in all hours of the year. This lowers fuel expenses that are recovered through the fuel clause. Witness Haynes stated that the capability to lower fuel expenses throughout the course of the year by system dispatch is accomplished by having available resources to efficiently serve utility loads during all hours of the year, not solely during the summer and winter peak hours. He asserted that when all classes of customers are effectively paying "average fuel cost" determined in fuel clause proceeding, then all customers are getting the benefit of the integrated system operation of the full range of generation resources from high capital cost/low operating cost generation to low capital cost/high operating cost generation.

Further, in the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that it is unnecessary at this time for the Company to re-evaluate the issues reviewed in the 1994 Fuel Study.

The Commission notes that cost responsibility based on energy (kWh) allocation has been deemed to produce just and reasonable rates in DNCP's past fuel proceedings. Further, the Commission agrees with DNCP and the other Stipulating Parties, including CIGFUR I, that it is unnecessary at this time to require DNCP to develop an analysis similar to the 1994 Fuel Study. The 1994 Fuel Study analysis preceded Nucor's arrival on to DNCP's system in 2000, Nucor's request in 2001 to transition to a more certain average fuel rate (similar to all other customers), and the subsequent 15 years of history, which informs the Commission's current understanding of DNCP's service to Nucor. In addition, with the weighting of the average of the winter and summer peaks and the ability of high load factor classes in North Carolina to reduce load during peak hours, such customers can reduce, and do reduce, their responsibility for fixed production costs. The Commission concludes based upon the record in this case that it is unreasonable and unnecessary to require DNCP to complete an analysis similar to the 1994 Fuel Study.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 42

The evidence for this finding and these conclusions is found in the Application, the testimony of Company witness Haynes, Public Staff witness Floyd, and Nucor witness Goins, and the Stipulation, and all other evidence of record.

The Application and the testimony and exhibits of Company witness Haynes explain how DNCP proposed to apportion the jurisdictional revenue requirement established using the Company's SWPA jurisdictional and class COSS amongst the customer classes. Witness Haynes' testimony and exhibits assigned the revenue requirement to specific rate schedules and then calculated the percent increase that customers on each rate schedule would experience.

In apportioning the revenue requirement among the customer classes, witness Haynes identified general and class-specific principles that the Company used to equitably distribute the base rate revenue increase, including: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional ROR; (2) for classes outside of a reasonable return index range of 0.90 and 1.10 (Parity Index Range), an effort must be made to more reasonably align the rates customers pay with their responsibility for cost, even if the index achieved after apportionment still remains outside of the Parity Index Range; (3) for purposes of apportioning the increase for the LGS and 6VP classes, the two classes are combined to treat large industrial customers within these classes in the same manner and also to recognize certain non-cost factors that support a lesser increase for large industrial customers with high load factors within these classes; and (4) for purposes of apportioning the increase to the NS Class, the Company balanced the need to equitably address certain legacy economic development rate (EDR) subsidy issues with the unique nature of the Company's electric service arrangement with its largest and most energy-intensive customer, Nucor.

Specific to the non-cost considerations that DNCP took into account in apportioning the revenue increase among the industrial customer classes, witness Haynes testified that he considered the quantity and timing of large industrial manufacturing customers' electric usage in their industrial operations, as well as factory utilization and the economic vitality of the Company's North Carolina service territory, as it relates to these industrial customers.

Witness Haynes presented an extensive history of the Company's agreement with Nucor under which DNCP provides electric service to Nucor, beginning with its approval as an EDR in 1999, and then noted DNCP's concern with the legacy rate of return (ROR) index deficiency in Nucor's contribution towards the Company's cost of service. Witness Haynes explained that the Schedule NS rate design has been beneficial to DNCP's operation of its system, as well as to the North Carolina jurisdiction and to Nucor, and stated that recognition of the partially interruptible nature of service to Nucor's arc furnace under Schedule NS and the Nucor agreement is consistent with North Carolina's policy that a utility may design different rates for different customers based upon differences in conditions of service. Witness Haynes testified that the Company is not opposed to continuing Schedule NS and the Nucor agreement in its current form (subject to Nucor electing otherwise, as discussed below), but that continuing the deficiency in the NS Class' rate of return index, and Nucor's deficient contribution to DNCP's cost of service represents an increasingly inequitable legacy benefit of the initial EDR. Witness Haynes explained that this legacy EDR benefit has extended well past the period originally contemplated in 1999, and significantly longer than the four-year term of EDRs offered to other customers. Accordingly, the Company's Application increased the NS Class ROR index from 0.44 to 0.74, which would move the NS Class two-thirds of the way towards the low end of the Parity Index Range (90% of jurisdictional ROR).

Company witness Haynes also testified that while DNCP developed its allocation and rate design proposals based upon the assumption of continued service, inclusive of the requested base rate increase, under current Schedule NS and the existing Nucor agreement, DNCP also provided notice to Nucor of its intent to terminate the existing Nucor agreement as of December 31, 2016, in order to explore whether Nucor is interested in modifying the current Nucor agreement, or alternatively, receiving service under another available DNCP rate schedule.

Public Staff witness Floyd recommended a more generalized approach to apportioning the revenue increase and designing rates, consistent with the approach and considerations that the Public Staff recommended and the Commission adopted in the Company's 2012 Rate Case. Specifically, witness Floyd recommended that the Commission look at changes to base non-fuel and base fuel revenues together and apply the following principles in spreading the impact to base non-fuel and base fuel revenues: (1) employ a +/- 10% "band of reasonableness" relative to the overall jurisdictional ROR such that, to the extent possible, the class ROR stays within this band of reasonableness following revenue assignment after the rate changes; (2) limit the combined base fuel and base non-fuel revenue increase to no more than two percentage points greater than the overall jurisdictional revenue percentage increase; and (3) minimize subsidization of customer classes by other customer classes.

Nucor witness Goins developed a revenue spread premised on the Commission's adoption of his proposed S/W CP methodology that took into account the following principles: 1) set base rates to bring the ROR for each class within plus or minus 10% (±10% constraint) of the system average ROR; 2) allow no base rate decrease for any class; and 3) limit the base rate increase for any class to no more than 1.5 times the system average increase (1.5x constraint) at a 7.80% ROR. According to Goins' analysis, using S/W CP, the proposed increase would be borne by residential and small general service customers, while other classes would receive no non-fuel base rate increase.

In rebuttal, Company witness Haynes critiqued the proposed revenue apportionment presented by Public Staff witness Floyd. He explained that while certain of witness Floyd's rate design considerations are reasonable from a policy perspective, the Company's significantly more detailed fully-adjusted approach to revenue apportionment and rate design is more reasonable and appropriate. In response to Nucor witness Goins' revenue spread proposal, witness Haynes explained that the rates of return based upon witness Goins' fully adjusted cost of service using the S/W CP method differ dramatically from the Company's results using SWPA, resulting in a significant shift in allocated responsibility for production plant, net operating income and the resulting rate of return. Specifically, he explained that allocated rate base responsibility for the residential class would be 17% higher under witness Goins' proposal and that residential rates must go up by $29.37 million in order to bring the residential class to an equal rate of return with the jurisdiction.

Witness Haynes affirmed the Company's support for its initial proposal to increase non-fuel base revenue for the NS Class two-thirds of the way to the bottom of the rate of return index Parity Index Range (0.90 to 1.10). Witness Haynes testified that DNCP's proposed revenue apportionment and rate design strikes a reasonable balance between Nucor and other customers and does not result in an unreasonable increase or "rate shock" to Nucor, as Nucor's overall rates will decrease on January 1, 2017 as a result of this case.

In the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that the stipulated overall $25.790 million increase in base non-fuel and decrease in base fuel revenues should be apportioned consistent with the rate design principles presented by Company witness Haynes in his direct and rebuttal testimony, subject to the Stipulating Parties' further agreement that: (1) all classes should share in the non-fuel base rate revenue increase in a manner that moves each class of customers closer to parity with the North Carolina jurisdictional rate of return; (2) the 6VP class Rate of Return Index will be 1.15; and (3) the NS Class Rate of Return Index will be 0.75, which moves the NS Class two-thirds of the way towards the low end of the Parity Index Range of 0.90 and 1.10.

Based on the Stipulation and the evidence in the record, the Commission concludes that for purposes of this proceeding it is appropriate to apportion the proposed base fuel and non-fuel revenue increase approved in this Order using the methodology recommended by DNCP as modified by the Stipulation. The Commission agrees with the Public Staff, Nucor, CIGFUR I, and the Company that revenue should be distributed so that class rates of return are close to the overall jurisdictional rate of return, whenever possible. Further, the effects of rate shock and other economic and inter-class conditions should also be considered. The Commission believes that the principles employed by Company witness Haynes, as modified by the Stipulation, appropriately balance these objectives.

The Commission also recognizes that DNCP provided notice to Nucor on March 1, 2016, of the Company's intent to terminate the existing Nucor agreement as of December 31, 2016, in order to explore with Nucor whether the customer would be interested in modifying the current Nucor agreement, or alternatively, receiving service under another available DNCP rate schedule, consistent with the terms of the Nucor agreement. Based upon the record in this proceeding, no changes have been proposed to the existing terms and conditions of Schedule NS and the Commission accepts DNCP's position as undisputed that the current Schedule NS rate design and partially-interruptible service to Nucor under the Nucor agreement has been beneficial to DNCP's operation of its system, as well as to the North Carolina jurisdiction and to Nucor. Based on the entire record in this proceeding, the Commission finds and concludes that DNCP should offer Nucor service pursuant to the terms and conditions of Schedule NS and the Nucor agreement approved on March 29, 2016 in Docket No. E-22, Sub 517, as modified to reflect the authorized change in non-fuel base revenues.

Basic Customer Charge

In his testimony, Public Staff witness Floyd discussed the Company's proposed changes to the basic customer charge. He explained that the unit cost data in Item 45e is an approximation of the cost associated with each unit of service for a given utility function and provides an indicative benchmark to use when designing individual rate elements of various rate schedules. Witness Floyd compared the unit cost data in this proceeding to similar data from the 2012 Rate Case and found that those costs designated as "customer" unit costs have decreased since the 2012 Rate Case. This review suggested to him that the basic customer charges currently approved for DNCP rate schedules are greater than the "customer" designated unit costs found in Item 45e. Witness Floyd therefore recommended that none of DNCP's basic customer charges be increased.

In his rebuttal, Company witness Haynes accepted witness Floyd's recommendation with the understanding that any needed revenue apportionment to the rate schedules would be apportioned to the other charges in the rate schedules. The Stipulation provides that in developing rates based upon the class apportionment agreed to in the Stipulation, the Company agrees to recover 100% of the stipulated revenue increase through the energy and demand components of rates and not to increase the basic customer charge component of rates. The Commission finds this provision of the Stipulation to be reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 43

The evidence for this finding of fact and these conclusions is found in the Application, the testimony of DNCP witness Haynes and Public Staff witness Floyd and the Stipulation.

The Company's Application proposed new Large General Service Schedule 6L, which is designed as an additional rate option for DNCP's large industrial customers in addition to existing rate schedules 6C, 6P, 6VP, and 10.

Company witness Haynes explained that the Company developed Schedule 6L in response to recent concerns expressed by DNCP industrial customers that the current industrial Schedule 6P rate is less preferable compared to rate options available in other utilities' service territories. He presented an example showing how the design of rates can impact economic competitiveness and factory utilization and potentially may cause a hypothetical industrial customer in DNCP's North Carolina service territory to consider moving production to a facility located elsewhere in order to lower its electricity bill and thus lower its cost of production. Witness Haynes described the new Schedule 6L as a potentially more advantageous option than existing Schedule 6P for "high load factor" customers that place demands on the Company's system during most if not all hours of the day for seven days per week, and generally maintain annual load factors of approximately 80% and higher. Witness Haynes testified that the new optional Schedule 6L would be applicable to large industrial customers that have achieved a demand of at least 3,000 kW in the three billing months during the most recent 12-month period. Witness Haynes explained that Schedule 6L is designed to recover more costs through demand charges and less through energy charges when compared to existing Rate Schedule 6P. Witness Haynes also explained that the Company has amended the Company's Rider EDR tariff to include Rate Schedule 6L as an eligible rate schedule. The Company proposed to continue to offer Rate Schedule 6P, as this schedule is appropriate for industrial and commercial customers that do not have an extensive need for electricity around the clock.

Public Staff witness Floyd recommended that the Commission approve proposed Schedule 6L, subject to one change in the tariff language to eliminate the NAICS "Manufacturing" classification as part of the qualification for this rate schedule. Witness Haynes testified in rebuttal that the Company agrees with witness Floyd's proposed change and that the specific NAICS "Manufacturing" classification eligibility limitation had been eliminated in the revised Schedule 6L included as Company Rebuttal Exhibit PBH-1, Schedule 12.

During the hearing, witness Haynes further explained that over the last 10 to 12 years, the Company has developed new rates and structures to address concerns of industrial customers. He testified that about 10 years ago, the Company developed a new Schedule 6VP rate to recognize that some large industrial high usage customers had the ability to curtail in certain hours given a price signal. He explained that proposed Schedule 6L is designed in response to the needs of certain high load factor customers and would recover more costs in the demand component. Under Schedule 6L, the average cost to a high load factor customer under Schedule 6L will be approximately 5.7 cents/kWh. Witness Haynes also testified that DNCP's industrial rates are competitive in North Carolina and significantly lower than industrial customer rates across the EEI South Atlantic region.

The Commission finds and concludes based upon all evidence in the record that Rate Schedule 6L, as presented in Company Rebuttal Exhibit PBH-1, Schedule 12 is reasonable and nondiscriminatory, and should be approved. No party objected to the Schedule 6L design, as amended by DNCP to address the Public Staff's eligibility recommendation. Further, no party disputed witness Haynes testimony during the hearing that certain of the Company's high load factor customers could benefit from the Schedule 6L design.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 44

The evidence supporting this finding of fact and these conclusions is contained in the Application, the testimony of Nucor witness Thomas, the direct and rebuttal testimony of Company witness Haynes, the Stipulation, and the entire record in this proceeding.

As described in the Application and the testimony of Company witness Haynes, DNCP develops its COSS for purposes of allocating and assigning the cost of utility service to the North Carolina jurisdiction and between the North Carolina customer classes. Since DNCP's 2012 Rate Case, the Company has evolved its cost of service model from a basic Microsoft Excel-based model to the Utilities International (UI) Model, a subscription software-supported model developed by UI. The UI Model provides the Company a staged database platform through which business units can directly input cost and other source information into the UI Model. The Company's Cost Allocation group then maintains the UI Model and uses to it perform all cost of service-related regulatory functions, including developing the COSS for North Carolina rate cases. During this proceeding, Nucor as well as other parties requested that DNCP run alternative COSS using alternative allocation methodologies to DNCP's SWPA method.

Nucor witness Thomas developed and supported a fully adjusted S/W CP COSS analysis. Witness Thomas explained that he relied upon information provided in discovery by the Company to develop Nucor's fully-adjusted S/W CP COSS analysis, but commented that the Company's transition to the UI Model has caused difficulty for Nucor and parties other than DNCP to run alternative cost of service (COS) analyses. Witness Thomas testified that DNCP held conference calls with Nucor to explain the UI Model and also made the UI Model available upon reasonable notice at the Company's offices in Richmond for in-person inspection. Witness Thomas testified that DNCP's historic use of spreadsheet-based COS models was more usable by Nucor and other parties who could run various scenarios to evaluate and test the impacts of potential changes in allocator methodologies, allocator selections, changes in recommended ratemaking adjustments, changes in revenue requirements, and other scenarios. He also explained that the UI Model uses its own programming language, and that it could take considerable time for someone unfamiliar with the software to learn how to use the software and subsequently audit the software to validate its functionality. Witness Thomas concluded that although Nucor was able to develop a fully-adjusted S/W CP COS model run, his opinion was that the UI Model presents an undue burden on parties in this proceeding and severely limits their capabilities relative to the spreadsheet-based COS models used by DNCP in prior proceedings.

In rebuttal, Company witness Haynes responded that the Company has worked diligently in this case to be supportive of the regulatory process by performing original work to run COSS requested through data requests and motions by CIGFUR I and Nucor, respectively, and also offered to make the UI Model available for inspection at the Company's office in Richmond. Witness Haynes testified that the Company plans to work with Utilities International to determine whether Utilities International can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in spreadsheet-based Excel, generally including manipulating allocation factors to prepare their own COSS in future rate case proceedings.

In the Stipulation, DNCP, the Public Staff, and CIGFUR I agreed that the Company will work with Utilities International to determine whether it can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings.

The Commission finds and concludes that the Company has worked in good faith and made reasonable efforts in this case to provide Nucor and other parties with COS-related information through the normal discovery process. The Commission finds that DNCP's commitment in the Stipulation to work with Utilities International regarding assessing reasonable additional COS functionalities that can be produced in an Excel spreadsheet-based format should be completed prior to DNCP filing its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 45

The evidence supporting this finding of fact and these conclusions is contained in the testimony and exhibits of Company witness Haynes and Public Staff witness Floyd and the Stipulation.

Public Staff witness Floyd testified that DNCP does not currently offer customers any lighting services or fixtures that use LED (light emitting diode) technologies. Schedule 26, DNCP's outdoor area and street lighting tariff, only offers mercury vapor and high pressure sodium fixtures. In response to a Public Staff data request, DNCP indicated that it was currently investigating new LED lighting services in conjunction with contract negotiations between the Company's Virginia affiliate and several Virginia municipalities. The Company's response suggested that once these negotiations were completed, and the Company had a better understanding of the LED lighting services that would be covered by those contracts, DNCP could bring new LED lighting services to the Commission for approval. Based on this information, witness Floyd recommended that the Commission require DNCP to either file a request for approval of new LED lighting services and fixtures within one year following the Commission's order in this proceeding or for DNCP to incorporate a new LED lighting services and fixtures rate option in its next general rate case, whichever comes first.

In his rebuttal, Company witness Haynes agreed with witness Floyd's recommendation. The Stipulation provides that the Company agrees to develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of the Commission's final order in this proceeding. The Commission finds and concludes that this provision of the Stipulation is reasonable and appropriate and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 46

The evidence for this finding of fact and these conclusions is found in the cross-examination of Company witness Haynes by CUCA, and the entire record before the Commission in this proceeding.

During cross-examination by CUCA, Company witness Haynes described Real Time Pricing (RTP) rates. Witness Haynes indicated that a RTP rate is no longer offered to customers in DNCP's service territory in North Carolina. He further stated that if the Company deemed a RTP rate to be something it wanted to offer its customers, it could bring that forward.

In its post-hearing Brief, CUCA submitted that RTP rates tend to have a significant beneficial impact on high load factor customers. CUCA urged the Commission to require DNCP to propose a pilot RTP rate by July 1, 2017, and to present its RTP proposal for a ruling by the Commission by the end of 2017.

The Commission is of the opinion that an RTP rate, if offered, could provide high load factor customers significant benefits. Therefore, the Commission finds and concludes that it is reasonable to require the Company to propose a pilot or experimental RTP rate offering no later than July 1, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 47

The evidence supporting this finding of fact and these conclusions is found in the testimony and exhibits of Company witness Haynes, the cross-examination by NCSEA and Commissioner Patterson, and the agreement between DNCP and NCSEA.

Company witness Haynes sponsored Company Exhibit PBH-1, which shows DNCP currently has a combined total of 307 residential customers participating in their Time of Use (TOU) rate tariffs (258 customers for Schedule 1P and 49 customers for Schedule 1T). This represents only 0.3% of DNCP's 102,058 residential customers. This is a decrease from 2007, when 366, or 0.4% of DNCP's residential customers received service under a TOU rate tariff.

In its post-hearing Brief, NCSEA requested that the Commission require DNCP to take three actions with regard to TOU rates: (1) offer a rate comparison and potential savings calculation to residential customers who receive a smart meter; (2) in its next general rate case, include a cost of service study that investigates the impacts of making TOU rates the default rate for new residential customers; and (3) file with the Commission the results of certain TOU pilot projects approved by the Virginia SCC.

On December 13, 2016, DNCP and NCSEA filed a letter with the Commission describing the agreement reached by them on the issues raised by NCSEA regarding TOU rate offerings by DNCP. In summary, the agreement provides that DNCP will file with the Commission and serve on all parties to this docket the final annual report to the Virginia SCC regarding DNCP's Dynamic Pricing Pilot Program and Electric Vehicle Pilot Program in the Company's Virginia jurisdiction.[1] Further, DNCP states that it objects to NCSEA's recommendation that the Company perform a rate comparison for every customer who has received a smart meter and is currently served on a non-TOU residential rate, but that the Company will agree to investigate improving the rate comparison process for residential customers. This investigation will include studying the feasibility of a web-based tool designed to educate customers about TOU rates and providing tools for residential customers to perform their own rate comparison. The Company agrees to discuss the findings of this investigation with NCSEA by the end of 2017.

In addition, the Company states that it objects to NCSEA's recommendation that the Company default residential customers to a TOU rate. The Company also objects to NCSEA's request that the Company develop an alternative cost of service study methodology for inclusion in a future general rate case application, as such an undertaking would be unduly burdensome. However, DNCP agrees to investigate a way to study the impacts of defaulting new residential customers onto TOU rates in a cost of service study and report to the Public Staff and NCSEA the findings of such a study by October 1, 2017. The Company will conduct this investigation using readily available information prepared for the Company's filing in Docket E-22 Sub 532. Moreover, DNCP will provide to NCSEA consolidated hourly profile information for rate schedules 1P and, separately, 1T.

Finally, the agreement states that NCSEA withdraws the recommendations in its post-hearing Brief in consideration of the Company's commitments as set forth above.

The Commission is sensitive to the impact that any residential rate increase has on utility customers in North Carolina, particularly low-income customers. The Commission wants to ensure

[1] Virginia Electric and Power Company's Proposed Pilot Program on Dynamic Rates, Virginia SCC Case No. PUE-2010-00135; Application of Virginia Electric and Power Company for Approval to Establish an Electric Vehicle Pilot Program pursuant to § 56-234 of the Code of Virginia, Virginia SCC Case No. PUE-2011-00014.

that DNCP's customers are fully aware of existing rate tariffs that could help them reduce monthly bills. The Company's response (in part) to the NCSEA Data Request Number 2, Question Number 6, states "Customers who received smart meters were not provided with information about DNCP's TOU rate schedules." The Commission finds and concludes that DNCP should be required to provide a written summary of its TOU rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter. In addition, the Commission encourages the Company to investigate opportunities to better educate its customers on the benefits of TOU rates.[1]

In addition, the Commission finds and concludes that the terms of the agreement between DNCP and NCSEA are reasonable, are in the public interest, and should be approved

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 48

The evidence supporting this finding of fact and these conclusions is contained in the Application, the testimony and exhibits of Company witness Haynes and Public Staff witness Floyd and the Stipulation.

Item 39 of the Company's Form E-1 filed with the Application and the Company's supplemental direct testimony showed the changes the Company proposed to make to each section of the Terms and Conditions, Rider D-Tax Effect Recovery, Fuel Rider A, and Rider EDR. No party testified in opposition to the adoption of the proposed changes to the Terms and Conditions, and the Stipulation provides that DNCP's Terms and Conditions should be revised as set forth in Item 39 of the Company's Form E-1 filed with its supplemental direct testimony. The Commission finds and concludes that this provision of the Stipulation is reasonable and appropriate and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 49

The evidence supporting this finding of fact and these conclusions is contained in the verified Application and DNCP's Form E-1, the testimony and exhibits of Company witness Curtis and Public Staff witness McLawhorn, and the entire record in this proceeding.

Company witness Curtis provided testimony regarding DNCP's performance with regard to customer service. He testified that the Company's generating fleet has demonstrated excellent performance results. He also stated that DNCP continues to provide excellent customer service, and that the Company has improved its North Carolina System Average Interruption Duration Index (SAIDI), excluding major storms performance, by over 20% since 2007, and maintained consistent performance below 120 minutes since 2012. He noted that because of DNCP's previous infrastructure investments, the Outer Banks area continues to be one of the best performing areas across DNCP's entire service territory.

[1] Report of the North Carolina Utilities Commission Regarding an Analysis of Rate Structures, Policies, and Measures to Promote Renewable Energy Generation and Demand Reduction in North Carolina, Docket No. E-100, Sub 116 (September 2, 2008).

Witness Curtis also testified that the Company continues to achieve excellence in customer service by offering innovative solutions in response to customer expectations, including leveraging technology to perform quick, seamless customer transactions. He noted that DNCP customers completed more than 13 million online transactions during 2015, and that usage of electronic transactions has increased by 61% since 2012. He described the Company's promotion of social media interactions with customers, including its implementation in 2014 of an interactive map that allows customers to view current outages and see details of current outages, such as status and estimated restoration time. Witness Curtis also testified about recognition for outstanding performance that the Company's parent, Dominion Resources, Inc., had received during the past several years.

Public Staff witness McLawhorn testified that the Public Staff had reviewed service-related complaints received by the Public Staff's Consumer Services Division, the Company's call center operation reports filed with the Commission, SAIDI and SAIFI statistics, the Company's report on new residential service installations, and complaints directly received by DNCP related to vegetation management. Based on the low number of service-related complaints and the relative level of its service metrics, witness McLawhorn found the overall quality of electric service provided by DNCP to retail customers to be adequate.

Based on the testimony of Company witness Curtis and Public Staff witness McLawhorn, the Commission finds and concludes that the overall quality of electric service provided by DNCP is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 50

The evidence supporting this finding of fact and these conclusions is contained in the Application, the direct, supplemental, and rebuttal testimony and exhibits of DNCP witnesses Hupp and Bailey, the Company's July 8, 2016 Supplemental Filing, the testimony of Public Staff witness McLawhorn, the Stipulation, and the hearing testimony. In addition the Commission relies on its April 19, 2005 Order Approving Transfer Subject to Conditions in Docket No. E-22, Sub 418 (the PJM Order), and the post-hearing exhibit filed by DNCP.

In the Application, the Company requested relief going forward from the regulatory conditions imposed in the PJM Order. The over-arching goal of the conditions in the 2005 PJM Order was stated as follows: "That Dominion's North Carolina retail ratepayers shall be held harmless from all direct and indirect effects and costs, either related to operations, quality of service, reliability, or rates, arising from its integration with PJM ...."

PJM Order Condition (1)a states that:

> Dominion's North Carolina retail customers shall continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law using the same ratemaking methodology as that employed by this Commission as of the time of Dominion's joining PJM notwithstanding Dominion's integration into PJM or decision to participate in any capacity or energy market administrated by PJM; that is, under no circumstances(s) or event(s) shall the costs of generation and

> transmission, among other things, included in Dominion's N.C. retail rates be greater than the lesser of (1) such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or (2) the marginal costs of generation and transmission supplied into or purchased from PJM;

PJM Order Condition (1)b states that:

> Dominion shall continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements before making power available for off-system sales;

PJM Order Condition (1)c states that:

> Dominion shall take all reasonable and prudent actions necessary to continue to provide its NC retail customers with the same (or higher) superior level of bundled electric service as that provided prior to Dominion's integration with PJM, including, for example, reliable generation, transmission, and distribution service; and responsive customer service;

PJM Order Condition (1)d states that:

> Dominion shall not include in base rates: (a) PJM administrative fees or any replacement mechanism for such fees approved by FERC[1]; (b) PJM transmission congestion costs or revenues from PJM for financial transmission rights (FTRs) or auction revenue rights (ARRs) or any replacement mechanism for such cost and revenues approved by the FERC; (c) any increase in transmission service charges to the Company resulting solely and directly from a change in rate structure from license plate rates to another rate structure for recovering the embedded costs of transmission facilities used to provide Network Integration Transmission Service; (d) any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone, and which are not included in the Company's transmission revenue requirement; or (e) any increase in transmission costs to the Company or any revenues resulting from the FERC's orders in Docket Nos. ER04-829 and ER05-6 et al. imposing the Seam Elimination Cost Adjustments (SECAs);

PJM Order Condition (1)e states that:

> Dominion shall allocate sufficient FTRs, ARRs, or other revenues toward its fuel costs to offset any congestion charges or other fuel-related costs resulting from Dominion joining PJM and sought to be recovered from Dominion's North Carolina retail ratepayers through the operation of G.S. 62-133.2;

[1] FERC is the Federal Energy Regulatory Commission.

PJM Order Condition (1)f states that:

> Neither PJM, Dominion nor any affiliate shall assert in any proceeding in any forum that federal law, including, but not limited to, the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were Dominion not a member of PJM) under North Carolina law to set the rates, terms and conditions of retail electric service to Dominion's North Carolina retail ratepayers and that Dominion shall bear the full risks of any such preemption;

<u>PJM Order Condition (2) states that:</u>

> Dominion and PJM shall, consistent with, and to the extent not altered by, the above regulatory conditions and this Order, comply with the terms of the Joint Offer of Settlement [JOS] filed December 16, 2004.

The JOS had two signatories: PJM and Dominion. Some of its provisions ended as of December 31, 2014, but others did not. Some of the provisions were reiterated by the Commission in the PJM Order and were put in place "until further Order of the Commission." In its July 8, 2016 Supplemental Filing, Dominion reiterated that it is seeking relief from compliance with the JOS.

<u>PJM Order Condition (3) states that:</u>

> Dominion and PJM shall, consistent with the above additional regulatory conditions, comply with the terms of the Settlement Agreement with Progress filed December 16, 2004. Dominion and PJM shall, with regard to all of the signatories thereof, honor , and discharge Dominion's obligations pursuant to, the various VACAR[1] and other regional agreements referenced in the Settlement Agreement, including, but not limited to the VACAR Reserve Sharing Agreement, as Dominion would have been so obligated to do prior to Dominion's integration with PJM. In fulfilling this condition, Dominion and PJM shall continue to follow the practices and operating procedures around these agreements that have been customarily observed by the participants but do not necessarily exist in written form.

The "Progress Settlement Agreement" among DNCP, PJM and Progress Energy Carolinas, Inc. (now Duke Energy Progress) contained six very detailed provisions intended to ensure that commitments and practices that DNCP had made or instituted in order to assure reliability in the VACAR region during emergencies would survive, with specific tasks being agreed to by PJM.

PJM Order Condition (4) states that Dominion would continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission. The PJM Order further stated that "the conditions imposed by the Commission shall remain in effect

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[1] VACAR is a sub-region of the SERC Reliability Corporation (SERC), and covers the states of Virginia, North Carolina and South Carolina. In the Southeast, SERC implements and enforces the reliability standards that are developed by NERC and approved by FERC.

for a period of not less than ten (10) years from the date of Dominion's integration into PJM and continuing thereafter indefinitely and until further Order of the Commission."

In his direct testimony, DNCP witness Hupp noted that the Commission imposed the PJM conditions for a period of not less than 10 years and indefinitely until further Commission order, and that more than 10 years have passed since DNCP integrated with PJM. Witness Hupp testified that to the best of his knowledge, since integration into PJM, DNCP has complied with all of the PJM Order conditions and has held customers harmless via the operational and financial benefits provided by DNCP's membership in PJM. Witness Hupp described the operational benefits as more reliable and efficient operations, improved outage and reserve planning, and participation in the PJM stakeholder process.

Witness Hupp also testified that in Docket No. E-22, Sub 428, the Commission ordered DNCP to perform, beginning with its next fuel case, a study of the fuel costs that would have been incurred had DNCP not joined PJM (the PJM Integration Study). Witness Hupp stated that in each of the ten PJM Integration Studies conducted from 2006 through 2015, DNCP demonstrated significant savings to customers as a result of DNCP's PJM membership. Particularly since 2009 when the Company began using the PJM Integration Study in its current form, witness Hupp testified that the studies demonstrate substantial financial savings that outweigh the costs, including administrative costs, associated with DNCP's integration into PJM.[1]

Witness Hupp testified that based on the consistently demonstrated benefits of DNCP's PJM integration since 2005, the Company should be relieved from further compliance with the PJM conditions. He explained that the Company's integration into PJM is now complete, and concerns about new and unknown aspects of joining a regional transmission organization no longer apply. Witness Hupp noted that in the Company's 2014 fuel factor proceeding the Commission recognized that due to the passage of time since the integration with PJM, one or more of the PJM conditions could be ripe for review.

Witness Hupp testified that several of the PJM conditions prohibit the Company from recovering through rates certain costs associated with PJM participation. These costs include congestion and other fuel-related costs which Condition 1(e) required DNCP to offset with Financial Transmission Rights (FTRs), Auction Revenue Rights (ARRs), and other revenues. Witness Hupp noted that in the Company's 2014 fuel case, due to this condition, the Commission disallowed recovery of $1.5 million of congestion costs that the Company believed were prudently incurred. Condition 1(d) similarly prohibits DNCP from recovering administrative costs associated with PJM membership. Witness Hupp clarified that DNCP is not asking to pass such costs on to customers without a prudence review. Instead, the Company seeks the opportunity to recover these prudently incurred costs.

In its July 8, 2016 Supplemental Filing the Company provided more specific representations regarding its ongoing commitments for its continued retail electric service in North Carolina, notwithstanding its request for relief from the PJM Order conditions. The Company also

[1] DNCP is not currently required to perform the PJM Integration Study pursuant to the Commission's final order in the Company's 2015 fuel clause adjustment proceeding, Docket No. E-22, Sub 526.

presented a detailed cost-benefit analysis of the impact of the PJM integration on customers, supported by the supplemental direct testimonies of witnesses Hupp and Bailey.

DNCP clarified in the Supplemental Filing that, while the Company is seeking relief from all of the PJM Order conditions, certain obligations to which it is subject as a North Carolina regulated electric utility exist separate and apart from the PJM conditions and will continue to apply to the Company even if the Commission grants the Company's request for relief. Furthermore, the Company is subject to some regulatory conditions that were imposed by the Commission before DNCP joined PJM, and DNCP stated that it would remain subject to all such conditions.[1] The Company clarified that it would continue to comply with the following obligations:

> (1) DNCP's North Carolina retail customers will continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law notwithstanding DNCP's integration into PJM or decision to participate in any capacity or energy market administered by PJM.
>
> (2) DNCP will continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements before making power available for off-system sales.
>
> (3) DNCP will continue to take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with superior bundled retail electric service and customer service.
>
> (4) Neither DNCP nor any of its affiliates will assert in any proceeding in any forum that federal law, including but not limited to the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were DNCP not a member of PJM) under North Carolina law to set the rates, terms, and conditions of retail electric service to DNCP's retail ratepayers, and DNCP shall bear the full risks of any such preemption.
>
> (5) DNCP will continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission.

The Company also provided information in the Supplemental Filing regarding how the other conditions contained in the PJM Order either are moot or are otherwise covered by other agreements.

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[1] Those previously imposed regulatory conditions include Regulatory Conditions 30-42 to the Commission's October 18, 1999 Order Approving Code of Conduct and Amending Conditions of Merger issued in Docket No. E-22, Sub 380, which prohibited the Company from asserting federal preemption of the Commission's authority in any forum.

With regard to Condition (1) of the PJM Order, DNCP clarified that it is requesting relief from the portion of this Condition that requires that the costs of generation and transmission, among other things, included in DNCP's North Carolina retail rates be no greater than the lesser of such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or the marginal costs of generation and transmission supplied into or purchased from PJM. The Company reiterated that it would continue to set rates for service based on its cost of service.

With regard to Condition (2) of the PJM Order, which requires DNCP and PJM to comply with the terms of the Joint Offer of Settlement, DNCP clarified that it is seeking relief from this condition. The Company stated that Paragraphs (1) through (6) of the Joint Offer of Settlement either were subsumed within broader obligations imposed by the conditions contained in the PJM Order or were subject to sunset dates that have since passed.

The Company also explained that Paragraphs (7)(a) through (7)(c) of the Joint Offer of Settlement outline curtailment protocols that have been superseded by current PJM and North American Electric Reliability Corporation (NERC) requirements as provided for in the PJM tariff and NERC reliability standards.

With regard to Paragraph (7)(d) of the Joint Offer of Settlement, which states that "nothing in this approval of this application shall alter the Commission's authority over the application of curtailment practices to Company's retail customers," DNCP stated that any current authority held by the Commission regarding the application of curtailment practices would remain in effect even if the Commission grants the Company's request for relief from these conditions.

DNCP explained that the obligations imposed by Paragraph (8) of the Joint Offer of Settlement, which required a stakeholder process related to locational marginal pricing and settlements, have been fulfilled by PJM's actions to implement Residual Metered Load market rules, which took effect June 1, 2015.

DNCP stated that Paragraphs (9) through (11) of the Joint Offer of Settlement address obligations to which it is already subject as a North Carolina regulated electric utility and that will continue to apply to the Company even if the Commission grants the Company's request for relief from the PJM Order conditions. These obligations include the need to seek permission to build electric generation and transmission facilities in North Carolina, the requirement to comply with the Commission's integrated resource planning requirements, the requirement to promptly address reliability and service quality issues, and the requirement to follow the laws, rules and policies of the Commission for the provision of retail electric service. The Company clarified that it is not seeking authorization to cease compliance with any of these obligations.

DNCP stated that the Commission's jurisdiction over any subsequent transfer of the Company's North Carolina transmission facilities exists independent of Paragraph (12), making that provision unnecessary.

Paragraph (13) provided for the confidentiality of the discussions that resulted in the Joint Offer of Settlement. DNCP stated that due to the passage of time and the application of other agreements, this provision is no longer relevant. Even so, DNCP will continue to treat as confidential any information provided as such.

Paragraph (14) asserted that changes to the Joint Offer of Settlement required the Company's agreement. DNCP stated that, to the extent this requirement is deemed to apply, the Company was submitting a written signed request for relief from the Joint Offer of Settlement.

Paragraph (15) addressed the possibility that the Commission might not accept the Joint Offer of Settlement. DNCP stated that because the Commission had issued its Notice of Decision on March 30, 2005, in Docket No. E-22, Sub 418, Paragraph (15) is moot.

With regard to Condition (3) of the PJM Order, which pertains to the Settlement Agreement between DNCP and DEP that was filed on December 16, 2004, in Docket No. E-22, Sub 418 (Progress Settlement), DNCP clarified that it is seeking relief from this condition. DNCP represented that it had conferred with counsel for DEP, and that DEP and DNCP agreed that the obligations and commitments contained in the VACAR Reserve Sharing Agreement and other regional agreements referenced in the Progress Settlement are being met pursuant to the current, updated versions of those agreements, as well as other agreements entered into subsequent to the Company's PJM integration, including the Joint Operating Agreement between PJM and DEP most recently filed with FERC in Docket No. ER15-29-000. DEP and DNCP therefore agreed that a Commission Order relieving DNCP of the obligation to comply with the terms of the Progress Settlement would not adversely impact the legal effectiveness of the terms and conditions applicable to DNCP, PJM, and DEP under these agreements.

In his supplemental testimony, witness Hupp presented the results of the Company's detailed analysis of the full costs and benefits of PJM integration over the period of 2006-2015. He explained that the analysis compares actual cost and benefit data from the 10-year period during which DNCP has been a PJM member to a theoretical environment in which DNCP did not join PJM and instead continued to operate as a separate control area. He stated that the Company analyzed several categories of cost and benefit data from 2006 through 2015, including market energy, FTRs, ancillary services, administrative costs, market capacity, and transmission costs. Witness Hupp provided detailed descriptions of how the Company derived the data for each category, and testified that the results of the analysis for all of the categories except administrative costs showed there was a substantial economic benefit to the Company's North Carolina retail customers from its integration into PJM. He noted that the Company did not attempt to speculate as to the comparable administrative costs that the Company would have incurred as a separate control area, and that the administrative costs associated with PJM membership were significantly more than offset by the economic benefits realized in each of the other analyzed categories.

In his supplemental testimony, DNCP witness Bailey testified in support of witness Hupp's discussion of the transmission-related costs and benefits associated with DNCP's PJM participation over the 2006-2015 period. Witness Bailey stated that the cost-benefit analysis assumes that the same transmission projects would be developed whether or not the Company was a member of PJM or a separate control area. In support of this assumption, witness Bailey explained that projects developed pursuant to the PJM Regional Transmission Expansion Plan (RTEP) process include "baseline," "supplemental," and "network" projects. He stated that the

RTEP process identifies baseline projects for development that are needed to comply with, for example, mandatory NERC reliability standards and, as such, those projects would likely have been developed whether or not the Company was a PJM member. He also stated that the vast majority of supplemental projects, which DNCP develops in response to specific customer needs are based on the need to support load growth or additions that also would be present whether or not DNCP was in PJM. Finally, witness Bailey testified that since network projects are developed in response to specific generation, merchant transmission, or long-term firm transmission service requests and are paid for by the requesting interconnection entity, those projects were not reflected in the cost/benefit analysis.

In his direct testimony, Public Staff witness McLawhorn summarized the PJM Order conditions and the Company's direct and supplemental filings. He stated that based on the Public Staff's review of DNCP's cost benefit analysis and its consultation with an outside consultant, Christensen Associates Energy Consulting, the Public Staff believes that DNCP's study methodology was generally reasonable and that the available data are verifiable. Witness McLawhorn noted that while the Public Staff believes that DNCP's quantification of the net benefits associated with its PJM membership may be overstated, the Public Staff agrees that there has been a net economic benefit to DNCP ratepayers from 2006-2015 as a result of the integration. He also stated that, based on the most current projections of natural gas prices, capacity prices, and other PJM-related costs, the Public Staff expects the net benefits of DNCP's membership in PJM to continue, driven mainly by fuel cost savings. Witness McLawhorn concluded that, based on its review of the cost/benefit analysis and the clarifications made in the Supplemental Filing, the Public Staff believes that the benefits of DNCP's integration into PJM exceed the costs, and that these benefits can be expected to continue under current forecasts, even with inclusion of the costs previously excluded by Conditions 1(d) and (e). He noted further that, as to Conditions 1(a)-(c), (f), 2, 3 and 4, the Public Staff believes that the clarifications made by the Company in the Supplemental Filing are appropriate and sufficient to support relief from those conditions, with the exception of the filing requirements in Paragraphs 5 and 6 of the JOS. These two paragraphs require the filing of information related to congestion costs and transmission constraints, revenues associated with FTRs and ARRs, a summary of DNCP's monthly capacity and energy transactions with the PJM markets, and locational marginal pricing information.

Witness McLawhorn recommended that, to the extent that DNCP does not already file the information required by these Paragraphs in its annual fuel rider application, DNCP should be required to file that information in the same or substantially similar detail as the filing made by the Company on August 31, 2016, with its annual fuel proceeding. Otherwise, he stated that the Public Staff does not oppose the Company's request for relief from the PJM conditions as clarified by DNCP in the Supplemental Filing. Witness McLawhorn recommended that the Commission's order granting the Company's request for relief from these conditions specifically address the subject matter of Conditions 1(a)-(c), (f), 2, 3, and 4 and incorporate the clarifications made by the Company in its Supplemental Filing. Finally, witness McLawhorn testified that the Public Staff believes that the Commission will be able to protect North Carolina ratepayers should DNCP's participation in PJM prove not to be beneficial in the future. He stated that the Commission has full authority to ensure that DNCP complies with the representations and commitments made in the Supplemental Filing with respect to obligations that exist separate and apart from the PJM conditions, including regulatory conditions previously imposed by the Commission. With regard to the additional

PJM costs that DNCP may seek to recover from ratepayers upon being relieved of the PJM conditions, that is, costs excluded from rates under Conditions 1(d) and (e), such costs would be recoverable only when they are shown to have been reasonable and prudently incurred.

In his rebuttal testimony, witness Hupp testified that the Company does not oppose witness McLawhorn's recommendation that the Company continue to file the information required by Paragraph 5 of the JOS in conjunction with its annual fuel cases. He also stated the Company's understanding that the independent market monitor for PJM will continue to file the information required by Paragraph 6 of the JOS. [1]

Section XIV of the Stipulation provides that the Company is relieved from further compliance with the PJM Order conditions, subject to: (1) the Company's clarifications regarding its ongoing commitments as contained in its July 8, 2016 Supplemental Filing in this docket; (2) the Company's continuing to file with its annual fuel clause adjustment filing the information required by Paragraph 5 of the JOS; and (3) the IMM for PJM continuing to annually file the information required by Paragraph 6 of the JOS. Section XIV also provides that the Company will comply with the representations and commitments made in the Supplemental Filing with respect to obligations that exist separate and apart from the PJM Conditions.

No other party submitted evidence regarding the Company's request for relief from the PJM conditions.

At the hearing, witness Hupp testified in response to Commission questions that the Company would not object to the Commission directing DNCP to continue to comply with the obligations it agreed to continue to meet in the Supplemental Filing notwithstanding the Company's request for relief from the conditions related to those obligations. On redirect, witness Hupp agreed that the Company took the approach of requesting relief from all the conditions while committing to continue compliance with its independent and ongoing obligations as a North Carolina retail electric utility as that would allow for a "clean slate" going forward. Witness Hupp noted that the forward-looking evaluation of costs and benefits that the Public Staff conducted indicated that the benefits and savings of PJM integration would continue. He stated on redirect that it is no longer valid to compare the circumstances before the Company joined PJM to those after integration, given the length of time that DNCP has been a PJM member and the benefits it has shown from integration. He also confirmed that regardless of whether it is a PJM member, the Company always seeks to provide service at least cost and to economically dispatch its fleet.

Witness Hupp confirmed in response to Commission questioning that certain decisions that the Company makes with regard to operating within PJM, such as whether to bid into the markets or buy market energy, would be subject to prudence review. He agreed that, with regard to other costs that PJM controls, such as administrative costs, the Company participates in various committees at PJM and could protest any inappropriate costs, and that either DNCP or the IMM

[1] The Commission notes that on November 16, 2016, counsel for Monitoring Analytics, LLC (PJM's independent market monitor) filed a letter in this docket stating that "should the Commission accept the Stipulation, Monitoring Analytics, LLC, acting as the [IMM] for PJM will continue to annually file ... the information specified in Paragraph 6 of the Joint Offer of Settlement ... filed in ... 2004."

could complain to FERC if there are disagreements with PJM. He also confirmed that in the Company's 2014 fuel case, even though DNCP's fuel costs as a PJM member were lower than they would have been had DNCP operated as a separate control area, FTR and ARR revenues were used to offset congestion costs that the Company incurred in order to gain the benefits of PJM participation. He confirmed that over $1 million from those FTR and ARR revenues were offset against those costs, which he viewed as one way in which the continuance of the conditions would be unfair.

On redirect, witness Hupp confirmed that the cost-benefit analysis included in the Company's Supplemental Filing was conducted at the request of the Public Staff, and that it built on the PJM Integration Studies that DNCP conducted as part of its fuel cases from 2006-2015. He agreed that in addition to the market energy costs addressed in those fuel case studies, the cost-benefit analysis also evaluated FTRs, capacity, transmission costs, ancillary services, and administrative costs, and that the overall result showed a substantial financial benefit to the North Carolina retail jurisdiction from DNCP joining PJM. He clarified that the reporting requirements that witness McLawhorn has asked to be continued were part of the JOS with PJM, and that DNCP is requesting relief from all of the conditions in the other settlement agreement in the PJM case, which was with Progress Energy Carolinas, Inc., now Duke Energy Progress, LLC (DEP). He testified that the Company conferred with DEP on all of the conditions contained in that settlement agreement and that DNCP and DEP agreed that all of them are being addressed now under other agreements. Finally, witness Hupp testified on redirect that the Company has for the past 11 years not been allowed to recover significant costs of doing business due to the PJM Order conditions. He testified that the Company is now seeking to be allowed the chance to recover all of the costs of providing reliable and least cost service to its customers.

In response to Commission questions, witness McLawhorn testified to his recommendation that the Company continue to file the information required by Paragraphs 5 and 6 of the JOS. He agreed that it would be sufficient for the PJM IMM to resume filing the Paragraph 6 information as it had done previously.

The post-hearing exhibit filed by DNCP and the Public Staff shows that, as stated in witness Hupp's testimony, all of the conditions imposed by the PJM Order are now either no longer applicable or are being met under subsequent and currently effective agreements, with the exception of the ongoing reporting requirements agreed to in the Stipulation. The exhibit also noted PJM's confirmation that all of the conditions are now covered elsewhere or no longer apply.

The Commission finds the testimony of Public Staff witness McLawhorn persuasive. He concluded that DNCP's cost-benefit analysis methodology and assumptions were reasonable, and that even if the quantification was overstated, there has been a net economic benefit to DNCP's customers from PJM membership. Witness McLawhorn also stated, based on the most current projections of natural gas prices, capacity prices and other PJM-related costs, the Public Staff expects the net economic benefits of DNCP's membership in PJM to continue. The Commission agrees with witness McLawhorn that it has full authority to ensure DNCP's compliance with the representations the Company made in the Supplemental Filing, and that any additional PJM-related costs that the Company seeks to recover will only be recoverable if the Company shows them to have been reasonable and prudently incurred.

The evidence presented in this case demonstrates that DNCP's integration into PJM has benefited its customers, and that those benefits can be expected to continue even if the Commission relieves the Company from compliance with most of the PJM Order conditions. Going forward and as clarified at the hearing and in witness McLawhorn's testimony, DNCP will be required to show that costs incurred with respect to PJM membership are reasonable and were prudently incurred, just as with any other costs for which the Company seeks recovery. The Commission fully expects Dominion to use its voice in various PJM committees at PJM to protest any inappropriate PJM-related costs, to complain to FERC if there are irreconcilable disagreements with PJM adversely affecting its North Carolina ratepayers, and to communicate any such concerns to the Commission and the Public Staff. Therefore, the Commission concludes that based on all of the evidence presented, it is appropriate to grant the Company's request for relief from most, but not all, of the conditions imposed by the PJM order.

The Company shall continue to comply, or shall compel PJM's independent market monitor to comply, with the reporting obligations established in Paragraphs 5 and 6 of the JOS and as provided at Section XIV of the Stipulation. The Company shall also continue to meet the five commitments that it agreed to be subject to as a North Carolina regulated retail electric utility and as it stated in its Supplemental Filing. Finally, the Company shall make a compliance filing in this docket within 30 days of the issuance of this Order, which filing shall consist of a comprehensive Code of Conduct that shall include all of the ongoing obligations and commitments to which the Company agrees to be bound, consistent with its representations, the Stipulation, and this Order. This filing shall include conditions that predate the PJM Order. The Public Staff is requested to review the filing and provide comments to the Commission within 30 days.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

The evidence supporting this finding of fact and these conclusions is contained in the testimony and exhibits of the Company and Public Staff, and in the Stipulation.

As fully discussed above, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations among DNCP, the Public Staff, and CIGFUR I. Comparing the Stipulation to DNCP's Application, and considering the direct testimony of the Public Staff witnesses, the Commission observes that there are provisions of the Stipulation that are more important to DNCP, and, likewise, there are provisions that are more important to the Public Staff. For example, DNCP is intent on obtaining deferral of the post-in-service costs of the Brunswick County and Warren County CC generating facilities, as well as deferral of the Chesapeake Energy Center impairment and closure costs. Indeed, the depth of DNCP's commitment to obtain deferral of the Warren County CC costs is evident from the fact that DNCP filed for reconsideration of the Commission's March 29, 2016 Order denying deferral of those costs. On the other hand, the Public Staff is intent on limiting DNCP's Marketing Percentage for the fuel cost of purchase power to 78%, substantially lower than the 100% sought by DNCP. Further, the Public Staff is focused on resisting any increase in the basic facilities charge component of DNCP's rates. Nonetheless, working from different starting points and different perspectives, the Stipulating Parties were able to find common ground and achieve a balanced settlement.

In addition, the Commission notes that the Stipulation provides customer benefits that are beyond what the Commission has the authority to require of DNCP. These include the $400,000 shareholder contribution by DNCP to the EnergyShare program that provides energy assistance to customers in need in the Company's North Carolina service territory; DNCP's withdrawal of its request for recovery of the site separation costs associated with the proposed North Anna 3 nuclear plant; and DNCP's accelerated refund of its fuel cost over-recovery through Rider A1.

The result is that the Stipulation strikes a fair balance between the interests of DNCP and its customers. As discussed above, the Commission has fully evaluated the provisions of the Stipulation and concludes, in the exercise of its independent judgment, that the provisions of the Stipulation are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest. The provisions of the Stipulation strike the appropriate balance between the interests of DNCP's customers in receiving safe, adequate, and reliable electric service at the lowest possible rates, and the interests of DNCP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the provisions of the Stipulation are just and reasonable under the requirements of the Public Utilities Act. Therefore, the Commission approves the Stipulation in its entirety. In addition, the Commission finds and concludes that the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52

The evidence for this finding of fact and these conclusions is contained in the Application, the testimony and exhibits of the DNCP witnesses and the Public Staff witnesses, the Stipulation, and the record as a whole.

Pursuant to G.S. 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See G.S. 62-133(b). DNCP's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DNCP's individual customers, as well as to the communities and businesses served by DNCP. DNCP presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

For example, DNCP witness Curtis testified that during the last three years the Company invested $2.3 billion to bring online a total of 2,700 MW of new generation. Witness Curtis stated that this new generation is cleaner and more highly-efficient combined cycle generating capacity that has the potential to create substantial fuel savings due to very favorable current natural gas prices. Witness Curtis cited in particular the operation of the Warren County CC since December 2014, and stated that this facility has created system-wide fuel savings of approximately

$65.9 million when compared to wholesale market power purchases. In addition, he stated that the Brunswick County CC is expected to produce similar fuel savings and operational benefits.

Witness Curtis further testified that DNCP has spent approximately $170 million on transmission improvements in North Carolina during the last three years. He stated that these improvements support improved reliability of the transmission system and local economic growth. He also testified that the Company plans to invest an additional $243 million in transmission improvements in North Carolina from 2016 through 2019.

In addition, witness Curtis testified that DNCP has invested over $102 million in its distribution system in North Carolina during the last three years. He stated that these investments balance the need for reliable service with prudent spending.

Witness Curtis also testified regarding the impact of current and proposed environmental regulations on the Company's operations. He stated that during the last decade electric utilities have been required to address compliance with a suite of new environmental standards adopted by the United States Environmental Protection Agency (EPA). He testified that compliance with these standards has had a direct impact on DNCP's operation of its coal-fired generating plants, citing as an example the EPA's Mercury Air Toxics Standards Rule (MATS). Witness Curtis stated that the cost of complying with MATS was a primary driver in the Company's decision to retire over 900 MW of coal-fired generating capacity. He also discussed the impact of the EPA's CCR Final Rule.

Moreover, witness Curtis testified that DNCP has invested approximately $296 million since 2014 to increase security at its transmission substations and at other critical points in its infrastructure. Further, he stated that the Company plans to invest an additional $260 million for such purposes between 2016 and 2018.

In addition, Company witness Mitchell described the 2013 conversion of the Altavista, Hopewell and Southamption Power Stations from coal-burning facilities to renewable biomass-fueled generation facilities.

These are representative examples of the capital investments that have been made and are planned to be made by DNCP in order to continue providing safe, reliable and efficient electric service to its customers. Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DNCP's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DNCP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of G.S. 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DNCP, the Public Staff, and CIGFUR I is hereby approved in its entirety.

2. That DNCP shall be allowed to increase its rates and charges effective for service rendered on and after January 1, 2017, so as to produce an increase in gross annual revenue for its North Carolina retail operations of $25,790,000, consisting of an increase of $34,732,000 in base non-fuel revenues, and a decrease of $8,942,000 in base fuel revenues.

3. That the proper aggregate base fuel factor for this proceeding is 2.070¢/kWh, excluding regulatory fee, and 2.073 ¢/kWh, including regulatory fee. The Company shall replace the voltage-differentiated base fuel factors approved in Docket No. E-22, Sub 479, with the following voltage-differentiated base fuel factors, including gross receipts tax, effective January 1, 2017:

Customer Class	Base Fuel Factor
Residential	2.095 ¢/kWh
SGS & PA	2.093 ¢/kWh
LGS	2.079 ¢/kWh
NS	2.014 ¢/kWh
6VP	2.043 ¢/kWh
Outdoor Lighting	2.095 ¢/kWh
Traffic	2.095 ¢/kWh

4. That the jurisdictional and class cost allocation, rate designs, rate schedules, and service regulations proposed by the Company, except as specifically addressed in this Order, are approved and shall be implemented. As discussed in this Order, DNCP shall continue to offer Nucor service pursuant to the terms and conditions of Schedule NS and the Nucor agreement approved on March 29, 2016 in Docket No. E-22, Sub 517, as modified to reflect the authorized change in non-fuel base revenues.

5. That DNCP shall implement Rider EDIT as shown on Settlement Exhibit IV via a rate that is calculated using the sales shown in Column 1 of Company Rebuttal Exhibit PBH-1, Schedule 11. Prior to the tenth month from the effective date of the Year 2 rider, the Company shall provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of Year 2. If there is a deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff shall work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect.

6. That as soon as practicable after the date of this Order, DNCP shall file for Commission approval five copies of rate schedules designed to comply with the rate design approved in this Order accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This shall include a schedule comparing the revenue produced by the filed schedules during the test period with the revenue that will be produced under the rate

schedules to be approved herein and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.[1]

7. That as soon as practicable after the issuance of the last Commission Order in DNCP's four pending rate-related proceedings, which are this proceeding, the Sub 534 fuel charge adjustment proceeding, the Sub 535 renewable energy and energy efficiency portfolio standard (REPS) cost recovery proceeding, and the Sub 536 demand-side management proceeding, DNCP shall file a consolidated proposed customer notice addressing the rate changes associated with the non-fuel base and base fuel rate changes approved in this proceeding (Sub 532), the Fuel Rider B in the Sub 534 proceeding, the Rider RP and RPE rate changes in Sub 535, and the demand-side management Rider C and Rider CE rate changes in Sub 536. Such notice shall include the effect of each rate-related proceeding on a residential customer using 1,000 kWh and the combined effect of all four rate-related proceedings on a residential customer using 1,000 kWh. Upon approval by the Commission, DNCP shall notify its North Carolina retail customers of the foregoing rate adjustments by including the approved notice as a bill insert with customer bills rendered during the next regular scheduled billing cycle.

8. That the Company may use levelization accounting for nuclear refueling costs as described in this Order**.**

9. That the Company shall continue to annually file a cost of service study with the Commission using the Summer/Winter Peak and Average methodology.

10. That the Company shall comply with Commission Rule R8-27(a)(2) regarding future establishments of regulatory assets and liabilities as provided at Section XI.D of the Stipulation.

11. That the Company shall file with the Commission, on the same date it files its quarterly ES-1 report, a report detailing: (1) the CCR deferrals recorded in the reporting period; and (2) regulatory accounting entries pursuant to the August 6, 2004 Order in Docket No. E-22, Sub 420, with regard to any costs other than nuclear decommissioning costs or CCR costs recorded in the reporting period.

12. That the Company shall notify the Commission when the Yorktown Power Station closure occurs and provide estimates of its undepreciated value at the time of closure and the level of costs to be incurred for closure.

13. That with the exception of the commitments in DNCP's July 8, 2016 Supplemental Filing, the Stipulation, and Commission-imposed conditions that predate DNCP's integration into PJM, DNCP is hereby relieved of the PJM Order conditions. Within 30 days of this Order the Company shall file in this docket a compliance filing which shall consist of a comprehensive Code of Conduct that includes all of these ongoing conditions and obligations, including those that

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[1] If necessary, the Commission will address in a subsequent order any refund due based on the any differences in the rates approved in this Order and the Company's temporary rates implemented on November 1, 2016.

predate the PJM Order. The Public Staff is requested to review the Code of Conduct and provide comments within 30 days of DNCP's compliance filing.

14. That the Company shall continue to file the information referenced in Paragraph 5 of the Joint Offer of Settlement dated December 16, 2004, between DNCP and PJM with its annual fuel clause adjustment filing.

15. That prior to DNCP filing its next general rate case, the Company shall work with Utilities International to determine whether it can produce an application that would enable an intervenor or the Public Staff to perform certain UI Model functionalities in Excel, generally including manipulating allocation factors to prepare their own cost of service studies in future rate case proceedings.

16. That the Company shall develop and file for Commission approval a new LED schedule for North Carolina jurisdictional customers within one year of this Order.

17. That the Company shall make a one-time shareholder contribution to its EnergyShare program of $400,000, over and above its usual contribution, for the benefit of its North Carolina customers by January 31, 2017.

18. That if DNCP continues to recover any deferred costs for a longer period of time than the amortization period approved by the Commission for those deferred costs, DNCP shall not record those deferred costs in its general revenue accounts, but, rather, shall continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for such deferred costs until the Company's next general rate case.

19. That the Company shall file with the Commission a proposed pilot or experimental Real Time Pricing rate offering no later than July 1, 2017.

20. That DNCP shall provide a written summary of its TOU rates, and its RTP rates, when developed, to each residential customer presently being served and to be served in the future by a smart meter.

21. That the agreement between DNCP and NCSEA regarding DNCP's TOU rate offerings shall be, and is hereby, approved.

22. That the Company shall file an Average and Excess cost allocation methodology in its next North Carolina general rate case, in addition to the cost allocation methodology proposed by the Company.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd of December, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

NORTH
CAROLINA
UTILITIES
COMMISSION

Volume II

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ONE-HUNDRED SIXTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume II

ISSUED FROM
JANUARY 1, 2016 THROUGH DECEMBER 31, 2016

ONE-HUNDRED SIXTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2016, through December 31, 2016

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

ToNola D. Brown-Bland, Commissioner

Don M. Bailey, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

*Lyons Gray, Commissioner

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*Lyons Gray, appointed January 26, 2016, replacing Susan W. Rabon

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DOCKET NO. E-22, SUB 517

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application by Virginia Electric and Power	)	ORDER APPROVING AMENDED
Company, d/b/a Dominion North Carolina	)	SCHEDULE NS AND DENYING
Power, for Approval of Amended Schedule	)	DEFERRAL ACCOUNTING
NS	)	

HEARD: Monday, June 15, 2015, Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Bryan E. Beatty, Susan W. Rabon, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Dominion North Carolina Power, Inc.:

E. Brett Breitschwerdt, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For Carolina Industrial Group For Fair Utility Rates I:

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

For the Using and Consuming Public:

Dianna W. Downey, Robert S. Gillam, Staff Attorneys, Public Staff − North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On December 22, 2014, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or the Company) filed, in this docket, an Application to Amend Schedule NS and Notice of Extension of Electric Supply Agreement Between DNCP and Nucor Steel-Hertford (Application).

On January 2, 2015, Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed a petition to intervene. Such petition was granted by Order issued January 6, 2015.

On January 30, 2015, DNCP filed a letter describing a modified plan for implementation of the new Schedule NS rates.

On February 24, 2015, the Public Staff – North Carolina Utilities Commission (Public Staff) filed comments and recommendations regarding DNCP's Application. Also on February 24, 2015, CIGFUR filed a letter in support of the Public Staff's comments and recommendations.

On March 10, 2015, DNCP filed reply comments to the Public Staff's comments and recommendations.

On April 29, 2015, the Commission issued an Order provisionally approving amended Schedule NS and scheduling oral argument.

On May 4, 2015, the Company made a compliance filing, submitting amended Schedule NS to become provisionally effective for usage on and after January 1, 2015.

On May 18, 2015, the Public Staff filed a notice of review and recommendation.

The oral argument was held on June 15, 2015 as scheduled. DNCP, the Public Staff, and CIGFUR (collectively, the Parties) appeared at the oral argument.

On June 19, 2015, the Public Staff submitted a late-filed exhibit (Late-Filed Exhibit 1) showing the calculation and breakdown of the revenues projected to be produced as a result of the proposed new rates for Schedule NS and the Public Staff's recommendation as to each category of revenue.

On August 3, 2015, the Parties filed proposed orders, as allowed by the Commission's July 2, 2015 notice.

Based on the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. DNCP is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. DNCP is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina.

2. On December 22, 2012, in Docket No. E-22, Sub 479, the Commission issued its Order Granting General Rate Increase (2012 Rate Order). The 2012 Rate Order, among other things, approved adjusted base rates for all classifications of electric service provided by DNCP in North Carolina. One of the rate classifications approved by the 2012 Rate Order was Schedule NS. The sole customer served by DNCP under Schedule NS is Nucor Steel-Hertford (Nucor).

3. Nucor, not a party in this docket, is DNCP's largest industrial customer. Nucor has operated a steel recycling and plate manufacturing facility in Hertford County since 2000, and has received electric service from DNCP under a unique economic development rate (EDR) arrangement that, in part, recognizes the curtailable and interruptible nature of DNCP's service to

Nucor. Schedule NS and the underlying Agreement for Electric Service between Nucor and DNCP (Agreement) have been reviewed and approved by the Commission in 1999, 2002, 2005, 2010, and, most recently, in the 2012 Rate Order.

4. As approved in DNCP's 2010 general rate case, Docket No. E-22, Sub 459, the initial term of the Nucor Agreement was extended through December 31, 2014.[1] On June 27, 2014, DNCP provided Nucor notice of termination of that extended Agreement at the end of its term on December 31, 2014.

5. DNCP and Nucor negotiated a revised Agreement in the summer and fall of 2014, prior to the termination of the then current Agreement. The negotiated revised Agreement does not materially modify the terms of the expired Agreement, except as to the rate to be charged for service and the term of the Agreement. The projected rate impact of the revised Agreement is to increase Nucor's rates for service by approximately $450,000 in 2015, an additional increase of approximately $225,000 in 2016 and again in 2017, based upon Nucor's test-period usage approved in the Commission's 2012 Rate Order. Nucor's annual cost of electricity during the 12-month test period ending December 31, 2011, presented in DNCP's 2012 base rate case, was approximately $44,000,000. Nucor's electricity usage has increased approximately 5% between the Company's most recent 2011 test year and calendar year 2014. The term of the revised Agreement extends until the earlier of December 31, 2019, or the effective date of rates established in the Company's next general rate case expected to be filed in 2016.

6. Amended Schedule NS and the underlying revised Agreement represent a just, reasonable, and nondiscriminatory rate for electric service to Nucor on and after January 1, 2015, and, as such, should be approved.

7. The Nucor-related incremental revenue at issue under amended Schedule NS is not unusual or extraordinary and thus the use of deferral accounting is not appropriate.

EVIDENCE AND CONCLUSIONS
FOR FINDINGS OF FACT NOS. 1 THROUGH 5

Findings of Fact Nos. 1 through 5 are essentially informational in nature and are uncontroverted. These findings of fact are supported by DNCP's Application, the Comments of the Public Staff, and the positions of the Parties during oral argument. The Commission also takes judicial notice of its 2012 Rate Order, as well as its prior Orders approving Schedule NS issued in Docket Nos. E-22, Sub 384, Sub 401, Sub 412, and Sub 459.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

This finding of fact is supported by the Company's Application and reply comments, the comments of the Public Staff, and the positions of the Parties during oral argument.

[1] Order Granting General Rate Increase, Approving Fuel Charge Adjustment, and Approving Stipulation and Supplemental Agreement, Docket No. E-22, Sub 459 (Dec. 13, 2010) (2010 Rate Order).

DNCP's Application explained that the initial term of the existing Agreement would end on December 31, 2014. After DNCP provided notice of termination of the existing Agreement to Nucor on June 27, 2014, the parties worked in good faith to evaluate new options for service to Nucor consistent with the Agreement. Article 7.a. of the Agreement provided Nucor the option to elect service under any available DNCP electric service tariff or to enter into good faith negotiations regarding an appropriate electric service agreement and firm level of demand.

At Nucor's election, DNCP commenced negotiations with Nucor. During negotiations, the parties discussed DNCP's cost to serve Nucor, as well as the value of Nucor's interruptible service to DNCP's total system and to the North Carolina jurisdiction. Although the parties considered a number of alternatives, they were unable to agree on a comprehensive revision to the existing Agreement. However, they did enter into a new Agreement, as of December 2014, representing an incremental step in an ongoing process of moving Nucor's base rates for service closer to meeting DNCP's fully distributed cost to serve Nucor.

DNCP maintained that Nucor was and is an important customer in North Carolina. DNCP further noted its contention that, as the Company continues to make major investments in its system for the benefit of all customers, Nucor's base rates should be designed to more fully recover what DNCP maintains to be DNCP's cost of service – similarly to the Company's other customer classes. DNCP's Application also recognized that Nucor does not agree with DNCP's view that Nucor's rates need to be increased in order to more appropriately recognize DNCP's cost to serve Nucor. The Application further noted that Nucor and DNCP continue to disagree on DNCP's cost to serve Nucor and the value of Nucor's interruptibility as they had in the 2012 base rate case, and that the Commission may be called on in the future to decide those issues just as it had done in its 2012 Rate Order, when it ultimately resolved the cost and value issues then in dispute.

In its Application, the Company requested that the negotiated revised Agreement become effective for service rendered on and after January 1, 2015.

The Public Staff's comments regarding the Application described the history of Schedule NS, stating that the terms and conditions of the new revised Agreement are very similar to those of the existing Agreement and that the terms are designed to reflect the unique nature of the electric service provided to Nucor. The Public Staff noted that the new Agreement will increase Nucor's base rates over three years beginning January 1, 2015. The Public Staff indicated that Schedule NS will continue to produce a rate of return on rate base (ROR) that is below DNCP's overall ROR for the Company's North Carolina retail jurisdiction, but nonetheless agreed with the Company that the new revised Agreement and amended Schedule NS represent progress in moving the Schedule NS ROR in the direction of the overall North Carolina retail ROR. The Public Staff recommended approval of amended Schedule NS and the new Agreement. However, the Public Staff also recommended that the Commission require DNCP to set aside in a deferred account the additional incremental revenue produced as a result of the increased rates in the amended Schedule NS.

In its reply comments, DNCP observed that no party has challenged the justness and reasonableness of amended Schedule NS and that Nucor, the only customer served under Schedule NS, had agreed to service under that Schedule. DNCP also reiterated that proposed amended Schedule NS and the underlying new revised Agreement represent an incremental and gradual step that moves Nucor's rates and charges closer to meeting what DNCP maintains to be DNCP's cost to provide electric service to Nucor.

At oral argument, CIGFUR generally expressed support for increasing the charges to Nucor under Schedule NS, as proposed, but did not address the justness and reasonableness of Schedule NS and the new revised Agreement for service to Nucor. CIGFUR's comments primarily focused on how the Commission should address the incremental revenue projected to be realized under amended Schedule NS.

Conclusions

Based upon the entire record, the Commission is of the opinion and, therefore, finds and concludes that Schedule NS, as provisionally approved April 29, 2015, *nunc pro tunc* for service rendered on and after January 1, 2015, is just and reasonable and, as such, should be approved as a finally-effective rate.

The Commission has reached the foregoing conclusion for the following reasons:

(a) No party disputes the Commission's authority to approve amended Schedule NS outside of a general rate case;

(b) DNCP, the Public Staff, and CIGFUR support the revisions to Schedule NS and the new revised Agreement, as does the Commission, for the reason that such revisions move Nucor's rates and charges closer to DNCP's fully distributed cost of service to Nucor;

(c) Nucor, while disagreeing with DNCP's views on the value of Nucor's interruptibility and its contribution to DNCP's cost of service, has agreed to amended Schedule NS and the new revised Agreement;

(d) No party has alleged that amended Schedule NS is unjust, unreasonable, or unlawfully discriminatory or that, as amended, Schedule NS does not benefit all ratepayers or fails to comply with existing applicable law prohibiting unjust discrimination and undue prejudice;

(e) No party has alleged or argued that the proposed amendments to Schedule NS change the benefits, rate structure, or terms and conditions such that they are no longer appropriately designed to address the unique operating conditions present at Nucor's facility; and

(f) To deny the request to approve the amended Schedule NS would serve as a disincentive to DNCP and Nucor to continue to work toward adjusting Nucor's rates and charges to allow DNCP to more fully recover its cost of service in line with its continued and new investments in its system, which investments benefit Nucor and all other customer classes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

This finding of fact is supported by the Company's Application and reply comments; the comments of the Public Staff; the positions of the Parties during oral argument; and the Public Staff's Late-Filed Exhibit 1. The Commission also takes judicial notice of the record in Docket No. E-22, Sub 519, DNCP's Application for an Accounting Order to Defer Certain Capital and Operating Costs associated with the Company's Warren County combined cycle (Warren County CC) plant addition, as the record in Sub 519 was relied upon by the Commission (as discussed hereinbelow) in this docket (Sub 517).

The Public Staff's comments expressed concern regarding the appropriateness of allowing DNCP to retain the additional revenue that will be realized under the new Agreement's base rates charged under amended Schedule NS. The Public Staff asserted that

> [a]mending base rates that were established for an existing customer in a general rate case, in which a utility's cost of service was examined in its totality and its revenue requirement was allocated among all customer classes, is different from approving new base rates to enable a utility to recover the costs associated with providing a new service or serving a new customer class, as in the case of Nucor in 1999. In the instant case, an existing customer has agreed to pay higher base rates than those established in the utility's most recent general rate case for the same level of service. Nothing in the Order approving current Schedule NS indicates that the Commission intended to allow termination of the Existing Agreement to upset the balance between revenues, expenses, and investment upon which DNCP's base rates were established. In the Public Staff's view, requiring DNCP to set aside the additional revenue produced based on the rate case assumptions, as described below, would preserve that balance and logically follows from approval of amended Schedule NS.

Consequently, the Public Staff recommended that DNCP should be required to defer the additional revenue realized by the Company (under amended Schedule NS − as applied to billing units from DNCP's last general rate case, Sub 479) until such time as this matter can be addressed in the Company's next general rate case.

The Public Staff observed that DNCP may argue that it should be permitted to retain the additional revenue because it is currently earning less than its authorized return. The Public Staff argued, however, that the Company's earnings are unrelated to the issue of whether it is appropriate for DNCP to retain the additional revenue in question outside of a general rate case.

CIGFUR agreed with and supported the Public Staff's view and recommendation regarding the appropriateness of the use of deferral accounting for additional revenue not approved in the most recent general rate case.

DNCP asserted, in reply comments, that the Public Staff's revenue-deferral recommendation was inconsistent with long-standing Commission policy and practice on deferral accounting and, as such, was inappropriate. The Company, in support of that view, argued that the

Commission, in the context of deferral, amortization, and prospective recovery of expenses incurred under certain circumstances, has long applied an established two-part test in determining whether the use of deferral accounting is justified. In particular, DNCP noted that the Commission's two-part test considers

(1) whether the costs in question are unusual or extraordinary in nature and

(2) whether, absent deferral, the costs would have a material impact on the Company's financial condition.

The Company commented that the Commission has a long history of allowing deferrals to mitigate the impact of regulatory lag to address unanticipated events (for example, significant storm restoration and repair costs) and large, material events (for example, construction of significant generating capacity) between rate cases. The Company maintained, however, that the Commission has never applied deferrals to account for minor variations in circumstances after a rate case, which according to DNCP, is what the Public Staff and CIGFUR are requesting here.

DNCP contended that the well-established, cost-deferral standards comprising the Commission's two-part test were equally applicable for use in determining the appropriateness of revenue-related deferrals. The Company requested that the Commission continue to apply such standards in an equitable and consistent manner in resolving the present issue.

The Company asserted that, under the Commission's two-part test, the adjustment to Schedule NS was not sufficiently unusual or extraordinary to satisfy the first part of the Commission's two-part test. DNCP observed that, as both the Company's Application and the Public Staff's comments noted, the December 31, 2014 termination date of the existing Nucor agreement's initial term had been contemplated since the Commission's Order in the Company's 2010 general rate case. Additionally, DNCP commented that, in fact, the Commission specifically stated in its 2010 Rate Order that, before any adjustment to the pricing methodology in the Agreement or any change to the term for service under Schedule NS is made, except as provided for in the Agreement, the Commission's approval must be obtained.[1]

DNCP further noted that, pursuant to the termination provision of the Nucor agreement, Nucor could elect to transition to an otherwise-existing rate schedule or could enter into good faith negotiations with DNCP regarding a new agreement for service. Thus, according to the Company, the revenue under then-existing Schedule NS was clearly contemplated to change – subject to Commission approval – upon termination of the pre-existing Nucor agreement at the end of the 2014 initial term.

DNCP further argued that the fact that the timing of the change associated with the new Agreement and amended Schedule NS would not line up perfectly with the filing of a general rate

[1] Order Granting General Rate Increase, Approving Fuel Charge Adjustment, and Approving Stipulation and Supplemental Agreement, Docket Nos. E-22, Sub 459 and 461, 47 (Dec. 13, 2010) (Ordering that "no change in the pricing methodology in the Amended Agreement on which Schedule NS has been based shall be made unless specifically allowed by this Commission nor shall the term of the Amended Agreement and Schedule NS be extended except as explicitly provided for in the Amended Agreement without prior approval of the Commission").

case demonstrated that the change was not extraordinary, but rather, was foreseeable (if not inevitable). Thus, a relatively modest adjustment to Schedule NS outside of a general rate case (in a complaint proceeding) − either upwards in this case or potentially downwards - according to the Company, is not extraordinary in nature.

Under the second part of the two-part test for deferral accounting, the Company asserted that the most obvious flaw in the Public Staff's and CIGFUR's position is that the Nucor-related revenue in question fails to meet the Commission's "materiality" standard. According to DNCP, the requested deferral would capture only approximately $450,000 of incremental revenue in 2015, which represents only 0.18% of DNCP's North Carolina retail jurisdictional non-fuel revenue requirement as established by the 2012 Rate Order.

DNCP further maintained that the aforesaid $450,000 equates to only a 6.5 basis-point impact on the Company's North Carolina retail jurisdictional rate of return on common equity and that no reasonable interpretation of the facts in this case can render the present amount "material" to either the Company or its customers when the Commission's prior precedent is fairly applied.

DNCP clarified its position, explaining that it is not arguing that all changes in revenue resulting from amendments of the Nucor Agreement and Schedule NS, without regard to the amounts, should be exempt from deferral. To the contrary, the Company indicated that it is of the opinion that, if a change is of a magnitude that it is truly material, it may be appropriate to consider use of deferral accounting. However, that issue is merely theoretical in the context of this proceeding, according to DNCP, because the $450,000 at issue (relative to a $238 million non-fuel jurisdictional revenue requirement) and the attendant 6.5 basis-point rate of return on equity impact are, in the Company's view, plainly immaterial to both the Company and its customers.

DNCP disagreed with the Public Staff's position that the Company's earnings are unrelated to the question of whether deferral is appropriate. DNCP explained that in addition to evaluating the materiality of the cost to be deferred, the Commission has also consistently evaluated the utility's experienced earnings as a proxy for its then-existing financial condition in determining whether, absent deferral, the utility would have a reasonable opportunity to earn its authorized rate of return on equity.

Pointing to its most recently filed NCUC ES-1 Reports (ES-1 Reports),[1] DNCP stated that the Company is currently earning below its authorized rate of return on equity, for service to Nucor specifically and for service to its entire customer base generally. Moreover, DNCP explained that it will very likely continue to under-earn its authorized rate of return on equity even if the Commission approves amended Schedule NS and denies the Public Staff's and CIGFUR's request for revenue deferral.

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[1] ES-1 Reports are submitted quarterly to the Commission by major electric utilities, including DNCP, in compliance with certain Commission reporting requirements associated with a long-standing, ongoing Commission surveillance program, which requires, among other things, the reporting of certain key financial benchmarks, including jurisdictional rate of return on equity.

At oral argument, the Public Staff reiterated its opinion that requiring deferral of the incremental revenue associated with the Nucor rate increase (1) would preserve the balance between revenue, expenses, and investment established in the Company's last general rate case and (2) would recognize that the Company's other ratepayers, not DNCP, have been subsidizing Nucor. The Public Staff further indicated that its deferral proposal would actually split the Nucor-related revenue increase between DNCP and the Company's other customer classes, as the determination of the revenue to be deferred would be based upon 2011 test-period billing units as adopted for use by the Commission in the context of DNCP's last general rate case.

The Public Staff also contended, during oral argument, that the Company's reliance on cost-related deferral cases, in this instance, is misplaced and that the issue of materiality or whether the change is extraordinary is irrelevant to the Commission's determination in this proceeding.

CIGFUR took the position that deferral was appropriate because Schedule NS, as approved in the 2012 Rate Order, was effectively a ratepayer-supplied subsidy to Nucor. CIGFUR indicated that allowing DNCP to keep the Nucor-related incremental revenue would result in DNCP being paid twice – once by Nucor and once by the Company's other ratepayers.

DNCP responded that deferral was inappropriate for three reasons:

First, the Company stated that the Commission's overarching task is to ensure that the Company's overall rates remain just and reasonable. DNCP pointed to its most recent ES-1 filings and rate of return on equity of 9.57% for the 12-month period ending December 31, 2014, and 8.66% for the 12-month period ending March 31, 2015. DNCP contended that, because it is under-earning its authorized 10.2% rate of return on equity, the Company is not receiving a subsidy, but rather, in fact, is receiving less revenue than was determined to be just and reasonable by the 2012 Rate Order.

Second, the Company contended that the Public Staff's theory that the correlation between revenue, expenses, and investments remained static and unchanging between rate cases could not be squared with the underlying principles of ratemaking. DNCP indicated that changes in revenue, expenses, and investments, including attendant relationships, have occurred routinely between the time the Company's rates were set in 2012 and the proposed effective date of the new Agreement, that is, January 1, 2015, and that, so long as the Company's overall rates remain just and reasonable, the cost of service impact of such changes should not be deferred, but rather, should be considered in the context of a future general rate case.

Third, DNCP reiterated that the Public Staff's recommendation does not meet the Commission's well-established test used in the past with regard to cost-related deferrals, that such test was equally applicable for use in determining the appropriateness of revenue-related deferrals, and that it would be consistent, fair, and equitable in this case for the Commission to apply that test.

DNCP also indicated that it would be fair to consider whether deferral of increased revenue associated with an extraordinary event was appropriate as an alternative interim step to an investigation of the utility's rates as unjust and unreasonable. The Company further asserted that the increase in revenue in the instant case is not material when the Commission's deferral standard is considered and therefore should not be deferred, but rather, should be considered in the context of a future general rate case.

Thus, the major issue before the Commission in this docket is whether DNCP should be required to defer a portion of the incremental revenue realized under amended Schedule NS and the new revised Agreement until such time as the Company's next general rate case, as recommended by the Public Staff and CIGFUR (hereafter, collectively, the Intervenors).

Discussion and Conclusions

As discussed below, the Commission is not persuaded that it should require deferral of the incremental revenue realized by DNCP under Schedule NS, as it was amended by agreement of Nucor and DNCP and filed by DNCP with the Commission on December 22, 2014. Accordingly, the Commission does not accept and will not allow the Public Staff's recommendation for revenue deferral.

Deferral accounting, moving the recognition of costs or revenue from one period to a future period, is not in keeping with the general principles of ratemaking and should be used sparingly on those rare occasions when clearly justified. Pursuant to N.C.G.S 62-133, future rates are to be fixed on the basis of the 12-month historical test period prior to the date new rates are to go into effect. Revenues and costs from outside that specific historical test period (except for limited changes allowed by statute) are not to be considered in fixing future rates, which is another way of saying they are not to be used in determining a utility's future revenue requirement. Where revenue or cost deferral is allowed on the Commission's authority, it creates an exception that allows revenue or costs outside the test year to be transferred to a future period and considered in determining the future revenue requirement that will be used to fix future rates. Thus, deferral accounting should be allowed sparingly and on a limited basis because it can, and often does, affect rates in future periods. Deferrals of increased or decreased costs result in customers being charged or benefitted, respectively, in future periods for spending experiences associated with providing service in earlier periods, while deferrals of increased or decreased revenues result in customers benefitting or being charged, respectively, in future periods for receipt of income by the utility associated with providing service in earlier periods.

Because deferral accounting is appropriately used only sparingly, the Commission has required that deferrals be justified on the basis of an unusual or extraordinary event or change of circumstance. Out-of-period items of revenue or cost should not be deferred, i.e., considered outside the historic test year period when fixing future rates, unless such out-of-period items are unusual or extraordinary. Revenues or costs can be unusual or extraordinary either because of their occurrence or size or both. The issue of whether an event or change results in revenues or costs that would materially impact a utility's financial condition, while in some cases may be dispositive, it is secondary to the first prong of the test historically relied on by the Commission to determine whether deferral accounting should be permitted or required. If it is determined that the subject of a deferral request is not unusual or extraordinary, that decision is dispositive and the materiality issue is not reached.

Under the Uniform Systems of Accounts, adopted by the Commission for electric utilities, extraordinary items are generally those that are unusual, unexpected, and that would not be expected to recur or be recurring factors in the ordinary normal operation of business. Extraordinary events or occurrences are unique in nature. In the case at hand, neither the amendment to Schedule NS, nor the fact of an increase in the rates under the Schedule, nor the size or amount of additional revenue that will be received by the Company as a result of the increase under the Schedule is extraordinary. In fact, no party argued to the Commission that the rate increase under the amended Schedule is in any way unusual or extraordinary.

It is clear that the Commission knew when it issued its 2010 Rate Order[1] that the initial term of the Company's Agreement with Nucor could terminate on December 31, 2014 and that the Company and Nucor could negotiate a new or revised Agreement that would modify both the term of Agreement and the prices charged to Nucor for service under Schedule NS. Contemplating, among other things, that such possible modifications could cause changes in revenue, the Commission provided in its Order that its prior approval would need to be obtained prior to such modifications becoming effective. At the time the 2010 Rate Order was approved it was not unexpected that the termination and possible renegotiation of the existing Agreement might occur at a time outside of a general rate case. Having contemplated these changes and the relative possible timing of these changes in 2010, the Commission certainly contemplated the same when it issued its 2012 Rate Order.[2] Moreover, the Commission is of the opinion that the size of the change in revenue resulting from the revised Agreement and the amended Schedule NS is not extraordinary. With respect to deferral accounting, under the guidance of the Uniform System of Accounts adopted by this Commission for electric utilities, unless the Commission decides otherwise, an item representing more than 5% percent of a utility's income is generally considered to be extraordinary.[3] The Company has pointed out that the $450,000 of 2015 incremental revenue subject to the deferral request at issue is no more than 0.18% of the Company's North Carolina jurisdictional non-fuel revenue requirement established in the 2012 Rate Order.

Finally, in the Commission's view, the contemplated and expected change in revenue (both in occurrence and size) that will result from the negotiated prices charged under Schedule NS represents a change that is in the same nature of the changes in revenues, expenses, and investments that happen routinely between the time a utility's rates are fixed by the Commission and the time of the next general rate case for that utility. In other words, under ratemaking principles long

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[1] E-22, Subs 459 and 461 (December 13, 2010).

[2] E-22, Sub 479 (December 21, 2012).

[3] 18 CFR Pt. 101, FERC Uniform System of Accounts, General Instruction 7, Extraordinary Items.

accepted by this Commission, such routine changes alone do not result in a change in the balance of revenues, expenses and investments struck by the Commission's last rate order which justifies deferral accounting. The Commission remains of the opinion it had when it issued the 2012 Rate Order that the Company's overall rates are just and reasonable and the contemplated additional revenues resulting from the changes in Schedule NS do not change that opinion.

Where, in contrast to this Sub 517 proceeding, the Company's earnings were addressed exhaustively in Docket No. E-22, Sub 519 in which the Company sought a cost deferral for costs associated with its Warren County CC plant addition, and as the deferral requests in the two dockets, generally speaking, concerned approximately the same timeframes, the Commission herein relies extensively upon earnings data from the Sub 519 proceeding.

Based upon information of record in Sub 519 for the 12-month period ending December 31, 2014, the Commission found that it was reasonable to conclude that DNCP's ongoing rate of return on equity of 11.57%,[1] on or about such time, could reasonably be expected to be approximately 11.10% after taking into account the 0.47%[2] pro forma effect of the Warren County CC addition to utility plant in service, and that the expected ongoing rate of return on equity of 11.19%,[3] based upon the 12-month period ending March 31, 2015, would appear to be approximately 10.72%, after considering the pro forma effect of the Warren County CC plant addition.

In consideration of the foregoing and other information of record, the Commission ruled in Sub 519, by Order issued concurrent herewith, that the facts and circumstances of record did not indicate that the effect of DNCP's having placed the Warren County CC into service created a financial emergency or other circumstance that would warrant approval of the Company's Warren County CC cost-related deferral request. Accordingly, the Commission denied the Company's request.

No party in Sub 519 argued that the projected ongoing ROEs of 11.10% or 10.72% exceeded the bounds of reasonableness. The rate of return on equity impact of the Nucor-related revenue at issue, in this docket, is 0.065%. Thus, the pro forma effect of the Nucor-related revenue in question would be to increase the Company's expected ongoing December 31, 2014-based rate of return on equity from 11.10% to 11.165% and the expected ongoing March 31, 2015-based rate of return on equity from 10.72% to 10.785%.

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[1] See Order Denying Deferral Accounting for Warren County CC (issued concurrent with this Order), Docket No. E-22, Sub 519, Page 23, Table C, Column (d), Line 2.

[2] The pro forma rate of return on equity impact of the costs associated with Warren County equates to a reduction of 47 basis points, according to the Public Staff, and 50 basis points, according to the Company.

[3] See Order Denying Deferral Accounting for Warren County CC (issued concurrent with this Order), Docket No. E-22, Sub 519, Page 23, Table C, Column (d), Line 3.

Those effects, in the Commission's opinion, are not so great as to justify a determination that the additional incremental revenue that is the subject of the Intervenors' revenue-related deferral request is extraordinary, particularly when considered in light of DNCP's 10.2% authorized rate of return on equity and the fact that current economic conditions do not appear to be significantly different from those that existed at the time the authorized rate of return on equity was established. Thus, deferral is not required to preserve the balance between revenue, expenses, and investment upon which DNCP's base rates were established.

Having determined that neither the amendment to Schedule NS, nor the fact of an increase in the rates under the Schedule, nor the size or amount of additional revenue that will be received by the Company as a result of the increase under the Schedule is extraordinary, the Commission is of the opinion and, therefore, finds and concludes that the Intervenors' recommendation that DNCP should be required to defer certain Nucor-related incremental revenue should be denied.

IT IS, THEREFORE, ORDERED as follows:

1. That the new Agreement between DNCP and Nucor and amended Schedule NS shall be, and are hereby, approved for service provided on and after January 1, 2015.

2. That the recommendation that DNCP be required to defer certain additional revenue realized under the new Agreement and amended Schedule NS shall be, and is hereby, denied.

3. That DNCP shall be, and is hereby, authorized to retain all revenue collected under provisionally-approved Schedule NS *nunc pro tunc* back to January 1, 2015.

4. That this Order shall be, and is hereby, entered without prejudice to the right of any party to take issue with the treatment accorded the revenues and costs associated with serving Nucor in future regulatory proceedings.

5. That no provision of this Order is intended, and/or is to be construed, to preclude the Commission from revisiting the issue of the need for the creation of a Nucor revenue-related regulatory liability to the extent that undue time passes without DNCP's having filed an application for a general rate increase.

ISSUED BY ORDER OF THE COMMISSION.
This the __29th__ day of March, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Commissioner Susan W. Rabon resigned from the Commission, effective December 31, 2015, and therefore, did not participate in this decision.

DOCKET NO. E-22, SUB 536

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application by Virginia Electric and Power Company d/b/a Dominion North Carolina Power for Approval of Demand Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	)))))	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD: Monday, November 7, 2016, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chairman Edward S. Finley, Jr.; Commissioners Bryan E. Beatty, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

FOR DOMINION NORTH CAROLINA POWER:

E. Brett Breitschwerdt, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

FOR THE USING AND CONSUMING PUBLIC:

David T. Drooz, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management and energy efficiency (DSM/EE) programs. In accordance with Commission Rule R8-69(b), such rider consists of the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and a DSM/EE experience modification factor (DSM/EE EMF) rider to collect or refund the difference between the utility's actual reasonable and prudent costs incurred during the test period and actual revenues realized during the test period under the DSM/EE rider then in effect. The Commission is also authorized to award incentives to electric utilities for adopting and implementing new DSM/EE programs, including appropriate rewards based on the sharing of savings achieved by the programs. These utility incentives are included in the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and DSM/EE EMF riders described above.

Further, Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover DSM/EE related costs and utility incentives. Commission Rule R8-69(e) provides that the annual DSM/EE cost recovery rider hearing for each public utility will be scheduled as soon as practicable after the annual fuel and fuel-related charge adjustment proceeding held by the Commission for the electric public utility under Commission Rule R8-55.

On August 16, 2016, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or the Company), filed in this docket its Application for Approval of Cost Recovery for Demand-Side Management and Energy Efficiency Measures (Application), seeking approval of new DSM/EE rider rates to recover the Company’s reasonable and prudent DSM/EE costs, common costs, taxes, net lost revenues (NLR), and a DSM/EE Program Performance Incentive (PPI).

Pertinent Proceedings in Prior Dockets

The Commission most recently approved DNCP’s recovery of its reasonable and prudent DSM/EE costs and utility incentives by Order issued on December 14, 2015, in Docket No. E-22, Sub 524 (2015 Order).

On October 14, 2011, in Docket No. E-22, Sub 464, the Commission issued its Order Approving Agreement and Stipulation of Settlement, Approving DSM/EE Rider, and Requiring Compliance Filing (2010 Cost Recovery Order). In the 2010 Cost Recovery Order, the Commission approved the Agreement and Stipulation of Settlement between the Public Staff and the Company (Stipulation), filed on March 2, 2011, as well as the Cost Recovery and Incentive Mechanism (Mechanism), attached as Stipulation Exhibit 1 to the Stipulation (collectively, Stipulation and Mechanism).

On December 13, 2011, in Docket No. E-22, Sub 473, the Commission issued its Order Approving DSM/EE Rider and Requiring Customer Notice in DNCP’s 2011 DSM/EE cost recovery proceeding (2011 Cost Recovery Order). The 2011 Cost Recovery Order also approved a first Addendum to the Stipulation and Mechanism (Addendum I) related to jurisdictional allocation of DSM/EE costs. Addendum I was then incorporated as part of the Stipulation and Mechanism.

On April 29, 2013, in Docket No. E-22, Sub 486, the Commission issued its Order Granting Conditional Approval of Cost Assignment Proposal that approved a cost assignment methodology for allocating 100% of the incremental costs of DNCP's prospective North Carolina-only Commercial Lighting Program and HVAC Upgrade Program to the North Carolina retail jurisdiction. On December 18, 2013, in Docket No. E22, Sub 494, the Commission approved this cost assignment methodology for programs offered only in North Carolina as the second Addendum to the Stipulation and Mechanism (Addendum II). Addendum II was then incorporated as part of the Stipulation and Mechanism.

On May 7, 2015, in Docket No. E-22, Sub 464, the Commission also issued its Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waiver (Order on Revised Mechanism). The Order on Revised Mechanism approved an updated Cost Recovery and Incentive Mechanism for Demand Side Management and Energy Efficiency Programs (Revised

Mechanism).The Revised Mechanism is effective for projected DSM/EE costs and utility incentives on and after January 1, 2016, and for true-up of DSM/EE costs and utility incentives for the period beginning July 1, 2014, through December 31, 2014, and on a lagging calendar year basis thereafter. The Revised Mechanism replaced the original Mechanism that had been in effect since 2011.

Proceedings in the Present Docket

On August 16, 2016, DNCP filed its Application for Approval of Cost Recovery for Demand-Side Management Programs and Energy Efficiency Measures consisting of the direct testimony of Michael T. Hubbard, and the direct testimonies and exhibits of Deanna R. Kesler, Jarvis E. Bates, C. Alan Givens, Melba L. Lyons, and Debra A. Stephens. In summary, DNCP's Application seeks recovery of DNCP's reasonable and appropriate estimate of expenses and utility incentives expected to be incurred during the rate period, Rider C, and a DSM/EE EMF rider, Rider CE, to collect or refund the difference between DNCP's actual reasonable and prudent costs and utility incentives incurred during the test period and actual revenues realized during the test period under the DSM/EE rider presently in effect.

On August 25, 2016, DNCP filed corrections to Appendices A, B, and C of its April 1, 2016 Evaluation, Measurement, and Verification Report.

On August 31, 2016, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. Pursuant to this Order, the Commission established deadlines for the filing of petitions to intervene, intervenor testimony and exhibits, and Company rebuttal testimony and exhibits, scheduled a public witness and expert witness hearing to be held on Monday, November 7, 2016, in Raleigh, North Carolina, and required DNCP to publish a customer notice.

On October 20, 2016, DNCP filed a corrected Schedule 2, page 3 of 6, for Exhibit DRK-1.

On October 24, 2016, the Public Staff filed the affidavit of Jack L. Floyd, Engineer, Electric Division, and the affidavit and exhibit of Michael C. Maness, Assistant Director, Accounting Division. The intervention and participation in this docket by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). No other parties intervened or presented testimony in this docket.

On October 31, 2016, DNCP filed the rebuttal testimony of C. Alan Givens and accompanying exhibits.

On November 2, 2016, the Public Staff and DNCP filed a Joint Motion to excuse witnesses from appearing at the November 7, 2016, expert witness hearing, stating that they had reached agreement on all issues in this docket and had agreed to waive cross-examination of each other's witnesses. On November 3, 2016, the Commission issued an Order granting the Joint Motion.

On November 7, 2016, DNCP filed its Affidavit of Publication indicating that it had provided notice in newspapers of general circulation.

On November 7, 2016, the Commission held the public witness and expert witness hearing as scheduled. No public witnesses appeared at the hearing. DNCP's application and the testimony and exhibits of DNCP and the Public Staff were introduced into evidence and accepted by the Commission.

On December 2, 2016, the Public Staff filed a letter with the Commission stating that based on its detailed review of the costs of the portfolio of DSM/EE programs of DNCP incurred during the 12-month test period ended December 31, 2015, the Public Staff did not recommend any adjustments to those costs.

On December 2, 2016, DNCP and the Public Staff filed a Joint Proposed Order.

Based upon DNCP’s application, the testimony, affidavits, and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Virginia Electric and Power Company (VEPCO) operates in the State of North Carolina as DNCP. VEPCO, d/b/a DNCP, is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility.

2. DNCP is lawfully before the Commission based upon its Application filed pursuant to G.S. 62-133.9 and Commission Rule R8-69.

3. Pursuant to the Revised Mechanism, the rate period for purposes of this proceeding is the 12-month period of January 1, 2017, through December 31, 2017.

4. Pursuant to the Revised Mechanism, the test period for purposes of this proceeding is the 12-month period of January 1, 2015, through December 31, 2015.

5. DNCP has requested rate period recovery of costs and utility incentives (NLR and PPI) related to the following approved DSM/EE Programs: (a) Phase I Air Conditioner Cycling Program; (b) Phase II DSM/EE programs: Non-residential Energy Audit Program, Non-residential Duct Testing and Sealing Program, Residential Home Energy Check-Up Program, Residential Duct Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program; (c) Phase III DSM/EE programs: Non-residential Lighting Systems and Controls Program, Non-residential Heating & Cooling Efficiency Program, and Non-residential Window Film Program; and (d) the Phase IV Income and Age Qualifying Home Improvement Program.

6. The Company has not included the projected costs and utility incentives for deploying the now-approved Small Business Improvement Program during the rate period in its proposed Rider C revenue requirement calculation. The costs associated with offering

this new Program will be submitted for recovery in a future proceeding through the Company's DSM/EE EMF, Rider CE.

7. In addition, DNCP has requested test period recovery of costs and utility incentives related to the following approved DSM/EE Programs: Residential Low Income Program, Commercial Lighting Program, Commercial HVAC Program, Air Conditioner Cycling Program, Residential Heat Pump Tune Up Program, Residential Heat Pump Upgrade Program, Residential Home Energy Check Up Program, Residential Duct Sealing Program, Nonresidential Duct Testing and Sealing Program, Non-residential Energy Audit Program, Non-residential Heating and Cooling Efficiency Program, Nonresidential Lighting Systems and Controls Program, and the Non-residential Window Film Program.

8. Recovery of DNCP's forecasted DSM/EE program costs, common costs, NLR, and PPI, as well as a true-up of DNCP's test period DSM/EE program costs, common costs, NLR, and PPI, is subject to the terms of the Revised Mechanism. DNCP should be allowed to recover its projected rate period and actual test period costs and utility incentives associated with offering each of its approved programs as requested in its Application. The requested cost recovery of program costs, common costs, NLR, and PPI is reasonable and consistent with the Revised Mechanism previously approved by the Commission.

9. DNCP is not seeking recovery of projected period NLR in Rider C, and its request to true up NLR in Rider CE in future proceedings is reasonable.

10. DNCP's proposed North Carolina retail DSM/EE Rider C rate period revenue requirement of $1,851,369, consisting of DSM/EE program costs, common costs, and a PPI, is reasonable.

11. For purposes of determining its DSM/EE EMF, Rider CE, DNCP's reasonable and prudent North Carolina retail total revenue requirement for the DSM/EE EMF test period, consisting of DSM/EE program costs, common costs, and utility incentives, is ($77,720). This DSM/EE EMF refund includes interest of 10% on the overrecovery amount, as contemplated by Commission RuleR8-69(b)(3) and the Revised Mechanism.

12. Rider C is reasonable and appropriate, and consists of the following customer class billing factors: Residential – 0.065 ¢/kWh; Small General Service and Public Authority – 0.062 ¢/kWh; Large General Service – 0.056 ¢/kWh; and no charge for 6VP, NS, Outdoor Lighting, and Traffic Lighting. It is reasonable and appropriate for Rider C to become effective for usage on and after January 1, 2017. The impact of the 2016 change in the regulatory fee is too small to change these billing factors.

13. Rider CE is reasonable and appropriate, and consists of the following decrements to customer class billing factors: Residential – (0.003) ¢/kWh; Small General Service and Public Authority – (0.002) ¢/kWh; Large General Service – (0.002) ¢/kWh; and no charge for 6VP, NS, Outdoor Lighting, and Traffic Lighting. It is reasonable and appropriate for Rider CE to become effective for usage on and after January 1, 2017. The impact of the 2016 change in the regulatory fee is too small to change these billing factors.

14. DNCP requested the recovery of NLR in the amount of $320,562 and PPI in the amount of $169,893 for the test period, and a projected PPI of $206,086, but no NLR for the rate period. DNCP's calculation and proposed recovery of NLR and a PPI is consistent with the Revised Mechanism, and is appropriate for recovery in this proceeding.

15. The jurisdictional and customer class cost allocations for Rider C and Rider CE included in the testimony and exhibits of Company witness Lyons are acceptable for purposes of this proceeding and are consistent with the Revised Mechanism.

16. DNCP satisfactorily explained its consumer education and awareness activities and the volume of activity associated with such initiatives during the test period, as directed by the Commission in the 2015 Order. It is appropriate for DNCP to continue to provide such information to the Commission in future rider proceedings.

17. The evaluation, measurement, and verification (EM&V) analyses and reports prepared by DNCP are reasonable for purposes of this proceeding. The EM&V data provided by DNCP and reviewed by the Public Staff for vintage year 2015 and earlier vintages are sufficient to consider those vintage years complete for all programs operating in those years.

18. Company witness Hubbard stated that DNCP was finalizing its program design for a North Carolina-only residential LED lighting program. In the 2015 Order, the Commission directed that DNCP determine whether a residential LED lighting program or lighting measures as a component of a new residential EE program would be cost effective and, if so, develop such a program as soon as feasible. DNCP has filed for approval of a North Carolina-only residential LED lighting program in Docket No. E-22, Sub 539, filed on October 31, 2016.

19. Public Staff witness Floyd noted that in separate dockets the Public Staff did not oppose the closure of certain Phase II programs and suspension of the Residential Heat Pump Upgrade program. However, he recommended that in the future the Company should strive to bring DSM/EE programs to North Carolina as soon as possible after their approval in Virginia, and that if a system-wide program is closed in Virginia, the Company should evaluate whether the program could be operated cost effectively on a North Carolina-only basis. The Commission finds that this recommendation is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The rate period and test period used by DNCP are consistent with the Revised Mechanism approved by the Commission in Docket No. E22, Sub 464, and with Commission Rule R8-69.

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

The evidence for these findings of fact is contained in DNCP's Application, the direct testimony and exhibits of Company witnesses Hubbard, Kesler, Bates, and Givens, the rebuttal testimony and exhibits of witness Givens, and the affidavits of Public Staff witnesses Floyd and Maness.

Company witness Givens testified that he included in the Rider C (rate period) revenue requirement certain projected costs associated with: (a) Phase I Air Conditioner Cycling Program; (b) Phase II DSM/EE programs: Non-residential Energy Audit Program, Non-residential Duct Testing & Sealing Program, Residential Home Energy Check-Up Program, Residential Duct Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program; (c) Phase III DSM/EE programs: Nonresidential Lighting Systems and Controls Program, Non-residential Heating and Cooling Efficiency Program, and Non-residential Window Film Program; (d) the Phase IV Income and Age Qualifying Home Improvement Program; and (e) the proposed[1] Phase V Small Business Improvement Program. Witness Givens also testified that he incorporated the projected PPI amounts provided by Company witness Bates in his development of the Rider C revenue requirement.

As noted in the affidavits of Public Staff witnesses Floyd and Maness, the projected costs associated with the Small Business Improvement Program were inadvertently excluded from the Rider C revenue requirement calculation. The Company plans to seek recovery of those costs in a future proceeding through its DSM/EE EMF (Rider CE).

Company witness Givens also testified that the Rider CE revenue requirement in the present case includes true-up for the Phase I, Phase II, and Phase III programs during the January 1, 2015, to December 31, 2015, test period, incorporating actual costs, NLR, and PPI. As mentioned in the testimony of Company witness Hubbard, the Phase I programs included Residential Low Income, Residential Lighting, Commercial HVAC Upgrade, and Commercial Lighting (all now closed) as well as the ongoing Residential Air Conditioner Cycling program.

Company witness Bates identified and explained the nature of common costs that are incurred to support DSM/EE programs generally, but are not tied to specific programs.

Public Staff witness Floyd concurred with the programs listed by DNCP for cost and incentive recovery in this proceeding.

Company witness Kesler presented testimony and exhibits setting forth the Company's estimated Utility Cost Test (UCT) and Total Resource Cost (TRC) test results for vintage year 2017 for (1) the active DSM and EE programs that are not subject to closure or suspension, and (2) the proposed Small Business Improvement Program. As shown on her exhibits, all programs have TRC results above 1.0, indicating cost effectiveness, with the exception of the Residential Income and Age Qualifying Home Improvement Program. All programs have UCT results above 1.0, with the exception of the Residential Income and Age Qualifying Home Improvement

[1] This Program was approved by Commission order dated October 26, 2016, in Docket No. E22, Sub 538.

Program and the Residential Air Conditioner Cycling program. Witness Kesler testified that DNCP would not be seeking PPI for those two programs.

Public Staff witness Floyd observed that over the last few DSM/EE rider proceedings the Residential Air Conditioner Cycling Program has been marginally cost effective under the TRC, and at times has struggled to be cost effective under the UCT. He stated the Public Staff plans to discuss this with DNCP to gain a better understanding of how this and other DSM programs are incorporated into the Company's Integrated Resource Plan. Witness Floyd also stated that the Company's cost effectiveness calculations had been performed in accordance with the Revised Mechanism.

Company witness Hubbard also testified that DNCP has not projected NLR for the rate period, consistent with its approach in the 2014 and 2015 DSM/EE cost recovery riders. He proposed to true-up NLR in future proceedings. Witness Hubbard also stated that the Company had not identified any found revenues. The Commission finds the DNCP approach to recovery of NLR, and the lack of found revenues, to be reasonable in this proceeding.

Consistent with the Commission's previous orders approving DNCP's DSM/EE programs and the evidence in the record, the Commission finds and concludes that DNCP should be allowed to recover its projected rate period and actual test period costs and utility incentives (NLR and PPI) associated with offering each of its approved Programs as requested in its Application and its direct and rebuttal testimony and exhibits. The Commission also finds and concludes that the requested cost recovery of program costs, common costs, NLR, and PPI is consistent with the Revised Mechanism previously approved by the Commission. Furthermore, the Commission finds and concludes that DNCP's request to true-up NLR in Rider CE in future proceedings is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-15

The evidence for these findings of fact is contained in the Company's Application; the direct testimony and exhibits of Company witnesses Hubbard, Kesler, Givens, Bates, Lyons, and Stephens; the corrected Schedule 2 of witness Kesler's Exhibit 1; the rebuttal testimony and exhibits of witness Givens; and the affidavit and exhibit of Public Staff witness Maness.

Company witness Bates determined the system-wide program and common costs for the DSM/EE programs in the rate period and in the test period. He also calculated the PPI for each program.

Company witness Lyons allocated the common costs among the DSM/EE programs. She then allocated a share of the system-wide program costs (including common costs as allocated to the individual programs) to the North Carolina retail jurisdiction. Pursuant to the Revised Mechanism, DSM costs were allocated on the basis of the Company's coincident peak[1], and

[1] To the extent the DNCP rate case in Docket No. E-22, Sub 532, results in a change to the coincident peak demand allocation factor, a corresponding adjustment will be made to the 2017 rate period costs in the 2017 DSM/EE rider proceeding.

EE costs were allocated on the basis of energy. Finally, witness Lyons allocated the North Carolina retail jurisdictional costs among the North Carolina retail customer classes pursuant to the methodology set out in the Revised Mechanism.

Company witness Givens used the operating expenses, capital costs, and PPI as provided by witness Bates, and as allocated jurisdictionally by witness Lyons, to develop a rate period revenue requirement for Rider C. He indicated the Company was not requesting any projected NLR amount be included in Rider C for recovery during the rate period. For capital costs, he used the same 6.53% depreciation rate from the 2015 DSM/EE rider proceeding, and used the 10.2% rate of return on common equity as a placeholder subject to true-up in a future DSM/EE EMF based on the rate of return on common equity that will be approved in the pending DNCP general rate case (Docket No. E22, Sub 532).

Likewise, witness Givens developed the test period true-up revenue requirement for Rider CE by comparing the test period actual revenues, received from the Company's accounting department, with the test period costs, NLR, and PPI, as provided by witness Bates and as allocated jurisdictionally by witness Lyons. For Rider CE, he determined the amount of NLR by taking the applicable non-fuel base rates provided by witness Stephens, and the jurisdictional energy savings as provided by witness Kesler, and then excluding lost revenues (1) outside the 36-month window established in the Revised Mechanism, and (2) already recognized through non-fuel base rates. Witness Kesler also determined the carrying costs on deferrals and the financing costs on overrecoveries.

Public Staff witness Maness testified that his investigation of DNCP's filing in this proceeding focused on determining whether the proposed DSM/EE and DSM/EE EMF billing rates were calculated in accordance with the Revised Mechanism, and otherwise adhered to sound ratemaking concepts and principles. He stated that among the other procedures performed by the Public Staff, the investigation included a review of the actual DSM/EE program costs incurred by DNCP during the 12-month period ended December 31, 2015, through the selection and review of a sample of source documentation for test year costs for which the Company seeks recovery. This process was intended to test whether the costs included by the Company in the DSM/EE billing rates are either valid costs of approved DSM and EE programs or administrative (common) costs supporting those programs.

Witness Maness testified that the Public Staff investigation of the Company's filing revealed certain minor issues and adjustments, which, at the time of the pre-filing of his affidavit, were either to be incorporated into the Company's rebuttal testimony as corrections or identified for true-up in a future DSM/EE rider proceeding. Subject to correction of the identified items, witness Maness testified that DNCP's calculations of the DSM/EE and DSM/EE EMF revenue requirements and Rider C and Rider CE were consistent with the Revised Mechanism, G.S. 62-133.9, and Commission Rule R8-69. However, he stated that this conclusion was subject to the caveat that the Public Staff was in the ongoing process of reviewing certain data responses received from the Company, including documentation of costs selected for review in the Public Staff's sample of test year program costs. Following the conclusion of its review, the Public Staff filed a letter with the Commission on December 2, 2016 stating that based on its detailed review of the costs of the portfolio of DSM/EE programs of DNCP incurred during the 12-month test period ended December 31, 2015, the Public Staff did not recommend any adjustments to those costs.

Finally, witness Maness noted that (1) the regulatory fee change from 0.148% to 0.140% on July 1, 2016 will not affect the billing factors; and (2) the scheduled to change from 4% to 3%, in the North Carolina state corporate income tax rate, effective January 1, 2017, may affect certain portions of the DSM/EE revenue requirement. He therefore recommended that the rate period revenue requirement calculations, along with the related billing rates, remain subject to true-up in future DSM/EE EMF Riders to reflect the tax rate change.

In his rebuttal testimony, witness Givens accepted the minor adjustments recommended by the Public Staff. These adjustments resulted in a $3,125 increase to the original Rider CE refund amount, but were too small to impact the billing factors.

On Exhibit CAG-1, Schedule 1, page 1, witness Givens calculated DNCP's requested North Carolina retail rate period (January 1, 2017, through December 31, 2017) revenue requirement (for Rider C) as follows:

1. Operating Expense	$1,473,724
2. Capital Cost	$ 171,560
3. NLR	$ 0
4. PPI	$ 206,086
5. Total	$1,851,369

On Company Exhibit CAG-1, Rebuttal Schedule 2, he calculated DNCP's requested North Carolina retail test period DSM/EE EMF (January 1, 2015, through December 31, 2015) revenue requirement (for Rider CE) as follows:

Operating expenses	$3,186,397
Capital costs (depr., rate base, prop. taxes)	$149,702
NLR	$320,561
PPI	$169,894
Test period Rider C revenues	($3,859,378)
Net revenue requirement subtotal	($32,824)
Carrying costs	($41,195)
Interest on EMF refund	($3,701)
Total Rider CE revenue requirement	($77,720)

Company witness Lyons, in Exhibit MLL-1, Schedule 3, pages 2 and 4, allocated the Rider C and initial Rider CE revenue requirement among the North Carolina retail customer classes. The results of her allocation for Rider C are shown below. Using the same methodology as used by witness Lyons, the Company allocated the revised Rider CE revenue requirement of $(77,720) as also shown below and set forth on Company Rebuttal Exhibit DAS-1, Schedule 4, page 1 of 2:

Rate Class	Rider C Amount	Rider CE Amount
Residential	$1,076,421	$(48,096)
SGS Co & Muni	$500,139	$(19,119)
LGS	$274,809	$(10,505)
6VP	$0	$0
NS	$0	$0
ST & Outdoor Lighting	$0	$0
Traffic Lighting	$0	$0

Company witness Stephens discussed how she calculated the Rider C and Rider CE rates proposed for the rate period. She determined the North Carolina retail forecasted net kWh sales for the rate period by revenue class, and further allocated those forecasted sales down to customer (rate) classes, less the kWh sales for customers who have opted out of the DSM/EE rider. Witness Stephens testified that she then divided the customer class revenue requirements by customer class forecasted kWh sales to calculate Rider C. She used the same methodology to calculate Rider CE for the test period.

Company witness Stephens also testified that she provided witness Givens with the monthly non-fuel average base rates for his use in determining lost revenues.

The Application, witness Stephens' Company Rebuttal Exhibit DAS-1, Schedule 1, page 10 and Schedule 4, page 2, and the rebuttal testimony and exhibits filed by witness Givens support the following customer class Rider C and Rider CE billing factors to be put into effect on January 1, 2017:

CUSTOMER CLASS	RIDER C RATE (cents/kWh)	RIDER CE RATE (cents/kWh)
Residential	0.065	(0.003)
Small General Service & Public Authority	0.062	(0.002)
Large General Service	0.056	(0.002)
6VP	0	0
NS	0	0

Outdoor Lighting	0	0
Traffic Lighting	0	0

The billing factors are unchanged by the regulatory fee change on July 1, 2016.

Based upon the evidence presented above and the entire record in this proceeding, the Commission finds and concludes that the DSM/EE EMF revenue requirement and proposed Rider CE billing factors to be charged during the rate period, as proposed in DNCP's direct and rebuttal filings, are appropriate. The Commission also finds and concludes that the projected DSM/EE rate period revenue requirement and Rider C billing factors to be charged during the rate period, as proposed in DNCP's direct and rebuttal filings, are appropriate. With regard to the requested recovery of NLR and PPI, the Commission finds and concludes that the amounts are appropriate for recovery in this proceeding and are calculated in a manner consistent with the Revised Mechanism. The Commission further notes that the change in the state corporate income tax rate could impact the revenue requirements determined in this proceeding, and, therefore, could potentially result in proposed adjustments to be addressed in a future DSM/EE EMF.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

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

In response to Ordering Paragraph No. 5 of the Commission's 2015 Order, Company witness Bates provided information on consumer education and awareness initiatives conducted by VEPCO's Energy Conservation (EC) department during the test period. He explained that most of the Company's communication and outreach activities are tied directly to specific DSM/EE programs, so actual costs for general education and awareness are limited. The EC department relies heavily on online tools for general education; the department's web pages received around 200,000 visits in the test period, and the web pages for the implementation contractor, Honeywell, also received over 82,000 visits. Other general education and awareness tools included use of social media and stories on local television stations.

The Public Staff did not oppose DNCP's consumer education and awareness activities or costs.

Based on the evidence presented above and all the information in the record, the Commission finds and concludes that DNCP's consumer education and awareness activities and costs are reasonable for purposes of this proceeding. Further, the Commission finds and concludes that the Company shall continue to include a list of consumer education and awareness activities and the volume of activity associated with each during the test period in its annual DSM/EE cost recovery filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence for this finding of fact is contained in the direct testimony of Company witness Kesler, the EM&V report filed by DNCP on April 1, 2016, in Docket No. E-22, Sub 524, and the affidavit of Public Staff witness Floyd.

Witness Kesler testified that the Company had included a chronology of changes to program attributes in its 2016 EM&V report for calendar year 2015, as recommended by the Public Staff. She further noted that DNCP plans to file its next EM&V report on May 1, 2017, to match filing requirements in Virginia.

Public Staff witness Floyd testified that he had reviewed DNCP's 2016 EM&V report for calendar year 2015 with the assistance of GDS Associates. He was of the opinion that the 2016 EM&V report for calendar year 2015 complied with previous Commission orders pertaining to EM&V. He testified that DNCP is appropriately incorporating the results of its EM&V efforts into the DSM/EE rider calculations, and that the EM&V for vintage year 2015 and earlier vintages could be considered complete.

Based upon the foregoing, the Commission finds and concludes that the EM&V analyses and reports prepared by DNCP are reasonable for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding is contained in the testimony of DNCP witness Hubbard. He testified that DNCP was finalizing the program design for a North Carolina-only point-of-sale Residential LED Lighting program. DNCP filed an application for this proposed program on October 31, 2016. If approved by the Commission, the costs of the program will be eligible to be considered for recovery in future DSM/EE rider proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding is contained in the testimony of Company witness Hubbard and the affidavit of Public Staff witness Floyd.

Witness Hubbard testified regarding the Company's motion in other dockets to close the Commercial Energy Audit, Commercial Duct Testing and Sealing, Residential Home Energy Check Up, Residential Heat Pump Tune-Up programs, and to suspend the Residential Heat Pump Upgrade and Residential Duct Sealing programs, effective February 7, 2017.[1]

Public Staff witness Floyd noted that in comments filed on October 21, 2016, the Public Staff did not oppose the Company's motion. However, he repeated the position of the Public Staff, as set out in its October 21, 2016, comments, that in the future the Company should strive to bring

[1] DNCP subsequently amended its motion to propose closure rather than suspension of the Residential Duct Testing and Sealing Program. The motion and amendment were filed in Docket Nos. E-22, Subs 495-500, and were approved by Order of the Commission issued on November 29, 2016.

DSM/EE programs to North Carolina as soon as possible after their approval in Virginia, and that if a system-wide program is closed in Virginia, the Company should evaluate whether the program could be operated cost effectively on a North Carolina-only basis.

The Commission concludes that the recommendations made by witness Floyd are reasonable.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate annual DSM/EE rider, Rider C, to become effective on and after January 1, 2017, consists of the following customer class billing factors increments (including Regulatory Fee): Residential – 0.065 ¢/kWh; Small General Service and Public Authority – 0.062 ¢/kWh; Large General Service – 0.056 ¢/kWh; and no charge for 6VP, NS, Outdoor Lighting and Traffic Lighting.

2. That the appropriate annual DSM/EE EMF rider, Rider CE, to become effective on and after January 1, 2017, consists of the following customer class decrement billing factors (including Regulatory Fee): Residential – (0.003) ¢/kWh; Small General Service and Public Authority – (0.002) ¢/kWh; Large General Service – (0.002) ¢/kWh; and no decrement for 6VP, NS, Outdoor Lighting and Traffic Lighting.

3. That DNCP 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 Nos. E-22, Subs 532, 534, and 535, and the Company shall file such notice for Commission approval as soon as practicable, but not later than three working days after the Commission issues the last of its orders in the above-referenced dockets.

4. That DNCP shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order as soon as practicable.

5. That DNCP shall continue to provide a listing of the Company's event sponsorship and consumer education and awareness initiatives during the test period in future DSM/EE rider proceedings.

6. That in the future, the Company should strive to bring DSM/EE programs to North Carolina as soon as reasonably possible after their approval in Virginia, and that if a system-wide program is closed in Virginia, the Company shall evaluate whether the program could be operated cost effectively on a North Carolina-only basis.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. E-7, SUB 1104

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	)	FUEL CHARGE
NCUC Rule R8-55 Relating to Fuel	)	ADJUSTMENT
and Fuel-Related Charge Adjustments	)	
for Electric Utilities	)	

HEARD: Tuesday, June 7, 2016, 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 Bryan E. Beatty, Commissioner ToNola D. Brown-Bland, Commissioner Don M. Bailey, Commissioner Jerry C. Dockham, Commissioner James G. Patterson and Commissioner Lyons Gray

APPEARANCES:

For Duke Energy Carolinas, LLC:

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

and

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Industrial Group for Fair Utility Rates III:

Adam Olls, Bailey & Dixon, L.L.P., 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, L.L.P., 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For North Carolina Sustainable Energy Association:

Michael Youth, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Antoinette Wike, Chief Counsel, Public Staff, North Carolina Utilities Commission, 430 N. Salisbury Street, 4326 MSC, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On March 9, 2016, 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 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Kim H. Smith, Swati V. Daji, Joseph A. Miller, Jr., T. Preston Gillespie, Jr., and David C. Culp.

Petitions to intervene were filed by the North Carolina Sustainable Energy Association (NCSEA) on March 10, 2016, by Carolina Industrial Group for Fair Utility Rates III (CIGFUR) on March 15, 2016, and by Carolina Utility Customers Association, Inc. (CUCA) on April 8, 2016. The Commission granted NCSEA's petition to intervene on March 15, 2016, CIGFUR's petition to intervene on March 16, 2016, and CUCA's petition to intervene on April 12, 2016. The North Carolina Attorney General's Office (AG) filed its notice of intervention on March 15, 2016.

On March 17, 2016, the Commission entered an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that direct testimony of intervenors should be filed on May 23, 2016, that rebuttal testimony should be filed on June 2, 2016, and that a hearing on this matter would be held on June 7, 2016.

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

On May 11, 2016, DEC filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

On May 23, 2016, the Public Staff filed the affidavits of Darlene P. Peedin and Jay B. Lucas.

On June 1, 2016, DEC and the Public Staff filed a motion requesting that all witnesses be excused from appearance at the evidentiary hearing. On June 3, 2016, the Commission granted the motion, excusing DEC witnesses Smith, Daji, Miller, Gillespie, and Culp, and Public Staff witnesses Peedin and Lucas from appearing at the evidentiary hearing and accepting their testimony and exhibits into evidence.

The case came on for hearing as scheduled on June 7, 2016. The prefiled direct testimony of DEC's witnesses and the prefiled affidavits and exhibits of the Public Staff's witnesses were received into evidence. Two exhibits offered by NCSEA were received into evidence by stipulation of the parties. No public witnesses appeared at the hearing.

The Public Staff and DEC filed a joint proposed order on July 1, 2016. NCSEA filed a post hearing brief on July 7, 2016.

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

FINDINGS OF FACT

1. Duke Energy Carolinas is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the 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 months ended December 31, 2015.

3. In its application and direct testimony in this proceeding, DEC requested a total decrease of $194.6 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEC included Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost over-recoveries experienced during the test period, with an overall over-recovery of $41.1 million. Interest applicable to the over-recovery is $6.9 million.

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

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

6. The Company's merger-related fuel savings for the test period as reported in Schedule 11 of the Company's Monthly Fuel Report are reasonable.

7. The test period per book system sales are 85,855,829 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 91,491,109 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	25,896,122
Natural Gas, Oil and Biomass	10,594,738
Nuclear	45,012,667
Hydro – Conventional	1,915,136
Hydro Pumped Storage	(778,969)
Solar DG	12,515
Purchased Power – subject to economic dispatch or curtailment	7,454,836
Other Purchased Power	1,548,866
Catawba Interchange	(164,802)
Total Net Generation	91,491,109

8. The appropriate nuclear capacity factor for use in this proceeding is 93.65%.

9. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 57,546,067 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	21,255,930
General Service/Lighting	23,144,221
Industrial	13,145,916
Total	57,546,067

10. The projected billing period (September 2016-August 2017) sales for use in this proceeding are 87,302,761 MWh on a system basis and 57,755,499 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,263,581
General Service/Lighting	23,335,364
Industrial	13,156,554
Total	57,755,499

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 93,867,520 MWh and is categorized as follows:

Generation Type	MWh
Coal	31,099,240
Gas Combustion Turbine (CT) and Combined Cycle (CC)	10,854,860
Nuclear	44,728,522
Hydro	1,682,372
Net Pumped Storage Hydro	(776,838)
Solar Distributed Generation (DG)	140,616
Purchased Power	6,138,748
Total	93,867,520

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

A. The coal fuel price is $27.51/MWh.
B. The gas CT and CC fuel price is $26.58/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $37,397,886.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.58/MWh.

E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $209,599,980.

F. System fuel expense recovered through intersystem sales is $26,569,895.

13. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,102,234,868.

14. The Company's North Carolina retail jurisdictional fuel and fuel-related expense over-collection for purposes of the EMF was $41.1 million, consisting of an over-recovery for the Residential, General service/lighting and Industrial classes of $9.9 million, $12.8 million and $18.4 million respectively. The over-collection resulted in interest of $6.9 million, consisting of $1.7 million, $2.1 million and $3.1 million for the Residential, General service/lighting and Industrial classes, respectively.

15. The decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1072, 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 that docket.

16. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.7555¢/kilowatt-hour (kWh) for the Residential class; 1.9247¢/kWh for the General Service/Lighting class; and 2.1287¢/kWh for the Industrial class.

17. The appropriate EMF decrements established in this proceeding, excluding the regulatory fee, are as follows: (0.0464)¢/kWh for the Residential class; (0.0553)¢/kWh for the General Service/Lighting class; and (0.1406)¢/kWh for the Industrial class.

18. The appropriate EMF interest decrements established in this proceeding, excluding the regulatory fee, are as follows: (0.0077)¢/kWh for the Residential class; (0.0092)¢/kWh for the General Service/Lighting class; and (0.0234)¢/kWh for the Industrial class.

19. The total net fuel and fuel-related costs factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.7014¢/kWh for the Residential class; 1.8602¢/kWh for the General Service/Lighting class; and 1.9647¢/kWh for the Industrial class.

20. The base fuel and fuel-related costs as approved in Docket No. E-7, Sub 1026 of 2.3182¢/kWh will be adjusted by amounts equal to (0.5627)¢/kWh, (0.3935)¢/kWh, and (0.1895)¢/kWh for the Residential, General Service/Lighting and Industrial customer classes, respectively. The resulting approved fuel and fuel-related costs will be further adjusted by EMF and EMF interest decrements totaling (0.0541)¢/kWh, (0.0645)¢/kWh, and (0.1640)¢/kWh for the Residential, General Service/Lighting and Industrial customer classes, respectively.

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 cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending December 31st as the test period for DEC. The Company's filing in this proceeding was based on the 12 months ended December 31, 2015.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the testimony of Company witnesses Gillespie and Miller and the affidavit of Public Staff witness Lucas.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Gillespie testified that the Company's seven nuclear units operated at a system average capacity factor of 95.68% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 93.91%, exceeded the five-year industry weighted average capacity factor of 87.80% for the period 2010-2014 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Witness Gillespie testified that for the 16th consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, ending the year, which included four refueling outages, with an average of 95.68%. For continuous operating days, Catawba Unit 1 achieved a run of 511 days and Unit 2 achieved a run of 497 days. Oconee achieved the third longest triple unit continuous run of 172 days, and had the highest capacity factor within the fleet at 98.06%.

Witness Gillespie testified that there were four refueling and maintenance outages during the test period beginning with the spring 2015 refueling and maintenance outage on Catawba Unit 2. Along with refueling, major work efforts included performing a 10-year reactor vessel in-service inspection, post-Fukushima tie-ins on the safety injection and auxiliary feed water lines, 100% Eddy Current Testing of all steam generator tubes, and power backbone tie-ins for several essential motor control centers. Motor replacements were completed for the 2D reactor coolant and 2A service water pumps. In addition, four sections of main feedwater piping were replaced to address flow accelerated corrosion issues. A required increase of five days over the outage allocation was required most predominantly as a result of emergency work to address low oil pressure on the main turbine oil pump. In total, DEC successfully completed 12,209 work order tasks within this outage.

Company witness Gillespie also testified that McGuire Unit 2 began the fall refueling and maintenance outage schedule. Major work along with refueling included replacement of the 2A reactor coolant pump motor, the 2A main step-up transformer, and the 2A chemical and volume control system pump rotating element. The site also replaced the 2B emergency diesel generator voltage regulator and completed enhancements to comply with NRC post-Fukushima orders. Work was completed within the scheduled allocation. In total, DEC successfully completed 9,057 work order tasks within this outage.

Company witness Gillespie testified that Oconee Unit 2 also had a fall refueling and maintenance outage. In addition to refueling efforts, major work involved replacement of the main step-up transformer, 100% steam generator Eddy Current Testing, replacement of the 2A and 2B letdown coolers, and a reactor building integrated leak rate test. Post-Fukushima tie-ins for primary and backup repower were also completed. Work was completed within the scheduled allocation and, in total, DEC successfully completed 10,522 work order tasks within this outage.

Company witness Gillespie further testified that Catawba Unit 1 had the final refueling and maintenance outage for 2015. In addition to refueling, major work activities included replacement of the 1A reactor coolant pump and hotwell pump motors, replacement of the 1B condensate pump motor and 1B1 component cooling pump and motor, and a refurbishment for the 1B main feed water pump turbine. The site also completed a 10-year reactor vessel in-service inspection and post-Fukushima tie-ins on the safety injection and auxiliary feed water lines. The outage was completed within the scheduled allocation and, in total, DEC successfully completed 10,136 work order tasks within this outage.

Company witness Miller testified concerning the performance of DEC's fossil/hydro assets. He stated that the primary objective of the Company's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEC's Carolinas customers, and that it achieves this objective by focusing on a number of key areas. Witness Miller further stated that environmental compliance is a "first principle" 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.

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

Company witness Miller presented the following chart, which shows operation results, as well as results from the most recently published North American Electric Reliability Council (NERC) Generating Availability Brochure for the period 2010 through 2014, and is categorized by generator type:

Generator Type	Measure	Review Period	2010-2014	Nbr of Units
		DEC Operational Results	NERC Average	
Coal-fired Test Period	EAF	78.3%	81.0%	740
	NCF	43.3%	63.0%	
	EFOR	14.0%	7.9%	
Coal-fired Summer Peak	EAF	88.0%	n/a	n/a
Total CC Average	EAF	92.4%	84.4%	179
	NCF	84.1%	51.3%	
	EFOR	0.29%	6.3%	
Total CT Average	EAF	92.2%	87.3%	928
	SR	99.1%	97.6%	
Hydro	EAF	88.4%	82.6%	1074

Company witness Miller testified that the NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating along with the EAF for the peak summer period of June through August. He also testified that the Company's CC fleet responded to the test period summer and winter peaks with a very strong performance. DEC customers established an all-time energy usage demand during the test period in the month of February 2015. The CC fleet EAF during the month of January and February was 98.95%, and 100% during the months June, July, and August.

Witness Miller also testified that Marshall Unit 4 completed the outage in the Spring of 2015 that carried over from 2014. Dan River CC completed a hot gas path inspection, which included an advanced gas path upgrade resulting in a capacity increase of 13 MWs. Cliffside Units 5 and 6 completed outages in Spring 2015. The Cliffside Unit 5 outage involved replacement of air preheater baskets, FGD maintenance, and boiler maintenance. The primary purpose of the Cliffside Unit 6 outage was to complete repairs on FGD absorber and baghouse bag replacement. Marshall Unit 3 completed an outage in Spring 2015. The purpose of the outage was to inspect and repair turbine bearings, conduct generator testing, and perform boiler maintenance. Belews Creek Units 1 and 2 completed outages in Spring 2015. Both units had upgrades completed on the FGD and Waste Water Treatment control systems and upgrades made to coal handling equipment. Belews Creek Unit 1 replaced HP Generator blades and the LP Exciter, and performed boiler maintenance.

Concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period, Company witness Miller testified that in general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize unit availability during periods of peak demand. During the test period, most of these units had at least one small planned outage to inspect and maintain plant equipment.

Public Staff witness Lucas testified that from April 21, 2014 to March 12, 2015, DEC's Marshall Unit 4 was out of service due to (1) a generator grounding issue that ultimately required the generator stator to be completely rebuilt and (2) bearing oil contamination. As part of its investigation into this matter, the Public Staff reviewed significant information on the causes of this particular outage and DEC's associated remedial actions. Witness Lucas testified that he was satisfied that DEC sufficiently investigated and corrected the problems related to this outage, and that he was also satisfied that DEC took the proper steps to minimize the likelihood of a reoccurrence of these issues at Marshall and its other coal plants. Therefore, the Public Staff did not recommend any replacement power adjustment related to the Marshall 4 outage as part of this proceeding.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

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 December 2014, and were in effect throughout the 12 months ending December 31, 2015. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses Smith, Daji, 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 Duke Energy Progress, LLC's (DEP) and DEC's respective skills in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined Company; and the joint dispatch of DEP's and DEC's generation resources.

Company witness Daji described DEC's fossil fuel procurement practices, set forth in Daji 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 Daji, the Company's average delivered coal cost per ton for the test period was $89.72 per ton, compared to $91.72 per ton in the prior test period, representing a decrease of 2%. This includes an average transportation cost of $27.66 per ton in the test period, compared to $32.11 per ton in the prior test period, representing a decrease of approximately 14%. Witness Daji stated that coal markets continue to be in a state of flux due to a number of factors, including (1) proposed and imposed U.S. Environmental Protection Agency regulations for power plants that have resulted in utilities retiring or modifying plants, which lowers total domestic steam coal demand, and can result in plants shifting coal sources to different basins; (2) abundant natural gas supply and storage resulting in lower natural gas prices combined with installation of new CC generation by utilities, especially in the Southeast, which has also lowered overall coal demand; (3) continued softening demand in global markets for both steam and metallurgical coal; (4) increasingly stringent safety regulations for mining operations, which result in higher costs and lower productivity; and (5) the on-going financial viability of many of the Company's coal suppliers. She also testified, however, that at the same time, the nation's natural gas supply has grown significantly and has outstripped demand. Over the longer term planning horizon, overall gas supply is forecasted to continue to grow, and currently observable forward market prices are at historically low price levels as producers continue to look for efficiencies to further enhance economics and lower production costs. In addition to the increase in natural gas supply, new pipeline infrastructure continues to be added to provide for opportunities to move the growing supply to various markets.

Witness Daji stated that DEC's coal burn for the test period was 9.8 million tons, compared to a coal burn of 12.0 million tons in the prior test period, representing a decline of 18%. Additionally, the 9.8 million tons burned in the test period represents a 23% decline compared to the average annual coal burn over the prior five-year period of over 12.7 million tons. The decline in coal burns in the test period is attributable to declining natural gas prices combined with milder than forecasted weather in the latter half of the test period. Witness Daji stated that DEC's current coal burn projection for the billing period is 11.9 million tons compared to 9.8 million tons consumed during the test period. DEC's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: delivered natural gas prices versus the average delivered cost of coal, volatile power prices, and electric demand. DEC's inventory levels were above target at the end of 2015, and future actual inventory levels may be above target levels at the end of 2016 as well. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $68.75 per ton for the billing period compared to $89.72 per ton in the test period. Witness Daji testified that this cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEC is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEC's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

According to witness Daji, DEC continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price increases and maintaining average fuel costs at or below those seen in the marketplace. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, and pursuing coal contract extension options that provide flexibility to extend terms within a particular price band. The Company expects to address any spot and long-term coal requirements throughout this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels.

Witness Daji also testified that the Company has implemented natural gas procurement practices that include periodic Request for Proposals (RFPs) and short-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply that supports DEC's Buck and Dan River CC facilities and the Company's combustion turbine (CT) facilities. The Company procures long-term firm transportation to support its natural gas needs at its generating facilities. In addition, as needed, DEC may procure shorter-term firm pipeline capacity through the capacity release market, as well as delivered market supply options that provide the needed natural gas supply to its generating facilities.

According to Witness Daji, through the Asset Management and Delivered Supply Agreement (AMA) between DEC and DEP, which was implemented on January 1, 2013, DEC serves as the designated Asset Manager that procures and manages the combined gas supply needs for both utilities, and performs the necessary scheduling and balancing on the pipelines. DEC does not have an agreement for storage capacity, nor does it maintain an inventory of natural gas. DEP, however, does have a storage agreement which was released to DEC as part of the AMA. As the Asset Manager, DEC procures all the needed supply for the combined Carolinas gas needs, and as part of the AMA, has access to the released storage agreement. On any given day, DEC may utilize the storage to balance and support the Carolinas gas needs.

Witness Daji further testified that the Company's natural gas consumption is expected to continue to increase. The Company's natural gas burn for the test period was 76.8 billion cubic feet (Bcf), compared to a gas burn of 55.7 Bcf in the prior test period, representing an increase of 38%. DEC's current natural gas burn projection for the billing period is approximately 84 Bcf, which is an increase from the 76.8 Bcf consumed during the test period. The current average forward Henry Hub price for the billing period is $2.69 per MMBtu, compared to $3.97 per MMBtu in the test period. Currently, spot and forward market prices for natural gas remain at historically low levels which have resulted in the Company's increased natural gas consumption projections.

G.S. 62-133.2(a1)(3) permits DEC to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Miller testified that the selective catalytic reduction (SCR) technology that DEC currently operates uses ammonia or, in the case of Marshall Unit 3, urea (which is converted to ammonia), for nitrogen oxide (NO_x) removal. The selective non-catalytic reduction technology (SNCR) employed by DEC at the Allen Station and Marshall Units 1, 2, and 4, injects urea into the boiler for NO_x removal, and the wet scrubber technology uses crushed limestone for sulfur dioxide (SO_2) removal. Cliffside Unit 6 has a state-of-the-art SO_2 reduction system which couples a wet scrubber (e.g., limestone) and dry scrubber (e.g., quicklime). Company witness Miller testified that the December 2015 issue of Electric Light and Power magazine includes Cliffside in the 2014 top 20 for lowest SO_2 emission rates in the country. SCR equipment is also an integral part of the design of the Buck and Dan River CC Stations in which aqueous ammonia (19% solution of NH_3) is introduced for NOx removal.

Company witness Miller further testified that overall, the type and quantity of chemicals used to reduce emissions at the Company's plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and the level of emissions reduction required. He stated that the Company 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. He also stated that the goal is to effectively comply with emissions 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 include 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 long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Culp explained that 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. He also stated that throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, 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, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces 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 or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Daji testified that in assessing power purchases and off-system sales opportunities, DEP and DEC consider the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at generating units, estimated forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions, in order to determine the most economic and reliable means of serving their customers.

In a post-hearing brief, NCSEA states that it does not challenge any costs for which DEC seeks recovery in this proceeding as unreasonable or imprudent. However, NCSEA requests that the Commission direct DEC and the Public Staff to explore 48 to 60-month natural gas hedging opportunities that can minimize the risk of future rate shocks for ratepayers. The Commission notes that NCSEA does not oppose recovery of DEC's proposed fuel and fuel-related costs in this proceeding. In future fuel and fuel-related charge adjustment proceedings, NCSEA is free to challenge DEC's proposed recovery of its fuel and fuel-related costs, including such costs affected by its natural gas fuel procurement practices.

No 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.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony of Company witnesses Daji and Smith.

Company witness Daji testified through January 2016, the combined merger savings from DEP and DEC's Joint Dispatch Agreement and fuel procurement activities totaled $630 million, of which DEC's North Carolina share was $258 million. The utilities' customers are allocated their share of the combined savings based upon the resource ratios of the combined company. This resource ratio is 61% for DEC and 39% for DEP through January 2016.

Company witness Smith testified that Merger fuel-related savings automatically flow through to DEC's retail customers through the fuel and fuel-related costs component of customers' rates. She explained that actual merger fuel-related savings during the test period are included in the EMF portion of the proposed fuel and fuel-related cost factors. In addition, in the prospective component of the factors, the projected merger fuel-related savings related to procuring coal and reagents, lower transportation costs, lower gas capacity costs, and coal blending are reflected in the cost of fossil fuel. Projected joint dispatch savings, which result from using DEC's and DEP's combined systems' lowest available generation to meet total customer demand, are also reflected in the cost of fossil fuel as well as the projected cost purchases and sales that include the purchases and sales between DEC and DEP.

Based on the evidence presented by DEC, and noting the absence of evidence presented to the contrary by any other party, the Commission finds and concludes that the Company's merger-related fuel savings for the test period are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

According to the exhibits sponsored by Company witness Smith, the test period per book system sales were 85,855,829 MWh, and test period per book system generation and purchased power equaled 91,491,109 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Smith Exhibit 6):

Net Generation Type	MWh
Coal	25,896,122
Natural Gas, Oil and Biomass	10,594,738
Nuclear	45,012,667
Hydro – Conventional	1,915,136
Hydro Pumped Storage	(778,969)
Solar DG	12,515
Purchased Power – subject to economic dispatch or curtailment	7,454,836
Other Purchased Power	1,548,866
Catawba Interchange	(164,802)
Total Net Generation	91,491,109

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party took issue with the portions of witness Smith's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 85,855,829 MWh and system generation and purchased power of 91,491,109 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Gillespie and the affidavit of Public Staff witness Lucas.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. The Company proposed using a 93.65% 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 2016-2017 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 87.80% for the period 2010-2014 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report. Public Staff witness Lucas did not dispute the Company's proposed use of a 93.65% 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 did not dispute the Company's proposed capacity factor, the Commission concludes that the 93.65% nuclear capacity factor, and its associated generation of 58,898,684 MWh[1], are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

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

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

On her Exhibit 4, Company witness Smith set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 57,546,067 MWh, comprised of Residential class sales of 21,255,930 MWh, General Service/Lighting class sales of 23,144,221 MWh, and Industrial class sales of 13,145,916 MWh.

Witness Smith used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Smith Exhibit 2, Schedule 1, is 87,302,761 MWh. The projected level of generation and purchased power used was 93,867,520 MWh (calculated using the 93.65% capacity factor found reasonable and appropriate above), and was broken down by witness Smith as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	31,099,240
Gas Combustion Turbine (CT) and Combined Cycle (CC)	10,854,860
Nuclear	44,728,522
Hydro	1,682,372
Net Pumped Storage Hydro	(776,838)
Solar Distributed Generation (DG)	140,616
Purchased Power	6,138,748
Total	93,867,520

As part of her Workpaper 7, Company witness Smith also presented an estimate of the projected billing period North Carolina retail Residential, General Service/Lighting, and Industrial MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,263,581
General Service/Lighting	23,335,364
Industrial	13,156,554
Total	57,755,499

[1] 44,728,522 MWh net of Catawba Joint Owners.

These class totals were used in Smith Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

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

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Smith and Daji and the affidavit of Public Staff witness Lucas.

Company witness Smith recommended fuel and fuel-related prices and expenses, for purposes of determining projected system fuel expense, as follows:

A. The coal fuel price is $27.51/MWh.
B. The gas CT and CC fuel price is $26.58/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $37,397,886.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.58/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $209,599,980.
F. System fuel expense recovered through intersystem sales is $26,569,895.

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

In his affidavit, Public Staff witness Lucas stated that, based on his review, it appears that the projected fuel and reagent costs set forth in DEC's testimony, and the prospective components of the total fuel factor, have been calculated in accordance with the requirements of G.S. 62-133.2.

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Smith and the affidavit of Public Staff witness Lucas.

Consistent with G.S. 62-133.2(a2), witness Smith testified 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 2015.

According to Smith Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,102,234,868. Public Staff witness Lucas did not take issue with her calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $1,102,234,868 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-19

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Smith and the affidavits of Public Staff witnesses Lucas and Peedin.

Company witness Smith presented DEC's original fuel and fuel-related expense over-collection and prospective fuel and fuel-related cost factors. Company witness Smith's testimony sets forth the projected fuel and fuel-related costs, the amount of over/(under) collection for purposes of the EMF, the method for allocating the increase in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs along with exhibits and workpapers. Public Staff witness Lucas recommended the approval of the prospective and EMF components and total fuel factors (excluding regulatory fee) set forth in Company witness Smith's testimony.

Public Staff witness Peedin testified that the EMF riders proposed by DEC are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost over-recoveries of $9.9 million, $12.8 and $18.4 million for the Residential, General Service/Lighting and Industrial classes, respectively. Public Staff witness Peedin also testified that interest on the over-recovered fuel and fuel-related amount from the Residential, General Service/Lighting and Industrial classes amounted to $1.7 million, $2.1 million and $3.1 million, respectively. She recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost over-recovery amounts, and on the Company's proposed normalized North Carolina retail sales of 21,255,930 MWh for the Residential class, 23,144,221 MWh for the General Service/Lighting class, and 13,145,916 MWh for the Industrial class, as proposed by the Company. She stated that these amounts produce EMF decrement riders for each North Carolina retail customer class as follows, excluding the regulatory fee:

Residential	(0.0464) cents per kWh
General Service/Lighting	(0.0553) cents per kWh
Industrial	(0.1406) cents per kWh

She also recommended an EMF interest decrement rider, excluding the regulatory fee, of (0.0077)¢/kWh for the Residential class; (0.0092)¢/kWh for the General Service/Lighting class; and (0.0234)¢/kWh for the Industrial class.

As a result of witness Peedin's recommendation, Public Staff witness Lucas recommended the following EMF and EMF interest decrement billing factors:

N.C. Retail Customer Class	EMF Decrement (cents/kWh)	EMF Interest Decrement (cents/kWh)
Residential	(0.0464)	(0.0077)
General Service/Lighting	(0.0553)	(0.0092)
Industrial	(0.1406)	(0.0234)

These factors are also set forth on Smith Exhibit 1.

The Commission concludes that the EMF and EMF interest decrement billing factors set forth in the affidavits of Public Staff witnesses Lucas and Peedin are reasonable and appropriate for use in this proceeding.

Company witness Smith calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the decrease in fuel costs from the amounts approved in Docket No. E-7, Sub 1072, should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEC fuel cases approved by this Commission. No party opposed the use of this allocation method. Public Staff witness Lucas recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in Company witness Smith's testimony.

Based upon the testimony and exhibits in the record, the Commission concludes that DEC's projected fuel and fuel-related costs of $1,102,234,868 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that (1) DEC's EMF decrements proposed in this proceeding, excluding the regulatory fee, (2) DEC's prospective fuel and fuel-related cost factors proposed in this proceeding for each of DEC's rate classes, and (3) DEC's EMF interest decrements proposed in this proceeding, excluding the regulatory fee, are all appropriate. Additionally, the Commission concludes that DEC's decrease in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1072 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEC's past fuel cases.

The following tables summarize the impact of the rates in this case and the rates approved in Docket No. E-7 Sub 1072 (excluding regulatory fee), as compared to the composite base fuel and fuel-related cost factor of 2.3182 cents/kwh approved by the Commission in the Company's most recent general rate case, Docket No. E-7, Sub 1026:

Approved in Docket No. E-7, Sub 1072 (excluding regulatory fee):

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Prospective Component	(0.2298)	(0.1604)	(0.1029)
EMF Component	0.0298	0.0173	(0.0034)
Total Fuel Factor	(0.2000)	(0.1431)	(0.1063)

Proposed in this Docket No. E-7, Sub 1104 (excluding regulatory fee):

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Prospective Component	(0.5627)	(0.3935)	(0.1895)
EMF Component	(0.0541)	(0.0645)	(0.1640)
Total Fuel Factor	(0.6168)	(0.4580)	(0.3535)

Summary of Differences Sub 1104 – Sub 1072 (excluding regulatory fee):

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Prospective Component	(0.3329)	(0.2331)	(0.0866)
EMF Component	(0.0839)	(0.0818)	(0.1606)
Total Fuel Factor	(0.4168)	(0.3149)	(0.2472)

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for this finding of fact is contained in the testimony of Company witness Smith and in the affidavits of Public Staff witnesses Peedin and Lucas and is discussed in more detail in Evidence and Conclusions for Finding of Fact No. 5.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 1.7014¢/kWh for the Residential class, 1.8602¢/kWh for the General Service/Lighting class, and 1.9647¢/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 1.7555¢/kWh, 1.9247¢/kWh, and 2.1287¢/kWh, EMF decrements of (0.0464)¢, (0.0553)¢, and (0.1406)¢/kWh, and EMF interest decrements of (0.0077)¢/kWh, (0.0092)¢/kWh, and (0.0234)¢/kWh, for the Residential, General Service/Lighting, and Industrial classes, all respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED, as follows:

1. That, effective for service rendered on and after September 1, 2016, DEC shall adjust the base fuel and fuel-related costs in its North Carolina retail rates of 2.3182¢/kWh, as approved in Docket No. E-7, Sub 1026, by amounts equal to (0.5627)¢/kWh, (0.3935)¢/kWh and (0.1895)¢/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively, and further, that DEC shall adjust the resulting approved fuel and fuel-related costs by EMF decrements of (0.0464)¢/kWh for the Residential class, (0.0553)¢/kWh for the General Service/Lighting class, and (0.1406)¢/kWh for the Industrial class (excluding the regulatory fee). DEC shall further adjust the fuel and fuel-related costs by EMF interest decrements of (0.0077)¢/kWh, (0.0092)¢/kWh, and (0.0234)¢/kWh, for the Residential, General Service/Lighting, and Industrial classes, all respectively, excluding the regulatory fee. The EMF decrements and EMF interest decrements are to remain in effect for service rendered through August 31, 2017.

2. That DEC shall file appropriate rate schedules and riders with the Commission in order to implement these approved rates as soon as practicable.

3. That DEC shall work with the Public Staff to prepare a notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub 1106, and the Company shall file such notice for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the _26th__ day of __July_____, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-7, SUB 1105

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	)))))	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD: On Tuesday, June 7, 2016, and Friday, July 29, 2016, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chairman Edward S. Finley, Jr.; and Commissioners Bryan E. Beatty; Don M. Bailey; Jerry C. Dockham; James G. Patterson; and Lyons Gray

APPEARANCES:

For Duke Energy Carolinas, LLC:

Robert W. Kaylor, Law Office of Robert W. Kaylor, PA, 353 East Six Forks Road, Suite 260, Raleigh, North Carolina 27609

Brian L. Franklin, Associate General Counsel, Duke Energy Corporation, 550 South Tryon Street, Charlotte, North Carolina 28202

Molly McIntosh Jagannathan, Troutman Sanders LLP, 301 South College Street, Suite 3400, Charlotte, North Carolina 28202

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For North Carolina Sustainable Energy Association:

Michael Youth, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Carolina Industrial Group for Fair Utility Rates III:

Adam Olls, Bailey & Dixon, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For Southern Alliance for Clean Energy:

Gudrun Thompson, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

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

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric public utilities, outside of a general rate case, for recovery of all reasonable and prudent costs incurred for adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) measures. The Commission is also authorized to award incentives to electric companies for adopting and implementing new DSM/EE measures, including, but not limited to, appropriate rewards based on (1) the sharing of savings achieved by the DSM and EE measures and/or (2) the capitalization of a percentage of avoided costs achieved by the measures. Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric public utility to establish an annual DSM/EE rider to recover the reasonable and prudent costs incurred by the electric utility in adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Further, Commission Rule R8-69(b) provides for the establishment of a DSM/EE experience modification factor (EMF) rider to allow the electric public utility to collect the difference between reasonable and prudently incurred costs and the revenues that were actually realized during the test period under the DSM/EE rider then in effect. Commission Rule R8-69(c) permits the utility to request the inclusion of utility incentives (the rewards authorized by the statute), including net lost revenues (NLR), in the DSM/EE rider and the DSM/EE EMF rider.

In the present proceeding, Docket No. E-7, Sub 1105, on March 9, 2016, Duke Energy Carolinas, LLC (DEC or the Company), filed an application for approval of its DSM/EE rider (Rider EE[1] or Rider 8) for 2017[2] (Application) and the direct testimony and exhibits of Carolyn T.

[1] DEC refers to its DSM/EE Rider as "Rider EE"; however, this rider includes charges intended to recover both DSM and EE revenue requirements.

[2] The Rider EE proposed in this proceeding is the Company's eighth Rider EE and includes components that relate to Vintages 1, 2, 3, and 4 of the cost recovery mechanism approved in Docket No. E-7, Sub 831, and components that relate to Vintages 2014, 2015, 2016, and 2017 of the cost recovery mechanism approved in Docket No. E-7, Sub 1032. For purposes of clarity, the aggregate rider is referred to in this Order as "Rider 8" or the proposed "Rider EE." Rider 8 is proposed to be effective for the rate period January 1, 2017 through December 31, 2017.

Miller, Rates Manager for DEC, and Robert P. Evans, Senior Manager – Strategy and Collaboration for the Company's Market Solutions Regulatory Strategy and Evaluation group.

On March 17, 2016, the Commission issued an Order scheduling a hearing for June 7, 2016, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice.

The intervention of the Public Staff – North Carolina Utilities Commission (Public Staff) is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On March 10, 2016, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted on March 15, 2016. The Carolina Industrial Group for Fair Utility Rates III (CIGFUR) filed a petition to intervene on March 15, 2016, which was granted on March 16, 2016. On April 6, 2016, the Southern Alliance for Clean Energy (SACE) filed a petition to intervene, which was granted on April 12, 2016. On April 8, 2016, the Carolina Utility Customers Association, Inc. filed a petition to intervene, which was granted on April 12, 2016.

On May 17, 2016, DEC filed revised Exhibit E of witness Evans.

On May 23, 2016, SACE filed the testimony of Jennifer Weiss, its Energy Policy Manager; and the Public Staff filed testimony in the form of the affidavits of Michael C. Maness, Assistant Director of the Accounting Division, and Jack L. Floyd, Engineer in the Electric Division.

On May 26, 2016, DEC filed the supplemental direct testimony and exhibits of witness Miller and the supplemental exhibits of witness Evans.

On May 26, 2016, DEC filed a Motion for Additional Public Hearing and Public Notice of Revised Proposed Rates.

On June 1, 2016, DEC and the Public Staff filed a joint motion to excuse their witnesses from appearing at the June 7, 2016 expert witness hearing. On June 3, 2016, the Commission issued an Order Granting Motion to Excuse Witnesses from Attending Hearing.

On June 3, 2016, SACE filed revised pages 14 and 15 of the testimony of witness Weiss.

The case came on for hearing as scheduled on June 7, 2016. No public witnesses appeared at the hearing.

On June 8, 2016, the Commission issued an Order scheduling an additional public hearing in this matter for July 29, 2016 and requiring public notice.

On June 20, 2016, the Commission issued a Notice setting the due date for post-hearing filings as August 10, 2016.

The case came on for additional public hearing as scheduled on July 29, 2016. No public witnesses appeared at the hearing.

On August 2, 2016, the Public Staff filed a letter with the Commission setting forth the results of its review of the Company's proposed revision to test year program costs as filed May 26, 2016, along with recommendations resulting from that review.

On August 10, 2016, the parties filed briefs or proposed orders, as allowed by the Commission.

Other Pertinent Proceedings: Docket No. E-7, Subs 831, 938, 979, and 1032

On February 9, 2010, the Commission issued an Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues in DEC's first DSM/EE rider proceeding, Docket No. E-7, Sub 831 (Sub 831 Order). In the Sub 831 Order, the Commission approved, with certain modifications, the Agreement and Joint Stipulation of Settlement between DEC, the Public Staff, SACE, Environmental Defense Fund (EDF), the Natural Resources Defense Council (NRDC), and the Southern Environmental Law Center (SELC) (Sub 831 Settlement), which described the modified save-a-watt mechanism (Sub 831 Mechanism), pursuant to which DEC calculated, for the period from June 1, 2009 until December 31, 2013, the revenue requirements underlying its DSM/EE riders based on percentages of avoided costs, plus compensation for NLR resulting from EE programs only. The Sub 831 Mechanism was approved as a pilot (Sub 831 Pilot) with a term of four years, ending on December 31, 2013.

On February 15, 2010, the Company filed an Application for Waiver of Commission Rule R8-69(a)(4) and R8-69(a)(5) in Docket No. E-7, Sub 938 (Sub 938 Waiver Application), requesting waiver of the definitions of "rate period" and "test period." Under the Sub 831 Mechanism, customer participation in the Company's DSM and EE programs and corresponding responsibility to pay Rider EE are determined on a vintage year basis. A vintage year is generally the 12-month period in which a specific DSM or EE measure is installed for an individual participant or group of participants.[1] For purposes of the modified save-a-watt portfolio of programs, the Company applied the vintage year concept on a calendar-year basis for administrative ease for the Company and its customers. Pursuant to the Sub 938 Waiver Application, "test period" is defined as the most recently completed vintage year at the time of the Company's DSM/EE rider application filing date.[2]

On February 24, 2010, in Docket No. E-7, Sub 938, the Commission issued an Order Requesting Comments on the Company's Sub 938 Waiver Application. After receiving comments and reply comments, the Commission entered an Order Granting Waiver, in Part, and Denying

[1] Vintage 1 is an exception in terms of length. Vintage 1 is a 19-month period beginning June 1, 2009 and ending December 31, 2010, as a result of the approval of DSM/EE programs prior to the approval of the cost recovery mechanism.

[2] Further, in the Sub 938 Second Waiver Order issued June 3, 2010, the Commission concluded that DEC should true up all costs during the save-a-watt pilot through the EMF rider provided in Commission Rule R8-69(b)(1). The modified save-a-watt approach approved in the Sub 831 Order requires a final calculation after the completion of the four-year program, comparing the cumulative revenues collected related to all four vintage years to amounts due the Company, taking into consideration the applicable earnings cap.

Waiver, in Part (Sub 938 Waiver Order) on April 6, 2010. In this Order, the Commission approved the requested waiver of R8-69(d)(3) in part, but denied the Company's requested waiver of the definitions of "rate period" and "test period."

On May 6, 2010, DEC filed a Motion for Clarification or, in the Alternative, for Reconsideration, asking that the Commission reconsider its denial of the waiver of the definitions of "test period" and "rate period," and that the Commission clarify that the EMF may incorporate adjustments for multiple test periods. In response, the Commission issued an Order on Motions for Reconsideration on June 3, 2010 (Sub 938 Second Waiver Order), granting DEC's Motion. The Sub 938 Second Waiver Order established that the rate period for Rider EE would align with the 12-month calendar year vintage concept utilized in the Commission-approved save-a-watt approach (in effect, the calendar year following the Commission's order in each annual DSM/EE cost recovery proceeding), and that the test period for Rider EE would be the most recently completed vintage year at the time of the Company's Rider EE cost recovery application filing date.

On February 8, 2011, in Docket No. E-7, Sub 831, the Commission issued its Order Adopting "Decision Tree" to Determine "Found Revenues" and Requiring Reporting in DSM/EE Cost Recovery Filings in Docket No. E-7, Sub 831 (Sub 831 Found Revenues Order), which included, in Appendix A, a "Decision Tree" to identify, categorize, and net possible found revenues against the NLR created by the Company's EE programs. Found revenues may result from activities that directly or indirectly result in an increase in customer demand or energy consumption within the Company's service territory.

On November 8, 2011, in Docket No. E-7, Sub 979, the Commission issued its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice (Sub 979 Order), in which it approved the Evaluation, Measurement, and Verification (EM&V) agreement (EM&V Agreement) reached by the Company, SACE, and the Public Staff. Pursuant to the EM&V Agreement, for all EE programs, with the exception of the Non-Residential Smart $aver® Custom Rebate Program and the Low Income EE and Weatherization Assistance Program, actual EM&V results are applied to replace all initial impact estimates back to the beginning of the program offering. For the purposes of the vintage true-ups, these initial EM&V results will be considered actual results for a program until the next EM&V results are received. The new EM&V results will then be considered actual results going forward and will be applied prospectively for the purposes of truing up vintages from the first day of the month immediately following the month in which the study participation sample for the EM&V was completed. These EM&V results will then continue to apply and be considered actual results until superseded by new EM&V results, if any. For all new programs and pilots, the Company will follow a consistent methodology, meaning that initial estimates of impacts will be used until DEC has valid EM&V results, which will then be applied back to the beginning of the offering and will be considered actual results until a second EM&V is performed.

On February 6, 2012, in the Sub 831 docket, the Company, SACE, and the Public Staff filed a proposal regarding revisions to the program flexibility requirements (Flexibility Guidelines). The proposal divided potential program changes into three categories based on the magnitude of the change, with the most significant changes requiring regulatory approval by the Commission prior to implementation; less extensive changes requiring advance notice prior to making such program changes; and minor changes being reported on a quarterly basis to the Commission. The Commission approved the joint proposal in its July 16, 2012 Order Adopting Program Flexibility Guidelines.

On October 29, 2013, the Commission issued its Order Approving DSM/EE Programs and Stipulation of Settlement in Docket No. E-7, Sub 1032 (Sub 1032 Order), which approved a new cost recovery and incentive mechanism for DSM/EE programs (Sub 1032 Mechanism) and a portfolio of DSM and EE programs to be effective January 1, 2014 to replace the cost recovery mechanism and portfolio of DSM and EE programs approved in Docket No. E-7, Sub 831. In the Sub 1032 Order, the Commission approved an Agreement and Stipulation of Settlement, filed on August 19, 2013, and amended on September 23, 2013, by and between DEC, NCSEA, EDF, SACE, the South Carolina Coastal Conservation League (CCL), NRDC, the Sierra Club, and the Public Staff (Stipulating Parties), which incorporates the Sub 1032 Mechanism (Sub 1032 Settlement).

Under the Sub 1032 Settlement, as approved by the Commission, the portfolio of DSM and EE programs filed by the Company was approved with no specific duration (unlike the programs approved in Sub 831, which explicitly expired on December 31, 2013). Also, the Sub 1032 Settlement also provided that the Company's annual DSM/EE rider would be determined according to the Sub 1032 Settlement and the terms and conditions set forth in the Sub 1032 Mechanism.

The overall purpose of the Sub 1032 Mechanism is to (1) allow DEC to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and EE measures; (2) establish certain requirements, in addition to those of Commission Rule R8-68, for requests by DEC for approval, monitoring, and management of DSM and EE programs; (3) establish the terms and conditions for the recovery of NLR (net of found revenues) and a Portfolio Performance Incentive (PPI) to reward DEC for adopting and implementing new DSM and EE measures and programs; and (4) provide for an additional incentive to further encourage kilowatt-hour (kWh) savings achievements. The Sub 1032 Mechanism also includes the following provisions, among several others: (a) it shall continue until terminated pursuant to Commission Order; (b) modifications to Commission-approved DSM/EE programs will be made using the Flexibility Guidelines; (c) treatment of opted-out and opted-in customers will continue to be guided by the Commission's Orders in Docket No. E-7, Sub 938, with the addition of an additional opt-in period during the first week in March of each year; (d) the EM&V Agreement shall continue to govern the application of EM&V results; and (e) the determination of found revenues will be made using the Decision Tree approved in the Sub 831 Found Revenues Order. Like the Sub 831 Mechanism, the Sub 1032 Mechanism also employs a vintage year concept based on the calendar year.[1]

[1] To distinguish from vintages under the Sub 831 Pilot (which are numbered 1 through 4), each vintage under the Sub 1032 Mechanism is referred to by the calendar year of its respective rate period (e.g., Vintage 2017).

Docket No. E-7, Sub 1105

Based upon consideration of DEC's Application, the pleadings, the testimony and exhibits received into evidence at the hearing, the parties' briefs and the record as a whole, the Commission now makes the following

FINDINGS OF FACT

1. DEC is a public utility with a public service obligation to provide electric utility service to customers in its service area in North Carolina and is subject to the jurisdiction of the Commission.

2. The Commission has jurisdiction over this Application pursuant to the Public Utilities Act. Based on the specific recovery of costs and incentives proposed by DEC in this proceeding, the Commission finds that it has the authority to consider and approve the relief the Company is seeking in this docket.

3. For purposes of this proceeding, DEC has requested approval of costs and incentives related to the following DSM/EE programs to be included in Rider 8: Appliance Recycling Program; Energy Assessments Program; EE Education Program; Energy Efficient Appliances and Devices; HVAC EE Program; Multi-Family EE Program; My Home Energy Report; Income-Qualified EE and Weatherization Program; Residential Retrofit Pilot Program; Power Manager; Nonresidential Smart $aver® Energy Efficient Food Service Products Program; Nonresidential Smart $aver® Energy Efficient HVAC Products Program; Nonresidential Smart $aver® Energy Efficient IT Products Program; Nonresidential Smart $aver® Energy Efficient Lighting Products Program; Nonresidential Smart $aver® Energy Efficient Process Equipment Products Program; Nonresidential Smart $aver® Energy Efficient Pumps and Drives Products Program; Nonresidential Smart $aver® Custom Program; Nonresidential Smart $aver® Custom Energy Assessments Program; PowerShare®; PowerShare® Call Option; Small Business Energy Saver; Smart Energy in Offices; Business Energy Report Pilot; and EnergyWise for Business.

4. For purposes of inclusion in Rider 8, the Company's portfolio of DSM and EE programs is cost-effective.

5. The Residential HVAC EE Program as modified is cost-effective and shall continue and not be terminated on March 31, 2017.

6. The EM&V analyses and reports prepared by DEC's independent third party evaluator are acceptable for purposes of this proceeding.

7. The EM&V recommendations contained in the affidavit of Public Staff witness Floyd are appropriate for inclusion in future EM&V reports for the applicable EE programs, including certain program vintages that remain to be verified and trued up.

8. As directed by the Commission's Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice issued on August 21, 2015 in Docket E-7, Sub 1073 (Sub 1073 Order), DEC and the Public Staff have reviewed and discussed the EM&V reports for the Company's Smart Energy Now Pilot[1] and the Specialty Bulb measures of DEC's Energy Efficient Appliances and Devices Program. As a result of those discussions, DEC and the Public Staff agreed that the Company should adjust the impacts relating to the Smart Energy Now Pilot, but not for the Specialty Bulb measures. It is reasonable and appropriate to accept the agreed upon revised impacts relating to the Smart Energy Now Pilot and the resulting EMF amounts for Vintages 1 through 4 as the final true-up associated with the Sub 831 Mechanism.

9. Pursuant to the Commission's Sub 938 Second Waiver Order and the Sub 1032 Order, the rate period for the purposes of this proceeding is January 1, 2017 through December 31, 2017.

10. Rider 8 includes EMF components for Vintage 2015 DSM and EE programs. Consistent with the Sub 938 Second Waiver Order, the test period for these EMF components is the period from January 1, 2015 through December 31, 2015 (Vintage 2015). Rider 8 also includes a true-up of Vintage 2014 based on additional EM&V results. In addition, Rider 8 includes adjustments to the EMF components previously approved for Vintages 1, 2, 3, and 4 to reflect revised impacts for the Smart Energy Now Pilot, which represents the final true-up for those four vintages under the Sub 831 Mechanism.

11. DEC's proposed rates for Rider 8 are comprised of both prospective and EMF components. The prospective components include factors designed to collect program costs and the PPI for the Company's Vintage 2017 DSM and EE programs, as well as the first year of NLR for the Company's Vintage 2017 EE programs; the second year of NLR for Vintage 2016 EE programs; the third year of NLR for Vintage 2015 EE programs; and the final half-year of NLR for Vintage 2014 EE programs. The EMF components include the true-up of Vintage 2015 program costs, NLR, and PPI; the true-up of Vintage 2014 NLR and PPI based on additional EM&V results received; and the final true-up of Vintages 1 through 4 under the Sub 831 Mechanism. DEC, as reflected in the supplemental testimony and exhibits of Company witness Miller and the supplemental exhibits of Company witness Evans, has calculated the components of Rider 8 in a manner that appropriately reflects the Commission's findings and conclusions in this Order, as well as the Commission's findings and conclusions as set forth in the Sub 831 Order, the Sub 831 Found Revenues Order, the Sub 938 Waiver Order, the Sub 938 Second Waiver Order, the Sub 979 Order, and the Sub 1032 Order.

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[1] The Smart Energy Now Pilot program was approved on February 14, 2011 in Docket No. E-7, Sub 961. On August 13, 2014, the Commission approved a fully commercialized version of the program, which is called Smart Energy in Offices, in the same docket.

12. The reasonable and prudent Rider 8 billing factor for residential customers[1] is 0.4291 cents per kilowatt hour (kWh), which, as is the case for all the other billing factors stated in these findings of fact, includes the regulatory fee.

13. The reasonable and prudent Rider 8 Vintage 2017 EE prospective billing factor for non-residential customers who do not opt out of Vintage 2017 of the Company's EE programs is 0.2437 cents per kWh.

14. The reasonable and prudent Rider 8 Vintage 2017 DSM prospective billing factor for non-residential customers who do not opt out of Vintage 2017 of the Company's DSM programs is 0.0789 cents per kWh.

15. The reasonable and prudent Rider 8 Vintage 2016 prospective EE billing factor for non-residential customers who participated in Vintage 2016 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2016 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0373 cents per kWh.

16. The reasonable and prudent Rider 8 Vintage 2015 prospective EE billing factor for non-residential customers who participated in Vintage 2015 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2015 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0418 cents per kWh.

17. The reasonable and prudent Rider 8 Vintage 2014 prospective EE billing factor for non-residential customers who participated in Vintage 2014 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0139 cents per kWh.

18. The reasonable and prudent Rider 8 Vintage 2015 EE EMF billing factor for non-residential customers who participated in Vintage 2015 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2015 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0821 cents per kWh.

19. The reasonable and prudent Rider 8 Vintage 2015 DSM EMF billing factor for non-residential customers who participated in Vintage 2015 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2015 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is (0.0125) cents per kWh.

20. The reasonable and prudent Rider 8 Vintage 2014 EE EMF billing factor for non-residential customers who participated in Vintage 2014 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0046 cents per kWh.

[1] The residential billing factor applicable to all residential customers is the sum of the residential prospective and residential true-up factors for the applicable vintage years.

21. The reasonable and prudent Rider 8 Vintage 2014 DSM EMF billing factor for non-residential customers who participated in Vintage 2014 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is (0.0015) cents per kWh.

22. The reasonable and prudent Rider 8 Vintage 4 EE EMF billing factor for non-residential customers who participated in Vintage 4 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 4 (2013) during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0004 cents per kWh.

23. The reasonable and prudent Rider 8 Vintage 4 DSM EMF billing factor for non-residential customers who participated in Vintage 4 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 4 (2013) during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0002 cents per kWh.

24. The reasonable and prudent Rider 8 Vintage 3 EE EMF billing factor for non-residential customers who participated in Vintage 3 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 3 (2012) during the annual enrollment periods for that vintage, nor (b) opted out of Vintage 2017) is (0.0024) cents per kWh.

25. The reasonable and prudent Rider 8 Vintage 3 DSM EMF billing factor for non-residential customers who participated in Vintage 3 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 3 (2012) during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0003 cents per kWh.

26. The reasonable and prudent Rider 8 Vintage 2 EE EMF billing factor for non-residential customers who participated in Vintage 2 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2 (2011) during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is (0.0053) cents per kWh.

27. The reasonable and prudent Rider 8 Vintage 2 DSM EMF billing factor for non-residential customers who participated in Vintage 2 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2 (2011) during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0002 cents per kWh.

28. The reasonable and prudent Rider 8 Vintage 1 EE EMF billing factor for non-residential customers who participated in Vintage 1 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 1 (2009-2010) during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0003 cents per kWh.

29. The reasonable and prudent Rider 8 Vintage 1 DSM EMF billing factor for non-residential customers who participated in Vintage 1 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 1 (2009-2010) during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2017) is 0.0002 cents per kWh.

30. The agreement between the Company and Public Staff to adjust the 2016 program costs by $3,851 and flow it through the EMF to be set in next year's proceeding is reasonable and should be approved.

31. DEC should continue to leverage its Collaborative to discuss with stakeholders ways of increasing DSM and EE program impacts and participation, including programs designed to increase the number of opt-out eligible customers electing to take advantage of the Company's programs and potential changes to existing programs or the development of new programs as discussed in the testimony of SACE witness Weiss.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 1-2

The evidence and legal bases in support of these findings and conclusions can be found in the Application, the pleadings, the testimony, and the exhibits in this docket, as well as in the statutes, case law, and rules governing the authority and jurisdiction of this Commission. These findings are informational, procedural, and jurisdictional in nature.

G.S. 62-133.9 grants the Commission the authority to approve an annual rider, outside of a general rate case, for recovery of reasonable and prudent costs incurred in the adoption and implementation of new DSM and EE measures, as well as appropriate rewards for adopting and implementing those measures. Similarly, Commission Rule R8-68 provides, among other things, that reasonable and prudent costs of new DSM or EE programs approved by the Commission shall be recovered through the annual rider described in G.S. 62-133.9 and Commission Rule R8-69. The Commission may also consider in the annual rider proceeding whether to approve any utility incentive (reward) pursuant to G.S. 62-133.9(d)(2)a through c.

Commission Rule R8-69 outlines the procedure whereby a utility applies for and the Commission establishes an annual DSM/EE rider. Commission Rule R8-69(a)(2) defines DSM/EE rider as "a charge or rate established by the Commission annually pursuant to G.S. 62-133.9(d) to allow the electric public utility to recover all reasonable and prudent costs incurred in adopting and implementing new demand-side management and energy efficiency measures after August 20, 2007, as well as, if appropriate, utility incentives, including net lost revenues." Commission Rule R8-69(c) allows a utility to apply for recovery of incentives for which the Commission will determine the appropriate ratemaking treatment.

G.S. 62-133.9, along with Commission Rules R8-68 and Rule R8-69 establish a procedure whereby an electric public utility files an application in a unique docket for the Commission's approval of an annual rider for recovery of reasonable and prudent costs of approved DSM and EE programs as well as appropriate utility incentives, potentially including "[a]ppropriate rewards based on capitalization of a percentage of avoided costs achieved by demand-side management and energy efficiency measures." Consistent with this provision, as well as the Commission-approved Sub 831 Mechanism, the Company filed an application for approval of such annual rider (Rider 8) and a portion of the cost recovery and utility incentives the Company seeks through Rider 8 is based on the Company recovering a percentage of the avoided capacity costs achieved by DSM measures, and a separate percentage of the net present value (NPV) of avoided capacity costs and avoided energy costs achieved by EE measures. In addition, the Sub 831 Mechanism provides for a limited period of recovery of the Company's NLR resulting from implementation of its EE measures approved as part of the Sub 831 Pilot, net of found revenues. The remaining portion of proposed Rider 8 provides for the recovery, pursuant to the Sub 1032 Mechanism, of DSM/EE program costs, NLR (net of found revenues), and a PPI incentive related to the DSM and EE programs approved in the Sub 1032 Order and those approved following the Sub 1032 Order.[1] Recovery of these costs and utility incentives is also consistent with G.S. 62-133.9, Rule R8-68, and Rule R8-69. Therefore, the Commission concludes that it has the authority to consider and approve the relief the Company is seeking in this docket.

EVIDENCE FOR FINDING AND CONCLUSION NO. 3

The evidence for this finding can be found in DEC's Application, the testimony and exhibits of Company witnesses Evans and Miller, the affidavit of Public Staff witness Floyd, and various Commission orders.

DEC witness Miller's testimony and exhibits show that the Company's request for approval of Rider 8 is associated with the Sub 831 Pilot and the Sub 1032 portfolio of programs, as well as the programs approved by the Commission after the Sub 1032 Order. The direct testimony and exhibits of DEC witness Evans listed the applicable DSM/EE programs as follows: Appliance Recycling Program; Energy Assessments Program; EE Education Program; Energy Efficient Appliances and Devices; HVAC EE Program; Multi-Family EE Program; My Home Energy Report; Income-Qualified EE and Weatherization Program; Power Manager; Nonresidential Smart $aver® Energy Efficient Food Service Products Program; Nonresidential Smart $aver® Energy Efficient HVAC Products Program; Nonresidential Smart $aver® Energy Efficient IT Products Program; Nonresidential Smart $aver® Energy Efficient Lighting Products Program; Nonresidential Smart $aver® Energy Efficient Process Equipment Products Program; Nonresidential Smart $aver® Energy Efficient Pumps and Drives Products Program; Nonresidential Smart $aver® Custom Program; Nonresidential Smart $aver® Custom Energy Assessments Program; PowerShare®; PowerShare® Call Option; Small Business Energy Saver; Smart Energy in Offices; Business Energy Report Pilot; and EnergyWise for Business.

In his affidavit, Public Staff witness Floyd also listed the DSM/EE programs and pilots for which the Company seeks cost recovery and noted that each of these programs and pilots has received approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under G.S. 62-133.9.

[1] The programs approved by the Commission following the Sub 1032 Order are as follows: Smart Energy in Offices (formerly, the Smart Energy Now Pilot), which was approved in Docket No. E-7, Sub 961 on August 13, 2014; Small Business Energy Saver, which was approved on August 13, 2014 in Docket No. E-7, Sub 1055; the Business Energy Report Pilot, which was approved in Docket No. E-7, Sub 1081 on August 19, 2015; and EnergyWise for Business, which was approved in Docket No. E-7, Sub 1093 on October 27, 2015. The Company's Energy Management Information Services Pilot has since been discontinued.

Thus, the Commission finds and concludes that each of the programs and pilots listed by witnesses Evans and Floyd has received Commission approval as a new DSM or EE program or pilot and is, therefore, eligible for cost recovery in this proceeding under G.S. 62-133.9.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 4-5

The evidence for these findings can be found in the testimony and exhibits of Company witness Evans and the affidavit of Public Staff witness Floyd.

DEC witness Evans testified that the Company reviewed the portfolio of DSM/EE programs and performed prospective analyses of each of its programs and the aggregate portfolio for the Vintage 2017 period, the results of which are incorporated in Evans Exhibit No. 7.[1] DEC's calculations indicate that with the exception of the Income-Qualified EE and Weatherization Program (which was not cost-effective at the time it was approved by the Commission, but was approved based on its societal benefit), the aggregate portfolio continues to be cost-effective.

Public Staff witness Floyd stated in his affidavit that he reviewed DEC's calculations of cost-effectiveness under each of the four standard cost-effectiveness tests - the Utility Cost (UC), Total Resource Cost (TRC), Participant, and Ratepayer Impact Measure (RIM) tests. He indicated that each program was cost-effective under both the UC and the TRC tests, with the exception of the Income-Qualified EE and Weatherization Program. Witness Floyd stated that his review indicated that the portfolio as a whole remains cost-effective under all four tests.

The Commission in its Order on Application For Approval of Program Modifications, issued on February 9, 2016 (February 9 Order) approved DEC's proposed modifications to the Residential HVAC EE program and granted DEC until March 1, 2017, to achieve projected cost effectiveness under the Total Resource Cost (TRC) test; otherwise the program would be terminated effective March 31, 2017. Public Staff witness Floyd notes in his affidavit that DEC did not include evaluations of cost-effectiveness for Residential HVAC EE programs in Evans Exhibit 7. He states that DEC provided the cost-effectiveness data for both of these programs in response to a data request, which showed projected 2017 TRC values of 1.04 for the Residential HVAC EE, making it cost-effective.

The Commission therefore concludes that DEC's portfolio of DSM and EE programs is cost-effective and eligible for inclusion in Rider 8. The Commission further concludes that the Residential HVAC EE program should continue as modified by the February 9 Order, as it is now cost-effective and should not be terminated on March 31, 2017.

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[1] Witness Evans noted that this analysis does not include any values for DEC's HVAC EE Program or its Appliance Recycling Program, as no costs have been included for these programs for Vintage 2017. The Appliance Recycling Program is currently suspended while the Company determines whether to continue with the program following the bankruptcy of the program vendor. While DEC is evaluating additional opportunities to modify the HVAC EE Program to make it cost-effective by the end of 2016, the HVAC EE Program will be terminated on March 31, 2017 if the program is unable to achieve a TRC score of 1.0 or greater by that time. However, Witness Floyd indicated that cost-effectiveness data provided by the Company in response to a data request projected TRC scores greater than 1.0 for both the HVAC EE Program and the Appliance Recycling Program in 2017.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 6-8

The evidence in support of these findings can be found in the testimony and exhibits of DEC witness Evans and the affidavits of Public Staff witnesses Floyd and Maness.

DEC witness Evans testified regarding the EM&V process, activities, and results presented in this proceeding. He explained that the EMF component of Rider 8 incorporates actual customer participation and evaluated load impacts determined through EM&V and applied pursuant to the EM&V Agreement. In addition, actual participation and evaluated load impacts are used prospectively to update estimated NLR. In this proceeding, the Company submitted, as exhibits to witness Evans' testimony, process evaluation and impact evaluation studies for the EE in Schools Program, Multi-Family EE Program, Energy Efficient Appliances and Devices (CFL Bulbs), and Energy Efficient Appliances and Devices (Save Energy and Water Kit). The Company also completed impact evaluation studies for Power Manager and the Appliance Recycling Program.

In the Company's last Rider EE proceeding in Docket No. E-7, Sub 1073, the Company and the Public Staff agreed that further discussion of the EM&V for the Smart Energy Now Pilot and the Specialty Bulb measures of the Energy Efficient Appliances and Devices Program was necessary. In its Sub 1073 Order, the Commission accepted the impacts from these EM&V reports provided that vintages of these programs covered by these EM&V reports would be subject to further adjustment in this proceeding depending upon the outcome of the Public Staff and DEC's discussions.

As described by witness Evans and Public Staff witness Maness, in accordance with the Sub 1073 Order, the Public Staff and DEC discussed EM&V for the Smart Energy Now Pilot and the Specialty Bulb measures. The parties agreed it was necessary to revise the EM&V impact results for the Smart Energy Now Pilot, but determined that no changes to the results reported for the Specialty Bulb measures were required.

The agreed-upon revisions to impacts for the Smart Energy Now Pilot address an inaccuracy in the data set that was used by the Company's third party evaluator, and also reflect a compromise between DEC and the Public Staff regarding the need to adjust the results for the impacts of weather. As a result, the Company is reporting lower results for its Smart Energy Now Pilot than it reported in Docket No. E-7, Sub 1073. Public Staff witness Maness indicated that the total impact of the agreement is a reduction of $921,623 in total revenue requirements, distributed over all of the vintages under the Sub 831 Pilot. The agreed-upon revisions are reflected in Rider 8 in the EMF components for Vintages 1 through 4, and are the basis for the final true-up under the Sub 831 Mechanism. Witness Maness testified that he had reviewed the revised impacts for the Smart Energy Now Pilot and found that they are reasonable and appropriate when compared to prior Public Staff calculations.

In his affidavit, Public Staff witness Floyd testified that with respect to program vintages for which EM&V reports were filed in this proceeding, he does not recommend any adjustment to the impacts at this time. He agreed with witness Evans' testimony that all program vintages under the Sub 831 Mechanism have been evaluated, that this rider represented the final true-up of the program impacts for these vintages and programs, and that he considered EM&V of these programs and vintages to be complete.

In addition, witness Floyd stated that DEC had appropriately addressed EM&V-related recommendations made in previous DSM/EE rider proceedings. He also provided recommendations concerning the content of future EM&V studies for particular EE programs, noting that DEC's implementation of these recommendations would be subject to the consideration of whether the cost would outweigh the benefit. Public Staff witness Floyd recommended that:

1. EE in Schools Program Report:
   (a) Future evaluations of this program should consider including a control group in the billing analysis to better explain naturally occurring savings and to more accurately assign program savings to either EE improvements or behavioral changes. If DEC's evaluator does not use a control group, then DEC should provide the rationale and analysis supporting the decision not to do so in a future evaluation plan.
   (b) To the extent available, DEC's evaluator should incorporate North Carolina-specific assumptions and data when possible, or explain why it did not.

2. Multi-Family EE Program Report:
   (a) DEC's evaluator should investigate the feasibility of collecting baseline data on a prospective basis in order to improve the accuracy of the baseline assumptions used in the evaluation.
   (b) DEC should investigate the feasibility of assessing vacancy rates at participating properties in order to determine if all measures installed are generating savings, and provide an update on the status of this investigation in its annual rider filing.

3. EE Appliances and Devices (CFL Bulbs) Report:
   (a) Pursuant to the EM&V Agreement, the impacts derived through this EM&V report will be applied beginning in April 2015. DEC transitioned from CFL to light emitting diode ("LED") measures for this program in 2016. Therefore, DEC should apply the impacts from this report for all free CFL measures distributed through DEC's direct-ship CFL and online store channels from April 2015 through the end of 2015. For its LED measures, the Company should develop LED-specific impacts and apply those impacts beginning in 2016.
   (b) Future evaluations of bulbs distributed through any of DEC's free bulb direct-ship channels should be consistent with the Uniform Methods Project (UMP) and should include evaluations of baseline wattages, hours-of-use, in-service rates, and other key variables. These evaluations should be based on primary data to the extent feasible. In the event the DEC's evaluator deviates from the UMP, it should provide support for its decision.
   (c) DEC should include a shelf-stocking survey to study the progression of market transformation for lighting in the DEC service territory. The study

can be part of the LED study currently underway or a separate study, as appropriate. The results of this study should be used to inform decision-making in regard to baseline efficiency assumptions as well as free-ridership.

4. Appliance Recycling Program Report:
   If DEC resumes offering the Appliance Recycling Program, the next EM&V evaluation for this program should investigate the feasibility of completing a primary metering study as recommended by the UMP to estimate per-unit energy consumption. If a primary metering study is cost-prohibitive, the evaluator should use the alternative method recommended by the UMP, i.e., using other metering data collected as part of other recycling program evaluations that occurred within the previous five years to estimate the per-unit energy consumption. Should this alternative be used, the evaluation should discuss the other program evaluations considered, whether it made any adjustments to the per-unit energy consumption data, and if so, provide an explanation of each adjustment.

5. EE Appliances and Devices (Save Energy and Water Kit) Report - DEC filed a revised EM&V report on May 17, 2016, that corrected errors that had been identified by the evaluator. The Public Staff will continue to evaluate the measures associated with the revised report and, if necessary, will address any concerns or make adjustments in the next DSM/EE rider proceeding.

6. If feasible, any evaluations completed after the Commission's order in this proceeding should use the same methodology to evaluate identical measures or measures performing the identical function in separate programs within a customer class. If different methodologies are selected by DEC's independent evaluator, then the rationale for the different methodologies should be provided.

7. If DEC's evaluator relies upon the findings of a prior Duke Energy Progress, LLC (DEP) EM&V report to support the future evaluation of a DEC EE program or measure, the evaluator should provide support for its decision to do so, including a comparison of the programs/measures, populations, delivery channels, identification of potential sources of uncertainty, and reasons why a cross-application of EM&V is appropriate. In the case that a DEC EM&V report leverages a prior DEP EM&V report of similar EE programs that provide identical measures or those performing the identical function through different delivery channels, the EM&V evaluator should analyze these differences and their impact on inputs in the savings calculations, including hours-of-use and installation rates.

Witness Floyd concluded that with the exception of the EE Appliances and Devices (CFL Bulbs) Report, the EM&V of the vintages of the measures covered by the remaining reports filed in this proceeding should be considered complete. With respect to the EE Appliances and Devices (CFL Bulbs) Report, he recommended that the findings in that report be applicable to all free CFL bulbs delivered through the direct-ship or online store channels through

December 31, 2015. Savings for LED bulbs delivered through the free direct shipment channels would be based on the results of the LED evaluation currently underway. He further testified that, if DEC decides to use the findings from Evans Exhibit D for any other program that includes the distribution of CFLs, regardless of the channels used for distribution, he recommend that application of the findings be limited to CFL measures only.

With the exception of those EM&V-related recommendations made by Public Staff witness Floyd (which were not disputed by DEC), no party contested the EM&V information submitted by the Company. The Commission therefore finds that the EM&V analyses and reports submitted by DEC are acceptable for purposes of this proceeding, the EM&V recommendations concerning future EM&V reports contained in the affidavit of Public Staff witness Floyd should be approved, and the EM&V reports and applicable effective dates as identified by witness Floyd should be considered complete for purposes of calculating program impacts. The Commission further concludes that Rider 8 includes the final settlement of issues relating to EM&V for the Smart Energy Now Pilot and the Specialty Bulb measures, that DEC and the Public Staff's agreement with respect to these issues and the resulting revisions to the Smart Energy Now Pilot impacts are reasonable and appropriate, that the vintages related to the Smart Energy Now Pilot and the Specialty Bulb measures impacted by the EM&V reports can now be considered complete, and that Rider 8 appropriately reflects the adjustment of impacts relating to the Smart Energy Now Pilot in the final true-up relating to the Sub 831 Mechanism.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 9-10

The evidence in support of these findings can be found in the Sub 938 Second Waiver Order; the Sub 1032 Order; the testimony of Company witnesses Miller and Evans; and the testimony of Public Staff witness Maness. The rate period and the scope of the EMF components of Rider 8 are consistent with the Commission's ruling in the Sub 938 Second Waiver Order and the Sub 1032 Order, and are uncontroverted by any party.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 11-30

The evidence in support of these findings and conclusions can be found in the Sub 831 Order, the Sub 831 Found Revenues Order, the Sub 938 Waiver Order, the Sub 938 Second Waiver Order, the Sub 979 Order, and the Sub 1032 Order; as well as in the Company's Application, as set forth in the direct and revised testimony and exhibits of Company witnesses Miller and Evans; and in the affidavits of Public Staff witnesses Maness and Floyd.

On March 9, 2016, DEC filed its Application seeking approval of Rider 8, which includes the formula for calculation of Rider EE, as well as the proposed billing factors to be effective for the 2017 rate period. Company witness Miller and Public Staff witness Maness testified that the methods by which DEC has calculated its proposed Rider EE are the Sub 831 Mechanism as described in the Sub 831 Settlement and approved, with certain modifications, in the Sub 831 Order and other relevant Orders of the Commission, and the Sub 1032 Settlement and Sub 1032 Mechanism approved in the Sub 1032 Order.

Witness Miller provided an overview of the Sub 1032 Mechanism, which is designed to allow the Company to collect revenue equal to its incurred program costs[1] for a rate period plus a PPI based on shared savings achieved by the Company's DSM and EE programs, and to recover NLR for EE programs only.

Company witness Miller explained that the PPI is calculated by multiplying the net dollar savings achieved by the system portfolio of DSM and EE programs by a factor of 11.5%. The system amount of PPI is then allocated to North Carolina retail customer classes in order to derive customer rates. Company witness Evans explained that the calculation of the PPI is based on avoided cost savings, net of program costs, achieved through the implementation of the Company's DSM and EE programs.

The Company is allowed to recover NLR associated with a particular vintage for a maximum of 36 months or the life of the measure, or until the implementation of new rates in a general rate case to the extent that the new rates are set to recover NLR. DEC witness Miller testified that for the prospective components of Rider EE, NLR are estimated by multiplying the portion of the Company's tariff rates that represent the recovery of fixed costs by the <u>estimated</u> North Carolina retail kW and kWh reductions applicable to EE programs by rate schedule, and reducing this amount by estimated found revenues. The fixed cost portion of the tariff rates is calculated by deducting the recovery of fuel and variable operation and maintenance costs from the tariff rates. The NLR totals for residential and non-residential customers are then reduced by North Carolina retail found revenues computed using the weighted average lost revenue rates for each customer class. For the EMF components of Rider EE, NLR are calculated by multiplying the fixed cost portion of the tariff rates by the <u>actual and verified</u> North Carolina retail kW and kWh reductions applicable to EE programs by rate schedule, and reducing this amount by actual found revenues.

Witness Evans described how, in accordance with the Sub 831 Settlement, the Commission's Sub 831 Found Revenues Order, and the Sub 1032 Settlement, DEC reduces NLR by net found revenues. Additionally, he stated that the Company has continued the practice the Commission approved in the Sub 1073 Order for purposes of that proceeding of reducing net found revenues by the monetary impact (negative found revenues) caused by reductions in consumption resulting from the Company's current initiative to replace Mercury Vapor lights with LED fixtures.

In each of its annual rider filings, DEC performs an annual true-up process for the prior calendar year vintages. The true-up will reflect actual participation and verified EM&V results for the most recently completed vintage, applied in accordance with the EM&V Agreement. The Company expects that most EM&V will be available in the time frame needed to true-up each vintage in the following calendar year. If any EM&V results for a vintage are not available in time for inclusion in DEC's annual rider filing, however, then the Company will make an appropriate adjustment in the next annual filing.

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[1] Rule R8-68(b)(1) defines "program costs" as all reasonable and prudent expenses expected to be incurred by the electric public utility, during a rate period, for the purpose of adopting and implementing new DSM and EE measures previously approved pursuant to Rule R8-68.

Under the Sub 1032 Settlement, as witness Miller explained, deferral accounting may be used for over- and under-recoveries of costs eligible for recovery through the annual DSM/EE rider. The balance in the deferral accounts, net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in the Company's then most recent general rate case. She testified that the methodology used for the calculation of interest shall be the same as that typically utilized for the Company's Existing DSM Program Rider proceedings. Pursuant to Commission Rule R8-69(c)(3), the Company will not accrue a return on NLR or the PPI.

Under the Sub 1032 Settlement, as with the Sub 938 First Waiver Order and the Sub 831 Pilot, qualifying non-residential customers may opt-out of the DSM and/or EE portion of Rider EE during annual election periods. Rider EE will be charged to all customers who have not elected to opt-out during an enrollment period and who participate in any vintage year of programs, and these customers will be subject to all true-up provisions of the approved Rider EE for any vintage in which the customers participate. Company witness Miller explained that the Sub 1032 Mechanism affords an additional opportunity for participation, whereby qualifying customers may opt-in to the Company's EE and/or DSM programs during the first five business days of March. Customers who elect to begin participating in the Company's DSM and/or EE programs during the special "opt-in period" during March of each year will be retroactively billed the applicable Rider EE amounts back to January 1 of the vintage year, such that they will pay the appropriate Rider EE amounts for the full rate period.

Witness Miller explained that the billing factors are computed separately for DSM and EE measures by dividing the revenue requirements for each customer class, residential and non-residential, by the forecasted sales for the rate period for the customer class. For non-residential rates, the forecasted sales exclude the estimated sales to customers who have elected to opt-out of paying Rider EE. The non-residential billing factors are separately computed for each vintage.

Company witness Miller testified that program costs and incentives for EE programs targeted at retail residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales (grossed up for line losses) to total retail kWh sales (grossed up for line losses), and then recovered only from North Carolina retail residential customers. Revenue requirements related to EE programs targeted at retail non-residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales (grossed up for line losses) to total retail kWh sales (grossed up for line losses), and then recovered from only North Carolina retail non-residential customers. The portion of revenue requirements related to NLR is computed based on the kilowatt (kW) and kWh savings of North Carolina retail customers.

For DSM programs, witness Miller noted, the aggregated revenue requirement for all retail DSM programs targeted at both residential and non-residential customers across North Carolina and South Carolina is allocated to the North Carolina retail jurisdiction based on the North Carolina retail contribution to total retail peak demand. Both residential and non-residential customer classes are allocated a share of total system DSM revenue requirements based on each group's contribution to total retail peak demand.

The allocation factors used in DSM/EE EMF true-up calculations for each vintage are based on the Company's most recently filed Cost of Service studies at the time that the Rider EE filing incorporating the true-up is made. If there are subsequent true-ups for a vintage, the allocation factors used will be the same as those used in the original DSM/EE EMF true-up calculations.

Witness Miller explained that DEC calculates one integrated (prospective) DSM/EE rider and one integrated DSM/EE EMF rider for the residential class, to be effective each rate period. The integrated residential DSM/EE EMF rider includes all true-ups for each applicable vintage year. Given that qualifying non-residential customers can opt-out of EE and/or DSM programs, DEC calculates separate DSM and EE billing factors for the non-residential class. Additionally, the non-residential DSM and EE EMF billing factors are determined separately for each applicable vintage year, so that the factors can be appropriately charged to non-residential customers based on their opt-in/out status and participation for each vintage year.

Prospective Components of Rider 8

Rider 8 consists of five prospective components, all of which are related to the Sub 1032 Mechanism: (1) a prospective Vintage 2014 component designed to collect the final half-year of estimated NLR for the Company's 2014 vintage of EE programs; (2) a prospective Vintage 2015 component designed to collect the third year of estimated NLR for the Company's 2015 vintage of EE programs; (3) a prospective Vintage 2016 component designed to collect the second year of estimated NLR for the Company's 2016 vintage of EE programs; (4) a prospective Vintage 2017 component designed to collect program costs, the PPI, and the first year of NLR for the Company's 2017 vintage of EE programs; and (5) a prospective Vintage 2017 component designed to collect program costs and the PPI for the Company's 2017 vintage of DSM programs.

Pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order, the rate period for the prospective components of Rider 8 is January 1, 2017 through December 31, 2017.

DEC witness Miller testified that the prospective revenue requirements for Vintage 2014 are determined separately for residential and non-residential customer classes and are based on the final half-year of estimated NLR for the Company's Vintage 2014 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and the Company's rates approved in DEC's most recent general rate case, Docket No. E-7, Sub 1026, which became effective September 25, 2013 (Sub 1026 Rates).

The prospective revenue requirements for Vintage 2015 are determined separately for residential and non-residential customer classes and are based on the third year of estimated NLR for the Company's Vintage 2015 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates.

The prospective revenue requirements for Vintage 2016 are determined separately for residential and non-residential customer classes and are based on the second year of estimated

NLR for the Company's Vintage 2016 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates.

The prospective revenue requirements for Vintage 2017 EE programs include estimates of program costs, the PPI, and the first year of NLR determined separately for residential and non-residential customer classes. The program costs and shared savings incentive are computed at the system level and allocated to North Carolina retail operations. The NLR for EE programs are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates.

On May 26, 2016, DEC witness Miller filed supplemental testimony and exhibits reflecting prospective billing factors for Rider 8 of 0.3861 cents per kWh for all North Carolina retail residential customers, 0.2437 cents per kWh for non-residential Vintage 2017 EE participants, 0.0789 cents per kWh for non-residential Vintage 2017 DSM participants, 0.0373 cents per kWh for non-residential Vintage 2016 EE participants, 0.0418 cents per kWh for non-residential Vintage 2015 EE participants, and 0.0139 cents per kWh for non-residential Vintage 2014 EE participants.

<u>EMF Components of Rider 8</u>

Rider 8 includes the following EMF components: (1) an EMF component which consists of the true-up of Vintage 2015 program costs, shared savings and participation for the Company's 2015 vintage of DSM and EE programs; (2) an EMF component which consists of the true-up of Vintage 2014 program costs, shared savings and participation for the Company's 2014 vintage of DSM and EE programs; and (3) EMF components for Vintages 1 through 4, which reflect the final true-up under the Sub 831 Mechanism.

Company witness Miller testified that pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order, the "test period" for the Vintage 2015 EMF component is January 1, 2015 through December 31, 2015. As the Sub 938 Second Waiver Order allows the EMF to cover multiple test periods, the test period for the Vintage 2014 EMF component is January 1, 2014 through December 31, 2014, and the test period for the EMF related to the final true-up of the Sub 831 Pilot includes the four prior Sub 831 vintages: Vintage 1 (June 1, 2009 through December 31, 2010); Vintage 2 (January 1, 2011 through December 31, 2011); Vintage 3 (January 1, 2012 through December 31, 2012); and Vintage 4 (January 1, 2013 through December 31, 2013).

Witness Miller explained the updates to the Vintage 2015 estimate filed in 2014 that comprise the Vintage 2015 EMF component of Rider 8. Estimated participation for Vintage 2015 was updated for actual participation for the period January through December 2015. With regard to NLR, estimated participation for the Year 1 Vintage 2015 estimate assumed a January 1, 2015 sign-up date and used a half-year convention, while the NLR Year 1 Vintage 2015 true-up was updated for actual participation for the period January through December 2015 and actual 2015 lost revenue rates. Found revenues for Year 1 of Vintage 2015 were trued up according to Commission-approved guidelines. To reflect the results of EM&V, Vintage 2015 estimated avoided cost savings were updated pursuant to the EM&V Agreement. Finally, while the Vintage 2015 estimate included only the programs approved prior to the filing of the estimated

Vintage 2015 revenue requirement, the Vintage 2015 true-up was updated for new programs and pilots approved and implemented during Vintage 2015. For DSM programs, the Vintage 2015 true-up reflects the actual quantity of demand reduction capability for the Vintage 2015 period.

Actual year one (2015) NLR for Vintage 2015 were calculated using actual kW and kWh savings by North Carolina retail participants by customer class in 2015, based on actual participation and load impacts applied according to the EM&V Agreement. The rates applied to the kW and kWh savings are those in effect for 2015, reduced by fuel and variable operation and maintenance costs. NLR were then offset by actual found revenues for Year 1 NLR of Vintage 2015. NLR were calculated by rate schedule within the residential and non-residential customer classes.

DEC witness Miller also described the basis for the Vintage 2014 EMF component of Rider 8. She explained that avoided costs and NLR for Vintage 2014 EE programs were trued-up based on updated EM&V participation results. Avoided costs for Vintage 2014 DSM were also trued-up to correct participation results. She explained that the actual kW and kWh savings were as experienced during the period January 1, 2014 through December 31, 2014. The rates applied to the kW and kWh savings are the retail rates that were in effect during each period the lost revenues were earned, reduced by fuel and other variable costs.

As witness Miller testified, Rider 8 is the last Rider EE containing components relating to the Sub 831 Mechanism. She explained that the Sub 831 Settlement calls for a final true-up, which includes a final comparison of the revenues collected from customers through Rider EE during the Sub 831 Pilot to the amount of revenue DEC is authorized to collect from customers based on the independently measured and verified results. The final true-up process also includes calculations that determine the earnings for the entire Sub 831 Pilot and ensure that the level of compensation recovered by DEC is capped so that the after-tax rate of return on actual program costs applicable to DSM/EE programs does not exceed the predetermined earnings cap levels set out in the Sub 831 Settlement.

In last year's DSM/EE cost recovery proceeding in Docket No. E-7, Sub 1073, DEC performed a calculation of the final true-up and earnings cap for the Sub 831 Mechanism, which included impacts from EM&V for the Smart Energy Now Pilot and the Specialty Bulb measures of the Energy Efficient Appliances and Devices Program. As described above, the Public Staff and the Company agreed that DEC would make certain adjustments to the impacts for the Smart Energy Now Pilot, but not for the Specialty Bulb measures. Witness Miller explained that the agreed-upon revisions to the avoided costs and NLR for the Smart Energy Now Pilot are the only changes to the final true-up of the Sub 831 Pilot filed in last year's proceeding and are the only charges included in Rider 8 that relate to the Sub 831 Mechanism.

Overall, as set forth on Supplemental Miller Exhibit 1, the Company proposed an EMF of 0.0430 cents per kWh for its North Carolina retail residential customers, 0.0821 cents per kWh for non-residential Vintage 2015 EE participants, (0.0125) cents per kWh for non-residential Vintage 2015 DSM participants, 0.0046 cents per kWh for non-residential Vintage 2014 EE participants, (0.0015) cents per kWh for non-residential Vintage 2014 DSM participants, 0.0004 cents per kWh for non-residential Vintage 4 EE participants, 0.0002 cents per kWh for non-residential Vintage 4 DSM participants, (0.0024) cents per kWh for non-residential Vintage 3 EE participants, 0.0003 cents per kWh for non-residential Vintage 3 DSM participants, (0.0053) cents per kWh for non-residential Vintage 2 EE participants, 0.0002 cents per kWh for non-residential Vintage 2 DSM participants, 0.0003 cents per kWh for non-residential Vintage 1 EE participants, and 0.0002 cents per kWh for non-residential Vintage 1 DSM participants.

Public Staff Review of Company Rider 8 Calculations

As discussed above, Public Staff witness Floyd filed an affidavit in this proceeding discussing several topics and issues related to the Company's filing. The Public Staff pointed out that none of these topics and issues necessitate an adjustment in this particular proceeding to the Company's billing factor calculations. Public Staff witness Maness testified that his investigation of DEC's filing in this proceeding focused on whether the Company's proposed DSM/EE billing factors (a) were calculated in accordance with the Sub 831 Settlement (as modified by the Commission) and the Sub 1032 Settlement, as applicable, as well as other relevant Commission orders, and (b) otherwise adhered to sound ratemaking concepts and principles. With the exception of the items discussed below, one of which does not require any adjustment to the Company's proposed billing factors and the remainder of which were subsequently corrected by DEC's supplemental filing, witness Maness testified that he believes that the Company has calculated the Rider 8 billing factors in a manner consistent with G.S. 62-133.9, Commission Rule R8-69, the Sub 831 Settlement as modified by the Commission, the EM&V Agreement, the Sub 1032 Settlement, and other relevant Commission orders.

Public Staff witness Maness noted that in the course of his investigation, the Public Staff and DEC became aware of an accounting error which resulted in the exclusion of $459,999 from the residential revenue requirement. Correction of this error was appropriately addressed by DEC in its supplemental filing made on May 26, 2016 and is reflected in the revised billing factors included in Supplemental Miller Exhibit 1. Witness Maness testified that the Public Staff had no objection to this correction.

Witness Maness also testified that as part of its investigation in this proceeding, the Public Staff performed a review of the DSM/EE program costs incurred by DEC during the 12-month period ended December 31, 2015. To accomplish this, the Public Staff selected and reviewed a sample of source documentation for test year costs included by the Company for recovery through the DSM/EE riders. Review of this sample was intended to test whether the costs included by the Company in the DSM/EE riders are valid costs of approved DSM and EE programs. During this review, the Public Staff identified an error in the amount of $1,840.63 being found in the costs included in the sample. However, this error was corrected by DEC in its supplemental filing, as reflected in Supplemental Miller Exhibit 1.

Witness Maness also noted that during this review it was discovered that the Company had not included approximately $154,000 of DSM/EE costs on a system basis. In her supplemental testimony and exhibits, DEC witness Miller provided support for $154,100.48 that was inadvertently excluded, which erroneously reduced the amounts used to calculate the billing factors for Vintage 2015. This adjustment is reflected in Supplemental Miller Exhibit 1. Based on the results of the Public Staff's investigation, witness Maness recommended approval of Rider 8 proposed by DEC in its Supplemental Filing in this proceeding, subject to the results of the Public Staff's review of the revisions to program costs included in Supplemental Miller Exhibit 1. He concluded that all the recommended billing factors in Supplemental Miller Exhibit 1 should be approved subject to any appropriate and reasonable true-ups in future cost recovery proceedings consistent with the Sub 831 and Sub 1032 Orders, as well as other relevant orders of the Commission, including the Commission's final order in this proceeding.

While the Public Staff was still in the process of reviewing the support provided for the program cost revisions at the time of the June 7, 2016 hearing, at the additional public hearing on July 29, 2016, the Public Staff stated that it had completed its review, and had found that with one exception the Company's proposed revision was reasonable and appropriate. The one exception, in the amount of $3,851, consists of capital costs that should be removed from annual expenses. Removal of this relatively small amount from test year program costs in this proceeding would not affect the rates being proposed by the Company in its supplemental filing. Therefore, the Company and the Public Staff agreed that the adjustment to remove the $3,851 could instead be made to 2016 program costs, which would flow it through the EMF to be set in next year's proceeding. On August 2, 2016, the Public Staff filed a letter with the Commission further explaining its findings and presenting its and the Company's recommendation to the Commission. The letter stated that based on the results of its review, the Public Staff recommended that the Commission approve the proposed rates set forth in the Company's Supplemental Filing of May 26, 2016.

In his affidavit, Public Staff witness Maness also identified a potential issue relating to the method by which DEC calculated interest on the over-recoveries of NLR and PPI to be under the Sub 1032 Mechanism. However, because the difference between interest amounts calculated using the Public Staff's approach and the Company's approach was so minimal that it would not impact the average customer's monthly bill, witness Maness did not propose that an adjustment be made in this case.

Witness Maness also provided testimony in support of DEC's calculation of its final true-up relating to the Sub 831 Pilot to reflect the Public Staff and DEC's agreement relating to EM&V for the Smart Energy Now Pilot.

On August 10, 2016, NCSEA filed a letter stating that it does not challenge as unreasonable or imprudent any of the costs for which DEC seeks recovery. However, NCSEA seeks to provide a temporal context for those costs with three graphs depicting DEC's DSM/EE rider charges since 2010.

Conclusions on Calculations of Rider EE

The Commission finds and concludes that the components of Rider 8, as revised in Supplemental Miller Exhibit 1, are appropriately in compliance with the Commission's findings and conclusions herein, as well as the Commission's findings and conclusions as set forth in the Sub 831 Order, the Sub 831 Found Revenues Order, the Sub 938 First Waiver Order, the Sub 938 Second Waiver Order, the Sub 979 Order, and the Sub 1032 Order. The Commission also finds that the agreement between the Company and Public Staff to adjust the 2016 program costs by

$3,851 and flow it through the EMF to be set in next year's proceeding is reasonable and should be approved.

EVIDENCE FOR FINDING AND CONCLUSION NO. 31

The evidence in support of this finding and conclusion can be found in the testimony of DEC witness Evans and SACE witness Weiss, as well as the post-hearing briefs filed by SACE and CIGFUR.

Company witness Evans noted that Vintage 2015 of the Company's DSM and EE programs produced over 649 million kWh of energy savings and nearly 1,004 megawatts (MW) of capacity savings, which produced NPV avoided cost savings of $351 million. During Vintage 2015, DEC's portfolio of DSM/EE programs was able to deliver energy and capacity savings that yielded avoided costs that were 124 percent of its target, while expending only 105 percent of targeted program costs.

Witness Evans testified that opt-outs by qualifying industrial and commercial customers have had a negative effect on the Company's overall non-residential impacts. For Vintage 2015, 2,727 eligible customer accounts opted out of participating in DEC's non-residential portfolio of EE programs, and 3,436 eligible customer accounts opted out of participating in the Company's non-residential DSM programs. To reduce opt-outs, the Company continues to evaluate and revise its non-residential portfolio of programs to accommodate new technologies, eliminate product gaps, remove barriers to participation, and make its programs more attractive to opt-out eligible customers. It also continues to leverage its Large Account Management Team to make sure customers are informed about product offerings and their ability to opt-into the Company's DSM and/or EE offerings during the March opt-in window.

SACE witness Weiss testified that the Company has achieved significant EE savings and that SACE supports the Company's requested Rider 8. She noted that though DEC met its own EE savings projection in 2015, the Company's energy savings forecasts are declining and the percentage of non-residential customers electing to opt-out of the Company's DSM and EE programs is increasing. While acknowledging DEC's efforts to increase non-residential participation in DSM/EE programs, witness Weiss recommended additional improvements in the Company's DSM/EE efforts, including several recommendations that could encourage commercial and industrial customers to participate in DEC's DSM/EE programs. She also made specific recommendations regarding ways to expand and improve the Company's non-residential programs, as well as its residential programs, including low income program opportunities. In particular, she recommended that:

(1) The Commission should require DEC to file a supplement to its Application that proposes a plan for implementing the Incremental Portfolio outlined in a report DEC filed with the South Carolina Public Service Commission (South Carolina Commission);

(2) The Commission should direct the Company to use a future Collaborative meeting to host a discussion about the costs of EE programs, both over time, and as participation increases;

(3) The Commission should direct the Company to conduct a survey of opted-out customers for discussion in a future Collaborative meeting;

(4) The Company should develop a standardized EM&V requirement for opting out;

(5) The Company should include an ongoing discussion of EM&V recommendations in future Collaborative meetings and a summary report on the results in each cost-recovery filing; and

(6) The Company should adopt new programs based on best practices from around the country, including on-bill financing programs, an enhanced multi-family affordable housing program and additional low income residential EE programs, and should consider bundling programs and encouraging cross-participation in EE programs.

Witness Weiss includes as an exhibit to her testimony a report prepared by DEC titled "Analysis of Energy Efficiency Portfolio," which was filed on March 1, 2016 with the South Carolina Public Service Commission (South Carolina PSC) as an exhibit in the Company's South Carolina Rider 8 proceeding in Docket No. 2016-92-E. This report estimates the EE costs, participation, and load impacts associated with fulfilling aspirational EE goals reflected in a Settlement Agreement entered into on December 8, 2011 by Environmental Defense Fund; South Carolina Coastal Conservation League (CCL); SACE; Duke Energy Corporation; Progress Energy, Inc.; DEC; and Progress Energy Carolinas, Inc. (now DEP) and approved by the South Carolina PSC on December 11, 2013, in Docket No. 2011-158-E. The "Incremental Portfolio" is the additional program participation that would be necessary to meet these aspirational (but not mandatory) targets – namely, annual EE savings totaling 1% of the Company's prior year retail electricity sales and cumulative savings of 7% of retail electricity sales over the time period from 2014-2018.

In a Revised Settlement Agreement made by Natural Resources Defense Council; SACE; CCL; Wal-Mart Stores, East, LP; Sam's East, Inc.; DEC; and the South Carolina Office of Regulatory Staff approved by the South Carolina PSC on December 20, 2013 in Docket No. 2013-298-E, the Company agreed to prepare and file this report for informational purposes with the South Carolina PSC in its annual DSM/EE rider proceeding. Neither settlement agreement requires the Company to implement the Incremental Portfolio.

Notably, this analysis is not required to be filed by the Company in North Carolina. Further, this report and the Incremental Portfolio focus on rate impacts for South Carolina customers and do not include the information necessary to evaluate the impact of the Incremental Portfolio on North Carolina customers. Finally, as witness Weiss acknowledged in response to questioning by Chairman Finley, to the extent that non-residential customers opt out of the Company's programs and implement their own DSM/EE programs, those programs do not count toward achievement of the Company's aspirational targets. Thus, while the retail electricity sales that the 1% goal is based upon include sales to customers who have opted out of paying Rider EE, the level of savings the Company is able to achieve is negatively impacted by the ability of certain non-residential customers to opt out of the DSM/EE rider. For these reasons, the Commission does not find that it is appropriate to require the Company to file a plan for implementing the Incremental Portfolio in North Carolina.

Witness Weiss also recommends that the Commission direct the Company to conduct a survey of opt-out customers. The Commission notes that the Collaborative has already discussed such a survey, and because the stakeholders did not come to a consensus as to whether such a survey was warranted, the Company did not pursue it further. As discussed in the Direct Testimony of Company witness Timothy Duff filed in Docket No. E-7, Sub 1050, a number of parties that were representing opt-out eligible customers opposed such a study. They pointed out that such a study or survey would be inconsistent with the requirements in Senate Bill 3 and could unnecessarily expose customers to the risk of disclosing confidential and proprietary competitive information. These parties, as well as representatives of DEC's Large Account Management Team, stated that many opt-out eligible customers regularly discuss the economics of investing in EE and participating in the Company's DSM and EE programs, but that they would not want to share this information publicly due to the competitive nature of it. In addition, the South Carolina Office of Regulatory Staff and Public Staff did not support conducting such a survey. Because the Collaborative has already considered this issue and did not elect to have the Company proceed with such a survey, the Commission will not direct DEC to conduct a survey of customers who have opted out.

In its Post-Hearing Brief, SACE notes that witness Weiss generally supported DEC's DSM/EE rider application. However, SACE summarizes witness Weiss' recommendations for improvements in DEC's DSM/EE programs, and submits that the Commission should adopt witness Weiss' recommendations.

In its Post-hearing brief, CIGFUR states that it believes the Commission should reject the recommendation by witness Weiss to develop a standardized EM&V opt-out protocol for non-residential customers. CIGFUR states that such a protocol is fundamentally inconsistent with both the unambiguous language of G.S. 62-133.9(f) and the Commission's rulemaking implementing Senate Bill 3.

With respect to witness Weiss's recommendation that the Company be required to develop an EM&V protocol for opted out customers, the Commission has already addressed this issue in its rulemaking proceeding implementing Senate Bill 3 and declined to adopt such a requirement. In particular, in its Order Adopting Final Rules issued on February 29, 2008, in Docket No. E-100, Sub 113, the Commission concluded that Commission Rule R8-69 should not be revised to include a proposal by EDF, SACE, and SELC that would have required customers desiring to opt out to provide detailed descriptions of measures they have planned or implemented and to quantify results and project impacts from these measures. See id. at 128-29. The Commission noted that under Senate Bill 3, "[a]ll that is required of a program used as the basis for a customer's decision to opt out is that: (1) the program have been implemented in the past or (2) that it be proposed to be implemented in the future in accordance with stated, quantified goals." Id. at 129. Accordingly, the Commission does not find that it is appropriate to require DEC to establish a standardized EM&V requirement for opting out.

Witness Weiss's remaining recommendations focus on topics of discussion in future Collaborative meetings and potential programs SACE would like to see adopted by the Company. The Commission believes that the Collaborative is the appropriate forum for reviewing potential programs and enhancements to existing DSM/EE programs in DEC's service territory. Specifically, the Commission finds that the Collaborative should continue to discuss how to increase program participation and impacts with an emphasis on increasing the participation of opt-out eligible customers; discuss the specific recommendations made by SACE witness Weiss regarding new programs or enhancements to existing programs; discuss the costs of EE programs, both over time, and as participation increases, as outlined by witness Weiss; and continue to review recommendations for improving programs and increasing participation provided by the Company's EM&V consultants.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby approves the calculation of Rider EE as filed by DEC and revised in the Supplemental Testimony and Exhibits of Carolyn T. Miller and the Supplemental Exhibits of Robert P. Evans, and the resulting billing factors as set forth in Supplemental Miller Exhibit 1, to go into effect for the rate period January 1, 2017 through December 31, 2017, subject to appropriate true-ups in future cost recovery proceedings consistent with the Sub 1032 Order and other relevant orders of the Commission.

2. That DEC shall work with the Public Staff to prepare a proposed Notice to Customers of the rate changes approved herein. Within 30 days from the date of this Order, the Company shall file said notice and the proposed time for service of such notice for Commission approval.

3. That the Company should incorporate the recommendations made by Public Staff witness Floyd into future EM&V reports filed with the Commission in subsequent DSM/EE rider proceedings.

4. That the Collaborative should (a) continue to discuss how to increase program participation and impacts with an emphasis on increasing the participation of opt-out eligible customers; (b) discuss the specific recommendations made by SACE witness Weiss regarding new programs or enhancements to existing programs; (c) discuss the costs of EE programs, both over time, and as participation increases, as outlined by witness Weiss; and (d) continue to review recommendations for improving programs and increasing participation provided by the Company's EM&V consultants.

ISSUED BY ORDER OF THE COMMISSION.
This the __25th__ day of ___August___, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ELECTRIC -- RATE SCHEDULES/RIDERS/SERVICE RULES & REGULATIONS

DOCKET NO. E-7, SUB 1106

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to G.S. 62-133.8 and Commission Rule R8-67	)))))	ORDER APPROVING REPS AND REPS EMF RIDERS AND 2015 REPS COMPLIANCE

HEARD: Tuesday, June 7, 2016 at 9:30 a.m. in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding, Chairman Edward S. Finley, Jr.; Commissioners ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson and Lyons Gray

APPEARANCES:

For Duke Energy Carolinas, LLC:

Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation, 410 South Wilmington Street, NCRH 20/P.O. Box 2551, Raleigh, North Carolina 27601

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 E. Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For North Carolina Sustainable Energy Association:

Michael D. Youth, Regulatory Counsel, North Carolina Sustainable Energy Association, 4600 Six Forks Road, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, NC, 27699

BY THE COMMISSION: On March 9, 2016, Duke Energy Carolinas, LLC (DEC or the Company) filed for Commission review and approval its 2015 REPS Compliance Report, and an application for an adjustment to its North Carolina retail rates and charges pursuant to G.S. 62 -133.8(h) and Commission Rule R8-67. These provisions require the Commission to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery by an electric public utility of its incremental costs incurred to comply with the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), G.S. 62-133.8(b), (d), (e) and (f), and to true-up any under-recovery or over-recovery of compliance costs. DEC's application was accompanied by the testimony and exhibits of Megan W. Jennings, Renewable Compliance Manager and Veronica I. Williams, Rates and Regulatory Strategy Manager. In its application and pre-filed testimony, DEC sought approval of its proposed REPS Rider, which incorporated the Company's proposed adjustments to its North Carolina retail rates.

On March 10, 2016, North Carolina Sustainable Energy Association (NCSEA) filed a motion to intervene. That motion was granted by the Commission on March 15, 2016.

On March 15, 2016, DEC filed a correction to its 2015 REPS Compliance Report.

On March 17, 2016, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice, in which the Commission set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and DEC rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

On April 8, 2016, Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene in this docket, which the Commission granted on April 12, 2016.

On May 12, 2016, DEC filed the required affidavits of publication for the notice of hearing in accordance with the Commission's March 17, 2016 Order.

On May 18, 2016, DEC filed supplemental testimony and revised exhibits of witnesses Jennings and Williams.

On May 23 and 25, 2016, the Public Staff filed motions for extension of time to file its testimony, which were granted by the Commission. On May 26, 2016, the Public Staff filed the affidavits of Darlene Peedin Supervisor, Electric Section, Accounting Division, and Jay Lucas, Electric Engineer, Electric Division. The intervention and participation by the Public Staff are recognized pursuant to G. S. 62-15(d) and Commission Rule R1-19(e).

On June 1, 2016, DEC and the Public Staff filed a joint motion to excuse their witnesses from the expert witness hearing, since all parties had waived the right to cross-examine these witnesses. On June 3, 2016, the Commission denied the motion in part, requiring witnesses Williams and Lucas to attend the hearing so that the Commission could obtain additional information regarding the Company's application.

The matter came on for hearing on June 7, 2016. DEC presented the testimony and exhibits of witnesses Jennings and Williams, and the Public Staff presented the affidavits of witnesses Peedin and Lucas. All pre-filed testimony, exhibits, and affidavits from the DEC and Public Staff witnesses were received into evidence as all parties had waived cross-examination of all witnesses.

The Commission asked questions of the parties' witnesses and requested that DEC submit late-filed exhibits related to some of the questions within 10 days of the hearing.

On June 16, 2016, DEC filed a motion requesting an extension until June 24, 2016, to file its late-filed exhibits, which the Commission granted. In that same Order, the Commission stated that proposed orders and briefs would be due no later than 30 days from June 24, 2016.

On June 24, 2016, DEC filed the late-filed exhibits requested during the expert witness hearing.

On July 25, 2016, NCSEA filed its Post-Hearing Brief.

Also, on July 25, 2016, the Public Staff filed a motion for extension of time until August 1, 2016, for all parties to file proposed orders. The Commission granted that motion the following day.

On August 1, 2016, the Public Staff and DEC filed their Joint Proposed Order in this proceeding.

Based upon the foregoing, the testimony, exhibits, and affidavits introduced at the hearing, the records in the North Carolina Renewable Energy Tracking System (NC-RETS) and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. DEC is a duly organized limited liability company existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEC is also an electric power supplier as defined in G.S. 62-133.8(a)(3). DEC is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. For calendar year 2015, the Company is required to meet at least 6% of its previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency (EE) measures. Also in 2015, energy in the amount of at least 0.14% of the previous year's total electric power sold by DEC to its North Carolina retail customers must be supplied by solar energy resources. These solar sources can be a combination of new solar electric facilities and new metered solar thermal energy facilities.

3. Beginning in 2012, G.S. 62-133.8(e) and (f) require DEC and the other electric suppliers of North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from electricity generated from swine and poultry waste, based on each electric power supplier's respective pro-rata share derived from the ratio of its North Carolina retail sales as compared to total North Carolina retail sales. In its Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief, issued on December 1, 2015, in Docket No. E-100, Sub 113 (December 1 Order), the Commission delayed for one year the swine waste set-aside requirement, directing that the swine waste set-aside requirements will commence in 2016. The

Commission also modified the 2015 poultry waste set-aside requirement to remain at the same level as the 2014 requirement and delayed by one year the scheduled increases in the requirement.

4. G.S. 62-133.8(h) authorizes an electric power supplier to recover the "incremental costs" of compliance with the REPS requirements through an annual REPS rider. The "incremental costs," as defined in G.S. 62-133.8(h)(1), include the reasonable and prudent costs of compliance with REPS "that are in excess of the electric supplier's avoided costs other than those costs recovered pursuant to G.S. 62-133.9." The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

5. Under Commission Rule R8-67(e), the total costs reasonably and prudently incurred during the test period to purchase unbundled renewable energy certificates (RECs) constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs.

6. DEC has agreed to provide compliance services, including the procurement of RECs, to the following electric power suppliers, pursuant to G.S. 62 133.8(c)(2)(e): Blue Ridge Electric Membership Corporation (EMC), the City of Concord, the Town of Dallas, the Town of Forest City, the Town of Highlands, the City of Kings Mountain and Rutherford EMC (collectively the Wholesale Customers).

7. DEC has complied with the 2015 solar set-aside requirements, for itself and the Wholesale Customers for which DEC is providing compliance services, through the procurement or generation of 84,844 RECs from solar electric facilities and metered solar thermal energy facilities. DEC has also complied with the 2015 poultry waste set-aside requirements, for itself and the Wholesale Customers for which DEC is providing compliance services, through the procurement or generation of 77,375 RECs from poultry waste-to-energy facilities.

8. DEC and the seven electric power suppliers for which DEC is providing compliance services met their 2015 REPS obligations, except for those from which they had been relieved under the Commission's Orders in Docket No. E-100, Sub 113. Therefore, DEC's 2015 REPS compliance report should be approved.

9. DEC projects that it will not meet either its 2016 swine waste resource requirement or its 2016 poultry waste resource requirement.

10. For purposes of DEC's annual rider pursuant to G. S. 62-133.8(h), the test period and the billing period for this proceeding are, respectively, the calendar year 2015 and the 12-month period beginning September 1, 2016 and ending August 31, 2017.

11. The research activities funded by DEC during the test period are renewable research costs which are recoverable under G.S. 62-133.8(h)(1)(b). These research costs are within the statute's $1-million annual limit.

12. For purposes of establishing the REPS experience modification factor (EMF) rider in this proceeding, DEC's incremental costs for REPS compliance during the test period were $17,087,280, including the costs incurred for its Wholesale Customers, and these costs were

reasonably and prudently incurred. The Company's projected incremental costs for REPS compliance for the billing period total $35,283,665, including the costs incurred for its Wholesale Customers.

13. DEC's sales of RECs reviewed in this proceeding are appropriate, and DEC has accounted for them correctly.

14. DEC appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and/or billing period, including those avoided and incremental costs specifically related both to the Company's Solar Photovoltaic Distributed Generation (Solar DG) program and to DEC's other owned solar facilities as required by the following Commission orders: (1) Order Granting Certificate of Public Convenience and Necessity with Conditions, issued December 31, 2008, and Order on Reconsideration, issued May 8, 2009, in Docket No. E-7, Sub 856; (2) Order Transferring Certificate of Public Convenience and Necessity, issued May 16, 2016, in Docket No. E-7, Sub1079, and (3) Order Transferring Certificate of Public Convenience and Necessity, issued May 16, 2016 in Docket No. E-7, Sub 1098.

15. DEC's other incremental costs are recoverable under G.S. 62-133.8(h)(1)(b) and will be approved for this proceeding.

16. DEC should continue to make refinements to its interconnection cost allocation process related to interconnection labor and other costs.

17. DEC should file with the Commission the detailed information requested in the body of this Order for subsequent REPS Rider proceedings. DEC should also file a worksheet explaining the discrete costs that DEC includes as "other incremental costs" in all future REPS Rider proceedings.

18. DEC's test period REPS expense (over-) or under-collections were an (over-) collection, including interest, of $(479,978) for the residential class, $(388,828) for the general service class, and $(54,216) for the industrial class, excluding the North Carolina regulatory fee (regulatory fee).

19. DEC's North Carolina retail prospective billing period expenses for use in this proceeding are $18,687,686, $12,356,656 and $1,290,559, for the residential, general service, and industrial classes, respectively, excluding regulatory fee.

20. The appropriate monthly REPS EMF riders per customer account, excluding regulatory fee, to be credited to customers during the billing period are $(0.02) for residential accounts, $(0.14) for general service accounts, and $(0.92) for industrial accounts.

21. The appropriate monthly prospective REPS riders per customer account, excluding regulatory fee, to be collected during the billing period are $0.93 for residential accounts, $4.32 for general service accounts, and $21.88 for industrial accounts.

22. The combined monthly REPS and REPS EMF rider charges per customer account, excluding the regulatory fee, to be collected during the billing period are $0.91 for residential

accounts, $4.18 for general service accounts, and $20.96 for industrial accounts. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the billing period are $0.91 for residential accounts, $4.19 for general service accounts, and $20.99 for industrial accounts.

23. DEC's REPS incremental cost rider, including the regulatory fee, to be charged to each customer account for the billing period is within the annual cost cap established for each class in G.S. 62-133.8(h)(4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-6

These findings of fact are essentially informational, jurisdictional and procedural in nature and are not contested.

G.S. 62-133.8(b)(1) establishes a REPS requirement for all electric power suppliers in the State. The statute requires each electric public utility to provide a certain percentage of its North Carolina retail sales from various renewable energy or EE resources which are listed in G.S. 62-133.8(b)(2) as follows: (a) generating electric power at a new renewable energy facility; (b) using a renewable energy resource to generate electric power at a generating facility other than the generation of electric power from waste heat derived from the combustion of fossil fuel; (c) reducing energy consumption through the implementation of energy efficiency measures; (d) purchasing electric power from a new renewable energy facility; (e) purchasing RECs produced from in-State or out-of-state new renewable energy facilities; (f) using electric power that is supplied by a new renewable energy facility or saved due to the implementation of an EE measure that exceeds the requirements of the REPS in any calendar year as a credit toward the requirements of the REPS in the following calendar year; or (g) electricity demand reduction. Each of these measures is subject to additional limitations and conditions. For 2015, an electric public utility in the state of North Carolina must meet a total REPS requirement equal to 6% of its previous year's North Carolina retail electric sales by a combination of these measures.

G.S. 62-133.8(d) requires a certain percentage of the total electric power sold to retail electric customers in the State, or an equivalent amount of energy, to be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. The percentage requirement for solar resources in 2015 is 0.14%.

G.S. 62-133.8(e) and (f) require DEC and the other electric suppliers of North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from electricity generated from swine and poultry waste. Pursuant to the Commission's Order on Pro-Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification, issued on March 31, 2010, in Docket No. E-100, Sub 113, DEC's share of the aggregate State set-aside requirements for energy from swine and poultry waste is based on the ratio of its North Carolina retail kilowatt-hour sales for the previous year divided by the previous year's total North Carolina retail kilowatt-hour sales. Pursuant to the Commission's Order Establishing Method of Allocating the Aggregate Poultry Waste Resources Set-Aside Requirement, issued April 18, 2016, in Docket No. E-100, Sub 113, starting with compliance year 2016, the aggregate poultry waste set-aside obligation shall be allocated among the electric power suppliers by averaging three years of historical retail sales, with the resulting allocation being held constant for three years. In its Order Modifying the Swine Waste Set-Aside Requirements and Providing Other Relief, issued on November 13, 2014, in Docket No. E-100, Sub 113, the Commission, after previous delays, delayed for one additional year the swine waste set-aside requirement, directing that the compliance requirements for the use of swine waste to generate electric power would commence in 2015. In its December 1 Order, the Commission further delayed for one year the commencement of the swine waste set-aside requirement, which will now commence in 2016. The Commission also modified the 2015 poultry waste set-aside requirement to remain at the same level as the 2014 requirement (an aggregate of 170,000 megawatt -hours of electricity generated via poultry waste divided amongst the electric power suppliers), and delayed by one year the scheduled increases in the requirement (the requirement is scheduled to increase to 700,000 megawatt-hours in the aggregate for all electric power suppliers).

G.S. 62-133.8(h)(4) requires the Commission to allow an electric power supplier to recover all of its incremental costs incurred to comply with G.S. 62-133.8 though an annual rider. G.S. 62-133.8(h)(1) provides that "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirement that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to G.S. 62-133.9. The term "avoided costs" includes both avoided energy and avoided capacity costs.

Commission Rule R8-67(e)(2) provides that "the cost of an unbundled renewable energy certificate, to the extent that it is reasonable and prudently incurred, is an incremental cost and has no avoided cost component."

Commission Rule R8-67(e)(5) provides that "the REPS EMF rider will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect."

In its 2015 compliance report, DEC stated that it provided renewable energy resources and compliance reporting services for Blue Ridge EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the Town of Highlands, the City of Kings Mountain, and Rutherford EMC, as allowed by G.S. 62-133.8(c)(2)(e).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-9

The evidence supporting these findings of fact appears in DEC's 2015 REPS compliance report, in the direct and revised testimony and exhibits of DEC witnesses Jennings and Williams, and in the affidavit of Public Staff witness Lucas. In addition, the Commission takes judicial notice of information contained in NC-RETS.

DEC witness Jennings testified that DEC submitted its 2015 REPS compliance report as Jennings Exhibit No. 1 and that this report contained all the information required by Commission Rule R8-67(c) in the aggregate for DEC and the Wholesale Customers for which DEC has contracted to provide REPS compliance services. Those customers are Blue Ridge EMC, Rutherford EMC, the Town of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain.

Witness Jennings further testified that DEC has submitted for retirement 3,636,018 RECs to meet its total requirement for 2015. She defined the "total requirement" as DEC's overall REPS requirement. Within this total, the Company submitted for retirement 84,844 RECs to meet the solar set-aside requirement, and 53,483 RECs, along with 11,946 SB 886 RECs (which count as 23,892 poultry waste RECs) to meet the poultry waste set-aside requirement. Witness Jennings testified that the billing period for this Application covers two separate compliance reporting periods with different requirements for each period. In 2016, the Company estimates that it will be required to submit for retirement 3,678,466 RECs to meet the requirements of G.S. 62-133.8(b), or its Total Requirement. Within this total, the Company is also required to retire the following to comply with the requirements of G.S. 62-133.8(d), (e) and (f), respectively: 85,835 solar RECs, 42,915 swine waste RECs, and 318,603 poultry waste RECs. DEC estimates that its 2017 total requirement will be 3,657,075 RECs to be submitted for retirement. Within this total, the Company estimates that it will be required to retire approximately 85,332 solar RECs, 42,666 swine waste RECs, and 409,632 poultry waste RECs to meet the requirements of G. S. 62-133.8(d), (e), and (f) respectively.

Witness Jennings testified that DEC has met its solar set-aside requirement for 2015 by procuring and producing 84,844 solar RECs and that, pursuant to NC-RETS Operating Procedures, the Company submitted for retirement. The Company did such by transferring these RECs from the Duke Energy Electric Power Supplier Account to the Duke Energy Compliance Sub-Account and the Sub-Accounts of its Wholesale Customers.

Witness Jennings further testified that the Company complied with its General Requirement for 2015. Pursuant to the NC-RETS Operating Procedures, the Company submitted for retirement 3,473,799 RECs to meet the General Requirement. Specifically, the RECs to be used for 2015 compliance have been transferred from the NC-RETS Duke Energy Electric Power Supplier account to the Duke Energy Compliance Sub-Account and the Sub-Accounts of the Wholesale Customers.

In her direct testimony Company witness Jennings testified that the Company is well-positioned to comply with its poultry waste set-aside requirements in 2016. However, in witness Jennings supplemental testimony, she stated that after her direct testimony was filed DEC became aware that a number of poultry waste RECs will no longer be available in 2016. Specifically, she stated that DEC received a letter from one of its poultry project developers, in which it gave notice that the project's original commercial operation date of April 1, 2016, will not be achieved, and that it plans to be operational later in 2016. Witness Jennings testified that the delay of this project and the resulting decrease in 2016 REC production adversely impacts DEC's compliance efforts and that as a result, DEC predicts that it will no longer be able to meet the 2016 poultry waste set-aside requirement.

Public Staff witness Lucas recommended that the Commission approve DEC's 2015 REPS compliance report. Specifically, he testified that for 2015 compliance, DEC needed to obtain a sufficient number of RECs and energy efficiency certificates (EECs) derived from any eligible sources so that the total equaled 6% of its 2014 North Carolina retail electricity sales and the retail sales of the Wholesale Customers. Witness Lucas stated that additionally, DEC needed to pursue retirement of sufficient solar RECs to match 0.14% of retail sales in 2014 for itself and the

Wholesale Customers, and of its pro-rata share of the 170,000 poultry waste RECs required by G. S. 62-133.8(f). The number of poultry waste RECs was determined by the Commission in its December 1 Order. The December 1 Order also delayed the swine waste requirement, under G.S. 62-133.8(e), for an additional year.

No party disputed that DEC had fully complied with the applicable REPS requirements, or that DEC's REPS compliance report for 2015 should be approved. Therefore, based on the evidence presented and the record as whole, the Commission finds and concludes that DEC and the seven electric power suppliers for which it is providing REPS compliance services have fully complied with the requirement of the REPS for 2015, as modified by the Commission's December 1 Order, and that DEC's 2015 REPS compliance report should be approved. Further, the Commission finds and concludes that the RECs and EECs in the related NC-RETS compliance sub-accounts should be permanently retired. Additionally, the Commission notes witness Jennings's testimony that the Company does not expect to be able to comply with its poultry waste obligation for 2016 and further notes that on August 11, 2016, DEC, along with the other electric suppliers in the State, filed in E-100 sub 113, a Joint Motion to Modify and Delay the 2016 Requirements of 62-133.S(e) and (f) Due to Lack of Sufficient Swine and Poultry Waste Resources.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

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

Commission Rule R8-67(e)(3) provides that the test period for REPS rider proceedings shall be the same as that used by the utility in its fuel charge adjustment proceedings, which is specified for DEC in Rule R8-55(c) to be the 12 months ending December 31 of each year. Commission Rule R8-67(e)(5) provides that "[t]he REPS EMF rider will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect." Commission Rule R8-67(e)(4) further provides that the REPS and REPS EMF riders shall be in effect for a fixed period, which "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." In its current fuel charge adjustment proceeding, in Docket No. E-7, Sub 1104, and in this proceeding, DEC proposed that its rate adjustments take effect on September 1, 2016, and remain in effect for a 12-month period. This period is referred to as the "billing period."

The test period and the billing period proposed by DEC were not challenged by any party. The Commission concludes that the test period and billing period appropriate for this proceeding are the calendar year 2015 and the twelve months ending August 31, 2017, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact can be found in the testimony of DEC witnesses Jennings and Williams.

Witness Jennings identified in Confidential Jennings Exhibit No. 2 the "Research" and "Other Incremental Costs" that the Company has incurred or projects to incur in association with REPS compliance. With respect to research costs, Revised Williams Exhibit No. 1 shows that the research costs are under the $1-million per year cap established in G.S. 62-133.8(h)(1)(b).

In prior Commission Orders, the Commission directed DEC to file in REPS rider applications the results of studies, the costs of which were recovered via its REPS EMF and REPS riders, including information (e.g., an internet or mailing address) regarding how parties can access the results of those studies.[1]

In compliance with the Commission's Order Approving REPS and REPS EMF Riders and 2014 REPS Compliance, Docket No. E-7, Sub 1074, witness Jennings supplied testimony and exhibits in the current docket on the results and status of various studies, the cost of which DEC is including for recovery in its incremental REPS cost for the calendar year 2015 test period. Specifically, her testimony provided detailed information on the following research and development costs incurred by the Company associated with the REPS riders:

- Loyd Ray Farms – The Company partnered with Duke University to develop a pilot-scale, sixty-five kilowatt (kW) swine waste-to-energy facility, which initiated operation and began producing renewable energy in 2011. Jennings Exhibit No. 4 summarized the project's progress through December 31, 2015.

- Operational Impacts of Solar at Various Penetration Levels – The 2014 Photovoltaic (PV) Integration Study entitled "Duke Energy Photovoltaic Integration Study: Carolinas Service Areas" was commissioned to research and understand the operational impacts of solar at various penetration levels. In 2015, DEC commissioned Pacific Northwest National Laboratory, Power Costs Inc., and Quanta Technology to perform a comprehensive and detailed generation, transmission, and distribution impact/integration study. In the 2015 work, the intent was to perform an integrated study of the generation and transmission system, modeling the generation fleet and its connections to the transmission system directly. Also, in 2015, the PV resource data was modeled differently from the 2014 study. In 2015, the modeling attempted to account for the geographical patterns of actual PV installations that were in-service and those in the interconnection queue. The study is still underway with an expected completion date in 2016.

- Distributed Energy Resource – Islanding Detection and Control (DER-IDC) – Consensus grows in the industry that as DER grows in its penetration levels, the effectiveness of anti-islanding schemes currently in use in inverters and protective relaying schemes will degrade, and future schemes will likely need to involve some sort of communications. This sentiment was discussed multiple times at recent Institute for Electrical and Electronics Engineers meetings, at which DEC is an active participant. DEC contracted with Northern

[1] Order Approving REPS and REPS EMF Riders and 2013 REPS Compliance, p. 10, Docket No. E-7, Sub 1052 (August 21, 2014); Order Approving REPS and REPS EMF Riders and 2012 REPS Compliance, p. 11, Docket No. E-7, Sub 1034 (August 20, 2013); Order Approving REPS and REPS EMF Riders and 2011 REPS Compliance, p. 11, Docket No. E-7, Sub 1008 (August 16, 2012).

Plains Power Technologies, an engineering consulting firm, to study data collected from DEC facilities and research potential algorithms and communication methods that would be effective for communications-based IDC methods. As part of the data collection effort, protection/control/monitoring equipment was purchased and installed at DEC's Marshall, McAlpine, and Rankin research and development sites. The equipment included several satellite clocks and a real-time automation controller. Further phases of this project are planned for 2016.

- Rankin Battery/Aquion Energy – The Company is continuing to advance its knowledge of energy storage. One aspect of energy storage is battery chemistry; specific chemistries are suited to specific use cases. For example, one type of chemistry might be well-suited to "energy battery" energy-shifting applications (charging over many hours in one part of the day and discharging for many hours in another part of the day), whereas other chemistries might work better for "power battery" applications, like being co-located with PV facilities to mitigate intermittent output. To this end, DEC is installing an energy storage facility at its Rankin substation that will utilize a hybrid arrangement that should allow use as both an energy battery and a power battery. This project included installation of the battery in 2015 and will test different use cases in 2016.

- Wind Resources – The Company commissioned the University of North Carolina at Chapel Hill to analyze wind resources outside the barrier islands where potential may exist for large scale offshore wind projects. Jennings Exhibit 5 includes three recent papers published on this work, providing stability-based estimates of the wind impact off the shore of North Carolina, and the impact of stability on the wind climate of coastal North Carolina.

- Closed Loop Biomass – The Company continues to support a closed-loop biomass research project to better understand yield potential for various woody and herbaceous crops, including loblolly pine and miscanthus grass. Crop production levels may take several years to reach full maturity. American Forest Management provides project management support and periodic updates to the Company, as seen in Jennings Exhibit No. 6.

- Rocky Mountain Institute (RMI) – The Company participates in eLab, a forum sponsored by RMI, composed of a number of North Carolina and nationally based entities, and organized to overcome barriers to economic deployment of distributed energy resources in the U.S. electric sector. Specifically, Duke seeks to gauge customer desires related to distributed resources and provide ideas of potential long-term solutions for distributed energy resources and microgrids. Additional information on eLab is available at http://www.rmi.org/elab.

- Electric Power Research Institute (EPR) – In 2015, the Company subscribed to the following EPRI programs, the costs for which were recovered via the REPS rider: Program 193 – Renewable Generation, which includes Program PS193C – Solar. The Company also supported an EPRI Supplemental Project, P170B, which studied demand response as a flexible resource. EPRI designates such study results as proprietary or as trade secrets and licenses such results to EPRI members, including DEC. As such, DEC may not disclose the information publicly. Non-members may access these studies for a fee. Information regarding access to this information can be found at http://www.epri.com/Pages/Default.aspx. In addition, DEC participated in the EPRI Flexible Demand Response (DR) Project, designed to explore the capability and value of employing DR as a flexible resource in system operations, by leveraging existing technology and infrastructure investments.

- National Renewable Energy Lab (NREL) Alliance for Sustainable Energy – In 2015, the Company commissioned new studies from NREL that consider the impact of smart inverters to the solar developer and model them in the Geographic Information System, Distribution Management System, Outage Management System, and Supervisory Control and Data Acquisition System. NREL performed the modeling, analysis, visualization and hardware implementation on a representative of the Company's utility feeders, which will allow the Company's engineers to understand the differences between operation of standard inverters and smart inverters, and the impact of smart inverters on the distribution system. Work continues on the final analysis for the report.

- NC State University's Future Renewable Electric Energy Delivery and Management (FREEDM) Systems Center – DEC supports NC State's FREEDM Center through annual membership dues. The FREEDM partnership provides DEC with the ability to influence and focus research on materials, technology, and products that will enable the utility industry to transform the electric grid into a two-way power flow system supporting distributed generation.

- Other Resources and Subscriptions – The Company subscribes to various renewable energy news and trade publications to gain access to market analyses, including price and supply/demand trends for renewable energy. Such publications are generally proprietary and provided to the Company under confidentiality licenses and, as such, the Company may not disclose the information publicly. Interested parties can obtain copies of such reports and analyses for a fee. The Company subscribes to or has purchased services from Bloomberg New Energy Finance and IHS Global.

The Commission concludes that the research activities described by DEC witness Jennings are appropriate research costs recoverable under G.S. 62-133.8(h)(1)(b). The Commission further concludes that the research costs incurred by DEC of $736,977 in the EMF period are within the $1-million annual limit provided in that statute. The Commission further concludes that, with the addition of the information filed in the testimony and exhibits of DEC's witnesses, the Company has complied with the requirement to file study results or information about how to access study results for research conducted with REPS rider funds. The Company shall continue to include that information in future REPS rider applications.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-17

The evidence for these findings of fact is found in DEC's Application and in the direct and supplemental testimony and exhibits, revised exhibits, and late-filed exhibits of DEC witnesses Jennings and Williams, as well as in the affidavits of Public Staff witnesses Peedin and Lucas.

DEC witness Williams testified regarding the calculation of DEC's avoided costs and its incremental costs of compliance with its REPS requirements, based on incurred and projected costs provided by witness Jennings. Consistent with Commission Rule R8 -67(e)(2), which provides that the cost of an unbundled REC is an incremental cost with no avoided cost component, witness Williams included in incremental costs the total amount of costs incurred during the test period for unbundled REC purchases. Revised Williams Exhibit No. 1 identified total retail and wholesale incremental costs incurred during the test period as $17,087,280, and projected incremental costs for the billing period as $35,283,665. Further, the projected costs of unbundled REC purchases discussed by witness Jennings during the billing period are included as estimated billing period incremental costs. Company witness Jennings additionally testified the company sold poultry RECs during the test period to other electric suppliers in North Carolina to enable the entire state to comply with the poultry waste set-aside requirements. She stated that the proceeds from the sale of these RECs were credited back to DEC's customers in 2015, and Revised Jennings Exhibit No. 2, page 7, reflects this credit. Ms. Jennings confirmed that the sales of poultry waste RECs did not negatively impact DEC's compliance.

Witness Williams testified that, consistent with Commission Rule R8-67(a)(2), DEC's approved avoided cost rates are set forth in Rate Schedule PP-N, Purchased Power Non-Hydroelectric, and Rate Schedule PP-H, Purchased Power Hydroelectric (collectively, Schedule PP). For executed purchased power agreements, where the price of the REC and energy are bundled, the Company used annualized combined capacity and energy rates shown on the Company's Exhibit No. 3, filed in Docket No. E-100, Sub 106; Exhibit No. 3 in Docket No. E-100, Sub 117; Exhibit No. 3 in Docket No. E-100, Sub 127; or Exhibit No. 3 in Docket No. E-100, Sub 136 (depending on the effective date of the executed contract). For those purchased power agreements with terms that did not correspond with the durational terms for which rates were established in the avoided cost proceeding (i.e., two, five, ten, or fifteen-year durations), DEC computed avoided cost rates for the particular term of the purchased power agreements using the same inputs and methodology used for the Schedule PP rates approved in Docket No. E-100, Subs 106, 117, 127, or 136, as appropriate. Witness Williams also stated that the estimated avoided cost components of energy and REC purchased power agreements effective during the prospective billing period were calculated in the same manner.

In addition to costs incurred or projected to be incurred for bundled or unbundled RECs, Revised Williams Exhibit No. 1, pages 1-2, identified the "Other Incremental Costs" that DEC has incurred or projects to incur in association with REPS compliance. Likewise, Revised Jennings Exhibit No. 2, pages 6-8, shows "Other Incremental Costs" related to REPS compliance. Witness Williams included the other incremental and research costs that were incurred in 2015 in the EMF calculation. She explained that these costs are estimated for the billing period and included in the proposed REPS rider.

With respect to DEC's Solar DG program, witness Williams testified that DEC determined the avoided cost using a process similar to that described for a purchased power agreement with a non-standard duration. The inputs and methodology used for the Schedule PP rates approved in Docket No. E-100, Sub 117 were used to determine the annualized combined capacity and energy rates for the twenty-year term, corresponding to the expected life of the solar facilities.

In response to questions from Commissioner Beatty, witness Williams discussed the adjustment that she made to reflect the Commission's approval of the transfer of two certificates of public convenience and necessity (CPCNs) for solar facilities to DEC in Docket Nos. E-7, Sub 1079 and E-7, Sub 1098. These transfers were approved after witness Williams pre-filed her testimony in this proceeding on March 9. She explained that an additional CPCN request for a solar facility was pending before the Commission in Docket No. E-7, Sub 1101. (These three solar facilities are collectively referred to as CPCN projects). She testified that none of these CPCN projects are currently used and useful, so their costs are not reflected in the EMF period; they are only reflected in the prospective billing period of September 2016 to August 2017. Witness Williams stated that she decreased the incremental costs for the prospective billing period by the amount necessary to comply with the Commission's Orders approving the transfers of two of the CPCN projects. These CPCN projects were treated just like other REPS compliance projects owned by DEC; the amount above avoided cost is the incremental cost for REPS compliance, but is subject to a cost cap.

Witness Williams next recounted how the costs for recovery were calculated. For each of the CPCN projects, DEC calculated an annual revenue requirement that included capital and operations and maintenance costs for each year of the life of the project (25 years). DEC then levelized the present value of the total revenue requirement over the project life, resulting in a level annual revenue requirement in dollars for each project. DEC then converted the dollar amount to a dollar per megawatt hour (MWh) and compared that amount to the avoided cost per MWh approved by the Commission in the appropriate avoided cost proceeding. The percentage of the total cost above the avoided cost was then used to calculate the incremental portion of that annual revenue requirement in dollars. The Commission had previously limited that amount to the standard offer REC price; accordingly, DEC recalculated the layer of the total costs that would be recovered through the REPS rider to be the percentage of the total cost that was equivalent to the standard offer REC price. Therefore, witness Williams concluded, the Company removed the amount that was above the cost cap from the proposed cost recovery dollars. Williams Late-Filed Exhibit No. 1 details those calculations.

Based on the above testimony and exhibits, and the entire record in this proceeding, the Commission concludes that DEC appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and the billing period. DEC's sale of poultry waste RECs appropriately offset the costs incurred in the EMF period. Accordingly, the Commission concludes that for purposes of establishing the REPS EMF rider in this proceeding, DEC's incremental costs for REPS compliance during the test period were $17,087,280, including the costs incurred for its Wholesale Customers, and these costs were reasonably and prudently incurred. The Company's appropriately projected incremental costs for REPS compliance for the billing period total $35,283,665, including the costs incurred for its Wholesale Customers.

The Commission further finds and concludes that DEC appropriately calculated the costs of its solar DG program and DEC's other owned solar projects for inclusion in the REPS rider. No party challenged or proposed any changes to the Company's methodology for including the costs of those projects in the REPS rider, and the calculations are consistent with the Commission Orders in Docket Nos. E-7, Sub 856 and Sub 984, as well as the Commission's past Orders approving the CPCN transfers and approving DEC's REPS cost recovery.

With respect to the "Other Incremental Costs" included for recovery via the REPS rider, witness Jennings described these as internal labor costs associated with REPS compliance activities and non-labor costs associated with administration of REPS compliance. Public Staff witnesses Peedin and Lucas both confirmed that, as part of its investigation, the Public Staff had reviewed the inclusion of these costs in DEC's proposed REPS rider and did not take issue with any of the costs DEC seeks to recover. However, witness Lucas noted in his affidavit that these costs included DEC's costs for interconnecting renewable facilities to the grid, and stated that this cost was seen as necessary in order for renewable energy to be produced for REPS compliance. He further stated that the landscape of renewable energy development has changed since DEC's first REPS cost recovery proceeding in 2009. He testified that in the early years of REPS, almost all developers seeking to interconnect with a utility such as DEC were driven by the desire to earn and sell RECs. Today, in contrast, he stated that a renewable energy developer's request for an interconnection can be driven by a variety of motivations, some of them entirely unrelated to REPS. He provided a list of several factors that have created additional demand for renewable energy resources. Some renewable energy developers certify as qualifying facilities (QFs) under PURPA[1] and sell their electricity to the utility, but choose not to sell their RECs to DEC. He stated that these developers may be taking advantage of State and federal tax credits, declining solar costs, and improved efficiencies to help finance and develop their projects. Some corporations want to self-generate and count the renewable energy toward their own sustainability goals. Some residential and small commercial customers choose to self-generate and net meter their electricity generation but do not sell their RECs to DEC. Witness Lucas further testified that DEC indicated that it expended a significant amount of resources in 2015 developing an interconnection IT platform to help address delays in its interconnection queue and to increase the efficiency of the interconnection process across Duke Energy. Additionally, witness Lucas testified that all of these factors have increased the amount of DEC resources devoted to renewable energy that are separate from DEC's REPS compliance. He stated that proper accounting is needed to ensure that only REPS-related costs are recovered through the REPS rider.

Public Staff witness Lucas further testified that with regard to interconnection costs, the Public Staff does not question the increase in expenditures reported by DEC, but it does stress the importance of ensuring that the costs associated with interconnecting specific projects should be borne by the interconnection customer in the form of interconnection charges. To the extent those costs are not related to REPS and cannot be recovered from the customer directly, they should be allocated to DEC's base rates. He noted that, for example, DEC and DEP both have significant numbers of interconnection applications within their queues, but not all of those projects are expected to be constructed and become operational. Witness Lucas testified that to the extent that some proposed facilities never generate RECs for REPS compliance purposes, the Public Staff believes it is inappropriate for the administrative and engineering costs associated with interconnecting those projects to be recovered through the REPS rider.

In his testimony, witness Lucas pointed out that in its application in the Rider GS docket[2], DEC stated that no costs associated with the Rider GS program would be recovered through the

[1] PURPA refers to a federal statute, the complete name for which is the Public Utilities Regulatory Policies Act.

[2] See Docket No. E-7, Sub 1043.

REPS rider and that the administrative charge paid by Rider GS customers would cover the costs associated with the program. In addition, DEC stated that it would "make reasonable efforts to separate the procurement processes for REPS compliance and for Rider GS, account for the costs of procurement or production as a result of Rider GS, and ensure that these costs are borne by the Rider GS customer." Witness Lucas stated that while DEC had one full-time position exclusively assigned to Rider GS in 2015, other DEC employees in the DER Department worked on both REPS and Rider GS issues and charged portions of their time to each program. Witness Lucas added that as different programs continue to be administered by personnel in similar positions, identifying the costs that are eligible for recovery as REPS compliance costs becomes more challenging. He stated that DEC, in response to data requests by the Public Staff, indicated that it provides guidance to all employees in the DER Department regarding the assignment of time and costs to the REPS rider, as well as to other distributed energy resource programs. He testified that DEC also indicated that it has created charge codes and accounts that break these costs down by category and performs periodic reviews of the time and costs charged to the REPS rider, but does not necessarily allocate the costs on a project-by-project basis. Witness Lucas testified that the Public Staff was unable to determine exactly project-by-project how DEC was charging costs towards REPS versus interconnection [costs]. Public Staff witness Lucas recommended that DEC continue to refine its charging and accounting processes to allow the direct assignment of costs to specific projects or program areas, to the maximum extent feasible in order to ensure that only those costs attributable to REPS compliance are submitted for recovery through the REPS rider.

DEC witness Jennings testified that DEC carefully scrutinizes all of the costs and labor hours that are charged to REPS, and it communicates with employees to ensure that they are aware of which activities should be shown on their time reports as REPS -related and which should not. She stated that DEC is planning to reinforce the charging guidance employees already receive from the Company by meeting with groups involved and reinforcing REPS charging practices. Jennings Late-Filed Exhibit No. 2, submitted after the hearing at Commissioner Beatty's request, showed that none of the employees who work on interconnections charged as much as half their time to DEC REPS. Witness Jennings agreed that renewables activities have increased, and as a result of the continued refinement of practices, DEC has developed a new charging practice where account managers who work on interconnection projects now have the ability to charge time directly to projects. Public Staff witness Peedin characterized this new practice as a great improvement in their process to try to identify REPS-related projects in the interconnection stage and in determining what costs should be assigned to REPS.

In its post-hearing brief, NCSEA stated that it did not challenge any costs for which DEC seeks recovery in this docket as unreasonable or imprudent. NCSEA stated that DEC's proposed riders were all well below the statutory caps that are set forth in G.S. 62-133.8(h)(4). Further, NCSEA expressed its belief that DEC should be allowed to recover certain costs associated with interconnecting independently-owned generation facilities in the REPS rider, as these costs ultimately benefit REPS compliance.

The Commission notes that no party has disputed the inclusion of interconnection costs in this rider proceeding, and the record in this case does not contain a specific dollar amount for such costs. Therefore, the Commission will approve the rider amounts as filed. However the Commission has several concerns regarding the charging of interconnection costs to the REPS rider that must be addressed in future proceedings. First, DEC's inclusion of interconnection costs in the category of "other incremental costs" in its rider applications has not been explicit despite the Commission's requirement that the Company fully explain its "other incremental costs" in its REPS rider applications.[1] The Commission first learned in this proceeding of this practice of including interconnection costs, and as a result the Commission will be even more prescriptive in requiring DEC to be transparent in its REPS rider requests in the future. Furthermore, the Commission has concerns regarding the charging of any interconnection costs to the REPS rider because the Commission has separately approved interconnection fees[2] that allow DEC to recover interconnection costs directly from those developers and customers who seek to interconnect electric generating facilities to DEC's distribution facilities[3].

Moreover, the Commission is troubled that the Public Staff was unable to determine exactly how or how much DEC was charging for interconnection costs or program costs on a project-by-project basis towards the REPS rider. The Public Staff was not able to verify that all of the costs were related to projects that will produce RECs that will be used toward REPS compliance. The Commission's uneasiness is somewhat assuaged by the fact that DEC is and has been working to further refine its charging procedures. Even so, DEC should ensure that it fully utilizes interconnection fees as a means of recovering its interconnections costs. To the extent it believes some interconnection costs are appropriate for recovery via the REPS rider, it should provide detailed and specific records and explanations for those costs as well as testimony by a witness who can explain them.

While the Commission will allow DEC to recover its "other incremental costs" as requested by the Company and as supported by other witnesses in this proceeding, the Commission finds and concludes that it is necessary again to order DEC to file detailed worksheets explaining the discrete costs that the Company includes as "other incremental costs" in all future REPS proceedings. In the future, labor and IT costs shall be listed separately and further subdivided by activity and/or program. Furthermore, DEC shall file additional information in its next REPS rider proceeding regarding its interconnection costs, billings, and fees which shall include detailed testimony from the Company explaining any interconnection costs that it includes in the REPS rider application and why these costs were not recovered via the interconnection fees charged pursuant to the interconnection procedures that were approved by the Commission in Docket No. E-100, Sub 101. The Commission also requests testimony from the Public Staff discussing its review of these items. Additionally, the Public Staff is requested to audit the REPS rider requests filed by the other public utilities and file comments as to whether they contain interconnection costs and whether such costs should be recovered via the REPS Rider.

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[1] In the Commission's August 20th, 2013 Order Approving REPS and REPS EMF Riders and 2012 REPS Compliance in Docket No. E-7 Sub 1034, ordering paragraph No. 6 specifies that in all future REPS rider applications, [DEC shall] provide a detailed worksheet explaining each discrete item contributing to "other incremental costs."

[2] See the Revised North Carolina Interconnection Procedures dated June 15, 2015, in Docket No. E-100, Sub 101 (interconnection procedures docket).

[3] Requests to interconnect to DEC's transmission facilities are regulated by the Federal Energy Regulatory Commission (FERC), and FERC's generation interconnection procedures similarly allow DEC to charge interconnecting facilities for processing their interconnection requests.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-23

The evidence for these findings of fact is found in DEC's application and in the direct and supplemental testimony and exhibits, revised exhibits, and late-filed exhibits of DEC witnesses Jennings and Williams, as well as in the affidavits of Public Staff witnesses Peedin and Lucas.

Williams Exhibit No. 2 shows total North Carolina retail test period (over)-collections (including interest) of \$(479,978) for the residential class, \$(388,828) for the general service class, and \$(54,216) for the industrial class. As reflected on Revised Williams Exhibit No. 4, witness Williams calculated proposed North Carolina retail monthly per-account REPS EMF credits (excluding regulatory fee) of \$(0.02) for residential accounts, \$(0.14) for general service accounts, and \$(0.92) for industrial accounts. Also on Revised Williams Exhibit No. 4, she calculated the projected North Carolina retail REPS costs for the billing period of \$18,687,686 for the residential class, \$12,356,656 for the general service class, and \$1,290,559 for the industrial class, all excluding regulatory fees. Revised Williams Exhibit No. 4 shows that the proposed monthly prospective REPS riders per customer account, excluding the regulatory fee, to be collected during the billing period are \$0.93 for residential accounts, \$4.32 for general service accounts, and \$21.88 for industrial accounts. The combined monthly REPS and REPS EMF rider charges per customer account, excluding regulatory fee, to be collected during the billing period are thus \$0.91 for residential accounts, \$4.18 for general service accounts, and \$20.96 for industrial accounts. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the billing period are \$0.91 for residential accounts, \$4.19 for general service accounts, and \$20.99 for industrial accounts. As further illustrated on Revised Williams Exhibit No. 4, the Company's REPS incremental cost rider to be charged to each customer account for the billing period is within the annual cost cap established for each customer class in G.S. 62-133.8(h)(4).

Public Staff witness Peedin stated in her affidavit that as a result of its investigation, the Public Staff recommended that the Company's proposed annual REPS EMF increment/(decrement) amounts and monthly EMF riders for each customer class be approved. Witness Peedin also stated that, excluding the regulatory fee, the annual decrement REPS EMF riders are \$(0.29), \$(1.63) and \$(11.03) and the monthly decrement REPS EMF riders are \$(0.02), \$(0.14), and \$(0.92), per retail customer account, for residential, general service, and industrial customers, respectively.

Public Staff witness Lucas stated that the Public Staff had reviewed the costs that produced the proposed, revised rates and that it took no issue with them. He recommended that the Company's proposed prospective monthly REPS rider amounts per customer account, excluding regulatory fee, of \$0.93 for residential accounts, \$4.32 for general service accounts, and \$21.88 for industrial accounts be approved.

The Commission concludes that DEC's calculations of its REPS and REPS EMF riders are reasonable and appropriate. Accordingly, the Commission finds that DEC's test period REPS costs and appropriate monthly REPS EMF riders are as set out on Revised Williams Exhibit No. 4. The Commission finds that DEC's projected REPS costs for the billing period and the appropriate monthly REPS riders are as shown on Revised Williams Exhibit No. 4 as well. Finally, the

Commission finds that these amounts are well below the respective annual per-account cost caps of $34.00, $150.00, and $1,000.00, as established in G.S. 62-133.8(h)(4).

IT IS, THEREFORE, ORDERED as follows:

1. That DEC shall establish a REPS rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning on September 1, 2016 and expiring on August 31, 2017;

2. That DEC shall establish an EMF rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning on September 1, 2016 and expiring on August 31, 2017;

3. That DEC shall file the appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order as soon as practicable, but not later than ten (10) days after the date of this Order;

4. That DEC 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 1104, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the date of this Order;

5. That DEC's 2015 REPS compliance report is hereby approved and the RECs in DEC's 2015 compliance sub-accounts in NC-RETS shall be retired; and

6. That DEC shall file in all future REPS rider applications the results of studies the costs of which were or are proposed to be recovered via its REPS EMF and rider and, for those studies that are subject to confidentiality agreements, information regarding whether and how parties can access the results of those studies.

7. That DEC shall work with the Public Staff and continue its refinement of its interconnection cost allocation process related to interconnection labor and other costs.

8. That DEC shall file a worksheet explaining the discrete costs that DEC includes as "other incremental costs" in all future REPS Rider proceedings.

9. That DEC shall file testimony and exhibits in its next REPS Rider proceeding regarding its interconnection costs as specified above in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the __16th___ day of August, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-7, SUB 1114

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Duke Energy Carolinas, LLC,	)	ORDER APPROVING REQUESTED
to Revise Outdoor Light Service Schedule OL	)	REVISIONS TO LIGHTING RATE
	)	SCHEDULE

BY THE COMMISSION: On May 25, 2016, Duke Energy Carolinas, LLC (DEC or the Company), filed a request to revise its Outdoor Lighting Rate Schedule OL to begin phasing out mercury vapor (MV) lighting fixtures and replacing them with new light emitting diode (LED) fixtures.

DEC noted in its filing that by order dated January 28, 2014, in Docket No. E-7, Sub 1026, the Commission approved changes to DEC's outdoor lighting schedules to allow the Company to replace failing MV lights and ballasts with LED lights and to replace MV lights with LED lights at the customer's request. In addition, the Company stated in its Reply Comments filed on March 10, 2014, in Docket No. E-7, Sub 1026 that its Lighting Modernization Plan would eventually move from a repair and voluntary replacement strategy to one of proactive replacement of MV lights.

DEC also stated that the federal law banning the manufacture and importation of MV lights and ballasts remains in effect and continues to present a challenge to repairing or replacing MV lights and ballasts. DEC stated that MV lights are among the oldest and least efficient lighting fixtures in its inventory, and that these fixtures have reached obsolescence.

DEC also stated that its market research continues to show that LED technology is growing. Industry trends are moving away from MV, high pressure sodium (HPS) and metal halide (MH) technologies and toward LED applications. Additionally, Commission Rule R8-47(d) encourages utilities to offer more efficient lighting systems. DEC's proposal will allow the Company to phase out obsolete MV fixtures more rapidly and cost-effectively by grouping the work geographically rather than replacing failing fixtures one by one.

DEC stated that it plans to replace approximately 171,000 MV fixtures served under Schedule OL. An additional 3,000 decorative MV fixtures will not be replaced at this time, but will remain in place until a more suitable and affordable LED replacement option is available. DEC expects that it will take approximately three years to convert the 171,000 MV fixtures.

DEC stated that it will provide an initial letter giving customers notice of the conversion process. DEC plans to conduct the conversion geographically for efficiency, but it will work with customers who have more than 20 lights per account to postpone the conversion (but not beyond the three-year duration of the conversion program) in order to minimize the financial impact on the customer.

Regarding the financial impact, DEC stated that upon conversion, customers with Suburban-style MV fixtures will see an increase in their lighting bills of $0.30 per light per month, while customers with Urban-style fixtures will see a decrease of $0.88 per light per month. DEC also indicated that approximately 130,000 customer accounts have only a single fixture, while approximately 180 accounts have more than 20 MV lights per account. Of these larger accounts, approximately 120 customers will see a bill increase, averaging approximately $11 per month; the remaining 60 accounts would receive lower bills, with an average reduction of approximately $31 per month. The maximum bill increase for any one customer will be $40 per month. In the aggregate, once all 171,000 fixtures are replaced, DEC expects its annual revenues from lighting to increase by $391,000. DEC further stated that no customer will be charged a transition fee for the replacement of MV with LED fixtures.

DEC also stated that it is not proposing a proactive replacement of the 60,000 MV fixtures served under Schedule PL. These MV fixtures will continue to be replaced with LED fixtures upon failure. DEC expressed concern that proactive replacement of MV fixtures served under Schedule PL could create financial challenges for governmental customers, and stated that it will continue to have a dialogue with these customers and would seek to proactively replace their MV fixtures when appropriate.

The Public Staff presented this matter to the Commission at its Regular Staff Conference on June 20, 2016. The Public Staff indicated that it had reviewed the request to replace MV lighting proactively and believed the proposal balances the need to replace MV fixtures with the impacts on customers. The Public Staff also stated that federal standards, customer acceptance, and technological changes associated with outdoor lighting will continue to drive a transition away from MV and HPS lighting toward LED technology.

With respect to the remaining 3,000 decorative MV fixtures not included in DEC's proactive replacement plan, the Public Staff stated that DEC has indicated it will continue to replace these decorative MV fixtures upon failure with either an LED or HPS option consistent with the existing provisions of Schedule OL.

The Public Staff further stated that it had reviewed the revenue analysis associated with DEC's proactive MV replacement plan. DEC will see an increase in revenues of approximately $391,000 per year once the replacement of the 171,000 MV fixtures is completed in three years. The Public Staff also noted that DEC has not proposed any change to the rates for lighting service. DEC plans to provide customers with advance notice of the conversion process. Customers will also receive a second notice immediately prior to the work beginning in their geographical area.

Based on the foregoing, the Commission is of the opinion that DEC's request to revise Rate Schedule OL to allow replacement of existing MV lighting proactively with new LED lighting options is appropriate and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC's request to revise Rate Schedule OL to replace mercury vapor lighting and ballasts proactively with LED lighting fixtures is hereby approved as filed.

2. That any mercury vapor fixtures or ballasts that are replaced proactively by the Company shall not be subject to the transition charges related to Rate Schedule OL.

3. That DEC shall ensure customers are given advance notice of the Company's plan to proactively replace mercury vapor lighting.

4. That DEC shall file with the Commission, within 10 days following the date of this order, revised tariffs showing the effective date of the tariffs.

ISSUED BY ORDER OF THE COMMISSION.
This the ___21st___ day of June, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ELECTRIC -- RATE SCHEDULES/RIDERS/SERVICE RULES & REGULATIONS

DOCKET NO. E-2, SUB 1108

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC,	)	ORDER APPROVING DSM/EE
for Approval of Demand-Side Management	)	RIDER AND REQUIRING
and Energy Efficiency Cost Recovery	)	FILING OF PROPOSED
Rider Pursuant to G.S. 62-133.9 and	)	CUSTOMER NOTICE
Commission Rule R8-69	)	

HEARD: Tuesday, September 20, 2016, at 9:40 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland; Presiding, Chairman Edward S. Finley, Jr., and Commissioners Bryan E. Beatty, Don M. Bailey, Jerry C. Dockham, James G. Patterson and Lyons Gray

APPEARANCES:

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For the Using and Consuming Public:

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BY THE COMMISSION: General Statute 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric public utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) programs. The Commission is also authorized to award incentives to electric utilities for adopting and implementing new DSM/EE programs, including rewards based on the sharing of savings achieved by the programs. Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover the reasonable and prudent costs incurred for adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Under Commission Rule R8-69, such rider consists of the utility's forecasted costs during the rate period, similarly forecasted performance incentives, including net lost revenues (NLR) as allowed by the Commission, and an experience modification factor (EMF) rider to collect the difference between the utility's actual reasonable and prudent costs and incentives incurred and earned during the test period and the actual revenues realized during the test period under the DSM/EE rider, based on previous forecasts, then in effect.

Docket No. E-2, Sub 1108

On June 22, 2016, Duke Energy Progress, LLC (DEP or the Company), filed an application for approval of its annual DSM/EE cost recovery rider (Application) pursuant to G.S. 62-133.9 and Commission Rule R8-69. Along with the Application, DEP filed the associated testimony and exhibits of Carolyn T. Miller and Robert P. Evans (Initial Testimony) in support of recovery of DSM/EE costs and utility incentives forecasted for the rate period of January 1, 2017, through December 31, 2017, including program expenses, amortizations and carrying costs associated with deferred prior period costs, Distribution System Demand Response (DSDR) depreciation and capital costs, NLR, and program and portfolio performance incentives (PPI). In addition, DEP asked for approval of an EMF component of its DSM/EE rider to true-up an under-recovery of its actual DSM/EE costs and utility incentives during the test period of January 1, 2015, through December 31, 2015.

On July 6, 2016, the Commission issued an Order scheduling a public hearing in this matter for September 20, 2016, immediately following the 9:30 a.m. hearings in Docket Nos. E-2, Subs 1107 and 1109, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice. On September 15, 2016, DEP filed its affidavits of publication indicating that the Company had provided notice in newspapers of general circulation as required by the Commission's July 6, 2016 Order.

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

On June 28, 2016, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted by Commission order on July 1, 2016. On June 29, 2016, the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) filed a petition to intervene, which was granted by Commission order on June 30, 2016. On July 14, 2016, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted by Commission order on July 19, 2016. On July 18, 2016, the Southern Alliance for Clean Energy (SACE) filed a petition to intervene, which was granted by Commission order on July 20, 2016.

On July 11, 2016, DEP filed the Supplemental Direct Testimony of witness Evans, Supplemental Direct Evans Exhibits 2 and 4, and Supplemental Direct Miller Exhibits 1 and 2 (July 11 Supplemental Filing).

On September 2, 2016, SACE filed the testimony and exhibit of Jennifer Weiss. Also on September 2, 2016, the Public Staff filed the affidavit and exhibits of Michael C. Maness and the affidavit of David M. Williamson.

On September 7, 2016, DEP filed the Revised Supplemental Direct Testimony of witness Evans, Revised Supplemental Direct Evans Exhibits 1 and 2, and Revised Supplemental Direct Exhibits 1 and 2 of witness Miller (Revised Supplemental Filing).

On September 12, 2016, DEP filed a joint motion on behalf of itself and the Public Staff requesting that the Company's and Public Staff's witnesses be excused from appearing at the hearing and that their prefiled testimony, exhibits, and affidavits be received into the record. On September 14, 2016, the Commission granted that motion.

On September 13, 2016, DEP filed a letter on the status of its Appliance Recycling Program.

On September 20, 2016, the hearing was held as scheduled; however, because the parties had no material disputes, this matter was heard before Docket No. E-2, Sub 1109, instead of after that docket. No public witnesses appeared at the hearing.

On November 3, 2016, the Public Staff filed a letter with the Commission stating that the Public Staff had found certain minor exceptions in its detailed review of the costs of DEP's portfolio of DSM/EE programs incurred during the 12-month test period ended December 31, 2015, but that these exceptions were not large enough to affect the rates proposed by the Company.

On November 3, 2016, DEP, SACE, and the Public Staff filed a Joint Proposed Order.

On November 4, 2016, CIGFUR filed its Post-Hearing Brief. Also on that date, NCSEA filed a letter in lieu of a Post-Hearing Brief.

<u>Cost Recovery Mechanism</u>

On June 15, 2009, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required

Modifications in DEP's first DSM/EE rider proceeding (Sub 931 Order). In that Order, the Commission approved, with certain modifications, an Agreement and Stipulation of Partial Settlement (Stipulation) between DEP, the Public Staff, and Wal-Mart Stores East, LP, and Sam's East, Inc., setting forth the terms and conditions for approval of DSM/EE measures and the annual DSM/EE rider proceedings pursuant to G.S. 62-133.9 and Commission Rules R8-68 and R8-69. The Stipulation included a Cost Recovery and Incentive Mechanism for DSM and EE Programs (Original Mechanism), which was modified by the Commission in its Sub 931 Order and subsequently in its Order Granting Motions for Reconsideration in Part issued on November 25, 2009, in the same docket (Reconsideration Order). The Original Mechanism as approved after reconsideration allows DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with G.S. 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Mechanism.

On January 20, 2015, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waivers. In that Order, the Commission approved an agreement between DEP, the Public Staff, the Natural Resources Defense Council, and SACE proposing revisions to the Original Mechanism, generally to be effective January 1, 2016 (Revised Mechanism). The Revised Mechanism allows DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with G.S. 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Revised Mechanism.

In the present proceeding, based upon DEP's verified application, the affidavits, testimony, and exhibits received into evidence, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. DEP is a duly organized limited liability company (LLC) existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North and South Carolina, and is subject to the jurisdiction of the Commission as a public utility. DEP is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.9 and Commission Rule R8-69.

2. The test period for purposes of this proceeding extends from January 1, 2015, through December 31, 2015.

3. The rate period for purposes of this proceeding extends from January 1, 2017, through December 31, 2017.

4. DEP has requested approval for the recovery of costs, and utility incentives where applicable, related to the following DSM/EE programs:

Residential

- Residential Home Advantage
- Appliance Recycling
- Energy Education in Schools
- Multi-Family EE
- My Home Energy Report (MyHER) (or Residential EE Benchmarking)
- Neighborhood Energy Saver (Low Income)
- Home Energy Improvement
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment

Non-residential

- EE for Business
- Small Business Energy Saver
- Commercial, Industrial, and Governmental (CIG) Demand Response
- Business Energy Report pilot
- EnergyWise for Business (Load Control)

Residential and Non-residential

- DSDR
- EE Lighting

These programs are eligible for cost and utility incentive recovery, where applicable.

5. The evaluation, measurement, and verification (EM&V) analyses and reports prepared by DEP are adequate for purposes of this proceeding, and DEP has appropriately incorporated the results of EM&V into the DSM/EE rider calculations, with two exceptions. The exceptions are the EE Lighting program report for 2014, which was completed by the evaluator too late to be incorporated into the Company's DSM/EE rider in this proceeding, and the Small Business Energy Saver report for 2014, which is accepted for purposes of the rates in this rider but is subject to further review in future proceedings.

6. In its Application and Initial Testimony, as revised by its July 11 Supplemental Filing, DEP requested the recovery of NLR in the amount of $37,567,912 and PPI in the amount of $13,135,287 through the EMF component of the total DSM/EE rider, and NLR of $38,841,779 and PPI of $17,122,405 for recovery in the forward-looking, or prospective component of the total rider. As a result of additional analysis performed by DEP and provided to the Public Staff during the course of the proceeding, the Company corrected its EMF NLR and PPI amounts to $37,249,538 and $13,138,541, respectively, and its prospective NLR and PPI estimates to $38,223,700 and $17,125,659, respectively, as reflected in its Revised Supplemental Filing. The Public Staff agreed with these corrections. DEP's proposed recovery of NLR and PPI, as adjusted, is consistent with the Original Mechanism and Revised Mechanism, and is appropriate, subject to further review to the extent allowed in the Mechanisms.

7. For purposes of the DSM/EE rider to be set in this proceeding and subject to review in DEP's future DSM/EE rider proceedings, the reasonable and appropriate estimate of the Company's North Carolina retail DSM/EE program rate period amounts, consisting of its amortized operations and maintenance (O&M) costs, depreciation, capital costs, taxes, amortized incremental administrative and general (A&G) costs, carrying charges, NLR, and PPI, is $163,099,763, and this is the appropriate amount to use to develop the forward-looking DSM/EE revenue requirement. This amount is the total of the $163,714,588 proposed in DEP's July 11 Supplemental Filing and the total prospective NLR and PPI adjustment of ($614,825) reflected in DEP's Revised Supplemental Filing.

8. For purposes of the EMF component of its DSM/EE rider, DEP's reasonable and prudent North Carolina retail test period costs and incentives, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, are $127,462,551. This amount is the total of the $127,777,671 proposed in DEP's July 11 Supplemental Filing and the total NLR and PPI EMF adjustment of ($315,120) reflected in DEP's Revised Supplemental Filing. The reasonable and appropriate amount of test period DSM/EE rider revenues and miscellaneous adjustments to take into consideration in determining the test period DSM/EE under- or over-recovery is $99,703,786. Therefore, the test period revenue requirement, minus the test period revenues collected and miscellaneous adjustments, leaves $27,758,765 as the test period under-collection that is appropriate to use as the DSM/EE EMF revenue requirement in this proceeding.

9. After assignment or allocation to customer classes in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Commission Orders in Docket No. E-2, Sub 931, the revenue requirements for each rate class, excluding the North Carolina Regulatory Fee (NCRF), are as follows:

DSM/EE PROSPECTIVE COMPONENT:	
Residential	$99,540,184
General Service EE	57,699,963
General Service DSM	5,435,508
Lighting	424,108
Total	$163,099,763

DSM/EE EMF:	
Residential	$22,002,072
General Service EE	5,781,635
General Service DSM	(28,584)
Lighting	3,642
Total	$27,758,765

10. The appropriate and reasonable North Carolina retail class level kilowatt-hour (kWh) sales for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding are:

Rate Class	kWh Sales
Residential	15,679,117,804
General Service	10,472,633,783
Lighting	388,621,587

11. The appropriate DSM/EE EMF billing factors, excluding NCRF, are increments of: 0.140 cents per kWh for the Residential class; 0.055 cents per kWh for the EE component of the General Service classes; 0.000 cents per kWh for the DSM component of the General Service classes, and 0.001 cents per kWh for the Lighting class. These DSM/EE EMF billing factors do not change when the NCRF of 0.140% is included. Customers eligible for opt-out pursuant to G.S. 62-133.9(f) and Commission Rule R8-69(d) who are participating in either only a DSM or only an EE program as of January 1, 2016, are eligible to opt out of the component (either DSM or EE) of the prospective and EMF riders in which they are not participating, effective as of or after that date, provided they follow the opt-out procedures set forth in the statute and Rule, as administered by the Company. The Company shall be allowed in the future to recover any reasonable and appropriately determined actual shortfall in revenues, due to such opt-outs and experienced during 2016 in recovery of the EMF revenue requirement established in this proceeding. The extent and timing of that recovery shall be determined by the Commission in future proceedings.

12. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, excluding NCRF, are increments of: 0.635 cents per kWh for the Residential class; 0.551 cents per kWh for the EE component of the General Service classes; 0.052 cents per kWh for the DSM component of the General Service classes; and 0.109 cents per kWh for the Lighting class. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, including NCRF of 0.140%, are increments of: 0.636 cents per kWh for the Residential class; 0.552 cents per kWh for the EE component of the General Service classes; 0.052 cents per kWh for the DSM component of the General Service classes; and 0.109 cents per kWh for the Lighting class.

13. In accordance with the Commission's November 16, 2015 Order in Docket No. E-2, Sub 1070 (Sub 1070 Order), DEP has incorporated or will incorporate the recommendations of Public Staff witness Floyd from that proceeding with regard to future EM&V reports relating to how regression modeling accounts for outliers, how savings attributable to other programs are accounted for in the Residential EE Benchmarking/MyHER program, use of the most recent metering data for review of the Appliance Recycling program, use of updated attributes from other programs' lighting metering evaluations for the Energy Efficient Lighting program, and the recommendation that DEP file an EM&V report on DSDR.

14. Also in accordance with the Sub 1070 Order, DEP has reported on the discussions of the Company's Carolinas Energy Efficiency Collaborative (the Collaborative) pertaining to program modifications recommended by SACE and to customer notifications of forecasted peak demand conditions. SACE's recommendations for program modifications will continue to be discussed at future meetings of the Collaborative. DEP should report on those discussions in its next DSM/EE rider application. No further action is necessary at this time with regard to customer notifications of forecasted peak demand conditions.

15. In accordance with the Sub 1070 Order requirement that DEP shall monitor the changes in annual ratios of allocations between non-DSDR and DSDR equipment and report the degree of change in its annual DSM/EE rider filing, the Company has complied. No change in allocation ratios was necessary for 2016. Annual review of the allocation ratios will continue, will be reported to the Public Staff each year, and any changes will be addressed in future rider proceedings.

16. In accordance with the Sub 1070 Order, DEP adjusted the timing of its EM&V reports for program year 2014 to be available by the time of the Company's filing in the present rider proceeding. DEP included copies of those EM&V reports with its 2016 DSM/EE rider application. To the extent feasible, the Company should make available all EM&V reports for the 2015 program year to interested parties as part of its 2017 DSM/EE rider application, and where available should make all new EM&V reports available to interested parties once those reports are completed.

17. DEP has provided total resource cost (TRC) test results for the DSDR program, as required by the Sub 1070 Order, and the DSDR program is deemed cost effective for purposes of this proceeding. It is reasonable for the Public Staff to continue to examine the topic of uses of DSDR for purposes other than DSM/EE.

18. DEP has complied with the Commission's February 9, 2016, order in Docket No. E-2, Sub 936, requiring Collaborative discussions on DSM/EE recommendations made by the Southern Environmental Law Center (SELC) and the NCSEA in that docket.

19. To the extent they are not cost prohibitive, the following recommendations of Public Staff witness Williamson regarding the development of future EM&V reports are reasonable: (i) future EM&V evaluations for the Residential New Construction program, and similar programs, should consider incorporating market effect savings; (ii) if the Appliance Recycling program is resumed, future EM&V evaluations should consider use of a primary metering study consistent with the Uniform Methods Protocol to estimate per-unit energy consumption; (iii) with respect to the 2014 EM&V report for EE Lighting, the Company and Public Staff should discuss whether the assumptions on baseline wattage and Net-to-Gross methodology are appropriate or need revision; (iv) future EM&V evaluations for the Neighborhood Energy Saver program should consider use of state-level data; and (v) with respect to the 2014 EM&V report for the Small Business Energy Saver program, the Company and Public Staff should discuss the inputs of the Net-to-Gross savings calculations.

20. Based on the recommendations of SACE witness Weiss, the Commission finds that DEP should continue to utilize its Collaborative to discuss and consider the following: (a) ways to improve current programs and to develop new programs, including an expansion of low-income programs and an enhanced multi-family program; (b) any additional potential for non-residential programs, with an emphasis on attracting opt-out eligible customers; (c) whether more detailed cost-reporting procedures and more consistent reporting of cost-effectiveness scores are feasible; and (d) means to encourage participation in cost-effective DSM/EE programs. DEP should also continue to convene its on-bill financing working group and report the progress at Collaborative meetings. In addition, based on the testimony of SACE witness Weiss, the Commission finds that

DEP should utilize its Collaborative to: (a) discuss and consider ways to avoid underestimating program performance, and (b) discuss and consider ways in which it can achieve annual energy savings of at least 1 percent of prior-year retail sales and cumulative savings of at least 7 percent over the period from 2014 through 2018. The Collaborative should also discuss and attempt to produce a recommendation that addresses witness Weiss' observations that there is currently no mechanism in place to monitor and verify the alternative DMS/EE measures implemented by customers who choose not to participate in DEP's DSM/EE programs and instead opt-out. The Collaborative should also address CIGFUR's position, as discussed in its post-hearing brief, that the only statutory obligation on opt-out customers is to notify the utility of their choice to opt-out.

21. It is appropriate for the Public Staff and the Company to make recommendations in the Company's 2017 DSM/EE rider proceeding on the question of whether DEP's 2015 outdoor lighting activities constitute the equivalent of "net found revenues."

22. After DEP filed its application in this docket, a regulatory fee change became effective on July 1, 2016, and a reduction in the state income tax rate is scheduled to become effective on January 1, 2017. It is not necessary to adjust the DSM/EE billing rates or the DSM/EE EMF billing rates in this proceeding to reflect the changes in regulatory fee and state income tax rate.

23. An in-service date of June 1, 2014, for DEP's DSDR program, for purposes of determining NLR, is appropriate and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact, which is supported by DEP's Application, is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-3

No party opposed DEP's proposed rate period and test period. The rate period and test period proposed by DEP are consistent with the Revised Mechanism approved by the Commission. The proposed rate period and test period are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact can be found in DEP's application, the testimony and exhibits of DEP witness Miller, the affidavit of Public Staff witness Williamson, and various Commission orders in program approval dockets.

The direct testimony of DEP witness Miller and her Exhibit 2 list the DSM/EE programs for which the Company is requesting cost recovery, and incentives where applicable, in this proceeding. Those programs are:

Residential
- Home Advantage
- Appliance Recycling
- Energy Education in Schools
- Multi-Family EE
- MyHER or Residential EE Benchmarking
- Neighborhood Energy Saver (Low Income)
- Home Energy Improvement
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment

Non-residential
- EE for Business
- Small Business Energy Saver
- CIG Demand Response
- Business Energy Report pilot
- EnergyWise for Business (Load Control)

Residential and Non-residential
- DSDR
- EE Lighting

Each of these programs has previously received Commission approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under G.S. 62-133.9.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact can be found in the testimony of DEP witness Evans and the affidavit of Public Staff witness Williamson.

Witness Evans provided the EM&V reports for the following programs and program years:
- EE for Business Program – 2013
- EE for Business Program – 2014
- Home Energy Improvement Program – 2013
- Home Energy Improvement Program – 2014
- Residential New Construction Program – 2013 & 2014
- Appliance Recycling Program – 2014
- CIG Demand Response Automation Program – 2014
- CIG Demand Response Automation Program – 2015
- Energy Efficient Lighting Program – 2014
- EnergyWise Program – Summer 2014
- EnergyWise Program – Summer 2015

- EnergyWise Program – Winter 2014/2015
- Neighborhood Every Saver Program – 2014
- Small Business Energy Saver Program – 2014

Public Staff witness Williamson testified that he had confirmed through sampling that the updated EM&V data properly flowed into the calculations of net present values (NPV) that serve as the basis for the NLR and PPI calculations. He tracked the data derived from EM&V as they were incorporated into the database, the NPV calculations and, ultimately, the rider calculation. Witness Williamson stated his belief that DEP was appropriately incorporating the results of EM&V into the DSM/EE rider calculations.

Witness Williamson also recommended that the Commission consider the vintages represented by these EM&V reports to be complete, with the exception of the EE Lighting and the Small Business Energy Saver programs. He testified that the EM&V report on EE Lighting was received too late for the Company to incorporate the findings into the present rider proceeding. He further testified that while the Small Business Energy Saver EM&V results were incorporated into the present rider proceeding, those results are subject to revision in the future. No party opposed these recommendations.

Based upon the testimony and evidence cited above, the Commission finds the net energy and capacity savings derived from the EM&V to be reasonable and appropriate. Further, the Commission concludes that DEP is appropriately incorporating the results of EM&V into the DSM/EE rider calculations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-12

The evidence for these findings of fact can be found in the Initial Testimony and Exhibits of DEP witnesses Miller and Evans, the July 11 Supplemental Filing, the Revised Supplemental Filing, and the affidavit and exhibits of Public Staff witness Maness.

In her Initial Testimony, as revised by her exhibits filed as part of the July 11 Supplemental Filing, DEP witness Miller calculated proposed North Carolina retail NLR in the amount of $37,567,912 and a PPI in the amount of $13,135,287 for the EMF component of the total DSM/EE Rider, and North Carolina retail NLR of $38,841,779 and a PPI of $17,122,405 for the forward-looking, or prospective component of the total Rider. Public Staff witness Maness and Company witness Evans (in the Revised Supplemental Filing) indicated that as a result of additional analysis performed by DEP and provided to the Public Staff during the course of the proceeding, the Company corrected its NLR and PPI amounts. The revised exhibits of witness Miller included in the Revised Supplemental Filing indicated that the EMF NLR and PPI amounts were adjusted to $37,249,538 and $13,138,541, respectively, and the prospective NLR and PPI estimates were adjusted to $38,223,700 and $17,125,659, respectively. Public Staff witness Maness testified that he agreed with the Company's corrections.

In her exhibits filed as part of the Revised Supplemental Filing, DEP witness Miller calculated DEP's total North Carolina retail adjusted test period costs and utility incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G

costs, carrying charges, NLR, and PPI to be $127,462,551. Witness Miller's testimony and exhibits also indicated that the amount of test period DSM/EE rider revenues and miscellaneous adjustments to take into consideration in determining the test period DSM/EE under- or over-recovery is $99,703,786. Therefore, the aggregate DSM/EE under-recovery recommended by DEP for purposes of this proceeding is $27,758,765, as reflected in the Revised Supplemental Filing.

Witness Miller also calculated DEP's estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized operations and maintenance (O&M) costs, depreciation, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, as $163,099,763.

According to the revised exhibits of DEP witness Miller as filed in the Revised Supplemental Filing, after assignment or allocation to customer classes in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Commission Orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding NCRF, are as follows:

DSM/EE PROSPECTIVE COMPONENT:	
Residential	$99,540,184
General Service EE	57,699,963
General Service DSM	5,435,508
Lighting	424,108
Total	$163,099,763

DSM/EE EMF:	
Residential	$22,002,072
General Service EE	5,781,635
General Service DSM	(28,584)
Lighting	3,642
Total	$27,758,765

Witness Miller's exhibits also set forth the North Carolina retail class level kWh sales that DEP believes are appropriate and reasonable for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding. She adjusted the kWh sales to exclude estimated sales to customers who have opted out of participation in DEP's DSM/EE programs. The adjusted sales amounts are as follows: Residential class – 15,679,117,804 kWh; General Service classes – 10,472,633,783 kWh; and Lighting class – 388,621,587 kWh.

According to her revised exhibits filed as part of the Revised Supplemental Filing, witness Miller calculated the DSM/EE billing factors without NCRF as follows:

DSM/EE PROSPECTIVE BILLING FACTORS (cents/kWh):	
Residential	0.635
General Service EE	0.551
General Service DSM	0.052
Lighting	0.109

DSM/EE EMF BILLING FACTORS (cents/kWh):	
Residential	0.140
General Service EE	0.055
General Service DSM	0.000
Lighting	0.001

Including the NCRF, the factors calculated by witness Miller are as follows:

DSM/EE PROSPECTIVE BILLING FACTORS (cents/kWh):	
Residential	0.636
General Service EE	0.552
General Service DSM	0.052
Lighting	0.109

DSM/EE EMF BILLING FACTORS (cents/kWh):	
Residential	0.140
General Service EE	0.055
General Service DSM	0.000
Lighting	0.001

Public Staff witness Maness indicated that the focus of the Public Staff's investigation of DEP's filing in this proceeding was whether the proposed DSM/EE rider was calculated in accordance with the Original and Revised Mechanisms, as applicable, and otherwise adhered to sound ratemaking concepts and principles. The Public Staff's investigation included a review of the Company's filing and relevant prior Commission proceedings and orders, and workpapers and source documentation used by the Company to develop the proposed billing rates, including the selection and review of a sample of source documentation for test period costs included by the Company for recovery.

Witness Maness testified that his investigation of DEP's filing indicates that the Company generally has calculated the proposed rider in accordance with the methods set forth in the approved Mechanisms, as applicable, for recovery of costs, NLR, and the PPI. Witness Maness noted that DEP had discovered certain errors in its calculation of NLR and the PPI used in the determination of the prospective and EMF billing rates. He testified that he had reviewed the Company's corrections of these errors and agreed with them. No other party objected to the Company's adjustments.

In his affidavit, Public Staff witness Maness noted that the Public Staff's review of the sample of program costs was ongoing. On November 3, 2016, the Public Staff filed a letter with the Commission stating that the review was complete and while certain minor exceptions had been discovered, they were not large enough to affect the rates proposed by the Company.

With respect to DEP's proposed recovery of NLR and PPI, the Commission notes that no party opposed such recovery. The Commission finds that such proposed recovery is consistent with the Commission's Orders in Docket No. E-2, Sub 931, and that NLR and PPI are appropriate for recovery in this proceeding, with the prospective rate period costs subject to further review in

DEP's future annual DSM/EE rider proceedings. The Commission concludes that DEP has complied with G.S. 133.9, Commission Rule R8-69, and the Commission's Orders in Docket No, E-2, Sub 931, with regard to calculating costs and utility incentives for the test and rate periods at issue in this proceeding.

Therefore, the Commission concludes that for purposes of the DSM/EE EMF billing rates to be set in this proceeding, DEP's reasonable and prudent North Carolina retail test period costs and incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, are $127,462,551. The reasonable and appropriate amount of test period DSM/EE rider revenues and adjustments to take into consideration in determining the test year and prospective period DSM/EE under- or over-recovery is $99,703,786. Therefore, the aggregate DSM/EE under-recovery for purposes of this proceeding is $27,758,765.

For purposes of the DSM/EE rider to be set in this proceeding, and subject to review in DEP's future DSM/EE rider proceedings, the Commission concludes that DEP's reasonable and appropriate estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, after incorporation of the NLR and PPI adjustments reflected in the Company's Revised Supplemental Filing and recommended by the Public Staff, is $163,099,763, and this is the appropriate amount to use to develop the DSM/EE revenue requirement.

With regard to the revenue requirements per class, the Commission concludes that after assignment or allocation to customer classes in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding NCRF, are as follows:

DSM/EE PROSPECTIVE COMPONENT:	
Residential	$99,540,184
General Service EE	57,699,963
General Service DSM	5,435,508
Lighting	424,108
Total	$163,099,763

DSM/EE EMF:	
Residential	$22,002,072
General Service EE	5,781,635
General Service DSM	(28,584)
Lighting	3,642
Total	$27,758,765

Furthermore, the Commission finds that the appropriate and reasonable North Carolina retail class level kWh sales for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding are as follows: Residential class – 15,679,117,804; General Service classes – 10,472,633,783; and Lighting class – 388,621,587.

In its post-hearing letter, NCSEA states that it does not challenge as imprudent or unreasonable any costs for which DEP seeks recovery in this docket. Rather, NCSEA states that it seeks to provide a temporal context for DEP's proposed DSM/EE rider. NCSEA provides a graph labeled Figure 1 that shows DEP's various DSM/EE rider charges from 2010 through 2016, as well as DEP's proposed DSM/EE charges for 2017.Based on the testimony and exhibits of DEP witnesses Miller and Evans, the affidavit and exhibits of Public Staff witness Maness, and the entire record in this proceeding, the Commission finds and concludes that the DSM/EE EMF billing factors as proposed by DEP in the Revised Supplemental Filing are appropriate. The Commission further concludes that the forward-looking DSM/EE rates as proposed by DEP in the Revised Supplemental Filing to be charged during the rate period for the Residential, General Service, and Lighting rate schedules are appropriate. All of these billing factors are set forth in the Revised Supplemental Filing and in Maness Exhibits I and II.

The Commission notes that pursuant to the Revised Mechanism and in accordance with the Sub 1070 Order, DEP's combined General Service DSM and DSM EMF billing factors, and its combined General Service EE and EE EMF billing factors, have been available to General Service customers for measures and programs implemented on and after January 1, 2016. No party has challenged this approach, and it is appropriate to continue. Furthermore, consistent with the Commission's decision approving the Revised Mechanism, the Commission hereby concludes that customers eligible for opt-out pursuant to G.S. 62-133.9(f) and Commission Rule R8-69(d) who were participating in either only a DSM or only an EE program as of January 1, 2016, are eligible to opt out of the component (either DSM or EE) of the prospective and EMF riders in which they are not participating, provided they follow the opt-out procedures set forth in the statute and Rule, as administered by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-18

The evidence for these findings of fact can be found in the testimony of DEP witness Evans and Public Staff witness Maness.

In the Sub 1070 Order, the Commission ordered the Company to incorporate the recommendations made in that docket by Public Staff witness Jack Floyd with regard to future EM&V for certain programs. Specifically, witness Floyd recommended that (i) future EM&V reports should provide more details on how outliers are addressed and categorized with respect to regression modeling used to estimate savings impacts; (ii) with respect to savings for MyHER program that are attributable to other EE programs, they should use the most current savings estimates from the other EE programs, and also for the MyHER program, the reports should exclude any energy savings attributable to the EnergyWise program as it is a DSM program; (iii) with respect to the Appliance Recycling program's use of secondary metering data for regression modeling, the most recent findings and metering data should be used; and (iv) the EE Lighting program should incorporate any updated attributes from the lighting metering evaluations of either the Small Business Energy Saver program or the EE for Business program, as appropriate. In the present proceeding, witness Evans testified that DEP had communicated witness Floyd's recommendations to the evaluators and that witness Floyd's recommendations would be implemented in future evaluation reports. The Commission concludes that DEP's response to these requirements from the Sub 1070 Order is satisfactory and DEP should implement those recommendations from witness Floyd in future evaluations.

Also in the Sub 1070 Order, the Commission required that DEP report the results of the Collaborative's discussions pertaining to program modifications recommended by SACE and customer notifications of forecasted peak demand conditions. Further, the Commission ordered that issues raised in SACE witness Allred's testimony in Docket No. E-2, Sub 1070, be discussed in the Collaborative and be reported by the Company in the present docket. Witness Evans testified that the Collaborative discussed the new programs and program enhancements recommended by witness Allred, and will continue to discuss them in the future. In addition, the Company has established a working group to study the potential of on-bill financing programs. Witness Evans also noted that customer notifications of forecasted peak demand conditions were discussed in the Collaborative. Because general customer notifications require notice to North American Electric Reliability Council, SERC Reliability Council, and the Department of Energy, and excessive notices can result in fines, the Company determined that no further action was warranted at this time with regard to customer notifications of forecasted peak demand conditions.

The Commission concludes that DEP has taken reasonable actions to comply with the requirements of the Sub 1070 Order, and that it should continue to discuss SACE's proposals for program modifications in future Collaborative meetings. DEP should report on those discussions as part of its next DSM/EE rider application.

The Sub 1070 Order also provided that DEP shall file all changes in annual ratios of allocations between non-DSDR and DSDR equipment, report the degree of change in its annual DSM/EE rider filing, and provide such changes to the Public Staff as they become available. Witness Evans informed the Commission that a review of 2014 units showed that no change in allocation ratios was necessary for 2016. He stated that 2015 units would be reviewed and any changes would be communicated to the Public Staff and implemented on January 1, 2017. The Commission concludes that DEP should file reports of changes to its allocations between non-DSDR and DSDR equipment in future proceedings and provide the Public Staff with information on any changes to the allocation factor as they become available.

The Sub 1070 Order required DEP to conduct EM&V on the DSDR program and file the TRC test results with the Commission. The Company filed its TRC result for the DSDR program on March 30, 2016. The TRC result was 1.47, demonstrating cost-effectiveness for purposes of this proceeding. Public Staff witness Maness testified that although the Public Staff is not proposing any adjustments in this proceeding to DSDR costs related to the balancing of the use of DSDR to reduce customer demand and energy requirements with other actual or potential uses of the system, this conclusion is for purposes of this proceeding only. The Public Staff will continue to examine this topic in the future. The Commission concludes that the Public Staff's plans to continue to examine this topic are reasonable.

Finally, in the February 9, 2016, order in Docket No. E-2, Sub 936, the Commission required DEP to discuss in the Collaborative various recommendations made by the SELC and the NCSEA. DEP witness Evans testified that the SELC and NCSEA recommendations were discussed in the February 18, 2016, Collaborative meeting and will be discussed further in future meetings. The Commission concludes that the Company has complied with this requirement from the order in Docket No. E-2, Sub 936, and that such discussions should continue.

In the Sub 1070 Order, the Commission accepted the recommendation of SACE witness Allred that DEP should adjust the timing of the filing of its EM&V reports so they are all available by the time of each rider proceeding for the year prior to the test period, and should include copies of the EM&V reports in its rider applications. The Company has complied by providing all EM&V reports relevant to the present proceeding in its Application. The Company should continue to follow this practice in future rider filings, either by including copies of its EM&V reports in its DSM/EE rider applications or by providing a web link in its applications to direct readers to the filed EM&V reports. Additionally, the Company should provide copies of its EM&V reports to the Public Staff as soon as those reports become available.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The recommendations of Public Staff witness Williamson with regard to future EM&V reports, as summarized in Finding of Fact No. 19, were not opposed by any other party. DEP should comply with those recommendations to the extent they are not cost prohibitive.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for these findings of fact can be found in the testimony of SACE witness Weiss and the post-hearing brief of CIGFUR.

SACE witness Weiss made several recommendations related to enhancement of DSM/EE programs. The Commission concludes that DEP's Collaborative is an appropriate forum for discussion of those recommendations. In particular, the Commission finds that DEP should continue to utilize its Collaborative to discuss and consider the following: (a) ways to improve current programs and to develop new programs, including an expansion of low-income programs and an enhanced multi-family program; (b) any additional potential for non-residential programs, with an emphasis on attracting opt-out eligible customers; (c) whether more detailed cost-reporting procedures and more consistent reporting of cost-effectiveness scores are feasible; and (d) means to encourage participation in cost-effective DSM/EE programs. DEP should also continue to convene its on-bill financing working group and report the progress at Collaborative meetings.

SACE witness Weiss also noted in her testimony that DEP is projecting a decline in energy savings in 2016 and 2017, and that DEP has underestimated program performance in the past. Based on these observations, the Commission finds that DEP should utilize its Collaborative to discuss and consider ways in which it can avoid underestimating program performance, while being cognizant that overestimating program performance and energy savings will result in an over-collection from customers.

SACE witness Weiss discussed in her testimony that DEP's 2015 energy savings fell short of the system-wide EE savings target that DEP agreed to in a settlement agreement with SACE, the South Carolina Coastal Conservation League, and the Environmental Defense Fund in connection with the then-proposed merger of Duke Energy and Progress Energy. Based on the testimony of witness Weiss, the Commission finds that DEP should utilize its Collaborative to discuss and consider ways in which it can meet the merger settlement target of annual energy savings of at least one percent of prior-year retail sales[1] and cumulative savings of at least seven percent over the period from 2014 through 2018.

In its post-hearing brief, CIGFUR states that it takes issue with one of SACE witness Weiss' recommendations. Witness Weiss, in her testimony, noted that there is currently no mechanism in place to monitor, verify and track savings that may result from DSM/EE measures that opt-out customers implement. She recommends that DEP develop a standardized online protocol for annually tracking the stated, quantified goals and the achieved level of energy savings for each opt-out customer to ensure that the EE measures are being installed and that the resulting savings are recorded and tracked. CIGFUR, in its post-hearing brief, recommends that the Commission reject witness Weiss' recommendation, as it is fundamentally inconsistent with the language of G.S. 62-133.9(f). CIGFUR argues that if an industrial customer "notifies" the utility that it has implemented or will implement alternative DSM/EE measures, and that it is electing not to participate in the utility's DSM/EE measures, then no DSM/EE costs may be assigned to that customer. CIGFUR states that the statute "imposes no other preconditions to a customer's ability to opt-out of the DSM/EE rider beyond this notification." CIGFUR's Post-Hearing Brief, at p. 2. CIGFUR further contends that "SACE's recommendation, however, threatens to add new conditions to a customer's statutory opt-out right: that a customer divulge through an unknown 'standardized online protocol' confidential and proprietary information regarding the customer's stated and quantified DSM/EE goals and the achieved level of energy savings produced by the customer's internal and competitively-sensitive DSM/EE measures." Id., at pp. 2-3.

The Commission takes note of CIGFUR's objections to witness Weiss' recommendation and orders that CIGFUR, SACE, DEP and the other parties discuss this topic at DEP's Collaborative meetings to see if there is an alternative that is acceptable to each party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

Public Staff witness Maness recommended that the Commission include in its Order a provision allowing the Public Staff to investigate, as part of the 2017 DSM/EE rider proceeding, DEP's 2015 outdoor lighting activities to determine if those activities might constitute "net found revenues." The Commission concludes that the Public Staff has the authority to conduct such an investigation, and moreover that it would be appropriate for both the Public Staff and the Company

[1] As the Commission noted in its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice issued August 25, 2016, in Docket No. E-7, Sub 1105, to the extent that non-residential customers opt out of the Company's programs and implement their own DSM/EE programs, that does not count toward achievement of the aspirational targets. Thus, while the retail electricity sales that the 1% goal is based upon include sales to customers who have opted out of paying the DSM/EE rider, the level of savings the Company is able to achieve is negatively impacted by the ability of certain non-residential customers to opt out of the DSM/EE rider.

to make recommendations in the Company's 2017 DSM/EE rider proceeding on the question of whether DEP's 2015 outdoor lighting activities constitute "net found revenues."

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

Public Staff witness Maness noted that the regulatory fee changed from 0.148% to 0.140% on July 1, 2016, but the change was not large enough to affect billing rates in the present proceeding. He also noted that the State corporate income tax rate will fall from 4% to 3% on January 1, 2017, but recommended that the effects of this change be addressed in the true-up in DEP's future DSM/EE EMF riders. The Commission agrees with witness Maness and concludes that the effect of the tax rate change should be addressed by true-up in future DSM/EE EMF riders.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The Company has requested recovery of NLR for the DSDR program, based on an in-service date of June 1, 2014, for the program. Public Staff witness Maness accepted that in-service date and, therefore, the Company's calculation of the amount of NLR for DSDR to be recovered in rates in the present proceeding. The Commission concludes that the in-service date for the DSDR program of June 1, 2014, and the amount of NLR for DSDR proposed by the Company in this proceeding are reasonable.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate DSM/EE EMF billing factors, excluding NCRF, for the Residential, General Service, and Lighting rate classes are increments of: 0.140 cents per kWh for the Residential class; 0.055 cents per kWh for the EE component of General Service classes; 0.000 cents per kWh for the DSM component of General Service classes, and 0.001 cents per kWh for the Lighting class. These DSM/EE EMF billing factors do not change when the NCRF is included.

2. That the appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period for the Residential, General Service, and Lighting rate classes (excluding NCRF) are increments of 0.635 cents per kWh for the Residential class; 0.551 cents per kWh for the EE component of General Service classes; 0.052 cents per kWh for the DSM component of General Service classes; and 0.109 cents per kWh for the Lighting class. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, including NCRF of 0.140%, are increments of: 0.636 cents per kWh for the Residential class; 0.552 cents per kWh for the EE component of the General Service classes; 0.052 cents per kWh for the DSM component of the General Service classes; and 0.109 cents per kWh for the Lighting class.

3. That the appropriate total DSM/EE annual riders including the DSM/EE rate and the DSM/EE EMF rate (including NCRF of 0.140%) for the Residential, General Service, and Lighting rate classes are increments of 0.776 cents per kWh for the Residential class, 0.607 cents per kWh for the EE portion of the General Service classes, 0.052 cents per kWh for the DSM portion of the General Service classes, and 0.110 cents per kWh for the Lighting class.

4. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these adjustments as soon as practicable. Such rates are to be effective for service rendered on or after January 1, 2017.

5. That DEP shall work with the Public Staff to prepare a joint proposed Notice to Customers giving notice of rate changes ordered by the Commission herein, and DEP shall file such proposed notice for Commission approval as soon as practicable.

6. That, as part of its 2017 DSM/EE rider filing, DEP shall report the results of the Collaborative's discussions pertaining to new programs and program modifications recommended by SACE.

7. That the issues raised in witness Weiss's testimony shall be discussed in the DEP Collaborative, and the results of such discussions shall be reported in the Company's application in the next DSM/EE rider proceeding.

8. That DEP shall file all changes in annual ratios of allocations between non-DSDR and DSDR equipment, report the degree of change in its annual DSM/EE rider filings, and provide such changes to the Public Staff as they become available.

9. That DEP shall incorporate the recommendations of Public Staff witness Williamson regarding future EM&V reports.

10. That to the extent possible DEP shall adjust the timing of its EM&V reports as appropriate, so they are all available by the time of each rider proceeding for the year prior to the test period. DEP shall include copies of or web links to those filed EM&V reports in its annual DSM/EE rider application.

11. That customers eligible for opt-out pursuant to G.S. 62-133.9(f) and Commission Rule R8-69(d) who are participating in either only a DSM or only an EE program as of January 1, 2016, shall be eligible to opt out of the component (either DSM or EE) of the prospective and EMF riders in which they are not participating, effective as of or after that date, provided they follow the opt-out procedures set forth in the statute and Rule, as administered by the Company, and that the Company shall be allowed in the future to recover any reasonable and appropriately determined actual shortfall in revenues, due to such opt-outs and experienced during 2016 in recovery of the EMF revenue requirement established in this proceeding. The extent and timing of that recovery shall be determined by the Commission in future proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of November, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. E-2, SUB 1109

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC, for	)	ORDER ALLOWING PROPOSED
Approval of Renewable Energy and Energy	)	REPS AND REPS EMF RIDER TO
Efficiency Portfolio Standard Cost Recovery	)	BECOME EFFECTIVE SUBJECT
Rider Pursuant to G.S. 62-133.8 and	)	TO REFUND
Commission Rule R8-67	)	

BY THE COMMISSION: On June 30, 2016, Duke Energy Progress, LLC (DEP or the Company), filed its annual Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance report and application for approval of REPS cost recovery pursuant to G.S. 62-133.8 and Rule R8-67. DEP's annual REPS Rider has two components: (1) a forward-looking component to recover DEP's projected REPS costs from December 1, 2016 through November 30, 2017, and (2) a REPS Experience Modification Factor (EMF) to true-up any over or under-recovery of REPS costs under the previous REPS Rider.

By its application, DEP proposes to implement the following combined monthly REPS and REPS EMF Rider charges per customer account (excluding regulatory fee), effective for service rendered on and after December 1, 2016: $1.31 for residential customers, an increase of $0.14; $10.76 for general service/lighting customers, an increase of $4.11; and $83.21 for industrial customers, an increase of $22.44.

The Commission issued orders granting petitions to intervene by the North Carolina Sustainable Energy Association (NCSEA) and the Carolina Utility Customers Association, Inc. (CUCA), on July 1 and 14, 2016, respectively.

On July 6, 2016, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice (Scheduling Order).

On September 20, 2016, this matter came on for public hearing as scheduled pursuant to the Scheduling Order for the purpose of considering the annual REPS compliance report and REPS cost recovery proceeding for DEP. During the hearing, the Commission heard arguments from the Company and the Public Staff regarding complex issues in dispute in this docket. The determination of these issues has a potential impact on the total REPS and REPS EMF charges DEP will be authorized to charge during the rate period from December 1, 2016 through November 30, 2017. Prior to the adjournment of the public hearing, the Presiding Commissioner ruled that post-hearing filings will be due 30 days from the date that transcripts are filed in this proceeding. Pursuant to that ruling and the filing of transcripts on October 10 and 11, 2016, the parties' post-hearing filings are due to be filed on November 10, 2016.

On November 4, 2016, DEP and the Public Staff filed a Joint Motion for Leave to Implement Interim Rates until Final Order (Joint Motion). DEP and the Public Staff (Movants) request that the Commission allow the implementation of the proposed rates as filed in DEP's application effective December 1, 2016, subject to refund with interest, if any such refund is required, after the Commission issues either a notice of decision or a final order in this matter approving the final REPS Rider charges. In support of their proposal, Movants state that the filing of the proposed orders on November 10, 2016, is only three weeks before the November 30, 2016 expiration of the existing rates, and that the implementation of new rates on December 1, 2016, requires sufficient time for DEP to change its billing programming and develop a notice to customers. Movants further state that their proposal will allow the Commission sufficient time to review the complex issues presented in this proceeding and that the Commission has approved interim rates in similar circumstances in other proceedings.[1] Therefore, Movants request that the Commission issue an order approving the interim rates requested in the Joint Motion no later than November 21, 2016, to allow DEP sufficient time to provide appropriate notice to its customers of the change in rates.

DEP subsequently informed the Commission that the other parties to this proceeding, NCSEA and CUCA, had been contacted and do not object to the requested relief.

Based upon the foregoing, the Commission finds good cause to grant the Movants' requested relief and allow DEP's proposed REPS Rider charges to become effective for service rendered on and after December 1, 2016, at the levels requested by DEP in its application, subject to refund with interest if the Commission sets the REPS and REPS EMF Rider charges at lower levels by final order entered in this docket.

IT IS, THEREFORE, ORDERED as follows:

1. That effective for service rendered on and after December 1, 2016, DEP shall be allowed to charge the following total monthly REPS and REPS EMF Rider charges per customer account (excluding regulatory fee), as proposed in its application for REPS Cost Recovery Rider filed in this docket on June 30, 2016, pursuant to G.S. 62-133.8 and Commission Rule R8-67: $1.31 for residential customers; $10.76 for general service/lighting customers; and $83.21 for industrial customers. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account DEP shall be allowed to charge are $1.31 for residential customers, $10.78 for general service service/lighting customers, and $83.33 for industrial customers;

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[1] Joint Motion at 3 (citing Order Allowing Proposed Rider BA-1 to Become Effective Subject to Refund, Docket No. E-2, Sub 931 (Nov. 14, 2008); Order Resolving Certain Issues, Requesting Information on Unsettled Matter, and Allowing Proposed Rider to Become Effective Subject to Refund, Docket No. E-7, Sub 831 (Feb. 26, 2009)).

2. That the above REPS and REPS EMF charges are allowed to become effective subject to refund with interest if the Commission, by final order in this docket, sets the REPS Rider at lower levels;

3. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement the approved rate adjustments ordered by the Commission in Docket No. E-2, Subs 1107, 1109, and 1110 as soon as practicable; and

4. That DEP shall work with Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket No. E-2, Subs 1107, 1109, and 1110, and the Company shall file the proposed customer notice for approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the __10th___ day of November, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Duke Energy Progress, LLC	)	
for Approval of Joint Agency Asset Rider	)	
for Recovery of Costs Related to Facilities	)	ORDER APPROVING JOINT AGENCY
Purchased from Joint Power Agency	)	ASSET RIDER ADJUSTMENT
Pursuant to G.S. 62-133.14 and Rule R8-70	)	

HEARD: Tuesday, September 20, 2016 at 10:00 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

For Duke Energy Progress, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, NCRH 20/Post Office Box 1551, Raleigh, North Carolina 27601-1551

For the Using and Consuming Public:

Dianna Downey, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

For the Carolina Industrial Group for Fair Utility Rates II:

Adam Olls, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

BY THE COMMISSION: On June 22, 2016, Duke Energy Progress, LLC (DEP or the Company) filed its Application for Approval of Joint Agency Asset Rider (JAAR) to recover costs related to facilities purchased from the North Carolina Eastern Municipal Power Agency (NCEMPA) pursuant to G.S. 62-133.14 and Commission Rule R8-70. DEP's application was accompanied by the testimony and exhibits of Jane L. McManeus – Director of Rates and Regulatory Filings.

On July 7, 2016, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice, in which the Commission set this matter for public witness and expert witness hearings, established discovery guidelines, and provided for public notice of the hearings. On June 29, 2016, Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed its petition to intervene. The Commission granted the petition by Order dated June 30, 2016. On July 14, 2016, Carolina Utility Customers Association, Inc. (CUCA) filed its petition to intervene. CUCA's petition was granted by Order dated July 14, 2016. The intervention and participation by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On September 2, 2016, the Public Staff filed a motion requesting an extension of time until September 8, 2016, for all intervenors to file testimony. The Commission granted the Public Staff's motion by Order dated September 2, 2016.

On September 2, 2016, DEP filed the supplemental testimony and exhibits (including revised exhibits) of witness McManeus and on September 7, 2016, DEP filed the revised supplemental testimony of witness McManeus.

On September 8, 2016, the Public Staff filed the affidavit of Michael C. Maness – Assistant Director of the Accounting Division of the Public Staff. No other party pre-filed testimony in this docket.

On September 12, 2016, DEP and the Public Staff filed a joint motion to excuse all witnesses from appearing at the hearing. The Commission granted this motion by Order dated September 14, 2016.

On September 16, 2016, DEP filed its affidavits of publication.

This matter came on for hearing as scheduled on September 20, 2016. No public witnesses appeared. Because the parties had waived cross-examination of witnesses, DEP asked that the Company's Application, the direct, supplemental, and revised supplemental testimony of witness McManeus be copied into the record and that her direct exhibits and supplemental exhibits be entered into evidence. The Commission granted those requests.

The Public Staff also moved into evidence the affidavit of witness Maness. That request was also granted. No other party presented witnesses.

On October 20, 2016, DEP and the Public Staff filed a joint proposed order.

Based upon the foregoing, DEP's verified application, the testimony, supplemental testimony, revised supplemental testimony, exhibits and revised exhibits, and affidavit received into evidence at the hearing, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. DEP is a duly organized corporation existing under the laws of the State of North Carolina, engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEP is lawfully before this Commission based upon its Application filed pursuant to G.S. 62-133.14 and Commission Rule R8-70.

2. On July 31, 2015, DEP acquired NCEMPA's undivided ownership interests of 18.33% in the Brunswick Steam Electric Plant (Brunswick Units 1 and 2), 12.94% in Unit No. 4 of the Roxboro Steam Electric Plant (Roxboro Unit 4), 3.77% in the Roxboro Plant Common Facilities, 16.17% in the Mayo Electric Generating Plant (Mayo Unit 1), and 16.17% in the Shearon Harris Nuclear Power Plant (Harris Unit 1) (collectively, Joint Units). On May 12, 2015, the Commission issued an Order Approving Transfer of Certificate and Ownership Interests in Generating Facilities in Docket No. E-2, Sub 1067 and Docket No. E-48, Sub 8, which approved the transfer of NCEMPA's ownership interests in the Joint Units to DEP.

3. G.S. 62-133.14 allows DEP to recover the North Carolina retail portion of all reasonable and prudent costs incurred to acquire, operate, and maintain the proportional interest in the generating facilities purchased from NCEMPA. Commission Rule R8-70(c) provides for an annual proceeding to establish the JAAR and requires the electric public utility to submit an application at the same time that it files the information required by Commission Rule R8-55.

4. Commission Rule R8-70 schedules an annual adjustment hearing for DEP and requires that the Company use a test period of the calendar year that precedes the end of the test period used for purposes of Commission Rule R8-55. The test period covered by the proposed rates is January 1, 2015 through December 31, 2015. Pursuant to Commission Rule R8-70, each annual filing will provide for the recovery of costs expected to be incurred in the rate period (prospective component), including the levelized annual cost of the plant initially acquired and

appropriate annual portions of the cost of other assets acquired (excluding construction work in progress), as well as ongoing annual non-fuel operating costs, reduced by the annual effects of the acquisition on North Carolina retail allocation factors. Commission Rule R8-70(b) provides for an over- or under-recovery component as a Rolling Recovery Factor or a “Joint Agency Asset RRF” and requires the Company to use deferral accounting and maintain a cumulative balance of costs incurred but not recovered through the Joint Agency Asset Rider. This cumulative balance will accrue a monthly return as prescribed by the Rule.

5. DEP’s proposed rates consist of a prospective component related to the future billing period December 2016 through November 2017 and a Joint Agency Asset RRF component that accomplishes the true-up of costs for August 2015 through December 2015.

6. In its application and testimony in this proceeding, as revised, DEP requested a total of $74.274 million for the prospective component of its North Carolina retail revenue requirement, for the period December 1, 2016 through November 30, 2017, associated with the acquisition and operating costs of NCEMPA’s undivided ownership interest in the Joint Units.

7. The annual levelized costs associated with the acquisition of the Joint Units at the time of purchase were $63.984 million. DEP also requested an additional $8.290 million in annual pre-tax costs associated with the acquisition costs not included in the levelized costs. The acquisition costs underlying these amounts are deemed reasonable and prudent under G.S. 62-133.14(b)(1).

8. DEP requested $7.236 million for the annual amortization of costs incurred during the four-month period after the purchase of the Joint Units (July 31, 2015) but prior to the initial JAAR rates becoming effective (December 1, 2015), which were deferred by the Company. The annual amortization is based on a three-year amortization period. To the extent the costs underlying the $7.236 million are acquisition costs, such costs are deemed reasonable and prudent under G.S. 62-133.14(b)(1). The Commission finds it reasonable for the Company to recover the remainder of the estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

9. DEP requested an additional $7.027 million in annual financing and operating costs relating to estimated capital additions during the rate period. The Commission finds it reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

10. DEP estimates the annual non-fuel operating costs from December 1, 2016 to November 30, 2017 to be $74.490 million. The Commission finds it reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

11. DEP requested $0.104 million for incremental regulatory fees. The Commission finds it reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

12. DEP has reduced the total prospective annual revenue requirement by $86.857 million to reflect the reduction in the North Carolina retail jurisdiction's portion of financing and operating costs related to DEP's other used and useful generating facilities owned at the time of the acquisition. This reduction in costs assigned to North Carolina retail customers results from greater costs being assigned to wholesale customers because the Company is now supplying the entire electric requirements of NCEMPA. The Commission finds it reasonable for the Company to include this estimated credit in the JAAR during the rate period, subject to true-up through the Joint Agency Asset RRF.

13. In addition to the prospective components, DEP requested a total of $0.351 million in its application and testimony in this proceeding for the Joint Agency Asset RRF component of its North Carolina retail revenue requirement for the period December 1, 2016 through November 30, 2017 related to under-recovery during the test period.

14. DEP began incurring costs August 1, 2015, upon closing its purchase of the Joint Units; however, the Company began collecting revenues under its Initial Rider effective with service rendered December 1, 2015. In its Initial Rider application, the Company requested that it be allowed to defer the costs incurred during the months of August through November 2015, prior to the implementation of the Initial Rider, and recover those costs over a 36-month period. The Joint Agency Asset RRF includes an adjustment for the over-recovery of revenues included in the deferral calculation of $2.822 million. DEP requested $3.173 million related to the under-recovery of financing and non-fuel operating costs for the month of December 2015, for a net amount due from ratepayers of $0.351 million for the test period. The Commission finds the actual costs and credits underlying this true-up amount to be reasonable and prudent, and recovery of this amount to be reasonable and appropriate.

15. Under G.S. 62-133.14(b)(5), these costs have been allocated under the customer allocation methodology approved by the Commission in Docket No. E-2, Sub 1023, DEP's last general rate case, to produce the following rates by customer class, which rates the Commission finds to be just and reasonable.

Rate Class	Applicable Schedule(s)	Prospective Rate	Rolling Recovery Factor	Combined Rate*
Non-Demand Rate Class (dollars per kilowatt-hour)				
Residential	RES, R-TOUD, R-TOUE, R-TOU	0.00222	0.00001	0.00223
Small General Service	SGS, SGS-TOUE	0.00267	0.00001	0.00268
Medium General Service	CH-TOUE, CSE, CSG	0.00219	0.00001	0.00220
Seasonal and Intermittent Service	SI	0.00142	0.00001	0.00143
Traffic Signal Service	TSS, TFS	0.00125	0.00001	0.00126
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	0.00000	0.00000	0.00000
Demand Rate Classes (dollars per kilowatt)				
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU	0.72	-	0.72
Large General Service	LGS, LGS-TOU	0.68	-	0.68

*Incremental Rates, shown above, include North Carolina regulatory fee of 0.14%.

16. The Public Staff has investigated and reviewed DEP's application and recommends that the revised rider amounts as proposed by the Company be approved.

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 FINDINGS OF FACT NOS. 2-4

The evidence for these Findings of Fact can be found in DEP's application, S. 62-133.14, and Commission Rule R8-70.

Under G.S. 62-133.14(a), upon the filing of a petition of an electric public utility and a public hearing, the Commission is required to approve an annual rider to the utility's rates for the North Carolina retail portion of reasonable and prudent costs incurred to acquire, operate and maintain the Joint Units. The acquisition costs shall be deemed reasonable and prudent and shall be levelized over the useful life of the Joint Units at the time of acquisition. Financing costs shall be included and shall be equal to the weighted average cost of capital as authorized in the utility's most recent general rate case.

The utility may recover an estimate of operating costs based on the experience of the test period and the costs projected for operation of the Joint Units for the next twelve months, subject to the filing of an annual adjustment including any under or over-recovery, any changes necessary to recover costs for the next twelve-month period, or any changes to the cost of capital or customer allocation methodology occurring in a general rate case after the establishment of the initial rider. Commission Rule R8-70(c) requires the Company to propose annual updates to its JAAR in order for the hearing to be held as soon as practicable after the hearing held by the Commission under Rule R8-55.

The Commission concludes that DEP's application is in compliance with the G.S. 62-133.14 and the Commission Rule R8-70.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence for these Findings of Fact can be found in the testimony, supplemental testimony, and revised supplemental testimony of DEP witness Jane L. McManeus and in the affidavit of Public Staff witness Michael C. Maness.

Witness McManeus testified that DEP's annual levelized cost associated with the acquisition price of the Joint Units was $63.984 million, and the Company followed the definition of these costs as set forth in G.S. 62-133.14 and Commission Rule R8-70, under which acquisition costs means the amount paid by DEP to acquire the proportional interest in generating facilities and related assets purchased from NCEMPA, including the amount paid above the net book value of the facilities. In general terms, levelized revenue requirement represents recovery of the acquisition cost for the NCEMPA assets, spread evenly over the remaining life of the assets at the time the Joint Units were purchased. Witness McManeus also included additional financing and operating costs of $8.290 million associated with assets purchased that were not included as part of the levelized costs. In her testimony, witness McManeus described these costs as including inventory amounts that are part of the asset acquisition costs, nuclear fuel inventory, and materials and supplies inventory. Because these assets are not depreciated, the financing costs for these amounts are calculated on the basis of the average investment for the rate period.

Additionally, the Company deferred financing and operating costs related to the purchase of the Joint Units following the acquisition, but prior to the effective date of the JAAR. The annual amortization over a three-year period of these deferred costs is $7.236 million. Witness McManeus noted that the Company has agreed to amortize these costs over three years for the benefit of customers.

G.S. 62-133.14(b)(2) states that the JAAR shall include financing costs equal to the weighted average cost of capital as authorized by the Commission in the electric public utility's most recent general rate case. The Company computed the debt and equity rate of return and the Company's weighted average net-of-tax cost of capital as authorized by the Commission in DEP's most recent general rate case.

In his affidavit filed with the Commission, Public Staff witness Maness stated that the Public Staff's investigation included a review of DEP's application, testimony, and exhibits filed in this docket and the initial JAAR proceeding in Docket No. E-2, Sub 1088. Additionally, the Public Staff's investigation included the review of responses to written and verbal data requests, as well as telephone conferences with the Company. He stated that the prospective JAAR annual revenue requirement in the current proceeding of $74,274,000 is an increase of approximately $8.4 million above the $65,797,000 of costs estimated for the initial JAAR rate period of December 2015 through November 2016.

The Commission concludes that, pursuant to G.S. 62-133.14(b)(1), DEP is allowed to recover in the annual JAAR, the financing and depreciation costs associated with the acquisition costs of the Joint Units on a levelized basis in the amount of $63.984 million annually, the annual amount of $8.290 million of financing and operating costs associated with acquisition costs that are not levelized, and $7.236 million annually reflecting a three-year amortization of deferred costs including a return on the deferred costs over this amortization period. To the extent the costs underlying these amounts are acquisition costs, such costs are deemed reasonable and prudent under G.S. 62-133.14(b)(1). The Commission further finds it reasonable for the Company to recover the remainder of these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-10

The evidence for these Findings of Fact can be found in DEP's application, the testimony, supplemental testimony, and revised supplemental testimony of DEP witness Jane L. McManeus and the affidavit of Public Staff witness Michael C. Maness.

The Company requested annual costs of $7.027 million to be included in the JAAR for financing and operating costs related to estimated capital additions to be incurred during the period December 1, 2016 through November 30, 2017, and an estimated $74.490 million for annual non-fuel operating costs over the period December 1, 2016 to November 30, 2017. Under G.S. 62-133.14(b)(3), the Commission shall include in the rider an estimate of operating costs based on the prior year's experience and the costs projected for the next twelve months and shall include the annual financing and operating costs for any proportional capital investments in the acquired electric generation facility. Public Staff witness Maness did not oppose the recovery of these cost components in his affidavit filed in this proceeding, and stated that the Public Staff recommended approval of the Company's revised proposed JAAR rates. The Commission concludes that it is reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this Finding of Fact can be found in the testimony of DEP witness Jane L. McManeus.

DEP's regulatory fee shall increase to $0.104 million based on the increase in the estimated JAAR costs for the period December 1, 2016 through November 30, 2017 and the reduction of the regulatory fee percentage from 0.148% to 0.14%, effective July 1, 2016. The Commission concludes that the calculation of the regulatory fee is just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this Finding of Fact can be found in DEP's application and the testimony, supplemental testimony, and revised supplemental testimony of DEP witness Jane L. McManeus, as well as the affidavit of Public Staff witness Michael C. Maness.

Under G.S. 62-133.14(b)(4), the JAAR shall include adjustments to reflect the North Carolina retail portion of financing and operating costs related to the electric public utility's other used and useful generating facilities owned at the time of the acquisitions to properly account for updated jurisdictional allocation factors. This adjustment benefits DEP customers by reducing DEP's annual retail revenue requirement by $86.857 million. Witness McManeus testified that the revenue reductions reflect changes in jurisdictional allocation factors resulting from the additional NCEMPA load that will be served by the Company's portfolio of generating facilities owned at the time of the acquisition. As a consequence, a greater portion of the cost of the Company's other generating facilities will be allocated to its wholesale jurisdiction, while a lesser portion will be allocated to its retail jurisdictions. The Commission concludes that a reduction in the JAAR of $86.857 million to reflect the annual reduction in DEP's retail revenue requirement because of greater costs being assigned to wholesale customers is appropriate.

In his affidavit, Public Staff witness Maness did not oppose the inclusion of this revenue requirement component and stated that the Public Staff recommended approval of the Company's revised proposed JAAR rates. The Commission concludes that it is reasonable for the Company to include this component in the prospective component of the rates, subject to true-up through the Joint Agency Asset RRF.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-14

The evidence for these Findings of Fact can be found in DEP's application, the testimony, supplemental testimony, and revised supplemental testimony of DEP witness Jane L. McManeus, DEP's revised exhibits to the JAAR and the affidavit of Public Staff witness Michael C. Maness.

The Company requested a Joint Agency Asset RRF adjustment of $0.351 million related to the under-recovery of costs incurred for the test year ended December 31, 2015. The Commission notes that DEP should file a Joint Agency Asset RRF adjustment rider to include a true-up between estimated and actual costs incurred during the test period under G.S. 62-133.14(c). The deferred costs related to any true-up are to be recorded as a regulatory asset or regulatory liability including a return on the deferred balance each month. Public Staff witness Maness did not oppose the recovery of this rate component in his affidavit filed in this proceeding, and stated that the Public Staff recommended approval of the Company's revised proposed JAAR rates. The Commission finds the actual costs and credits underlying this true-up amount to be reasonable and prudent, and that recovery of this amount is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this Finding of Fact can be found in DEP's application, the testimony, supplemental testimony, and revised supplemental testimony of DEP witness Jane L. McManeus, DEP's revised exhibits to the JAAR and the affidavit of Public Staff witness Michael C. Maness.

Pursuant to G.S. 62-133.14(b)(5), the costs of the rider shall be allocated utilizing the cost allocation methodology approved in DEP's last general rate case, Docket No. E-2, Sub 1023. DEP witness McManeus testified that after the Company reduced its retail allocation factor to reflect the increase in wholesale power sales to NCEMPA, it allocated the resulting revenue requirement based on the methodology consistent with its last general rate case to produce the rates reflected for each rate class as shown:

Rate Class	**Applicable Schedule(s)**	**Incremental Rate***
Non-Demand Rate Class (dollars per kilowatt-hour)		
Residential	RES, R-TOUD, R-TOUE, R-TOU	0.00223
Small General Service	SGS, SGS-TOUE	0.00268
Medium General Service	CH-TOUE, CSE, CSG	0.00220
Seasonal and Intermittent Service	SI	0.00143
Traffic Signal Service	TSS, TFS	0.00126
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	0.00000
Demand Rate Classes (dollars per kilowatt)		
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU	0.72
Large General Service	LGS, LGS-TOU	0.68

*Incremental Rates, shown above, include North Carolina regulatory fee of 0.14%.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this Finding of Fact can be found in the affidavit of Michael C. Maness of the Public Staff.

The Commission notes that Public Staff witness Maness recommended the rider amounts as proposed by the Company be approved. Witness Maness noted that the prospective rate component of the JAAR did not incorporate the reduction in the State corporate income tax rate from 4% to 3% that is scheduled to become effective January 1, 2017. However, witness Maness stated that no adjustment was necessary for this case as the prospective rates will be trued-up in subsequent proceedings. In addition, witness Maness indicated that the rolling recovery factor rates were calculated on an across the board basis instead of on a class-specific basis. The Public Staff accepted this approach for this proceeding, given the amount of the true-up, but reserved the right to recommend using a class-specific approach in future proceedings.

Witness Maness further stated that the Company and the Public Staff will continue to develop the details and procedures for the monthly reporting requirements under Commission Rule R8-70 and submit them to the Commission for approval.

IT IS, THEREFORE, ORDERED, as follows:

1. That DEP shall be allowed to charge in a rider $74.625 million on an annual basis to recover the costs in relation to the acquisition and operation of the Joint Units;

2. That the costs shall be allocated using the customer allocation methodology used in DEP's last general rate case as shown in DEP's application and the affidavit of Michael C. Maness of the Public Staff;

3. That the rates reflected in the table shown in the Evidence and Conclusions for Finding of Fact No. 15 of this Order are just and reasonable and hereby approved, effective December 1, 2016;

4. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement the approved rate adjustments ordered by the Commission in Docket Nos. E-2, Subs 1107, 1109, and 1110 as soon as practicable;

5. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket Nos. E-2, Subs 1107, 1109, and 1110, and the Company shall file the proposed customer notice for approval as soon as practicable; and

6. That DEP and the Public Staff shall continue to develop details and procedures for the monthly reporting requirements for submission and approval to the Commission.

ISSUED BY THE ORDER OF THE COMMISSION.
This the _7th_ day of __November__, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

NATURAL GAS – ADJUSTMENTS OF RATES/CHARGES

DOCKET NO. G-40, SUB 130

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Frontier Natural Gas	)	ORDER ON ANNUAL
Company, LLC, for Annual Review	)	REVIEW OF GAS COSTS
of Gas Costs Pursuant to G.S. 62-133.4(c)	)	
and Commission Rule R1-17(k)(6)	)	

HEARD: Wednesday, June 1, 2016, at 1:30 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; and Commissioners Don M. Bailey, and James G. Patterson

APPEARANCES:

For Frontier Natural Gas Company, LLC:

Karen M. Kemerait, Smith Moore Leatherwood LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Elizabeth D. Culpepper, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: According to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), each LDC shall file and submit to the Commission the information required for an historical 12-month period for an annual review. This information shall be filed by Frontier Natural Gas, LLC (Frontier or Company) on or before December 1 of each year based on a test period ending September 30.

On December 1, 2015, Frontier filed a motion for an extension of time to file testimony in this proceeding, which on December 2, 2015, was granted by the Commission.

On December 3, 2015, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Frontier filed the joint direct testimony and exhibits of Fred A. Steele, President/General Manager, and Gary L. Moore, Technical Services Manager, in connection with the annual review of Frontier's gas costs for the twelve-month period ended September 30, 2015.

On December 3, 2015, Frontier filed a motion for an extension of time to file the supplemental information required by the Commission's Order Requiring Reporting issued June 28, 2013, in Docket No. G-100, Sub 91 (G-100, Sub 91 Order), which was granted by the Commission on December 9, 2015.

On December 4, 2015, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice. This Order established a hearing date of March 1, 2016, set pre-filed testimony dates, and required Frontier to give notice to its customers of the hearing on this matter.

On December 10, 2015, Frontier filed the information required by the G-100, Sub 91 Order, as a supplement to the joint direct testimony of Frontier's witnesses.

On February 11, 2016, the Public Staff filed a motion to suspend the procedural schedule as it pertained to active parties and to hold the March 1, 2016, hearing for the purpose of receiving public witness testimony.

On February 12, 2016, the Commission issued its Order Revising Procedural Schedule, suspending the date for the Public Staff and other intervenors to file their testimony, the date for Frontier to file its rebuttal testimony, and the date for the expert witness hearing.

On February 18, 2016, Frontier filed its Affidavits of Publication.

On March 1, 2016, the public witness hearing was held as scheduled. No public witnesses appeared to offer testimony.

On March 1, 2016, the Commission issued its Order Scheduling Filing of Testimony and Expert Witness Hearing and established the expert witness hearing in this docket for May 17, 2016, and ordered that the Public Staff file its direct testimony and exhibits on or before May 2, 2016, and that Frontier file its rebuttal testimony, if any, on or before May 12, 2016.

On April 29, 2016, the Public Staff filed a motion to reschedule the expert witness hearing and extend the due dates for the filing of direct testimony by the Public Staff and rebuttal testimony by Frontier.

On May 3, 2016, the Commission issued an Order Extending Dates for Filing Testimony and Continuing Expert Witness Testimony (May 3rd Order), ordering that on or before May 10, 2016, the Public Staff file its direct testimony and exhibits, and that Frontier file its rebuttal testimony on or before May 20, 2016. The Commission further ordered that that on or before May 17, 2016, the Public Staff and Frontier file a status report informing the Commission of their progress in resolving the issues in this docket, and recommending a date for the Commission to schedule the expert witness hearing, with the recommendation being no later than July 7, 2016.

On May 9, 2016, Frontier filed a motion to extend the time for the Public Staff to file its direct testimony and exhibits to May 12, 2016, and to set the expert witness hearing for June 1, 2016 at 10:00 a.m., which was granted by the Commission on May 10, 2016, with the exception that the hearing was scheduled to begin at 1:30 p.m.

On May 12, 2016, the Public Staff filed the joint direct testimony and exhibits of Julie G. Perry, Supervisor, Natural Gas Section, Accounting Division, and Jan A. Larsen, Utilities

Engineer, Natural Gas Section. On that same date, the Public Staff filed a revised Page 13 of its joint direct testimony.

On May 17, 2016, Frontier filed a status report, as required by the May 3rd Order.

On May 20, 2016, Frontier filed the rebuttal testimony of Company witness Steele.

No other party intervened in this docket.

On May 24, 2016, Frontier and the Public Staff filed a joint motion for witnesses to be excused from appearance at the expert witness hearing and requested that the pre-filed testimony and exhibits of all witnesses be received into the record without requiring the appearance of any such witnesses. On May 26, 2016, the Commission granted the motion.

On June 1, 2016, the matter came on for hearing as scheduled. The testimony and exhibits of the Company and the Public Staff were admitted into evidence without objection.

On June 2, 2016, Frontier made a filing regarding the reporting of its deferred account in response to questions from the Commission at the hearing on June 1, 2016.

On July 1, 2016, the Joint Proposed Order of Frontier and the Public Staff was filed.

Based upon the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

<u>FINDINGS OF FACT</u>

1. Frontier is a public utility as defined by G.S. 62-3(23), organized and existing under the laws of the State of North Carolina with its headquarters in Elkin, North Carolina.

2. Frontier is a natural gas local distribution company (LDC), primarily engaged in the business of purchasing, transporting, distributing, and selling natural gas to approximately 3,113 customers in North Carolina, as of September 30, 2015.

3. The Company has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of the statute and rule.

4. The review period in this proceeding is the twelve months ended September 30, 2015.

5. During the review period, Frontier incurred total gas costs of $6,295,493, comprised of pipeline demand charges of $524,313, gas supply costs of $6,254,514, and other gas costs of ($483,333).

6. Frontier had a Deferred Gas Cost Account debit balance of $422,077 as of September 30, 2015, owed by ratepayers to Frontier.

7. Frontier determined that it had overstated the gas cost collections reflected in the Deferred Gas Cost Account during the review period. In June 2015, Frontier made a debit adjustment of $662,251 to its Deferred Gas Cost Account to address the overstatement.

8. The Public Staff recommended a reduction of $60,000, plus accrued interest, to Frontier's June 2015 adjustment to account for the proration of the Benchmark City Gate Delivered Gas Cost (Benchmark) in the determination of the gas cost collections during the review period.

9. Frontier agreed to begin prorating its Benchmark cost of gas in the calculation of its gas cost collections from customers in a manner consistent with how Frontier prorates customers' bills.

10. Frontier agreed to perform an annual computation in a low gas sales month, either June, July, or August, to true-up its estimate of unbilled and lost and unaccounted for volumes.

11. Frontier agreed to work with the Public Staff to develop a new reporting format for determining the gas cost collections in order to have more transparency with the calculation of billed and unbilled volumes and the rate changes in effect that may impact the Deferred Gas Cost Account.

12. Frontier properly accounted for its gas costs during the review period.

13. Frontier's hedging activities during the review period were reasonable and prudent.

14. During the review period, Frontier purchased all of its gas supply requirements from a full requirements gas supplier, with the exception of transportation imbalance cash-outs.

15. Frontier utilized pipeline capacity from Transcontinental Gas Pipe Line Company, LLC (Transco), during the review period.

16. Frontier has adopted a gas purchasing policy that it refers to as a "best evaluated cost" supply strategy.

17. Based on the Public Staff's adjustment, the gas costs incurred by Frontier during the review period were prudently incurred.

18. Frontier should be permitted to recover 100% of its prudently incurred gas costs.

19. Frontier should not be required to implement a rate increment in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 2

These findings are essentially informational, procedural or jurisdictional, and are based on evidence uncontested by any of the parties. The evidence supporting these findings is contained in the official files and records of the Commission, the testimony and exhibits of Frontier witnesses, and the testimony of the Public Staff witnesses.

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

The evidence supporting these findings is contained in the testimony of Frontier witnesses and the testimony of the Public Staff witnesses. These findings are made pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an historical twelve-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(c) requires the filing of work papers, direct testimony, and exhibits supporting the information.

Frontier witnesses testified that the Company is responsible for and has complied with reporting gas costs and deferred account activity to the Commission and the Public Staff on a monthly basis as required by Commission Rule R1-17(k). The Public Staff witnesses confirmed that the Public Staff reviewed the filings and monthly reports filed by Frontier. The Commission, therefore, concludes that Frontier has complied with all of the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 - 12

The evidence supporting these findings of fact is contained in the testimony and exhibits of Frontier witnesses and the testimony and exhibits of the Public Staff witnesses.

Company Schedule 1 reflected that Frontier's total gas costs for the review period were $6,295,493. The Public Staff witnesses testified that total gas costs were comprised of pipeline demand charges of $524,313, gas supply costs of $6,254,514, and other gas costs of ($483,333).

The Public Staff witnesses testified that the Public Staff reviewed the testimony and exhibits of Company witnesses, the Company's monthly Deferred Gas Cost Account reports, monthly financial and operating reports, the gas supply and transportation contracts, the reports filed with the Commission in Docket No. G-100, Sub 24A, and the Company's responses to Public Staff data requests. The responses to the Public Staff data requests contained information related to Frontier's gas purchasing philosophies, customer requirements, and gas portfolio mixes.

Company witnesses testified that Frontier's Deferred Gas Cost Account had a $422,077 debit balance, as shown on Company Schedule 8, owed by ratepayers to Frontier on September 30, 2015. The Public Staff witnesses testified that there was a $500,686 change in Frontier's Deferred Gas Cost Account filed balance compared to the prior review period ending credit balance of ($78,609), owed by the Company to ratepayers, that was approved by the Commission in Frontier's prior annual review of gas costs proceeding (Docket No. G-40, Sub 125). This change consisted of a prior annual review adjustment of $67,335, gas cost true-up collections of $128,270, commodity true-up adjustments of ($2,847), June 2015 prior period unbilled adjustment of $662,251, transportation customer balancing true-up of ($115,755), increment of ($181,022), Transco refund of ($59), and accrued interest of $9,848.

The Public Staff witnesses also recommended a $60,000 adjustment to the Company's deferred account balance to reflect the Public Staff's calculation of revised gas cost collections during the review period. The Public Staff testified that the adjustment is based on the fact that Frontier determined its June 2015 adjustment by multiplying the correction to its unbilled volumes by the $5.90 per dekatherm (dt) Benchmark that was in effect at the time the adjustment was recorded. The Public Staff explained that because many of the unbilled volumes are related to periods when the Benchmark was not $5.90 per dt, the Company's methodology does not properly match the volumes sold with the rate that was actually billed to customers. The Public Staff witnesses testified that they applied a weighted Benchmark of $5.37 per dt based on the rates in effect during the review period to the Company's volume adjustment to calculate the adjustment to gas cost collections. The Public Staff witnesses recommended a total credit adjustment, including interest for the review period, of $67,393, as shown on Public Staff Panel Exhibit II. The Public Staff witnesses stated that based on discussions with the Company, Frontier agreed with the adjustment to the Deferred Gas Cost Account. The Public Staff witnesses testified that based on their adjustment, the recommended debit balance in the Deferred Gas Cost Account as of September 30, 2015, is $354,684, owed to the Company. Frontier witness Steele testified that the Company agreed with the Public Staff's adjustment.

The Public Staff witnesses further testified that based on their investigation they had the following recommendations that Frontier should implement for the review period beginning October 1, 2015: (1) Frontier should prorate its Benchmark cost of gas in the calculation of its gas cost collections from customers in a manner consistent with how Frontier prorates customers' bills; (2) Frontier should perform an annual computation in a low gas sales month, either June, July, or August, to true-up its estimate of unbilled and lost and unaccounted for volumes; and (3) Frontier should work with the Public Staff to develop a new reporting format for determining the gas cost collections in order to have more transparency with the calculation of billed and unbilled volumes and the rate changes in effect that may impact the deferred account. Frontier witness Steele testified that Frontier agreed to the Public Staff's recommendations.

The Public Staff witnesses testified that, based on the Public Staff's investigation, its review of the data in this docket, and the Public Staff's adjustment to the deferred account, Frontier had properly accounted for its gas costs during the review period.

Based on the foregoing, the Commission concludes that Frontier has properly accounted for its gas costs incurred during the review period and that the Deferred Gas Cost Account balance, as adjusted, is correct. The Commission further concludes that the Public Staff's recommendations are appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is contained in the testimony and exhibits of Frontier witnesses and the testimony of the Public Staff witnesses.

Frontier witnesses testified that the Company engaged in hedging activity during the current review period. Frontier's Schedule 11 reflected that Frontier hedged approximately 37% of its forecasted purchased gas volumes needed during the test period, and the Public Staff witnesses testified that Frontier's hedging activity resulted in 44% of Frontier's actual gas supply volumes being hedged due to the fact that actual volumes were less than forecasted during the review period. Frontier witnesses further testified that market pricing met the targeted reductions that Frontier looked for as part of the purchasing strategy, which helped Frontier reduce potential volatility and price risk for its customers.

The Public Staff witnesses testified that Frontier's hedging program is an integral part of an overall gas purchasing strategy that attempts to establish price stability, utilize cost efficient purchasing, and reduce the risk of price increases to customers. The Public Staff also testified that Frontier uses a weighted average, three-part approach in purchasing its physical gas supplies: first-of-the-month baseload; hedging; and, daily swing. Furthermore, the Public Staff witnesses stated that a core part of Frontier's strategy is to obtain reliability and price stability by fixing components of its gas costs, primarily commodity costs, through hedging.

The Public Staff witnesses further testified that the primary difference in Frontier's hedging approach compared to other LDCs is that Frontier uses physical hedges exclusively and does not use financial hedges such as options, futures, or swaps. They stated that Frontier's gas supply portfolio includes the physical purchase of fixed price gas supplies for delivery at its city gate on a monthly basis.

The Public Staff witnesses further testified that based on what was reasonably known or should have been known at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, that their analysis led them to conclude that the decisions were prudent.

Based on the foregoing, the Commission concludes that Frontier's hedging activities during the review period were reasonable and prudent.

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

The evidence for these findings of fact is contained in the testimony of Frontier witnesses and the testimony of the Public Staff witnesses.

Frontier witnesses testified that the Company's gas supply policy is best described as a "best evaluated costs" supply strategy. This strategy is based upon the following criteria: flexibility, security/creditworthiness, reliability of supply, the cost of the gas, and the quality of supplier customer service. Frontier witnesses stated that the primary criteria for the Company are flexibility, security/creditworthiness, and reliability of supply.

Frontier witnesses stated that flexibility is required because of the daily changes in Frontier's market requirements caused by the unpredictable nature of weather, the production levels/operating schedules of Frontier's industrial customers, the industrial customers' option to switch to alternative fuels, and customer growth during the test period. While Frontier's gas supply agreements have different purchase commitments and swing capabilities (i.e., the ability to adjust purchase volumes within the contract volume), the gas supply portfolio as a whole must be capable of handling the seasonal, monthly, daily, and hourly changes in Frontier's market requirements.

Frontier witnesses testified that Frontier understands the necessity of having security of supply to provide reliable and dependable natural gas service and has demonstrated its ability to do so. Frontier's gas supply strategy and its contracts implementing this strategy have allowed Frontier to accomplish its objective of security of supply.

Frontier witnesses testified that the Company continues to incorporate a three-part pricing strategy to help establish price stability and reduce risk to customers: hedging, first of the month index purchases, and daily purchases. Frontier will adjust the weights of each component and incorporate the best pricing methodology to obtain the optimum opportunity in savings and price stability. Frontier witnesses further stated that the Company's gas pricing strategy reduced the risk and volatility in commodity gas pricing while also providing flexibility to take advantage of competitive pricing opportunities that may occur.

The Public Staff witnesses testified that during the review period Frontier experienced customer growth of 12.3%, which is approximately nine times the growth rate of legacy LDCs in North Carolina.

Frontier witnesses testified that the Company had outgrown its initial capacity and had to acquire supplemental swing and peaking services to offset the additional need through its all requirements supplier each winter. Frontier witnesses stated that the Company determined the need to purchase additional Transco capacity. Frontier witnesses further testified that the Company had a daily reservation capacity of 3,613 dts per day, but with a successful bid of 2,337 dts per day in August of 2015, its capacity increased to 5,950 dts per day effective in January 2016.

The Public Staff witnesses testified that effective November 1, 2014, Frontier began purchasing all of its gas supply requirements from a full requirements gas supplier, with the exception of transportation imbalance cash-outs. The Public Staff further testified that subsequent to the review period, Frontier initiated a request for proposal for its all requirements gas supply contract. Effective April 1, 2016, Frontier agreed to a one year arrangement with UGI Energy Services, LLC (UGI), to manage all of its delivered gas supply purchases, including hedge purchases. The Public Staff witnesses testified that UGI will be managing Frontier's current Transco capacity contracts along with the additional Transco pipeline capacity of 2,337 dts that

Frontier acquired effective January 1, 2016. The Public Staff witnesses stated that Frontier believes that, with the new gas supply agreement and the additional year round capacity, its total gas supply costs, including hedging, will be greatly reduced in the coming year.

Based upon its investigation and review of the data filed in this docket and the adjustment to Frontier's Deferred Gas Cost Account, the Public Staff witnesses testified that Frontier's gas costs during the review period were prudently incurred.

Based on the foregoing, the Commission concludes that the Company's gas costs during the review period were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding of fact is contained in the testimony and exhibits of Frontier witnesses and the testimony and exhibits of the Public Staff witnesses.

Frontier witnesses testified that Frontier strategically tries to minimize adjustments in pricing which results in some fluctuations of the deferred account over the course of the year as the cost of gas changes. Frontier witnesses also testified that they had filed to decrease the Benchmark effective January 1, 2015, and to increase the Benchmark effective April 1, 2015. Frontier witnesses stated those measures have allowed Frontier to recover its gas costs and reduce its Benchmark to more closely track its current cost of gas. Frontier witnesses testified that although the Company had under-collected its gas costs as of September 30, 2015, the Company anticipated that the current balance would be moving back toward $0 over the winter months.

The Public Staff witnesses testified that they strongly recommended that Frontier closely monitor the Deferred Gas Cost Account balance in order to avoid high balances either owed to the Company or to the ratepayers in the future; and, if needed, Frontier should request Commission approval for the implementation of a new temporary increment or decrement through its purchased gas adjustment (PGA) mechanism, which provides procedures for Frontier to file to adjust its rates pursuant to G.S. 62-133.4.

The Public Staff witnesses testified that a Deferred Gas Cost Account balance as of September 30, 2015, of $354,684, owed from the ratepayers to the Company, is appropriate. The Public Staff witnesses testified that they would typically recommend a rate increment to collect the $354,684 debit balance. The Public Staff witnesses explained that since the end of the review period, Frontier's deferred account balance had decreased to $192,025 as of February 29, 2016. The Public Staff witnesses also testified that based on Frontier's forecasted balances, the Company anticipated that the deferred account balance would continue to decline and, therefore, they did not recommend a rate increment be implemented at this time.

NATURAL GAS – ADJUSTMENTS OF RATES/CHARGES

The Commission agrees with the recommendation of the Public Staff witnesses and concludes that it is not appropriate to require Frontier to implement a temporary rate increment at this time. In addition, the Commission concludes that, if needed, Frontier should adjust its deferred account balances at any point during future review periods by implementing new temporary increments or decrements through the purchased gas adjustment procedures that are available for use by the Company.

IT IS, THEREFORE, ORDERED as follows:

1. That Frontier's accounting for gas costs during the twelve month period ended September 30, 2015, is approved;

2. That the gas costs incurred by Frontier during the twelve-month period ended September 30, 2015, were reasonably and prudently incurred, and Frontier is hereby authorized to recover 100% of its gas costs incurred during the period of review;

3. That as proposed by Frontier witnesses and agreed to by the Public Staff, Frontier shall not at this time implement any temporary rate changes for service rendered on and after September 1, 2016;

4. That Frontier shall begin prorating its Benchmark cost of gas in the calculation of its gas cost collections from customers in a manner consistent with how Frontier prorates customers' bills;

5. That Frontier shall perform an annual computation in a low gas sales month, either June, July, or August, to true-up its estimate of unbilled and lost and unaccounted for volumes; and

6. That Frontier shall work with the Public Staff to develop a new reporting format for determining the gas cost collections in order to have more transparency with the calculation of billed and unbilled volumes and the rate changes in effect that may impact the deferred account.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of August, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. G-9, SUB 690

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas	)	
Company, Inc., for Annual Review of Gas	)	ORDER ON ANNUAL
Costs Pursuant to G.S. 62-133.4(c) and	)	REVIEW OF GAS COSTS
Commission Rule R1-17(k)(6)	)	

HEARD: Monday, October 3, 2016, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Commissioner Jerry C. Dockham and Commissioner Lyons Gray

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

James H. Jeffries IV, Moore & Van Allen PLLC, Bank of America Corporate Center, 100 N. Tryon Street, Suite 4700, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Elizabeth D. Culpepper, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On August 1, 2016, pursuant to G.S.62-133.4(c) and Commission Rule R1-17(k)(6), Piedmont Natural Gas Company, Inc. (Piedmont or Company), filed the direct testimonies and exhibits of MaryBeth Tomlinson, Manager of Gas Accounting; Michelle R. Mendoza, Director of Pipeline Services; and Sarah E. Stabley, Director of Gas Supply, Scheduling and Optimization, attesting to the prudence of the Company's gas purchasing practices and the accuracy of the Company's gas cost accounting for the twelve-month period ended May 31, 2016.

On August 2, 2016, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of October 3, 2016, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On August 19, 2016, Carolina Utility Customers Association, Inc. (CUCA), filed a petition seeking to intervene in this docket. On August 25, 2016, the Commission issued an Order Granting Petition to Intervene.

On September 15, 2016, the Public Staff filed the prefiled joint testimony of Michelle M. Boswell, Staff Accountant, Accounting Division; Poornima Jayasheela, Staff Accountant, Accounting Division; and Neha Patel, Utilities Engineer, Natural Gas Division (Public Staff Panel or Panel).

On September 19, 2016, Piedmont and the Public Staff filed a joint motion for witnesses to be excused from appearance at the evidentiary hearing and requested that the prefiled testimony and exhibits of all witnesses be received into the record without requiring the appearance of any such witnesses. CUCA waived cross-examination of the witnesses for Piedmont and the Public Staff and did not otherwise object to the relief sought therein. The Commission granted the motion on September 23, 2016.

On September 22, 2016, the Company filed its affidavits of publication.

On October 3, 2016, the matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing.

On October 26, 2016, the Joint Proposed Order of Piedmont and the Public Staff was filed.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Piedmont is a public utility as defined in Chapter 62 of the North Carolina General Statutes and is subject to the jurisdiction and regulation of the Commission.

2. Piedmont is engaged primarily in the business of transporting, distributing, and selling natural gas to customers in North Carolina, South Carolina, and Tennessee.

3. Piedmont has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended May 31, 2016.

5. The Company properly accounted for its gas costs incurred during the review period.

6. During the review period, the Company incurred total North Carolina gas costs of $249,929,687, which was comprised of demand and storage charges of $133,227,638, commodity gas costs of $164,506,303, and other gas costs of ($47,804,254).

7. At May 31, 2016, the Company had a credit balance of $603,118, owed from the Company to the customers, in its Sales Customers Only Deferred Account and a debit balance of $6,372,791, owed from the customers to the Company, in its All Customers Deferred Account.

8. During the review period, Piedmont actively participated in secondary market transactions earning $38,400,770 of margins for the benefit of North Carolina ratepayers.

9. Piedmont operated a gas cost hedging program on behalf of customers during the review period. Piedmont's hedging activities during the review period were reasonable and prudent.

10. At May 31, 2016, the balance in the Company's Hedging Deferred Account was a debit balance of $3,859,421.

11. It is appropriate for the Company to transfer the $3,859,421 debit balance in its Hedging Deferred Account to its Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a debit balance of $3,256,303.

12. The Company has transportation and storage contracts with interstate pipelines, which provide for the transportation of gas to the Company's system, and long-term supply contracts with producers, marketers, and other suppliers.

13. The Company utilized a "best cost" gas purchasing policy during the applicable review period consisting of five main components: price of gas, security of the gas supply, flexibility of the gas supply, gas deliverability, and supplier relations.

14. The Company's gas purchasing policy and practices during the review period were prudent.

15. The Company's gas costs during the review period were prudently incurred, and the Company should be permitted to recover 100 percent of such prudently incurred gas costs.

16. The Company should implement the temporary rate increment applicable to the Sales Customers Only Deferred Account and the temporary rate increments applicable to the All Customers Deferred Account proposed by Company witness Tomlinson and agreed to by the Public Staff Panel.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings of fact is contained in the official files and records of the Commission and the testimony of Company witnesses Tomlinson, Mendoza, and Stabley. These findings are essentially informational, procedural, or jurisdictional in nature and are not contested by any party.

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

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Tomlinson, Mendoza, and Stabley, and the testimony of the Public Staff Panel. These findings are made pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for a historical twelve-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(a) establishes May 31, 2016, as the end date of the annual review period for the Company in this proceeding. Commission Rule R1-17(k)(6)(c) requires that Piedmont file weather-normalized sales volumes, workpapers, and direct testimony and exhibits supporting the information.

Company witness Tomlinson testified that the Company filed with the Commission and submitted to the Public Staff throughout the review period complete monthly accountings of the computations required by Commission Rule R1-17(k)(6)(c). Witness Tomlinson included the annual data required by Commission Rule R1-17(k)(6)(c) as Exhibit_(MBT-1) to her direct testimony. The Public Staff Panel stated that they had presented the results of their review of the gas cost information filed by Piedmont in accordance with G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

Based upon the foregoing, the Commission concludes that Piedmont has complied with the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the twelve-month review period ended May 31, 2016.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence supporting these findings of fact is contained in the testimony of Company witness Tomlinson and the Public Staff Panel.

Company witness Tomlinson testified that Piedmont incurred total North Carolina gas costs of $249,929,687 during the review period, which was comprised of demand and storage charges of $133,227,638, commodity gas costs of $164,506,303, and other gas costs of ($47,804,254).

Company witness Tomlinson's prefiled testimony and exhibits reflected a credit balance of $603,118 in its Sales Customers Only Deferred Account and a debit balance of $6,372,791 in its All Customers Deferred Account as of May 31, 2016. The Public Staff Panel agreed with these balances and testified that the Company properly accounted for its gas costs incurred during the review period.

Based upon the foregoing, the Commission concludes that the Company properly accounted for its gas costs incurred during the review period. The Commission also concludes that the appropriate level of total North Carolina gas costs incurred for this proceeding is $249,929,687. The Commission further concludes that the appropriate balances of the Company's deferred accounts, as of May 31, 2016, are a credit balance of $603,118, owed from the Company to the customers, in its Sales Customers Only Deferred Account, and a debit balance of $6,372,791, owed from the customers to the Company, in its All Customers Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony of Company witness Stabley and the Public Staff Panel.

Company witness Stabley provided testimony on the process that Piedmont utilized and the market intelligence that was evaluated during the review period to determine the prices charged for secondary market sales. Witness Stabley explained that the process and information used by Piedmont in pricing secondary market sales depends upon the location of the sale, term and type of the sale, and prevailing market conditions at the time of the sale. Witness Stabley stated that for long-term delivered sales (longer than one month), Piedmont generally solicits bids from potential buyers and, if acceptable, awards volumes based on bids received and its evaluation. Witness Stabley further stated that, for short-term transactions (daily or monthly), Piedmont monitors prices and volumes on the Intercontinental Exchange, as well as by talking to various market participants and, for less liquid trading points, estimating prices based on price relationships with more liquid points. The Company also evaluates the amount of supply available for sale and weighs that against current market conditions in formulating its sales strategy.

The Public Staff Panel testified that the Company earned actual total company margins of $60,179,860 on secondary market transactions and credited the All Customers Deferred Account in the amount of $38,400,770 for the benefit of North Carolina ratepayers ($60,179,860 x NC demand allocator x 75% ratepayer sharing percent). The margins earned were a result of Piedmont's participation in asset management arrangements, capacity releases, and off system sales.

Based on the foregoing, the Commission concludes that Piedmont actively participated in secondary market transactions, resulting in $38,400,770 of margin for the benefit of North Carolina ratepayers during the review period.

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

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Tomlinson and Stabley and the Public Staff Panel.

Company witness Tomlinson stated in her testimony that the Company had a debit balance of $3,859,421 in its Hedging Deferred Account at May 31, 2016. The Public Staff Panel testified that the net hedging costs were composed of Premiums Paid of $3,349,120, Brokerage Fees and Commissions of $45,276, and Interest on the Hedging Deferred Account of $465,025.

Company witness Stabley testified that Piedmont's Hedging Plan accomplished its goal of providing an insurance policy to reduce gas cost volatility for customers in the event of a sudden gas price increase or spike. Witness Stabley testified that the Company did not make any changes to its Hedging Plan during the review period. Witness Stabley further testified that the Company continues to utilize storage as a physical hedge to stabilize cost, and that the Company's Equal Payment Plan, the use of the Purchased Gas Adjustment benchmark price, and deferred gas cost accounting also provide a smoothing effect on gas prices.

The Public Staff Panel testified that its review of the Company's hedging activities is performed on an ongoing basis and includes analysis and evaluation of information contained in several documents and other data. These include the Company's monthly hedging deferred account reports, detailed source documentation, workpapers supporting the derivation of the maximum targeted hedge volumes for each month, periodic reports on the status of hedge coverage for each month, periodic reports on the market values of the various financial instruments used by the Company to hedge, monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report, and minutes from the meetings of Piedmont's Energy Price Risk Management Committee (EPRMC). In addition, the

Public Staff reviews minutes from the meetings of the Board of Directors and its committees that pertain to hedging activities, reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events and plan modifications under consideration by the EPRMC. Further, the Public Staff examines the testimony and exhibits of the Company's witnesses in the annual proceeding.

The Public Staff Panel concluded that Piedmont's hedging activities were reasonable and prudent and recommended that the $3,859,421 debit balance in the Hedging Deferred Account as of the end of the review period be transferred to the Sales Customers Only Deferred Account. Based on this recommendation, the Panel stated that the combined balance in the Sales Customers Only Deferred Account as of May 31, 2016 is a net debit balance of $3,256,303.

Based on the testimony and exhibits provided by Piedmont and the Public Staff, the Commission finds that Piedmont's hedging program has met the objective of contributing to the mitigation of gas price volatility and avoiding rate shock to customers. The Commission concludes that Piedmont's hedging activities were reasonable and prudent and the $3,859,421 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a net debit balance of $3,256,303, owed from the customers to the Company.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-15

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Stabley and Mendoza, and the Public Staff Panel.

Company witness Stabley testified that the Company maintains a "best cost" gas purchasing policy. This policy consists of five main components: price of the gas; security of the gas supply; flexibility of the gas supply; gas deliverability; and supplier relations. Witness Stabley testified that all of these components are interrelated and that the Company weighs the relative importance of each of these factors in developing its overall gas supply portfolio to meet the needs of its customers.

Witness Stabley further testified that the Company purchases gas supplies under a diverse portfolio of contractual arrangements with a number of reputable gas producers and marketers. In general, under the Company's firm gas supply contracts, Piedmont may pay negotiated reservation fees for the right to reserve and call on firm supply service up to a maximum daily contract quantity (nominated either on a monthly or daily basis), with market-based commodity prices tied to indices published in industry trade publications. Some of these firm contracts are for winter only (peaking or seasonal) service and some provide for 365 day (annual) service. Firm gas supplies are purchased for reliability and security of service and are generally priced on a reservation fee basis according to the amount of nomination flexibility built into the contract with daily swing service generally being more expensive than monthly baseload service.

Witness Stabley testified that the Company identifies the volume and type of supply that it needs to fulfill its market requirements and generally solicits requests for proposals from a list of suppliers that the Company continuously updates as potential suppliers enter and leave the market place. The type of supply is classified as either baseload or swing. Witness Stabley stated that swing supplies priced at first of month indices command the highest reservation fees because suppliers incur all the price risk associated with market volatility during the delivery period. Keep-whole contracts require the Company to reimburse suppliers for the difference between first of the month index prices and lower daily market prices if the Company does not take its full contractual volume.

Witness Stabley testified that because the Company assumes the volatility risk associated with falling prices, a lower reservation fee is warranted. Lower reservation fees are also associated with swing contracts based upon daily market conditions since both buyer and seller assume the risk of daily market volatility. Witness Stabley stated that after forecasting the ultimate cost of gas delivered to the city gate for each point of supply and evaluating the cost of the reservation fees associated with each type of supply and its corresponding bid, the Company makes a "best cost" decision on which type of supply and supplier best fulfills its needs. Company witness Stabley also testified regarding the current U.S. supply situation and the various pricing alternatives available, such as fixed prices, monthly market indexing, and daily spot market pricing.

Witness Stabley also described how the interrelationship of the five factors affects the Company's construction of its gas supply and capacity portfolio under its best cost policy. The long-term contracts, supplemented by long-term peaking services and storage, generally are aligned with the firm market; the short-term spot gas generally serves the interruptible market. In order to weigh and consider the five factors, the Company stays abreast of current issues facing the natural gas industry by intervening in all major Federal Energy Regulatory Commission (FERC) proceedings involving its pipeline transporters, maintaining constant contact with existing and potential suppliers, monitoring gas prices on a real-time basis, subscribing to industry literature, following supply and demand developments, and attending industry seminars. Witness Stabley further testified that the Company did not make any changes in its best cost gas purchasing policies or practices during the test period. Witnesses Mendoza and Stabley also indicated that during the past year the Company has taken several additional steps to manage its costs, including actively participating in proceedings at the FERC and other regulatory agencies that could reasonably be expected to affect the Company's rates and services, and promoting more efficient peak day use of its system. In addition, the Company has utilized the flexibility within its existing supply and capacity contracts to purchase and dispatch gas, and to release capacity in the most cost effective manner.

Company witness Mendoza testified about the market requirements of Piedmont's North Carolina customers and the acquisition of capacity to serve those markets. Witness Mendoza testified that the Company expects the economy to continue recovering and to result in potentially increasing residential, commercial and industrial demand, and in turn, to result in greater firm temperature sensitive requirements that will require firm sales service from the Company.

Witness Mendoza further testified that Piedmont and the natural gas industry have not seen evidence that conservation/reduced usage occurs during design day conditions. For that reason, witness Mendoza testified that Piedmont is confident the conservative approach to design day forecasting is the most prudent approach.

Witness Mendoza testified that the Company currently believes that it has sufficient supply and capacity rights to meet its near term customer needs into the 2016-2017 winter period but that growth projections begin to show a capacity deficit beginning in the 2017-2018 timeframe. Witness Mendoza testified that in light of prospective growth requirements, Piedmont reviewed new capacity options in addition to continuous monitoring of interstate pipeline and storage capacity offerings. Witness Mendoza further stated that although the Company subscribed to the Leidy Southeast expansion project of Transcontinental Gas Pipe Line Company, LLC (Transco), for 100,000 dekatherms (dts) per day of year around capacity and 20,000 dts per day on Transco's Virginia Southside expansion project, the Company signed a Precedent Agreement with Atlantic Coast Pipeline in 2014 for 160,000 dts of firm capacity scheduled to go in service in November 2018. Witness Mendoza testified that previously contracted capacity for Leidy Southeast went into service in several tranches beginning December 2015 with the full 100,000 dts per day going into service in January 2016. Witness Mendoza further stated that Virginia Southside (20,000 dts per day) went into service November 2015 and that the previously arranged permanent release of Transco's telescoped capacity (75,000 dts per day) went into effect in March 2016.

Witness Mendoza testified that capacity additions are acquired in "blocks" of additional transportation, storage, or liquefied natural gas (LNG) capacity, as they become needed, to ensure Piedmont's ability to serve its customers based on the options available at that time. Witness Mendoza explained that as a practical matter, this means that at any given moment in time, Piedmont's actual capacity assets will vary somewhat from its forecasted demand capacity requirements. Witness Mendoza also stated that this aspect of capacity planning is unavoidable but Piedmont attempts to mitigate the impact of any mismatch through its use of bridging services, capacity release, and off-system sales activities.

The Public Staff Panel testified that they had reviewed the testimony and exhibits of the Company's witnesses, the monthly operating reports, and the gas supply and pipeline transportation and storage contracts, as well as the Company's responses to the Public Staff's data requests. Based on this review, the Panel testified that the Company's gas costs were prudently incurred.

The Public Staff Panel further testified that, although the scope of Commission Rule R1-17(k) is limited to a historical review period, they also considered other information in order to anticipate the Company's requirements for future needs, including design day estimates, forecasted load duration curves, forecasted gas supply needs, projection of capacity additions and supply changes, and customer load profile changes.

Based on the foregoing, the Commission concludes that the Company's gas costs incurred during the review period were reasonable and prudently incurred and that the Company should be permitted to recover 100 percent of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is contained in the testimony of Company witness Tomlinson and the Public Staff Panel.

Company witness Tomlinson testified that based on the Company's deferred accounts end-of-period balances, as reflected on Tomlinson Exhibit_(MBT-3) and Exhibit_(MBT-4), she recommended that the increments/decrements to Piedmont's rates be placed into effect for a period of twelve months after the effective date of the final order in this proceeding.

The Public Staff Panel testified that they had reviewed the temporary rate increments applicable to the Sales Customers Only Deferred Account balance and to the All Customers Deferred Account proposed by Company witness Tomlinson and agreed that they should be implemented. The Panel also recommended that Piedmont remove all temporary rates that were implemented in Docket No. G-9, Sub 673, Piedmont's last annual review proceeding.

Based on the foregoing, the Commission concludes that it is appropriate for the Company to remove the temporary rates that were implemented in Docket No. G-9, Sub 673, and implement the temporary rate increments in the instant docket.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the twelve-month period ended May 31, 2016, is approved;

2. That the gas costs incurred by Piedmont during the twelve-month period ended May 31, 2016, including the Company's hedging costs, were reasonably and prudently incurred, and Piedmont is hereby authorized to recover 100 percent of its gas costs incurred during the period of review;

3. That the Company shall remove the existing temporary rates that were implemented in Docket No. G-9, Sub 673, and implement the temporary rate increments for the Sales Customers Only Deferred Account and for the All Customers Deferred Account, as found appropriate herein, effective for service rendered on and after the first day of the month following the date of this Order;

4. That Piedmont shall give notice to its customers of the rate changes allowed in this Order; and

5. That Piedmont shall file revised tariffs within five (5) days of the date of this Order implementing the rate changes approved in Ordering Paragraph No. 3 above.

ISSUED BY ORDER OF THE COMMISSION.
This the _21st_ day of _November_, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. G-5, SUB 568

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of	)	
North Carolina, Inc. for Annual Review of	)	ORDER ON ANNUAL
Gas Costs Pursuant to G.S. 62-133.4(c)	)	REVIEW OF GAS COSTS
and Commission Rule R1-17(k)(6)	)	

HEARD: Tuesday, August 9, 2016, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Commissioner Don M. Bailey, and Commissioner Lyons Gray

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

Mary Lynne Grigg, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For Carolina Utility Customers Association, Inc.:

Robert F. Page; Crisp, Page & Currin, LLP; 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 1, 2016, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Public Service Company of North Carolina, Inc. (PSNC or Company), filed the direct testimony and exhibits of Candace A. Paton, Rates & Regulatory Manager for PSNC, and Rose M. Jackson, General Manager – Supply & Asset Management for SCANA Services in connection with the annual review of PSNC's gas costs for the 12-month period ended March 31, 2016.

On June 3, 2016, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of Tuesday, August 9, 2016, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On July 21, 2016, the Carolina Utility Customers Association, Inc. filed a petition seeking to intervene in this docket. On July 26, 2016, the Commission issued an Order Granting Petition to Intervene.

On July 21, 2016, the Company filed its affidavits of publication.

On July 25, 2016, the Public Staff prefiled the joint direct testimony and exhibits of Julie G. Perry, Supervisor, Accounting Division, and Richard C. Ross, Public Utilities Engineer, Natural Gas Division (Public Staff Panel or Panel). On July 27, 2016, the Public Staff filed revised pages 11 and 12 to its prefiled joint testimony.

On August 1, 2016, PSNC filed a Motion for Witnesses to be Excused from Appearance at Evidentiary Hearing and requested that the prefiled testimony and exhibits of all witnesses be received into the record without requiring the appearance of such witnesses. The Commission granted the motion on August 2, 2016.

On August 9, 2016, the matter came on for hearing as scheduled, and all prefiled testimony and all exhibits were admitted into evidence. No public witnesses appeared at the hearing.

On September 7, 2016, the Joint Proposed Order of PSNC and the Public Staff was filed.

Based on the testimony and exhibits received into evidence and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PSNC is a corporation duly organized and existing under the laws of the State of South Carolina, having its principal office and place of business in Gastonia, North Carolina. PSNC operates a natural gas pipeline system for the transportation, distribution, and sale of natural gas to approximately 540,000 customers in the State of North Carolina.

2. PSNC is engaged in providing natural gas service to the public and is a public utility as defined in G.S. 62-3(23), subject to the jurisdiction of this Commission.

3. PSNC has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended March 31, 2016.

5. During the review period, PSNC incurred total gas costs of $138,196,802, comprised of demand and storage charges of $89,333,008, commodity gas costs of $111,515,164, and other gas costs of ($62,651,370).

6. In compliance with the Commission's December 22, 1995 Order in Docket No. G-100, Sub 67[1], the Company credited 75% of the net compensation from secondary market transactions, which amounted to $30,094,100, to its All Customers Deferred Account.

[1] Docket No. G-100, Sub 67 concerns the Matter of Accounting for Secondary Market Transactions by Gas Natural Local Distribution Companies.

7. At March 31, 2016, the Company had a credit balance (owed to customers) of $7,702,433 in its Sales Customers Only Deferred Account and a credit balance (owed to customers) of $6,702,930 in its All Customers Deferred Account.

8. The Company properly accounted for its gas costs incurred during the review period.

9. PSNC's hedging activities during the review period were reasonable and prudent.

10. As of March 31, 2016, the Company had a debit balance of $2,706,480 in its Hedging Deferred Account.

11. It is appropriate for the Company to transfer the $2,706,480 debit balance in the Hedging Deferred Account to its Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a net credit balance of $4,995,953, owed to customers.

12. PSNC has adopted a gas supply policy that it refers to as a "best cost" supply strategy. This gas supply acquisition policy is based upon three primary criteria: supply security, operational flexibility, and the cost of gas.

13. PSNC has firm transportation (FT) and storage contracts with interstate pipelines, which provide for the transportation of gas to the Company's system, and both long-term and supplemental short-term supply contracts with producers, marketers, and other suppliers.

14. The gas costs incurred by PSNC during the review period were prudently incurred, and the Company should be permitted to recover 100% of such prudently incurred gas costs.

15. As proposed by PSNC witness Paton and agreed to by the Public Staff, the Company should not implement any temporary rate changes in the instant docket at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

These findings are essentially informational, procedural, or jurisdictional in nature and were not contested by any party. They are supported by information in the Commission's public files and records and the testimony and exhibits filed by the witnesses for PSNC and the Public Staff.

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

The evidence supporting these findings of fact is contained in the testimony of PSNC witnesses Jackson and Paton, and the testimony of the Public Staff Panel. These findings are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that PSNC submit to the Commission information and data for an historical 12-month review period, including PSNC's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. In addition to such information, Commission Rule R1-17(k)(6)(c) requires that PSNC file weather normalization, sales volume data, workpapers, and direct testimony and exhibits supporting the information.

Witness Paton testified that Rule R1-17(k)(6) requires PSNC to submit to the Commission on or before June 1 of each year certain information with supporting workpapers based on the 12-month period ending March 31. Witness Paton indicated that the Company had filed the required information. Witness Paton also stated that the Company had provided to the Commission and the Public Staff on a monthly basis the gas cost and deferred gas cost account information required by Commission Rule R1-17(k)(5)(c). The Public Staff Panel presented the results of their review of the gas cost information filed by PSNC in accordance with G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

Based on the foregoing, the Commission concludes that PSNC has complied with the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the 12-month review period ended March 31, 2016.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence supporting these findings of fact is found in the testimony and exhibits of PSNC witness Paton and the testimony of the Public Staff Panel.

PSNC witness Paton's exhibits show that the Company incurred total gas costs of $138,196,802 during the review period, which was comprised of demand and storage costs of $89,333,008, commodity gas costs of $111,515,164, and other gas costs of ($62,651,370). The Public Staff Panel confirmed that total gas costs for the review period ended March 31, 2016, were $138,196,802.

The Public Staff Panel stated that the Company recorded $40,125,467 of margin on secondary market transactions, including capacity release transactions and storage management arrangements, during the review period. Of this amount, $30,094,100 was credited to the All Customers Deferred Account for the benefit of ratepayers.

PSNC witness Paton's prefiled testimony and exhibits reflected a Sales Customers Only Deferred Account credit balance of $7,702,433 (owed to customers) and a credit balance (owed to customers) of $6,702,930 in its All Customers Deferred Account as of March 31, 2016. The Public Staff Panel agreed with these balances and testified that PSNC properly accounted for its gas costs during the review period.

Based upon the foregoing, the Commission concludes that the Company properly accounted for its gas costs incurred during the review period. The Commission also concludes that the appropriate level of total gas costs incurred by PSNC for this proceeding is $138,196,802. The Commission further concludes that the appropriate balances as of March 31, 2016, are a credit balance of $7,702,433, owed to customers, in its Sales Customers Only Deferred Account and a credit balance of $6,702,930, owed to customers, in its All Customers Deferred Account.

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

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Paton and Jackson and the testimony of the Public Staff Panel.

PSNC witness Paton testified that the Company's Hedging Deferred Account balance for the 12-month review period ended March 31, 2016, was $2,706,480, a net debit balance, due from customers. The Public Staff Panel testified that this balance was composed of: Economic Gains - Closed Positions of ($480); Premiums Paid of $2,386,410; Brokerage Fees and Commissions of $11,856; Interest on the Brokerage Account of $9; and Interest on the Hedging Deferred Account of $308,685. The Panel further stated that the hedging charges resulted in an annual charge of $4.03 for the average residential customer which equates to approximately $0.34 per month. The Panel also testified that PSNC's weighted average hedged cost of gas for the review period was $3.73 per dekatherm (dt).

PSNC witness Jackson testified that the primary objective of PSNC's hedging program has always been to help mitigate the price volatility of natural gas for PSNC's firm sales customers at a reasonable cost. She further testified that PSNC's hedging program meets this objective by having financial instruments such as call options or futures in place to mitigate, in a cost effective manner, the impact of unexpected or adverse price fluctuations to its customers.

Witness Jackson testified that its hedging program provides protection from higher prices through the purchase of call options for up to 25% of PSNC's estimated sales volume. Witness Jackson further stated that in order to help control costs, the call options are purchased at a price no higher than 10% of the underlying commodity price. She also stated that PSNC limits its hedging to a 12-month future time period, which allows PSNC to obtain more favorable option pricing terms and better react to changing market conditions.

PSNC witness Jackson explained that PSNC's hedging program continues to utilize two proprietary models developed by Kase and Company that assist in determining the appropriate timing and volume of hedging transactions. She stated that the total amount available to hedge is divided equally between the two models.

Witness Jackson further testified that no changes were made to PSNC's hedging program during this review period. Witness Jackson stated that PSNC will continue to analyze and evaluate its hedging program and implement changes as warranted.

The Public Staff Panel stated that its review of the Company's hedging activities involves a continuous and ongoing analysis and evaluation of the Company's monthly Hedging Deferred Account reports, detailed source documentation, workpapers supporting the derivation of the maximum targeted hedge volumes for each month, periodic reports on the status of hedge coverage for each month, periodic reports on the market values of the various financial instruments used by the Company to hedge, monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the Hedging Deferred Account report, minutes from the meetings of SCANA's Risk Management Committee (RMC). In addition, the Public Staff reviews minutes from the meetings of the Board of Directors and its committees that pertain to hedging activities, reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events and plan modifications under consideration by SCANA's RMC. Further, the Public Staff examines the testimony and exhibits of the Company's witnesses in the annual review proceeding.

The Public Staff Panel testified that based on its analysis of what was reasonably known or should have been known at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, it concluded that the Company's hedging decisions were prudent.

The Public Staff Panel further testified that the $2,706,480 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Sales Customers Only Deferred Account. Based on this recommendation, the Panel stated that the appropriate balance in the Sales Customers Only Deferred Account as of March 31, 2016, after the hedging balance transfer, should be a credit balance of $4,995,953, owed to customers by the Company.

Based on the testimony and exhibits provided by PSNC and the Public Staff, the Commission finds that PSNC's hedging program has met the objective of contributing to the mitigation of gas price volatility and avoiding rate shock to customers. The Commission concludes that PSNC's hedging activities during the review period were reasonable and prudent and that the $2,706,480 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Company's Sales Customers Only Deferred Account. The Commission finds that the appropriate combined balance for the Hedging and Sales Customers Only Deferred Accounts is a credit balance of $4,995,953.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

The evidence for these findings of fact is found in the testimony of PSNC witness Jackson and the testimony of the Public Staff Panel.

PSNC witness Jackson testified that the most appropriate description of PSNC's gas supply acquisition policy would be a "best cost" supply strategy, which is based on three primary criteria: supply security, operational flexibility, and cost of gas. PSNC witness Jackson stated that security of supply is the first and foremost criterion, which refers to the assurance that the supply of gas will be available when needed. Witness Jackson also testified that supply security is especially important for PSNC's firm customers, who have no alternate fuel source. Witness Jackson went on to state that supply security is obtained through PSNC's diverse portfolio of suppliers, receipt points, purchase quantity commitments, and terms. She also testified that potential suppliers are evaluated on a variety of factors, including past performance, creditworthiness, available terms, gas deliverability options, and supply location.

Further, witness Jackson testified that the second criterion is maintaining the necessary operational flexibility in its gas supply portfolio that will enable PSNC to react to unpredictable weather and the changing requirements of industrial customers coupled with their ability to burn other fuels. She noted that PSNC's gas supply portfolio as a whole must be capable of handling the monthly, daily, and hourly changes in customer demand needs. Witness Jackson also testified that operational flexibility largely results from PSNC's gas supply agreements having different purchase commitments and swing capabilities (for example, the ability to adjust purchased gas within the contract volume on either a monthly or daily basis) and from PSNC's injections into and withdrawals out of storage.

In regard to the third criterion, cost of gas, PSNC witness Jackson stated that in evaluating costs, it is important to consider not only the actual commodity cost, but also any transportation-related charges such as reservation, usage, and fuel charges. She further explained that PSNC routinely requests gas supply bids from suppliers to help ensure the most cost-effective proposals. Witness Jackson also testified that in securing natural gas supply for its customers, PSNC is committed to acquiring the most cost-effective supplies while maintaining the necessary security and operational flexibility to serve the needs of its customers. She further observed that PSNC has developed a gas supply portfolio made up of long-term agreements and supplemental short-term agreements with a variety of suppliers, including both producers and independent marketers.

Witness Jackson testified that the majority of PSNC’s interstate pipeline capacity is obtained from Transcontinental Gas Pipe Line Company, LLC (Transco), the only interstate pipeline with which PSNC has a direct connection. The Company also has a backhaul transportation arrangement with Transco to schedule deliveries of gas from pipelines and storage facilities downstream of PSNC’s system, as well as transportation and/or storage service agreements with: Dominion Transmission, Inc.; Columbia Gas Transmission, LLC; Texas Gas Transmission, LLC; East Tennessee Natural Gas LLC; Dominion Cove Point LNG, LP; Saltville Gas Storage Company, L.L.C.; and Pine Needle LNG Company, LLC.

Witness Jackson testified that PSNC has engaged in the following activities to lower gas costs while maintaining security of supply and delivery flexibility:

1. PSNC continues to optimize the flexibility available within its supply and capacity contracts to realize their value;

2. PSNC participates in matters before the Federal Energy Regulatory Commission whose actions could impact PSNC’s rates and services to its customers;

3. PSNC has continued to work with its industrial customers to transport customer-acquired gas;

4. PSNC routinely communicates directly with customers, suppliers, and other industry participants, and actively monitors developments in the industry;

5. PSNC has frequent internal discussions concerning gas supply policy and major purchasing decisions;

6. PSNC utilizes deferred gas cost accounting to calculate the Company’s benchmark cost of gas to provide a smoothing effect on the gas volatility; and,

7. PSNC conducts a hedging program to help mitigate price volatility.

Further, witness Jackson testified that effective January 5, 2016, PSNC began receiving firm transportation service from Transco under an agreement with a 15-year initial term to receive

100,000 dekatherms (dts) per day of Firm Transportation capacity on the mainline facilities associated with Transco's Leidy Southeast Expansion Project (LSE). She noted that, as she had testified in the previous year's gas costs review, PSNC had entered into a precedent agreement with Transco to acquire the LSE capacity to serve additional forecasted design-day demand beginning in the winter of 2015-2016.

Witness Jackson also testified that PSNC has entered into a precedent agreement with Atlantic Coast Pipeline, LLC for a 20-year primary term to acquire 100,000 dts per day of capacity on a new pipeline that is expected to be in service by November 2018. When completed, the project will provide PSNC with a second interstate pipeline connection to gas supplies located in the Marcellus and Utica shale basins of West Virginia, Pennsylvania, and Ohio.

Additionally, witness Jackson testified that the projected design-day demand of PSNC's firm customers is calculated using a statistical modeling program prepared by SCANA Services Resource Planning personnel. She further explained that the model assumes a 50 heating degree-day (HDD) on a 60 degree Fahrenheit base and uses historical weather to estimate peak-day demand. Witness Jackson also testified that PSNC presented its forecasted firm peak-day demand requirements for the review period and for the next five winter seasons. She further explained that the assets available to meet PSNC's firm peak-day requirements include year-round, seasonal, and peaking capabilities and consist of firm transportation and storage capacity on interstate pipelines as well as the peaking capability of PSNC's on-system liquefied natural gas facility.

The Public Staff Panel testified that they had reviewed the testimony and exhibits of the Company's witnesses; monthly operating reports; gas supply and pipeline transportation and storage contracts; and the Company's responses to the Public Staff's data requests.

The Public Staff Panel testified that the Public Staff had independently calculated the customer load profile and peak design day demand using current (review period) data and the results of the Public Staff's analysis are slightly higher, but are comparable to PSNC's levels reflected in Jackson Exhibit 1. The Panel further testified that, in their opinion, PSNC's gas costs were prudently incurred for the 12-month review period ending March 31, 2016.

Based upon the foregoing, the Commission concludes that the Company's gas costs incurred during the review period ended March 31, 2016, were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is found in the testimony of PSNC witness Paton and the testimony of the Public Staff Panel.

PSNC witness Paton testified that the Company was not proposing new temporary rate increments or decrements at this time. Witness Paton testified that the Company proposes to continue its practice of taking into consideration the balance in the Sales Customers Only Deferred Account when evaluating whether to file for a change in the benchmark cost of gas and that PSNC believes that making periodic, and smaller, adjustments in the benchmark cost of gas is preferable to making one adjustment annually based on the over- or under-collection in the commodity cost of gas that may exist as of the end of the review period.

The Public Staff Panel testified that the All Customers Deferred Account credit balance (owed to customers) of $6,702,930 would typically result in a recommendation for a rate decrement to refund the balance owed. However, the Panel recommended that no action be taken in this docket since the Company stated the All Customers Deferred Account balance decreased to $6,373,775 as of April 30, 2016, and the Company estimated the balance will flip to a debit balance of approximately $13.7 million as of October 31, 2016. The Public Staff also stated that it is not unusual to have a change in the balances since fixed gas costs are typically over-collected during the winter period when throughput is higher due to heating load, and under-collected during the summer when throughput is lower.

The Public Staff Panel further testified that the Public Staff agrees with PSNC's proposal to not place a temporary rate decrement in rates for the refund of the net credit balance of $4,995,953 (owed to customers) in the Sales Customers Only Deferred Account. The Panel stated that the Company plans to manage it by using the Purchased Gas Adjustment (PGA) mechanism, pursuant to G.S. 62-133.4, which PSNC has previously used for this purpose.

Based upon the foregoing, the Commission concludes that it is appropriate not to require PSNC to implement the temporary rate decrements in the instant docket at this time.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's accounting for gas costs for the 12-month period ended March 31, 2016, is approved.

2. That the gas costs incurred by PSNC during the 12-month period ended March 31, 2016, were reasonably and prudently incurred, and PSNC is hereby authorized to recover 100% of these gas costs as provided herein.

3. That, as proposed by PSNC witness Paton and agreed to by the Public Staff in the instant docket, PSNC shall not implement any temporary rate changes effective for service rendered on and after November 1, 2016.

ISSUED BY ORDER OF THE COMMISSION
This the ___7th____day of November, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. G-41, SUB 47

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Toccoa Natural Gas for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Wednesday, November 2, 2016, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Commissioner Don M. Bailey and Commissioner James G. Patterson

APPEARANCES:

For Toccoa Natural Gas:

Karen M. Kemerait, Smith Moore Leatherwood, LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On September 1, 2016, Toccoa Natural Gas (Toccoa or Company), filed the direct testimony and exhibits of Rai Trippe, Member Support Senior Business Analyst for the Municipal Gas Authority of Georgia (Gas Authority), and Harry F. Scott, Jr., Utilities Director for the City of Toccoa, Georgia, in connection with the annual review of Toccoa's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), for the twelve-month period ended June 30, 2016.

On September 2, 2016, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of November 2, 2016, set prefiled testimony dates, and required Toccoa to give at least 30 days prior notice to its customers of the hearing on this matter.

On October 7, 2016, Toccoa filed its affidavit of publication.

On October 12, 2016, Toccoa filed the revised testimony of Rai Trippe.

On October 14, 2016, the Public Staff filed the testimony of Richard C. Ross, Utilities Engineer, Natural Gas Division; and Iris Morgan, Accountant, Water Section, Accounting Division.

On October 17, 2016, Toccoa and the Public Staff filed a Joint Motion to Excuse Witnesses and Accept Testimony, which was granted by the Commission on October 27, 2016.

On November 2, 2016, the matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing.

On November 30, 2016, the Joint Proposed Order of Toccoa and the Public Staff was filed.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Toccoa, a division of the City of Toccoa, Georgia, is a public utility as defined by G.S. 62-3(23) and as such is subject to the jurisdiction of the Commission.

2. Toccoa is primarily engaged in the business of purchasing, transporting, distributing, and selling natural gas to approximately 6,481 retail customers of which approximately 683 are in North Carolina.

3. The Company has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended June 30, 2016.

5. During the review period, Toccoa incurred total North Carolina gas costs of $298,562, which was comprised of demand and storage costs of $91,257 commodity costs of $198,950, and other gas costs of $8,355.

6. At June 30, 2016, Toccoa had a credit balance of $109,739, owed by Toccoa to customers, in its North Carolina Deferred Gas Cost Account (NC Deferred Account).

7. Toccoa properly accounted for its gas costs during the review period.

8. Toccoa's hedging activities during the review period were reasonable and prudent.

9. Toccoa has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to Toccoa's system and an "all requirements" gas supply contract with the Gas Authority.

10. Toccoa released unutilized capacity during the review period to mitigate the cost of demand capacity, and all margins earned on secondary market transactions reduced the cost of gas and were flowed through to ratepayers.

11. Toccoa has adopted a "portfolio approach" gas purchasing policy that consists of four main components: long-term firm supply, short-term spot market purchases, seasonal peaking, and contract storage services.

12. Toccoa's gas purchasing policy and practices during the review period were prudent, and its gas costs during the review period were prudently incurred.

13. Toccoa should be permitted to recover 100% of its prudently incurred gas costs.

14. As a result of this proceeding, the Company should continue the current temporary rate decrement of $0.7649 per dekatherm (dt) as recommended by Public Staff witness Ross and agreed to by Toccoa.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings is contained in the official files and records of the Commission and the testimony and exhibits of Toccoa witnesses Trippe and Scott. These findings are essentially informational, procedural, or jurisdictional in nature and are not contested by any party.

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

The evidence supporting these findings of fact is contained in the testimony of Toccoa witness Trippe, Public Staff witness Ross, and the testimony of Public Staff witness Morgan. These findings are made pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4(c) requires that each natural gas utility submit to the Commission information and data for a historical twelve-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(c) establishes June 30, 2016, as the end date of the annual review period for the Company in this proceeding. Commission Rule R1-17(k)(6)(c) requires that Toccoa file weather-normalized sales volumes, work papers, and direct testimony and exhibits supporting the information.

Toccoa witness Trippe testified that he was not aware of any outstanding issues regarding the reporting requirements of Commission Rule R1-17(k)(5)(c), which requires the Company to file a complete monthly accounting of computations under the provisions of the Rule for gas costs and deferred account activity. Public Staff witness Morgan confirmed that the Public Staff had reviewed the filings and monthly reports filed by Toccoa.

Based upon the foregoing, the Commission concludes that Toccoa has complied with all procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the twelve-month review period ended June 30, 2016.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence supporting these findings of fact is contained in the testimony of Toccoa witness Trippe and Public Staff witness Morgan.

Company witness Trippe testified that Toccoa incurred total North Carolina gas costs of $298,562 during the review period, which was comprised of demand and storage costs of $91,257, commodity costs of $198,950, and other gas costs of $8,355. Public Staff witness Morgan stated that every month the Public Staff reviews the NC Deferred Account reports filed by Toccoa for accuracy and reasonableness, and performs audit procedures on the calculations. Public Staff witness Morgan also provided testimony that Toccoa had properly accounted for its gas costs during the review period.

Public Staff witness Morgan stated that Toccoa operates in both Georgia and North Carolina and that the Company maintains the NC Deferred Account, which includes both commodity and demand gas charges incurred and recovered during each review period. Public Staff witness Morgan explained that Toccoa allocates the deferred gas cost account balance to North Carolina based on the monthly firm sales volumes for the review period. Public Staff witness Morgan confirmed that, as of June 30, 2016, Toccoa’s NC Deferred Account had a credit balance of $109,739, owed by Toccoa to customers, compared to the previous review period ending credit balance of $137,386, owed by Toccoa to customers. Witness Morgan also testified that the $27,647 change in Toccoa’s NC Deferred Account consisted of the following Deferred Account activity: Commodity True-up of ($2,100), Demand True-up of ($44,162), Firm Hedges of $8,355, and Increment activity of $65,554.

Based on the foregoing, the monthly filings by Toccoa pursuant to Commission Rule R1-17(k)(5)(c), and the findings and conclusions set forth above, the Commission concludes that Toccoa has properly accounted for its gas costs incurred during the review period and that Toccoa’s NC Deferred Account balance reflected in the Company’s exhibits is correct.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony of Toccoa witness Trippe and testimony of Public Staff witness Morgan.

Company witness Trippe testified that Toccoa participates in the Gas Authority's “WinterHedge” program under the Gas Authority’s Option 2. Witness Trippe stated that the Gas Authority’s objective in hedging prices is to achieve price stability at a reasonable level for its members’ retail customers. Witness Trippe further testified that as stated in the testimony in the prior review period, Docket No. G-41, Sub 44, Toccoa reviewed its Winter Hedge Program participation and elected to reduce its winter hedge volumes to approximately 23% of its forecasted firm residential gas sales for November 2015 through March 2016.

Company witness Trippe also testified that although hedging helps manage volatility in the wholesale cost of gas, it can create its own challenges. He explained that some customers have unrealistic expectations of the benefits of hedging, because a common benchmark for evaluating hedged prices is the actual spot market price. Witness Trippe further testified that this can be an unfair measure because it is only available after the fact, and assumes that the goal of hedging is "to beat the market." To the contrary, he testified that the principal goal of hedging is to achieve price stability, at a reasonable level, for the consuming public.

Public Staff witness Morgan testified that when a Gas Authority member enters into hedging arrangements with the Gas Authority, the member specifies the targeted level of volumes to hedge and that these arrangements typically span two to three years and includes fixed price swaps. Public Staff witness Morgan stated that during the current review period, Toccoa's hedging program resulted in an $8,355 charge to its gas supply cost for North Carolina customers.

Public Staff witness Morgan testified that as stated in the prior review period, Docket No. G-41, Sub 44, Toccoa had reviewed its Winter Hedge Program participation and elected to reduce its winter hedge volumes to approximately 23% of all firm North Carolina gas sales for November 2015 through March 2016. Public Staff witness Morgan further stated that at the time this decision was made, Toccoa chose to adopt more conservative hedge volumes for its participation in the Winter Hedge Program because market and futures pricing was significantly lower than it had been at the time the previous Winter Hedge Program volumes were put in place. Public Staff witness Morgan also explained that Toccoa elected the maximum hedging program term offered by the Gas Authority of two years beginning November 1, 2015.

Public Staff witness Morgan further testified that based on what was reasonably known or should have been known by Toccoa at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, she concluded that the Company's hedging decisions were prudent.

Based on the testimony presented by the Company and the Public Staff, the Commission concludes that the Company's hedging activities during the review period were reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-14

The evidence for these findings of fact is contained in the testimony of Toccoa witness Trippe and Public Staff witnesses Ross and Morgan.

Company witness Trippe testified that Toccoa is a charter member of the Gas Authority, the largest non-profit joint action natural gas agency in the nation. Company witness Trippe also testified that, as a member of the Gas Authority, Toccoa receives all of its gas supply at very competitive rates. He further explained that the Gas Authority uses a portfolio approach to supply its 79 member cities' needs, relying on a combination of long-term firm supply arrangements, short-term spot market purchases, seasonal peaking, and contract storage services. He also testified that Toccoa is assured adequate, dependable, and economical gas supplies through the Gas Authority's efforts.

Public Staff witness Ross testified that Toccoa has contracts for pipeline capacity and storage service from Transcontinental Gas Pipe Line Company, LLC, a storage service contract with Pine Needle LNG Company, LLC, and a gas supply contract with the Gas Authority. Witness Ross further explained that as the all requirements supplier for Toccoa, the Gas Authority manages all of Toccoa's pipeline, storage service, and gas supply contracts. Based upon the Public Staff's investigation and review of the data filed in this docket, witness Ross concluded that Toccoa's gas costs during the review period were prudently incurred.

Company witness Trippe testified that the Gas Authority, on behalf of Toccoa, was able to release a portion of Toccoa's unutilized capacity each month of the test period to mitigate the cost of extra demand capacity, generating a savings during the period of July 2015 - June 2016 that totaled $18,487. Public Staff witness Morgan testified that Toccoa's policy has always been to flow through 100% of its capacity release credits to ratepayers.

Public Staff witness Morgan also testified that the balance in Toccoa's deferred account at June 30, 2016, was a $109,739 credit balance, owed to customers. Public Staff witness Ross testified that while the Public Staff would typically recommend a rate decrement to refund the credit balance at June 2016, he concluded that no action should be taken at this time in this docket. He explained that the Company is projecting that the current decrement in rates should adequately refund the deferred account balance to customers once it is in effect for an entire 12-month period and that requiring Toccoa to change its temporary decrement in the instant docket at this time would not be productive. Public Staff witness Ross testified that Toccoa agreed to his recommendation and also noted that Toccoa has managed its deferred account balance in the past by adjusting its rates using its Purchased Gas Adjustment (PGA) procedures, which can be used at any time during a review period.

Based on the foregoing, the Commission concludes that the Company's gas purchasing policies and practices during the review period were reasonable and prudent, that its gas costs during the review period were prudently incurred, and that the Company should be permitted to recover 100% of it's prudently incurred gas costs. The Commission further concludes that the current temporary rate decrement in Toccoa's rates is appropriate and should continue as recommended by Public Staff witness Ross and agreed to by Toccoa.

IT IS, THEREFORE, ORDERED as follows:

1. That Toccoa's accounting for gas costs for the 12-month period ended June 30, 2016, is approved.

2. That the gas costs incurred by Toccoa during the 12-month period ended June 30, 2016, were reasonably and prudently incurred, and that Toccoa is authorized to recover 100% of its gas costs incurred during the period of review.

3. That Toccoa's current temporary rate decrement is appropriate and shall continue in effect until further order by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of December, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. G-9, SUB 678

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Piedmont Natural Gas Company, Inc., for Approval of a Compressed Natural Gas Fuel Purchase Agreement	)))	ORDER APPROVING AGREEMENT

BY THE COMMISSION: On November 12, 2015, Piedmont Natural Gas Company, Inc. (Piedmont), filed a petition requesting approval of a Compressed Natural Gas (CNG) Fuel Purchase Agreement (Agreement) between Piedmont and W.W. Transport, Inc. (Customer). Piedmont submitted the Agreement under seal on the grounds that it is confidential and proprietary and has been designated as such pursuant to G.S. 132-1.2.

The Agreement provides the Customer with CNG service pursuant to Piedmont's Rate Schedule 142. Piedmont stated that no other customers will be impacted by the Agreement and that the Agreement is in the public interest.

The Public Staff presented this matter at the Commission's Regular Staff Conference on January 25, 2016. The Public Staff stated it had reviewed the Agreement and other information provided by Piedmont in response to Public Staff data requests. Based on its investigation, the Public Staff determined that the terms of the Agreement are within the parameters set forth in G.S. 62-140. The Public Staff recommended that the Commission issue an order: 1) concluding that the Agreement is not unlawful and does not violate the rules and regulations of the Commission; 2) allowing Piedmont to provide service to the Customer pursuant to the Agreement; and 3) stating that the Commission's acceptance of the Agreement neither constitutes approval of the amount of any compensation paid thereunder nor prejudices the right of any party to take issue with any provision of the Agreement in question in a future proceeding.

The Commission, having carefully reviewed the Agreement between Piedmont and the Customer, concludes that the Agreement is not unlawful and does not violate the rules and regulations of the Commission. Accordingly, the Commission finds good cause to allow the Agreement to become effective as filed and authorizing Piedmont to provide service to Customer under the Agreement as recommended by the Public Staff.

IT IS, THEREFORE, ORDERED as follows:

1. That the Agreement between Piedmont and W.W. Transport, Inc., is hereby allowed to become effective as filed.

2. That Piedmont is hereby authorized to provide CNG service to the Customer pursuant to the Agreement.

3. That authorizing Piedmont to provide CNG service to the Customer pursuant to the Agreement filed in this docket neither constitutes approval of the amount of any compensation paid thereunder nor prejudices the right of any party to take issue with any provision of the contract in question in a future proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the __26th___ day of January, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Commissioner Jerry C. Dockham did not participate in this decision.

DOCKET NO. G-9, SUB 691

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Piedmont Natural Gas Company,	)	
Inc., for Approval of a Compressed Natural	)	ORDER APPROVING AGREEMENT
Gas Fuel Purchase Agreement	)	

BY THE COMMISSION: On August 11, 2016, Piedmont Natural Gas Company, Inc. (Piedmont), filed a petition requesting approval of a Compressed Natural Gas (CNG) Fuel Purchase Agreement (Agreement) between Piedmont and Worthington Wholesale (Customer). Piedmont submitted the Agreement under seal on the grounds that it is confidential and proprietary and has been designated as such pursuant to G.S. 132-1.2.

The Agreement provides the Customer with CNG service pursuant to Piedmont's Rate Schedule 142. Piedmont stated that no other customers will be impacted by the Agreement and that the Agreement is in the public interest.

The Public Staff presented this matter at the Commission's Regular Staff Conference on October 17, 2016. The Public Staff stated it had reviewed the Agreement and other information provided by Piedmont in response to Public Staff data requests. Based on its investigation, the Public Staff determined that the terms of the Agreement are within the parameters set forth in

G.S. 62-140. The Public Staff recommended that the Commission issue an order: 1) concluding that the Agreement is not unlawful and does not violate the rules and regulations of the Commission; 2) allowing Piedmont to provide service to Customer pursuant to the Agreement; and 3) stating that the Commission's acceptance of the Agreement neither constitutes approval of the amount of any compensation paid thereunder nor prejudices the right of any party to take issue with any provision of the Agreement in a future proceeding.

The Commission, having carefully reviewed the Agreement between Piedmont and the Customer, concludes that the Agreement is not unlawful and does not violate the rules and regulations of the Commission. Accordingly, the Commission finds good cause to allow the Agreement to become effective as filed and authorizing Piedmont to provide service to Customer under the Agreement as recommended by the Public Staff.

IT IS, THEREFORE, ORDERED as follows:

1. That the Agreement between Piedmont and the Customer is hereby allowed to become effective as filed.

2. That Piedmont is hereby authorized to provide CNG service to the Customer pursuant to the Agreement.

3. That authorizing Piedmont to provide CNG service to the Customer pursuant to the Agreement filed in this docket neither constitutes approval of the amount of any compensation paid thereunder nor prejudices the right of any party to take issue with any provision of the Agreement in a future proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the __18th__ day of October, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. G-5, SUB 569

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Public Service Company of North Carolina,	)	
Inc.'s, Request for a Natural Gas Pipeline	)	ORDER ALLOWING AGREEMENT
Construction and Transportation Agreement	)	TO BECOME EFFECTIVE
between PSNC and Duke Energy Carolinas	)	

BY THE COMMISSION: On August 15, 2016, Public Service Company of North Carolina, Inc. (PSNC), filed a Natural Gas Pipeline Construction and Transportation Agreement (Agreement) between PSNC and Duke Energy Carolinas, LLC (DEC). PSNC submitted the Agreement under seal on the grounds that it is confidential and proprietary and has been designated as such pursuant to G.S. 132-1.2.

PSNC stated that the Agreement will provide long-term gas transportation and redelivery service to DEC's Cliffside Steam Station coal-fired electric power generation units in Cleveland and Rutherford Counties in order for DEC to utilize natural gas to co-fire such units. PSNC further indicated that the Agreement is in the public interest.

On September 1, 2016, Carolina Utility Customers Association, Inc., filed a petition to intervene in the docket. By order issued September 8, 2016, the Commission granted the petition.

The Public Staff presented this matter at the Commission's Staff Conference on December 19, 2016. The Public Staff stated that it had reviewed the Agreement and other information provided by PSNC in response to Public Staff data requests. The Public Staff stated that based on its investigation, it had determined that the terms of the Agreement are within the parameters set forth in G.S. 62-140 and G.S. 62-142. The Public Staff recommended that the Commission issue an order: (1) concluding that the Agreement is not unlawful and does not violate the rules and regulations of the Commission, and (2) allowing the Agreement to become effective as filed and authorizing PSNC to provide service to DEC pursuant to the Agreement. The Public Staff also recommended that the Commission's order state that acceptance of the Agreement neither constitutes approval of the amount of any compensation paid thereunder nor prejudices the right of any party to take issue with any provision of the Agreement in a future proceeding.

The Commission, having carefully reviewed the Agreement, concludes that the Agreement is not unlawful and does not violate the rules and regulations of the Commission. Accordingly, the Commission finds good cause to allow the Agreement to become effective as filed and authorize PSNC to provide service to DEC pursuant to the Agreement as recommended by the Public Staff.

IT IS, THEREFORE, ORDERED as follows:

1. That the Agreement between PSNC and DEC is hereby allowed to become effective as filed.

2. That PSNC is hereby authorized to provide natural gas service to the DEC pursuant to the Agreement.

3. That authorizing PSNC to provide natural gas service to DEC pursuant to the Agreement neither constitutes approval of the amount of any compensation paid thereunder nor prejudices the right of any party to take issue with any provision of the Agreement in question in a future proceeding.

ISSUED BY ORDER OF THE COMMISSION
This the 20th day of December, 2016

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Acting Deputy Clerk

DOCKET NO. G-40, SUB 133

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Frontier Natural Gas	)	
Company, LLC for Conditional Approvals	)	ORDER GRANTING
Relating to Corporate Reorganization and	)	CONDITIONAL APPROVALS
Debt Refinancing	)	

BY THE COMMISSION: On February 17, 2016, Frontier Natural Gas Company, LLC (Frontier or the Company), pursuant to G.S. 62-111, G.S. 62-160, et seq., and Commission Rule R1-16, filed an Application for Conditional Approvals of Corporate Reorganization and Debt Refinancing (Application). The Application requests approval for reorganization of Frontier's relationship with its corporate parents, and for conditional approval of debt financing for Frontier (Frontier 2016 Financing) by its parent Gas Natural Inc. (GNI). The Frontier 2016 Financing consists of: (1) the intercompany loan agreement between GNI and Frontier (Intercompany Revolving Loan Agreement), (2) the long-term intercompany note payable by Frontier to GNI (Term Debt Note), and (3) the shorter term intercompany note payable by Frontier to GNI (SAP Loan Agreement).

On February 25, 2016, Frontier filed a letter with the Commission stating that Frontier waives the requirement of G.S. 62-164 that the Commission render a decision on the utility financing arrangement within thirty (30) days of the filing.

On March 9, 2016, the Commission issued its Order Requesting Additional Information, Investigation by the Public Staff and Comments. In that Order, the Commission accepted Frontier's waiver of the 30-day requirement of G.S. 62-164, ordered Frontier to answer questions attached to the Order, and set a procedural schedule for intervention and the filing of comments, briefs, and proposed orders.

On March 14, 2016, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a letter identifying and requesting information required by Commission Rule R1-16. On March 22, 2016, Frontier filed supplemental information, as requested by the Public Staff.

On April 7, 2016, Frontier filed the information requested by the Commission in its March 9, 2016 Order, along with the affidavits of Fred A. Steele, President and General Manager of Frontier, and James E. Sprague, Chief Financial Officer of GNI.

On April 8, 2016, Frontier filed an Amended Appendix A-2 to the Application.

On May 5, 2016, the Public Staff filed a motion requesting that the Commission issue an order extending the time to file comments and proposed orders. On May 5, 2016, the Commission granted in part the requested extensions of time.

On May 23, 2016, the Public Staff filed its Comments, and on June 15, 2016, Frontier filed its Reply Comments. No other party intervened or filed comments in this docket.

On June 30, 2016, Frontier filed a second affidavit of James E. Sprague that provided information about the GNI Term Loan and the Term Debt Note. The Application for Approvals of Corporate Reorganization and Debt Refinancing filed on February 17, 2016, and the additional information and affidavits filed by Frontier on and since that date described immediately above are collectively referred to as the Application.

On July 1, 2016, the Public Staff filed proposed Ordering Paragraphs and Regulatory Conditions that had been agreed to by Frontier and the Public Staff.

Also on July 1, 2016, Frontier filed a Proposed Order Granting Approval that incorporated the proposed Ordering Paragraphs and Regulatory Conditions agreed upon with the Public Staff, and that would grant approval of the proposed debt financing transactions as described in Frontier's Application.

Based upon the verified Application in this proceeding and the exhibits attached thereto, and the Commission's files and records regarding Frontier's previous financing and corporate structure, the Commission makes the following:

FINDINGS OF FACT

1. Frontier is a limited liability company duly organized and existing under the laws of the State of North Carolina for the purpose of providing natural gas service in certain parts of North Carolina pursuant to Certificates of Public Convenience and Necessity that have been issued by the Commission. Under the laws of this State, Frontier is a public utility operating in North Carolina and is, therefore, subject to the jurisdiction of the Commission.

2. Frontier began construction of its natural gas transmission and distribution systems in 1998 and completed construction of its transmission system in 2002. The construction of distribution pipelines and facilities for service to new customers continues in all six of Frontier's franchised counties. Frontier has experienced significant customer growth and significant growth in sales and transportation volumes. The number of customers served by Frontier has increased 26% from 2011 to 2012, 28% from 2012 to 2013, 27.7% from 2013 to 2014, and 11.8% from 2014 to 2015.

3. Frontier is still considered a relatively new company, and as such is a unique local distribution company. Although it has experienced strong growth, it has a low market saturation rate, and thus has excellent growth prospects.

4. Frontier is currently a wholly-owned subsidiary of Frontier Utilities of North Carolina, Inc. (Frontier Utilities). Frontier Utilities is a corporation organized and existing under the laws of the State of North Carolina. Frontier Utilities is currently a wholly owned subsidiary of Energy West, Incorporated (EWI), a Montana corporation doing business in Montana as a regulated natural gas utility. The Commission approved EWI's purchase of the stock of Frontier Utilities and the consequent transfer of control of Frontier to EWI pursuant to its Order Approving

Purchase of Stock and Transfer of Control of Company issued on September 13, 2007, in Docket No. G-40, Sub 67 (Order of CPCN Transfer). EWI consummated its purchase of Frontier on October 1, 2007.

5. Pursuant to Regulatory Condition No. 3, attached to the Order of CPCN Transfer, Frontier and Frontier Utilities are considered to be a consolidated entity to the extent that Frontier Utilities' affiliation with Frontier has an effect on Frontier's rates or services so as to cause Frontier Utilities to be a public utility under G.S. 62-3(23)c.

6. On June 27, 2008 in Docket No. G-40 – Company Folder, Frontier filed with the Commission a Notice of Corporate Reorganization of Parent Company regarding EWI's formation into a holding company structure. In that Notice, Frontier reported that EWI had filed a petition for approval of the reorganization with the Montana Public Service Commission (Montana Commission) and that a similar petition would be filed with the Wyoming Public Service Commission (Wyoming Commission).

7. In a Status Update letter filed with the Commission on May 19, 2009, in Docket No. G-40 – Company Folder, Frontier provided the Joint Proposal for Approval of Corporate Reorganization Petition and Ring-Fencing Measures and a Stipulation for Approval of Corporate Reorganization and Ring-Fencing Measures (Montana Stipulation) that had been filed with the Montana Commission in Docket No. D2008.5.57 (Petition of Energy West Incorporated for an Order Approving its Corporate Reorganization to Create a Holding Company Structure.) The Montana Stipulation was entered into by EWI and the Montana Consumers Counsel for resolution of the pending reorganization proceeding. The Montana Stipulation contained Sub-paragraph 3(d), which established "ring-fencing measures," that could affect Frontier. On June 23, 2009, the Montana Commission issued Order No. 6960a in that docket approving the Montana Stipulation.

8. Frontier acknowledged in the Status Update Letter that a change in the direct ownership of Frontier Utilities by EWI to a holding company would constitute a transaction requiring Commission approval pursuant to G.S. 62-111(a). Frontier stated that a change in the terms of the debt financing (the triggering event for the timing of the contemplated future spin-off of Frontier Utilities) would require approval by the Commission pursuant to G.S. 62-160 et seq. Accordingly, Frontier committed to filing an application for approval of any new debt financing and/or transfer of ownership of Frontier Utilities to the holding company, if such transfer of ownership were to occur.

9. On July 16, 2010, in Docket No. G-40 – Company Folder, Frontier filed with the Commission a Notice of Corporate Reorganization of Affiliated Company, advising the Commission that Energy, Inc. was the parent company of EWI and that, effective July 9, 2010, Energy, Inc. and GNI had merged, with GNI remaining as the surviving entity after the merger. GNI was reincorporated with the Ohio Secretary of State as an Ohio Corporation on July 9, 2010.

10. On March 7, 2012, in Docket No. G-40, Sub 105, Frontier filed an Application for Approval of Debt Refinancing Transactions by Energy West Incorporated, and on June 22, 2012, Frontier filed an Amended Application for Approval of Debt Refinancing Transactions by Energy West Incorporated that described the restructuring of EWI. EWI also requested approval of the reorganization from the Montana, Wyoming, and Maine Commissions. In its Order Granting

Conditional Approval issued on August 8, 2012, the Commission conditionally approved the Amended Application.

CORPORATE REORGANIZATION

11. According to the Application, GNI's corporate structure has evolved through mergers, acquisitions, the formation of new companies, and the dissolution of old ones. GNI currently has nine direct subsidiaries: EWI; Brainard Gas Corporation; Independence Oil, LLC (Independence Oil); Gas Natural Service Company, LLC; Gas Resources, LLC; Lightning Pipeline Company, Inc.; Great Plains Natural Gas Company; Gas Natural Resources, LLC; Public Gas Company, Inc.; and Lone Wolfe Insurance, LLC (collectively, Direct Subsidiaries).

12. According to the Application, EWI currently has eight direct subsidiaries: Frontier Utilities, Penobscot Natural Gas Company, Inc., Energy West Montana, Inc., Cut Bank Gas Company, Energy West Development, Inc., Energy West Resources, Inc., Energy West Propane, Inc., and Energy West Properties, LLC (collectively, Energy West Subsidiaries). Some of the GNI Direct Subsidiaries and some of the Energy West Subsidiaries have, themselves, subsidiaries, so that, in total, twenty-seven companies are in the GNI organization.

13. According to the Application, Frontier requests conditional approval of the reorganization which simplifies its relationship with its corporate parents. Under the current corporate structure, GNI is the parent of several entities, including EWI. GNI separately owns other regulated utilities that operate distribution systems and an intrastate pipeline in Ohio. GNI is also the parent of several unregulated entities. EWI is the parent of Frontier Utilities and regulated utilities in Montana and Maine.

14. According to the Application, under the current corporate structure, having EWI, which is regulated by the Montana Commission, serve as the parent of Frontier Utilities and other regulated utilities, as well as GNI's ownership of other unregulated businesses in other states, has created the potential for jurisdictional conflict, confusion in accountability, and the potential for inconsistent practices among subsidiaries.

15. According to the Application, under the proposed corporate structure, GNI would continue to be the ultimate parent of Frontier. Frontier Utilities and EWI would be dissolved, and EWI would be replaced by New Intermediate Company (NIC), a newly formed intermediary company. NIC would serve as the holding company for the regulated utilities, which includes Frontier as well as the other regulated utilities operating in Ohio, Montana, and Maine. NIC will have no subsidiaries other than regulated entities. The regulated subsidiaries would all become direct, separate subsidiaries of GNI through NIC. All of the former EWI and GNI unregulated business entities would be directly owned by GNI. The proposed holding company structure would place all GNI regulated subsidiaries under NIC, with all unregulated GNI subsidiaries being separate from NIC. The new corporate structure would facilitate a much simpler financing by allowing each subsidiary to be responsible for its own debt, without the complexities and risks of cross-collateralization, guarantees, or funds pooling.

16. According to the Application, the new corporate structure will accomplish several key goals and is beneficial because it:

(a) eliminates divested companies and discontinued operations;
(b) separates non-regulated activities completely from regulated activities, and provides an intermediary company between GNI and the regulated operating utilities;
(c) simplifies the organizational structure and clarifies lines of responsibility by reducing intermediary companies from five to one;
(d) clearly establishes the regulated operating utilities under the single intermediary company level to ensure appropriate separation from GNI, efficiencies and coordination of regulatory compliance activities, and operational consistency through the implementation of best practices; and
(e) provides a structure for clear and understandable state- and utility-specific access to short-term and long-term debt while permitting discrete, distinctive, and independent utility-specific obligations and ring-fencing -- limited to each of the in-state activities and debt obligations and shielded from out-of-state obligations and unregulated activities and risks.

17. Frontier contends that the elimination of Frontier Utilities as a legal entity is consistent with Regulatory Condition No. 3 attached to the Order of CPCN Transfer issued on September 13, 2007, in Docket No. G-40, Sub 67, pursuant to which Frontier and Frontier Utilities are considered to be a consolidated entity for Commission regulatory purposes.

CURRENT FINANCING ARRANGEMENT

18. In the Order Granting Conditional Approval issued in Docket No. G-40, Sub 105, on August 8, 2012, the Commission conditionally approved an amended and restated credit agreement between Bank of America, N.A. (BOA) and EWI (Amended and Restated Credit Agreement), an intercompany credit agreement and continuing guaranty of Frontier Utilities and Frontier to EWI, and a term note between Frontier and EWI. The Amended and Restated Credit Agreement consisted of a $30 million unsecured revolving line of credit and a $10 million unsecured long-term debt facility. Frontier was a part of the pool of guarantors of this financing, along with other EWI subsidiaries, and Frontier provided a limited recourse guarantee of $12.8 million of the Energy West debt amount. Frontier issued to Energy West a term note payable in the principal amount of approximately $6.1 million as its share of the notes. The $6.7 million balance represented Frontier's share of the revolving line of credit that it could access. EWI's current line of credit, which is still in effect, will expire on April 1, 2017.

EFFORTS TO OBTAIN FINANCING FROM AN INDEPENDENT LENDER

19. Frontier states that since the Commission's approval of its current financing in 2012, Frontier has taken numerous actions to improve its creditworthiness and ability to obtain standalone financing from independent, unrelated parties. Frontier contacted several lending institutions to request proposals for the financing of Frontier. Despite the requests, only one financial institution submitted a term sheet to Frontier. Upon evaluation of the proposal, Frontier found the terms and conditions required by that bank to be unacceptable. Thus, Frontier has not

received an alternative standalone proposal with terms that would be in the best interest of Frontier and its customers. Frontier is of the opinion that its small size was a major impediment to receiving attractive financing options from independent lenders. Also, if Frontier had obtained financing from an independent lender, Frontier would have been required to pledge its assets and GNI would have been required to serve as a guarantor for the financing.

PROPOSED REFINANCING

20. The Application states that due to the expiration of the current financing in 2017, Frontier requires both short-term and long-term debt resources in order to have sufficient access to meet cyclical cash flow needs throughout the year, to pay fixed expenses during non-heating months, to benefit from seasonal opportunities and provide operational flexibility to lower overall costs. In addition, Frontier needs long-term financing for capital investments to allow it to continue to grow as it has over the past few years. Frontier will use funds from the refinancing for repayment of its current outstanding debt, short-term funding of capital additions and system expansions, funding of system betterment and replacements, payment for working capital needs, payment for flowing gas and gas storage, payment for support services benefitting Frontier, its general corporate needs, and financing the SAP accounting system software, licenses and installation.

21. According to the Application, in order to replace the Amended and Restated Credit Agreement before its expiration GNI has entered into a proposed financing arrangement with BOA that will provide funds for debt financing for Frontier. GNI's financing will consist of the following components:

(a) BOA Revolving Credit Facility. The unsecured revolving credit facility (BOA Revolving LOC) is in the amount of $42,000,000 and will be available for a period of five years, until 2021. The BOA Revolving LOC can be paid down and re-utilized over the term of the loan, is at a market-rate-based Federal Funds Rate and Eurodollar Rate, when applicable, and is sufficiently sized to allow for GNI to provide funds pursuant to intercompany notes to Frontier and the other regulated operating utilities.

(b) GNI Term Loan. The GNI Term Loan will be placed by Merrill Lynch, Pierce, Fenner & Smith (the lending party(ies) being the Note Purchaser(s)) for the issuance and sale of up to $50,000,000 in senior debt securities. According to the Second Affidavit of James Sprague, it will have a term of twelve years, and GNI has locked-in an interest rate of 4.23%, if closed by October 27, 2016. This pricing will be incorporated into the Term Debt Note between Frontier and GNI for the $8.7 million portion of Frontier's financing. Frontier states that in the course of the negotiations with the Note Purchasers, there may be some minor changes from the precise terms of the sample Note Purchase Agreement that was filed as Exhibit 6 to the Application. However, these changes will not affect the terms of the Term Debt Note with Frontier, which will be in substantially the same form as the document filed as Exhibit 9 to the Application.

(c) SAP Loan. The loan from Banc of America Leasing & Capital, LLC is in the amount of $7,000,000, payable over a forty-eight (48) month-period. The SAP Loan will be used to refinance multiple other loan obligations, including its capital lease obligation with Varilease, Inc., for the acquisition of the SAP Operating Platform software, licensing, and implementation used by all of the subsidiaries of GNI. The SAP software, license, and installation would serve as collateral for this loan.

The BOA Revolving LOC, the GNI Term Loan, and the SAP Loan are collectively referred to as the BOA Refinancing Package.

22. According to the Affidavit of James Sprague, the allocation and apportionment of the total debt among the GNI subsidiaries is based upon necessary and appropriate debt/equity limitations, company financing needs, growth projections, and forecasts. According to the Application, the financing for each of GNI's regulated utilities in Maine, Montana, Ohio, and North Carolina (the respective Financing Packages) will need to be approved by the respective regulatory authorities in each state where the utilities operate.

23. According to the Application, neither Frontier nor any of GNI's other regulated utilities will have any obligation for the activities, borrowings, or guarantees provided by any other GNI company under the BOA Refinancing Package. In the unlikely event of a default in repayment of any other company's specific obligations, neither GNI nor BOA can pursue or demand repayment beyond the defaulting party's specific and limited borrowing.

24. According to the Application, Frontier will not guarantee the BOA Refinancing Package, and it will not be an obligor of any obligations directly to BOA. The BOA Refinancing Package is unsecured by assets of Frontier and the other regulated utilities, with the exception of the SAP accounting system, software, and licenses, which are being financed by and, therefore, serve as collateral for the SAP Loan. Thus, in the event of default, neither BOA nor the holder of the long-term senior debt securities will have any recourse against the utility assets of Frontier.

25. Frontier's financing for which approval is requested will consist of the following three components (collectively Frontier 2016 Financing):

(a) The Intercompany Revolving Loan Agreement, which is an agreement that Frontier will enter into with GNI, will provide Frontier access to $7.2 million as a revolving line of credit under the same terms and at the same interest rate applicable to the BOA Revolving LOC.

(b) The Term Debt Note is an intercompany long-term note in the amount of $8.7 million that Frontier will issue to GNI to refinance its current debt obligations under the same terms and at the same interest rate applicable to the GNI Term Note. The term and pricing of the GNI Term Note will be incorporated into Frontier's Term Debt Note, and thus will have an interest rate of 4.23% and a term of twelve years if closed by October 27, 2016.

(c) The SAP Loan Agreement is a shorter term intercompany note payable by Frontier to GNI in the amount of $1,075,000 to finance a portion of the SAP Operating System that has been installed and is being used by Frontier. The SAP Loan Agreement will also provide Frontier with additional funding from the SAP Loan under the same terms and at the same interest rate applicable to the SAP Loan.

26. According to the Application, there will be no cross-default, cross-collateralization, or cross-border obligations by or to Frontier under the Intercompany Revolving Loan Agreement, the Term Debt Note, or the SAP Loan Agreement.

27. Frontier asserts that the Frontier 2016 Financing should be approved by the Commission since the assumption of liabilities in connection with the debt refinancing is (i) for some lawful object within the corporate purposes of the public utility, (ii) is compatible with the public interest, (iii) is necessary or appropriate for or consistent with the proper performance by such utility of its service to the public and will not impair its ability to perform that service, and (iv) is reasonably necessary and appropriate for such purpose.

PUBLIC STAFF RECOMMENDATION

28. The Public Staff believes that the Frontier 2016 Financing, as provided by GNI, provides tangible benefits for Frontier's ratepayers without some of the accompanying obligations that are typically part of standalone financing from independent lenders. Such benefits are as follows:

(a) If Frontier had obtained standalone financing, the Public Staff believes that the pledging of assets required for such financing would have created a degree of risk for Frontier ratepayers if the Company were to default on its obligation. Since the agreement between BOA and GNI does not require Frontier to provide a guarantee or pledge any assets, Frontier's assets will not be placed at risk and are isolated from being used for the obligations and rights of GNI's other subsidiaries. The Public Staff believes that this isolation is a benefit to Frontier's ratepayers without an accompanying obligation.

(b) Standalone financing would require Frontier to provide regular financial statements and be subject to regular audits by the lender, which would have resulted in additional costs. The Public Staff notes that these costs would have increased Frontier's operating expenses and the cost of providing natural gas utility service to Frontier's ratepayers. In addition, the issuance of debt at the holding company level allows for allocation of debt issuance expenses across a greater number of customers.

(c) By obtaining financing at the holding company level, GNI is able to replace current debt held by EWI with less expensive debt and with more favorable and less restrictive terms. The larger size of the loan and the creditworthiness of GNI allows Frontier to receive more favorable interest rates, terms, and conditions. The interest rate on a 12-year term note has been locked in at 4.3%, while the interest rate on the debt being refinanced is 6.16%. This reduced borrowing cost with the longer term 12-year note is expected to improve GNI's and Frontier's creditworthiness, which is beneficial to Frontier's ratepayers.

29. The Public Staff concluded that the debt refinancing meets the requirements of G.S. 62-161(b) and recommends that the Commission conditionally approve the GNI Refinancing Package and authorize Frontier to execute the Intercompany Revolving Loan Agreement, the Term Debt Note, and the SAP Loan Agreement, so long as Frontier satisfies certain conditions recommended by the Public Staff.

30. The Public Staff recommended that Frontier file with the Commission the fully executed financing agreements between GNI and BOA, and the fully executed Intercompany Revolving Loan Agreement, Term Debt Note, and the SAP Loan Agreement payable to GNI within ten (10) days of their execution and no later than ninety (90) days following the date of the Commission's order in this docket.

31. The Public Staff recommended that Frontier enter into separate support services agreements with GNI and NIC, and that the support services agreements include a list of all requested services and the cost allocation basis by category or tier that will be used to directly assign or allocate expenditures to Frontier from each holding company. The Public Staff also recommended that Frontier file the new support services agreements with the Commission for approval no later than thirty (30) days from the approval of the corporate reorganization.

32. The Public Staff further recommended that if Frontier plans to take service or provide service to another subsidiary of GNI or NIC, then Frontier should execute a new support services agreement with each such subsidiary and file the agreements with the Commission pursuant to G.S. 62-153.

33. The Public Staff recommended that Frontier file notices with the Commission within ten (10) days after Energy West and Frontier Utilities have been dissolved and NIC has been created.

34. As the business operations of Independence Oil, a North Carolina limited liability company and unregulated subsidiary of GNI, have ceased and Frontier is hopeful that the legal entity will be dissolved in the near future, the Public Staff recommended that Frontier file notice with the Commission within ten (10) days after Independence Oil has been dissolved.

35. The Public Staff recommended that Frontier file with the Commission a chart of the new organizational structure of GNI and its subsidiaries within ten (10) days of the execution of the final document(s) needed to effectuate the reorganization described herein.

36. The Public Staff recommended that Frontier work with the Public Staff to provide a revised annual affiliated transaction report format beginning with the first annual report due after approval of the corporate reorganization.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

The corporate reorganization requested in the Application is justified by the public convenience and necessity as required by G.S. 62-111(a) and should be approved.

Pursuant to G.S. 62-153, the Intercompany Revolving Loan Agreement, Term Debt Note and SAP Loan Agreement should be accepted for filing as affiliate agreements, and Frontier should be authorized to make payments under those agreements, subject to the Regulatory Conditions and other provisions of this Order.

The Commission has the authority pursuant to G.S. 62-162 to approve a debt issuance and a guarantee of debt upon such terms and conditions as the Commission may deem necessary or appropriate in the circumstances.

Based upon the foregoing Findings of Fact and the entire record in the proceeding, the Commission is of the opinion and so concludes that the Frontier 2016 Financing will be:

(a) For a lawful object within Frontier's corporate purposes;
(b) Compatible with the public interest;
(c) Necessary and appropriate for and consistent with the proper performance by Frontier of its service to the public and that it will not impair its ability to perform that service; and
(d) Reasonably necessary and appropriate for such services.

The Commission further concludes that these approvals should be conditioned upon Frontier's compliance with the Regulatory Conditions attached as Appendix A and incorporated herein by reference.

IT IS, THEREFORE, ORDERED as follows:

1. That the corporate reorganization described herein is conditionally approved, provided that Frontier complies with the Regulatory Conditions attached hereto as Appendix A;

2. That Frontier shall file with the Commission a chart of the new organizational structure of GNI and its subsidiaries within ten (10) days of the execution of the final document(s) needed to effectuate the reorganization described herein;

3. That Frontier shall file notices with the Commission within ten (10) days after Energy West has been dissolved, after Frontier Utilities has been dissolved, and after NIC has been created;

4. That Frontier shall file notice with the Commission within ten (10) days after Independence Oil has been dissolved;

5. That the Frontier 2016 Financing described herein is conditionally approved and Frontier is conditionally authorized to execute and deliver the Intercompany Revolving Loan Agreement, the Term Debt Note, and the SAP Loan Agreement substantially in the forms previously filed in this docket, provided that Frontier complies with the Regulatory Conditions attached hereto as Appendix A;

6. That Frontier is conditionally authorized to execute and deliver such documents and to perform such other acts that may be or may become necessary or appropriate to facilitate the financing transactions described herein;

7. That Frontier shall file copies of the fully executed BOA Revolving LOC, GNI Term Loan, SAP Loan, Intercompany Revolving Loan Agreement, Term Debt Note, and SAP Loan Agreement within ten (10) days of their execution and no later than ninety (90) days following the date of this Order;

8. That the Intercompany Revolving Loan Agreement, the Term Debt Note, and the SAP Loan Agreement filed by Frontier in this docket are accepted for filing pursuant to G.S. 62-153 and the payment of compensation from Frontier to GNI pursuant to G.S. 62-153 is authorized;

9. That Frontier shall enter into separate support services agreements with GNI and NIC, and that the support services agreements shall include a list of all requested services and the cost allocation basis by category or tier that is intended to be used to directly assign or allocate expenditures to Frontier from each holding company, and that Frontier shall file the new support services agreements with the Commission for acceptance pursuant to G.S. 62-153 no later than thirty (30) days from the closing of the corporate reorganization;

10. That if Frontier plans to take service from or provide service to another subsidiary of GNI or NIC, then Frontier shall execute a new support services agreement with each such subsidiary and file the agreement(s) with the Commission for acceptance pursuant to G.S. 62-153;

11. That Frontier shall work with the Public Staff to develop a revised annual affiliated transaction report format;

12. That Frontier shall comply with the Regulatory Conditions attached hereto as Appendix A, which shall replace and supersede those previously ordered in Docket No. G-40, Subs 67 and 105, and those dockets shall be closed;

13. That nothing in this Order shall be construed to deprive the Commission of its regulatory authority under law, including its right to review and adjust, if deemed appropriate, the Company's cost of capital or expenses in future ratemaking proceedings for the effects of these transactions. Furthermore, for ratemaking purposes, the authority granted by this Order is without prejudice to the right of any party to take issue with the cost of capital, cost of debt expenses and provisions of the affiliated agreements in question in a future proceeding;

14. That Frontier shall file with the Commission copies of all orders from the state commissions in Montana, Ohio, and Maine related to the corporate reorganization of GNI and its subsidiaries and the respective Financing Packages of each of GNI's utilities within ten (10) days of issuance;

15. That this docket shall remain open for the purpose of receiving the filings required by the Regulatory Conditions; and

16. That any future application filed by Frontier pursuant to G.S. 62-160, et seq., and Commission Rule R1-16 for the purpose of replacing the 2016 Financing shall include information describing Frontier's continuing effort to obtain standalone financing, and information demonstrating that the proposed financing will provide the best tangible benefits for Frontier's ratepayers.

ISSUED BY ORDER OF THE COMMISSION.
This the 2nd day of August, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Chairman Edward S. Finley, Jr., did not participate in this decision.

APPENDIX A
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DOCKET NO. G-40, SUB 133
REGULATORY CONDITIONS

These Regulatory Conditions set forth commitments made by Frontier Natural Gas Company, LLC (Frontier) as a precondition of approval of the application by Frontier pursuant to G.S. 62-111, G.S. 62-160, et seq., and Commission Rule R1-16, for Conditional Approvals of Corporate Reorganization and Debt Refinancing filed in this docket on February 17, 2016. These Regulatory Conditions become effective upon closing of the Frontier 2016 Financing, as defined herein.

For purposes of these Regulatory Conditions, Energy West Incorporated is referred to as "Energy West," Gas Natural Inc. is referred to as "GNI", New Intermediate Company is referred to as "NIC," the North Carolina Utilities Commission is referred to as "the Commission," and the Public Staff – North Carolina Utilities Commission is referred to as "the Public Staff." "Related Party or Parties" shall include officers, directors, five percent (5%) beneficial holders of GNI, Frontier, NIC, close family members of these individuals, and companies owned or controlled by such persons. Bank of America, N.A. is referred to as "BOA." "BOA Refinancing Package" shall refer collectively to GNI's financing arrangement with BOA, which consists of: (1) the revolving credit facility ("BOA Revolving LOC"), (2) the term loan placed by Merrill Lynch, Pierce, Fenner & Smith (the lending party(ies) being the "Note Purchaser(s)") ("GNI Term Loan"), and (3) the loan from Banc of America Leasing & Capital, LLC ("BAL") to refinance the acquisition of the SAP Operating Platform software, licensing, and implementation ("SAP Loan"). Frontier's allocated portion of the BOA Refinancing Package from GNI shall be collectively referred to as the "Frontier 2016 Financing" and consists of (1) the intercompany loan agreement between GNI and Frontier ("Intercompany Revolving Loan Agreement"), (2) the long-term intercompany note payable by Frontier to GNI ("Term Debt Note"), and (3) the shorter term intercompany note payable by Frontier to GNI ("SAP Loan Agreement"). "Affiliate" shall mean GNI and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by GNI. For purposes of these Regulatory Conditions, GNI and each business entity so controlled by it are considered to be Affiliates of Frontier.

1. **Utilization of the Frontier 2016 Financing.** Frontier may utilize the Frontier 2016 Financing for the following purposes: refinancing of Frontier's current outstanding debt obligations, including debt related to acquisition of the SAP accounting system software, licenses, and installation; short-term funding of capital additions and system expansions; funding of system betterment and replacements; payment for working capital needs (*e.g.*, paying bills and paying for gas supply); payment for support services benefitting Frontier; and payment for non-regulated activities that benefit Frontier, if approved by the Commission. GNI, NIC, or any other Affiliate of Frontier may not utilize any funds provided under the Frontier 2016 Financing unless approved by the Commission.

2. **Intercompany Revolving Loan Agreement and SAP Loan Agreement Reports.** Within forty-five (45) days following the end of each month, Frontier shall

file a report of the principal amounts outstanding at the beginning of the month, drawn during the month, repaid during the month, and outstanding at the end of each month on the Intercompany Revolving Loan Agreement and the SAP Loan Agreement.

Prior to any quarterly dividend payments made by Frontier to GNI (directly or through NIC) (generally which occur at the end of each quarter), Frontier shall ensure that its access to funds under the Intercompany Revolving Loan Agreement are not impaired and, further, that if Frontier's access becomes impaired, it shall submit a report to the Commission within three (3) business days of learning of such impairment describing the circumstances surrounding the same and shall suspend any dividend payments to GNI (directly or through NIC) until after such time as Frontier regains access to the Intercompany Revolving Loan Agreement.

3. **BOA Revolving LOC Reports**. Within forty-five (45) days following the end of each quarter, Frontier shall file a report of the principal amounts outstanding on the BOA Revolving LOC at the beginning of that quarter and outstanding at the end of that quarter for each GNI subsidiary.

4. **Default or Violation of BOA Refinancing Package Terms**. Frontier shall notify the Commission of any default or violation of the terms of the BOA Refinancing Package that could have an adverse effect on Frontier's ability to draw on its Intercompany Revolving Loan Agreement, Term Debt Note, or SAP Loan Agreement. Such notification shall be filed within ten (10) days of notice from BOA or the Note Purchaser(s) and should include a plan for remedying the default or violation(s).

5. **Default or Violation of Frontier 2016 Financing Terms**. Frontier shall notify the Commission of any default or violation of the terms of the Frontier 2016 Financing that could have an adverse effect on Frontier's ability to draw on its Intercompany Revolving Loan Agreement, Term Debt Note, or SAP Loan Agreement. Such notification shall be filed within ten (10) days of notice from GNI and should include a plan for remedying the default or violation(s).

6. **Distributions to GNI and NIC.** Frontier shall not pay to GNI (directly or through NIC) any distribution exceeding 100% of Frontier's net income calculated on a two-year rolling average basis. In addition, Frontier shall limit cumulative distributions paid to GNI (directly or through NIC) subsequent to closure of the Frontier 2016 Financing to (i) the amount of its retained earnings on the day prior to the closure of the Frontier 2016 Financing, plus (ii) any future earnings recorded by Frontier subsequent to closure of the Frontier 2016 Financing. Frontier shall not make any distributions to any Affiliates other than NIC and GNI, unless approved by the Commission. The Commission retains the right to impose future limitations on the distributions of Frontier.

7. **Obligations with Affiliates and Related Parties**. Frontier will not make a loan to any Affiliate or Related Party, issue a guarantee for an obligation of any Affiliate or

Related Party, or otherwise assume any obligation of any Affiliate or Related Party without prior Commission approval.

8. **Acquisition / Expansion of Utilities.** The funds that Frontier utilizes from the Frontier 2016 Financing will not be used for the acquisition or expansion of utilities located outside the State of North Carolina, unless the use of the funds for such acquisition or expansion is approved by the Commission.

9. **Notice of Certain GNI Investments.** Frontier shall file a notice with the Commission, subsequent to GNI Board approval and as soon as practicable following any public announcement, of any new investment in a regulated utility or a non-regulated business that represents ten percent (10%) or more of GNI's book capitalization.

10. **Notice of Certain NIC Investments.** Frontier shall file a notice with the Commission, subsequent to NIC Board approval and as soon as practical following any public announcement, of any new investment in a regulated utility.

11. **Notice of Level of Non-Utility Investment by GNI.** Frontier shall notify the Commission within ten (10) days following the filing of the GNI 10K or 10Q reports to the Securities and Exchange Commission for which GNI reports in its audited financial statements assets in its operations other than regulated utilities that are in excess of 15% of its consolidated total assets of GNI. For purposes of this computation, companies subject

to the regulation by a state utilities regulatory commission are considered regulated utilities.

12. **Notice by Frontier of Default or Bankruptcy of Affiliate or Related Party.** If an Affiliate or Related Party of Frontier experiences a default on an obligation that is material to GNI or files for bankruptcy, and such bankruptcy is material to GNI, Frontier shall notify the Commission in advance, if possible, or as soon as possible but not later than ten (10) days from such event. For purposes of this section, materiality shall be any default or bankruptcy that would be required to be disclosed in the audited financial statements of GNI.

13. **Annual Financing Forecasts.** By the end of the first quarter of each calendar year, Frontier will provide to the Public Staff annual financing forecasts in the format of pro forma financial statements with supporting assumptions that cover a prospective five year period for repayment of the principal at the maturity date and the periodic interest payments of the Term Debt Note payable to GNI by Frontier. The annual financing forecasts shall cover the appropriate capitalization types, amounts, ratios, and cost rates of short-term and long-term financings that Frontier intends to execute in order to provide adequate service. These forecasts shall be confidential and subject to a Non-Disclosure Agreement between Frontier and the Public Staff.

14. **Revised Affiliate Transactions Report.** Frontier shall file an annual report of affiliated transactions with the Commission in a revised format prescribed by the Commission. The first such report on affiliated transactions shall be filed on

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March 31, 2017, for activity through December 31, 2016, and annually thereafter on March 31.

15. **Revised GS-1 Report Format.** Effective with the filing for the quarter ending March 31, 2017, Frontier will begin utilizing a revised NCUC GS-1 Earnings Surveillance Report format that is similar to the format of the ES-1 Earnings Surveillance Report that is submitted to the Commission by the electric utilities.

16. **Post-Closing Financial Information.** Frontier shall file pre- and post-closing balance sheets and the journal entries, including relevant descriptions and disclosures for the transactions recorded, for GNI, NIC, and itself concurrent with GNI's first regularly scheduled 10Q or 10K filing with the Securities and Exchange Commission.

17. **Regulatory Staffing.** Frontier shall maintain sufficient, adequately trained personnel to ensure that regulatory reporting requirements are complied with in a timely and accurate manner, including the reporting requirements listed on Attachment A hereto.

18. **Natural Gas Bond Fund Report.** Frontier shall file a Natural Gas Bond Fund Economic Feasibility Report on November 30, 2017, and every two years thereafter. Frontier shall utilize the same report format as has been filed by Frontier in Docket No. G-40, Sub 67.

19. **Service Company Formation.** Frontier shall notify the Commission of its plans or the plans of any Affiliate to form a service company at least 60 days prior to the formation of such a service company. In addition, Frontier shall notify the Commission posthaste in the event Frontier or any Affiliate receives a formal request to form such a service company. Frontier shall bear the full risk of any preemptive effects and consequences related to the formation of such a service company and will take all such actions as the Commission finds necessary and appropriate to hold North Carolina ratepayers harmless from any preemption.

20. **Allocation Methods and Procedures.** Frontier shall file a description of the methods and procedures used to allocate and assign costs to and from Affiliates within 60 days of the closing. Frontier shall notify the Commission and Public Staff of any plans to modify its corporate cost allocation methods and procedures at least 90 days prior to implementation of the change.

21. **Access to Books and Records.** In accordance with North Carolina law, the Commission and the Public Staff shall continue to have access to the books and records of Frontier, GNI, NIC, and other Affiliates.

22. **Changes to Board of Directors or Management.** Frontier shall notify the Commission within ten (10) days of any changes to the Board of Directors or management of GNI, NIC, or Frontier.

23. **Compliance with Sub 124 Stipulation.** Frontier shall continue to remain bound by the terms and conditions of the Stipulation entered into with the Public Staff on June 27, 2014, as amended on September 14, 2015, and filed in Docket

No. G-40, Sub 124, to the extent that those terms and conditions are ongoing and have not previously been satisfied.

Attachment A

FRONTIER NATURAL GAS COMPANY, LLC
REGULATORY REPORTING REQUIREMENTS

Item #	Description	Frequency	Deadline	Requirement	Docket/Statute/Rule Reference
1.	FERC Form 2 Report	Annual	120 days	One copy filed with PS Acctng. Div. Copies provided to PS Natural Gas Div and NCUC Fiscal Management Div.	Rule R6-5(9)
2.	Financial & Operating Report	Monthly	45 days	Provided to PS Acctng. Div.	G.S. 62-36. Official NCUC Request.
3.	Deferred Account Report	Monthly	45 days	Filed w/Chief Clerk. Detailed workpapers provided to PS Acctng. Div.	Rule R1-17(k)(5)(c)
4.	Annual Review Of Gas Costs Filing	Annually	October 1	Filed w/Chief Clerk.	G.S. 62-133.4(c) and Rule R1-17(k)
5.	Daily Dispatch Report for last day of month	Monthly	3 days	Filed with Chief Clerk and provided to PS Natural Gas Div.	Rule R6-5(7)
6.	Source of Supply, Sales, Customers and Transportation	Monthly	45 days	Filed w/Chief Clerk.	G-100, Sub 24
7.	Customer Bill Formats	Each Time Changed		Filed w/Chief Clerk and provided to PS Natural Gas Div.	Rule R6-5(3)
8.	Natural Gas Bond Fund Economic Feasibility Report	Biennially	November 30	Filed w/Chief Clerk.	Rule R6-93
9.	Meter Report	Monthly	30 days	Filed w/Chief Clerk and provided to PS Natural Gas Div.	Rule R6-5(7)b
10.	Contracts with Customers	Each Occurrence	Prior to effective date	If term > 1 year, then filed w/ Chief Clerk for approval. If term < 1 year, then provide to PS Acctng. Div. in Annual Review.	Rule R6-5(2)

Attachment A

FRONTIER NATURAL GAS COMPANY, LLC
REGULATORY REPORTING REQUIREMENTS

Item #	Description	Frequency	Deadline	Requirement	Docket/Rule Reference
11.	Incentive Plans	Each Program	Prior to Offer	Filed w/Chief Clerk. Approval required.	G.S 62-140(c), Rule R6-95
12.	Regulatory Fee Report	Quarterly	45 days	Filed w/NCUC Fiscal Management Div.	Rule R15-1
13.	Notice of Supplier Refunds Received	Each Occurrence	1 week	Filed w/Chief Clerk.	G-100, Sub 57
14.	Construction Budget	Annual		Filed w/Chief Clerk.	Rule R6-5(6)
15.	GS-1 Report 1/	Quarterly	45 days	Provided to NCUC Operations Div. and PS Acctng. Div.	G.S. 62-36. NCUC Official Request by letter dated April 25, 1972.
16.	Gas Pipeline Safety Reports	Various	Various	Filed w/Chief Clerk, otherwise contact the NCUC Pipeline Safety Div.	G.S. 62-50, Rules Chapter 6, and G-100, Sub 92
17.	Annual Affiliated Transactions Report	Annual	March 31	Filed w/Chief Clerk.	NCUC Final Order Docket No, G-40, Sub 133, Attachment A.

1/ Frontier will begin filing GS-1 Reports as of December 31, 2015, and will file on a quarterly basis going forward.

DOCKET NO. G-9, SUB 696

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request of Piedmont Natural Gas Company,	)	ORDER APPROVING
Inc., for Expedited Approval of a Waiver of	)	REQUEST FOR
Late Payment Penalties for Certain Customers	)	TEMPORARY WAIVER

BY THE COMMISSION: On October 20, 2016, Piedmont Natural Gas Company, Inc. (Piedmont or the Company), filed a request with the Commission for a temporary waiver of the application of late-payment penalties provided for in various Commission-approved rate schedules for Piedmont customers located in North Carolina counties impacted by Hurricane Matthew. Piedmont requested expedited action on this request in order to implement this waiver as soon as practicable.

In support of this request, Piedmont stated that Hurricane Matthew, which crossed the eastern coast of North Carolina on October 7-8, 2016, resulted in significant and, in some cases, unprecedented flooding and severely disrupted normal life for residents in the Company's service territory in the affected areas. In many cases, customers were forced to evacuate homes and businesses until flooding subsided and now are faced with significant challenges to clean-up and rebuild flood-damaged properties.

Piedmont stated that the most hard hit areas within Piedmont's North Carolina service territory include those served from the following Piedmont district offices: Rockingham, Fayetteville, Wilmington, Goldsboro, New Bern, Tarboro, and Elizabeth City. Piedmont stated that it recognizes that customers within these service districts may, in many cases, be facing challenges related to flood damage and recovery that are a higher priority than the timely payment of utility bills. Piedmont wants to support customer recovery efforts by temporarily waiving the 1% monthly late payment penalty provided for in Piedmont's various Commission-approved rate schedules for these customers.

Accordingly, Piedmont requested authorization from the Commission to implement such a waiver effective upon approval by the Commission and to maintain this waiver through the subsequent two billing cycles for each such impacted customer.

Piedmont conferred with the Public Staff prior to filing the request. The Public Staff presented this matter at the Commission's Regular Staff Conference on October 24, 2016. The Public Staff stated that it believes that the requested temporary waiver is consistent with the public interest and that good cause exists to authorize Piedmont to implement the waiver as proposed.

Based upon the foregoing, the Commission finds and concludes that the requested waiver is in the public interest and that Piedmont should be authorized to implement the waiver effective on the date of this order.

IT IS, THEREFORE, ORDERED as follows:

1. That Piedmont is hereby authorized, on a temporary basis, to waive the application of late-payment penalties for customers located in its North Carolina counties impacted by Hurricane Matthew through the subsequent two billing cycles for each affected customer

ISSUED BY ORDER OF THE COMMISSION.
This the ___24th___ day of October, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

NATURAL GAS – RATE INCREASE

DOCKET NO. G-5, SUB 565

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of	)	ORDER APPROVING RATE
North Carolina, Inc. for a General Increase	)	INCREASE AND INTEGRITY
in its Rates and Charges	)	MANAGEMENT TRACKER

HEARD: Gaston County Courthouse, Gastonia, North Carolina, on August 23, 2016; Buncombe County Courthouse, Asheville, North Carolina, on August 24, 2016; Government Center, Statesville, North Carolina, on August 25, 2016; and Commission Hearing Room 2115, Dobbs Building, Raleigh, North Carolina, on August 29 and 30, 2016

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Chairman Edward S. Finley, Jr., Commissioners Bryan E. Beatty, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

Mary Lynne Grigg, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

William R. Pittman, Post Office Box 706, Raleigh, North Carolina 27602

B. Craig Collins, Associate General Counsel, SCANA Corporation, MC C222, 220 Operation Way, Cayce, South Carolina 29033-3701

For the Using and Consuming Public:

Gina C. Holt, William Grantmyre, and Heather Fennell, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

NATURAL GAS – RATE INCREASE

For Blue Ridge Paper Products, Inc., d/b/a Evergreen Packaging:

Adam Olls and Jeffrey D. McKinney, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, NC 27601

BY THE COMMISSION: On February 17, 2016, Public Service Company of North Carolina, Inc. (PSNC or the Company), filed its Letter of Intent to File for authority to adjust and increase its retail natural gas rates and charges pursuant to Commission Rule R1-17(a).

On March 3, 2016, the Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene, which was granted by the Commission on March 7, 2016.

On March 31, 2016, PSNC filed an Application for a General Rate Increase (Application) seeking a general increase in and revisions to its rates and charges, implementation of a new Integrity Management Tracker mechanism, implementation of new depreciation rates, updates and revisions to the Company's service regulations and tariffs, and proposed funding for gas distribution research activities conducted by the Gas Technology Institute. Included with its Application was information and data required by NCUC Form G-1, pursuant to Commission Rule R1-17(b)(12). In addition, the Application was supported by the direct testimony and exhibits of Company witnesses: D. Russell Harris, President and Chief Operating Officer of PSNC and President of Gas Operations for South Carolina Electric & Gas Company (SCE&G); Jimmy E. Addison, Executive Vice President and Chief Financial Officer of PSNC, SCANA Corporation, and the other subsidiaries of SCANA; George B. Ratchford, Vice President – Gas Operations for PSNC; Sharon D. Boone, Business Unit Controller of PSNC; James A. Spaulding, Financial Accounting Manager for PSNC; Candace A. Paton, Rates & Regulatory Manager for PSNC; Rose M. Jackson, General Manager – Supply & Asset Management for SCANA Services, Inc.; Robert B. Hevert, Partner of ScottMadden, Inc.; and John J. Spanos, Senior Vice President of Gannett Fleming Valuation and Rate Consultants, LLC.

By Order Scheduling Investigation and Hearing, Suspending Proposed Rates, Establishing Intervention and Testimony Dates and Discovery Guidelines, and Requiring Public Notice issued April 26, 2016, and corrected in the Errata Order issued on April 27, 2016 (collectively, Scheduling Order), the Commission declared the Company's Application to be a general rate case pursuant to G.S. 62-137 and suspended the proposed rates for a period of up to 270 days from and after May 1, 2016. In addition, the Scheduling Order set the matter for public witness and expert witness hearings, required the Company to give notice of the hearings, established discovery guidelines, and established a date for petitions to intervene and for the prefiling of direct testimony by the Public Staff and other intervenors, and established a date for the filing of rebuttal testimony by the Company.

On May 31, 2016, Blue Ridge Paper Products Inc. d/b/a Evergreen Packaging (Evergreen) filed a Petition to Intervene. Evergreen's Petition was granted by Commission Order dated June 2, 2016.

On June 13, 2016, the Attorney General filed its Notice of Intervention pursuant to G.S. 62-20. Also on this date, PSNC, on behalf of attorney B. Craig Collins, filed a Motion for Admission to Practice pursuant to G.S. 84-4.1 seeking an order from the Commission allowing Mr. Collins to appear before the Commission on behalf of PSNC in this proceeding. By Order dated June 14, 2016, the Commission granted the request of Mr. Collins for admission pro hac vice in the present docket.

On June 16, 2016, PSNC filed affidavits of publication of public notice.

Between June 22, 2016 and September 21, 2016, the Commission received four consumer statements of position regarding PSNC's rate increase proposal.

On June 23, 2016, PSNC filed its Certification that it had provided Notice of Hearing to each of its customers.

On August 8, 2016, the Public Staff filed a Motion for Extension of Time in which it sought an extension of the dates for filing Public Staff, Intervenor, and Company rebuttal testimony. The Commission approved a shortened extension of time by Commission Order dated August 9, 2016.

On August 12, 2016, PSNC and the Public Staff filed a Joint Motion for Extension of Time in which the parties requested the Commission to reconsider its prior order and grant the extension period originally requested. The Commission approved the extension by Order dated August 17, 2016. On August 17, 2016, the Public Staff by verbal motion requested that the Commission grant the Public Staff and Intervenors an extension until noon of the following day within which to file their testimony. This motion was granted by Order dated August 17, 2016.

On August 18, 2016, PSNC, CUCA, Evergreen, and the Public Staff (Stipulating Parties) filed a Partial Stipulation resolving most of the issues between these parties. On the same date, the Public Staff filed the direct testimony and exhibits of James G. Hoard, Director, Accounting Division; Michelle M. Boswell, Staff Accountant, Natural Gas Section, Accounting Division; Julie G. Perry, Supervisor of the Natural Gas Section of the Accounting Division; and Jan A. Larsen, Director of the Natural Gas Division.

On August 22, 2016, PSNC filed a Motion for Extension of Time in which it sought a two-day extension of time for PSNC to file a list of hearing witnesses and estimate of cross-examination times. On the same date, the Stipulating Parties filed a corrected page 7 of the Partial Stipulation.

On August 23, 2016, the Commission issued an Order granting PSNC's request for an extension of time to file the witness list and cross-examination estimate.

On August 24, 2016, PSNC filed the supplemental testimony of Robert B. Hevert. On the same date, PSNC filed its Witness List and Motion to Excuse Witnesses, wherein the Company, after consulting with all of the parties of record, provided the proposed order of appearance of witnesses and estimates of cross-examination times. PSNC also requested in the filing that Company witnesses Harris, Boone, Spaulding, Jackson, and Spanos and Public Staff witness Larsen be excused from appearing at the expert witness hearing, since none of the parties had questions for these witnesses. PSNC also filed a Motion for Extension of Time requesting an extension until noon on August 25, 2016, for PSNC to file its rebuttal and supplemental testimony.

On August 23, 2016, the matter came on for a public witness hearing in Gastonia as scheduled. No person appeared to testify as a public witness.

On August 24, 2016, a public witness hearing was held in Asheville as scheduled. No person appeared to testify as a public witness.

By Order dated August 25, 2016, the Commission granted the Company's extension of time to file rebuttal and supplemental testimony.

On August 25, 2016, PSNC filed the supplemental testimony of Candace A. Paton, the rebuttal testimony of Jimmy E. Addison, and the rebuttal testimony of Candace A. Paton. On the same date, the Stipulating Parties filed an Amended Partial Stipulation. The Public Staff also filed an Amended Exhibit C, which amended page 2 of Public Staff witness Larsen's original filed Exhibit C in support of the Amended Partial Stipulation.

Also on August 25, 2016, a public witness hearing was held in Statesville as scheduled. No person appeared to testify as a public witness.

On August 29, 2016, the Commission issued an Order Denying in Part Motion to Excuse Witnesses, in which the Commission excused only Company witnesses D. Russell Harris, James A. Spaulding, and John J. Spanos from attending the expert witness hearing. In addition, the Commission accepted their testimony and exhibits into evidence.

Also on August 29, 2016, the Stipulating Parties filed a Stipulation and Exhibits by and between the Stipulating Parties resolving all issues between them. On the same date, PSNC filed the supporting supplemental testimony and Exhibits of Candace A. Paton, and the Public Staff filed witness Boswell's Revised Exhibit 1 in support of the Stipulation.

On August 29, 2016, a public witness hearing was held in Raleigh as scheduled. No person appeared to testify as a public witness.

On August 30, 2016, the Commission convened the final public witness hearing and the expert witness hearing in Raleigh as scheduled. No person appeared to testify as a public witness. On the same date, the Stipulating Parties filed an Amended Stipulation, which made corrections to the Stipulation filed on the previous day.

At the hearing, the Company reported, and the Stipulating Parties confirmed, that following substantial negotiations a comprehensive agreement had been reached between the Company, the Public Staff, CUCA, and Evergreen, and that this agreement resolved all issues in the case as between those parties, and that this agreement was reflected in the Amended Stipulation.

At the hearing, the various prefiled direct and supplemental testimony and exhibits of the following Company witnesses were offered and accepted into evidence by the Commission: D. Russell Harris, Jimmy E. Addison, Robert B. Hevert, John J. Spanos, George B. Ratchford, Sharon D. Boone, James A. Spaulding, Candace A. Paton, and Rose M. Jackson. Company witnesses Addison, Hevert, Ratchford, Boone, Paton, and Jackson testified at the hearing. The various prefiled direct testimony and exhibits of the following Public Staff witnesses were offered and accepted into evidence by the Commission: Michelle Boswell, Julie Perry, and Jan Larsen. Public Staff witnesses Boswell and Larsen testified at the hearing.

On September 1, 2016, the Public Staff filed two late-filed exhibits pertaining to the supporting workpapers and the calculation of the lead-lag working capital reflected in the Amended Stipulation pursuant to Commission request.

On September 6, 2016, PSNC filed Late-Filed Exhibits B and D and Revised Exhibit C to the Amended Stipulation.

On September 14, 2016, PSNC filed a letter with the Commission stating that it had reviewed the two late-filed exhibits filed by the Public Staff on September 1, 2016, which included work papers with updated adjustments to working capital, and agreed that the exhibits accurately reflect the information that Presiding Commissioner Brown-Bland requested PSNC to provide.

On October 10, 2016, PSNC and the Public Staff filed a Joint Proposed Order.

On October 10, 2016, the Attorney General filed a post-hearing Brief.

On October 14, 2016, PSNC filed a motion requesting leave to file a Reply Brief, and filed its proposed Reply Brief.

On October 19, 2016, the Attorney General filed a motion for leave to file a Response Brief, and filed his Response Brief.

The Commission hereby accepts the filing of PSNC's Reply Brief and the Attorney General's Response Brief.

Based upon the verified Application, the testimony and exhibits received into evidence at the hearings, the Amended Stipulation, the late-filed exhibits, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

1. PSNC is a corporation organized and existing under the laws of the State of South Carolina, duly authorized to do business in and engaged in the business of transporting, distributing, and selling natural gas within North Carolina.

2. PSNC is a public utility within the meaning of G.S. 62-3(23).

3. The Commission has jurisdiction over, among other things, the rates and charges, rate schedules, classifications, and practices of PSNC in its capacity as a public utility.

4. In the Application in this docket, PSNC is seeking approval of: (a) a general increase in and revisions to the rates and charges for customers served by the Company; (b) certain changes to the cost allocation, rate designs, and practices underlying existing rates for the

Company; (c) changes to the Company's existing service regulations and tariffs; (d) implementation of a new Integrity Management Tracker (IMT) mechanism; (e) implementation of new depreciation rates; (f) proposed funding of gas distribution research and development activities conducted by the Gas Technology Institute (GTI); (g) authority to include $2,000,000 related to distribution integrity management program operations in the Company's cost of service; and (h) implementation of a rate decrement to refund to its customers over a one-year period the Company's excess deferred income tax balance as of December 31, 2015.

5. The Company is properly before the Commission with respect to the relief sought in the Application in this proceeding pursuant to the provisions of Chapter 62 of the North Carolina General Statutes, and the Commission's Rules.

Test Period

6. The parties submitting evidence in this case with respect to revenue, expenses, and rate base levels used a test period of the twelve months ended December 31, 2015, adjusted for certain known and measurable changes through June 30, 2016, or thereafter, and the Amended Stipulation was based upon the same test period.

7. The appropriate test period for use in this proceeding is the twelve months ended December 31, 2015, updated for certain known and measurable changes through June 30, 2016, or thereafter.

Amended Stipulation

8. In summary, the Amended Stipulation executed by PSNC, the Public Staff, CUCA, and Evergreen resolves all issues in this docket, and is actively supported or not opposed by all parties to this docket with the exception of the Attorney General.

9. After carefully reviewing the Amended Stipulation, the Commission finds and concludes that the Amended Stipulation is the product of give-and-take in settlement negotiations among the Stipulating Parties, and is material evidence entitled to be given appropriate weight by the Commission.

Revenue Increase

10. The Application seeks an increase in annual revenues for the Company of $41,583,020. The Amended Stipulation provides for a total increase in annual revenues for the Company of $19,054,160, of which $276,576 is recovered through the proposed increase in other operating revenues. The Commission finds and concludes that the revenue increase agreed upon in the Amended Stipulation is just, reasonable and appropriate for use in this proceeding.

Rate Base

11. The Stipulating Parties agreed that the original cost of the Company's used and useful property, or property to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the public within North Carolina is $946,722,235, consisting of gas plant in service of $1,839,643,565, and working capital – lead lag of $13,714,498, reduced by accumulated depreciation of $657,141,088, working capital – other of $7,817,284, and accumulated deferred income taxes of $241,677,456, as set forth in Paragraph 4 and Exhibit A of

the Amended Stipulation, the Public Staff Late-Filed Exhibit I, and reflected on Schedule 1 hereto. These provisions of the Amended Stipulation are just, reasonable and appropriate for use in this docket.

<u>Revenues and Operating Expenses</u>

12. The Stipulating Parties agree that the Company's end-of-period *pro forma* revenues under present rates for use in this proceeding are $434,445,667, comprised of $430,126,449 of sales and transportation revenues, $792,254 of special contract revenues, and $3,526,964 of other operating revenues, as set forth in Paragraph 5 and Exhibit A of the Amended Stipulation. The Amended Stipulation further details that the Company's *pro forma* annual operating revenues under the agreed upon rates, which are appropriate for use in this proceeding are $453,499,827, comprised of $448,904,033 of sales and transportation revenues, $792,254 of special contract revenues, and $3,803,540 of other operating revenues, as set forth in Paragraph 5 and Exhibit A of the Amended Stipulation. These provisions of the Amended Stipulation are just, reasonable and appropriate for use in this docket.

13. The Stipulating Parties agreed that the Company's operating expenses are $201,794,646, including actual investment currently consumed through reasonable actual depreciation, as set forth on Public Staff Late-Filed Exhibit I. These provisions of the Amended Stipulation are just, reasonable and appropriate for use in this docket.

<u>Capital Structure</u>

14. The capital structure set forth in Paragraph 5.B. of the Amended Stipulation and supported by expert witness evidence, consisting of 52.0% common equity, 44.62% long-term debt at a cost of 5.52%, and 3.38% short-term debt at a cost of 0.77%, is just, reasonable and appropriate for use in this docket.

<u>Return</u>

15. Based on the expert witness evidence and the Amended Stipulation, the overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 7.53%, as set forth in Paragraph 5.D. and Exhibit A of the Amended Stipulation. This overall rate of return is just, reasonable and appropriate for use in this docket.

16. Based on the expert witness evidence and the Amended Stipulation, the rate of return on common equity that the Company should be allowed the opportunity to earn in this docket is 9.70%, as set forth in Paragraph 5(C) of the Amended Stipulation. This rate of return on common equity is just, reasonable and appropriate for use in this docket.

17. The authorized levels of overall rate of return and rate of return on common equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of G.S. 62-133, and are fair to PSNC's customers in light of changing economic conditions or otherwise.

18. With respect to the foregoing ultimate findings on the appropriate overall rate of return on rate base and allowed rate of return on common equity for use in this proceeding, the Commission relies on the following more specific findings of fact:

a. The overall rate of return on rate base and allowed rate of return on common equity underlying PSNC's current base rates are 8.54% and 10.60% respectively.[1]

b. PSNC's current base rates became effective on November 1, 2008 and have been in effect since that date except for adjustments due to the Company's Customer Usage Tracker mechanism and state tax changes.

c. In its Application, PSNC sought approval for rates which were based on an overall rate of return on rate base of 8.14% and an allowed rate of return on common equity of 10.60%.

d. In the Amended Stipulation, the Stipulating Parties seek approval of an overall rate of return on rate base of 7.53% and an allowed rate of return on common equity of 9.70%.

e. The current Commission authorized allowed rate of return on common equity underlying Piedmont Natural Gas Company, Inc.'s base rates is 10.0%.[2]

f. The current Commission authorized allowed rate of return on common equity for Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and Dominion North Carolina Power is 10.2%.[3]

g. Since January 1, 2014, a total of 24 of the 54 authorized rates of return on equity for natural gas utilities were 9.70% or above, with the average authorized rate of return on equity in all such cases being 9.65%.

h. In determining the rate of return on equity for PSNC, it is inappropriate to rely on past rate of return on equity determinations authorized for other utilities without evidence tying those determinations to the facts of this case. It is, however, appropriate to note such past determinations as a check or as corroboration of the Commission's decision regarding the cost of equity demonstrated by the evidence in the present proceeding.

i. The stipulated overall rate of return on rate base of 7.53% and allowed rate of return on common equity of 9.70% are supported by credible, competent, material, and substantial evidence.

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[1] See In the Matter of Application of Public Service Company of North Carolina, Inc., for a General Increase in its Rates and Charges, Order Approving Partial Rate Increase and Requiring Conservation Program Filing and Reporting, Docket No. G-5, Sub 495 (Oct. 24, 2008) (2008 Rate Order).

[2] Order Approving Partial Rate Increase and Allowing Integrity Management Rider, Docket No. G-9, Sub 631 (December 17, 2013).

[3] Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (September 24, 2013); Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013); and Order Granting General Rate Increase, Docket No. E-22, Sub 479 (December 12, 2012).

j. Continuous safe, adequate, and reliable natural gas service by PSNC is essential to the well-being of the people, businesses, institutions and economy of PSNC's North Carolina service area.

k. The rate of return on PSNC's equity approved by the Commission appropriately balances the benefits received by PSNC's customers from PSNC's provision of safe, adequate, and reliable natural gas in support of the well-being of the people, businesses, institutions, and economy of North Carolina, with the difficulties that some of PSNC's customers will experience in paying PSNC's increased rates.

l. Substantial expert evidence presented in this matter, uncontroverted by other expert testimony on the subject, indicates that the overall economic climate in North Carolina and PSNC's service territory (as well as nationally) continues to improve. This evidence includes data and projections from reliable sources indicating that in the few months before the hearing in this matter: (i) unemployment rates were declining; (ii) real gross domestic product growth was continuing; (iii) median household income was growing; (iv) total personal income and disposable income was increasing; (v) personal consumption was improving; (vi) wages and salaries were increasing; (vii) the number of mortgages past due decreased; (viii) North Carolina exports were materially increasing; (ix) residential construction permits were increasing; and (x) housing market indicators were mostly positive. No public witnesses appeared at the public hearings held in Gastonia, Asheville, Statesville, and Raleigh.

m. The 9.70% rate of return on equity takes into account the impact of changing economic conditions on consumers. The authorized revenue amount available to pay a return on equity is lower for PSNC because the Amended Stipulation reduced downward PSNC's requested revenue requirement, and this reduction is intertwined with the decision on rate of return on equity in that it affects the earnings available to investors and the rates customers will pay.

n. No party submitted evidence showing that any regulatory commission applies increments or decrements to the return on equity to account for economic conditions or customer ability to pay.

o. PSNC has made significant capital investments since its last rate case in 2008, much of which relates to the Company's integrity management programs in compliance with federal regulations to enhance the safety and integrity of its natural gas transmission facilities. Additionally, the Company plans to make significant capital investments in the future.

p. Access to capital at reasonable rates is critical to PSNC's ability to fund its ongoing capital investment requirements and PSNC's provision of safe, adequate, and reliable natural gas.

q. Establishing an allowed rate of return on common equity at a rate of 9.70% is as low as reasonably possible without unduly jeopardizing PSNC's ability to access capital on reasonable terms.

r. The 9.70% return on equity and the 52.00% equity financing approved by the Commission in this case results in a cost of capital that will enable PSNC by sound management to produce a fair return for its shareholders, considering changing economic conditions, and is just, reasonable and fair to PSNC's customers. It appropriately balances PSNC's need to obtain financing and maintain a strong credit rating with its customers' need to pay the lowest possible rates.

Throughput

19. For the purpose of this proceeding, the appropriate level of adjusted sales and transportation volumes is 937,082,412 therms, which is comprised of 491,921,582 therms of sales quantities, 316,664,980 therms of transportation quantities, and 128,495,850 therms of special contract quantities. The appropriate level of lost and unaccounted for gas is 7,027,614 therms and company use gas is 870,521 therms. The appropriate level of purchased gas supply is 499,819,717 therms, consisting of sales volumes and company use and lost and unaccounted for gas.

Cost of Gas

20. The total cost of gas reasonable and appropriate for use in this proceeding is $180,388,055, as described in Paragraph 7.B. and Exhibit E of the Amended Stipulation and consisting of $110,682,356 in commodity costs, $1,777,080 in company use and lost and unaccounted for costs, and $67,928,619 in fixed gas costs.

21. The Benchmark Commodity Cost of Gas reasonable and appropriate for use in this proceeding is $0.225 per therm, as described in Paragraph 7.A. of the Amended Stipulation subject to any filed changes in such rate prior to implementation of effective rates in this docket.

22. The fixed gas costs that should be embedded in the proposed rates and used in true-ups of fixed gas costs for periods subsequent to the effective date of rates in this docket, in proceedings under Commission Rule R1-17(k), subject to any filed changes in such costs prior to the effective date of rates in this docket, are those derived from the fixed gas cost allocation percentages discussed in Paragraph 5 of the Amended Stipulation and set forth in Exhibit C to the Amended Stipulation.

Rate Design

23. The rate design and rates, including volumetric rates, fixed monthly charges, and other charges, as described in Paragraph 5 of the Amended Stipulation and reflected in the columns entitled "Monthly Facilities Charges" and "Energy Charges" on Exhibit B of the Amended Stipulation (as the same may be adjusted for any changes in the Company's Benchmark or changes in Demand and Storage Charges prior to the effective date of the rates in this docket), are just, reasonable and appropriate for use in this docket.

Integrity Management Tracker

24. The IMT attached to the Amended Stipulation in Exhibit H is just, reasonable, appropriate and consistent with G.S. 62-133.7A, and should be approved and implemented as provided in Paragraph 10 of the Amended Stipulation, and Rider E of the Company's tariffs.

Customer Usage Tracker Factors

25. The "R" values, baseload and heat sensitive factors set forth on Late Filed Exhibit D to the Amended Stipulation and reflected in Paragraph 6 of the Amended Stipulation are reasonable and appropriate for use with the Company's Customer Usage Tracker (CUT) mechanism on or after the effective date of rates, and should be approved.

Amortization of Deferred Regulatory Assets

26. The proposed amortization of certain deferred regulatory assets, as set forth and described in Paragraphs 5(G) through 5(I) of the Amended Stipulation, is just, reasonable and appropriate and should be approved.

Implementation of State Income Tax Changes

27. The Stipulating Parties' agreement to decrease the North Carolina corporate income tax reflected in rates pursuant to North Carolina Session Law 2015-241, and as set forth in Paragraph 8 of the Amended Stipulation, is just, reasonable and appropriate and should be approved.

Depreciation Rates

28. The Stipulating Parties' agreement regarding the depreciation rates proposed by the Company as set forth in Paragraph 9 of the Amended Stipulation is just, reasonable and appropriate and should be approved effective January 1, 2017.

Changes to Tariff Rules and Regulations

29. PSNC's Tariff and Rules and Regulations included in witness Paton's Exhibit 4, with the exception of the Summary of Rates and Charges, Riders C and E, and the Transportation Pooling agreement, are just, reasonable and appropriate and should be approved. In addition, revised Riders C and E and the revised Transportation Pooling Agreement, as described in Paragraph 11 and Exhibit H of the Amended Stipulation, are just, reasonable and appropriate and should be approved.

Excess Deferred Income Taxes

30. The Stipulating Parties agreed to implement a temporary decrement in rates to refund excess deferred income taxes (EDIT) over a one-year period, as set forth in Paragraph 12 of the Amended Stipulation, and further agreed that any balance remaining after the twelve-months should be transferred to the All Customers' Deferred Account. This proposed treatment is just, reasonable and appropriate and should be approved.

Conservation Program Expenditures

31. The Stipulating Parties' agreement to continue funding of conservation programs at a level of $750,000 per year, as reflected in test year operating expenses and set forth and described in Paragraph 13 of the Amended Stipulation, is just, reasonable and appropriate and should be approved.

Gas Technology Institute Research Funding

32. The funding of GTI research and development activities of $268,631 per year, as discussed in Paragraph 14 of the Amended Stipulation and set forth in the Public Staff Late-Filed Exhibit I, is just, reasonable and appropriate and should be approved.

Miscellaneous Matters

33. Use of the overall rate of return, adjusted for income taxes, as the Allowance for Funds Used During Construction rate for the Company is just, reasonable and appropriate, and should be approved.

34. The Stipulating Parties agreed that beginning with the month in which rates become effective in this docket, PSNC will use an interest rate of 6.6% per annum as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in PSNC's Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The Stipulating Parties also agreed that the methods and procedures used by PSNC for the accrual of interest on the Deferred Gas Cost Accounts will remain unchanged. These provisions of the Amended Stipulation are just, reasonable and appropriate and should be approved.

35. The Stipulating Parties agreed that PSNC shall file its GS-1 Report in a format similar to the ES-1 Reports filed by the electric utilities. This is reasonable and appropriate and should be approved.

36. Beginning with the January 2017 report, PSNC shall add to its monthly report on the SCANA Utility Money Pool the net daily balance of loans and receipts, and the total net interest amount on the balances. This information will be provided for the month, and for the calendar year to date.

Consumer Statements of Position

37. Although not evidence in this proceeding, the Commission has read and given appropriate consideration to the consumer statements of position received by the Commission, the Public Staff and the Attorney General.

Acceptance of Amended Stipulation

38. The Commission finds and concludes in light of the evidence presented that the provisions of the Amended Stipulation are just and reasonable to the customers of PSNC and to all parties to this proceeding, and serve the public interest. Therefore, the Amended Stipulation should be approved in its entirety. In addition, it is entitled to substantial weight and consideration in the Commission's decision in this matter.

Just and Reasonable Rates

39. The Commission finds and concludes that the rates approved herein are just and reasonable to the customers of PSNC, to PSNC, and to all parties to this proceeding, and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence supporting these findings is contained in the Company's verified Application, the testimony and exhibits of the Company's witnesses, the Form G-1 that was filed with the Application, and the Commission's records as a whole. These findings are jurisdictional and procedural in nature and are not contested by any party.

On March 31, 2016, PSNC filed a verified Application for an increase in its base rates. In summary, the application seeks a $41,583,020 increase in PSNC's annual North Carolina revenues. This would be an overall increase of 9.66% in PSNC's revenue. Further, the application seeks approval of a 10.6% rate of return on common equity (ROE), an 8.14% overall return on rate base, and a capital structure of 53.5% common equity, 3.38% short-term debt, and 43.12% long-term debt. PSNC's present authorized ROE and overall return are 10.6% and 8.54%, respectively. PSNC's present authorized capital structure is 54% common equity, 10.5% short-term debt, and 35.5% long-term debt. Its authorized cost of debt is 3.25% for short-term debt and 6.96% for long-term debt. See Order Approving Partial Rate Increase, Docket No. G-5, Sub 495 (Oct. 24, 2008) (2008 Rate Order). The Application states that during the 12-month test period PSNC's overall rate of return on its North Carolina retail rate base was 7.84%.

According to the Application, since its last general rate case in 2008 PSNC's business has been impacted by a heightened awareness of and focus on pipeline safety, low and stable natural gas prices, the opportunity to acquire additional pipeline capacity, PSNC's need to invest in pipeline enhancement projects, and the expanded use of technology to more efficiently serve its customers. PSNC states that it has added 77,025 customers, installed over 1,424 miles of transmission and distribution mains, invested approximately $609 million in its utility property, and incurred over $19 million in deferred environmental and pipeline safety costs.

In its Application, PSNC requests approval of a rider to its rates to provide for ongoing recovery of its capital costs related to pipeline safety improvements and management. In addition, PSNC recommends new annual depreciation rates based on a depreciation study conducted pursuant to Commission Rule R6-80. Further, PSNC seeks to update and revise certain tariff provisions, including changes to its industrial tariff and pooling agreement, and a new Medium General Service rate. Moreover, PSNC requests approval of a rate decrement for one year to refund to its customers an excess accumulated income tax balance of $7.3 million. PSNC requests that its new rates be effective on November 1, 2016.

PSNC is a public utility within the meaning of G.S. 62-3(23). Therefore, pursuant to G.S. 62-30, et seq., the Commission has jurisdiction to consider and decide PSNC's Application for a rate increase.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence supporting these findings is contained in the Company's verified Application, the testimony and exhibits of the Company's witnesses, and the Form G-1 that was filed with the Application.

The Company filed its Application and exhibits using a test period of the twelve months ended December 31, 2015. In its Order of April 26, 2016, the Commission ordered the parties to use a test period of the twelve months ended December 31, 2015, with appropriate adjustments. The Amended Stipulation is based upon the test period ordered by the Commission, and this test period is not contested by any party. In the Amended Stipulation, the Stipulating Parties agreed to make appropriate adjustments to the test period data for circumstances occurring or becoming known through June 30, 2016, or thereafter. These adjustments were not contested by any party.

The Commission finds and concludes that the Company's use of a test period of the twelve months ended December 31, 2015, with appropriate adjustments, comports with the requirements of G.S. 62-133 and Commission Rule R1-17, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

These findings are supported by the testimony of Company witness Paton, Public Staff witness Hoard, and the provisions of the Partial Stipulation and the Amended Stipulation.

On August 25, 2016, PSNC, CUCA, Evergreen, and the Public Staff (Stipulating Parties) filed an Amended Partial Stipulation resolving most of the issues between the Stipulating Parties. For example, in Paragraph 5.H. the Stipulating Parties stated that they agreed that it is appropriate to amortize and allow recovery of the balance of PSNC's deferred asset representing manufactured gas plant (MGP) clean-up costs, but did not agree on the balance of the deferred asset or the amount of the annual amortization expense. Similarly, in Paragraph 5.I., the Stipulating Parties stated that they agreed it is appropriate to amortize and allow recovery of the balance of PSNC's deferred asset representing PSNC's pipeline integrity management (PIM) costs, but did not agree on the balance of the deferred asset or the amount of the annual amortization expense.

On August 25, 2016, the Public Staff filed the direct testimony and exhibits of James G. Hoard, Director, Accounting Division. Witness Hoard testified to the ongoing disagreement between PSNC and the Public Staff regarding the treatment of MGP clean-up costs, and PSNC's deferred PIM costs. In summary, witness Hoard testified to adjustments made to the amortization of PSNC's MGP and PIM costs that, if accepted by the Commission, would substantially reduce the Company's recovery of those costs in this rate proceeding.

On August 29, 2016, the Stipulating Parties filed the Amended Stipulation. The Amended Stipulation recites that it is filed on behalf of PSNC, the Public Staff, CUCA, and Evergreen. The Amended Stipulation further states that it represents a complete and integrated settlement of all matters at issue between the Stipulating Parties.

In her supplemental testimony filed on August 29, 2016, PSNC witness Paton testified that the Stipulating Parties engaged in substantial discovery regarding the issues involved in PSNC's Application. Witness Paton further stated that the Public Staff spent several days at PSNC's office in Gastonia and at SCANA's corporate office in Cayce, South Carolina, performing audits and interviewing Company employees. In addition, she testified that after lengthy negotiations in multiple meetings and conference calls, the Stipulating Parties reached a partial settlement on all but one issue in the case.[1] Witness Paton further testified that the Stipulating Parties reached agreement on the remaining issue, which resulted in the filing of the Amended Stipulation on August 29, 2016. Moreover, witness Paton testified that the Amended Stipulation was the result of give-and-take negotiations in which each Stipulating Party made substantial compromises on individual issues in order to obtain a compromise from other Stipulating Parties on other issues. She testified that the end result is a settlement in which each party believes that the aggregate results are fair to PSNC and its customers.

As the Amended Stipulation has not been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject the Amended Stipulation is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I the Supreme Court held that

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding.
>
> The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id. at 231-32, 524 S.E.2d at 16 (emphasis added).

The Commission gives substantial weight to the testimony of PSNC witness Paton regarding the Stipulating Parties' efforts in negotiating the Amended Stipulation. Further, the Commission gives some weight to the fact that there was only an Amended Partial Stipulation as of August 25, 2016, and that the Public Staff filed testimony in support of its position on the

[1] Witness Paton referenced "one issue in the case," which perhaps grouped the amortization of MGP and PIM deferred costs as one amortization issue.

unresolved issues. The Public Staff's filing of testimony in preparation for litigating the contested issues indicates the Public Staff's resolve and determination to fully represent the using and consuming public.

As a result, the Commission finds and concludes that the Amended Stipulation is the product of the give-and-take between the Stipulating Parties during their settlement negotiations in an effort to appropriately balance PSNC's need for increased revenues and its customers' needs to receive safe, adequate and reliable natural gas service at the lowest possible rates. In addition, the Commission finds and concludes that the Amended Stipulation was entered into by the Stipulating Parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket that is supported, or not opposed, by all parties except the Attorney General. As a result, the Amended Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

This finding is supported by the Application, the direct testimony and Exhibits of Company witness Boone, the supplemental testimony of Company witness Paton, the Amended Stipulation, the Public Staff's Late Filed Exhibit I, and the direct testimony of Public Staff witness Boswell.

Revised Boone Exhibit 6, attached to the direct testimony of Company witness Boone, indicates that the Company filed for a total revenue increase in this proceeding of $41,583,021. The Amended Stipulation, in Exhibit A, indicates that pursuant to the agreement of the Stipulating Parties the Company should be allowed to increase annual revenues by $19,054,160, of which $276,576 would be recovered through the proposed increase in other operating revenues. This increase in revenues is further reflected in the supplemental testimony and exhibits of Company witness Paton and the Revised Public Staff's Late Filed Exhibit 1. These findings are not contested by any party.

Based upon the evidence recited above and the cumulative testimony and evidence supporting the individual components of the stipulated revenue increase discussed throughout this Order, including the discussion and analysis related to the proper rate of overall return and return on common equity for use in this proceeding, the Commission finds, in the exercise of its independent judgment, that the stipulated revenue increase in this case is just, reasonable, and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding is contained in the Company's verified Application, the testimony and exhibits of the Company's witnesses, the Form G-1 that was filed with the Application, and the Amended Stipulation.

The reasonable original cost of the Company's used and useful property, or property to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the public within North Carolina, less that portion of the cost that has been consumed by depreciation expense, is described and set forth in Paragraph 4 and Exhibit A to the Amended Stipulation, Public Staff Late Filed Exhibit I. The amounts shown on Exhibit A to the Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the

Amended Stipulation, the direct testimony of Public Staff witness Boswell, and the supplemental testimony of Company witness Paton. The stipulated reasonable original cost of the Company's used and useful property, or property to be used and useful within a reasonable time after the test period, in providing natural gas service to the public, less depreciation expense, is not contested by any party.

No other party presented evidence on these matters.

The Commission has carefully reviewed these amounts, as well as all record evidence relating to the Company's rate base, which collectively constitute the only evidence in this docket regarding the Company's rate base, and concludes that the stipulated amounts are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding is set forth in the Amended Stipulation, Public Staff Late Filed Exhibit I, the supplemental testimony of Company witness Paton, and the direct testimonies of Public Staff witnesses Boswell and Larson.

The end of test period *pro forma* revenues under the Company's present and stipulated proposed rates are set forth in Paragraph 5 and Exhibit A to the Amended Stipulation, and Public Staff Late Filed Exhibit I to the Amended Stipulation. These amounts are the result of negotiations among the Stipulating Parties in this docket following an extensive audit of the Company's filed case by the Public Staff and are described in the Amended Stipulation. No other party submitted evidence on the Company's *pro forma* revenues, and the stipulated *pro forma* revenues are not challenged by any party.

The Commission has carefully reviewed these amounts, as well as all record evidence relating to *pro forma* revenues, and concludes based on its own independent judgment that the stipulated *pro forma* revenues are reasonable and appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding is set forth in the testimony of Company witness McLeod, Public Staff Late Filed Exhibit I and the Amended Stipulation.

The Company's reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are set forth in Exhibit A to the Amended Stipulation, Public Staff Late Filed Exhibit I. The amounts shown on Exhibit A to the Amended Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the Amended Stipulation and the supplemental testimony of Company witness Paton, and are not contested by any party.

The Commission has carefully reviewed these amounts, as well as all record evidence relating to the Company's reasonable operating expenses, and concludes that the stipulated reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding is contained in the prefiled direct testimony of PSNC witness Jimmy E. Addison, the prefiled direct and supplemental testimony of PSNC witness Robert B. Hevert, the hearing testimony of witness Addison and witness Hevert, and the Amended Stipulation.

In the Application, and as explained by PSNC witness Addison in his direct testimony, the Company proposed a capital structure reflecting long-term debt of 43.12%, short-term debt of 3.38%, and equity of 53.50%. The short-term debt reflected the estimated average of gas inventory for the 13 months ending June 30, 2016, consistent with Commission practice. The long-term debt and equity figures reflected actual balances adjusted for forecasted changes through June 30, 2016. Witness Addison testified that PSNC planned to issue $100 million in unsecured long-term debt in June of 2016.

In his direct testimony, witness Hevert discussed the generally accepted approaches to developing the appropriate capital structure for a regulated natural gas distribution company, and explained how the capital structure affects the cost of capital and overall level of risk for the company. He explained that the capital structure should enable the company to maintain its financial integrity, thereby enabling access to capital at competitive rates under a variety of economic and financial market conditions. Witness Hevert then presented and provided support for his proxy group, described his analysis of the proxy companies' capital structures, and concluded based on his review that a capital structure consisting of 53.50% common equity, 3.38% short-term debt, and 43.12% long-term debt is reasonable and appropriate for PSNC. Witness Hevert explained the concept of maturity matching. He stated that, because it is perpetual in nature, adding equity to the capital structure extends the weighted average life of long-term liabilities, and mitigates incremental refinancing risk, but that relying more heavily on debt as the means of financing long-lived assets increases the risk of refinancing maturing obligations during less accommodating market environments.

Following settlement negotiations between PSNC, the Public Staff, CUCA and Evergreen, as reflected in Paragraph 5.B. of the Amended Stipulation, the Stipulating Parties proposed a capital structure of 52.00% common equity, 3.38% short-term debt and 44.62% long-term debt. The Stipulating Parties agreed to use 5.52% for the cost of long-term debt and agreed to use 0.77% for the cost of short-term debt.

In his supplemental testimony and associated exhibits, witness Hevert addressed the capital structure agreed to in the Partial Stipulation dated August 18, 2016 among PSNC, the Public Staff, CUCA, and Evergreen. (The Stipulating Parties filed two amended stipulations on August 25, 2016 and August 30, 2016, but those amended agreements did not adjust the capital structure reflected in the Partial Stipulation filed on August 18, 2016, to which witness Hevert testified.) In his supplemental testimony, witness Hevert stated that the capital structure ratios agreed upon by the Stipulating Parties fall well within the range of those in place at the proxy companies (from the first calendar quarter of 2014 through the second calendar quarter of 2016), and that on that basis, he believed the stipulated capital structure to be reasonable.

No other party submitted testimony on the issue of the appropriate capital structure for the Company.

The proposed stipulated capital structure was also supported by the hearing testimony of PSNC witnesses Hevert and Addison. At the hearing in this matter, in response to cross-examination by the Attorney General, witness Addison confirmed that PSNC issued $100 million in unsecured long-term debt in June 2016 at a rate of 4.13%. Witness Addison also explained that PSNC operates in a “lumpy” business, in which it raises both debt and equity capital as needed to make required investments in rate base, which in turn results in different proportions of debt and equity at different points in time for the Company. He explained that if the debt ratio of capital structure is increased too much, the cost of debt would also increase due to the increased risk to debt investors. He testified that because PSNC’s actual equity component is slightly higher than 53.5%, but it will only receive the 9.70% stipulated ROE on the 52.0% equity contained in the stipulated capital structure, if the Commission approves the Amended Stipulation the shareholders’ actual return will be lower than the Company’s authorized return on equity. Witness Addison also explained the reasons for the differences in capital structure between PSNC and its parent company SCANA.

Also at the hearing, witness Hevert further supported witness Addison’s discussion of the reasons for higher cost of equity as compared to cost of debt. One of those reasons is that equity holders bear the “residual risk,” meaning they are last in line to receive cash flows generated by the Company, and receive what is left after the debt holders, who have a contractual claim on cash flows, are paid. Another reason is that the cost of debt is specified while the cost of equity is based on observable market information. Witness Hevert also testified that with respect to the proxy companies, the comparison to be made is the extent to which PSNC’s capital structure is consistent with the range of the proxy companies, rather than with their average, and that including short-term debt in the capital structure does not affect his conclusion that 52% equity in PSNC’s capital structure is reasonable. In various contexts, witness Hevert reiterated the value of using multiple sources of data in order to produce the range for capital structure.

Witness Hevert also discussed his rationale for looking primarily to the operating company level for determining the appropriate capital structure. He testified that utilities in general are required to finance very large, essentially irreversible long-lived investments, and have to be able to enter the capital markets at any given point in time, regardless of market conditions, and do not have the ability or option to defer those decisions. He noted that there are a number of approaches to developing the appropriate capital structure, and the reasonableness of the approach used depends on the nature and circumstances of the subject company. He testified that if a company does not issue its own securities, it may be reasonable to look to the parent’s capital structure, or to develop a “hypothetical” capital structure based on the proxy companies or other industry data. However, if the company issues its own securities, as does PSNC, and if its capital structure is reasonable in reference to industry practice, it is not necessarily important to look at the parent company’s capital structure. Witness Hevert concluded that in PSNC's case it is reasonable to look at the operating company level in setting the appropriate capital structure, rather than looking at SCANA.

Counsel for the Attorney General questioned witnesses Addison and Hevert about other approaches to viewing capital structure. On redirect, witness Hevert stated that the Value Line common equity ratios for the proxy companies include 55% for Atmos, 58% for New Jersey

Resources, 56% for Northwest Natural, and 49% for Laclede. He noted that these data showed that distribution companies had much higher equity ratio expectations from Value Line as compared to SCANA, the holding company, with a 46% equity ratio.

On October 10, 2016, the Attorney General filed a post-hearing Brief. In summary, the Attorney General states that small increases or decreases in the ratio of equity financing versus debt make a large difference in the utility's revenue requirement, because equity is much more expensive, particularly when the cost of income taxes is taken into account. The Attorney General includes several tables demonstrating the impact of different capital structures on the Company's revenue requirement. In addition, the Attorney General criticizes witness Hevert's updated capital structure evidence included in his supplemental testimony because witness Hevert added two more recent calendar quarters to his original analysis of eight quarters. The Attorney General states that when the average equity ratio is calculated for witness Hevert's proxy companies using the same eight periods as in his original testimony, the equity ratio averages 49.69%, and when calculated using the most recent eight periods, the equity ratio averages 48.73%. Moreover, the Attorney General asserts that PSNC's holding company, SCANA, maintains an equity ratio that has typically been less than 45% during the last five years. In addition, the Attorney General notes that during the 56 months from March 2010 through October 2014 PSNC loaned money to the SCANA Utility Money Pool (UMP) in all but one month. The Attorney General interprets this to mean that PSNC had more cash available for its operating costs than PSNC needed. In conclusion the Attorney General states that it is reasonable and appropriate for PSNC to use a 45% equity ratio.

On October 14, 2016, PSNC filed a Reply Brief. With regard to the Attorney General's arguments on capital structure, PSNC submits that the Attorney General on several occasions makes inferences that are not supported by the witnesses' testimony. As an example, PSNC notes the Attorney General's argument concerning PSNC's loans to the UMP. PSNC contends that witness Addison's testimony actually supports the conclusion that PSNC's loans to the UMP coincide with issuances of long-term debt, noting his testimony that "PSNC is going to be moving back into that period where they're going to likely be a net borrower until the points that we go out and issue long-term debt." (T Vol. 5, p. 117) Further, PSNC states that this is borne out by the reports the Company filed in Docket No. G-5, Sub 422, on financings it made in March 2010 and February 2011, and the reports of its UMP activities filed in Docket No. G-5, Sub 484, as referenced in Commissioner Brown-Bland's question to witness Addison. (T Vol. 5, p. 116)

In addition, PSNC maintains that the Attorney General's focus on the average equity ratios of witness Hevert's proxy companies is inapposite for two reasons. First, the equity balances used by witness Hevert are end-of-month, and therefore not necessarily representative of the average balances during the course of the month. Secondly, it is the range of results and not the average that is relevant to the analysis of the proxy group's capital structure.

On October 19, 2016, the Attorney General filed a Response Brief. With regard to PSNC's loans to the SCANA UMP, the Attorney General takes issue with PSNC's characterization of witness Addison's testimony as showing these loans coincided with issuances of long-term debt by PSNC. Rather, the Attorney General notes that witness Addison testified that during "the historical period" from 2010 to 2014, PSNC did not have as many capital investments to make as it will prospectively, "so we've not had to issue a great deal of long-term debt, anything like that, not been into the commercial paper markets a lot in the past." (T Vol. 5, p 117)

With respect to witness Hevert's conclusion regarding the equity ratios of his proxy companies, the Attorney General notes that witness Hevert's support of a 52% equity ratio for PSNC means that his position is at the high end of the equity range for the proxy group. The Attorney General posits that this is a pattern in witness Hevert's results, wherein he tends to recommend the high end of the range rather than the mid or low points.

The Attorney General's contentions with regard to witness Hevert's proxy group of utilities and their average equity financing are not persuasive. The Commission does not view witness Hevert's addition of two more current quarters to his analysis as discrediting witness Hevert's conclusions. In addition, the data and analytical tool used by witness Hevert was intended to produce a meaningful range of equity ratios for his proxy companies. The Attorney General attempts to use the data and tool for a different purpose – to compute the average equity ratios of the proxy companies. The Commission is not persuaded that the use of the data in this manner produces probative or reliable evidence regarding the equity ratios of the proxy companies.

With regard to the comparison of the capital structure of SCANA with that of PSNC, witness Addison explained that one reason for SCANA's higher debt ratio is approximately $700 million in debt that SCANA issued to purchase PSNC and is now being carried by SCANA. He described this as an unusual situation for SCANA, noting that it is the only time that SCANA has issued debt during his tenure as chief financial officer. Witness Addison also noted that SCANA's other regulated utilities have a capital structure similar to that of PSNC.

The Attorney General did not provide a witness or affirmative evidence that would support a capital structure, particularly a 45% common equity component of capital structure. Indeed, no expert witness provided an analysis after the Amended Stipulation that showed 52% as the appropriate level of equity financing for PSNC. Therefore, the Commission must consider the evidence and exercise its independent judgment in determining the appropriate capital structure for PSNC in the context of setting PSNC's rates.

The Commission gives substantial weight to witness Addison's testimony regarding the Company's effort to find the appropriate balance between equity and debt financing. The Commission finds credible his explanation that increasing the debt ratio of PSNC's capital structure too much can lead to an increase in the cost of debt, as debt investors see more risk in the higher debt level. The Commission also gives significant weight to witness Addison's testimony regarding the reasons for the differences in capital structure between PSNC and its parent company SCANA. The Commission finds credible his explanation that one reason SCANA has a higher debt ratio is its issuance of approximately $700 million of debt to finance the purchase of PSNC.

In addition, the Commission gives significant weight to witness Hevert's testimony regarding the differences in the financing needs of holding companies and operating companies. The Commission finds credible witness Hevert's explanation that utilities generally are required to finance very large, long-lived investments, and may find it necessary to enter the capital markets at any given time. Thus, the appropriate mix of debt and equity for a public utility operating company can be significantly different from that of its holding company.

Based on the above-discussed capital structure testimony of witnesses Addison's and Hevert, the Commission finds their recommendations regarding the appropriate capital structure of PSNC to be substantial and credible evidence.

Based upon the evidence described above and the record in this docket as a whole, the Commission finds and concludes that the amended stipulated capital structure and costs of long-term and short-term debt are fair and reasonable, and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-18

The evidence supporting these findings is contained in the Application, the prefiled direct and supplemental testimony and Exhibits of Company witnesses Addison and Hevert, the hearing testimony of witnesses Addison and Hevert, and the Amended Stipulation. No other party submitted expert testimony on the appropriate overall rate of return on rate base (ROR or Overall Return) or allowed rate of return on common equity (ROE) appropriate for use in this proceeding.

Summary of the Evidence on Return

PSNC's current allowed rate of return on common equity, established by the Commission in 2008 in Docket No. G-5, Sub 495, is 10.6%.[1] Its current approved overall rate of return on rate base is 8.54%.[2] In its Application, PSNC proposed that the allowed rate of return on common equity in this proceeding be established at 10.6%. This proposed rate of return on common equity, in conjunction with the other elements of the Company's proposed capital structure, resulted in a proposed overall rate of return on rate base for the Company of 8.14%.

PSNC's original return on common equity request was supported by the direct testimony and Exhibits of PSNC witnesses Addison and Hevert. Witness Hevert, who holds a Bachelor of Arts degree in business and economics and a Master of Business Administration with a concentration in finance, and is designated as a Chartered Financial Analyst and is a Partner with the ScottMadden, Inc. consulting firm, served as PSNC's cost of equity witness. Witness Hevert filed direct testimony and 13 exhibits in support of PSNC's request for 10.6% return on equity. He explained that the cost of equity is the return that investors require to make an equity investment in a company, that it should reflect the return that investors require in light of the company's risks and the returns available on comparable investments, and that it differs from the cost of debt because it is neither directly observable nor a contractual obligation.

Witness Hevert's direct testimony and Exhibits document the specific analyses he conducted in support of PSNC's rate filing and provides a detailed description of the results of his analyses and resulting cost of equity recommendations. He applied the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), and the Bond Yield Plus Risk Premium approach to develop his ROE recommendation.

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[1] See 2008 Rate Order.

[2] Id.

Witness Hevert testified that it is important for a utility to be allowed the opportunity to earn a return adequate to attract equity capital at reasonable terms and commensurate with the returns expected elsewhere in the market for investments of equivalent risk, because that enables the utility to provide service while maintaining financial integrity. He stated that the Commission's decision should provide PSNC with the opportunity to earn an ROE that is (1) adequate to attract capital at reasonable terms, thereby enabling it to continue to provide safe and reliable natural gas service; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He discussed the need to select a group of proxy companies to determine the cost of equity, and how he selected the proxy group for this case.

According to witness Hevert, the results of his Constant Growth DCF analysis produced a range of 8.14% to 11.32% ROE, the results of his Multi-Stage DCF analysis were a range of 8.96% to 10.07%, and the results of his Multi-Stage DCF analysis that used the current proxy group P/E ratio to calculate the terminal value was a range of 9.26% to 11.97%. The results of witness Hevert's CAPM analysis showed a range of 9.13% to 11.42%. The results of his Bond Yield Risk Premium analysis indicated an ROE range from 9.98% to 10.39%. Based on his analyses, Witness Hevert concluded that a rate of return on common equity in the range of 10.00% to 10.75% represents the range of equity investors' required rate of return for investment in natural gas utilities such as PSNC. Within that range, he recommended an ROE of 10.6%.

Witness Hevert explained that his ROE recommendation also took into consideration several additional factors, including (1) the combined dilutive effects of operating expense increases and increasing capital investments on the Company's operating income; (2) the Company's relatively high capital expenditure program; (3) the Company's relatively small size; (4) the effect of the proposed infrastructure recovery mechanism on the Company's cost of equity; and (5) the regulatory environment in which the Company operates. He also considered equity flotation costs. With regard to the regulatory environment, he noted that North Carolina is generally considered to be a constructive regulatory jurisdiction, and that authorized ROEs tend to be correlated with the degree of regulatory supportiveness (utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns). He did not, however, make any specific adjustment to his ROE estimates for the effect of these factors.

Witness Hevert also considered the economic conditions in North Carolina in arriving at his ROE recommendation. He noted that the rate of unemployment has fallen substantially in North Carolina and the U.S. generally since late 2009 and early 2010, with December 2015 rates of 5.60% in the state and 5.30% in PSNC's service territory. He also noted that in 2014 the state exceeded the national rate for real gross domestic product growth, and that since 2009 median household income in North Carolina has grown at a somewhat faster annual rate than the national median income. In addition, while housing permits and housing starts experienced a decline from late 2015 to early 2016, total personal income, disposable income, personal consumption, and wages and salaries were generally on an increasing trend. Witness Hevert also testified to recent business expansions in the state. Based on all of these factors, witness Hevert opined that North Carolina and the counties contained within PSNC's service area continue to steadily emerge from the economic downturn that prevailed during the Company's 2008 rate case, and have experienced significant economic improvement during the last several years, that is projected to continue. In his opinion, PSNC's proposed ROE was fair and reasonable to PSNC, its shareholders and its customers, considering the impact of changing economic conditions.

Witness Hevert also addressed the capital market environment, and reiterated that the current market is one in which it is important to consider a broad range of data and models when determining the cost of equity, as exemplified by his use of the DCF, CAPM and Bond Yield Plus Risk Premium approaches.

In his direct testimony, witness Addison, Executive Vice President and Chief Financial Officer for PSNC, stated that, based on his training, experience, and knowledge of the financial community and how it perceives PSNC, he agreed with witness Hevert's conclusion that a 10.60% ROE is appropriate in this case. Witness Addison explained that adopting an unduly low ROE would ignore the changing economic conditions being experienced nationally and in North Carolina and could increase the cost of capital, a cost ultimately borne by PSNC's customers.

As reflected in Paragraph 5.C. of the Amended Stipulation, the Stipulating Parties agreed to a stipulated ROE of 9.70%. As stated in Paragraph 5.D. of the Amended Stipulation, the Stipulating Parties also agreed that PSNC should be allowed to earn an overall rate of return on its rate base of 7.53%.

The overall return on rate base and the proposed allowed rate of return on common equity set forth in the Amended Stipulation were supported by the supplemental testimony of PSNC witness Hevert and the hearing testimony of witnesses Hevert and Addison.

In his supplemental testimony and associated exhibits, witness Hevert addressed the agreed-upon ROE and overall rate of return agreed to in the August 18, 2016 Partial Stipulation. As with capital structure discussed above, while the Stipulating Parties filed two amended stipulations – one on August 25, 2016 and one on August 30, 2016 - those amended agreements did not adjust the stipulated ROE and overall rate of return reflected in the Partial Stipulation filed on August 18, 2016, to which witness Hevert testified. Witness Hevert testified to his understanding that the Stipulating Parties agreed to an ROE of 9.70%, with an overall rate of return of 7.53%. Witness Hevert stated that he supported PSNC's decision to agree to the stipulated ROE, explaining that although 9.70% is somewhat below the lower bound of his recommended range (i.e., 10.00%), he recognized that the Partial Stipulation represents a give and take among the Stipulating Parties regarding multiple issues that would otherwise be contested. He stated further that if the Company determined that the terms of the Partial Stipulation, taken as a whole, are such that it will be able to raise the external capital required to continue the investments required to provide safe and reliable service, and that it will be able to do so when needed and at reasonable cost rates, then he appreciated and respected that decision, and viewed the 9.70% stipulated ROE as a reasonable resolution of an otherwise contentious issue.

In his supplemental testimony, witness Hevert also updated his cost of capital analysis. He considered the stipulated ROE in the context of authorized returns for other natural gas utilities, finding that since January 1, 2014, a total of 24 of 54 returns authorized for natural gas utilities were 9.70% or above, with the average authorized ROE over all such cases being 9.65%. He again testified that North Carolina is generally considered to have a constructive regulatory environment, and in that context noted that the stipulated ROE is a reasonable, though conservative, measure of PSNC's cost of equity.

Witness Hevert also updated his review of economic conditions in North Carolina with respect to those factors for which updated data was available. He found that by 2015, North Carolina's real GDP exceeded its 2010 level by nearly 7.00%, and that from 2013 through 2015 the state's average rate of real GDP growth was somewhat higher than the national average. As to the rate of unemployment, he found that although North Carolina's December 2015 seasonally adjusted unemployment rate of 5.60% was somewhat higher than the U.S. average of 5.00%, by June 2016 both the national and North Carolina unemployment rates fell to 4.90%, with the rate in PSNC's service territory being only slightly higher at 5.14%. He found that personal income and consumption in the state have continued to expand at the national level. Finally, he reported that in its August 2016 "Snapshot of North Carolina," the Federal Reserve Bank of Richmond (FRB-Richmond) concluded that North Carolina's economy strengthened as total employment grew notably, household conditions continued to improve, and housing market indicators were mostly positive. The FRB-Richmond also observed that: (1) North Carolina employers added 19,400 jobs in June and almost every industry expanded payrolls that month; (2) the state's unemployment rate fell 0.2 percentage points to 4.90% in June and declined 0.9 percentage points since June 2015, and during the first quarter of 2016, the share of mortgages with payments 90 or more days past due fell 0.2 percentage point to 1.50%; and (3) North Carolina issued 5,210 new residential permits in June, up 7.10% from the prior month and up 11.9% from June 2015. Witness Hevert also noted that the models used to estimate the cost of equity reflect capital markets and therefore general economic conditions. He noted further that given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in ROE estimates. In summary, witness Hevert stated that it continues to be his view that on balance, the regional economic challenges in the state are substantially similar to those in the rest of the country, and that economic data regarding North Carolina and the United States do not alter the cost of equity estimates, or his recommendation, one way or the other.

Finally, witness Hevert considered the stipulated overall rate of return, stating that it is consistent with the average return authorized across the country, but lower than those returns authorized in the top-ranked regulatory jurisdictions, and that the stipulated overall rate of return is, like the stipulated ROE, reasonable, though in his opinion a conservative estimate of PSNC's overall investor-required rate of return.

At the hearing, in response to cross-examination by the Attorney General, witness Addison reiterated that two reasons for the higher cost of equity than cost of debt is that the equity investor requires more return commensurate with the higher risk associated with equity, and that while interest on debt is tax-deductible, equity earnings are not.

Witness Hevert also responded to cross examination by the Attorney General regarding his use of the DCF, CAPM, and Bond Yield Plus Risk Premium approaches to determine a recommended ROE range for PSNC. Witness Hevert confirmed the nature of his ROE recommendations in recent electric rate cases in North Carolina. He also explained the value of using diverse sources of data for purposes of conducting the constant growth DCF analysis, discussed why he uses projected earnings to determine growth for the same analysis rather than another metric such as projected dividends, and testified that using different sources for the GDP for his multi-stage DCF would produce different results. During this discussion he answered questions from the Attorney General related to data on natural gas companies that are comparable to PSNC provided by Value Line. He also responded to questions regarding the source data he used for risk premiums for his CAPM analysis, and testified that use of some alternative sources would result in very low estimated ROEs that would have significant adverse impacts to the Company's financial standing. With regard to his Bond Yield Plus Risk Premium approach, witness Hevert clarified the nature and value of the numerous authorized rates of return on equity he used in that analysis, which in turn reflect market data.

In response to questioning by Chairman Finley, witness Hevert confirmed his belief that equity investors make investment decisions based on the risks they observe for the companies in which they are interested. He also clarified the distinction between expected and required returns, such that if the return that an investor requires is higher than the return that investor expects, that investor will choose not to invest. Witness Hevert testified that if a company operates in a state with poor economic conditions, such that many of its customers are unable to pay their bills, that company would have a large amount of uncollected revenues for the services it provided, which would in turn cause that company's risk to increase and the cost of equity that the equity investor would require to be higher. He testified further that, if the rate of return on equity was based on current economic conditions, and if in that scenario the investor was penalized during poor economic conditions by giving him less rate of return, symmetry would suggest that a higher return on equity would be provided during robust economic conditions. Witness Hevert also testified that, in comparison to the economic conditions that existed when previous electric rate cases were decided involving Duke, Progress, and Dominion North Carolina Power that were referenced by the Attorney General, the North Carolina economy has improved. Witness Hevert explained that the unemployment rate in the state is down considerably and is now approximately equal to the national rate, and that state GDP growth has expanded with projections for continued expansion. He agreed that the investment community looks upon the Commission, together with the state legislature and executive branch, as providing a constructive regulatory environment. He also agreed that the previous cases referenced by the Attorney General were, after remand to the Commission, reapproved at the same rates.

In response to further questioning by Chairman Finley, witness Hevert testified that, if it became a permanent requirement in North Carolina that the Commission change the rate of return on equity based on customers' ability to pay, that would have a negative impact on the constructive regulatory environment in the state. He explained that would be a departure from the Commission's past practice and would also be a departure from well-established practice of other regulatory commissions, which added together would add a considerable amount of risk. Witness Hevert further confirmed in response to questioning by Chairman Finley that other regulatory commissions will take economic conditions into consideration. He testified that, in this way, such commissions balance the interests of investors and ratepayers. However, he stated that he was unaware of any regulatory commissions that apply adjustments to the return on equity to account for economic conditions or customer ability to pay.

No other party presented direct evidence on the Company's cost of capital or overall rate of return on rate base.

Legal Standards Applicable to Rate of Return Findings by the Commission

The Commission's analysis of and decision on rate of return on rate base and allowed rate of return on common equity in this case is governed by the United States Supreme Court's Hope and Bluefield decisions,[1] the requirements of G.S. 62-133, and the North Carolina Supreme Court decisions interpreting and applying each of the foregoing to rate of return decisions by the Commission.

In Bluefield, the United States Supreme Court established the basic framework for rate of return regulation of public utilities. On this subject, the Court held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield, 262 U.S. at 692-93.

In the subsequent Hope decision, the Court expanded on its analysis by stating:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock…. By that standard the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Hope, 320 U.S. at 603.

The Commission has looked to the Hope and Bluefield standards as guidance for setting rates. In Docket No. E-7, Sub 1026, the Commission noted that:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944)

[1] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope); Bluefield Waterworks & Imp. Co. v. Public Service Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield).

> (Hope). To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S. E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id. at 7.

The Commission must balance the interests of investors and customers in setting the rate of return on equity. As the Commission has stated, "…the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[1] In that regard, the return should be neither excessive nor confiscatory; it should be the minimum amount needed to meet the Hope and Bluefield Comparable Risk, Capital Attraction, and Financial Integrity standards.

The Commission also has found that the role of cost of capital experts is to recommend to the Commission the investor-required return, not to estimate increments or decrements of return in connection with consumers' economic environment. As the Commission pointed out:

> … adjusting investors' required costs based on factors upon which investors do not base their willingness to invest is an unsupportable theory or concept. The proper way to take into account customer ability to pay is in the Commission's exercise of fixing rates as low as reasonably possible without violating constitutional proscriptions against confiscation of property. This is in accord with the "end result" test of Hope. This the Commission has done.[2]

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[1] North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, at 24 (Sept. 24, 2013); see also North Carolina Utilities Commission, Docket No. G-9, Sub 631, Order Approving Partial Rate Increase and Allowing Integrity Management Rider at 26, (Dec. 17, 2013) (noting North Carolina Supreme Court's determination that the provisions of G.S. 62-133 "effectively require the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States, those of the State Constitution, Art. I, § 19, being the same in this respect"), DNCP Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.").

[2] North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, at 34 – 35 (October 23, 2013); see also DNCP Remand Order at 26 (stating that the Commission is not required to "isolate and quantify the effect of changing economic conditions on consumers in order to determine the appropriate rate of return on equity").

The Supreme Court agreed, and upheld the Commission's Order on Remand.[1] The Supreme Court has also, however, made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[2] In Cooper II, which addressed an appeal of the Commission's order on Dominion North Carolina Power's previous base rate application, the Supreme Court directed the Commission on remand to "make additional findings of fact concerning the impact of changing economic conditions on customers."[3] The Commission made such additional findings of fact in its order on remand.[4]

On October 10, 2016, the Attorney General filed a post-hearing Brief. With regard to the appropriate ROE for PSNC, the Attorney General contends that the stipulated 9.70% ROE is a higher ROE than what is adequate. As an example of the interrelationship between changes in the ratio of equity financing versus debt and the impact on the ROE, the Attorney General states that the proposed overall rate of return in the present case, 7.53%, is higher than the overall rate of return the Commission approved for Piedmont three years ago, 7.51%, in Docket No. G-9, Sub 631, even though the approved ROE for Piedmont was 10.0%. Further, the Attorney General asserts that capital costs have trended downward since Piedmont's rate case.

In its Reply Brief, PSNC asserts that the Attorney General's citation to the Transcript, Vol. 5, p. 75, does not support the above assertion. PSNC states that on this page of the Transcript PSNC witness Addison testified on cross-examination that Piedmont's lower overall rate of return in Docket No. G-9, Sub 631, as compared to the stipulated rate of return in this case, may have been due to the lower percentage of equity in Piedmont's capital structure as compared to the stipulated equity in this case. Further, PSNC states that witness Addison also testified that the 9.70% stipulated return on equity in the present docket is higher than PSNC's embedded cost of long-term debt of approximately 5.5%.

In addition, PSNC asserts that there is no evidence that capital costs have trended downward since Piedmont's rate case. Rather, PSNC contends that witness Hevert's direct testimony indicates that capital costs have increased since Piedmont's rate case, noting that witness Hevert testified that "since December 2013, relative volatility has increased, suggesting greater increasing uncertainty in the natural gas utility industry"; "credit spreads have increased"; "[t]o the extent that credit spreads have increased, it is an observable measure of the capital markets' increased risk aversion"; and "increased risk aversion clearly is associated with an increased Cost of Equity." (T Vol. 5, p. 204)

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[1] State of North Carolina ex rel. Utilities Commission v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014).

[2] State of North Carolina ex rel. Utilities Commission v. Cooper, 367 N.C. 430, 437, 758 S.E.2d 635, 642 (2014) (Cooper II); see also State of North Carolina ex rel. Utilities Commission v. Cooper, 366 N.C. 484, 739 S.E.2d 541 (2013) (Cooper I).

[3] Cooper II, 367 N.C., at 438, 758 S.E.2d, at 643.

[4] DNCP Remand Order, at 4-10.

In his Response Brief, the Attorney General states that the full Transcript citation should have been Vol. 5, pp. 73-75. Further, he notes that the point of comparing Piedmont's cost of equity and capital structure is to highlight the fact that the lower ROE in this case is deceptive because the 52% equity ratio offsets it.

With regard to the downward trend in capital costs, the Attorney General notes witness Hevert's testimony that stock prices for utilities went up in late 2015 and early 2016, which effectively reduced the dividend yield for shareholders. In turn, this tended to produce a lower cost of capital under the Constant Growth DCF analysis.

Most of the Attorney General's ROE argument focuses on criticism of the techniques used and results obtained by witness Hevert. With respect to witness Hevert's DCF analysis, the Attorney General asserts that there are two features that skew his results. One is his reliance on what the Attorney General calls "the most extreme data." That is, witness Hevert calculates his "High ROE" from the highest growth data that exists. However, as the Attorney General notes, witness Hevert also calculates a "Low ROE" from the lowest growth data, but his recommended ROE range draws from the high results, not the low results. The other feature that the Attorney General contends skews witness Hevert's DCF results upward is his over-reliance on sources of data that reflect five-year projections of annual growth in earnings per share -- Zack's, First Call, and Value Line -- without consideration of other factors available to investors for measuring growth. For example, the Attorney General points out that there are 15 measures of growth provided in Value Line reports for witness Hevert's proxy companies, including the annual rates of change per share for revenues, cash flow, earnings, dividends, and book value, each provided for the past 10 years, the past 5 years, and as estimates for future years.

In its Reply Brief, PSNC contends that the Attorney General's assertion that witness Hevert considered only the high range of his analysis is not supported by the record. PSNC cites witness Hevert's cross-examination testimony stating that he took into account both the high and low estimates of the growth data, and notes that his Table 2: Summary of Constant Growth DCF Results (T Vol. 5, p. 147) shows that his recommended ROE range of 10.00% to 10.75% did not draw only from the high results, which ranged from 11.08% to 11.32%, but was within the overall range of high and low results.

With regard to the Attorney General's criticism that witness Hevert's DCF study did not consider factors other than earnings growth, PSNC cites witness Hevert's cross-examination testimony explaining why it was appropriate to use earnings growth and not the other factors. For example, witness Hevert stated that it was better to use earnings growth than dividends "simply because … the dividends are derived from earnings. You cannot pay dividends unless you have earnings." (T Vol. 6, p. 25) He further testified that he did not give historical earnings growth any weight, in part, "because a lot of analysts will already look at historical earnings growth and they would be reflected in the earnings projected." (T Vol. 5, p. 26)

In response, the Attorney General notes that witness Hevert agreed that the "mean high" estimate in his Constant Growth DCF study reflects the highest result based on the multiple growth data sources he used, and the "mean low" estimate reflects the lowest result, and that his 10.6% ROE recommendation is higher than the midpoint between the mean results and the highest results. With regard to witness Hevert's exclusive use of earnings growth, the Attorney General points out that other measures of growth are available to investors, and that relying on only one factor may have distorted witness Hevert's results, and asserts that this was illustrated by the Value Line information available to investors provided as an attachment to the Attorney General's Brief, as well as the box showing the growth data for Laclede Group.

With regard to witness Hevert's Multi-Stage DCF analysis, the Attorney General contends that his results are skewed upward by his use of a 5.31% long-term growth rate that he calculated, rather than using lower growth rates available from reliable sources such as the Social Security Administration (SSA), 4.35%, and the Energy Information Administration (EIA), 4.24%. In its Reply Brief, PSNC states that witness Hevert explained during cross-examination that the SSA and EIA growth rates are "not necessarily" lower than his if scenarios other than the SSA's and EIA's reference cases are considered. He stated that these alternative scenarios produce high and low case scenarios, and concluded that his estimate was "well within the range" of the high and low case scenarios that SSA and EIA provide. (T Vol. 6, pp. 33-34)

In response, the Attorney General notes witness Hevert's cross-examination testimony that he used the SSA and EIA rates in recent testimony that he filed in a Missouri rate case.

With respect to witness Hevert's CAPM analysis, the Attorney General asserts that his results are skewed because instead of relying on a published market source to estimate the risk premium associated with stocks, generally, compared to risk-free investments, witness Hevert derived his own risk premium estimates by performing a DCF study using data obtained from Bloomberg and Value Line. The Attorney General presents calculations derived by substituting the risk premium provided in a "Client Alert" issued by Duff & Phelps, an investor service that publishes data on the market risk premium and investor expectations regarding that parameter, which produces lower CAPM results.

In reply, PSNC states that in witness Hevert's cross-examination testimony he notes that the Duff & Phelps estimated risk premium of 5% to 5.5% is not their CAPM approach but only one component of their "building block approach" under which other risk factors would be layered on to this component to calculate the cost of equity. (T Vol. 6, pp. 40-41) PSNC also states that witness Hevert testified that using this 5% to 5.5% risk premium would produce a cost of equity of only 7.49%, which would result in significant negative market consequences. PSNC further states that the Attorney General concedes that "data published by Duff & Phelps … may not be appropriate to determine a point-estimate for the cost of equity capital in this proceeding …." See Attorney General's Brief, at pp. 23-24.

The Attorney General responds that PSNC's position is contrary to the following statement in the Duff & Phelps Client Alert summary that was introduced as Attorney General Hevert Cross-Examination Exhibit 5:

> The ERP [Equity Risk Premium] is a key input used to calculate the cost of equity capital within the context of the Capital Asset Pricing Model (CAPM) and other models.

With respect to witness Hevert's Bond Yield Plus Risk Premium analysis, the Attorney General asserts that this approach does not rely on financial market data, but rather on the authorized rates of return that have been established by regulatory agencies for other utilities. The Attorney General states that the authorized rates of return were determined in other jurisdictions based on policies and underlying data estimates of market conditions that are not provided in the record in this case, and, therefore, it is not appropriate for the Commission to determine PSNC's ROE based on such evidence. In support of his position, the Attorney General cites State ex rel. Utilities Comm'n v. Cooper, 367 N.C. 430, 443, 758 S.E.2d 635, 643 (2014); and State ex rel. Utilities Comm'n v. Public Staff, 331 N.C. 215, 225, 415 S.E.2d 354, 361 (1992).

In conclusion, the Attorney General submits that PSNC has not shown that a 9.70% ROE is required. Rather, the Attorney General maintains that market-based data indicates that the Company's cost of equity is at least 35 basis points lower than 9.70%.

As witness Hevert testified, the cost of equity is not precisely quantifiable. Therefore, financial analysts use a number of quantitative models to develop estimates from market data. Witness Hevert further testified that analysts must exercise some judgment in making assumptions and using proxies. The Attorney General's criticisms of witness Hevert's DCF and CAPM analyses constitute disagreements with witness Hevert about some of his judgments in choosing the market data that he uses in his quantitative models. The Commission is not persuaded that the Attorney General's criticisms undermine or reduce the credibility of witness Hevert. Rather, the Attorney General's criticisms go to the weight of witness Hevert's DCF and CAPM analyses and testimony, and the Commission has given those criticisms due consideration in weighing witness Hevert's analyses and testimony.

With regard to witness Hevert's Bond Yield Plus Risk Premium (Bond Plus) analysis, the Commission has not relied on that analysis or witness Hevert's testimony regarding the Bond Plus analysis to arrive at its ROE decision. Instead, the Commission has considered it as a check or as corroboration with regard to other evidence on ROE in this proceeding. That check allows the Commission to ensure that its ROE decision is not vastly out of line with rates of return authorized for regulated utilities in other jurisdictions.

The Attorney General did not provide a witness or affirmative evidence that would support a ROE lower than the stipulated 9.70%. Indeed, no expert witness provided an analysis after the Amended Stipulation that showed 9.70% as the appropriate level of ROE for PSNC. Therefore, the Commission must consider the evidence and exercise its independent judgment in determining the appropriate ROE for PSNC in the context of setting PSNC's rates. With these legal principles in mind, the Commission now turns to the analysis and weighing of the evidence in this proceeding relating to a determination of the appropriate overall rate of return on rate base and allowed return on common equity for use in this proceeding.

Analysis of the Evidence

In order to reach an appropriate independent conclusion regarding return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541, 546-47 (2013) (Cooper).

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the proper return on equity for a public utility. Cooper, 366 N.C. at 491, 739 S.E.2d at 548. There is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers. However, the impact on customers of changing economic conditions is embedded in the return on equity expert witnesses' analyses. The Commission noted this in its Order Granting General Rate Increase in Docket No. E-22, Sub 479: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return." Order Granting General Rate Increase, Docket No. E-22, Sub 479, at 38 (2012) (DNCP Rate Order).

The only evidence in this proceeding related to the determination of an overall rate of return on rate base or allowed rate of return on common equity is provided in the testimony and exhibits of PSNC's witnesses Addison and Hevert. Therefore, the substantial expert return on equity evidence that is entitled to the greatest weight is not contradicted by any direct cost of capital expert testimony. Witness Hevert indicated in his supplemental testimony that, although the stipulated ROE is somewhat below the lower bound of his recommended range (i.e., 10.0%), he views the 9.70% stipulated ROE as a reasonable resolution of an otherwise contentious issue. Witness Hevert also presented supplemental testimony in which he updated his analysis of the changing economic conditions in North Carolina. The analysis included a review of a number of economic statistics regarding the condition of the economy in North Carolina that continue to indicate improving economic conditions. Based on this analysis witness Hevert testified that economic conditions in the state do not alter his cost of equity estimates or recommendations one way or the other.

In his direct testimony, witness Addison testified to the importance of PSNC maintaining its ability to access national capital markets on reasonable terms in this time of financial uncertainty, an ability that ultimately benefits PSNC's ratepayers. He noted that return on equity is a key consideration for investors when assessing whether to invest in a company like PSNC. He highlighted the Company's significant and ongoing capital needs as well as the important and real financial consequences that the Commission's determinations regarding rate of return can have in the capital markets and the terms under which PSNC can access those markets.

The Attorney General questioned witness Hevert about various aspects of his analysis, but did not provide any affirmative evidence that would support a return on common equity lower than the 9.70% proposed in the Amended Stipulation. The Attorney General's cross-examination established only that the outcomes of the DCF and CAPM analyses would have been different had witness Hevert, for example, used different sources for the growth estimate in the third stage of the multi-stage DCF analysis, or had he used another approach to the CAPM method. The Commission finds witness Hevert to be a credible witness in this case and accepts witness Hevert's support of the 9.70% ROE as probative evidence for purposes of establishing a return on common equity for PSNC in this proceeding. The Commission notes that witness Hevert's direct and supplemental testimony is the only economic rate of return testimony in this case.

There is no record evidence in this case establishing meaningful customer opposition to the stipulated overall rate of return on rate base of 7.53% or the stipulated rate of return on common equity of 9.70%, or suggesting that the stipulated rates are either unfair or would cause substantial hardship to PSNC's customers. No public witnesses appeared at any of the four public hearings held to receive public testimony.

The lack of substantive evidence of consumer opposition to PSNC's stipulated rate increase does not relieve the Commission of its obligation to reach its own independent conclusion as to whether the Amended Stipulation is just and reasonable, fair to customers, the Company and its shareholders in light of changing economic conditions, and otherwise sufficient to satisfy the requirements of G.S. 62-133. Further, even though the record evidence does not establish this fact with respect to any specific PSNC customer, the Commission of its own experience acknowledges and accepts as true the proposition that some percentage of PSNC's customers, particularly those living on fixed incomes, are economically vulnerable and may struggle to pay an increase in PSNC's rates granted in this docket. Likewise, the Commission must keep this in mind as it undertakes to balance the interests of customers with the constitutional requirements of establishing adequate rates for PSNC.

As noted above, the record evidence in this proceeding supports the legitimacy and reasonableness of the levels of return on rate base and allowed rate of return on common equity reflected in the Amended Stipulation. In light of this fact, the question for the Commission becomes whether the Amended Stipulation represents an appropriate balancing of the interests of customers, the Company, and shareholders, by establishing rates that are as low as may be reasonably consistent with the requirements of due process. As explained below, the Commission concludes, based on its own independent judgment, that the Amended Stipulation satisfies the requirements of North Carolina law in this respect.

First, in his supplemental testimony witness Hevert acknowledges that the stipulated allowed rate of return on common equity of 9.70% is below what he recommended as the range of returns for PSNC. However, witness Hevert indicates that his support for the stipulated ROE is based on the fact that the stipulated ROE represents the give and take among the Stipulating Parties regarding multiple and otherwise contested issues. Finally, he presents a detailed updated review of economic conditions in the State, concludes that these data support his initial conclusion that economic conditions in North Carolina continue to improve, and notes that the changing economic conditions in North Carolina do not impact his recommendations in this case.

It is also significant to note that the direct testimony of PSNC witnesses Addison and Hevert establish without question that PSNC is actively engaged in a significant capital investment program that will continue for the next several years that is driven by federal pipeline safety and integrity requirements and that access to capital on reasonable terms is critical to PSNC in order to fund that investment.

Conclusions on Return

The Commission understands that rate increases are not favored by ratepayers and that some portion of any utility's customer base will find it difficult to pay their utility bills from time to time. The Commission further acknowledges that it is the Commission's primary responsibility to protect the interests of utility customers in setting rates for public utilities by complying with the legal principles discussed earlier in this Order. It is also the Commission's responsibility to abide by the constitutional requirements of the Hope and Bluefield cases as reflected in the provisions of G.S. 62-133 and to balance the interests of customers and the utilities which the Commission regulates in that process.

The Commission gives substantial weight to witness Hevert's DCF analysis, particularly on the basis of mean growth rates. Witness Hevert testified that for each of his proxy companies he calculated mean, mean high and mean low results. Based on 30-day, 90-day and 180-day averages, the rate of return on equity range based on witness Hevert's mean growth rate analysis is from 8.33% to 10.01%. This range provides support for the stipulated rate of return on equity of 9.70%, particularly in light of the Supreme Court's decision in State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Southeast, 285 N.C. 671, 681, 208 S.E.2d 681, 670 (1974) (a "zone of reasonableness extending over a few hundredths of one percent" exists within which the Commission may appropriately exercise its discretion in choosing a proper rate of return on equity).

In addition, the Commission gives substantial weight to witness Hevert's supplemental testimony in support of the stipulated 9.70% ROE. He testified that although the Stipulated ROE is somewhat below the lower bound of his recommended range (i.e., 10.0%), he recognized that the Stipulation represents the give-and-take among the Stipulating Parties regarding multiple issues that would otherwise be contested by the Stipulating Parties. In addition, he relied on PSNC's determination that the terms of the Amended Stipulation, taken as a whole, are such that PSNC will be able to raise the capital required to continue the investments required to provide safe and reliable service, and that it will be able to do so when needed and at a reasonable cost.

The Commission also gives substantial weight to witness Hevert's testimony that although the stipulated ROE falls within the range of analytical results presented in his direct testimony, current capital market conditions are such that the models used to estimate the cost of equity continue to produce a wide range of sometimes conflicting estimates.

The Commission finds it credible that although witness Hevert's three DCF analyses reflect a range of 8.14% to 11.97%, the average of the nine mean DCF results is 9.78%, as can be calculated using the mean results in Table 9a on page 94 of his direct testimony. This average mean of 9.78% is only eight basis points higher than the stipulated 9.70% ROE.

The Commission also gives substantial weight to witness Hevert's testimony that it is important to keep in mind that the models used to estimate the cost of equity reflect capital markets and, therefore, general economic conditions. Given that changes in economic conditions in North Carolina are related to the domestic economy, it is reasonable to conclude that both are reflected in ROE estimates.

The Commission also finds credible witness Hevert's testimony that it is his view that on balance, economic data regarding North Carolina and the United States do not alter the cost of equity estimates, or his recommendation, one way or the other.

In his Brief, the Attorney General contends that even though the stipulated 9.70% ROE appears to move the rate of return gradually toward the lower cost of capital reflected in financial market data, that appearance is deceptive because it ignores the offsetting effect of the higher stipulated equity ratio. The Attorney General further states that the overall rate of return – taking into account the ROE along with other factors proposed in this case – is actually higher at 7.53% than the overall rate of return the Commission fixed for Piedmont three years ago in Docket No. G-9, Sub 631 (which was 7.51%) although Piedmont's ROE was fixed at 10% in that case and capital costs have trended downward. (T5 p 75) Further, the Attorney General states that PSNC appears to be giving customers a lower profit (ROE), but is more than taking it all back by raising the ratemaking equity ratio, absent any showing that PSNC has significantly increased business risk that would warrant such a high equity ratio.

The Commission is not persuaded by the Attorney General's analysis, for two reasons. First, the difference in the Piedmont overall rate of return, 7.51%, and the stipulated overall rate of return, 7.53%, is not significant given the differences in the two utilities and the passage of three years since the Piedmont overall rate of return was established. Secondly, to the extent that comparisons with prior rates are helpful, it is more instructive to note that PSNC's overall rate of return, ROE, and equity ratio will all be significantly lower under the Amended Stipulation than those approved in PSNC's 2008 Rate Order. In the 2008 Rate Order, the approved overall rate of return, ROE, and equity ratio were 8.54%, 10.6% and 54%, respectively. In the present case, the stipulated overall rate of return, ROE, and equity ratio are 7.53%, 9.7% and 52%, respectively.

Consumers pay rates, a charge in cents per therm for the natural gas they consume. They do not pay a rate of return on equity. To the extent that the Commission makes downward adjustments to rate base, reduces the approved common equity component of capital structure, disallows test year expenses or increases pro forma test year revenues, the Commission reduces the rates consumers pay during the future period rates will be in effect. However, the utility's investors' compensation for the provision of service to consumers takes the form of return on investment. As the North Carolina Supreme Court has stated:

> The "rate of return" on equity, PSNC's outstanding common stock, "is a percentage that the Commission concludes should be earned on the value of the utility's investment, commonly referred to as the 'rate base.'" Carolina Util. Customers Ass'n, 348 N.C. at 461, 500 S.E.2d at 700. Several variables factor into determining a "just and reasonable" rate of return, including:
>
> > (1) The rate base which earns the return; (2) the gross income received by the applicant from its authorized operations; (3) the amount to be deducted for operating expenses, which must include the amount of capital investment currently consumed in rendering the service; and (4) what rate constitutes a just and reasonable rate of return on the predetermined rate base.

Id. at 461-62, 500 S.E.2d at 700.

State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 351 N.C. 223, 232, 524 S.E.2d 10, 17 (2000) (emphasis added).

To the extent the Commission makes adjustments to reduce the overall cost of service, the Commission reduces the rates consumers otherwise must pay irrespective of its determination of rate of return on equity expressed as a percentage, in this case 9.70%. To the extent these adjustments reflect current economic conditions, and consumers' ability to pay, these adjustments reduce not only consumers' rates but also the return on equity, expressed in terms of dollars that investors actually earn. This is also in accord with the end result test of Hope.

In the present case, PSNC's initial Application requested a $41,583,020 increase in PSNC's annual North Carolina revenues. That revenue increase would require an over-all rate increase of 9.66%. In addition, PSNC requested a 10.6% rate of return on common equity, an 8.14% overall return on a rate base of $949,341,460, and a capital structure that included 53.5% common equity. These are the "big picture" numbers. However, the crucial details of PSNC's general rate Application, as in all general rate cases, are in the hundreds of line items in NCUC Form G-1 that detail the Company's cost of service.

PSNC's Application is supported by substantial and credible evidence that, standing alone, could form the basis of a decision by the Commission to approve a $41,583,020 increase in PSNC's annual North Carolina revenues. However, the details of PSNC's Application, including the cost of service line items, are reviewed by the Public Staff and, in some rate cases, by other intervenors. The Public Staff typically recommends numerous adjustments to the utility's cost of service items, some adjustments increasing an item and some adjustments decreasing another item. These adjustments are presented by the Public Staff in its testimony, or, as in the present docket, in a settlement agreement with the utility.

In the present docket, the Public Staff's adjustments are shown in Exhibit A, Page 2, of the Amended Stipulation. There are about 40 adjustments, some up and some down. For example, an adjustment reducing PSNC's service company charges by $3,228,865 is made on line 34, and an adjustment adding $91,901 to PSNC's cost of materials and supplies is made on line 9. However, the end result of all the adjustments is a reduction in PSNC's revenue requirement from the requested $41,583,020 to the stipulated amount of $19,054,160. Thus, the numerous adjustments made by the Public Staff, and approved herein by the Commission, reduce the total annual base revenues to be received by PSNC from ratepayers by $22,528,860, including a reduction of approximately $6,000,000 in the return to be paid to equity investors.[1] Although the ROE downward adjustment produces a direct reduction in the authorized rate of return on investment financed by equity investors, the numerous other downward adjustments reflected on Exhibit A further reduce the dollars the investors actually have the opportunity to receive. Thus, while the equity investor's cost was calculated under the terms of the Amended Stipulation by applying a rate of return on equity of 9.70%, instead of the 10.6% requested in the Application, based in part on existing macroeconomic

[1] Compare Boone Exhibit 6, p. 2, Statement Showing Rates of Return after Adjustments for Proposed Rates, line 3, with Public Staff Late-Filed Exhibit I, Schedule 4, Return on Equity and Original Cost Rate Base, line 3.

conditions affecting customers' ability to pay, this is only one of many approved adjustments that reduces ratepayer responsibility and equity investor reward.

This is not to say that the Commission accepts the stipulated 9.70% rate of return on equity merely because it is lower than the 10.6% requested by PSNC. Rather, it is to emphasize that each of the approximately 40 adjustments made by the Public Staff, and accepted herein by the Commission, reflects the fact that ratemaking, and the impact of rates on consumers, must be viewed as an integrated process where the ratemaking end result is what directly affects customers. The Commission's acceptance of the foregoing ratemaking adjustments, including the 9.70% rate of return on equity, reflects the Commission's application of its subjective, expert judgment under the Public Utilities Act that the end result is in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints.

Solely focusing on the authorized rate of return on equity in assessing the impact of the Commission's decision on consumers' ability to pay in the current economic environment would fail to give a true and accurate picture of the issues presented to the Commission for decision and the totality of the Commission's order. Such an analysis would also be inconsistent with Hope and the Carolina Util. Customers Ass'n cases. For example, when the Commission approves, in part due to current economic conditions, a reduction in the investment against which the authorized 9.70% rate of return on equity is multiplied to produce the dollars in return on equity investment, the financial impact is a reduction in the rates paid by ratepayers and a reduction in the amount received by equity investors, the same result as if the Commission had instead reduced the 9.70% rate of return on equity.

As previously noted from the Hope decision, it is the "end result" of the Commission's order that must be examined in determining whether the order produces just and reasonable rates. Therefore, the Commission cannot, as suggested by the Attorney General, simply conclude that 9.70% "exceeds the ROE that is adequate" for PSNC. Instead, the Commission has incorporated into its analysis all of the myriad factors that make up PSNC's revenue requirement, including the rate of return on equity and the impact of the Commission's decision regarding the consumers' ability to pay in the current economic environment. Based on that impact and the total effect of the rate order, the Commission concludes that a 9.70% rate of return on equity produces just and reasonable rates for PSNC and for its ratepayers. Any further reduction in the authorized rate of return on equity is not justified by the evidence.

Based on the above-discussed cost of equity testimony of witness Hevert, the Commission finds his recommendations regarding the appropriate cost of equity for PSNC to be substantial and credible evidence.

After a careful review of all the evidence in this case, and adhering to the requirements of the above cited legal precedents, the Commission finds that the overall rate of return on rate base and the allowed rate of return on common equity, as well as the resulting customer rates provided for under the Amended Stipulation, are just and reasonable, fair to both PSNC and its customers, and appropriate for use in this proceeding and should be approved. The rate increase approved herein, as well as the rates of return underlying such rates, are just, reasonable and fair to customers considering changing economic conditions, and are required in order to allow PSNC, by sound management, to produce a fair return for its shareholders, maintain its facilities and provide services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and existing investors.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence supporting this finding of fact is set forth in the verified Application, the testimony of the Company's witnesses, and the Amended Stipulation.

The level of adjusted sales and transportation volumes used in the Amended Stipulation is 937,082,412 therms. The sales and transportation throughput volume level is derived as follows:

Sales	491,921,582
Transportation	316,664,980
Special Contract	128,495,850
Total Throughput	937,082,412

The level of purchased gas supply is 499,819,717 therms, and is derived as follows:

Sales	491,921,582
Company Use and Lost & Unaccounted For	7,898,135
Purchased Gas Supply	499,819,717

The throughput level and level of purchased gas supply are the result of negotiations among the Stipulating Parties, as described in the Amended Stipulation, and are not opposed by any party. No other party submitted evidence on the Company's throughput.

The Commission has carefully reviewed the evidence regarding the appropriate throughput level in this docket and concludes that the stipulated throughput levels are a fair and reasonable approximation of the Company's *pro forma* adjusted sales and transportation volumes. The Commission has also carefully reviewed the purchased gas supply level and concludes that it is a fair and reasonable approximation of the Company's *pro forma* purchased gas supply level.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-22

The evidence for these findings is contained in the verified Application, the testimony of the Company's witnesses, and the Amended Stipulation.

The test period cost of gas is set forth in Paragraph 7 and Exhibit E to the Amended Stipulation. The amounts shown on Exhibit E to the Amended Stipulation are the result of negotiations among the Stipulating Parties in this docket. The Amended Stipulation reflects the following agreements among the parties regarding PSNC's cost of gas:

Commodity Costs	$110,682,356
Company Use and	
Lost and Unaccounted For	$1,777,080
Fixed Costs	$67,928,619
Total Cost of Gas	$180,388,055

The stipulated cost of gas is not contested by any party to this proceeding. The Commission has carefully reviewed these amounts, as well as all record evidence relating to the *pro forma* cost of gas, and concludes that the stipulated cost of gas is reasonable and appropriate for use in this docket.

Under the Commission's procedures for truing-up fixed gas costs in proceedings under Commission Rule R1-17(k), it is necessary and appropriate to determine the amount of fixed gas costs that are embedded in the rates approved herein. In the Amended Stipulation, the Stipulating Parties agree that for the purpose of this proceeding and future proceedings under Commission Rule R1-17(k) during the effective period of rates approved in this proceeding, the appropriate amount of fixed gas costs to be allocated to each rate schedule is as set forth in Exhibit C to the Amended Stipulation. No party contests this allocation and no other party submitted evidence supporting a different allocation.

The Commission has carefully examined these amounts, as well as all record evidence on fixed gas cost allocations, and concludes that the stipulated allocations of fixed gas costs are fair and reasonable.

Under the Commission's procedures for establishing rates and truing-up commodity gas costs, it is necessary to establish a Benchmark Commodity Cost of Gas (Benchmark) embedded in sales customer rates. The Amended Stipulation provides that in establishing rates for this proceeding, the parties have agreed to use PSNC's current Benchmark of $0.225 per therm subject to any filed changes in such rate prior to implementation of revised rates in accordance with the Commission's final order in this docket. No party contests the use of a $0.225 per therm Benchmark in establishing rates for this proceeding and no other party submitted evidence on this issue. The Commission has carefully examined this proposal and concludes that the use of a $0.225 per therm Benchmark for purposes of establishing rates in this proceeding is fair and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence for this finding is contained in the Amended Stipulation, as supported by the direct and supplemental testimony of Company witness Paton and the testimony and revised exhibits of Public Staff witness Larsen.

The stipulated rate design and rates, necessary and appropriate to provide PSNC a reasonable opportunity to recover the stipulated revenue requirement in this docket, are reflected in Exhibit B to the Amended Stipulation. On Exhibit B, PSNC has included a new Medium General Service rate schedule 140 (MGS Rate 140) applicable to commercial and small industrial customers who use more than 25,000 but less than 60,000 therms per year. According to witness

Paton, the larger customers who will move to MGS Rate 140 will no longer distort the average usage levels for the Small General Service Rate 125. Witness Larsen agreed with the Company's reasoning for creating the MGS Rate 140 and recommended that it be approved.

In addition, Exhibit B to the Amended Stipulation reflects that the Stipulating Parties have agreed to an additional usage tier for Rate Schedule 175. The additional usage tier for Rate 175 is also shown on Public Staff witness Larsen's Amended Exhibit C, page 2 of 2. The Stipulating Parties agreed that the additional usage tier will not result in any revenue shifting between rate classes.

The computations on Exhibit B show that the proposed rates will produce the revenues calculated under the rate design, as well as the proposed gas costs rates approved for use in this proceeding. The Commission has carefully reviewed these rates, as well as all record evidence relating to the proper rates to be implemented in this proceeding, and concludes that the stipulated rates are just and reasonable.

A portion of the rate increase will be recovered through the increase in reconnect fees. At the evidentiary hearing, Public Staff witness Larsen testified that the proposed reconnect fee of $80 for residential customers during regular working hours was justified. During questions from the Commission, witness Larsen stated that the Public Staff requested justification of the increase in a data request sent to the Company, and PSNC responded that the increase reflected an annual inflation adjustment since 2006 of approximately two percent per year. Witness Larsen further testified that there was an in-depth analysis performed a number of years ago where all of the components of the cost of reconnecting gas service were analyzed. Witness Larsen cited the various steps and tasks involved in this process. Witness Larsen stated that, in today's dollars, the result is it costs almost $100 for a reconnect. He testified that customers avoid paying the monthly facilities charge while they are disconnected. Witness Larsen concluded that $80 was reasonable and did not exceed the cost that the Company had to incur to provide that service.

The Commission has carefully reviewed the cost components of the reconnection process and concludes that the proposed reconnect fees proposed by PSNC and agreed upon by the Stipulating Parties are fair and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding is contained in the Application, the direct testimony of Company witness Ratchford, the direct and supplemental testimony of Company witness Paton, the direct testimony of Public Staff witness Perry, the Amended Stipulation, and Rider E of the Company's tariffs.

In its Application, PSNC indicated that it was incurring substantial and ongoing capital expenses associated with efforts to comply with federal pipeline safety and integrity management requirements. In order to address the magnitude and impact of its capital investments required to comply with federal pipeline safety and integrity requirements on a going-forward basis, and as authorized by G.S. 62-133.7A, PSNC proposed the adoption of an IMT mechanism in its tariffs.

According to PSNC, this mechanism would allow the capital cost of pipeline integrity activities to be recovered in a timelier manner than they would be if PSNC had to wait for a general rate case.

In his direct testimony, Company witness Ratchford testified to the Company's ongoing capital investments driven by compliance with federal pipeline safety and integrity requirements and emphasized the importance of pipeline safety to the Company, its customers, and the public in general. Witness Ratchford set out a detailed description of the federal Transportation Integrity Management Plan (TIMP) and Distribution Integrity Management Plan (DIMP) processes required of the Company. He also described in some detail the Company's evolving techniques and efforts to comply with TIMP and DIMP requirements as well as the Company's future planned compliance activities. In his testimony, witness Ratchford described the nature of TIMP and DIMP compliance activities and the fact that federal regulation was an actively evolving process that could generate substantial additional compliance requirements in the future and that the full scope of those requirements could not be known at this time. Witness Ratchford also explained that the IMT mechanism proposed by the Company to track these costs would allow the capital cost of pipeline integrity activities to be recovered in a timelier manner than if PSNC were required to wait for a general rate case. He explained that, in this way, the Company's customers are not subjected to a large, one-time rate increase, and the amount of the increase is reduced by minimizing debt expense on the capital necessary to make integrity management improvements, as well as minimizing general rate cases and their associated expenses.

In her direct testimony, witness Paton explained the Company's proposed IMT mechanism and provided a proposed form of such tracker in Paton Exhibit 4.

Witness Paton testified that in broad terms, the IMT provides for PSNC to adjust its rates biannually in order to recover the revenue requirement associated with Integrity Management Plant Investment and associated costs incurred by PSNC resulting from prevailing federal standards for pipeline integrity and safety that are not otherwise included in current base rates.

Public Staff witness Perry testified that after several months of discussions, PSNC and the Public Staff agreed to a modified form of the IMT mechanism filed by the Company. Witness Perry stated that the IMT mechanism will assist PSNC in the implementation and timely recovery of costs associated with its investment of capital in compliance with the requirements of federal and state laws and regulations regarding pipeline integrity (including both transmission and distribution integrity), reliability and safety.

Witness Perry testified that the Public Staff has had approximately 2 ½ years of experience auditing the Piedmont Natural Gas, Inc. IMR mechanism.[1] This experience was very helpful in discussions with PSNC regarding its proposed IMT. The Amended Stipulation includes a provision that sets out how to determine excluded costs from the Company's Integrity Management Plant Investment using both the exclusion percentages based on PSNC's budgeted integrity management (IM) projects, as well as the direct assignment approach for specific IM projects that have a significant non-IM component. Witness Perry testified that the Public Staff and PSNC agreed that

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[1] See Order Approving Partial Rate Increase and Allowing Integrity Management Rider (G-9, Sub 631, December 17, 2013); and Order Approving Stipulation (G-9, Sub 631, November 23, 2015).

the excluded reasonable and prudent costs shall be eligible for inclusion in recoverable rate base in PSNC's next general rate case proceeding.

The Amended Stipulation further stated that the Stipulating Parties agreed that costs incurred for system expansion/improvement or routine maintenance, repair and replacement of system components that are not required to comply with federal gas pipeline safety requirements shall not be included in amounts recovered under the IMT mechanism.

Witness Perry also stated that the Public Staff and PSNC worked hard to determine a fair and reasonable approach to enable the Company to recover its prudently incurred capital investment and associated costs of complying with federal gas pipeline safety requirements.

No other party submitted evidence on the issue of the proposed IMT mechanism.

In the Attorney General's Brief, the Attorney General states several concerns about the proposed IMT. In summary, the Attorney General acknowledges that the legislature authorized the Commission in G.S. 62-133.7A to adopt a rate adjustment mechanism to allow the recovery of prudent costs of compliance with federal pipeline safety requirements. Nevertheless, the Attorney General contends that the IMT is not in the public interest because PSNC has not shown that there is a need for such rate adjustment mechanism, and any benefit it offers to investors is outweighed by disadvantages to consumers, such as frequent additional rate increases, an expedited review, no regard for offsetting cost factors, and a lack of meaningful public input. The Attorney General further contends, based on testimony by PSNC witness Addison, that the IMT is not needed to address investor concerns about timely recovery of capital costs.

In its Reply Brief, PSNC takes issue with the Attorney General's interpretation of witness Addison's testimony regarding investor concerns. PSNC submits that the Commission's rejection of the IMT would be viewed by investors as a sign of an unsupportive regulatory environment, particularly when the IMT is a part of a near-unanimous settlement.

The Commission has carefully considered the evidence in this proceeding related to the proposed IMT mechanism, as well as the Attorney General's concerns, and has reached the following conclusions. First, the Commission concludes that the form of IMT mechanism attached in Exhibit H to the Amended Stipulation falls within the scope of G.S. 62-133.7A. That statute authorizes the Commission to adopt "a rate adjustment mechanism to enable the company to recover the prudently incurred capital investment and associated costs of complying with federal gas pipeline safety requirements, including a return based on the company's then authorized return." In this case, the proposed form of IMT attached to the Amended Stipulation provides for the recovery of return, taxes, and depreciation on capital investment associated with federal gas pipeline safety requirements in a manner consistent with the statute and in the same fundamental manner that PSNC is permitted to recover those items of its cost of service in a general rate case proceeding. This approach to IM cost recovery is reasonable and consistent with statutory requirements and normal regulatory practices.

Second, the Commission concludes that the IMT mechanism proposed for adoption and implementation in the Amended Stipulation is beneficial to customers because it provides for the use of both the exclusion percentages determined using PSNC's budgeted IM projects, as well as the direct assignment approach for specific projects that have a significant non-IM component.

Third, the proposed IMT Rider expressly provides for Commission review of the mechanism at the earlier of PSNC's next general rate case proceeding or four years from the implementation of the mechanism and also specifically grants any party the right to apply to the Commission to terminate or modify the mechanism at any time on the grounds that the rider mechanism, as approved by the Commission, is no longer in the public interest.

Fourth, consistent with the requirements of G.S. 62-133.7A, the Commission concludes that adoption and implementation of the IMT mechanism as reflected in Rider E of the Company's tariffs and attached to the Amended Stipulation as Exhibit H is in the public interest. The Commission finds the uncontested evidence of PSNC's required capital expenditures on TIMP/DIMP compliance convincing. It is equally persuaded that regular and repeated general rate case proceedings, otherwise necessary to reflect such investments in PSNC's rate base, would be a detriment to PSNC and its customers, and would serve no purpose other than to increase regulatory costs paid by ratepayers and the regulatory burden on all parties who participate in PSNC's general rate proceedings. The Commission recognizes, as the Attorney General points out, that separately accounting for TIMP/DIMP compliance costs and addressing them through the IMT mechanism on an intra-rate case basis effectively isolates those costs from other aspects of PSNC's cost of service. The Commission is satisfied that the public interest is protected from any potentially adverse impacts from such treatment through a variety of means, including the limited nature of the costs recoverable through the mechanism, using the exclusion percentages determined using PSNC's budgeted IM projects, as well as the direct assignment approach for specific IM projects, the special contract crediting provision contained therein, the mandatory and permissive review provisions contained in the rider, and the Commission's general and continuing oversight of the Company's earnings. The Commission also concludes that the tracker provides an overall benefit to customers since it would allow the capital cost of pipeline integrity activities to be recovered in a timelier manner than if PSNC were required to wait for a general rate case, and therefore avoids subjecting the Company's customers to a large, one-time rate increase. In addition, the amount of the increase is reduced by minimizing debt expense on the capital necessary to make integrity management improvements, as well as minimizing general rate cases and their associated expenses. Further, the tracker is subject to Commission review after four years.

With respect to the Attorney General's concerns about the expedited nature of the review process and ensuring meaningful public input, the Commission is not persuaded that the expedited procedure is a detriment to the Commission's decision-making process, or that there will be a lack of opportunity for meaningful public input. As Public Staff witness Perry testified, the Public Staff has about 2 ½ years of experience auditing the Piedmont Natural Gas, Inc., IMR mechanism. Similarly, the Commission has that same level of experience in reviewing the evidence and making decisions regarding the proper implementation of Piedmont's IMR. Further, the Commission is not aware of any complaints from parties to the Piedmont IMR dockets or the public that the semi-annual reviews have not afforded interested persons a full and fair opportunity to be heard. In addition, if the Commission receives such complaints with regard to its reviews of PSNC's IMT, the Commission has the authority and the procedural tools to remedy those concerns.

Finally, the Commission believes that implementation of the proposed IMT mechanism will promote public safety by supporting the timely recovery of costs associated with pipeline safety and integrity expenditures by the Company. Safety and reliability of utility infrastructure is of critical importance to the State and the Commission, and this mechanism facilitates the accomplishment of that goal.

Based on the foregoing, and in the absence of any evidence to the contrary, the Commission finds the Integrity Management Tracker mechanism as reflected in Rider E of the Company's tariffs and described in Paragraph 10 and attached as Exhibit H to the Amended Stipulation to be just, fair, reasonable, in the public interest, and appropriate for adoption in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence for this finding is contained in the Amended Stipulation reflected in Paragraph 6 and Late Filed Exhibit D.

Under PSNC's CUT mechanism, certain baseload and heat factors, as well as "R" values, are needed in order to make the calculations periodically required under that mechanism. The Stipulating Parties have provided updated factors in this proceeding as reflected in Paragraph 6 and Late Filed Exhibit D of the Amended Stipulation. These values are not contested by any party and no other party has offered evidence supporting other factors. Based on the Amended Stipulation, and the entire record of evidence in this proceeding, the Commission finds and concludes that the updated CUT factors, including the "R" values, identified on Late Filed Exhibit D to the Amended Stipulation are reasonable and appropriate and should, therefore, be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence for this finding is contained in the Company's initial filing and the Amended Stipulation.

In PSNC's Application, supported by the direct testimony of Company witness Boone, the Company proposed to amortize and recover a number of previously deferred regulatory assets including PIM and manufactured gas plant (MGP) O&M costs. It also proposed to amortize and recover DIMP O&M costs. In Paragraph 5 of the Amended Stipulation, the Stipulating Parties propose certain agreed upon changes to the Company's proposed amortizations and recovery of PIM, MGP, and DIMP O&M costs. The Stipulating Parties support the five year amortization periods set forth in Paragraph 5 of the Stipulation and the ongoing interim deferral mechanism for PIM and DIMP O&M costs. No party has opposed the proposals contained in Paragraph 5 of the Amended Stipulation and no other evidence has been submitted regarding these issues.

The Commission has carefully considered the proposed amortization periods and related matters set forth in Paragraph 5 of the Amended Stipulation, as well as all record evidence on the amortization of these regulatory assets, and concludes that the stipulated amortization treatment and specified amortization periods are consistent with the Commission's prior treatment of similar costs and are otherwise fair and reasonable and should be approved. The Commission further concludes that the proposed continuation of the existing regulatory asset treatment for ongoing PIM and DIMP O&M costs is fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence for this finding is contained in the North Carolina General Statutes, the Amended Stipulation, the supplemental testimony of Company witness Paton, and the testimony of Public Staff witness Boswell.

North Carolina Session Law 2015-241 established a prospective downward adjustment in the North Carolina corporate income tax rates to be effective for tax year 2017. The Amended Stipulation states that PSNC will make downward adjustments to its rates to recognize the reduction in the state corporate income tax rate to 3% beginning January 1, 2017. In the Amended Stipulation, the Stipulating Parties further agreed to work together on determining the appropriate revenue requirement reduction and effectuating such reductions and to file notice of such rate reductions with the Commission prior to implementation. No party opposed this plan to adjust PSNC's rates for reductions in income tax expense and no other evidence on this issue was presented to the Commission in this docket.

The Commission has considered the proposed adjustment to corporate income tax set forth in Paragraph 8 of the Amended Stipulation, as well as all evidence of record regarding the corporate tax changes effectuated by North Carolina Session Law 2015-241, and concludes that the stipulated treatment is consistent with the Commission's prior treatment of other tax reductions and is otherwise fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence for this finding is set forth in the direct testimony of Company witnesses Spanos and Boone, the testimony of Public Staff witness Boswell, and in the Amended Stipulation.

In the Amended Stipulation, the Stipulating Parties agreed that the revised depreciation rates, as presented in the deprecation study filed along with and supported by Company witness Spanos' direct testimony, should be implemented effective January 1, 2017. Public Staff witness Boswell testified that the Public Staff reviewed the depreciation study, found no issues with the new depreciation rates, and recommends approval of the proposed depreciation rates. No party contested the implementation of PSNC's revised depreciation rates as proposed in the Amended Stipulation and no other party submitted any additional evidence on this issue.

Based on the direct testimony of Company witnesses Spanos and Boone and the Amended Stipulation, the Commission concludes that implementation of the revised depreciation rates filed in the instant docket, effective January 1, 2017, as proposed in the Amended Stipulation, is just and reasonable and should be approved for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence for this finding is contained in the direct testimony of Company witnesses Paton and Jackson and the Amended Stipulation.

Company witnesses Paton and Jackson testified to proposed additional changes in the Company's tariffs and service regulations and the reasons underlying those changes. Witness Paton testified that minor changes were made to PSNC's rate schedules, including: (1) adding language stating that the rate schedules are subject to the Integrity Management Tracker; (2) adding language to the Large General Service and transportation rate schedules to indicate a change in billing to state the customer's consumption on the basis of dekatherms rather than therms; and (3) other minor changes as noted on Paton Exhibit 4.

With regard to changes to PSNC's service regulations, witness Paton testified that the Company is proposing several minor changes, including: (1) deleting current Section 29, which addresses the methodology for determining rate service priority pursuant to Commission Rules R6-12 and R6-19.2, and providing this information in a new Rider B to the tariff; (2) adding a provision allowing reclassification of a customer outside of the annual review period under certain circumstances; (3) adding language in Section 21 regarding gas quality and measurement; and (4) adding new Section 29 to clarify the customer's responsibility for paying certain taxes. Witness Paton further stated that PSNC is proposing other minor changes to its riders for clarification, formatting and grammatical corrections.

Witness Paton also testified regarding proposed additional language in Section 21 to address gas quality and measurement. With respect to gas quality, the language in Section 21 assumes that all gas will be delivered by an interstate pipeline and will be, "subject to the quality specifications of the interstate transporter's Federal Energy Regulatory Commission-approved contract." The Commission asked what would happen if gas was produced in North Carolina and put into PSNC's system. Witness Paton responded that she didn't know that the Company, "contemplated anything above and beyond what's coming off the interstate now." (T Vol. 6, p. 121) Witness Jackson responded that the Company had been contacted about biogas projects over the past few years and had contemplated installing a chromatograph at the site where the supply source would come into PSNC's system. When asked whether PSNC would have responsibility for the quality of biogas it accepts, witness Jackson responded that "The producer is required to meet the gas quality standard so that our customers will not be impacted." (T Vol. 6, p. 166) No party objected to the adoption of the proposed language in Section 21 dealing with gas quality. The Commission notes that, should parties seek to place gas into PSNC's system from a North Carolina location, it could be necessary to clarify and amend this section. Further, the language in this Section should not be seen as intended to bar or hinder the development of gas supplies in North Carolina.

With regard to the use of a weighted average BTU content of gas entering PSNC's system, the Commission asked about differences in heat content from different sources of supply. Witness Paton responded that, in the past, PSNC used only one BTU reading, but now that the Company has gas coming from different directions, a weighted average of the BTU content of the gas at different take-off stations is used. Witness Paton added that the difference has not been significant. When asked how much variance would be acceptable, she responded that the use of a system–wide average BTU factor "would balance out any of the pricing concerns." (T Vol. 6, p. 123) No party objected to the adoption of the proposed language in Section 21 dealing with the measurement of gas and the conversion from cubic feet to therms or dekatherms using a weighted average BTU content.

Witness Jackson testified that PSNC reviewed its tariffs and guidelines governing interruptible service following the failure of numerous customers to curtail their usage during an unusually cold period in January 2014. She testified that PSNC is recommending changes in those tariffs and guidelines to improve the Company's ability to serve its firm customers in the event of a curtailment. Regarding proposed changes to Rider A, Curtailment of Service under Commission Rule R6-19.2 and Emergency Services, witness Jackson testified to the following changes: (1) elimination of on-peak emergency service, resulting in one level of emergency service with a single assessment rate; (2) an increase in the assessment rate for Unauthorized Gas from $2.50 per therm to $5.00 per therm, or $50.00 per dekatherm; and (3) removal of the allowance of 10 therms per day for pilot usage, and modification of the rider to allow a maximum of 10 dekatherms per day in Emergency service without prior authorization from PSNC. Witness Jackson testified that these changes will be more effective in deterring noncompliance with curtailment, and more efficient for the Company to administer.

Witness Jackson further testified to two changes being made to PSNC's interruptible Rate Schedules 150, 160, 165 and 180. The first change requires customers to provide and update contact information for two authorized representatives. The second change adds language describing some of the costs, not addressed in Rider A, that a customer may incur for taking Unauthorized Gas during a curtailment event. Witness Jackson described a third change, needed only for Rate Schedule 180, to clarify that non-compliance with a curtailment order may result in PSNC valving off the customer's gas service. Witness Jackson stated that PSNC is proposing these changes to make the curtailment process more effective and efficient.

Finally, witness Jackson described several changes to PSNC's Transportation Pooling Agreement designed to improve the transportation nomination process and encourage poolers to maintain balance in their deliveries of gas to PSNC's system.

Company witness Paton filed Exhibit 4 with her direct testimony. Exhibit 4 includes the Company's proposed tariffs, Rules and Regulations and Transportation Pooling Agreement. For the most part, the Stipulating Parties accepted the tariffs, Rules and Regulations as filed in Paton Exhibit 4. However, the Stipulating Parties made changes to Riders C and E, and the Transportation Pooling Agreement. Those changes are reflected in Exhibit H to the Amended Stipulation. No party objected to these changes.

The Commission has carefully reviewed these changes to the Company's service regulations, tariffs, riders and the Transportation Pooling Agreement. The Commission finds and concludes that they are just, fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The evidence for this finding is contained in the Application, the direct testimony of Company witness Paton, and the Amended Stipulation.

In its Application, PSNC proposed to refund over a one-year period the EDIT as set forth in Paton Exhibit 13. In the Amended Stipulation, the Stipulating Parties agreed, in Paragraph 12, that it was appropriate to implement a temporary decrement in rates to refund the EDIT as set forth in Paton Exhibit 13 over a one year period. The parties also agreed that in accordance with North Carolina Session Law 2013-316 (House Bill 998), PSNC will refund the additional EDIT over a one-year period, and any amount remaining after twelve months shall be transferred to the All Customers' Deferred Account. No party has contested the refund of EDIT as proposed in the Application and agreed to in the Amended Stipulation, and no other party has presented any additional evidence on this issue.

The Commission has carefully considered the refund of EDIT as proposed in the Amended Stipulation, as well as all of the evidence in the record, and concludes that it is fair and reasonable and should be approved. The Commission further finds that any amount of EDIT remaining after twelve months should be transferred to the All Customers' Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence supporting this finding is contained in the Amended Stipulation.

In Paragraph 13 of the Amended Stipulation, the Stipulating Parties proposed to continue funding of conservation programs at a level of $750,000 per year, as reflected in test year operating expenses. No party contested the continued level of conservation spending or recovery of conservation dollars provided in the Amended Stipulation.

The Commission has carefully considered the proposed continuous level and treatment of conservation funding in the Amended Stipulation and finds it to be fair and reasonable. As a general statement, the Commission believes that energy conservation and efficiency serve the public interest and that conservation measures provide long-term and year-round benefits to PSNC's customers and to the public as a whole.

Based on the foregoing, the Commission concludes that the amount of conservation spending provided for by the Amended Stipulation, and the recovery of those costs through rates, is appropriate for this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence for this finding is contained in the Application, the direct testimony of Company witness Ratchford, the Amended Stipulation, Public Staff Late-Filed Exhibit I, and the direct testimony of Public Staff witness Boswell.

In its Application, PSNC proposed to include in its cost of service in this proceeding $275,000 for the funding of GTI research into natural gas pipeline safety and reliability. In his direct testimony, Company witness Ratchford indicated that the Company's proposal to include a contribution to GTI in this case was targeted at GTI's Operations Technology Development (OTD) initiative. Witness Ratchford described the OTD initiative as a program specifically targeted towards developing tools and technologies that will assist local distribution companies such as PSNC in meeting the requirements associated with their TIMP and DIMP.

In Public Staff Late-Filed Exhibit I, witness Boswell demonstrated that PSNC's proposal of $275,000 for the funding of GTI was based on an estimate of the number of meters as of December 31, 2016, multiplied by $0.50 per meter. The Amended Stipulation reflects a downward adjustment to the actual number of meters on June 30, 2016, found in Public Staff Late-Filed Exhibit I.

In the Amended Stipulation, the Stipulating Parties agreed, in Paragraph 14, "that the Company may fund research and development activities through annual payments to GTI that have been included in operating expenses in this proceeding."

No party has contested the funding of GTI proposed in the Application and agreed to in the Amended Stipulation and no other party has presented evidence on this issue.

The Commission has carefully considered the GTI funding proposed in the Amended Stipulation, and concludes that the funding of GTI at the level of $268,631 per year to support the development of new technologies, practices and processes which enhance the safety and reliability of natural gas transmission systems is in the public interest and is also fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33 – 35

The evidence supporting these findings is contained in the testimony and exhibits of the Company and Public Staff, and in the Amended Stipulation.

In PSNC's last general rate case in Docket No. G-5, Sub 495, the Stipulating Parties agreed that the appropriate Allowance for Funds Used During Construction (AFUDC) rate for the Company should be the overall rate of return, adjusted for income taxes. In that docket, Company witness Paton testified in response to a question from the Commission that the AFUDC rate would remain in effect until the Company's next general rate case proceeding, which is the docket now before the Commission. The Stipulating Parties in this docket agreed to continue using the overall rate of return, adjusted for income taxes. The Commission finds that the continued use of the overall rate of return for the AFUDC rate, adjusted for income taxes, is just, reasonable and appropriate and should be approved.

PSNC has been applying the statutory maximum of 10% authorized in G.S. 62-130(e) to balances in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The Stipulating Parties agreed in the Amended Stipulation that beginning with the month in which the Order is issued, PSNC will use an interest rate of 6.6% per annum as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The methods and procedures used by PSNC for the accrual of interest on the Deferred Gas Cost Accounts will remain unchanged.

In response to a question from the Commission, PSNC witness Paton stated that the 6.6% is also applied to the balances in the Customer Utilization Tracker (Rider C) and the Integrity Management Tracker (Rider E). Those two riders explicitly call for a reevaluation of the rate every year, and witness Paton confirmed that the 6.6% rate applied to Deferred Gas Cost Accounts would also be reevaluated annually.

The Commission finds that a reduction in the interest rate applied to the balances in the Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts with the rate to be reevaluated annually is just, reasonable and appropriate and should be approved.

Public Staff witness Perry testified that the Stipulating Parties agreed to changes in certain PSNC reporting requirements including filing the GS-1 Report in a format similar to the ES-1 filed by the electric utilities, effective with filings after January 1, 2017. No party opposed this change, which is administrative in nature. The Commission finds that requiring PSNC to file its GS-1 report in a format similar to the ES-1 filed by the electric utilities is reasonable and appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence for this finding is contained in the hearing testimony of Company witness Addison.

The Commission questioned PSNC witness Addison about PSNC's participation in the SCANA Utility Money Pool (UMP). It was noted that the monthly reports provided by PSNC to the Commission in Docket No. G-5, Sub 484 disclosed a distinctive trend of PSNC being far more often a lender than a borrower in its UMP transactions, and generally lending far more than it has borrowed. Witness Addison was asked what benefits he saw PSNC receiving from its participation in the SCANA UMP.

He responded that "The Pool is set up so that the different Companies can take advantage of each other's cash flow or investment abilities at different points in time." Witness Addison testified that PSNC is "moving back into that period where they're going to be a net borrower." (T Vol. 5, p. 117) However, he also testified that:

> PSNC has not had as much capital to invest in the business as it does prospectively, so we've not had to issue a great deal of long-term debt, anything like that, not been into the commercial paper markets a lot in the past. That has changed now and so now PSNC is a net borrower just like SCE&G is. (T Vol. 5, p. 117)

Witness Addison further testified that the UMP has allowed PSNC to earn some return when it has had excess cash. He stated that participation in the UMP is a prudent and efficient use of PSNC's capital. He pointed out that SCANA could have altered its dividend policies, and moved more PSNC cash to SCANA, "but we wanted to keep that capital structure, maintain those credit ratings at PSNC, so we've kept the dividend payouts ratio very similar over the period of time." (T Vol. 5, p. 118)

To help the Commission monitor PSNC's activity in the SCANA UMP, the Commission finds good cause to require PSNC to add to the information provided in its monthly UMP report filed in Docket No. G-5, Sub 484. Beginning with the January 2017 report, PSNC shall report the net daily balance of loans and receipts, and the total net interest amount on the balances. This information will be provided for the month, and for the calendar year to date.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

The evidence supporting this finding of fact is contained in the consumer statements of position received by the Commission, the Public Staff and the Attorney General. The following is a summary of these statements.

Bruce Sampsell, from Chapel Hill, submitted a consumer statement of position to the Public Staff stating that for the past 15 years the returns on equity for both gas and electric utilities have been declining. He provided an economic analysis and other documentation. He further noted that there is absolutely no sound rationale to support PSNC's request for a 10.6% ROE. Mr. Sampsell urged the Public Staff to carefully review his submissions as it considers what rate increases and authorized ROE percentage are justified in this circumstance.

Marie Christy, from Kannapolis, submitted a consumer statement of position to the Attorney General's office stating that she lives by herself on a fixed income. She stated that gas prices have come down all over the nation, but not for heating gas. Ms. Christy stated that she will soon be 75 years old and lives alone. Her only income is from Social Security. She said she bundles up and keeps her heat low, but still the bills are high.

Bill Raleigh submitted a consumer statement of position by email to the Commission stating that he recently received notification from PSNC of a proposed increase in residential gas pricing. He stated that in 2008, wellhead pricing for gas was just short of $8.00 per thousand cubic feet (tcf) and today it is $3.00 per tcf. The increase requested is supposedly for infrastructure improvements. With the price of gas dropping since 2008 he questions why that increase in operating income was not used for the improvements and why is it needed now if we have been able to exist since 2008. Based on the above and other noted considerations, he does not believe an increase is warranted at this time.

Diana Asbury submitted a consumer statement of position by email to the Commission stating that she seeks help on behalf of those on a limited/fixed income, herself included, for the 9.7% rate increase requested by PSNC. She acknowledges that rate increases are a way of life, but the requested percentage is too high for the senior community. The extra $3.41 per month that bills would increase may not sound like a lot but to the senior community, it could mean a loaf of bread or a container of milk. She stated that for those on a limited/fixed income who are having difficulties making ends meet any increase causes a hardship.

The Commission is aware that some areas of the state, including portions of PSNC's service territory, continue to have significant levels of unemployment and include significant numbers of low-income customers. As a result, the Commission has fully considered the negative impacts of the proposed rate increase on PSNC's customers and weighed those against PSNC's need to remain financially sound so that the Company is able to continue providing all of its customers safe, adequate and reliable natural gas service.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 38

The evidence supporting this finding of fact is contained in the testimony and exhibits of the Company and Public Staff, and in the Amended Stipulation.

As fully discussed above, the provisions of the Amended Stipulation are the product of the give-and-take of settlement negotiations between PSNC, the Public Staff, CUCA, and Evergreen. Comparing the Amended Stipulation to PSNC's Application, and considering the direct testimony of the Public Staff witnesses, the Commission observes that there are provisions of the Amended Stipulation that are more important to PSNC, and, likewise, there are provisions that are more important to the Public Staff. For example, PSNC is intent on obtaining approval for the IMT, which it views as imperative to a fair recovery of its costs of pipeline safety. On the other hand, the Public Staff is intent on limiting the IMT recovery to those costs directly related to pipeline safety, as indicated by the restrictions placed on the IMT in Paragraph 10.B. of the Amended Stipulation

The end result is that the Amended Stipulation strikes a fair balance between the interests of PSNC and its customers. As discussed above, the Commission has fully evaluated the provisions of the Amended Stipulation and concludes, in the exercise of its independent judgment, that the provisions of the Amended Stipulation are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest. Therefore, the Commission approves the Amended Stipulation in its entirety.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 39

The evidence for this finding of fact is contained in the Application, the testimony and exhibits of the PSNC and Public Staff witnesses, and the record as a whole.

Pursuant to G.S. 62-30, et seq., the Commission is required to set just and reasonable rates for North Carolina's regulated public utilities. In summary, under G.S. 62-133(a) the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the two most important factors the Commission considers are (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See G.S. 62-133(b).

PSNC's continued operation as a safe and reliable source of natural gas for its customers is vitally important to PSNC's individual customers, as well as to the community and business entities served by PSNC, and the economy in general. PSNC presented credible and substantial evidence of its need for increased capital investment to, among other things, meet the requirements of pipeline safety laws, expand and upgrade its pipeline and other infrastructure to serve new customers, and expand the use of technology to more efficiently serve its customers.

For example, PSNC witness Harris testified that the Company has strengthened its pipeline safety efforts in response to the federal Pipeline and Hazardous Materials Safety Administration's (PHMSA's) transmission and distribution pipeline safety regulations. Witness Harris stated that the PHMSA regulations place a great deal of responsibility on PSNC, and are complex, costly and subject to continued change.

In addition, witness Harris testified that since 2008 PSNC has added 77,025 customers, 1,424 miles of transmission and distribution mains, and 83,866 service lines. He also described significant system improvements made by PSNC, such as new compressor stations, and new transmission and high-pressure distribution pipelines.

Further, witness Harris testified that since 2008 PSNC has completed the conversion to automated meter reading, and enhanced its computer-aided dispatch system to enable service calls to be routed more efficiently. Witness Harris also testified that PSNC has 154 vehicles that operate on compressed natural gas (CNG), and that in 2015 alone the Company saved more than $300,000 by using CNG, compared to the cost of using gasoline and diesel fuel.

These are representative examples of the capital investments made by PSNC since its last rate case in order to continue providing safe and efficient service to its customers. Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of PSNC's customers in receiving safe, adequate and reliable natural gas service at the lowest possible rates, and the interests of PSNC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of G.S. 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Amended Stipulation is hereby approved in its entirety.

2. That the Company is hereby authorized to adjust its rates and charges in accordance with the Amended Stipulation and this Order (as such rates may be adjusted for any changes in the

Benchmark, and changes in Demand and Storage Charges prior to the effective date of the revised rates) effective for service rendered on and after November 1, 2016.

3. That the Company is authorized to implement the Integrity Management Tracker as described in Paragraph 10 of the Amended Stipulation and Rider E to the Company's tariffs.

4. That the Company is authorized to implement the changes to its Rate Schedules and Service Regulations contained in Paton Exhibit 4 and attached to the Amended Stipulation as Exhibit H for periods effective on and after November 1, 2016.

5. That the Company shall file clean versions of the new and revised tariffs and service regulations to comply with this Order within five (5) days from the date of this Order. Rider E of such filing shall include the appropriate percentages for Section III.(f) and Section IV.(b).

6. That in the true-up of fixed gas costs for periods subsequent to November 1, 2016, in proceedings under Commission Rule R1-17(k), the Company shall use the fixed gas costs allocations set forth in Exhibit C to the Amended Stipulation.

7. That the Customer Usage Tracker mechanism factors set forth on Late-Filed Exhibit D to the Amended Stipulation are approved for use in the implementation of the provisions of that mechanism subsequent to November 1, 2016.

8. That the Company shall refund the EDIT as set forth in Paragraph 12 of the Amended Stipulation, and any balance that remains at the end of twelve months shall be transferred to the All Customers' Deferred Account.

9. That for quarters ending after the effective date of the Order in this docket, the Company shall begin utilizing a revised NCUC GS-1 Earnings Surveillance Report format that is similar to the format of ES-1 Earnings Surveillance Report that is submitted to the Commission by the electric utilities.

10. That beginning November 1, 2016, the Company shall use 6.60% as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Sales Customers Only, All Customers, and Hedging Deferred Gas Cost Accounts. The methods and procedures used by the Company for the accrual of interest on the Deferred Gas Cost Accounts shall remain unchanged.

11. That beginning with its January 2017 UMP monthly report in Docket No. G-5, Sub 484, regarding the SCANA Utility Money Pool, PSNC shall report the net daily balance of loans and receipts, and the total net interest amount. This information shall be provided for the month, and for the calendar year to date.

12. That the Company is authorized to implement the other actions, practices, principles, and methods agreed upon in the Amended Stipulation.

13. That the Company shall send the notice attached hereto as Attachment A to its customers beginning with the billing cycle that includes the rate changes approved herein.

ISSUED BY ORDER OF THE COMMISSION.
This the __28th__ day of October, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ATTACHMENT A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-5, SUB 565

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Public Service Company of North Carolina, Inc. for a General Increase in its Rates and Charges	)))	PUBLIC NOTICE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) issued an Order allowing Public Service Company of North Carolina, Inc. (PSNC or the Company) to increase its rates and charges by approximately $19 million annually, or 4.39% overall, effective for service rendered on and after November 1, 2016.

On March 31, 2016, PSNC filed an application seeking a general increase in its rates and charges, implementation of a new Integrity Management Tracker mechanism, implementation of new depreciation rates, updates and revisions to the Company's service regulations and tariffs, and proposed funding for gas distribution research activities conducted by the Gas Technology Institute (GTI).

In its application, the Company requested an increase of approximately $41.6 million annually. The Company stated that the rate increase was needed because it has, since its last general rate case in 2008, greatly expanded natural gas service in its rapidly growing service area by making significant capital improvements to its system, and has invested substantial additional capital in order to comply with federal environmental and pipeline safety and integrity regulations and requirements. In support of its request for a rate increase, the Company explained that the increase is necessary in order to allow PSNC to access capital markets on reasonable terms, earn a fair return on its investment, and allow the Company to continue investing in the growth, safety, and reliability of its system.

NATURAL GAS – RATE INCREASE

The increase approved by the Commission was the result of a stipulation (Stipulation) entered into between the Company and other parties to the proceeding, including the Public Staff – North Carolina Utilities Commission. The Commission notes that the increase to specific classes of customers will vary in order to have each customer class pay its fair share of the cost of providing service.

Overall, the Commission has approved a residential rate increase for the Company of 4.0%. This represents an increase to the typical residential bill of approximately

ATTACHMENT A

$24 per year or $2.00 per month. These approved increases are associated with allowed expenses and return on investment only and do not contemplate increases or decreases that may occur in association with gas cost adjustments to rates as allowed by North Carolina law.

The Commission has also approved an Integrity Management Tracker mechanism, which will allow the Company to recover the capital related costs of compliance with federal pipeline and distribution integrity management requirements on an intra-rate case basis. This mechanism will facilitate timely recovery of costs related to capital investment needed to comply with federal law and will help to avoid frequent general rate proceedings.

A list of approved rates can be obtained from the Company's website, www.psncenergy.com, or at the Office of the Chief Clerk of the Commission, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, where copies of the Commission's Order and the Stipulation are available for review by any interested person. The Commission's Order, the Stipulation, and other filings in this docket, can be viewed/printed from the Commission's website at http://www.ncuc.net using the Docket Search function.

ISSUED BY ORDER OF THE COMMISSION
This the __28th _ day of October, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. G-5, SUB 525

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of North Carolina, Inc., for Authorization to Flow Through Alternative Fuel Tax Credits to CNG Retail Sales Customers	))))	ORDER APPROVING RATE ADJUSTMENTS EFFECTIVE MARCH 1, 2016

BY THE COMMISSION: On February 10, 2016, Public Service Company of North Carolina, Inc. (PSNC), filed a petition pursuant to Commission Rules R1-4 and R1-5 requesting authorization to flow through certain Alternative Motor Fuel Excise Tax Credits (tax credits) to customers taking compressed natural gas (CNG) service under its Rate Schedule 135.

Pursuant to Public Law 114-113 (2015), the United States Congress (Congress) has extended a tax credit of $0.50 per gallon of gasoline equivalent for all CNG sold at retail as an alternative motor vehicle fuel effective December 31, 2015, through December 31, 2016. Without further action such as the flow-through requested in its petition, PSNC as the eligible taxpayer will receive the benefit of the tax credit in the form of reduced tax obligations to the federal government. PSNC, however, stated that it determined that the tax credits should flow through to the CNG customers who are actually generating the credit. PSNC proposed to effectuate this reallocation of the alternative motor vehicle fuel excise tax credit to its CNG sales customers by implementing a temporary decrement of $0.50 per gallon of gasoline equivalent under Rate Schedule 135. PSNC requested expedited Commission approval of the temporary rate decrement and attached revised tariff rates to its petition.

PSNC further noted that as the extension passed late in 2015, any further extension would likely occur late in 2016. Should such an additional extension occur, PSNC stated that it would prefer that the tax credit continue to flow through to customers uninterrupted; or, if the tax credit is not extended or otherwise revised, PSNC would like to have the capability to remove or modify the flow-through. Therefore, PSNC requested authority to remove or modify the temporary decrement to reflect any future changes in the tax credit that Congress may enact without seeking prior Commission approval. PSNC stated that it would promptly notify the Commission of such removal or modification of the temporary decrement.

Based on the foregoing, PSNC respectfully requested expedited Commission approval of the reduction in its CNG rates and provided revised tariff rates.

The Public Staff presented this matter to the Commission at its February 29, 2016, Staff Conference. The Public Staff stated it had reviewed the petition and proposed rate adjustments, and recommended that the Commission issue the order for PSNC to implement its proposal to flow through the excise tax credit associated with the retail sale of CNG for motor fuel purposes.

Based on review of the petition and the recommendation of the Public Staff, the Commission finds good cause to approve the petition.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC be authorized to implement its proposal to flow through the excise tax credits associated with the retail sale of compressed natural gas for motor fuel purposes for its Rate Schedule 135 through December 31, 2016, and thereafter to extend the tax credit or modify it based on any future action of the Congress.

2. That PSNC shall promptly file with the Commission, for information purposes, notification of any removal or modification of the temporary decrement, including revised tariffs.

3. That PSNC shall file revised tariffs reflecting the rate changes provided herein within five (5) days of the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the ___1st____ day of March, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. T-4631, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Branch Out Delivery, Inc., 5321 Pronghorn Lane, Raleigh, North Carolina 27610 - Application for Certificate of Exemption to Transport Household Goods	))))	ORDER RULING ON FITNESS TO OBTAIN CERTIFICATE OF EXEMPTION

HEARD: Tuesday, September 27, 2016, at 10:00 a.m., in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner Bryan E. Beatty, Presiding, and Commissioners Don M. Bailey and Jerry C. Dockham

APPEARANCES:

For Branch Out Delivery, Inc.:

Charlotte A. Mitchell, Law Office of Charlotte Mitchell, Post Office Box 26212, Raleigh, North Carolina 27611

BY THE COMMISSION: On May 31, 2016, Branch Out Delivery, Inc. ("Applicant"), pursuant to G.S. 62-261(8) and Commission Rule R2-8.1, filed an application ("Application") in the above-captioned docket with the North Carolina Utilities Commission ("Commission") for a certificate of exemption from compliance with the provisions of Chapter 62, Article 12 of the North Carolina General Statutes. No protests were filed to the application. The Application included the required confidential SBI and FBI criminal history records check.

On August 24, 2016, the Commission issued an Order Scheduling Application for Hearing to address questions regarding the Application and whether the Applicant is fit, willing and able to provide the transportation of household goods in intrastate commerce.

On September 14, 2016, the Public Staff – North Carolina Utilities Commission notified the Commission that it did not intend to participate in the hearing.

The hearing was held in Raleigh, North Carolina on Tuesday, September 27, 2016, as scheduled. The Applicant was represented by counsel. Mr. Walter Branch and Mrs. Lisa Branch,[1] principals of the Applicant, appeared and testified in support of the Application and responded to questions from the Commission. Applicant also offered testimony from Jeanne Tedrow, in support of Lisa Branch and Walter Branch, and Beverly McGehe, in support of Walter Branch. At the

[1] The Application identifies Walter Branch and Lisa Johns as the principals of Branch Out Delivery, Incorporated. Per testimony given at the hearing, subsequent to the filing of the application, Lisa Johns, spouse to Walter Branch, legally changed her name to Lisa Branch. <u>See</u> Transcript of Hearing Held on September 27, 2016, Docket No. T-4631, Sub 0, October 4, 2016 ("Hearing Tr."), vol. 1, p. 40, l. 18 – p. 41, l. 6.

hearing, the Applicant proffered eight statements regarding the fitness of Mr. and Mrs. Branch, which were received by the Commission as statements of support.

On October 4, 2016, the Applicant, through counsel, filed its proposed order.

Based upon the testimony and the exhibits presented at the hearing, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. On May 31, 2016, Branch Out Delivery, Inc., filed the Application with the Commission, seeking a certificate to transport household goods by motor vehicle for compensation within North Carolina. Walter Branch and Lisa Branch are the principals of Applicant, and Applicant's office is located in Raleigh, North Carolina.

2. Applicant is properly before the Commission pursuant to G.S. 62-261(8) and Rule R2-8.1, seeking authority to transport household goods by motor vehicle for compensation within North Carolina.

3. At the hearing on September 27, 2016, Mr. Branch and Mrs. Branch appeared, gave testimony and answered the Commission's questions under oath to the satisfaction of the Commission.

4. Mr. Branch possesses approximately fifteen years of experience in the moving industry.[1] He first gained experience in the moving industry in 1999-2000 while working with TROSA Moving.[2] After leaving TROSA Moving, he worked for Two Men and a Truck, a company offering home and business moving services, and Holloway Moving, a small moving company.[3] Thereafter, he worked for Final Touch Delivery, a freight delivery company that delivered freight for corporations, including Rooms to Go and La-Z-Boy.[4] Mr. Branch managed a warehouse and team of employees while working for Final Touch Delivery.[5] The record indicates that through his years of employment in the industry, Mr. Branch has gained experience in loading and unloading furniture,[6] preparing bills of lading, supervising crews and preparing cost estimates for customers.[7]

5. Mrs. Branch possesses more than ten years of office administration work, including information technology, human resources, bookkeeping, marketing and payroll experience.[8] Mrs. Branch testified that she has been employed as a general manager of a corporate hotel, as a

[1] Hearing Tr. vol. 1, p. 73, ll 5-18.

[2] Application, Ex. C.

[3] Application, Ex. C; Hearing Tr. vol. 1, p. 68, l. 24 – p. 69, l. 15.

[4] Hearing Tr. vol. 1, p. 63, ll 1-9.

[5] Id. at 63, ll 14-16.

[6] Id. at 62, ll 19-24.

[7] Application, Ex. C.

[8] Application, Ex. C; Hearing Tr. vol. 1, p. 99, l. 1 – 22.

director of sales for a corporate hotel, and worked as an office administrator for a web design services company.[1] Mrs. Branch testified that her knowledge of the moving industry has been gained through observing Walter and that she attended a training seminar offered by the North Carolina Utilities Commission regarding the maximum rate tariff.[2]

6. Mr. and Mrs. Branch founded Branch Out Delivery, Inc., in 2015.[3] The company owns one truck and leases one truck.[4] From November 2015 up to the date of the hearing, Branch Out Delivery, Inc. has continued providing services related to the moving industry, such as non-regulated moves and the interstate transportation of freight, but the company has not engaged in the intrastate transporting of household goods for compensation pending the Commission's decision on the application.[5]

7. Branch Out Delivery, Inc., is registered with the North Carolina Secretary of State.

8. Ms. Jeanne Tedrow testified as a character witness for Mrs. Branch. Ms. Tedrow is the founder and Chief Executive Officer of the non-profit organization at which Mrs. Branch works, and Ms. Tedrow has known Mrs. Branch for approximately nine years.[6] She testified as to Mrs. Branch's dedication to her own personal[7] and professional development, as well as Mrs. Branch's responsibilities at work.[8] Ms. Tedrow testified that Mrs. Branch is a person of high character, deep loyalty, high integrity, and care for others.[9] Ms. Tedrow testified regarding her knowledge of the challenges Mr. Branch has overcome and the work he has done to redirect his life.[10] She also testified that Mr. Branch is a supportive husband and father.[11] Finally, she testified that it is her opinion that Mr. and Mrs. Branch are fit, willing, and able to properly provide for the transportation of household goods and that she would unquestionably and absolutely trust the Branches to perform the job of transporting household goods reliably.[12]

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[1] Hearing Tr. vol. 1, p. 99, ll 1 – 22.

[2] Id. at 99, l. 24 – p. 100, l. 10.

[3] Id. at 101, l. 13 – p. 105, l. 2.

[4] Id. at 64, ll 3-4.

[5] Id. at 73, l. 17 – p. 74, l. 12.

[6] Id. at 12, l. 8 – p. 16, l. 7.

[7] Id. at 18, ll 9 – 18; p. 20, l. 16 – p. 21, l. 8.

[8] Id. at 14, ll 2 – 22; p. 15, ll 7-23.

[9] Id. at 16, ll 1-3.

[10] Id. at 20, ll 9 – 14.

[11] Id. at 20, l. 15.

[12] Id. at 21, l. 23 – p. 22, l. 9.

9. Ms. Beverly McGahee testified as a character witness for Mr. Branch.[1] She testified that she is Mr. Branch's cousin and has known him his entire life, has knowledge of his past challenges and of his effort to work through those challenges.[2] She testified that he has experienced significant and inspirational growth in working through his challenges,[3] emphasized that the work has been gradual but that he has remained committed,[4] and that he has kept making progress in this regard for more than a decade.[5] She testified that he a different person now than when he was going through difficult times and has benefitted from continued support from his family and from community organizations.[6] She testified that Mr. Branch is hardworking, diligent, trustworthy, caring, and industrious individual.[7] She testified that she has hired Mr. Branch to assist her and her family members in moving on several occasions and has recommended him to her colleagues and business friends.[8] She testified that she trusts Mr. Branch and holds him in high regard.[9] She testified that he is fair, honest, committed to excellent customer service and that she highly recommended him for approval by the Commission.[10]

10. The Commission received a total of eight statements in support of Mr. Branch, Mrs. Branch and Applicant's application, each of which expressed confidence in and endorsement of the Branches and their request to the Commission for a certificate of exemption to provide for the transportation of household goods in North Carolina. The Commission received no statements of protest.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

On September 27, 2016, Mr. Branch and Mrs. Branch, principals of Branch Out Delivery, Inc., appeared before the Commission to respond to questions of the Commission regarding whether the Applicant is fit, willing and able to provide for the transportation of household goods in intrastate commerce. After receiving evidence presented at the hearing, including Mr. and Mrs. Branch's testimony, and after reviewing the record as a whole, the Commission finds that both Mr. and Mrs. Branch have satisfactorily answered questions regarding their knowledge of and experience in the moving industry and overall fitness to provide for the transportation of household goods in intrastate commerce.

[1] Id. at 29, ll 10 – 13.

[2] Id. at 30, ll 13 – 15.

[3] Id. at 30, ll 16 – 18.

[4] Id. at 34, ll 18 – 24.

[5] Id. at 35, ll 7 – 11.

[6] Id. at 33, ll 1 - 19.

[7] Id. at 31, l. 9.

[8] Id. at 31, ll 14 – 16.

[9] Id. at 38, ll 7 – 16.

[10] Id. at 31, ll 16 – 18.

The record is uncontroverted that Mr. Branch has more than fifteen years of experience in the moving and freight delivery industry. He first became employed in the industry in or around 1999, when he worked for TROSA Moving, and has been employed in the industry since that time in various capacities, including with a large moving company (Two Men and Truck), a small moving company (Holloway Moving), and a freight delivery service (Final Touch Delivery). The record demonstrates that Mr. Branch has developed a number of skills over his years of employment in the industry, including truck driving, loading and unloading furniture, preparing bills of lading, preparing cost estimates for customers and supervising crews of employees. Further, at the hearing, a character witness provided sworn testimony that Mr. Branch is a hardworking, diligent, trustworthy, caring, and industrious individual and that she has hired Mr. Branch to assist her and her family members in moving on several occasions, as well as recommended him to her colleagues and business friends. She testified that he is fair and honest and is committed to good customer service. In response to question by a Commissioner, she testified that she trusts him and holds him in high regard, in light of his commitment to turning his life around.

The record demonstrates that Mrs. Branch possesses more than ten years of office administration experience, including information technology, human resources, bookkeeping, marketing and payroll experience. The record indicates that she has been employed as a general manager of a corporate hotel, as a director of sales for a corporate hotel, and as an office administrator for a web design services company. The record indicates that she is currently employed at a non-profit organization where she coordinates volunteer activities and serves on the leadership team of the organization. The record indicates that while Mrs. Branch's knowledge of the moving industry has been gained through observing Walter, her role within Branch Out Delivery, Inc., will involve the business and administrative tasks, for which she is well-suited given her experience. The record also indicates that, to increase the likelihood of successful operation in the event of a favorable decision by the Commission on the application, she attended a training seminar offered by the North Carolina Utilities Commission regarding the maximum rate tariff. At the hearing, a witness presented testimony on Mrs. Branch's character—including her personal development, her professional work ethic, her commitment to her family and her trustworthiness.

The record further shows that Mr. and Mrs. Branch founded Branch Out Delivery, Inc. in 2015 with the objective of providing for the transportation of household goods. From November 2015 up to the date of the hearing, Branch Out Delivery, Inc., has provided services related to the moving industry, such as non-regulated moves and the interstate transportation of freight, but the company has not engaged in the intrastate transporting of household goods for compensation pending the Commission's decision on the application. Obtaining certification from the Commission will allow Branch Out Delivery, Inc., to add intrastate household goods moving to its list of services offered and realize fully its business objective.

The Commission is persuaded that Mr. and Mrs. Branch are committed to operating a business that is fully compliant with all applicable laws and does not violate any laws and/or Commission rules. The company has retained the services of an independent auditor to assist with bookkeeping and tax responsibilities. The company possesses a Federal Motor Carrier Number, which authorizes it to perform interstate moves.

The record further shows that Mr. and Mrs. Branch have the ability to provide satisfactory customer service. The character witness for Mr. Branch testified that she has hired Mr. Branch to assist her and her family members in moving on several occasions and has recommended him to her colleagues and business friends, as well. She further testified that he is fair, honest, committed to excellent customer service. The character witness for Mrs. Branch testified as to Mrs. Branch's character, integrity and professionalism. She testified that Mrs. Branch is routinely in contact with volunteers of the organization for which she works, as well as with the leadership team of the organization, managing to interact successfully with both groups of people. Thus, the Commission is persuaded that the Branches possesses the practical experience to provide satisfactory customer service.

Based upon the foregoing, the Commission finds and concludes that Mr. and Mrs. Branch have sufficiently addressed the Commission's questions regarding their fitness to obtain a certificate, have demonstrated reasonable and adequate knowledge of the household goods moving industry, have shown an ability and intent to follow the applicable statutes and Commission rules, and demonstrated a commitment to provide satisfactory service to the using and consuming public. Therefore, the Commission concludes that their fitness should not be a basis for denying the Applicant a certificate. Furthermore, if the Applicant has complied with all the requirements of the applicable law and Commission rules, the Commission has determined that it would be appropriate to issue a certificate of exemption to the Applicant to transport household goods within North Carolina.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of October, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. T-4584, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Amanda Faye Sheppard, d/b/a 24 Hour Movers, 412 Bethlehem Road, Knightdale, North Carolina 27545 – Application for Certificate of Exemption	))))	ORDER RULING ON APPLICANT'S FITNESS

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Thursday, September 10, 2015, at 10:00 a.m.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; and Commissioners Bryan E. Beatty and Don M. Bailey

APPEARANCES:

For the Applicant:

Amanda Faye Sheppard, d/b/a 24 Hour Movers, pro se, 412 Bethlehem Road, Knightdale, North Carolina 27545

For the Using and Consuming Public:

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

BY THE COMMISSION: On June 23, 2015, Amanda Faye Sheppard, d/b/a 24 Hour Movers (Applicant), pursuant to G.S. 62-261.8(1) and Commission Rule R2-8.1, filed an application with the Commission for a certificate of exemption to transport household goods by motor vehicle within North Carolina for compensation. The application included the required confidential SBI and FBI criminal history records check.

On July 27, 2015, the Commission issued an Order Scheduling Application for Hearing to ask questions of the Applicant regarding the application and her fitness to obtain a certificate of exemption.

On July 28, 2015, the Public Staff – North Carolina Utilities Commission (Public Staff) filed Notice of Participation. The Public Staff's intervention is recognized pursuant to G.S. 62-15 and Commission Rule R1-19(e).

On September 10, 2015, the hearing was held in Raleigh, as scheduled. The Applicant appeared pro se, testified in support of the application, and responded to questions from the Public

Staff and Commission. On the same day, the Applicant filed updated Exhibits A, B, and C to her application.

On October 16, 2015, the Public Staff filed its Proposed Recommended Order.

Based upon the information contained in the application, the testimony received at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. On June 23, 2015, the Applicant filed an application with the Commission for a certificate of exemption to transport household goods by motor vehicle within North Carolina for compensation. Amanda Faye Wooten Sheppard is the sole owner of 24 Hour Movers, which is located in Knightdale, North Carolina. The Applicant is properly before the Commission seeking a certificate of exemption pursuant to G.S. 62-261(8) and Commission Rule R2-8.1 to transport household goods by motor vehicle for compensation within North Carolina.

2. The Applicant currently provides labor-only services, but wants to expand her business by performing full-service moves of household goods.

3. The Public Staff has advised the Applicant how she can properly advertise 24 Hour Movers' labor-only services. In addition to advertising on Craigslist, the Applicant relies on word-of-mouth referrals and repeat customers to grow her customer base.

4. The Applicant has six years of experience in the moving industry. She obtained most of this experience while employed with Ken's Pack & Move, where she was involved with packing, unpacking, loading, unloading, billing, advertising, booking jobs, providing estimates, and supervising the crew. Ken's Pack & Move is owned and operated by her ex-husband, Kenneth Sheppard.

5. There have been two customer complaints lodged against 24 Hour Movers since it began operation. These complaints involved broken furniture. Both complaints were resolved amicably after the Applicant adjusted her loading fee to satisfy the customers.

6. The Applicant purchased a 1999 Ford Cargo Van for use in her business and plans to obtain the required vehicle liability, cargo, and general liability insurance once her application is granted.

7. The Applicant submitted her criminal history check as required by Commission Rule R2-8.1.

8. In June of 2015, a civil judgment in the amount of $820.00 was issued against the Applicant stemming from a dispute regarding items purchased at a garage sale. She has since satisfied the judgment against her. The dispute was not related to the operation of 24 Hour Movers.

9. The Applicant appeared before the Commission and satisfactorily answered the Commission's questions regarding her moving experience, her application, including the criminal history background check, and her overall fitness to obtain a certificate of exemption from the Commission.

10. The Applicant should be eligible for a conditional certificate of exemption with specified conditions.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

The Applicant appeared before the Commission at the September 10, 2015 hearing to address any and all issues surrounding her fitness to obtain a certificate of exemption to engage in the business of moving household goods for compensation within the State of North Carolina. After receiving her testimony and reviewing her supporting documentation, the Commission finds that the Applicant has answered its questions regarding her moving experience, criminal history background, and overall fitness to receive a certificate.

The Commission finds that the Applicant has six years of experience in the moving industry. Her initial involvement with the moving industry occurred while she was employed with Ken's Pack & Move, a North Carolina certificated mover owned and operated by her ex-husband. While employed with Ken's Pack & Move, she was involved with packing, unpacking, loading, unloading, billing, advertising, booking jobs, providing estimates, and supervising the company's work crews.

The Applicant used the business knowledge and administrative skills she obtained from Ken's Pack & Move to start 24 Hour Movers. The business is not a full service mover, but a labor-only business, and has five part-time employees who perform the labor services. Because of its nonmoving designation, 24 Hour Movers does not operate trucks for its customers. Instead, all full-service moves that come to 24 Hour Movers are referred to Ken's Pack & Move.

The Applicant is seeking a certificate of exemption so that 24 Hour Movers can also perform intrastate household moves. The Applicant is pursuing this expansion of her business as an avenue to increase her income so that she can provide for herself and her two children. The Applicant has sought the assistance of the Public Staff to ensure that the current business advertising is appropriate for a company that offers labor-only services. The Applicant advertises on Craigslist, secures word-of-mouth referrals, and relies on repeat customers.

The Commission finds that the Applicant is in the process of acquiring the resources necessary to provide adequate moving services to the using and consuming public. In preparation of securing a certificate, the Applicant has recently purchased a 1999 Ford Cargo Van for use in her business. She is having it repaired so that it can be licensed by the Division of Motor Vehicles. The Applicant has also obtained a quote for the required vehicle liability, cargo, and general liability insurance, which she will purchase if her application is granted.

The Commission further finds that the Applicant has the ability to provide moving services in a professional manner and to resolve disputes in an amicable and expedient manner. In her sworn testimony, the Applicant states that she is committed to providing her customers with a satisfactory experience. According to the Applicant, since 24 Hour Movers began operation, there have been only two recorded complaints, both involving damage to furniture. The Applicant testified that both complaints were resolved amicably through negotiation and by favorably adjusting the customers' bills.

The Commission also reviewed the Applicant's criminal history check and other background information in determining whether the Applicant is fit to be a certificated household goods mover. The Commission's review yielded no evidence compelling a finding that Applicant should be denied a certificate of exemption or that granting such exemption would be contrary to the public interest. Additionally, the Commission learned from the Public Staff's cross-examination of the Applicant that an outstanding civil judgment resulting from a private transaction with another Wake county resident was entered against the Applicant in Wake County in 2015. On October 20, 2015, the Applicant filed with the Commission a copy of the payments she made towards the satisfaction of the civil judgment. As proof of satisfaction, the Commission will require the Applicant to obtain and submit a certified copy of a Satisfaction of Judgment from the Wake County Clerk of Court prior to the issuance of any certificate of exemption.

Based upon the foregoing, the Commission concludes that the Applicant has shown she has adequate knowledge of the household goods moving industry, an ability to follow the statutes and Commission rules, and a desire to provide satisfactory service to customers. It is the Commission's opinion based on the evidence of record that the Applicant is reasonably fit to be a certificated household goods mover, provided that she meets all statutory and regulatory requirements. However, after a full review of the evidentiary record, the Commission finds it appropriate to review the Applicant's operations once certificated in order to be assured that the Applicant is exercising proper judgment, her company is solvent, and that she is complying with the rules and regulations associated with the intrastate transport of household goods in North Carolina. Accordingly, the Commission further concludes and determines that it is in the public interest that the Applicant's initial certificate of exemption be subject to specified conditions. The conditions required by the Commission are as follows:

1. Prior to the issuance of the conditional certificate of exemption, Applicant shall obtain and submit to the Commission a certified copy of a Satisfication of Judgment from the Wake County Clerk of Court with regard to the civil judgment obtained against her in 2015.

2. Within 180 days after the Applicant is issued a conditional certificate of exemption, the Applicant and the Public Staff shall have made arrangements for the Public Staff to conduct an audit of the Applicant's operations, books and records. Within 30 days of completion of the audit, the Public Staff shall file with the Commission a report of the result of its audit and of any information regarding known complaints against the Applicant, if any.

3. No later than one year after the date of this Order, the Applicant and the Public Staff shall arrange for the Public Staff to conduct a second audit of the Applicant's operations, books and records. Within 30 days of completion of the second audit, the

Public Staff shall file with the Commission a final report with its recommendation as to whether Applicant should be granted a non-conditional certificate of exemption.

Following receipt of the reports from the Public Staff and an opportunity for the Applicant to respond to the Public Staff's recommendation, the Commission will review the record and determine whether it is appropriate to grant the Applicant a non-conditional certificate.

IT IS, THEREFORE, ORDERED as follows:

1. That Applicant is fit to be a certificated household goods mover.

2. Prior to the issuance of any certificate of exemption, the Applicant shall submit to the Commission a certified copy of a Satisfication of Judgment from the Wake County Clerk of Court.

3. That upon fulfillment of all requirements necessary to become a certificated household goods mover, the Applicant may be issued a certificate of exemption subject to the conditions as set forth above in this Order, which conditions shall be attached to the certificate.

4. Within 180 days after the Applicant is issued a conditional certificate of exemption, the Applicant and the Public Staff shall have made arrangements for the Public Staff to conduct an audit of the Applicant's operations, books and records. Within 30 days of the completion of the audit, the Public Staff shall file with the Commission a report of the result of its audit and of any information regarding known complaints against the Applicant, if any.

5. No later than one year after the date of this Order, the Applicant and the Public Staff shall arrange for the Public Staff to conduct a second audit of the Applicant's operations, books and records. Within 30 days of the completion of the second audit, the Public Staff shall file with the Commission a final report with its recommendation as to whether Applicant should be granted a non-conditional certificate of exemption.

6. That any conditional certificate of exemption issued to Applicant shall remain in effect until the Commission issues an order granting a non-conditional certificate of exemption, issues an order modifying the conditions, or cancels the Applicant's authority to perform household goods moves in North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of January, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. T-4584, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Amanda Faye Sheppard, d/b/a 24 Hour Movers, 412 Bethlehem Road, Knightdale, North Carolina, 27545 – Application for Certificate of Exemption	))))	ORDER GRANTING CONDITIONAL CERTIFICATE OF EXEMPTION

BY THE COMMISSION: On June 23, 2015, the above-captioned Applicant, pursuant to G.S. 62-261.8(1) and Commission Rule R2-8.1 filed an application with the Commission for a certificate of exemption. No protests were filed to the application. The application included the required confidential SBI and FBI criminal history records check.

On July 27, 2015, the Commission issued an Order Scheduling Application for Hearing to address questions regarding the Applicant's application and fitness. On July 28, 2015, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a Notice of Participation.

The hearing was held in Raleigh, on Thursday, September 10, 2015, as scheduled. The Applicant appeared pro se, testified in support of the application, and responded to questions from the Public Staff and Commission.

Also, on September 10, 2015, a supplement to the application was filed.

On October 16, 2015, the Applicant filed a letter with the Commission in support of her application.

On January 14, 2016, the Applicant filed with the Commission a certified copy of a Satisfaction of Judgment from the Wake County Clerk of Court.

Also, on January 14, 2016, the Commission issued an Order Ruling on Applicant's Fitness concluding that Ms. Sheppard has shown to the satisfaction of the Commission that she possesses adequate knowledge of the household goods moving industry, an ability to follow the statutes and Commission rules, and a desire to provide satisfactory service to the using and consuming public. However, the Commission concluded that it would be appropriate to review the Applicant's operations once certificated in order to be assured that the Applicant is exercising proper judgement, her company is solvent, and that she is complying with the rules and regulations associated with the intrastate transport of household goods in North Carolina. Accordingly, the Commission concluded that the Applicant's initial certificate of exemption should be subject to the following conditions:

a. Prior to the issuance of the conditional certificate of exemption, Applicant shall obtain and submit to the Commission a certified copy of a Satisfaction of Judgement from the Wake County Clerk of Court with regard to the civil judgement obtained against her in 2015.

b. Within 180 days after the Applicant is issued a conditional certificate of exemption, the Applicant and the Public Staff shall have made arrangements for the Public Staff to conduct an audit of the Applicant's operations, books and records. Within 30 days of completion of the audit, the Public Staff shall file with the Commission a report of the result of its audit and of any information regarding known complaints against the Applicant, if any.

c. No later than one year after the date of this Order, the Applicant and the Public Staff shall arrange for the Public Staff to conduct a second audit of the Applicant's operations, books and records. Within 30 days of completion of the second audit, the Public Staff shall file with the Commission a final report with its recommendation as to whether Applicant should be granted a non-conditional certificate of exemption.

Upon consideration of the application for a certificate of exemption filed with the Commission on June 23, 2015, the Commission's January 14, 2016 Order, and the entire record in this docket, the Commission finds and concludes that the Applicant should be granted a conditional certificate of exemption to transport household goods. Further, the Commission finds and concludes that the Applicant has complied with the terms and conditions attached to the conditional certificate of exemption:

1. Applicant is fit, willing, and able to properly perform the service of household goods transportation within North Carolina, is familiar with the moving industry, and has a reasonable and adequate knowledge of the rules and regulations governing the moving industry, including safety requirements as enforced by the North Carolina Division of Motor Vehicles.

2. Applicant will abide by the tariff requirements as established by the Commission and adopted in Maximum Rate Tariff No. 1.

3. Applicant is financially solvent and able to furnish adequate service on a continuing basis by maintaining the required insurance protection, maintaining safe, dependable equipment, and being able to settle any damage claims which may arise.

4. Applicant will maintain and has on file with the North Carolina Division of Motor Vehicles liability and cargo insurance coverage as required by law and Commission rules and regulations.

5. Applicant will maintain and has on file with the Commission's Operations Division a certificate of general liability insurance coverage in the minimum amount of $50,000.

IT IS, THEREFORE, ORDERED as follows:

1. That the application for certificate of exemption filed by Amanda Faye Sheppard, d/b/a 24 Hour Movers, be, and the same is hereby, conditionally granted, and that the Applicant is hereby authorized to transport household goods between all points and places within North Carolina.

2. That the Applicant shall maintain her books and records in such a manner that all of the applicable items of information required in the prescribed Annual Report to the Commission can be used by the Applicant in the preparation of such Annual Report. A copy of the Annual Report form shall be furnished upon request made to the Public Staff – North Carolina Utilities Commission, Transportation Rates Division.

3. That the Applicant shall maintain her books and records in such a manner that all of the applicable items of information requested in its prescribed quarterly Public Utilities Regulatory Fee Report can be used by the Applicant in the preparation of such report and payment of quarterly regulatory fee. Any questions regarding the regulatory fee report and/or regulatory fee should be directed to the Commission's Fiscal Management Division at 919-733-5265.

4. That all vehicles, whether owned or leased, and used by the Applicant in its household goods operations must be identified with Applicant's name, city, state, and certificate of exemption number on both sides of each vehicle in letters not less than three (3) inches high. Such vehicles must also be identified with Applicant's certificate of exemption number on the left upper quadrant of the rear of each vehicle in letters not less than three (3) inches high.

5. Within 180 days after the Applicant is issued a conditional certificate of exemption, the Applicant and the Public Staff shall have made arrangements for the Public Staff to conduct an audit of the Applicant's operations, books, and records. Within 30 days of the completion of the audit, the Public Staff shall file with the Commission a report of the result if its audit and any information regarding known complaints against the Applicant, if any.

6. No later than one year after the date of this Order, the applicant and the Public staff shall arrange for the Public Staff to conduct a second audit of the Applicant's operations, books, and records. Within 30 days of the completion of the second audit, the Public Staff shall file with the Commission a final report with its recommendation as to whether Applicant should be granted a non-conditional certificate of exemption.

7. That this Order shall constitute a conditional certificate of exemption until a formal conditional Certificate of Exemption No. C-2617 has been issued and transmitted to the Applicant, along with a copy of Maximum Rate Tariff No. 1. Such conditional certificate of exemption shall remain in effect until the Commission issues an order granting a non-conditional certificate of exemption, issues an order modifying the conditions, or cancels the Applicant's authority to perform household moves in North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of April, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

TRANSPORTATION – COMMON CARRIER CERTIFICATE

DOCKET NO. T-4615, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Jaime Gordon Eaker, d/b/a Ashe Van	)	ORDER RULING ON
Lines & Janitorial Services –	)	APPLICANT'S FITNESS
Application for Certificate of Exemption	)	

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Tuesday, May 10, 2016, at 10:00 a.m.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Commissioners Jerry C. Dockham and Lyons Gray

APPEARANCES:

For Jaime Gordon Eaker, d/b/a Ashe Van Lines & Janitorial Services:

Britton H. Allen, Allen Law Offices, PLLC, 1514 Glenwood Ave., Raleigh, North Carolina 27608

BY THE COMMISSION: On February 8, 2016, Jaime Gordon Eaker, d/b/a Ashe Van Lines & Janitorial Services (Mr. Eaker, Applicant or Ashe Van Lines), filed an application with the Commission pursuant to G.S. 62-261.8(1) and Commission Rule R2-8.1 for a certificate of exemption (certificate) to transport household goods by motor vehicle for compensation within North Carolina. The application named Jaime Gordon Eaker as the sole principal of the business.

On February 29, 2016, the certified criminal history record check for Jaime Gordon Eaker was filed with the Commission as required by G.S. 62-273.1 and Rule R2-8.1(a)(3).

On March 28, 2016, the Commission issued an Order Scheduling Application for Hearing to address questions regarding Mr. Eaker's application and his fitness for certification. The Order also provided that the Public Staff – North Carolina Utilities Commission (Public Staff) may participate in the hearing on behalf of the using and consuming public.

On May 3, 2016, the Public Staff notified the Commission that it did not intend to participate in the hearing.

On May 10, 2016, the hearing was held in Raleigh, as scheduled. Mr. Eaker was represented before the Commission by counsel. Mr. Eaker, sole principal of the applicant business, appeared and testified in support of the application, responded to questions from the Commission and also offered testimony from Catherine Ann Montgomery.

On May 25, 2016, Chris and Melissa Barringer filed a statement of protest.[1]

On June 3, 2016, Mr. Eaker, through counsel, filed a motion to strike letters and on June 6, 2016, filed his proposed order.

On June 7, 2016, Mr. Eaker, through counsel, filed a confidential letter concerning late filed exhibits.

Based upon the information contained in the application, the testimony received at the hearing, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. On February 8, 2016, Mr. Eaker filed an application with the Commission for a certificate to transport household goods by motor vehicle for compensation within North Carolina. Mr. Eaker is the sole principal of the business located in Hickory, North Carolina. Mr. Eaker is properly before the Commission seeking a certificate pursuant to G.S. 62-261(8) and Rule R2-8.1 to transport household goods by motor vehicle for compensation within North Carolina.

2. At the May 10, 2016 hearing, Mr. Eaker appeared, gave testimony and answered the Commission's questions under oath to the satisfaction of the Commission.

3. Mr. Eaker possesses over twelve years of business knowledge. Most of his business experience involves the operation of two restaurants and two convenience stores.

4. Of his total business experience, Mr. Eaker worked about sixteen months from August 2014 - December 2015 in the household goods moving industry in the employ of Barringer Moving & Storage in Hickory, North Carolina.

5. Mr. Eaker formed and began operating Ashe Van Lines & Janitorial Services in January of 2016. The business currently employs two individuals in addition to Mr. Eaker. From January until the date of the hearing, as owner and operator of Ashe Van Lines, Mr. Eaker has continued providing services related to the moving industry such as non-regulated moves and cleaning, but he has not engaged in the intrastate transporting of household goods for compensation pending the Commission's decision on the Application.

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[1] In Chris and Melissa Barringer's statement of protest filing, the couple asserts that they did not receive prior notice of Mr. Eaker's application before the hearing. They claim to have received e-mail notice of other certificate of exemption applications in the past. The Commission only sends e-mail notifications pertaining to specific dockets when a recipient has subscribed to receive such notices. Because the Barringers are not subscribed to the Commission's docket notification system, they would not have received e-mail notices related to this docket. However, the information is always available on the Commission's website. Certificated movers especially should know to periodically check the website if they are interested in monitoring applications for certificates of exemption.

6. Ashe Van Lines & Janitorial Services is registered with the North Carolina Secretary of State and is compliant with its tax obligations to the state of North Carolina. The business is also in compliance with insurance requirements, having cargo, general liability, fleet and commercial insurance in place.

7. Mr. Eaker's business has authority from the Federal Motor Carrier Safety Administration to perform interstate moves of household goods.

8. Mr. Eaker's business operates out of a 25,000 square foot warehouse. The warehouse is also used as storage space for the business.

9. Catherine Ann Montgomery testified as a character witness for Mr. Eaker. In January 2015, Ms. Montgomery began working with Mr. Eaker by telephone to coordinate her family's move from Northern Virginia to Hickory, North Carolina. At the time, Mr. Eaker was working for the household goods mover, Barringer Moving & Storage. Upon moving to North Carolina, Ms. Montgomery testified she met Mr. Eaker in person and rather quickly established a close friendship with him. She found him to be trustworthy and further testified that she and her husband entrusted Mr. Eaker with the key to their home in case of emergency. She testified that if Mr. Eaker is certificated by the Commission, she would use his services if she moved again and that she feels comfortable recommending him to others for the purpose of performing household goods moves.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

On May 10, 2016, Mr. Eaker appeared before the Commission to address all issues surrounding his fitness to obtain a certificate to engage in the business of moving households goods for compensation within the state of North Carolina. After receiving evidence presented at the hearing on behalf of the Application, including Mr. Eaker's testimony, and after reviewing the record as a whole, the Commission finds that Mr. Eaker has satisfactorily answered questions regarding his experience in the moving industry, background, and overall fitness to receive a certificate.

The record shows that Mr. Eaker has approximately twelve years of experience operating small businesses.[1] For around ten years, he owned and operated two restaurants and two convenience stores in Gastonia, North Carolina.[2] As a business owner/operator, Mr. Eaker learned a wide variety of tasks, including, but not limited to, managing inventory and accounts payable. He has almost two years additional business experience working in the moving industry. He

[1] Hearing Transcript, p. 17.

[2] Id, p. 32 (Mr. Eaker operated the following businesses: J's Café, Firestone Grill, Quick Stop I, and Quick Stop II).

obtained this experience while working for certificated household goods mover, Barringer Moving & Storage (Barringer) in Hickory, North Carolina, and while working for himself with his business, Ashe Van Lines. He was hired by Barringer in August of 2014 as the executive assistant to the owner, Chris Barringer. In his position, he assisted Mr. Barringer in day-to-day administrative activities, including handling incoming calls, scheduling moves, marketing, establishing online advertising, and customer reviews.[1] He also worked with the owner to develop cooperative relationships with the Commission and the local Better Business Bureau.

The record shows that Mr. Eaker left Barringer in January 2016 to start his own business, Ashe Van Lines, based in Hickory, North Carolina, which operates out of a 25,000 square foot warehouse.[2] Mr. Eaker's business currently provides two types of services to the using and consuming public. The business undertakes nonregulated moves, such as moves within the same apartment complex and commercial (non-household goods) moves, and provides residential and commercial cleaning services. Obtaining certification from the Commission will allow the business to add intrastate household goods moving to its list of services offered. Ashe Van Lines currently has two employees that provide services to customers. [1]

Mr. Eaker is committed to operating a business that is fully compliant with all applicable laws and does not violate any laws and/or Commission rules.[3] Mr. Eaker's business is registered with the North Carolina Secretary of State and is in compliance with its tax obligations to the North Carolina Department of Revenue.[4] Mr. Eaker's business possesses a Federal Motor Carrier Number, which authorizes it to perform interstate moves.[5] Moreover, Mr. Eaker has the following insurance in place for his business: cargo, general liability, fleet, and commercial insurance.[6] Mr. Eaker informed the Commission that he has several trucks that he can utilize to perform intrastate household goods moves.[7] If his business is certificated, Mr. Eaker plans to open a second office in Asheville, North Carolina.

To increase the likelihood of a successful operation, Mr. Eaker communicates regularly with the Public Staff about his business activities and leans on that agency for information and guidance.[8] Mr. Eaker reports that he follows the agency's recommendations in operating his business.[9] He has also recently contacted the North Carolina Movers' Association about potential membership in the trade association.

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[1] Id, p. 19.

[2] Id, p. 22.

[3] Id, p. 53.

[4] Id, p. 47-48.

[5] Id, p. 21.

[6] Id.

[7] Id, p. 33.

[8] Id, p. 19.

[9] Id, p. 20.

The record further shows that Mr. Eaker has the ability to provide customers with a satisfactory moving experience. Mr. Eaker introduced evidence through his witness, Catherine Ann Montgomery, that she was satisfied with his coordination and oversight of her family's move from Northern Virginia to Hickory, North Carolina. She was impressed with the attention he gave to the job, stating that she found him professional and informative during the entire moving process, beginning with telephone conversations in January 2015 regarding pricing through the completion of the move in March 2015.[1] She further testified that after she met Mr. Eaker in person, she fast formed a friendship with him that has continued to this date. She stated that she and her husband have come to rely on Mr. Eaker to assist them with their North Carolina home. According to Ms. Montgomery, Mr. Eaker has become their "go-to" person if she or her husband needs anything. They have even entrusted Mr. Eaker with a key to their current home in case of emergency.[2] Ms. Montgomery indicated by testimony that through the friendship she has formed with Mr. Eaker, she has learned of his background, work ethic and character.[3] She indicated that she trusts Mr. Eaker, considers him to be honest,[4] and believes that he will be a good intrastate household goods mover.[5]

Based upon the foregoing and Mr. Eaker's having answered the Commission's questions to the Commission's satisfaction, the Commission finds and concludes that Jaime Gordon Eaker, the Applicant, has shown that he possesses the necessary knowledge of the household goods moving industry and has the ability and intent to follow the applicable statutes and Commission rules to provide satisfactory service to the using and consuming public. Therefore, the Commission finds and concludes that the Applicant has satisfactorily shown himself fit to obtain a certificate of exemption to transport household goods by motor vehicle for compensation within North Carolina.

The Commission recognizes that several filings were made after the hearing in this docket. First, Chris and Melissa Barringer filed a statement of protest[6] on May 25, 2016, and requested denial of Mr. Eaker's application for a certificate of exemption. Mr. Eaker, through counsel, then filed a motion on June 3, 2016, to strike the Barringers' statement from the record. The

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[1] Id, p. 10-11.

[2] Id, p. 12.

[3] Id, p. 14.

[4] Id, p. 12.

[5] Id, p. 13.

[6] In their filing, Chris and Melissa allege that Mr. Eaker had on two different occasions delivered furniture from Fine Consign in Hickory, North Carolina, in and out of customers' homes. However, the Commission does not regulate the transportation of furniture to and from commercial establishments. The Barringers also note that Mr. Eaker advertised his service but they do not allege such advertising was in violation of the prohibition against advertising to perform regulated household goods moves without being certificated. Moreover, evidence in the record is to the contrary, establishing that Mr. Eaker's advertising concerned nonregulated activities.

Commission considers Mr. Eaker's motion to strike as an objection to admit the Barringers' statement of protest into evidence. After a careful review, the Commission finds good cause to sustain the Applicant's objection to the statement of protest on the grounds that the Barringers are not parties to this proceeding[1], that their statement of protest was not timely filed[2], and that the statement is an attempt to introduce inadmissible hearsay into the record.

Having made our ruling on Applicant's fitness and on the outstanding motion to strike, the Commission takes no further action in this order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of July, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

[1] Commission Rule R1-11, sets forth how a person without specific leave to intervene may protest any motor carrier application for operating rights to transport passengers or household goods.

[2] Commission Rule R2-8.1(c)(1), in relevant part states, any party desiring to file a protest with the Commission must do so in writing by setting forth the reasons for the protest and filing that protest with the Commission no later than 15 days from the filing date of the certificate of exemption application.

TRANSPORTATION – COMMON CARRIER CERTIFICATE

DOCKET NO. T-4617, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Juan Lamont Nelson, d/b/a Bull City Movers Plus – Application for Certificate of Exemption to Transport Household Goods	)))	ORDER RULING ON APPLICANT'S FITNESS

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Monday, June 13, 2016, at 10:00 a.m.

BEFORE: Commissioner Bryan E. Beatty, Presiding; Commissioners Jerry C. Dockham and Lyons Gray

APPEARANCES:

For Juan Lamont Nelson, d/b/a Bull City Movers Plus:

Juan Lamont Nelson, 511 Latta Road, Durham, North Carolina 27712 (pro se)

BY THE COMMISSION: On February 22, 2016, Juan Lamont Nelson, d/b/a Bull City Movers Plus (Mr. Nelson, Applicant or Bull City), filed an application with the Commission pursuant to G.S. 62-261(8) and Commission Rule R2-8.1 for a certificate of exemption (certificate) to transport household goods by motor vehicle for compensation within North Carolina. The application named Juan Lamont Nelson as the sole principal of the business.

On March 15, 2016, the certified criminal history record check for Juan Lamont Nelson was filed with the Commission as required by G.S. 62-273.1 and Rule R2-8.1(a)(3).

On May 19, 2016, the Commission issued an Order Scheduling Application for Hearing to address questions regarding Mr. Nelson's application and his fitness for certification. The Order also provided that the Public Staff – North Carolina Utilities Commission (Public Staff) may participate in the hearing on behalf of the using and consuming public.

On June 8, 2016, the Public Staff notified the Commission that it did not intend to participate in the hearing.

On June 13, 2016, the hearing was held in Raleigh, as scheduled. Mr. Nelson appeared pro se before the Commission, testified in support of the application, responded to questions from the Commission, and offered the testimony of Darrell Randolph.

Based upon the information contained in the application, the testimony received at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. On February 22, 2016, Mr. Nelson filed an application with the Commission pursuant to G.S. 62-261(8) and Rule R2-8.1 for a certificate of exemption (certificate) to transport household goods by motor vehicle for compensation within North Carolina. Mr. Nelson is the sole principal of Bull City Movers Plus located in Durham, North Carolina, and is properly before the Commission.

2. At the June 13, 2016 hearing, Mr. Nelson appeared, gave testimony, and answered questions from the Commission.

3. Mr. Nelson possesses over 18 years of moving experience. Over the years, he has worked for Two Men and a Truck, All My Sons, and Act of Class Moving in Charlotte, North Carolina.

4. Presently, Mr. Nelson operates Bull City Movers Plus, which has been in operation for four years.

5. Mr. Nelson is involved with the StepUp Ministry, a nonprofit program that works with people from all walks of life and seeks to provide jobs and life skills to those in need. He has been involved with this program since 2008.

6. Mr. Nelson is the Senior Pastor of Peacekeeper United Community Church, a non-denominational church that works directly in the community with people to assist them in changing their lives in various areas. He was installed as the Pastor of Peacekeeper approximately three years ago.

7. Mr. Nelson does not receive a salary from his work in the community. Therefore, Mr. Nelson relies heavily on his income from Bull City Movers Plus to support his family.

8. Mr. Nelson is the sole proprietor of Bull City Movers Plus in Durham, North Carolina. The business provides pack and load services to the using and consuming public.

9. Bull City Movers Plus has two permanent employees. The business also employs five men on a temporary basis.

10. Bull City Movers Plus does not own trucks, but leases them from Enterprise and/or Budget Rentals.

11. Mr. Nelson has performed several full-service moves. However, he was advised by the Public Staff that he could not do so without a certificate from the Commission. He has not performed any other moves after being advised by the Public Staff.

12. In preparation for receiving his certificate, Mr. Nelson has obtained all the insurance needed to operate as a duly regulated carrier, such as general liability and cargo insurance.

13. Bull City Movers Plus had 75 reviews last year on Thumbtack, an Internet site and smartphone application that allows individuals to search for professional assistance and to leave customer reviews on the service they receive. Of these 75 reviews, three of them were negative.

14. Mr. Nelson has support from the community for his application to obtain a certificate. He has received letters of support from Ms. Linda Nunnallee, Executive Director of StepUp, Mr. Jesse Leake of the Accounting Department of Community Development in the City of Durham, and Bishop Peter L. Baker.

15. Darrell Randolph, who is a case manager with the North Carolina Department of Public Safety, testified that Mr. Nelson has a passion about moving and is very professional and very serious about it. He further testified that he not only trusts Mr. Nelson with his worldly possessions, but more importantly with the guidance of his soul.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

On June 13, 2016, Mr. Nelson appeared before the Commission to address all issues surrounding his fitness to obtain a certificate to engage in the business of moving households goods for compensation within the state of North Carolina. After receiving evidence presented at the hearing on behalf of the Application, including Mr. Nelson's testimony, and after reviewing the record as a whole, the Commission finds that Mr. Nelson has satisfactorily answered questions regarding his experience in the moving industry, background, and overall fitness to receive a certificate.

The record is uncontroverted that Mr. Nelson possesses a total of 18 years of experience in the moving industry.[1] Over the years, he has worked for Two Men and a Truck, All My Sons, and Act of Class Moving in Charlotte, North Carolina.[2] Presently, he owns and works for Bull City Movers Plus, which he began four years ago. Through these several work experiences, he believes he has gained an understanding of the administrative and physical aspects of operating a moving business.

The record is also uncontroverted that Mr. Nelson is very involved in his community. Since 2008 Mr. Nelson has been involved with the StepUp Ministry, a nonprofit program that works with people from all walks of life and seeks to provide jobs and life skills to those in need.[3] The program partners with entities such as Duke University and employment agencies in Wake and Durham Counties to offer the participants a second chance.[4] He was part of the team that opened up the offices in Durham and Greensboro, North Carolina. He initially started out as a part-time

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[1] Tr. at 29.

[2] *Id.* at 30.

[3] *Id.* at 25.

[4] *Id.* at 26.

temporary staff, but through his dedication and commitment to the program's mission he has been asked to serve on its board.

Mr. Nelson also serves as the Senior Pastor of Peacekeeper United Community Church (Peacekeeper), a non-denominational church that works directly in the community with people to assist them in changing their lives in various areas.[1] Mr. Nelson was installed as the Pastor of Peacekeeper approximately three years ago. The church meets on Sunday mornings and Thursday nights and will go out into the community to offer its services to those in need. Mr. Nelson is not directly paid a salary for his work with the church, but periodically receives monetary gifts.

The record further shows that Mr. Nelson does not benefit financially from his work in the community. Therefore, Mr. Nelson relies heavily on his income from Bull City Movers Plus to support his family.[2] Mr. Nelson is the sole proprietor of Bull City Movers Plus in Durham, North Carolina. The business provides pack and load services to the using and consuming public. Mr. Nelson has two permanent employees and five men on a temporary basis.[3] The business is growing, and Mr. Nelson has established relationships with several local storage facilities and POD companies. At present, Bull City Movers Plus does not have its own trucks. Instead, Mr. Nelson prefers to lease trucks when there is a job.[4] In fact, his business has direct relationships with both Enterprise and Budget Truck Rentals.[5] Once Bull City Movers Plus obtains a certificate from the Commission, he will seek to purchase his own vehicle.

Mr. Nelson understands that a certificate from the Commission will allow him to operate legally as a household goods mover. The company, however, performed several full-service moves in the past before it was notified by the Public Staff that it was violating the law. When he was contacted by the Public Staff regarding his illegal moving activities, he immediately ceased performing full service moves. Through his contact with the Public Staff, he has learned what he can and cannot do. He is committed to operating a legal and compliant business. In preparation for receiving his certificate, he has obtained all the insurance needed to operate as a duly regulated carrier, such as general liability and cargo insurance.[6] He is prepared to obtain insurance for his employees. He has also advised the Commission that he is compliant with the state's tax laws.

Mr. Nelson also shows the Commission that he possesses the appropriate temperament to be a successful household good mover. He claims that over the last year the company had 75 reviews on Thumbtack, an Internet site and smartphone application that allows individuals to search for professional assistance and to leave customer reviews on the service they receive. Of these

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[1] *Id.* at 23.

[2] *Id.* at 30. Mr. Nelson has been married for 21 years and has three adult children.

[3] *Id.* at 27.

[4] *Id.* at 29.

[5] *Id.*

[6] *Id.* at 28.

75 reviews, three of them were negative.[1] He believes that these three negative reviews came from customers who simply could not be satisfied. However, he is not opposed to attempting to resolve customer complaints. Mr. Nelson understands that he will need to become more familiar with the Commission's Maximum Rate Tariff (MRT) in order to be successful. He has already contacted the Public Staff about the schedule of the training. He testified that he is looking forward to attending a tariff training so that he may obtain the knowledge he needs to better serve those in the using and consuming public.

Mr. Nelson has support from the community for his application to obtain a certificate. He has offered the testimony of his witness Darrell Randolph, who is a case manager with the North Carolina Department of Public Safety.[2] Mr. Randolph also works with Bull City Movers Plus on a temporary basis. Mr. Randolph testified that he and Mr. Nelson are friends and that he has worked with Mr. Nelson for about three years. He further testified that Mr. Nelson has a passion about moving and is very professional and very serious about it.[3] He further testified that he not only trusts Mr. Nelson with his worldly possessions, but more importantly with the guidance of his soul.[4] Mr. Nelson also has support from the greater community. He has offered into the record supportive letters of reference from Ms. Linda Nunnallee, Executive Director of StepUp, Mr. Jesse Leake of the Accounting Department of Community Development in the City of Durham, and Bishop Peter L. Baker.[5]

Based upon the foregoing and Mr. Nelson's answers to the Commission's questions, the Commission finds and concludes that Juan Lamont Nelson, the Applicant, has shown that he possesses the necessary knowledge of the household goods moving industry and has the ability and intent to follow the applicable statutes and Commission rules to provide satisfactory service to the using and consuming public. Therefore, the Commission finds and concludes that the Applicant has satisfactorily shown himself fit to obtain a certificate of exemption to transport household goods by motor vehicle for compensation within North Carolina.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of July, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

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[1] *Id.* at 34.

[2] *Id.* at 39.

[3] *Id.* at 43.

[4] *Id.*

[5] *Id.* at 33-34.

DOCKET NO. T-4588, SUB 0
DOCKET NO. T-4588, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. T-4588, SUB 0

In the Matter of
Rashard Amon Generette, d/b/a Carolina Pack “N” Load, 8334 Pineville-Matthews Road, Suite 103-285, Charlotte, North Carolina 28226 – Application for Certificate of Exemption

DOCKET NO. T-4588, SUB 1

In the Matter of
Rashard Amon Generette, d/b/a Carolina Pack “N” Load, Queen City Movers, and Five Star Movers, 8334 Pineville-Matthews Road, Suite 103-285, Charlotte, North Carolina 28226 – Unlawful Representation of Authority and Unauthorized Transportation of Household Goods

ORDER RULING ON FITNESS, ASSESSING PENALTIES, AND ASSIGNING CONDITIONS TO PROBATIONARY CERTIFICATE

HEARD: Tuesday, December 15, 2015, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioners Bryan E. Beatty, Presiding, Don M. Bailey, and Jerry C. Dockham

APPEARANCES:

For Rashard Amon Generette, d/b/a Carolina Pack “N” Load, Queen City Movers, and Five Star Movers:

Rashard Amon Generette, 8334 Pineville-Matthews Road, Suite 103-285, Charlotte, North Carolina 28226, pro se

For the Using and Consuming Public:

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

BY THE COMMISSION: On July 6, 2015, pursuant to G.S. 62-261(8) and Commission Rule R2-8.1, Rashard Generette filed an application with the Commission in Docket No. T-4588, Sub 0 for a certificate of exemption to transport household goods within North Carolina by motor vehicle for compensation. On July 7, 2015, Mr. Generette amended his application to indicate that the name of his business was Rashard Amon Generette, d/b/a Carolina Pack "N" Load (Applicant).

On September 28, 2015, the Public Staff filed a Petition to Show Cause in Docket No. T-4588, Sub 1 against Rashard Amon Generette, d/b/a Carolina Pack "N" Load, Queen City Movers, and Five Star Movers alleging that Mr. Generette is in continuing violation of Commission Rule R2-8.1, G.S. 62-280.1(a) and G.S. 62-262(a) by operating as a de facto public utility. The Public Staff requested that the Commission issue an Order requiring that Mr. Generette appear and show cause (1) why he should not be found to have represented himself as holding a certificate and otherwise authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a) and assessed a civil penalty not in excess of five thousand dollars ($5,000) for such violation; and (2) why he should not be found to be a de facto public utility by holding himself out as a common carrier of household goods, as defined in G.S. 62-3(7), while engaging in the intrastate transport of household goods without possessing a certificate as required by G.S. 62-261(8) and Commission Rule R2-8.1 in violation of G.S. 62-262(a) and subject to sanctions or penalties provided by G.S. 62-310(a), recoverable pursuant to G.S. 62-312.

On October 23, 2015, the Commission issued an Order Consolidating Dockets, Providing Notice of Show Cause and Scheduling Hearing.

The matter was heard, as scheduled, on December 15, 2015. In support of its Petition to Show Cause, the Public Staff presented the testimony of Cynthia Smith, Director of the Transportation Rates Division of the Public Staff, and Krishna Rajeev, Rates Specialist with the Division. The Applicant appeared and represented himself pursuant to Commission Rule R1-22. The Applicant offered testimony in support of the application and answered questions from the Public Staff and the Commission.

On February 10, 2016, the Public Staff filed its Proposed Recommended Order.

Based upon the information contained in the Petition to Show Cause and the attached exhibits, the verified application and the attached exhibits, the testimony received at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. The Commission has jurisdiction over public utilities, including those engaged in the intrastate transportation of household goods for compensation in North Carolina, as defined by G.S. 62-3(7) and (15). The Commission has authority to issue certificates to applicants for the purpose of engaging in intrastate transportation of household goods for compensation in North Carolina, pursuant to G.S. 62-261(8) and Commission Rule R2-8.1.

2. Rashard Amon Generette is the sole owner of Carolina Pack "N" Load, Queen City Movers, and Five Star Movers.

3. Mr. Generette submitted an application for a certificate of exemption for Carolina Pack “N” Load on July 6, 2015.

4. On July 7, 2015, Commission Staff sent Mr. Generette an acknowledgement of receipt of his application, requesting additional information and advising him that he could not lawfully transport household goods in this state until the Commission granted its application for a certificate.

5. On October 23, 2015, the Commission issued an Order Consolidating Dockets, Providing Notice of Show Cause, and Scheduling Hearing. In Ordering Paragraph No. 5, the Commission advised the Applicant that he was prohibited from operating as a mover of household goods within this state prior to the Commission approving his application for a certificate.

6. The Applicant violated G.S. 62-280.1 by advertising his services as a household goods carrier to the public without first having been issued a certificate from the Commission.

7. The Applicant acted as a de facto public utility by holding himself out as a common carrier of household goods, as defined in G.S. 62-3(7), while engaging in the intrastate transport of household goods without possessing a certificate in violation of G.S. 62-262(a).

8. The Applicant admitted that within the past year, his companies have repeatedly engaged in the intrastate transportation of household goods for compensation within North Carolina without a certificate, as required by G.S. 62-261(8) and Commission Rule R2-8.1.

9. The Applicant has purchased a 2000 International box truck and has been trying to obtain liability and cargo insurance.

10. The Applicant has more than ten years of experience in the moving industry and employs a crew of approximately seven people.

COMMISSION JURISDICTION

The Commission has jurisdiction over public utilities, including those engaged in the intrastate transportation of household goods for compensation in North Carolina, as defined by G.S. 62-3(7) and (15). The Commission has authority to issue certificates for the intrastate transportation of household goods for compensation in North Carolina, pursuant to G.S. 62-261(8). Pursuant to its jurisdiction over the intrastate transportation of household goods, the Commission has the power to assess civil penalties for violations of Chapter 62 and Commission rules. G.S. 62-310.

DISCUSSION AND CONCLUSIONS

Violation of G.S. 62-280.1(a)

G.S. 62-280.1(a)(1) provides, in pertinent part, as follows:

> (a) It is unlawful for a person not issued a certificate to operate as a carrier of household goods under the provisions of this Chapter to do any of the following:
>
> > (1) Orally, <u>in writing, in print, or by sign</u>, including the use of a vehicle placard, phone book, <u>Internet</u>, magazine, newspaper, billboard, or business card, or <u>in any other manner</u>, directly or by implication, represent that the person holds a certificate or is otherwise authorized to operate as a carrier of household goods in this State.

(Emphasis added.) Section (c) of G.S. 62-280.1 allows the Commission to assess a civil penalty not in excess of five thousand dollars ($5,000) for the violation of subsection (a) of this section.

Mr. Generette admitted at the hearing that prior to and after filing his application for a certificate he regularly advertised his businesses, Carolina Pack "N" Load, Queen City Movers, and Five Star Movers, on posted signs and on the following websites: Craig's List, Living Social, Groupon, Amazon Local, Yelp, Facebook, Twitter, Angie's List, and Thumbtack.com. Many of the posted signs and some of the Internet advertising indicate that the moving services are licensed, insured and bonded. However, the Commission has not issued a certificate to any of Mr. Generette's companies, and, therefore, they are not licensed. Further, Mr. Generette testified that the Commission's insurance requirement was one reason he did not apply for a certificate sooner and that he was still working to obtain insurance on his 2000 International box truck. Thus, the claims that the moving services provided by Mr. Generette's companies are "licensed, insured and bonded" were false and misleading. This advertising reasonably gives the using and consuming public the impression that Mr. Generette's companies are moving companies authorized by the Commission. However, these companies never received authorization from the Commission to perform full-service household goods moves.

Both the Public Staff and the Commission advised Mr. Generette that he could not advertise intrastate residential moving services until his companies were granted certificates by the Commission. Public Staff witnesses Smith and Rajeev testified that they individually held several conversations with Mr. Generette stressing that he could not advertise the provision of intrastate residential moving services until the Commission granted him a certificate. The Commission further reiterated this prohibition in Commission Staff's July 7, 2015 letter to Mr. Generette filed in this docket. Nevertheless, Mr. Generette continued to advertise residential moving services, and the Public Staff received a complaint on September 24, 2015, about four signs that Mr. Generette admitted were posted on behalf of his companies.[1]

Further, the Public Staff received several complaints from consumers who were dissatisfied with the services received from Mr. Generette. Each of these customers learned of Mr. Generette's companies through his posted signs or Internet advertising. Eleanor Nichols contacted the Public Staff on June 2, 2015, regarding a voucher she had bought for a residential move from Five Star Movers through the website Amazon Local.[2] She stated that she believed some items were stolen in the move. Lesley Brown contacted the Public Staff on the same day about damages caused by Five Star Movers on a residential move and a price quote that was increased. She stated that she had learned of the company through its posted signs.[3] Bridget Lorigan contacted the Public Staff on July 13, 2015, about damages caused by Five Star Movers in a residential move that she had purchased through an Amazon Local voucher.[4]

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[1] See Public Staff Exhibit U, which was a complaint regarding three different types of signs recently found in the Charlotte area around September 24, 2015. At the hearing, Mr. Generette stated that two of the three types of signs belonged to his companies. According to the complaint received by the Public Staff, of the signs that Mr. Generette said belonged to his companies, one sign was found of the first style and three were found of the second style. (Tr. at 55.)

[2] Ms. Nichols contends that items were stolen in the move. The police investigated, but no charges were issued. The complaint has not been resolved.

[3] Mr. Generette stated that he did not recall performing this move.

[4] Mr. Generette has repaired Ms. Lorigan's bed, but her damaged table has not been repaired.

Given the foregoing, the Commission finds that members of the using and consuming public were led to believe that Mr. Generette's companies were licensed, insured and bonded based on the language on their signs and Internet advertising when, in fact, they were not. Based on the facts and circumstances presented, the Commission finds and concludes that Mr. Generette has represented himself as holding a certificate and otherwise authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a) by advertising the provision of intrastate moving of household goods to the using and consuming public throughout the greater Charlotte area. Moreover, the Commission finds and concludes that Mr. Generette's actions were willful and without regard to the law governing the transportation of household goods by motor vehicle for compensation in this State. Because of his conduct, the Commission finds that Mr. Generette should be assessed a civil penalty of one thousand, five hundred dollars ($1,500) in a certified check or U.S. currency.

Violation of G.S. 62-262(a)

It has long been determined that the Commission has authority to regulate motor carriers of household goods as "public utilities." G.S. 62-3(23)a.4. This authority also extends to persons and/or entities that may not have specifically met all of the Commission's authorization requirements, but are operating as de facto public utilities. The Commission has previously stated:

> The status of an entity as a public utility does not depend upon whether it has obtained operating authority from the Commission, but rather upon whether it is in fact operating a business defined as a public utility by the General Statutes. State ex rel. Utilities Commission v. Carolina Telephone and Telegraph Co., 267 N.C. 257 (1966); State ex rel. Utilities Commission v. Mackie, 79 N.C. App. 19 (1986), modified and aff'd, 318 N.C. 686 (1987). "If an entity is, in fact, operating as a public utility, it is subject to the regulatory powers of the Commission notwithstanding the fact that it has failed to comply with G.S. 62-110 before beginning its operation" Mackie, 79 N.C. App., at 32. "The same conclusion applies when an entity is required to obtain a certificate of exemption from the Commission, but fails to do so." (quoting Weathers Bros. Transfer Co, Inc., d/b/a Weathers Moving and Distribution v. Movers at Demand, Inc., Docket No. T-4176, Sub 1, and Movers at Demand, Inc., Docket No. T-4176, Sub 2 (May 11, 2004)).

(citing Docket No. T-4418, Sub 1 (2012), see also Docket No. T-4422, Sub 0 (July 27, 2009)).

The record shows that the Public Staff and the Commission informed Mr. Generette repeatedly that he was not to perform household goods moves until a certificate was issued to him. Ms. Smith and Mr. Rajeev testified that in their conversations with Mr. Generette beginning in August 2014, they advised him on numerous occasions that he could not legally perform intrastate residential moves without first obtaining a certificate from the Commission and provided him information on how to file an application. On July 7, 2015, Commission Staff sent Mr. Generette correspondence to acknowledge receipt of his application and requested additional information. The correspondence also contained a statement informing Mr. Generette that he could not transport household goods in the state without first obtaining a certificate from the Commission.

Despite not being issued a certificate, Mr. Generette has performed full-service moves in the state. Mr. Generette testified that in the last twelve months, his companies had performed approximately 250 residential moves, 98% of which were intrastate. Several of these unauthorized moves performed by Mr. Generette's companies were reflected in the three complaints received by the Public Staff, as discussed in the previous section. The Public Staff also presented evidence of a fourth complaint it had received from Anna Thomas on November 3, 2015, regarding a television that was broken in a move by Carolina Pack "N" Load on July 28, 2015.[1]

After carefully considering the evidence, the Commission finds and concludes that Mr. Generette operated as a de facto public utility by holding himself out as a common carrier of household goods, as defined in G.S. 62-3(7), and violated G.S. 62-262(a) by engaging in the intrastate transport of household goods without possessing a certificate of exemption as required by G.S. 62-261(8) and Commission Rule R2-8.1. Pursuant to G.S. 62-310(a),

> [a]ny public utility which violates any provision of this Chapter or refuses to conform to or obey any rule or regulation of the Commission shall … pay a sum up to one thousand dollars ($1,000) for each offense, to be recovered in an action to be instituted in the Superior Court of Wake County ... and each day such public utility continues to violate any provision of this Chapter or continues to refuse to obey or perform any rule, order or regulation prescribed by the Commission shall be a separate offense.

The Commission further finds that Mr. Generette was willful in his activities, as he performed at least 250 moves while he did not have a certificate and after he was specifically informed that he could not transport household goods until a certificate was issued to him. Because of his actions, the Commission finds and concludes that Mr. Generette should be assessed a civil penalty of one thousand, five hundred dollars ($1,500) in a certified check or U.S. currency**.**

Application for a Certificate of Exemption

Commission Rule R2-8.1 sets forth the specific requirements that must be met in order to obtain a certificate from the Commission. These requirements are also contained on the applications that the Commission provides to prospective applicants.

In order to obtain a certificate, an applicant must demonstrate to the Commission that it is fit, willing, and able to properly perform the service of household goods transportation within North Carolina, is familiar with the moving industry, has a reasonable and adequate knowledge of the rules and regulations governing the moving industry, including safety requirements as enforced by the N.C. Division of Motor Vehicles, and has knowledge of and will abide by the tariff requirements as established by the Commission in Maximum Rate Tariff No. 1. An applicant must also do the following: (1) show that it is financially solvent, (2) maintain minimum limits of

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[1] Mr. Generette disputes that the move damaged the television.

liability and cargo insurance coverage, (3) file proof of general liability insurance, (4) permit only persons possessing a valid driver's license to operate the motor vehicles that will be used for transporting household goods, (5) submit a Federal certified criminal record check, and (6) certify that the applicant has valid authorization to work in the United States. If an applicant cannot successfully meet these requirements, it will not be granted a certificate from the Commission to transport household goods.

After carefully reviewing the record, including all of the testimony, exhibits and filings, the Commission finds and concludes that, after paying the fines as set out above, Rashard Amon Generette, d/b/a Carolina Pack "N" Load, should be granted a probationary certificate with conditions. In making this determination, the Commission has carefully considered the issue of "fitness" with regard to Mr. Generette's background in the moving industry, his candor at the hearing, his actions with respect to the using and consuming public, and his adherence to directives from the Public Staff and Commission, Commission rules, and the law.

Mr. Generette testified that he has over ten years of experience in the moving industry. Currently, he employs a crew of approximately seven people. He has purchased a 2000 International box truck and is working to obtain the necessary insurance on it. While Mr. Generette has not yet attended the Maximum Rate Tariff training, he appears to have good working knowledge of the moving industry.

In his testimony, Mr. Generette admitted to all of the allegations regarding advertising and acting as a de facto utility as laid out in the Public Staff's Petition, except he denied that some of the signs in Public Staff Exhibit U were his. While he stated that he did not recall performing the move for Lesley Brown, neither did he deny performing the move, and he admitted to performing the moves for Ms. Nichols, Ms. Lorigan, and Ms. Thomas. Mr. Generette admitted to performing approximately 250 intrastate moves over the past year. Mr. Generette testified that he performed illegal moves to help him raise the money to obtain the insurance required by the Commission to be a certificated carrier. The Commission finds that Mr. Generette was honest with the Commission and generally did not attempt to make excuses for his behavior.

However, while the Commission appreciates Mr. Generette's desire to obtain certification to be a legal carrier, generating revenue by performing illegal moves is clearly inappropriate and unlawful. Unless and until the Commission grants him a certificate, the Applicant cannot perform intrastate moves of household goods in North Carolina. However, he can transport commercial goods and perform labor-only moves.

Mr. Generette's actions have given rise to four complaints to the Public Staff. While Mr. Generette may dispute his companies' responsibility for all of the issues raised by these four complaints, but for his advertising and moving without authority from the Commission, none of these complaints would likely have arisen. Thus, consumers have been detrimentally affected by Mr. Generette's actions.

Finally, as noted in the previous sections, Mr. Generette has demonstrated a disregard of the law and Commission rules despite numerous warnings. He has engaged in continued unauthorized activities, i.e., advertising and performing moves without a certificate, and used false names in dealing with the Public Staff. This cannot continue. The Commission is willing to grant a probationary certificate with conditions upon payment of the civil penalties, as discussed below.

The Commission has considered the factors surrounding the Applicant's fitness and concludes that the Applicant should be granted a probationary certificate of exemption with conditions that will ensure that he is complying with the rules and regulations associated with the intrastate transport of household goods in North Carolina, but that the effective date of the certificate will be stayed pending the payment of the civil penalties assessed herein. The conditions are as follows:

1. Prior to being issued a probationary certificate of exemption, Mr. Generette must attend the MRT training seminar, obtain all required insurance and DMV registrations, and provide proof of insurance and registration to the Commission.

2. Prior to being issued a non-probationary certificate of exemption, Mr. Generette must pay the full amount of the civil penalties as ordered below.

3. Within 180 days of the Applicant's being issued a probationary certificate of exemption, the Public Staff shall audit the Applicant's books and records. Within 30 days of this audit, the Public Staff shall report to the Commission the results of its audit and information on any complaints received involving the Applicant.

Following receipt of the reports from the Public Staff, the Commission will review the record and determine whether it is appropriate to continue the probationary certificate, cancel the certificate, or grant the Applicant a non-probationary certificate.

IT IS, THEREFORE, ORDERED as follows:

1. That Rashard Amon Generette, d/b/a Carolina Pack "N" Load, shall pay a civil penalty of $1,500 to the Commission, Office of the Chief Clerk, for his violation of G.S. 62-280.1(a).

2. That Rashard Amon Generette, d/b/a Carolina Pack "N" Load, shall pay a civil penalty of $1,500 to the Commission, Office of the Chief Clerk, for his violation of G.S. 62-262(a).

3. That the total $3,000 civil penalty assessed hereby shall be payable in six (6) equal monthly installments of $500 each, into the Office of the Chief Clerk, commencing thirty (30) days following the issuance of this Order and every subsequent thirty (30) days thereafter until satisfied, in a certified check (made payable to the North Carolina Department of Commerce/Utilities Commission) or cash.

4. That the Commission may seek to recover the total $3,000 civil penalty assessed by this Order in an action instituted in the Superior Court of Wake County, North Carolina, pursuant to G.S. 62-310(a), should Rashard Amon Generette, d/b/a Carolina Pack "N" Load, fail to remit the payment as hereby ordered.

5. That this Order will be shared with the Enforcement Division of the North Carolina State Highway Patrol to monitor the activities of Rashard Amon Generette, d/b/a Carolina Pack "N" Load.

6. That Rashard Amon Generette, d/b/a Carolina Pack "N" Load, shall be granted a probationary certificate of exemption to transport household goods in the State of North Carolina.

7. That the probationary certificate of exemption shall be subject to the conditions as set forth above in this Order, which shall be attached to the probationary certificate.

8. That the probationary certificate of exemption shall remain in effect until the Commission issues an order granting a non-probationary certificate of exemption, issues an order modifying the conditions, or cancels the Applicant's authority to perform household goods moves in North Carolina.

9. That prior to being issued a probationary certificate of exemption, Mr. Generette shall attend the MRT training seminar, obtain all required insurance and DMV registrations, and provide proof of insurance and registration to the Commission.

10. That within 180 days of the Applicant being issued a probationary certificate of exemption by the Commission, the Public Staff shall audit the Applicant's books and records. Within 30 days of this audit, the Public Staff shall report to the Commission the results of its audit and information on any complaints received involving the Applicant.

11. That the Applicant shall properly perform the service of household goods transportation within North Carolina in accordance with the Order granting the probationary certificate of exemption and shall obtain a reasonable and adequate knowledge of the rules and regulations governing the moving industry, including the safety requirements as enforced by the North Carolina Division of Motor Vehicles.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of March, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

TRANSPORTATION – COMMON CARRIER CERTIFICATE

DOCKET NO. T-4580, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Kenneth James Scallions, d/b/a South Park	)	
Movers.net - Application for Certificate of	)	RECOMMENDED ORDER
Exemption to Transport Household Goods	)	DISMISSING PROTEST

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Wednesday, February 4, 2016, at 10:02 a.m.

BEFORE: Commission Hearing Examiner, Corrie V. Foster

APPEARANCES:

For Applicant:

Kenneth James Scallions, d/b/a South Park Movers.net (Pro se)

For Protestant:

James Thorton, Esq., Cranfill Sumner & Hartzog, LLP, Post Office Box 27808, Raleigh, North Carolina 27611-7808.

BY THE HEARING EXAMINER: On May 22, 2015, Kenneth James Scallions, d/b/a South Park Ballantyne Moving Company (the Applicant) filed an Application with the North Carolina Utilities Commission (Commission) for a Certificate of Exemption (Certificate) to transport household goods by motor vehicle for compensation within the state of North Carolina.

On June 5, 2015, Greg Causey, owner of Ballantyne & Beyond Moving, Inc. (Protestant), filed with the Commission a Protest and Petition to Intervene to the Application.

On June 8, 2015, Protestant, through counsel, file an Amended Petition to Protest.

On September 17, 2015, the Applicant filed with the Commission an Amended Application for a certificate including a name change to Kenneth James Scallions, d/b/a South Park Movers.net.

On January 6, 2016, the Applicant filed a copy of a purchase agreement. The next day, the Commission issued an Order Granting Intervention and Scheduling Hearing. The hearing was scheduled for Tuesday, January 26, 2016, in Raleigh, North Carolina.

On January 20, 2016, Protestant, through counsel, filed a motion to continue hearing. The next day, the Commission issued an Order Rescheduling Hearing. The hearing scheduled for January 26, 2016, in Raleigh, North Carolina was cancelled and rescheduled for February 4, 2016, in Raleigh.

On February 4, 2016, the hearing was held as scheduled. The Applicant was present and testified in support of his application for a certificate. Protestant was present and represented by counsel, James Thornton. Protestant testified and submitted exhibits in support of his protest to Applicant's application in this matter.

Based upon the testimony and the exhibits presented at the hearing, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. On May 22, 2015, the Applicant filed an application for a certificate to operate as a household goods mover in the state of North Carolina for compensation.

2. The Commission has jurisdiction over public utilities, including those engaged in the intrastate transportation of household goods for compensation in North Carolina, as defined by G.S. 62-3(7) and (15).

3. Protestant is the new owner of Ballantyne & Beyond Moving, Inc. He filed a Petition to Protest Application on June 5, 2015, with the Commission.

4. Ballantyne & Beyond Moving, Inc., was previously owned and operated by the Applicant. The Applicant owned the company for about 14 years until he sold it to the Protestant in 2014.

5. Ballantyne & Beyond Moving, Inc., has certificates from the state of North Carolina and the state of South Carolina to move household goods for compensation.

6. The Applicant advertised his previous business through yellow page ads and flyers.

7. The Protestant earned a Bachelor of Arts Degree in Finance and Master of Business Administration Degree from Winthrop University.

8. On November 10, 2014, the Protestant purchased Ballantyne & Beyond Moving, Inc., from the Applicant for $925,000.

9. The Protestant's purchase agreement contained a non-compete provision which limited the Applicant to operating a moving business outside 200 miles of the greater Charlotte area for five years.

10. On February 6, 2015 in Docket No. T-4400, Sub 8, the Commission received email notification from the Applicant to authorize suspension of operations for his moving business associated with C-2468 for one year. On February 9, 2015, the Commission issued an Order Authorizing the Suspension. The request, however, was rescinded by Commission Order the next day.

11. On February 9, 2015, the Protestant signed a document releasing the Applicant from the non-compete provision contained in their purchase agreement.

12. The Applicant currently has a 26-foot straight truck, a pick-up truck, a small 16-foot trailer, several appliance dollies and 200 moving pads to use during his moves.

13. The Applicant has operational plans to hire two employees to assist him with the actual moving and administrative duties and to establish a terminal at 3435 Beam Road, Suite C, Charlotte, North Carolina 28217.

14. The Applicant has all the necessary insurance required by the Commission to operate his new household goods moving business.

WHEREUPON, the Commission makes the following

CONCLUSIONS

Commission Rule R2-8.1(b)(6)(1), in pertinent part, states any party desiring to file a protest must do so in writing by setting forth the reasons for the protest and filing that protest with the Commission no later than 15 days from the filing date of the application. Protests may be filed based only upon the applicant's fitness or financial solvency.

The Hearing Examiner has reviewed and considered all the evidence in this proceeding and finds that good cause exists to dismiss the protest. During the hearing, the Protestant from the witness stand confirms that the first two of his three issues were resolved by the Applicant's subsequent filings. Specifically, the Applicant has changed the name of his company from South Park Ballantyne Moving Company to South Park Movers.net and that the company decided to operate his new company out of 3435 Beam Road, Suite C, in Charlotte, North Carolina instead of 136 Marvin Road, Indian Land, South Carolina, as originally planned. The Protestant, however, maintains that the Applicant's actions with regard to the purchase agreement disqualify him from obtaining a certificate from the Commission.

Specifically, the Protestant points to two incidents that he offers as evidence of the Applicant's fitness. The first incident is the Applicant's action of contacting the Commission on February 6, 2015, to suspend the company's C-2468[1] without notifying the Protestant. The second incident occurred when the Applicant met the Protestant at a local bank on February 9, 2015, to sign a waiver of the non-compete provision and transfer $10,000 to extend the use of his certificate. According to the Protestant, the Applicant should not be able to operate due to the non-complete provision in the purchase agreement.

[1] A C-Number is assigned to every regulated household goods mover in North Carolina. Ballantyne & Beyond Moving, Inc, was assigned its number on May 8, 2008, in Docket No. T-4400, Sub 0.

The Hearing Examiner has considered these incidents and does not agree with the Protestant's conclusion that they disqualify the Applicant from obtaining a certificate from this Commission. First, the Hearing Examiner recognizes that the Protestant is upset that the Applicant's actions while they were attempting to figure out how to proceed with transferring the business' operating authority. It is clear, that the Applicant did not always act or demonstrate that he had the Protestant's best interests in mind with his actions. The Applicant had varying excuses for his actions. The Applicant claimed that the Protestant was "dragging his feet in getting his own insurance" and "was not a good manager of the business." As a result, he contacted the Commission to suspend the business' C-Number to get the Protestant's attention. The Hearing Examiner does not agree that this was the best way to act with the Protestant. The Applicant's actions were undeniable contrary to the Protestant's best interests. His behavior; however, does not rise to the level that it would automatically disqualify him from now obtaining a certificate from the Commission. Despite the Applicant's actions, there was no evidence presented to show that the Protestant's company lost business or was otherwise harmed by the Applicant's conduct. In fact, the record does show that the Commission issued an Order Suspending the Certificate on February 9, 2015. The suspension, however, was rescinded by Order of the Commission the next day.

Second, the Hearing Examiner realizes that the Protestant requests that the Hearing Examiner interpret the parties' rights and obligations under the purchase agreement including enforcing a non-compete provision. This is something that the Hearing Examiner will not do. The Hearing Examiner acknowledges the parties' intent to transfer ownership of a household goods moving business. However, the Hearing Examiner will make no legal conclusions with regard to the parties' specific rights and responsibilities under the purchase agreement including whether the Protestant's waiver of the non-compete provision is invalid. The Hearing Examiner finds that any such conclusions should be made by the General Court of Justice in their county. The Hearing Examiner recognizes that the Protestant cites *C&P Enters v. State ex rel. North Carolina Utils. Comm'n* 126 N.C.App. 495, 498 (1997) for support for the Commission to take action against the Applicant. However, in the C&P Enters case, the Commission enforced a ruling of the Superior Court constructing a private agreement for the operation of a sewage treatment plant. In the case at hand, the Protestant, a sophisticated businessman[1], had an opportunity to take legal action against the Applicant for his actions but elected not to do so. The result of the Protestant's omission to act in this matter is that the Applicant is now seeking approval from the Commission to start a new moving business. The Hearing Examiner further recognizes that the agreement deals primarily with the transfer of the business and not directly with providing a service to the using and consuming public. Due to the nature of the agreement, it does not appear that it adversely impacts the using and consuming public. At this juncture, the Hearing Examiner sees no basis to intercede in the parties' allege dispute. Therefore, the Hearing Examiner will take no action in this matter without a prior legal conclusion being made by a competent Court of Justice.

[1] The Protestant earned a Bachelor of Arts Degree in Finance and Masters of Business Administration Degree from Winthrop University. He acquires businesses and is responsible to initial the contracts and performs due diligence before agreeing to purchase businesses.

The Hearing Examiner now considers the Applicant's background in the moving industry. The record shows that the Applicant's experience and knowledge of the household goods moving business is uncontroverted. The Applicant previously owned Ballantyne & Beyond Moving, Co., for about 14 years before selling it to the Protestant in 2014. The company was certified by both the North Carolina Utilities Commission and the South Carolina Utilities Commission to perform household goods moves for compensation. The Applicant grew the business by publicizing its services through yellow page ads and distributing flyers at local apartments throughout the greater Charlotte area. He also grew the company to employ about 34 employees and utilized over ten moving vehicles.

After selling his first moving business to the Protestant, the Applicant expressed an interest in operating a smaller moving company. He plans to operate the business in a partnership with his father. He plans to use the same methods to advertise his new company - South Park Movers.net's moving services. He also intends to hire two employees to assist him with the moving and administrative responsibilities. He plans to establish a terminal at 3435 Bean Road, Suite C., in Charlotte, North Carolina. The Applicant presently has several resources that he can use to perform moves. Specifically, he possesses a 26-foot International straight truck, a pick-up truck, one 16-foot trailer, and several appliance dollies and 200 moving blankets. He also has all the necessary insurance required by the Commission to operate a certified household goods moving company.

Based on the foregoing, the Hearing Examiner finds that good cause exists to dismiss the protest in this proceeding. The Hearing Examiner further finds that the Applicant possesses experience, knowledge of the moving industry, and resources to operate a household goods moving business. Overall, the Hearing Examiner finds that the Applicant has satisfactorily addressed the issues regarding his fitness to obtain a certificate of exemption from this Commission to transport household goods.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of June, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

TRANSPORTATION – COMMON CARRIER CERTIFICATE

DOCKET NO. T-4580, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Kenneth James Scallions, d/b/a South Park	)	
Movers.net - Application for Certificate of	)	ERRATA ORDER
Exemption to Transport Household Goods	)	

BY THE HEARING EXAMINER: On June 14, 2016, the Commission Hearing Examiner issued a Recommended Order Dismissing Protest in the above-captioned proceeding. In the Order, the Hearing Examiner recommended that the protest filed in the docket on June 5, 2015, be dismissed. The Hearing Examiner further concluded that Kenneth James Scallions, d/b/a South Park Movers.net (Applicant), had satisfactorily addressed the issues regarding his fitness to obtain a certificate of exemption from this Commission to transport household goods.

It has come to the attention of the Hearing Examiner that there is an error in the Order. On page 4, bottom of the last paragraph beginning with the sentence - However, in the C&P Enters case, the Hearing Examiner inadvertently used the word "constructing" in the sentence.

The sentence should actually read – However, in the C&P Enters case, the Commission enforced a ruling of the Superior Court **construing** a private agreement for the operation of a sewage treatment plant.

The Hearing Examiner finds that good cause exists to correct the error in the Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of June, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-1300, SUB 19
DOCKET NO. W-888, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Old North State Water Company, LLC, 4700 Homewood Court, Suite 108, Raleigh, North Carolina 27609, and Horse Creek Farms Utilities Corporation, Post Office Box 14046, New Bern, North Carolina 28561, for Authority to Transfer Franchise in the Horse Creek Farms Subdivision Onslow County, North Carolina, and for Approval of Increased Rates	)	RECOMMENDED ORDER APPROVING TRANSFER, GRANTING FRANCHISE, APPROVING ACQUISITION ADJUSTMENT, APPROVING INTERIM RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: 7:00 p.m., Tuesday, June 14, 2016, in the Onslow County Courthouse, 625 Court Street, Jacksonville, North Carolina

9:30 a.m., Thursday, August 11, 2016, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commission Hearing Examiner Freda H. Hilburn

APPEARANCES:

For Old North State Water Company, LLC:

Karen M. Kemerait, Smith Moore Leatherwood LLP, 434 Fayetteville Street, Suite 2800, Raleigh North Carolina 27601

For Horse Creek Farms Utilities Corporation:

No attorney of record.

For the Using and Consuming Public:

William E. Grantmyre, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

HILBURN, COMMISSION HEARING EXAMINER: On March 4, 2016, Old North State Water Company, LLC (ONSWC or Company), and Horse Creek Farms Utilities Corporation (Horse Creek Farms) filed an application (Application) with the Commission seeking authority to transfer the wastewater utility system assets and franchise from Horse Creek Farms to ONSWC so that ONSWC may provide wastewater utility service in the Horse Creek Farms Subdivision in Onslow County, North Carolina, and for approval of increased rates.

On May 3, 2016, the Commission entered an Order Requiring Customer Notice, Requiring the Prefiling of Testimony, and Scheduling Hearings. Such Order scheduled a public hearing for public witness testimony only on June 14, 2016 in Jacksonville, North Carolina, and scheduled another public hearing for August 11, 2016 in Raleigh, North Carolina. ONSWC was required to provide customer notice of the public hearings and the proposed rate increase to all affected customers. On May 10, 2016, ONSWC filed its Certificate of Service notifying the Commission that the required customer notice had been provided.

On June 14 2016, the public hearing was held in Jacksonville, North Carolina as scheduled. Approximately 20 customers attended the hearing and the following five customers testified: Derrick Reynolds, Dorothy Bledsoe, Henry Boyd, William Schrader and Judy Hernandez. All the customers expressed concerns regarding the magnitude of the proposed increase. The customers did not express any quality of service concerns.

On July 8, 2016, ONSWC filed the direct testimony and exhibits of Michael Myers, President of ONSWC.

On July 21, 2016, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a motion for extension requesting that the Commission extend the time for the Public Staff to prefile testimony until July 29, 2016. The Public Staff also requested that the Commission extend the time for ONSWC to file its rebuttal testimony until August 8, 2016. By Order dated July 21, 2016, the Commission granted the Public Staff's requested extensions.

On July 29, 2016, the Public Staff filed a Second Motion for Extension requesting that the Commission extend the time for the Public Staff to prefile testimony until August 3, 2016. The Public Staff also requested that the Commission extend the time for ONSWC to file its rebuttal testimony until August 9, 2016. By Order dated July 29, 2016, the Commission granted the Public Staff's requested extensions.

On August 4, 2016, the Public Staff filed the testimony and exhibit of Windley E. Henry, Supervisor, Water Section Accounting Division, and the testimony and exhibits of Babette K. McKemie, Utilities Engineer, Water Division.

On August 10, 2016, ONSWC filed the rebuttal testimony of Michael Myers.

The matter was called for evidentiary hearing on August 11, 2016. No public witnesses attended the August 11, 2016 public hearing. Michael Myers, ONSWC's President and Rudy Shaw, ONSWC's Business Development Manager, were in attendance on behalf of the Company, and witness Myers testified on behalf of ONSWC. Public Staff witnesses Henry and McKemie presented their testimony.

At the conclusion of the hearing, ONSWC made an oral motion that the Hearing Examiner waive the time period set forth in G.S. 62-78 afforded for parties to the proceeding to file exceptions to a recommended order. Specifically, ONSWC requested that the Hearing Examiner's Recommended Order approving the transfer and interim rate increase be final and effective upon the date of issuance. The Public Staff had no objection to ONSWC's motion.

On August 22, 2016, ONSWC filed the amended rebuttal testimony of Michael Myers to correct a typographical error.

On September 8, 2016, ONSWC, Horse Creek Farms, and the Public Staff filed a Joint Proposed Recommended Order. On September 12, 2016, ONSWC filed a letter with the Commission stating that the Company waives its right to file exceptions to the Hearing Examiner's Recommended Order and requested that such Recommended Order be adopted as the final Order and effective upon issuance.

On the basis of the Application, the testimony, the exhibits, and the entire record in this proceeding, the Hearing Examiner makes the following

FINDINGS OF FACT

General Matters

1. Horse Creek Farms owns the wastewater utility assets and holds a franchise to provide wastewater utility service to residential customers in the Horse Creek Farms Subdivision in Onslow County, North Carolina.

2. Horse Creek Farms currently serves approximately 347 residential wastewater customers.

3. Horse Creek Farms was granted a certificate and public convenience and necessity and the current rates were approved by Commission Order dated July 17, 1985, in Docket No. W-888, Sub 0, and recently reduced by Commission Order dated February 13, 2015, in Docket No. W-888, Sub 5, to reflect the repeal of the gross receipts tax and comply with House Bill 998, An Act to Simplify the North Carolina Tax Structure and to Reduce Individual and Business Tax Rates enacted by the North Carolina General Assembly in 2013. Horse Creek Farms has not applied for or received a rate increase in more than 31 years.

4. ONSWC is a public utility as defined by G.S. 62-3(23), and is authorized to provide water and/or wastewater utility service to customers in North Carolina. ONSWC owns a number of water and wastewater systems throughout North Carolina, including in Onslow County and neighboring Carteret and Pender Counties.

5. The test period appropriate for use in this proceeding is the 12-month period ending November 30, 2015, updated for known and measurable changes.

6. ONSWC has the technical, managerial, and financial capacity to own and operate the wastewater system serving the Horse Creek Farms Subdivision.

Acquisition Adjustment

7. Horse Creek Farms and ONSWC entered into an Asset Purchase Agreement dated September 11, 2015, pursuant to which Horse Creek Farms has agreed to sell and ONSWC has

agreed to purchase the wastewater assets of Horse Creek Farms for a total purchase price of $123,655.

8. The Public Staff has calculated Horse Creek Farms' original cost net investment in the wastewater system to be zero.

9. The Public Staff has recommended a positive purchase price acquisition adjustment of $118,855, which includes $3,000 to be paid to Horse Creek Farms' attorney, such that ONSWC's cost net investment is $118,855.

10. The Public Staff found that the Horse Creek Farms system requires substantial maintenance, repairs, and capital improvements to meet the requirements of the North Carolina Department of Environmental Quality, Division of Water Resources (DWR) permits. The system has a history of noncompliance. The wastewater system has not been maintained, and the equalization basin has collapsed. As a result of the continued noncompliance and poor maintenance, the facility was assessed civil penalties and enforcement costs of $2,276. Due to the ongoing noncompliance issues, Horse Creek Farms and DWR entered into a settlement agreement executed on November 4, 2015, that requires Horse Creek Farms to transfer ownership of the system.

11. Within the first 150 days of ONSWC's ownership of the system, ONSWC plans to make approximately $113,000 in capital improvements to the wastewater system, including: replacing the piping on lift station no. 1, replacing the electrical system on lift station no. 2, replacing a pump at lift station no. 1, purchasing a spare lift station pump, replacing the safety grating at the wastewater treatment plant, and performing renovations to the collapsed equalization tank. Through the year 2020, ONSWC plans to make approximately $168,000 in system improvements to the wastewater system.

12. The Horse Creek Farms customers will benefit from the substantial improvements that ONSWC will make to the wastewater system and from ONSWC's management supervision and extensive field service operations. The system improvements will significantly improve wastewater service reliability for the customers.

13. The $118,855 acquisition adjustment results in an original cost net investment of $343 per customer based upon the current 347 customers.

14. ONSWC will have standalone rates for the Horse Creek Farms service area so the other ONSWC customers will not be affected by the approval of the positive acquisition adjustment.

15. The transaction is prudent and the result of arm's length bargaining. The benefits accruing to the Horse Creek Farms customers will outweigh the costs of inclusion of the purchase price in the rate base.

16. The Public Staff recommended that the purchase price acquisition adjustment in the amount of $118,855 be allowed.

Interim Rate Increase

17. The Public Staff recommended that the Hearing Examiner approve as interim rates a flat rate of $29.17 per month per residential customer.

18. The Public Staff also recommended that this proceeding be bifurcated as follows: first, by the approval of the transfer of the franchise and approval of the interim rates, and by leaving the final rate increase open for 150 days after the closing of the transfer of the system from Horse Creek Farms to ONSWC in order for ONSWC to complete necessary improvements to the system; and second, for approval of the final rate increase upon the completion of the improvements by ONSWC that will occur on or before the 150-day period after the closing. Once the system improvements are completed, ONSWC will submit to the Public Staff documentation of the completed system improvements and paid invoices, and the Public Staff will then recalculate the recommended rates including depreciation expense and return on rate base to include the completed system improvements. Within 20 days of receiving ONSWC's completed system improvement documentation, the Public Staff stated it would file a proposed order for the second phase of the rate increase proceeding.

19. Appendix B, attached hereto, is the approved Schedule of Interim Rates for ONSWC.

Bond

20. The Public Staff has recommended that ONSWC be required to post a $50,000 bond for Horse Creek Farms Subdivision. ONSWC agreed with the Public Staff's recommendation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 1-5

The evidence supporting these findings is found primarily in the Application and testimony of Public Staff Witness Henry. These findings are jurisdictional, informational, and are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 6

The evidence supporting this finding of fact is found in the testimony ONSWC witness Myers and the records of the Commission.

ONSWC witness Myers testified that ONSWC has the resources to properly operate, manage, and invest in the Horse Creek Farms wastewater system. Witness Myers testified that he is familiar with the Horse Creek Farms wastewater system as ONSWC has been overseeing operations and providing customer service, billing, and bookkeeping services since 2014. Witness Myers stated that ONSWC entered into a Utility Management Service Agreement with Horse Creek Farms by which ONSWC assumed operations and maintenance responsibilities for the wastewater system as of July 1, 2014. Witness Myers commented that Horse Creek Farms has not been able to pay all the necessary costs of the wastewater system; consequently, ONSWC has been subsidizing the operating and maintenance costs of the systems in an average amount of $2,252 per month. Witness Myers contended that ONCSWC has paid certain necessary operating expenses for the wastewater system to ensure that wastewater operations continue. Witness Myers stated that ONSWC has not been reimbursed by Horse Creek Farms for these operating and maintenance costs.

Based upon the foregoing and the records of the Commission, the Hearing Examiner finds and concludes that ONSWC has the technical, managerial, and financial capacity to own and operate the wastewater system serving the Horse Creek Farms Subdivision.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 7-16

The evidence supporting these findings is found in the testimony of Public Staff witnesses Henry and McKemie and ONSWC witness Myers.

The Commission has heretofore allowed a positive acquisition purchase price adjustment when: (1) the benefit to customers outweighs the cost of inclusion in rate base of the excess purchase price; (2) the transaction is prudent; and (3) the transaction is the result of arm's length bargaining. See Order Approving Transfer, Acquisition Adjustment, and Maintaining Current Rates, Docket No. W-274, Sub 122, April 30, 1997 (the Hardscrabble Order), Finding of Fact No. 14.

Witnesses McKemie, Henry, and Myers testified as to the deficiencies in the Horse Creek Farms wastewater system and Horse Creek Farms' history of noncompliance with the requirements of the DWR permits. Specifically, witness McKemie testified that she has reviewed the DWR compliance inspection reports for the past three years, conducted a visit to the site, and met with representatives of the Wilmington Regional Office of DWR. She stated that the system has a history of noncompliance and poor maintenance. The facility appears to have not been maintained, and the equalization basin has collapsed. Furthermore, on July 12, 2016, DWR conducted an inspection, and determined that the facility is "in an advanced state of deterioration".

Witness McKemie testified that as a result of continued noncompliance and poor maintenance, the facility was assessed civil penalties and enforcement costs of $2,276. Witness McKemie noted that due to ongoing compliance actions, DWR and Horse Creek Farms entered into a settlement agreement which requires the transfer of ownership of the facility.

Witness Myers testified that the wastewater system is a troubled system. Witness Myers stated that, to date, Horse Creek Farms has not made any significant investment in the wastewater system, and that he does not believe that Horse Creek Farms has the funds to invest in the wastewater system now. He testified the system deficiencies would go unaddressed if ONSWC does not acquire the wastewater system.

Witnesses Henry and Myers testified that the following capital improvements need to be performed after the closing: replace the piping on lift station no. 1, replace the electrical system on lift station no. 2, replace a pump at lift station no. 1, purchase a spare lift station pump, replace the safety grating at the wastewater treatment plant, and perform renovations to the collapsed equalization tank.

Witnesses Henry and Myers testified that the purchase price is prudent and the result of arm's length bargaining, and that the benefits accruing to the customers of Horse Creek Farms will outweigh the cost of inclusion in rate base of the excess purchase price. In particular, witness Myers testified that the purchase price amount was required in order for the system to be sold. The Asset Purchase Agreement between Horse Creek Farms and ONSWC contains a contingency that ONSWC has the right to terminate the agreement if the purchase price is not included in the rate base. Witness Myers testified that ONSWC will not purchase the system unless the purchase price is included in the rate base. Witness Myers also testified that Horse Creek Farms and ONSWC engaged in prolonged and difficult negotiations over a period of several months for the sale of the wastewater system.

Witnesses Henry and Myers also testified that the customers will benefit from the approximately $168,000 in system improvements that ONSWC will make to the wastewater system through 2020. Witness Myers testified that ONSWC will make system improvements costing approximately $113,000 in 2016, $3,500 in 2017, $18,500 in 2018, $14,000 in 2019, and $19,000 in 2020. Those improvements will allow for the proper functioning of the system and will resolve noncompliance issues. Witness Henry testified that the customers will receive significantly improved wastewater service reliability from the plant improvements that ONSWC will make and from ONSWC management supervision and field service operations. In light of the circumstances in this matter, witness Henry concluded that the benefits to the Horse Creek Farms customers of having reliable wastewater service clearly outweigh the resulting increased rates resulting from the acquisition adjustment.

Therefore, the Hearing Examiner finds and concludes that the benefits to customers outweighs the cost of inclusion in rate base of the excess purchase price, that the transaction is prudent, and the transaction is the result of arm's length bargaining. Based on the foregoing, and the specific facts and circumstances of this case, the Hearing Examiner concludes that the purchase price adjustment of $118,855 recommended by the Public Staff should be allowed, such that ONSWC's cost net investment is $118,855.

As the Commission noted in its <u>Hardscrabble Order</u>, "the Commission has articulated a position of encouraging the orderly transfer of water [and wastewater] system[s] from developers and small owners to reputable water utilities . . . ." <u>Hardscrabble Order</u>, p. 11. The Hearing Examiner notes that ONSWC is a reputable water and wastewater owner, with the technical, managerial, and financial capacity to own and operate the wastewater system. Hence, the decision to allow the purchase price adjustment, based upon the facts and circumstances presented, promotes and serves this position and is in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 17-19

The evidence supporting these findings is found in the testimony of Public Staff witnesses Henry and McKemie.

Witness Henry testified that ONSWC has requested authorization to increase its total operating revenues from $68,077 to $175,716. After making adjustments, the Public Staff found that the test year level of total operating revenue deductions, updated for known and measurable changes, is $109,702. As presented in Henry Exhibit I, Schedule 2, Witness Henry determined that the original cost rate base amount for ONSWC is $128,556. Consequently, Witness Henry stated that, as allowed under G.S. 62-133, he used the rate base method to evaluate ONSWC's proposed rate increase. Witness Henry calculated an increase in the gross revenue requirement using the overall rate of return on rate base of 7.50%. Use of the return on rate base produces an increase in the wastewater revenue requirement of $52,958, which results in a total revenue requirement of $121,035, of which $121,456 is service revenues. Therefore, the Public Staff recommends that the interim wastewater service rates be set to reflect a $52,958 increase, resulting in an annual level of service revenues of $121,456.

Witnesses Henry and McKemie recommended that the Hearing Examiner approve as interim rates the flat rate of $29.17 per month. Witness Henry noted that although the Public Staff is recommending a 77% interim rate increase, the current rates were approved by Order dated July 17, 1985, in Docket No. 888, Sub 0, and recently reduced by Commission Order dated February 13, 2015, in Docket No. W-888, Sub 5, to comply with HB 998.

Witness Henry testified that ONSWC must have an immediate interim rate increase effective on the date of closing in order to have adequate revenues to operate the wastewater system and not experience substantial operating losses.

Witness Henry recommended that the Hearing Examiner bifurcate the proceeding as follows: first, by the approval of the transfer of the franchise and the interim rates, and by leaving the final rate increase open for 150 days after the closing of the transfer of the system from Horse Creek Farms to ONSWC in order for ONSWC to complete necessary improvements to the system; and second, for approval of the final rate increase upon the completion of the improvements by ONSWC that will occur on or before the 150-day period after the closing. Once the system improvements are completed, ONSWC will submit to the Public Staff documentation of the completed system improvements and paid invoices, and the Public Staff will then recalculate the recommended rates including depreciation expense and return on rate base to include the completed system improvements. He testified within 20 days of receiving ONSWC's completed system improvement documentation, the Public Staff would file a proposed order for the second phase of the rate increase proceeding. Witness Henry recommended that ONSWC be allowed to include in the updated documentation a maximum of $4,800 for the reasonable and prudent additional engineering/surveying expenses for documenting and recording the required easements. ONSWC stated its agreement with the Public Staff's recommendation that the proceeding be bifurcated.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 20

The evidence supporting this finding of fact is found in the testimony of Public Staff witness McKemie.

Public Staff witness McKemie supplemented her prefiled testimony at the August 11, 2016 evidentiary hearing to recommend that ONSWC post a $50,000 bond with the Commission for the Horse Creek Farms Subdivision service area. The Company agreed with the Public Staff's recommendation.

The Hearing Examiner accepts the recommendation of the Public Staff and notes that on September 19, 2016, in Docket No. W-1300, Sub 28 (Sub 28 Proceeding), ONSWC filed an amendment to increase its existing $250,000 irrevocable letter of credit to $400,000. In the Commission's Order Approving Bond and Surety and Releasing Bond issued on September 19, 2016, in the Sub 28 Proceeding, the Commission assigned $50,000 of the approved increase of $150,000 in bond surety to this docket. The Hearing Examiner observes that ONSWC's remaining unassigned bond surety is $100,000.

CONCLUSIONS

Based upon the Application and the testimony and exhibits contained in the record, the Hearing Examiner concludes that the transfer of the franchise and wastewater utility assets from Horse Creek Farms to ONSWC is in the public interest and should be approved and that the interim rate increase recommended by the Public Staff should be approved. Further, the Hearing Examiner finds and concludes the following: (1) that the rate increase portion of this proceeding should be held open for a period of 150 days after the transfer closing; (2) that on or before the 150th day, ONSWC should submit to the Public Staff documentation of ONSWC's completed system capital improvements; (3) that the Public Staff should then recalculate the Public Staff's recommended rates including depreciation expense and return on rate base for the completed system capital improvements; and (4) that the Public Staff should, within 20 days after receiving ONSWC's completed system capital improvement documentation, file a proposed recommended order for the second phase of the rate increase portion of this proceeding.

IT IS THEREFORE ORDERED as follows:

1. That, as required by the Commission's Order issued on September 19, 2016, in Docket No. W-1300, Sub 28, $50,000 of the approved $150,000 increase to ONSWC's bond surety shall be assigned to Horse Creek Farms Subdivision service area. ONSWC's remaining unassigned bond surety shall be $100,000.

2. That the application for the transfer of the wastewater system and certificate of public convenience and necessity to provide wastewater utility service in Horse Creek Farms Subdivision in Onslow County, North Carolina from Horse Creek Farms to ONSWC, is hereby approved.

3. That Appendix A, attached hereto, shall constitute the Certificate of Public Convenience and Necessity for the Horse Creek Farms Subdivision.

4. That the positive acquisition adjustment of $118,855 is just and reasonable and is hereby approved. ONSWC shall, in future rate case proceedings, be allowed rate base treatment of $118,855.

5. That the attached Schedule of Interim Rates, Appendix B, is approved and deemed filed with the Commission pursuant to G.S. 62-138. This Schedule of Interim Rates shall become effective upon the closing of the transfer of wastewater utility system assets to ONSWC.

6. That the rate increase portion of this proceeding shall be held open for a period of 150 days after the transfer closing. That on or before the 150th day, ONSWC shall submit to the Public Staff documentation of ONSWC's completed system capital improvements. That the Public Staff shall then recalculate the Public Staff's recommended rates including depreciation expense and return on rate base for the completed system capital improvements. That the Public Staff shall, within 20 days after receiving ONSWC's completed system capital improvement documentation, file a proposed recommended order for the second phase of the rate increase portion of this proceeding.

7. That the Notice to Customers, attached hereto as Appendix C, shall be mailed with sufficient postage or hand delivered to all customers in Horse Creek Farms Subdivision within five calendar days of the effective date of this Order.

8. That ONSWC shall submit to the Commission the attached Certificate of Service properly signed and notarized not later than 10 days after the next billing of the affected customers.

9. That ONSWC shall notify the Commission within five business days after the closing of the transfer of assets.

10. That the Certificate of Public Convenience and Necessity to provide wastewater utility service granted to Horse Creek Farms Utilities Corporation (Docket No. W-888, Sub 0) is canceled on the date which ONSWC files with the Commission written notification that the closing of the transfer of the wastewater utility system has been completed.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of September, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1300, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

OLD NORTH STATE WATER COMPANY, LLC

is granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

to provide wastewater service

in

HORSE CREEK FARMS SUBDIVISION

Onslow County, North Carolina

subject to any order, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the _19th_ day of September, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX B

SCHEDULE OF INTERIM RATES

for

OLD NORTH STATE WATER COMPANY, LLC

for providing wastewater utility service in

HORSE CREEK FARMS SUBDIVISION

Onslow County, North Carolina

WATER AND SEWER – CERTIFICATE

Interim Monthly Residential Flat Rate for Sewer Utility Service:	$29.17
Connection Fee:	$2,000.00 per REU [1/]
Reconnection Fees: If sewer is cut off by utility for good cause	Actual cost [2/]
New Account Fee:	$20.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date

[1/] REU is one Residential Equivalent Unit.

[2/] The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to the customer with the cut-off notice.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1300, Sub 19, on this the __19th__ day of September, 2016.

APPENDIX C
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1300, SUB 19
DOCKET NO. W-888, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

NOTICE IS HEREBY GIVEN that the Commission has approved the transfer of the sewer utility system serving Horsecreek Farms Subdivision in Onslow County to Old North State Water Company, LLC (ONSWC).

NOTICE IS FURTHER GIVEN that the North Carolina Utilities Commission (Commission) has approved a partial interim rate increase.

The Commission-approved rates are as follows:

Interim Monthly Residential Flat Rate for Sewer Utility Service: $29.17

The Commission will hold open ONSWC's applied for rate increase for 150 days subsequent to the closing of the transfer of the sewer utility system assets from Horse Creek Farms Utilities Corporation to ONSWC for ONSWC to make sewer system improvements, including: replacing the piping on lift station no. 1, replacing the electrical system on lift station no. 2, replacing a pump at lift station no. 1, purchasing a spare lift station pump, replacing the safety grating at the wastewater treatment plant, and performing renovations to the collapsed equalization tank. These ONSWC system improvements, which are estimated to cost about $113,000, will improve the sewer utility system's reliability. After ONSWC provides the Public Staff with complete documentation regarding the final cost of the improvements, and the Public Staff completes its audit of these improvement costs and ONSWC's rate base investment to purchase the system, the Public Staff will recommend increased rates for ONSWC.

The Commission will evaluate all evidence in this proceeding, including the Public Staff's recommendation on the sewer rates, and then issue a further order for ONSWC's sewer rates. Customers will be notified as to the final decision of the Commission regarding new rates.

This the _19th_ day of September, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket Nos. W-1300, Sub 19 and W-888, Sub 6, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2016.

By: ____________________________________
Signature

____
Name of Utility Company

The above named Applicant, __________________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket Nos. W-1300, Sub 19 and W-888, Sub 6.

Witness my hand and notarial seal, this the ____ day of _______________, 2016.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ____________________________________
Date

DOCKET NO. W-864, SUB 11

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Webb Creek Water and Sewage, Inc. – Petition for Appointment of Emergency Operator	))))	ORDER APPOINTING EMERGENCY OPERATOR, APPROVING INCREASED RATES, AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On August 3, 2016, the Public Staff filed a petition pursuant to G.S. 62-116(b) and G.S. 62-118(b), requesting the Commission to issue an order: (1) declaring an emergency, (2) appointing Pluris Webb Creek, LLC (Pluris), as emergency operator, and (3) approving an emergency rate increase for the Webb Creek Water and Sewage, Inc. (Webb Creek), wastewater utility system in Onslow County, North Carolina.

The Public Staff presented this matter at the Commission's Staff Conference on August 8, 2016.

Based upon the Public Staff's Petition and the Commission's records, the Commission makes the following

FINDINGS OF FACT

1. a. The Commission granted Webb Creek its first certificate of public convenience and necessity for the Webb Creek wastewater utility system by Order issued January 14, 1987, in Docket No. W-864, Sub 0. The system currently serves a total of 975 residential customers, the Sandy Ridge Elementary School, and six other commercial customers. The Onslow Water and Sewer Authority (ONWASA) provides water service to the Webb Creek service areas.

b. The subdivisions currently served by the Webb Creek wastewater utility system are as follows:

Buckhead
Creekertown
Creekertown Villas
Cooper's Court
Foxden
Foxlair
Fox Trace Sections I, II, and III
Fox Trace Section IV, Phases 1 through 6
Fox Trace Section V

Fox Trace Point I and II
Jack's Branch
Jack's Branch Townhomes
Quail Roost

2. The president of Webb Creek is Joseph Hal Kinlaw, Jr., who has been a stockholder and officer of the corporation since it was incorporated in 1985. Mr. Kinlaw has also been a principal in each of the developer groups or entities that developed the residential subdivisions served by the Webb Creek wastewater system.

3. Webb Creek holds a National Pollutant Discharge Elimination System (NPDES) Permit issued by the Division of Water Resources (DWR) of the North Carolina Department of Environmental Quality (DEQ) to discharge 300,000 gallons per day (GPD) of wastewater effluent treated at its sequencing batch reactor (SBR) wastewater treatment plant (WWTP). Webb Creek also holds a collection system permit (Collection Permit) for its wastewater collection system, which consists of approximately 11.9 miles of gravity sewer main, 2.6 miles of force main, 0.25 miles of pressure main, three simplex pump stations, and eight duplex pump stations.

4. Due to material non-compliance with G.S. 143-215.1, the NPDES Permit, and the Collection Permit, Webb Creek has incurred numerous Notices of Violation (NOVs) and administrative penalties for construction, operations, effluent parameter discharges, and reporting violations.

5. The Public Staff, accompanied by DWR, conducted a site inspection of both the WWTP and the collection system on June 14, 2016. Pluris independently conducted two site inspections.

6. A number of important components of the wastewater system are owned by entities other than Webb Creek, and which Mr. Kinlaw has or once had an ownership interest.

7. As of October 2015, there were recorded liens in Onslow County against the ownership entities totaling $39.3 million, including liens against Webb Creek totaling $2.1 million plus accruing interest. With the liens against Webb Creek exceeding $2.1 million, there can be no question that Webb Creek faces a real emergency.

8. Due to the ownership issues with five collection system duplex lift stations and the massive liens against those five lift stations, plus the judgments and liens against the Webb Creek plant, the conveyance of the Webb Creek wastewater utility system to a new owner will be a complex and lengthy process, probably taking several years. Webb Creek has executed documents authorizing BB&T to conduct the sales process.

9. The majority of the single-family residences served by the Webb Creek wastewater utility system are owned by active or retired U.S. Marines and their families. The house mortgages are normally VA loans, which require a certification from DWR that the Webb Creek wastewater utility system is in compliance its permits. Since DWR is unable to provide these certifications,

many military personnel attempting to purchase or sell houses in the Webb Creek service area are unable to close on the transactions.

10. G.S. 62-116(b) provides that the Commission, after notice to the owner and operator of a water or sewer utility franchise, may grant emergency operating authority to any person to furnish water or sewer utility service to the extent necessary to relieve an emergency upon a finding that a real emergency exists, that the relief authorized is immediate, pressing, in the public interest, and that the person so authorized is able and willing to perform the service. An emergency is defined as "the imminent danger of losing adequate water or sewer utility service or the actual loss thereof."

11. G.S. 62-118(b) provides that if the Commission finds that a person or corporation furnishing water or sewer utility service has abandoned such service [as provided in G.S. 62-118(a)] and that such abandonment causes an emergency to exist, the Commission may, unless the owner or operator consents, apply to a superior court judge having jurisdiction in the district or set of districts where the person or corporation so operates to appoint an emergency operator to assure the continued operation of the service. As in G.S. 62-116(b), an emergency is defined as "the imminent danger of losing adequate water or sewer utility service or the actual loss thereof."

12. A real emergency exists regarding the Webb Creek wastewater utility system, as Webb Creek does not have and has no prospect of obtaining the funds for necessary operations, system replacements and upgrades, and is in material non-compliance with G.S. 143-215.1, its NPDES Permit, and its Collection Permit, and its customers are in imminent danger of losing adequate wastewater utility service.

13. Webb Creek, through its president Hal Kinlaw, has advised the Public Staff that Webb Creek consents to the appointment of Pluris as the emergency operator of the Webb Creek wastewater utility system. Pluris has agreed to be appointed emergency operator.

14. Pluris has requested that the Commission's Order appointing Pluris emergency operator clearly state:

> a. That Pluris as emergency operator shall not be responsible for, or liable for, any acts, omissions, system operations and maintenance, or system installations, occurring prior to the date of the appointment as emergency operator.
>
> b. That Pluris shall have no responsibility for Webb Creek's handling of any customer deposits, if any, or any other obligations or liabilities of Webb Creek arising from its operation of the wastewater treatment system.
>
> c. That Pluris shall not be responsible for, or liable for, any acts, omissions, obligations or liabilities of Group Eight Ltd., Parnell Kinlaw Group, Inc., Kinlaw Investment Company, and Hal Kinlaw, Jr., or any of them.

d. That Pluris as emergency operator may petition the Commission at any time to be discharged as the emergency operator, which discharge the Commission shall approve.

The Public Staff supports all of these provisions.

15. Pluris is a wholly owned subsidiary of Pluris Holdings, LLC (Pluris Holdings). Other wholly owned subsidiaries of Pluris Holdings include Pluris, LLC (Docket No. W-1282), which holds a certificate for the wastewater utility system serving North Topsail Beach and nearby mainland areas near Sneads Ferry, and Pluris Hampstead, LLC (Docket No. W-1305), which holds a certificate for a regional wastewater system near Hampstead in Pender County extending north along US 17. Pluris proposes to manage the Webb Creek wastewater utility system from its operations at North Topsail Beach. DWR and the Public Staff believe that Pluris is well qualified to perform the service of emergency operator.

16. Pluris as emergency operator plans to place back in service the third SBR basin and operate the Webb Creek WWTP with three SBR basins. Pluris has advised the Public Staff that if it purchases this system, it will replace the SBR basins with a membrane bioreactor (MBR) wastewater treatment system when the SBR basins need to be replaced. Pluris' affiliates have constructed large MBR wastewater treatment plans in their service areas.

17. Pluris has identified the need for approximately $100,000 in immediate system renovations and replacements in order to materially improve the operation and compliance record of the Webb Creek wastewater utility system. Pluris has agreed to immediately invest its own funds for these improvements in order to expedite the system improvements and bring the system closer to permit compliance.

18. The rates currently in effect for the Webb Creek wastewater utility system were approved by Order issued September 3, 1998, in Docket No. W-864, Sub 4, as decreased by Order issued October 15, 2015, in Docket No. W-864, Sub 9, to comply with House Bill 998. These current rates are as follows:

Flat Rate (Residential)	$23.49 per month
Metered Rates (Commercial)	
Sand Ridge Elementary School	$ 4.46 per 1,000 gallons
Other Commercial	$ 4.46 per 1,000 gallons

These rates cannot possibly generate sufficient revenues to properly operate the Webb Creek wastewater utility system, and provide adequate customer service.

19. The Public Staff has recommended that Pluris be authorized to charge rates that include a return on its $100,000 investment in plant and the annual depreciation expense related to the investment. The Public Staff believes that an appropriate return would be the overall rate of return of 7.67% approved for the North Topsail Beach and Sneads Ferry Service Areas by Order issued December 10, 2012, in Docket No. W-1282, Sub 8. The 7.67% rate or return is based upon

a capital structure of 57.81% long-term debt with a cost of 6.12% and 42.19% common equity with a return on equity of 9.8%. The net income that Pluris will receive from the return on its $100,000 investment in plant after interest expense and payment of federal and state income taxes is approximately $4,000.

20. The Public Staff has also recommended that Pluris be allowed to charge rates that include a margin on its reasonable and prudent operating expenses. As Pluris would receive the annual depreciation funds as its plant investment declines, the operating margin would not apply to the depreciation expense as is normal rate making practice under the operating ratio Montclair method previously approved by the Commission. The Public Staff believes that a 7.5% operating margin will be fair compensation for Pluris given the magnitude and difficulty of its responsibilities as emergency operator of the Webb Creek system.

21. Pluris has been in negotiations with BB&T to acquire the Webb Creek wastewater utility system, assuming a reasonable purchase price to justify Commission approval of an acquisition adjustment can be agreed upon (the Public Staff has determined that the Webb Creek rate base does not exceed zero), and clear title can be obtained, both of which will be difficult to achieve. Should Pluris acquire ownership of the Webb Creek wastewater utility system and be granted a certificate, Pluris would be a rate base company, and the operating ratio would no longer apply.

22. The Public Staff has recommended that the Commission approve the appointment of Pluris as emergency operator of the Webb Creek wastewater system and an emergency rate increase with the following provisional rates subject to true up:

Flat Rate (Residential)	$37.69 per month
Commercial (Monthly) Sand Ridge Elementary School and Other Commercial Users	
Monthly base charge, zero usage	$28.34
Usage charge, per 1,000 gallons	$ 9.04

23. These recommended rates will increase the average residential bill by 60% from $23.49 to $37.69. The Public Staff believes that these rates will generate sufficient revenues to enable Pluris to operate the Webb Creek wastewater system, perform necessary administrative functions, provide the necessary supplies and repair parts, compensate the two on-site independent contract operators, and have reserves for emergencies.

CONCLUSIONS

Based upon the foregoing and the recommendations of the Public Staff, the Commission concludes an emergency exists for the Webb Creek wastewater utility system, which is in imminent danger of losing adequate wastewater utility service. The Commission further concludes that Pluris Webb Creek, LLC, should be appointed emergency operator and the emergency rate increase recommended by the Public Staff should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That Pluris Webb Creek, LLC, is hereby appointed as emergency operator of the Webb Creek wastewater utility system effective August 8, 2016 (the Effective Date). All expenses associated with the operation of the Webb Creek wastewater utility system accruing or relating to the period up to the Effective Date shall be Webb Creek's sole responsibility. All such expenses accruing or relating to the period commencing on and after the Effective Date shall be the emergency operator's sole responsibility.

2. That a copy of this Order and Schedule of Provisional Rates, attached as Appendix A, shall be mailed with sufficient postage or hand delivered by Pluris to all the Webb Creek wastewater utility system customers, no later than 10 days after the date of this Order and that Pluris submit to the Commission the attached Certificate of Service property signed and notarized not later than 15 days after the date of this Order.

3. That the Schedule of Provisional Rates, attached as Appendix A, is approved effective as of the Effective Date, on a provisional basis for wastewater utility service provided by Pluris as emergency operator of the Webb Creek wastewater utility system, effective the date of this Order and subject to refund of any amounts found unjust and unreasonable, and subject to true up if the emergency operator has not recovered its costs and approved returns or has over-recovered.

4. That the following provisions are adopted by this Order:

a. That the emergency operator shall maintain full records of receipts and expenses and shall file with the Commission and Public Staff, by the end of the subsequent month, a summary financial report on a quarterly basis.

b. That the emergency operator shall have charge of the daily operation of the Webb Creek wastewater utility system, and the emergency operator's duties and responsibilities shall include, among others, the following:

(i) Regular inspections and testing of the wastewater utility system;
(ii) Billing of all customers and collection of bills;
(iii) Routine and emergency maintenance and repair;
(iv) System renovations and additions necessary to maintain adequate wastewater utility service;
(v) Quarterly accounting to the Utilities Commission and the Public Staff of all rates collected, expenses incurred, checks written, and all monies spent;

(vi) Providing a telephone number to customers for routine and emergency calls and a mailing address; and
(vii) Filing all required reports with DWR.

c. That the emergency operator may contract with any person to carry out any of the duties necessary for operation and repair of the wastewater utility system, but the emergency operator shall have the ultimate, sole responsibility to see that such duties are carried out.

d. That the emergency operator in the performance of its duties, shall be free to seek assistance from the customers of the wastewater utility system, contractors, engineers, attorneys, and such other persons as may be necessary for the performance of its duties and responsibilities.

e. That the emergency operator shall, when it becomes necessary in the performance of its duties, seek the assistance of the Division of Water Resources of DEQ, the North Carolina Utilities Commission, the Public Staff of the Utilities Commission, and the Onslow County Health Department.

f. That the emergency operator shall collect from the customers of the wastewater utility system such rates, assessments, and surcharges as may be approved by the North Carolina Utilities Commission and shall be fully authorized to bill and collect those rates, assessments, and surcharges and to disburse those funds as may be necessary to provide safe, reliable, and adequate wastewater utility service to the customers. All funds received from customers shall be deposited in separate bank accounts to be opened and maintained by the emergency operator. Any customer who fails to pay the bill(s) authorized by this paragraph shall be disconnected by the emergency operator as provided by the orders, rules, and regulations of the North Carolina Utilities Commission.

g. Subject to any true up for under collection or over collection required by the Commission, all revenues received by the emergency operator from the date of this Order in connection with its operation of the Webb Creek wastewater utility system, not used in payment of operating expenses, shall be the sole property of the emergency operator.

h. That the emergency operator shall be entitled to all available records relating to the wastewater utility system and those records shall include, but not be limited to, a list of customer names, addresses, and billing records.

i. That the emergency operator shall keep records of all monies collected through the rates, assessments (if any), and surcharges (if any), and all monies expended in the operation of the wastewater utility system. In order to protect the customers' interests in the wastewater utility system, the emergency operator is required to keep a separate record of all monies and assessments collected from customers and expended on improving and upgrading the wastewater utility system, and the cost of the labor associated with those improvements, whether performed by the emergency operator or contractor hired by the emergency operator.

j. The emergency operator shall account for any funds advanced by it for operation of the wastewater utility system.

k. That the emergency operator shall be responsible for and pay only those liabilities incurred by the emergency operator on and after the date of the appointment of the emergency operator. Those liabilities shall be defined as the liabilities arising from the emergency operator's operation of the Webb Creek wastewater utility system pursuant to Commission Order. The emergency operator shall not be responsible for, or liable for, any acts, omissions, system operations and maintenance, or system installations, occurring prior to the date of the appointment as emergency operator. The disbursements by the emergency operator shall be made from the separate emergency operator accounts including bank accounts set up by the emergency operator; the emergency operator shall account for any funds advanced by it for the operations.

l. That the emergency operator shall have no responsibility for Webb Creek's handling of customer deposits, if any, or any other obligations or liabilities of Webb Creek arising from its operation of the wastewater treatment system. The emergency operator shall not be responsible for, or liable for, any acts, omissions, obligations, commitments or liabilities of Group Eight Ltd., Parnell Kinlaw Group, Inc., Kinlaw Investment Company, and Hal Kinlaw, Jr., or any of them.

m. That the emergency operator may petition the Commission at any time to be discharged as the emergency operator of the Webb Creek wastewater utility system, which discharge the Commission shall approve. Prior to its discharge, the emergency operator shall provide an acceptable accounting of the Utilities Commission of all monies collected and disbursed during its tenure as emergency operator, as well as the amounts due and owing the emergency operator at the time of its discharge for its services performed as emergency operator. The emergency operator filing a petition for discharge shall also mail a copy of the petition to the Division of Water Resources of DEQ.

n. That this docket shall remain open for further motions, reports, etc., of the emergency operator, DWR, the Public Staff, and for further orders of the Commission.

o. Revenues received from customers for wastewater utility service rendered prior to the date of this Order, including proration for August 2016, shall be the property of Webb Creek. Any customer bills which relate to wastewater utility service provided both before and on or after the Effective Date shall be allocated between Webb Creek and the emergency operator on a per diem basis. (For example, if a customer's bill for the calendar month of August 2016, is $25.00

and the Effective Date is August 10, 2016, $7.26 [(9/31 x $25.00] would be allocated to Webb Creek and the balance ($17.74) allocated to the emergency operator.) If the emergency operator receives payment in the form of a check made out to Webb Creek, for wastewater utility service provided after the Effective Date, Webb Creek shall endorse that check over to the emergency operator to enable it to make the necessary allocations described above.

5. Webb Creek shall within 20 days of the Effective Date, refund all customer deposits plus accrued interest.

6. That the following items of information shall be made available to Pluris:

a. Customer information for each residence connected to the system, containing at a minimum, customer name, service address, billing address, contact phone numbers (home and work), and billing records.

b. Copy of latest electrical power bill for each electric service location needed for transfer of service.

c. Copy of each system plans and specifications.

d. Copies of all monitoring reports and evaluations completed by Webb Creek or its certified operator for the past 36 months.

e. The names, addresses, and telephone number of all vendors providing materials and supplies for the wastewater system operations.

f. Copies of all 2015 and 2016 (if available) property tax bills.

g. Copies of all correspondence with DWR including NOVs for the past five years.

7. That the Public Staff shall file a report with the Commission within one year from the issuance date of this Order. This report shall include: (1) a review of the status of compliance with the requirements pertaining to Webb Creek's NPDES Permit and Collection Permit; (2) a summary description of the improvements made by Pluris to the WWTP and the associated costs; (3) a review of correspondence from customers, if any; (4) a summary of the financial reports filed by Pluris to date; and (5) the Public Staff's recommendation as to whether the provisional rates should be continued or adjusted.

ISSUED BY ORDER OF THE COMMISSION.
This the _8th_ day of August, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Commissioner Jerry C. Dockham did not participate in this decision.

APPENDIX A
PAGE 1 OF 2

SCHEDULE OF PROVISIONAL RATES

for

WEBB CREEK WATER AND SEWAGE, INC.
(Pluris Webb Creek, LLC, Emergency Operator)

for providing wastewater utility service in

ALL OF THE SERVICE AREAS SERVED BY THE
WEBB CREEK WASTEWATER UTILITY SYSTEM
Onslow County, North Carolina

Monthly Flat Rate (Residential):	$37.69
Monthly Metered Rates (Commercial Service):	
Monthly base charge, zero usage	$28.34
Usage charge, per 1,000 gallons: (based on metered water usage)	
Sand Ridge Elementary School	$ 9.04
Nonresidential Sewer Service	$ 9.04
Connection Charge:	
Residential	$1,800 payable when tap is made
Sand Ridge Elementary School	$125,000
Nonresidential (other)	$5.00 per gallon of designated daily flow based on DWR criteria
Reconnection Charge:	
If sewer service cut off by utility for good cause	$141.00

WATER AND SEWER – EMERGENCY OPERATOR

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Returned Check Fee:	$20.00
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-864, Sub 11, on this the _8th_ day of August, 2016.

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers a copy of the Order issued by the North Carolina Utilities Commission in Docket No. W-864, Sub 11, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________ 2016.

By: ____________________________________
Signature

____
Name of Utility Company

The above named Applicant, _________________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Commission Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-864, Sub 11.

Witness my hand and notarial seal, this the ______ day of _______________ 2016.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ____________________________________
Date

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Reporting Requirements from Docket No. W-218, Sub 363 – Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Approval to Implement Secondary Water Quality System Improvement Projects Pursuant to G.S. 62-133.12	)	ORDER APPROVING SECONDARY WATER QUALITY IMPROVEMENT PROJECTS

BY THE COMMISSION: G.S. 62-133.12 authorizes the Commission in a general rate case proceeding to approve a rate adjustment mechanism to allow water and sewer utilities to recover the incremental depreciation expense and capital costs associated with reasonable and prudently incurred investments in eligible water and sewer system improvements. By Order issued May 2, 2014, the Commission in Docket No. W-218, Sub 363, the last general rate case proceeding for Aqua North Carolina, Inc. (Aqua), the Commission approved Aqua's request to utilize a water system improvement charge/sewer system improvement charge (WSIC/SSIC) mechanism pursuant to G.S. 62-133.12, finding that the mechanism is in the public interest.

Commission Rules R7-39(f) and R10-26(f) provide that once WSIC and SSIC mechanisms are approved and eligible water and sewer system improvements are in service, the utility (in this case, Aqua) may file a request with the Commission for authority to impose the water and sewer system improvement charges pursuant to the mechanisms.

G.S. 62-133.12(c)(2) and (c)(4) provide, in pertinent part, that specific approval from the Commission is necessary before Aqua may undertake and recover its incremental depreciation expense and capital costs through the WSIC mechanism for eligible water system improvements implemented to comply with secondary drinking water standards.

On January 13, 2016, Aqua filed an application for approval to implement five secondary water quality system improvement projects pursuant to G.S. 62-133.12 and Commission Rule R7-39. The five projects and the estimated costs associated with each project are summarized below.

System	County	Well Gallons Per Minute	Aqua Estimated Cost 000's
Mallard Crossing Well 2	Gaston	82	$220-$235
Shadow Lake Well 1	Johnston	68	$220-$235
Surry Point Well 3	Wake	85	$300-$315
Village of Wynchester Well 1 & Sedgemoor Well 1	Wake	108	$335-$350 (1)
Wakefield Well 6 & 8	Wake	248	$370-$395 (1)
		Total	$1.445-$1.530 Million

(1) Combined entry of two wells with filtration by one system.

On February 23, 2016, the Public Staff filed its Secondary Water Quality Report and Recommendations regarding Aqua's application. The Public Staff stated that it had thoroughly reviewed each of the five filter projects proposed by Aqua in its January 13, 2016 filing. Based upon its review of documents and other information provided by Aqua, site visits, and discussions with customers and Aqua's engineers and operations managers, the Public Staff recommended that the Commission approve each of the proposed projects with the exception of the Surry Point Well 3 project.

In recommending approval of the projects, the Public Staff advised that decisions to install manganese greensand-type filters be made judiciously, as installation of such filters is many times more costly than sequestration coupled with adequate flushing. According to the Public Staff, the annual revenue requirement increase for the minimum estimated capital expenditure of \$1.445 million for the filtration systems proposed in Aqua's application is approximately \$178,357 compared to the annual revenue requirement for the chemical cost for sequestration of approximately \$1,950. The Public Staff stated that the sequestration treatment of iron and manganese with polyphosphates and orthophosphates on water from North Carolina water wells, coupled with comprehensive water main flushing programs, has largely provided adequate secondary standard water quality on many water systems at a very reasonable cost. The process of testing whether the iron and manganese is soluble (clear liquid) or insoluble (solid particles and visible) in raw untreated water at the well head, after treatment with polyphosphate/orthophosphate or SeaQuest at the entry point, and in the distribution system, has been widely used in North Carolina for many years and provides extremely valuable information to assist in evaluations of whether filtration is necessary. The Public Staff recognized, however, that for secondary water quality issues of considerable magnitude and consistency, sequestration treatment and flushing may not be effective and may necessitate filtration.

As discussed in previous reports, the Public Staff strongly supports the implementation of two additional secondary water quality processes: a comprehensive water main flushing program and a comprehensive customer education program. The Public Staff repeated its recommendation that Aqua materially upgrade its flushing program and substantially increase the flushing frequency to improve the secondary water quality in its service areas. Regarding customer education, the Public Staff noted that with its input Aqua has prepared and posted on its website (https://www.aquaamerica.com/our-states/north-carolina.aspx) a fact sheet titled "Flushing Water Mains," and a best practices document titled "Iron and Manganese in Drinking Water". According to Aqua, these documents have been made available to its employees to distribute to customers they may visit who experience a discolored water issue. The Public Staff stated that it considers the documents to be a useful resources to help customers better understand flushing and minimize the negative effects of discolored water caused by the presence of iron and manganese.

In summary, the Public Staff stated that it will continue to carefully and thoroughly review secondary water quality information and documentation presented by Aqua, including meetings with Aqua engineers and operations managers, conduct selected site visits, discuss secondary water quality issues with customers, and recommend, when appropriate, Commission approval of equipment and infrastructure installations.

The Public Staff presented this matter to the Commission at its Staff Conference on February 29, 2016. The Public Staff stated that each of the filters are necessary for Aqua to provide adequate secondary standard water quality. The Public Staff therefore recommended that the Commission approve all of Aqua's proposed secondary standard water quality projects with the exception of the Surry Point Well 3 project. The Public Staff has requested further clarification from Aqua pertaining to the scope and cost of that project, and plans to address the project in a future report.

Based upon the foregoing, Aqua's application, the Public Staff Secondary Water Quality Report and Recommendations, and the entire record in this matter, the Commission finds and concludes that Aqua should proceed to implement secondary standard water quality improvements through the installation of all of Aqua's proposed filtration projects except the Surry Point Well 3 project.

IT IS, THEREFORE, ORDERED that Aqua is authorized to implement all of the proposed filtration projects in its January 13, 2016 application except the Surry Point Well 3 project to comply with secondary water quality standards.

ISSUED BY ORDER OF THE COMMISSION.
This the_1st_ day of March, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. W-778, SUB 91A
DOCKET NO. W-354, SUB 354

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by CWS Systems, Inc.,	)	
5701 Westpark Drive, Suite 101, Charlotte,	)	ORDER APPROVING SEWER
North Carolina 28217, for Authority to	)	SYSTEM IMPROVEMENT CHARGE
Implement Sewer System Improvement	)	ON A PROVISIONAL BASIS, AND
Surcharge Rate Adjustment Pursuant to	)	REQUIRING CUSTOMER NOTICE
G.S. 62-133.12	)	

BY THE COMMISSION: On August 1, 2016, CWS Systems, Inc. (CWSS), filed an application pursuant to G.S. 62-133.12, Commission Rules R7-39 and R10-26, and CWSS's water system improvement charge (WSIC) and sewer system improvement charge (SSIC) mechanisms, which were approved in CWSS's general rate case, Docket No. W-778, Sub 91 (Sub 91 Rate Case), requesting authority to implement a SSIC in its Fairfield Harbour service area effective October 1, 2016.

On August 17, 2016, the Commission issued an Order in Docket No. W-354, Sub 350, approving the merger of CWSS into Carolina Water Service, Inc. of North Carolina (CWSNC). The Articles of Merger were filed with the North Carolina Department of the Secretary of State on August 30, 2016, whereupon the corporate existence of CWSS ceased. The Chief Clerk of the Commission has established the above-captioned separate CWSNC subdocket for this and future WSIC/SSIC filings involving the former CWSS systems. In light of the consummated merger, CWSS will hereinafter be referred to as CWSNC.

On September 9, 2016, the Public Staff filed Notice of Public Staff Plan to Present Comments and Recommendations at the Commission's September 26, 2016 Staff Conference.

On the basis of CWSNC's verified Application and the records of the Commission, and the comments and recommendations of the Public Staff, the Commission makes the following

FINDINGS OF FACT

1. CWSNC is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. CWSNC is a franchised public utility providing water and sewer utility service to customers in North Carolina.

2. In CWSS's Sub 91 Rate Case, the Commission approved, in its Order dated February 24, 2016, CWSS's request to utilize a WSIC and SSIC mechanism pursuant to G.S. 62-133.12 concluding the mechanism is in the public interest, and established WSIC and SSIC procedures for CWSS.

3. The WSIC and SSIC procedures allow for semiannual adjustments to CWSNC's rates every April 1st and October 1st based upon reasonable and prudently incurred investment in eligible system improvements completed and placed in service prior to the filing of the request. Eligible system improvements are water and sewer system improvements set forth in G.S. 62-133.12(b), (c), and (d) and shall include only those prudent and reasonable improvements found necessary by the Commission to provide safe, reliable, and efficient service in accordance with applicable water quality and effluent standards.

4. This is CWSNC's first filing to implement charges under the WSIC and SSIC mechanism for the former CWSS systems since the Sub 91 Rate Case. CWSNC's request includes one SSIC project completed and placed in service in the month of May 2016. This project consists of replacement of 50 feet of sewer main in the Fairfield Harbour sewer service area at a cost of $122,131.

5. CWSNC's proposed SSIC percentage to be implemented on October 1, 2016, is as follows:

	SSIC Revenue Requirement	Projected Service Revenues	SSIC Percentage
Fairfield Harbour sewer	$12,029	$870,747	1.38%

6. The 1.38% SSIC percentage results in a $0.52 increase to the flat rate residential and commercial bill per month. Metered commercial customers bills will increase by 1.38% per month.

7. Pursuant to G.S. 62-133.12(g), the cumulative WSIC and SSIC percentages are capped at 5% of the total annual service revenues approved by the Commission in the Sub 91 Rate Case, resulting in the following maximum revenue requirement for CWSNC's SSIC for the Fairfield Harbour sewer operations:

	Sub 91 Rate Case Annual Service Revenues	Maximum SSIC Revenue Requirement
Fairfield Harbour sewer	$870,747	$43,537

8. CWSNC's proposed SSIC revenue requirement does not exceed the maximum SSIC revenue requirement for the Fairfield Harbour sewer operations.

9. As stated by the Commission in its Order adopting Rules R7-39 and R10-26 issued on June 6, 2014, in Docket No. W-100, Sub 54, the Public Staff is to review all infrastructure improvements proposed for recovery for eligibility and reasonableness prior to making its recommendation to the Commission on WSIC or SSIC rate adjustments. Furthermore, any WSIC or SSIC rate adjustments will be allowed to become effective, but not unconditionally approved. The adjustments may be rescinded retroactively in the Company's subsequent general rate case, at

which time the adjustment may be further examined for a determination of its justness and reasonableness.

10. The Public Staff has carefully reviewed CWSNC's SSIC improvement project, including construction work in progress ledgers and transactions, invoices, work orders, and other accounting records. Based on this review, the Public Staff has identified one adjustment to CWSNC's SSIC percentage to correct the calculation of the average balance of accumulated deferred income taxes (ADIT). This adjustment would not have a significant impact on the SSIC percentage proposed by CWSNC in its August 1, 2016 filing. Therefore, the Public Staff recommends that this adjustment be addressed in the annual audit and reconciliation for the 12 months ending March 31, 2017.

11. Based on the Public Staff's investigation to date, the SSIC project included in CWSNC's request is an eligible sewer system improvement as defined in G.S. 62-133.12(b), (c), and (d).

12. The Public Staff will continue to review the reasonableness and prudence of this improvement during its review of CWSNC's future SSIC filings pertaining to the Fairfield Harbour service area and in CWSNC's next general rate case.

Based upon the foregoing, the Commission concludes that CWSNC should be allowed to implement its proposed SSIC percentage for its Fairfield Harbour service area effective for service rendered on or after October 1, 2016, subject to true-up.

IT IS, THEREFORE, ORDERED as follows:

1. That CWSNC is authorized to implement the sewer system improvement charge set forth in the attached Appendix A-4 to CWSNC's Schedule of Rates effective for service rendered on and after October 1, 2016, subject to true-up.

2. That the attached Appendix A-4 is approved and is deemed filed with the Commission pursuant to G.S. 62-138.

3. That CWSNC shall mail to each of its affected customers with the next regularly scheduled customer billing the Notice to Customers, attached as Attachment A hereto.

4. That CWSNC shall file the attached Certificate of Service, properly signed and notarized, not later than 10 days after the Notice to Customers is mailed to customers.

ISSUED BY ORDER OF THE COMMISSION.
This the _26th_ day of September, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A-4

CAROLINA WATER SERVICE INC. OF NORTH CAROLINA
FORMER CWS SYSTEMS, INC. SERVICE AREAS
WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

SEWER SYSTEM IMPROVEMENT CHARGE

Fairfield Harbour service area	1.38% [1/ and 2/]

Notes

[1/] The Sewer System Improvement Charge will be applied to the total sewer utility bill of each customer under the Company's applicable rates and charges.

[2/] On August 1, 2016, in Docket No. W-778, Sub 91A, CWSS filed an application for a sewer system improvement charge for the Fairfield Harbour service area which was approved on September 26, 2016. Such filing did not include a request for a water or sewer system improvement charge in CWSS's other franchised service areas.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 91A and W-354, Sub 354 on this the _26th_ day of __September___, 2016.

ATTACHMENT A
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 91A
DOCKET NO. W-354, SUB 354

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by CWS Systems, Inc.,	)	
5701 Westpark Drive, Suite 101, Charlotte,	)	
North Carolina 28217, for Authority to	)	NOTICE TO CUSTOMERS
Implement Sewer System Improvement	)	
Charge Pursuant to G.S. 62-133.12	)	

WATER AND SEWER – FILINGS DUE PER ORDER

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated September 26, 2016, pursuant to G.S. 62-133.12 and Commission Rule R10-26, authorizing Carolina Water Service Inc. of North Carolina (CWSNC) (formerly CWS Systems, Inc.)[1], to implement a sewer system improvement charge (SSIC) for service rendered on and after October 1, 2016, in its Fairfield Harbour sewer service area in North Carolina.

By Order entered in Docket No. W-778, Sub 91 on February 24, 2016, the Commission approved CWSS's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC and SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC and SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC and SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in CWSS's last general rate case.

ATTACHMENT A
PAGE 2 OF 2

Commission Rules R7-39(h) and R10-26(h) specify that the WSIC and SSIC shall be applied to the total utility bill of each customer under the utility's applicable service rates and charges.

The Public Staff carefully reviewed Fairfield Harbour's stated SSIC improvement, including a review of construction work in progress ledgers and transactions, invoices, work orders, and other accounting records, and recommended that CWSNC's proposed SSIC charge be approved.

The SSIC charge proposed by CWSNC and approved by the Commission is as follows:

Fairfield Harbour sewer	1.38%

The 1.38% SSIC percentage results in a $0.52 increase to the flat rate residential and commercial bill per month. Metered commercial customers' bills will increase by 1.38% per month.

Additional information regarding the WSIC and SSIC mechanism is contained in the Commission's Order dated February 24, 2016, in Docket No. W-778, Sub 91, the Commission's

[1] By Order dated August 17, 2016, the Commission approved an application filed by CWS Systems, Inc. (CWSS) and four other public utility subsidiaries owned by Utilities, Inc. (the Parent Corporation) to merge CWSS and the four other utilities into Carolina Water Service, Inc. of North Carolina (CWSNC). The corporate merger was consummated on August 30, 2016 and bills for customers in the Fairfield Harbour service area, which was formerly a CWSS system, will be sent in the name of CWSNC. The Commission's August 17, 2016 Order did not adjust any other customer rates.

WATER AND SEWER – FILINGS DUE PER ORDER

Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the CWSS SSIC Application filed August 1, 2016, the September 9, 2016 Public Staff Notice, and the September 26, 2016 Commission Order in Docket No. W-778, Sub 91A and W-354, Sub 354, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e., for Docket No. key: W-778 Sub 91A or W-354 Sub 354).

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the _26th_ day of September, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-778, Sub 91A and W-354, Sub 354, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2016.

By: ____________________________________
Signature

____
Name of Utility Company

The above named Applicant, __________________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-778, Sub 91A and W-354, Sub 354.

Witness my hand and notarial seal, this the ____ day of _______________, 2016.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ____________________________________
Date

DOCKET NO. W-408, SUB 9

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition to Discharge Carolina Water Service, Inc. of North Carolina, from Emergency Operator Status for Parkway East Water System	)	RECOMMENDED ORDER APPROVING ABANDONMENT AND DISCHARGING EMERGENCY OPERATOR
and	)	
Petition by Public Staff for Abandonment of Water Utility Service for the Parkway East Water System in Ashe and Wilkes Counties	)	

HEARD IN: Ashe County Courthouse, 150 Government Circle, Jefferson, North Carolina, on Tuesday, April 14, 2015, at 7:00 p.m.

BEFORE: Ronald D. Brown, Hearing Examiner

APPEARANCES:

For Cross-State Development Company:

No Attorney

For Carolina Water Service, Inc. of North Carolina:

No Attorney

For the Using and Consuming Public:

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

BROWN, HEARING EXAMINER: On February 25, 2015, Carolina Water Service, Inc. of North Carolina (Carolina Water), filed a petition to be discharged as emergency operator of the Parkway East water system in Ashe and Wilkes Counties (Discharge Petition).

On February 27, 2015, the Public Staff – North Carolina Utilities Commission (the Public Staff) filed a petition for abandonment of water utility service for the Parkway East water system (Abandonment Petition).

On March 10, 2015, the Commission issued an Order Requiring Customer Notice and Scheduling a Public Hearing on Tuesday, April 14, 2015, at 7:00 p.m. in the Ashe County Courthouse, 150 Government Circle, Jefferson, North Carolina.

On March 12, 2015, Carolina Water filed its Certificate of Service indicating that customer notice was provided as required by the March 10, 2015 Order.

On April 8, 2015, the Public Staff filed a motion to excuse Cross-State witness Don Raff from attending the evidentiary hearing scheduled for April 14, 2015. On April 9, 2015, the Commission issued an Order Granting Motion to Excuse Witness.

On April 14, 2015, the matter was called for hearing. There were four customers in attendance but they did not testify. Carolina Water did not present a witness. Public Staff attorney William Grantmyre presented testimony on the customers' positions and requests.

On January 25, 2016, the Public Staff filed the Public Staff Progress Report (Progress Report). On that same date, the Public Staff filed a Proposed Recommended Order.

On the basis of the Discharge Petition, the Abandonment Petition, the Progress Report, the testimony of Public Staff witness Grantmyre, the Commission records, and the entire record in this proceeding, the Hearing Examiner makes the following:

FINDINGS OF FACT

1. Cross-State Development Company (Cross-State) is the owner of water systems serving (a) Nikanor Acres Section of Blue Ridge Manor Subdivision, (b) Ashe Lake – Beaver Creek Section, (c) Ashe Lake – Holiday Lane Section in Ashe County, and (d) Parkway East Subdivision in Wilkes County, North Carolina. Parkway East also extends into Ashe County. On August 28, 1987, in Docket No. W-408, Sub 3, the Commission ordered Cross-State to file a franchise application for its Parkway East water system. Cross-State has never filed the franchise application. The Commission has never issued a certificate of pubic convenience and necessity for Parkway East.

2. The Division of Environmental Health (DEH), within the North Carolina Department of Environmental Quality (formerly known as the North Carolina Department of Environment and Natural Resources), deregulated the Parkway East water system in May 1992 because it is a *noncommunity* water system due to its small size and population. The other three Cross-State water systems are *community*[1] water systems regulated by the Public Water Supply Section (PWSS), which is the successor to DEH.

[1] "…A public water system is either a "community water system" or a "noncommunity water system" as follows:

a. "Community water system" means a public water system that serves at least 15 service connections used by year-round residents or regularly serves at least 25 year-round residents.

b. "Noncommunity water system" means a public water system that is not a community water system." See G.S. 130A-313(10).

3. The Parkway East noncommunity water system serves 11 customers and consists of two wells, neither of which meets the PWSS' 100-foot radius requirement. There are two groups: eight customers on one of the two wells and three customers on the other well. Each group of customers is served by a separate water line. There are no well houses (only well covers) and no storage tanks. The water is untreated. In short, the system consists of two private wells with shared recipient houses.

4. On September 24, 2014, the Public Staff filed a motion, pursuant to G.S. 62-118(b), requesting that the Commission issue an order: (1) declaring an emergency, (2) appointing Carolina Water as emergency operator, and (3) approving an emergency rate increase for the water systems serving Nikanor Acres Section of Blue Ridge Manor Subdivision, Ashe Lake – Beaver Creek Section, Ashe Lake – Holiday Lane Section in Ashe County, and Parkway East Subdivision in Wilkes County, North Carolina. The Public Staff stated that an EO was needed because of poor operation by Cross-State.

5. On October 1, 2014, the Commission issued an order (EO Order) declaring an emergency, appointing Carolina Water as emergency operator, and approving an emergency rate increase for the referenced four water systems, effective October 15, 2014. Ordering Paragraph 4.k. of the Commission's EO Order provided:

> That the emergency operator may petition the Commission at any time to be discharged as the emergency operator of the Nikanor Acres Section of Blue Ridge Manor, Ashe Lake – Beaver Creek Section, Ashe Lake – Holiday Lane Section, and Parkway East water systems, which discharge the Commission shall approve. Prior to its discharge, the emergency operator shall provide an acceptable accounting of [sic] the Utilities Commission of all monies collected and disbursed during its tenure as emergency operator, as well as the amounts due and owing the emergency operator at the time of its discharge for its services performed as emergency operator. The emergency operator filing a petition for discharge shall also mail a copy of the petition to the Ashe County Health Department and the PWWS [sic].

6. The Commission, in its EO Order dated October 1, 2014, approved the Public Staff's recommended emergency rate increase for all four Cross-State water systems including Parkway East. The following monthly rates were approved effective October 15, 2014:

<u>Metered Rates</u> (Residential Service)	
Monthly base charge, zero usage	$28.00
Usage charge, per 1,000 gallons	$ 8.64

These rates resulted in an average monthly water bill of $40.34 based upon the average monthly residential consumption of 1,428 gallons.

7. Carolina Water has been evaluating the acquisition of the three Cross-State *community* water systems at the request of the Public Staff. Carolina Water has no interest in acquiring the Parkway East *noncommunity* water system. The Public Staff also inquired whether another large North Carolina water company would be interested in acquiring Parkway East, but that company had no interest either.

8. The Public Staff advised the Commission that if Cross-State is allowed to abandon the Parkway East system and the customers are left to operate it, they may realize a reduction in the $40.34 average monthly water bill per customer.

9. The Public Staff also advised the Commission that if Parkway East water system is abandoned and left to the customers, it would be best for them to have legal control of or access to the wells and water system equipment. During the public notice period, the Public Staff communicated with the customers as to their interest in taking over the operational responsibilities and communicated with Cross-State on Cross-State's interest in conveying the water system facilities to the customers.

10. Carolina Water in its Discharge Petition requested to be relieved as the EO as soon as possible. However, Carolina Water recognized that the Public Staff was seeking to resolve other issues concerning abandonment of service. Carolina Water stated that it will cooperate with the Public Staff's efforts, towards the goal of the earliest possible discharge of Carolina Water as EO for Parkway East.

11. The Public Staff in its Abandonment Petition recommended abandonment of the Parkway East water system pursuant to G.S. 62-118(a) for the following reasons:

a. There is no reasonable probability of a public utility realizing sufficient revenue from the water service to meet its expenses;

b. The system is not a community water system and was deregulated by DEH and continues to be deregulated by PWSS;

c. The system has two wells with no water treatment and can easily be operated by the homeowners as shared individual private residential wells;

d. No one wants to be EO of this remote water system (actually two separate systems with 3 and 8 customers);

e. No public utility wants to own the system; and

f. Upon Carolina Water's discharge as EO, there will not be a responsible operator of this water system.

12. The Public Staff recommended that the Commission hold a public hearing on the petition to allow abandonment of water service.

13. The evidentiary hearing was held as scheduled on April 14, 2015, in the Ashe County Courthouse, Jefferson, North Carolina. Four customers attended the hearing. Martin Lashua, Vice President of Operations for Carolina Water, attended. The Public Staff attended the hearing on behalf of the using and consuming public.

14. At the written request of Don Raff, President of Cross-State, the Commission by Order dated April 9, 2015, excused Don Raff's attendance as a witness at this evidentiary hearing. The Public Staff had recommended to the Commission that Don Raff's required attendance at the April 14, 2015 evidentiary hearing be excused, as the Public Staff believed his testimony and attendance was unnecessary, as Don Raff had expressed his willingness to execute for Cross-State whatever was necessary to transfer the water system ownership to the customers at Parkway East.

15. As stated in the January 25, 2016 Progress Report of the Public Staff, prior to the commencement of the evidentiary hearing, the Public Staff explained to the customers the processes for the water system abandonment, the water system transfer to the customers, the discharge of the EO, and the evidentiary hearing. William Grantmyre stated that he contacted all but two of the eleven customers, and all the customers he spoke with were in favor of the customers taking ownership of the two water systems.

16. The customers in attendance at the April 14, 2015 evidentiary hearing requested that William Grantmyre present the customers' positions to the Hearing Examiner as none of the customers wanted to testify. William Grantmyre presented the following customers' positions:

a. The customers supported the transfer of the two wells, pumps and distribution piping systems to the customers.

b. The customers supported the Commission approving the abandonment of the water system including the two wells, pumps and distribution piping systems.

c. Mr. Delgado, a customer, has agreed to purchase three lots from Cross-State including Lot 235 upon which the well serving Mr. Delgado and two other customers is located. There would be a reservation of easements to the three customers for access to the well for operations, maintenance, repair, and replacement.

d. The eight customer well is located on Lot 85 near the front of the subdivision, which lot also contains an old barn. These customers requested a fee simple deed for all of Lot 85.

e. The eight customer group needed some time to organize.

f. The customers supported the discharge of the EO.

g. The Public Staff would be working to facilitate the transition, including working with the customers and attorney in the drafting of the deed and easement.

17. The three customers organized quickly and the Deed of Easement for the three-customer well from Cross-State was recorded in the Wilkes County Register of Deeds on May 28, 2015, in Book 1208, Page 354. The three customers took over the operations of the well including the transfer of the electric service in June 2015.

18. Ms. Ginny Sandberg, a customer who attended the April 14, 2015 evidentiary hearing, agreed to coordinate the formation of the eight-customer well group and the facilities transfer. Ms. Sandberg encountered difficulties communicating with a number of the customers that lived primarily in Florida. Ms. Sandberg contacted the Public Staff and requested a delay until after the week of July 4, 2015, when all the customers would be at Parkway East and the customers could then meet and discuss the transfer, the transfer process, and future operations.

19. The seven-customer well group[1] also requested that Carolina Water remain as EO until Lot 85, the well facilities, and the water distribution piping were transferred to the customers and all the operational responsibilities were transferred to the customers. Carolina Water agreed to this request, and then Carolina Water fully and expeditiously cooperated.

20. Seven customers agreed to be served by the Lot 85 well and be owners of the lot, well, and pumping facilities. They retained a law firm in West Jefferson to obtain all necessary information, draft the deed, have the deed executed by Cross-State, and then recorded the deed. There was not a purchase price paid to Cross-State, but the customers agreed to pay the outstanding current and past due property taxes.

21. Substantial unforeseen delays were encountered in the Lot 85 deed preparation and execution. The executed general warranty deed to the seven customers was recorded on December 8, 2015, in Deed Book 466, page 412, Ashe County, Register of Deeds. The seven customers took over all the operational responsibilities of the well, pumping equipment, and water distribution piping including the transfer of the electric service, on December 30, 2015.

22. Both well facilities and the water distribution piping have been transferred to the customers. The customers have taken over all operational, maintenance, repair, and replacement responsibilities.

[1] Although there were originally eight customers served by the Lot 85 well group, only seven customers decided to remain on the well after the transfer of the water system to the customer group.

CONCLUSION

Based upon the foregoing and the Commission records, the Carolina Water Discharge Petition, the Public Staff Abandonment Petition, the Public Staff Report, and the evidence presented at the evidentiary hearing, the Hearing Examiner concludes that pursuant to G.S. 62-118(a) the Parkway East water system in Ashe and Wilkes Counties should be abandoned, and Carolina Water should be discharged as EO.[1]

IT IS, THEREFORE, ORDERED as follows:

1. That the Parkway East water system is abandoned and no longer regulated by the Commission.

2. That Carolina Water is discharged as the emergency operator.

3. That Carolina Water shall in its quarterly reports to the Commission provide an accounting as EO for the Parkway East water system.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of January, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

APPENDIX A

SCHEDULE OF RATES

for
CROSS-STATE DEVELOPMENT COMPANY
(Carolina Water Company, Inc. of North Carolina, Emergency Operator)

for providing water utility service in

[1] Pursuant to the Commission's October 1, 2014 Order in this docket, Carolina Water shall remain the EO for the remaining three Cross-State water systems (Nikanor Acres Section of Blue Ridge Manor, Ashe Lake – Beaver Creek Section, and Ashe Lake – Holiday Lane Section until further order of the Commission. See amended Appendix A attached hereto reflecting removal of Parkway East Subdivision.

WATER AND SEWER – MISCELLANEOUS

NIKANOR ACRES SECTION OF BLUE RIDGE MANOR,
ASHE LAKE – BEAVER CREEK SECTION, AND
ASHE LAKE – HOLIDAY LANE SECTION

Ashe County, North Carolina

WATER RATES AND CHARGES

Metered Rates: (Residential Service)

Monthly base charge, zero usage	$28.00
Usage charge, per 1,000 gallons	$ 8.64

Reconnection Charge:

If water service cut off by utility for good cause:	$27.00
If water service discontinued at customer's request:	$27.00

If water service is reconnected to the same customer at the same address within nine months of disconnection, then the reconnection charge shall be the base charge times the number of months disconnected.

New Water Customer Charge:	$27.00
Bills Due:	On billing date
Bills Past Due:	25 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-408, Sub 9, on this the 1st day of October, 2014, effective October 15, 2014.

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-778, SUB 91

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by CWS Systems, Inc., 5701 Westpark Drive, Suite 101, Charlotte, North Carolina 28217, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina	))))))	ORDER APPROVING STIPULATIONS, GRANTING PARTIAL RATE INCREASE, APPROVING RATE ADJUSTMENT MECHANISMS, AND REQUIRING CUSTOMER NOTICE

HEARD: Wednesday, September 30, 2015, at 7:00 p.m., in New Hanover County Courthouse, 316 Princess Street, Wilmington, North Carolina

Thursday, October 1, 2015, at 7:00 p.m., in Craven County Courthouse, District Courtroom #4, Second Floor, 302 Broad Street, New Bern, North Carolina

Tuesday, October 20, 2015, at 7:00 p.m., in Transylvania County Courthouse, 7 East Main Street, Brevard, North Carolina

Wednesday, October 21, 2015, at 7:00 p.m., in Jackson County Courthouse, 401 Grindstaff Cove Road, Sylva, North Carolina

Thursday, October 22, 2015, at 7:00 p.m., in Rutherford County Courthouse, 229 North Main Street, Rutherfordton, North Carolina

Thursday, September 17, 2015, at 7:00 p.m.; Monday, November 30, 2015, at 2:00 p.m.; and Tuesday, December 15, 2015, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioners Bryan E. Beatty, Susan W. Rabon, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For CWS Systems, Inc.:

Jo Anne Sanford, Sanford Law Office, PLLC, P.O. Box 28085, Raleigh, North Carolina 27611

Robert H. Bennink, Jr., Bennink Law Office, 130 Murphy Drive, Cary, North Carolina 27513

Charlotte A. Mitchell, Law Office of Charlotte Mitchell, Post Office Box 26212, Raleigh, North Carolina 27611

For the Using and Consuming Public:

Gina C. Holt and William E. Grantmyre, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On November 26, 2014, CWS Systems, Inc. (CWSS or Company) filed a letter notifying the North Carolina Utilities Commission (Commission) of its intent to file a general rate case as required by Commission Rule R1-17(a), which was updated by a subsequent letter filed on March 30, 2015. On June 29, 2015, CWSS filed an application in this proceeding (Application) seeking authority to increase and adjust its rates and charges for water and sewer utility service in all of its service areas in North Carolina and for approval of a water and sewer system improvement charge mechanism pursuant to G.S. 62-133.12. On July 22, 2015, CWSS filed a revised Appendix A, Proposed Schedule of Rates, to the Application.

On July 29, 2015, the Commission issued an Order Declaring General Rate Case, Suspending Rates, Scheduling Hearings and Requiring Customer Notice, scheduling the application for public hearings in Raleigh, Wilmington, New Bern, Brevard, Sylva, and Rutherfordton, North Carolina, and for evidentiary hearing in Raleigh, North Carolina; establishing the dates for filing testimony; and requiring notice to all affected customers of the proposed rate increase and hearings.

The intervention and participation by the Public Staff - North Carolina Utilities Commission (Public Staff) was made and recognized pursuant to G.S. 62-15(d) and Rule R1-19(e) of the Rules and Regulations of the North Carolina Utilities Commission. No other party intervened.

On September 2, 2015, the Public Staff and CWSS filed a Stipulation Between CWS Systems, Inc. and the Public Staff – North Carolina Utilities Commission Regarding Cost of Capital and Capital Structure Issues (First Stipulation).

Also, on September 2, 2015, CWSS filed its Certificate of Service as required by the July 29, 2015 Order stating under oath that the required customer notice was mailed to all affected customers.

The public hearings were held as scheduled. The following public witnesses testified at the public hearings held in this proceeding:

September 17, 2015	Raleigh	None
September 30, 2015	Wilmington	None
October 1, 2015	New Bern	Paul Hill[1]
October 20, 2015	Brevard	Walter Green
October 21, 2015	Sylva	None
October 22, 2015	Rutherfordton	Jack Zinselmeier
		Tom Judson
		Richard McCallum
		Bruce Barrett
		Bill Frykberg
		Ron Cantrall
		Peggy Dahle

On October 16, 2015, CWSS filed the direct testimony and exhibits of CWSS witness David Liskoff, Senior Financial Analyst, Utilities, Inc.

On November 10, 2015, CWSS and the Public Staff filed a joint motion to extend the dates for the filing of testimony and to reschedule the evidentiary hearing, which was granted by Commission Order dated November 13, 2015.

On November 20, 2015, CWSS filed a report regarding customer concerns raised at the public hearing held in Brevard on October 20, 2015.

On November 23, 2015, CWSS and the Public Staff filed a joint motion setting forth their recommended procedural dates and requesting that CWSS witness David Liskoff be excused from attending the evidentiary hearing. On November 25, 2015, the Commission issued an Order Granting Joint Motion to Reschedule Evidentiary Hearing, Adopt Procedural Dates and Excuse Witness, thereby adopting the procedural schedule proposed by CWSS and the Public Staff, excusing CWSS witness David Liskoff from appearing at the evidentiary hearing, and requiring CWSS representative Martin J. Lashua to appear at the evidentiary hearing.

On November 25, 2015, CWSS filed a report regarding customer concerns raised at the public hearing held in Rutherfordton on October 22, 2015.

On November 30, 2015, the Commission held the Raleigh public hearing portion of the proceeding, as originally scheduled in the Order Declaring General Rate Case, Suspending Rates, Scheduling Hearings and Requiring Customer Notice issued in July 29, 2015 and for which notice had been provided to customers pursuant to that same Order.

On December 11, 2015, CWSS and the Public Staff filed a Stipulation (the Second Stipulation), setting forth the terms and conditions of the settlement agreement among the parties. Also on December 11, 2015, the Public Staff filed the testimony and exhibits of Katherine A. Fernald, Assistant Director, Accounting Division; Fenge Zhang, Staff Accountant, Water Section,

[1] Paul Hill testified that the Company has been "a good provider for Fairfield Harbour". He did not express any quality of service concerns.

Accounting Division; Babette McKemie, Utilities Engineer, Water Division; and Calvin C. Craig, III, Financial Analyst, Economic Research Division supporting the First and Second Stipulations.

On December 11, 2015, the Public Staff filed a motion requesting that all of its witnesses be excused from appearing at the evidentiary hearing and that all of their prefiled testimony and exhibits be copied into the record and received into evidence. On December 14, 2015, the Commission issued an Order granting in part and denying in part the Public Staff's motion. Specifically, the Commission excused Public Staff witnesses Fenge Zhang, Babette K. McKemie, and Calvin C. Craig, III, from appearing at the December 15, 2015, evidentiary hearing. As to those witnesses, the Commission admitted their prefiled testimony and exhibits into evidence and made them a part of the evidentiary record in this proceeding. As to Public Staff witness Katherine A. Fernald, the Commission identified portions of her testimony or exhibits for which it sought clarification or elaboration and, therefore, denied the motion to excuse her appearance at the evidentiary hearing.

On December 15, 2015, the matter was called for hearing in Raleigh, North Carolina as scheduled. At the hearing, the prefiled testimony offered by CWSS witness Liskoff was copied into the record as if given orally from the witness stand, and the exhibits of witness Liskoff were received into evidence. The Application, including the confidential and public sections thereof and also including the revised Appendix A filed on July 22, 2015, the reports by CWSS responding to service quality concerns, the First Stipulation and the Second Stipulation were also received into evidence by the Commission. At the hearing, Public Staff witness Fernald testified in response to questions from the Commission regarding her prefiled testimony and exhibits. In addition, CWSS witness Martin J. Lashua, the Company's Vice President of Operations, testified in response to questions from the Commission.

On December 18, 2015, in response to a request by the Commission at the evidentiary hearing, the Public Staff filed exhibits detailing the major components of CWSS' rate case expenses and detailing the calculation of CWSS' franchise tax amount.

On January 14, 2016, CWSS and the Public Staff filed a Joint Proposed Order.

On the basis of the Application; the First Stipulation; the Second Stipulation; the testimony of the public witnesses; the testimony and exhibits of CWSS witness Liskoff and Lashua; the testimony and exhibits of Public Staff witnesses Fernald, Zhang, McKemie, and Craig; and the entire record in this proceeding, the Commission is of the opinion that the provisions of the First Stipulation and Second Stipulation are just and reasonable. Accordingly, the Commission hereby makes the following

FINDINGS OF FACT

1. CWSS is a corporation duly organized under the law and is authorized to do business in the State of North Carolina. CWSS is a franchised public utility providing water and

sewer utility service to customers in nine counties in North Carolina. CWSS is a wholly-owned subsidiary of Utilities, Inc.[1]

2. CWSS is properly before the Commission pursuant to Chapter 62 of the General Statutes of North Carolina seeking a determination of the justness and reasonableness of its proposed rates and charges for its water and sewer utility operations.

3. CWSS provides service to approximately 7,425 water customers and 3,267 sewer customers in North Carolina.

4. A total of nine customers testified at the seven public hearings and the evidentiary hearing, with three of those customers expressing service-related concerns. Such concerns included a three-day water outage in which a number of customers were not notified, unsatisfactory road repairs which had to be re-done by the Company, alleged property damage which resulted from a leak in a water main, and poor water pressure. In addition, the majority of the customers who appeared as witnesses testified, in general, in opposition to the proposed rate increase.

5. CWSS filed two reports[2] with the Commission, verified by Company Vice President of Operations, Martin J. Lashua, addressing the service-related concerns expressed by public witnesses who testified at the public hearings. Such reports described each of the witnesses' specific service-related concern(s), the Company's response, and how each concern was addressed, if applicable.

6. The overall quality of service provided by CWSS is adequate.

7. The test period for this rate case proceeding is the 12 months ended December 31, 2014, adjusted for certain changes in plant, revenues, and costs that were not known at the time the case was filed but are based upon circumstances occurring or becoming known through August 31, 2015. In addition, several major construction projects completed and placed into service prior to the evidentiary hearing were included in rate base.

8. The present rates for water and sewer service in all of CWSS' service areas have been in effect since June 27, 2014, pursuant to the Commission's Order issued June 27, 2014, in Docket Nos. M-100, Sub 138 and W-778, Sub 90. CWSS' last general rate case was decided by Commission Order entered on August 30, 2013, in Docket No. W-778, Sub 89 (Sub 89). The Sub 89 rate increase applied only to customers served by the Company's Fairfield Harbour, Fairfield Mountains, and Fairfield Sapphire Valley water and sewer systems. Rates for customers

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[1] Utilities, Inc., owns regulated utilities in approximately 15 states, including several in North Carolina. Presently, the regulated utilities owned by Utilities, Inc. in North Carolina are: (1) Carolina Water Service, Inc. of North Carolina (Docket No. W-354); (2) Bradfield Farms Water Company (Docket No. W-1044); (3) Carolina Trace Utilities, Inc. (Docket No. W-1013); (4) CWS Systems, Inc. (Docket No. W-778); (5) Elk River Utilities, Inc. (Docket No. W-1058); and (6) Transylvania Utilities, Inc. (Docket No. W-1012).

[2] The service-related concerns were expressed by customers testifying at the public hearings held in Brevard, North Carolina on October 20, 2015, and in Rutherford, North Carolina on October 22, 2015.

served by the Company's Clearwater, Forest Hills, and Treasure Cove systems were last increased in Docket No. W-778, Sub 88, a general rate case proceeding, effective August 3, 2011.

9. The average monthly residential bills under CWSS' present and proposed water and sewer rates are as follows:

WATER OPERATIONS

Service Area	Average Usage (Gallons)	Current Bill	Proposed Bill
Fairfield Harbour	3,922	$18.54	$23.78
Fairfield Mountains	2,440	$35.83	$42.38
Fairfield Sapphire Valley	2,199	$34.96	$49.81
Clearwater Systems	4,342	$33.60	$40.76
Forest Hills	3,405	$34.60	$41.65
Treasure Cove	5,008	$19.57	$26.30

SEWER OPERATIONS

Service Area	Current Bill (Flat Rate)	Proposed Bill (Flat Rate)
Fairfield Harbour	$34.50	$40.81
Fairfield Mountains	$49.07	$58.03
Fairfield Sapphire Valley	$39.56	$39.49

10. On September 2, 2015, the Public Staff and CWSS filed the First Stipulation regarding cost of capital and capital structure issues, and on December 11, 2015, CWSS and the Public Staff filed the Second Stipulation, regarding all remaining terms and conditions. The First Stipulation and the Second Stipulation settled all issues between CWSS and the Public Staff. CWSS and the Public Staff are the only formal parties to this proceeding.

11. By its Application, CWSS requested a total annual revenue increase in its water and sewer rates of $920,325, a company-wide 21.36% increase over the total revenue level generated by the rates currently in effect for CWSS.

12. CWSS' present and proposed service revenues for the 12-month period ending August 31, 2015, are shown below:

Service Area	Present	Proposed
Fairfield Harbour-Water	$ 454,918	$ 583,368
Fairfield Harbour-Sewer	790,633	935,254
Fairfield Sapphire Valley-Water	899,286	1,281,215
Fairfield Sapphire Valley-Sewer	501,681	500,766
Fairfield Mountains-Water	508,797	601,787
Fairfield Mountains-Sewer	322,975	390,419

Clearwater Systems	838,055	1,016,566
Treasure Cove	71,869	96,560
Forest Hills	66,546	80,098
Total CWSS	$4,454,760	$5,486,033

13. The appropriate level of total operating revenues under present rates for use in this proceeding is $4,452,550. The total operating revenues under present rates, by service area, is as follows:

Service Area	Service Revenues	Other Revenues & Uncollectibles	Total Operating Revenues
Fairfield Harbour-Water	$454,918	$ 1,570	$456,488
Fairfield Harbour-Sewer	790,633	(4,391)	786,242
Fairfield Sapphire Valley-Water	899,286	(6,530)	892,756
Fairfield Sapphire Valley-Sewer	501,681	(5,544)	496,137
Fairfield Mountains-Water	508,797	633	509,430
Fairfield Mountains-Sewer	322,975	(972)	322,003
Clearwater Systems	838,055	10,941	848,996
Treasure Cove	71,869	1,225	73,094
Forest Hills	66,546	858	67,404
Total CWSS	$4,454,760	$ (2,210)	$4,452,550

14. CWSS' original cost rate base as of December 31, 2014, updated through the close of the evidentiary hearing, is $13,612,988. The Company's rate base, by service area, is as follows:

Service Area	Original Cost Rate Base
Fairfield Harbour-Water	$ 1,072,247
Fairfield Harbour-Sewer	3,023,904
Fairfield Sapphire Valley-Water	3,764,430
Fairfield Sapphire Valley-Sewer	1,192,035
Fairfield Mountains-Water	1,695,019
Fairfield Mountains-Sewer	212,747
Clearwater Systems	2,160,607
Treasure Cove	211,592
Forest Hills	280,407
Total CWSS	$13,612,988

15. On July 23, 2013, North Carolina Session Law 2013-316 (House Bill 998) was signed into law. Among other things, House Bill 998 added a new section, G.S. 105-130.3C, to the general statutes concerning possible future rate reductions in the corporate state income tax rate. On August 6, 2015, the North Carolina Department of Revenue announced that, pursuant to this new section, the target for the fiscal year ended 2014-2015 had been met, and the state corporate income tax rate would decrease from the then-current rate of 5% to 4%, effective for taxable years beginning on or after January 1, 2016. It is reasonable and appropriate to calculate

state income taxes in this proceeding based on the statutory corporate rate of 4%, which became effective January 1, 2016. It is reasonable and appropriate to calculate federal income taxes in this proceeding based on the corporate rate of 34%.

16. Due to the reduction in the state income tax rate from 6.9% to 6% effective January 1, 2014, and to 5% effective January 1, 2015, CWSS has excess deferred income taxes. In its May 13, 2014 Order issued in Docket No. M-100, Sub 138, the Commission ordered that excess deferred taxes for all utilities be held in a deferred tax regulatory liability account until they can be amortized as credits to income tax expense in each utility's next general rate case proceeding. The regulatory liability related to excess deferred income taxes should be amortized over three years, consistent with the amortization period for rate case expense. Since the North Carolina Department of Revenue has announced that the target has been met and the state corporate income tax rate will decrease to 4% effective January 1, 2016, the regulatory liability related to the excess deferred taxes due to the decrease from 5% to 4% should also be amortized over three years. The total regulatory liability related to excess deferred taxes is $92,467, amortized over three years, for an annual amortization credit to expenses of $30,822.

17. It is reasonable and appropriate for CWSS to recover total rate case expenses of $243,104, consisting of $220,350 related to the current proceeding and $22,754 of unamortized rate case expense from prior proceedings, to be amortized and collected over a three-year period, for an annual level of rate case expense of $81,035.

18. It is reasonable and appropriate for CWSS' sewer easement clearing expense of $7,500 for Fairfield Sapphire Valley to be amortized and recovered through rates over three years, and 100% of the cost should be assigned to sewer operations.

19. It is reasonable and appropriate for CWSS' cost of the 2015 sewer tank painting for Fairfield Harbour to be amortized and recovered through rates over 10 years.

20. The legal fees incurred by CWSS regarding the investigation of Toxaphene levels (a synthetic organic compound, or SOC) related to the Company's water utility operations constituted a reasonable and appropriate extraordinary expense and should be amortized over five years with no unamortized balance included in rate base and the amortization should be allocated between the various water rate divisions of CWSS, based on the number of equivalent residential customers (ERCs).

21. CWSS' total operating expenses under present rates are $3,561,491. The Company's operating expenses under present rates, by service area, are as follows:

Service Area	Operating Expenses Under Present Rates
Fairfield Harbour-Water	$ 395,322
Fairfield Harbour-Sewer	588,274
Fairfield Sapphire Valley-Water	667,504
Fairfield Sapphire Valley-Sewer	366,055

Fairfield Mountains-Water	377,512
Fairfield Mountains-Sewer	342,040
Clearwater Systems	707,488
Treasure Cove	66,001
Forest Hills	51,295
Total CWSS	$3,561,491

22. The testimony of Public Staff witness Craig, regarding the reasonableness of the stipulated capital structure, cost of debt, and return on equity component of the overall rate of return, adequately supports the capital structure consisting of 49.00% long-term debt and 51.00% common equity, the cost of long-term debt of 6.60% and the return on equity of 9.75% agreed to by CWSS and the Public Staff in the First Stipulation. The stipulated capital structure and debt and equity returns are just and reasonable and appropriate for use in setting rates in this proceeding. Accordingly, the just, reasonable, and appropriate components of the rate of return for CWSS are as follows:

a.	Long-Term Debt Ratio:	49.00%
b.	Common Equity Ratio:	51.00%
c.	Embedded Cost of Debt:	6.60%
d.	Return on Common Equity:	9.75%
e.	Overall Weighted Rate of Return:	8.20%

23. It is reasonable and appropriate to determine the revenue requirement for CWSS using the rate base method as allowed by G.S. 62-133.

24. It is reasonable and appropriate to use the statutory regulatory fee rate of 0.148%[1] when calculating CWSS' revenue requirement.

25. G.S. 62-133.12(a) requires that the Commission approve a Water System Improvement Charge (WSIC) or Sewer System Improvement Charge (SSIC) rate adjustment mechanism only upon a finding that the mechanism is in the public interest. The Commission finds that implementation and use of the WSIC and SSIC mechanisms by CWSS is in the public interest.

26. The Three-Year WSIC/SSIC Plan filed by CWSS as Exhibit C to the Application meets the requirements of Commission Rules R7-39(m) pertaining to WSIC and R10-26(m) pertaining to SSIC.

27. The rates agreed upon in the Second Stipulation will provide CWSS with an increase in its annual level of total operating revenues through rates and charges approved in this case by $341,765. After giving effect to this authorized increase in revenues, the total annual operating revenues for CWSS will be $4,794,315. The operating revenues under present rates, approved increase / (decrease) in operating revenues, and resulting annual level of operating revenues by service area are as follows:

[1] The regulatory fee rate of 0.148% became effective July 1, 2015, pursuant to North Carolina Session Law 2015-134 (House Bill 356), which was signed into law on June 30, 2015.

WATER AND SEWER – RATE INCREASE

Service Area	Under Present Rates	Stipulated Increase/ (Decrease)	Under Stipulated Rates
Fairfield Harbour-Water	$ 456,488	$ 42,403	$ 498,891
Fairfield Harbour-Sewer	786,242	79,328	865,570
Fairfield Sapphire Valley-Water	892,756	132,257	1,025,013
Fairfield Sapphire Valley-Sewer	496,137	(50,987)[1]	445,150
Fairfield Mountains-Water	509,430	11,355	520,785
Fairfield Mountains-Sewer	322,003	43,677	365,680
Clearwater Systems	848,996	56,588	905,584
Treasure Cove	73,094	16,234	89,328
Forest Hills	67,404	10,910	78,314
Total CWSS	$4,452,550	$ 341,765	$4,794,315

28. CWSS is entitled to changes in its water and sewer rates that will produce the $4,794,315 in operating revenues. The service revenues, other revenues and uncollectibles, and total operating revenues under approved rates, by service area, are:

Service Area	Service Revenues	Other Revenues & Uncollectibles	Total Operating Revenues
Fairfield Harbour-Water	$ 497,741	$ 1,150	$ 498,891
Fairfield Harbour-Sewer	870,747	(5,177)	865,570
Fairfield Sapphire Valley-Water	1,033,353	(8,340)	1,025,013
Fairfield Sapphire Valley-Sewer	449,997	(4,847)	445,150
Fairfield Mountains-Water	520,194	591	520,785
Fairfield Mountains-Sewer	366,814	(1,134)	365,680
Clearwater Systems	894,610	10,974	905,584
Treasure Cove	88,121	1,207	89,328
Forest Hills	77,481	833	78,314
Total CWSS	$4,799,058	$ (4,743)	$4,794,315

29. Based on the agreed-upon service revenues set forth in the Second Stipulation, the WSIC and SSIC rate caps after this rate case will be:

[1] On cross-examination, Public Staff witness Fernald testified that the stipulated decrease in annual operating revenues for Fairfield Sapphire Valley-Sewer was primarily due to the following factors: (1) an increase in service customers which resulted in additional revenues and an additional customer base over which to spread fixed costs; (2) the net plant in service amount did not increase significantly since the last rate case proceeding; and (3) certain operations and maintenance expenses (transportation expense, maintenance and repairs expense, and chemicals expense) decreased since the last rate case proceeding.

Service Area		Service Revenues			WSIC & SSIC Cap
Fairfield Harbour-Water	$	497,741	x 5% =	$	24,887
Fairfield Harbour-Sewer	$	870,747	x 5% =	$	43,537
Fairfield Sapphire Valley-Water	$	1,033,353	x 5% =	$	51,668
Fairfield Sapphire Valley-Sewer	$	449,997	x 5% =	$	22,500
Fairfield Mountains-Water	$	520,194	x 5% =	$	26,010
Fairfield Mountains-Sewer	$	366,814	x 5% =	$	18,341
Clearwater Systems-Water	$	894,610	x 5% =	$	44,731
Treasure Cove-Water	$	88,121	x 5% =	$	4,406
Forest Hills-Water	$	77,481	x 5% =	$	3,874

30. The Schedules of Rates for water and sewer service agreed to by CWSS and the Public Staff, attached hereto as Appendices A-1, A-2, A-3, A-4, A-5, and A-6 are just and reasonable.

31. The First Stipulation and the Second Stipulation contain the provision that the Stipulating Parties agree that none of the positions, treatments, figures, or other matters reflected in the agreements should have any precedential value, nor should they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matters in issue.

32. The First Stipulation and the Second Stipulation contain the provision that the agreements made therein do not bind the Stipulating Parties to the same positions in future proceedings, and the parties reserve the right to take different positions in any future proceedings. The Second Stipulation also contains the provision that no portion of the Second Stipulation is binding on the Stipulating Parties unless the entire Second Stipulation is accepted by the Commission.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The evidence for the following conclusions is contained in: the Application; in the First Stipulation; in the Second Stipulation; in the testimony of the public witnesses; in the prefiled testimony and exhibits of CWSS witnesses Liskoff and Lashua; in CWSS' Report on Customer Service Quality Issues From Public Hearing in Brevard, North Carolina, filed on November 20, 2015; in CWSS' Report on Customer Service Quality Issues From Public Hearing in Rutherfordton, North Carolina, filed on November 25, 2015, in the testimony and exhibits of Public Staff witnesses Fernald, Zhang, McKemie, and Craig; and in the entire record in this proceeding.

Public Hearings and Service Quality

No customers appeared to testify at the public hearings in Raleigh, North Carolina on September 17, 2015, November 30, 2015, and December 15, 2015; in Wilmington, North Carolina on September 30, 2015; or in Sylva, North Carolina on October 21, 2015.

One customer, Paul Hill, appeared to testify at the public hearing in New Bern, North Carolina on October 1, 2015. Witness Hill, a customer in CWSS' Fairfield Harbour service area, expressed concerns regarding the venue of the public hearing. In response to a question from Commissioner Beatty, witness Hill testified that Fairfield Harbour's relationship with CWSS is a very positive relationship and that, in general, CWSS has been a good provider for Fairfield Harbour. Witness Hill expressed no concerns regarding service quality.

One customer, Walter Green, appeared to testify at the public hearing in Brevard, North Carolina on October 20, 2015. Witness Green resides at 145 Rhododendron Court, Sapphire, North Carolina, in the Holly Forest Subdivision. Witness Green serves as the President of the Sapphire Valley Master Association, which is comprised of the owners' associations of 32 subdivisions located in Sapphire Valley. With respect to service quality, witness Green testified as to a recent outage experienced in the service area that lasted approximately three days during which time a number of customers failed to receive notice of the outage from CWSS. Witness Green testified that, typically in the event of outages, CWSS has a system in place in which "robocalls" are made to customers alerting them to the issue. He testified that during the outage, however, a number of customers were not reached by the "robocalls" and that, as a result, he received numerous calls and emails related to the outage from residents who had not been informed about the outage by the Company.

In its written report, CWSS explained that the most efficient way for the Company to reach customers quickly in the event of an outage is to send out an automated phone message or voice reach. These messages are also referred to as "robocalls." A voice-reach message was sent to all CWSS water customers in the affected service area. CWSS' message system is able to track the success rate of each message and, unfortunately, a large number of customers (approximately 250) were not reached because the call "failed" or there "was no answer". CWSS explained that there are multiple reasons for this success rate, including: the customer could have call waiting and chose not to answer; the telephone number on file does not have an answering machine; the number has been changed; or CWSS has an incorrect number for the customer. To ensure an improved success rate in the future, CWSS informed the Commission that it is sending a letter to each of these customers asking them to contact CWSS Customer Service and provide the single best phone number for their account. A copy of that letter was provided to the Commission.

Seven customers appeared to testify at the public hearing in Rutherfordton, North Carolina on October 22, 2015. Of those seven customers, two testified as to service quality concerns. Specifically, Jack Zinselmeier testified as to road repairs undertaken within his subdivision by CWSS. He testified that when the road repairs did not receive the approval of the Infrastructure Committee of the owners' association, the road repairs were re-done by CWSS. In response to a question by Commissioner Brown-Bland, witness Zinselmeier testified that the re-done repairs had been completed to the satisfaction of the Infrastructure Committee.

Witness Zinselmeier also testified as to a leak in the water main feeding his residence and indicated concern that the water had leaked onto his property, necessitating repairs. He testified that he notified CWSS personnel once he suspected a leak, that CWSS personnel worked to identify the leak, and that CWSS fixed the leak as soon as it was identified.

In its written report addressing witness Zinselmeier's testimony regarding the leak, CWSS informed the Commission that Company employees had been to witness Zinselmeier's residence on several occasions to look for a leak but were not able to find one. However, eventually a leak was identified and promptly repaired. CWSS representative Martin Lashua investigated the leak and complaint history and contacted witness Zinselmeier regarding the retaining wall damage. CWSS and witness Zinselmeier agreed to a mutually acceptable reimbursement for a portion of the cost of replacing the retaining wall. CWSS informed the Commission that witness Zinselmeier acknowledged to Mr. Lashua that the resolution of this matter was satisfactory.

Ron Cantrall testified regarding poor water pressure at his residence. In response to a question from Public Staff counsel, witness Cantrall testified that he had contacted CWSS about the water pressure and that CWSS had been to his residence to investigate. He testified that CWSS concluded, after investigating, that the problem was in his water line, as opposed to the CWSS water main. In response to a question from Commissioner Bailey, witness Cantrall testified that he has no water quality problems at his residence.

In addressing witness Cantrall's concerns in its written report, CWSS informed the Commission that it has previously investigated these concerns. The result of the most recent previous investigation is detailed in the reports addressing customer service and/or service quality complaints expressed at the public hearing held in Lake Lure on March 31, 2011, filed by CWSS in Docket No. W-778, Sub 88 on April 20, 2011. In an effort to further address witness Cantrall's concerns regarding water pressure, CWSS again visited witness Cantrall's residence to investigate. On November 18, 2015, CWSS sent a letter to witness Cantrall explaining CWSS' efforts, conclusion, and recommendation. A copy of that letter was provided to the Commission.

Public Staff witness McKemie testified that she reviewed reports on service quality issues filed by CWSS and is satisfied with the Company's responses concerning service quality issues.

Witness McKemie further testified that she inspected several of CWSS' systems. Specifically, on September 30, 2015, she inspected the water systems at Treasure Cove in New Hanover County, at which CWSS has recently started using SeaQuest for sequestration treatment of iron and manganese. She noted that the SeaQuest technology seems to be working well.

On October 1, 2015, witness McKemie inspected the water and sewer systems at Fairfield Harbour in Craven County. She noted that CWSS had placed a SCADA control system into service in 2014. She explained that a large project had been undertaken at the wastewater treatment plant which resulted in the development of a method to achieve denitrification in the existing plant by alternating aerobic and anoxic cycles using SCADA probes to control dissolved oxygen levels. She testified that, as a result, the plant now consistently meets its permit limits for nitrogen removal and is no longer under a moratorium. She also noted an ongoing capital project of adding tertiary filters to address fecal coliform violations. The filters were on-site and ready to install during her visit, and she testified that CWSS has since completed that work.

On October 15-16, 2015, witness McKemie inspected the Clearwater systems in Wake and Durham Counties, which are well water systems. She observed that the Company is in the process of installing radiological filters at Country Crossing well no. 1 and that Neuse Woods Mobile Home Park has activated carbon filters to treat for Toxaphene (a synthetic organic compound, or SOC). She also noted that CWSS has recently undertaken a tank study program, and, as a result, it is in the process of replacing many of the old hydro tanks. She observed during her inspection that many of these tank replacements were in the final stages of installation and many of the old tanks were still on-site pending removal. She testified that, since her inspection, the new tanks have been installed and placed in service.

On October 21, 2015, witness McKemie inspected the Forest Hills water system in Jackson County and the Fairfield Sapphire Valley water and sewer systems in Jackson and Transylvania Counties. She noted during her inspection that Fairfield Sapphire Valley was in the process of installing automatic meter reading (AMR) technology on the water system. She testified that the meters have since been installed and placed into service. She also testified that CWSS demonstrated the functioning of the AMR technology in the Company's water systems located in the North Carolina mountains, and that such meters are able to be read remotely, provide meter readings during winter weather of snow and ice and remote access to meters in difficult mountain terrains.

On October 22, 2015, witness McKemie inspected the Fairfield Mountains water and sewer systems in Rutherford County. Work ongoing during her inspection involved the removal of the existing hydro tank and installation of a small bladder tank as a hydraulic buffer. She testified that the old tank has since been removed and modifications have been completed and placed into service.

Based upon the foregoing, and after careful review of the testimony of the customers at the public hearings, the Reports on Customer Concerns filed by CWSS, and the Public Staff's engineering and service quality investigation, the Commission concludes that the overall quality of service provided by CWSS in North Carolina is adequate.

Capital Structure and Cost of Capital

In its Application, the Company proposed rates that would produce an overall rate of return on CWSS' rate base of 8.44%. The Application incorporated a proposed return on common equity of 10.40%; a cost of long-term debt of 6.60%; and a capital structure consisting of 48.97% long-term debt and 51.03% common equity. Pursuant to the First Stipulation, CWSS and the Public Staff agreed that a capital structure consisting of 49.00% long-term debt and 51.00% common equity, a cost of long-term debt of 6.60%, and a return on equity of 9.75% are reasonable and appropriate for use in this proceeding.

Public Staff witness Craig testified in support of the agreed upon capital structure and cost rates for the components of the capital structure. Witness Craig contended that it is widely recognized that a public utility should be allowed a rate of return on capital that will allow the utility, under prudent management, to attract capital under the criteria or standards referenced by the Hope[1] and Bluefield[2] decisions. He maintained that if the allowed rate of return is set too high, consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. However, if the return is set too low and the utility is not able to attract capital on reasonable terms to meet future expansion for its service area, witness Craig asserted that future service obligations may be impaired. Witness Craig explained that because a public utility is capital intensive, the cost of capital is a very large part of its overall revenue requirement and is a crucial issue for a company and its ratepayers.

With respect to capital structure, witness Craig testified that in this proceeding, through discovery, it was determined that CWSS was in a position to update its capital structure to 48.61% long-term debt and 51.39% common equity; however, as part of the First Stipulation, CWSS agreed to a lower (i.e., less expensive) cost capital structure consisting of 49.00% long-term debt and 51.00% common equity.

With respect to cost of common equity, witness Craig testified that his recommendation is based on: (1) the discounted cash flow (DCF) model for water and local natural gas distribution companies (LDCs); (2) the risk premium method using a regression analysis of allowed returns for LDCs; and (3) the comparable earnings analysis on a comparable group of water utilities. He testified that because the common equity of CWSS is not publically traded, he could not apply the DCF method directly to CWSS. As such, he applied the DCF method to a comparable group of water utilities and a group of natural gas LDCs. He testified that based upon the DCF results for the comparable group of water utilities, he determined that the cost of common equity is within the range of 8.20% to 9.20%. He testified that applying the risk premium method produced a predicted return on common equity of 9.66%. Finally, witness Craig testified that applying the comparable earnings analysis produced a range of 8.70% to 9.80%. Based on the results of the three methods, witness Craig concluded that a reasonable range of estimates for the cost of common equity for CWSS is between 8.80% and 9.80%.

CWSS and the Public Staff stipulated that the cost of common equity should be 9.75%, which is supported by witness Craig's analysis.

Witness Craig testified as to the extent to which the recommended cost of common equity takes into consideration the impact of changing economic conditions on customers. He testified that he is aware of no clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an appropriate return on equity in setting rates for a public utility. Rather, he testified that the impact of changing economic conditions nationwide is inherent in the methods and data used in his study to determine the cost of equity for utilities that are comparable in risk to CWSS. In addition, customer testimony at the public hearings in this proceeding focused on the amount of proposed rate increases in the various service areas.

[1] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[2] Bluefield Waterworks & Impr. Co. v. Public Service Comm'n, 262 U.S. 679, 692-93 (1923).

With respect to overall cost of capital, witness Craig recommended 8.20% as set forth in Exhibit CCC-7 of his testimony. In regard to a reasonableness assessment of financial risk with respect to his recommended return on common equity and overall cost of capital, witness Craig testified that he considered the pretax interest coverage ratio. Witness Craig testified that based upon the recommended capital structure, cost of debt, and equity return of 9.75%, the pretax interest coverage ratio is approximately 2.9 times.

G.S. 62-133(b)(4) requires the Commission to fix rates for service which will enable a public utility, by sound management, to produce a fair profit for its stockholders, in view of current economic conditions, maintain its facilities and services and compete in the market for capital, and no more. This is the ultimate objective of ratemaking. Utilities Commission v. General Telephone Company, 281 N.C. 318, 189 S.E.2d 705 (1972). The Commission is of the opinion that there is adequate evidence in the record to support the return on equity agreed to by the Public Staff and CWSS and that such return should allow CWSS to properly maintain its facilities and services, provide adequate service to its customers, and produce a fair return, thus enabling CWSS to attract capital on terms that are fair and reasonable to its customers and investors. Consequently, the Commission finds and concludes that the return on common equity of 9.75% that was agreed to by CWSS and the Public Staff is just and reasonable and should be approved. Further, in light of witness Craig's testimony and analysis, the Commission finds and concludes that there is adequate evidence in the record to support the capital structure and cost of debt agreed to by CWSS and the Public Staff.

Therefore, the capital structure consisting of 49.00% long-term debt and 51.00% common equity, a cost of debt of 6.60%, and a return on equity of 9.75% are appropriate for use in this proceeding considering the impact of changing economic conditions on customers and relevant statutory and case law.

Water System Improvement Charge (WSIC) and
Sewer System Improvement Charge (SSIC)

On June 12, 2013, North Carolina Session Law 2013-106 (House Bill 710), An Act to Permit Water Utilities to Adjust Rates for Changes in Costs Based on Third-Party Rates and to Authorize the Utilities Commission to Approve Rate Adjustment Mechanism for Water and Sewer Utilities to Recover Costs for Water and Sewer System Improvements, was signed into law, having previously been ratified by the North Carolina General Assembly, resulting in the enactment of G.S. 62-133.12. This statute provides that the Commission may approve a rate adjustment mechanism in a general rate case proceeding to allow a water or sewer public utility to recover through a system improvement charge the incremental depreciation expense and capital costs associated with the utility's reasonable and prudently incurred investment in "eligible water and sewer system improvements".[1] Cumulative system improvement charges for a water or sewer utility may not exceed 5% of the total annual service revenues approved by the Commission in the water or sewer utility's last general rate case. G.S. 62-133.12 further states that the Commission

[1] Pursuant to G.S. 62-133.12, "eligible water system improvements" or "eligible sewer system improvements" shall include only those improvements found necessary by the Commission to enable the water or sewer utility to provide safe, reliable, and efficient service in accordance with applicable water quality and effluent standards.

shall approve such rate adjustment mechanism only upon a finding that the mechanism is in the public interest.

In this general rate case proceeding, CWSS has requested that the Commission find and conclude that it is in the public interest to approve a WSIC/SSIC mechanism for eligible investments in water and sewer improvements for immediate implementation by the Company.

CWSS witness Liskoff testified that the adjustment mechanism will provide for recovery of CWSS' investment in eligible water and wastewater infrastructure projects, subject to statutory consumer safeguards and the Commission's oversight. Witness Liskoff testified that, if authorized by the Commission to implement a WSIC/SSIC mechanism, CWSS shall comply with the requirements set forth in Commission Rule R7-39 (Water System Improvement Charge Mechanism) and Rule R10-26 (Sewer System Improvement Charge Mechanism).

Witness Liskoff justified a public interest determination by the Commission on several bases. He testified that the primary legislative purpose of the statute, G.S. 62-133.12, is to establish a means by which investments of a certain type—widely understood to be needed with respect to our state and national water and wastewater infrastructure—can be incented and accelerated by virtue of a mechanism that allows incremental and timely recovery, subject to a strict, legislatively-imposed rate cap and an array of other customer protections, both between general rate cases and at the next rate case. Witness Liskoff submitted that there are several policy reasons for the passage of G.S. 62-133.12 which underlie the Company's request for approval of a WSIC/SSIC mechanism and that these reasons support a finding by the Commission that approval of a WSIC/SSIC mechanism in this rate case is in the public interest.

Witness Liskoff testified that, first, the legislature sought to encourage water and wastewater providers to replace aging infrastructure throughout the state. This has many positive effects for residents in North Carolina, including reduction of non-revenue water, increased water pressure, fewer main breaks, elimination of dead-end mains, and better management of inflow and infiltration for wastewater systems. If approved for implementation by CWSS, the mechanism will promote additional investment in infrastructure by the Company, thereby resulting in significant benefits to customers, including, but not limited to, better water quality and improved water and wastewater system reliability.

Witness Liskoff testified that, second, the legislature specifically commented on and addressed secondary water quality issues. CWSS's North Carolina water sources throughout the State are principally groundwater. Groundwater in this State often contains naturally-occurring iron and manganese, which in some instances causes discolored water. While discolored water can be, and is, provided in compliance with environmental regulations, many customers and water providers do not find this acceptable. The Commission, the Public Staff, and CWSS are all aware of customer issues about these naturally-occurring minerals. G.S. 62-133.12 specifically addresses secondary water quality and will incent water providers to address secondary water quality issues that may arise from the groundwater sources for various residential communities. The new statute provides a funding mechanism, subject to a rate cap and other rigorous oversight by the Commission and the Public Staff, to accelerate the investment needed to address these concerns.

Witness Liskoff further testified that, third, a beneficial result of the recent legislation is to minimize the impact of necessary rate increases by allowing for incremental adjustments, rather than the sharp rate changes that are characteristic of general rate cases. G.S. 62-133.12 will allow CWSS to "smooth out" the impact of necessary rate increases and, hopefully, expand the time between filing rate cases. This, in turn, improves the capital attractiveness of CWSS and reduces rate case expense and the carrying costs associated with extended periods of time between investment and recovery (regulatory lag). The result benefits both customers and the regulated utilities, including CWSS.

Witness Liskoff testified that, fourth, the public interest is promoted where consumers, such as those served by CWSS, are protected by the rigorous regulatory oversight and procedures which have been established by the Legislature and the Commission for the review and approval of any costs to be recovered through the WSIC/SSIC rate adjustment mechanism. The WSIC/SSIC mechanism, and any WSIC/SSIC filings made by CWSS, will be subject to full and complete scrutiny and oversight by both the Public Staff and Commission at all stages of rate adjustment proceedings.

Public Staff witness Fernald testified that the Public Staff does not object to a finding by the Commission that the implementation and use by CWSS of a WSIC and/or SSIC mechanism is in the public interest.

Commission Rules R7-39(c)(1) and R10-26(c)(1) require that a public utility file an initial three-year plan in the general rate case in which it is seeking approval of a WSIC/SSIC mechanism. Public Staff witness McKemie reviewed the WSIC and SSIC three-year improvement plan filed by CWSS as Exhibit C to the Application. The purpose of witness McKemie's review was to make an initial determination as to whether the listed projects were eligible WSIC or SSIC projects as defined in G.S. 62-133.12(c) and (d). After an initial review of the nine projects submitted by the Company, witness McKemie concluded that the projects seem to qualify for WSIC/SSIC treatment, with the exception of the Apple Valley interconnect and the Apple Valley new well projects. In the opinion of witness McKemie, these two projects will not qualify for WSIC treatment, as they address a capacity issue and not a drinking water standards issue, and she noted that if the interconnection is done, the need for a new well is delayed or eliminated. However, witness McKemie concluded that the remaining seven projects appear to qualify for WSIC/SSIC treatment. Therefore, witness McKemie concluded that CWSS' three-year improvement plan, as so modified, is reasonable and supports a finding that it is in the public interest to authorize CWSS to implement a WSIC/SSIC mechanism.

In Paragraph 10 of the Second Stipulation, the Public Staff and CWSS agreed that a WSIC and SSIC mechanism should be approved for the Company in this rate case proceeding.

Accordingly, the Commission is persuaded by Paragraph 10 of the Second Stipulation and the testimony of CWSS witness Liskoff and Public Staff witnesses Fernald and McKemie that it is in the public interest to authorize CWSS to implement a WSIC/SSIC mechanism, subject to all statutory and regulatory requirements. The Commission agrees with the observations of Public Staff witness McKemie and concludes that the illustrative three-year plan filed by CWSS as

Exhibit C to the Application supports the Commission's finding that it is in the public interest for the Commission to authorize the Company to implement a WSIC/SSIC mechanism.

Additionally, the Commission agrees that the WSIC/SSIC reporting requirements set forth in the Second Stipulation are reasonable and appropriate and are, therefore, approved. Thus, CWSS' right to implement a WSIC/SSIC rate adjustment mechanism, subject to all statutory and regulatory requirements, is effective as of the date of this Order. Furthermore, subject to all statutory and regulatory requirements, CWSS may apply on February 1 and August 1 for approval of semi-annual WSIC/SSIC rate adjustments to become effective on April 1 and October 1 of each calendar year, beginning in February 2016.

Approval of Stipulations

The Commission, having carefully reviewed the First Stipulation, the Second Stipulation, and all of the evidence of record, finds and concludes that the First Stipulation and Second Stipulation are the product of the give-and-take settlement negotiations between CWSS and the Public Staff; that they constitute material, competent evidence; that they are entitled to be given appropriate weight in this proceeding, along with all other evidence in the record; and that they are fully supported by material, competent evidence in the record.

In regard to the extraordinary legal fees incurred by CWSS concerning the investigation of Toxaphene levels related to the Company's water utility operations addressed in Paragraph 13 of the Second Stipulation, during cross-examination, CWSS witness Lashua testified that the Wake County Health Department issued a notice to the Company's affected customers that was contradictory to the notice that CWSS was required to provide by the Department of Environmental Quality (DEQ),[1] Public Water Supply Section (PWSS). Witness Lashua explained that the PWSS notice was "more of a chronic nature letting the customers know that toxaphene was long-term exposure situation" while the Wake County Health Department, based on advice from the Department of Health and Human Services (DHHS), "took more of an immediate, acute-type impact and advised the customers not to shower for very long, not to drink the water, not to be exposed to the water". Witness Lashua maintained that such position was contradictory to PWSS' position and confusing to both the customers and the Company. As a result, the Company retained environmental legal defense to work through this issue with DHHS and DEQ and to develop some type of communication to its customers that could be jointly conveyed. Witness Lashua stated that the dispute regarding the conflicting information continued for some time but ultimately the Company and the Wake County Health Department developed a joint message which was communicated to CWSS' affected customers. Further, on cross-examination, witness Lashua testified that there were no civil penalties assessed against CWSS pertaining to this matter and that the Company "acted very quickly, unusually fast in terms of putting in a temporary, portable [filtration] unit" prior to the installation of the permanent filtration system to remediate the situation. CWSS and the Public Staff stipulated at Paragraph 13 of the Second Stipulation that

[1] Formerly known as the Department of Environment and Natural Resources (DENR).

> the legal fees related to the investigation of Toxaphene levels related to the Company's water utility operations constituted an extraordinary expense and should be amortized over five years with no unamortized balance included in rate base and the amortization should be allocated between the various water rate divisions of CWSS, based on the number of ERCs.

In regard to customer billing, during the evidentiary hearing, CWSS acknowledged a history of billing issues and informed the Commission that efforts are underway, working independently and with the Public Staff, to identify and correct past billing errors and, more importantly, prevent any such billing issues from arising in the future. As set forth in Paragraph 14 of the Second Stipulation, CWSS has agreed to conduct a monthly review of rate schedules to ensure that all customers have been set up with the proper rate schedules and CWSS is billing authorized rates. In addition, as set forth in the Second Stipulation, CWSS management will review future rate case filings for accuracy and completeness prior to filing with the Commission and the Company will more clearly footnote its workpapers, and include workpapers for all pro forma adjustments, in the minimum filing requirements, NCUC Form W-1, Item 10.

Pursuant to Paragraph 14 of the Second Stipulation, the Company further agreed to (a) adjust its books to reflect the ratemaking treatment of the acquisition of Treasure Cove, so that amounts on the books are consistent with the amounts allowed by the Commission; (b) correct the recording of the UR entries[1] on CWSS' books so that they are recorded to the correct systems, and remove the roll-forward entry for accumulated depreciation; and (c) record the amortization expense of testing costs in testing expense on its books, instead of including these amounts in maintenance and repairs.

Based on the foregoing findings of fact and the entire record in this proceeding, the Commission finds and concludes that all of the provisions of the First Stipulation and Second Stipulation, which are incorporated herein by reference, are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the First Stipulation and the Second Stipulation are incorporated by reference herein, and are hereby approved in their entirety.

2. That the Schedules of Rates, attached hereto as Appendices A-1, A-2, A-3, A-4, A-5, and A-6 are hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138.

3. That the Schedules of Rates, attached hereto as Appendices A-1, A-2, A-3, A-4, A-5, and A-6, are hereby authorized to become effective for service rendered on and after the issuance date of this Order.

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[1] UR entries are journal entries based upon the adjustments included in Commission orders.

4. That the Notices to Customers, attached hereto as Appendices B-1, B-2, B-3, B-4, B-5, and B-6 shall be mailed with sufficient postage or hand delivered to all affected customers in each relevant service area, respectively, in conjunction with the next regularly scheduled billing process.

5. That CWSS shall file the attached Certificate of Service, properly signed and notarized, not later than 10 days after the Notices to Customers are mailed or hand delivered to customers.

6. That the First Stipulation, the Second Stipulation and the parts of this Order pertaining to the contents of those agreements shall not be cited or treated as precedent in future proceedings.

7. That the late-filed exhibits concerning rate case expenses and franchise taxes, filed by the Public Staff on December 18, 2015, are hereby admitted in evidence in this proceeding.

8. That CWSS shall adjust its books to reflect the ratemaking treatment of the acquisition of Treasure Cove, so that amounts on the books are consistent with the amounts allowed by the Commission, as stipulated.

9. That CWSS shall correct the recording of the UR entries on CWSS' books so that they are recorded to the correct systems, and remove the roll-forward entry for accumulated depreciation, as stipulated.

10. That CWSS shall record the amortization expense of testing costs in testing expense on its books, instead of including these amounts in maintenance and repairs, as stipulated.

11. That CWSS shall conduct a monthly review of rate schedules to ensure that all customers have been set up with the proper rate schedules and the Company is billing its authorized rates, as stipulated.

12. That Utilities, Inc. management shall review future rate case filings by any of its regulated subsidiaries in North Carolina, including CWSS, for accuracy and completeness before they are filed with the Commission, more clearly footnote workpapers, and include workpapers for all pro forma adjustments, in the minimum filing requirements, NCUC Form W-1, Item 10 of any future rate case filings, as stipulated.

13. That CWSS' request to utilize a WSIC/SSIC mechanism pursuant to G.S. 62-133.12 to recover certain incremental costs related to eligible investment in water and sewer infrastructure projects completed and placed in service between general rate case proceedings is in the public interest and is hereby approved.

This the __24th_ day of ___February___, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Commissioner Susan W. Rabon resigned from the Commission, effective December 31, 2015, and therefore, did not participate in this decision.

APPENDIX A-1
PAGE 1 OF 3

SCHEDULE OF RATES

for

CWS SYSTEMS, INC.

for providing water utility service

in

FORMER CLEARWATER SYSTEMS - AMBER ACRES, AMBER ACRES NORTH, AMBER RIDGE, ASHLEY HILLS NORTH, BISHOP POINTE, CARRIAGE MANOR, COUNTRY CROSSING, COVINGTON CROSS, HEATHER GLEN, HIDDEN HOLLOW, JORDAN WOODS, LINDSEY POINT, NEUSE WOODS, OAKES PLANTATION, RANDSDELL FOREST, RUTLEDGE LANDING, SANDY TRAILS, STEWART'S RIDGE, TUCKAHOE, AND WILDER'S VILLAGE SUBDIVISIONS

Wake, Durham, Franklin, and Nash Counties, North Carolina[1]

Monthly Metered Water Rates:

A. Base charge, zero usage

5/8" meter	$ 16.30
1" meter	$ 40.75
1½" meter	$ 81.50
2" meter	$130.40
3" meter	$244.56
4" meter	$407.58
6" meter	$815.00

B. Usage charge, per 1,000 gallons $ 4.51

Monthly Flat Water Rate:
(Per residence or single family equivalent) $ 37.25

[1] These above-captioned subdivisions are all located in Wake County, except for the following: Heather Glen Subdivision is located in Durham County, Wilder's Village is located in Franklin County, and Randsdell Forest is located in Nash County.

APPENDIX A-1
PAGE 2 OF 3

Connection Charge:

Lindsey Point Subdivision	$ 0.00
Amber Acres North Subdivision, Sections II & IV	$570.00
All other service areas:	
A. 5/8" meter	$500.00
B. All other meter sizes - actual cost of meter and installation	

Management Fee:

Covington Cross Subdivision (Phases 1 & 2)	$100.00

Irrigation Meter Installation:	Actual Cost
New Meter Charge:	Actual Cost
New Water Customer Charge:	$ 27.00
Meter Testing Fee: [1/]	$ 20.00

Reconnection Charge:

If water service cut off by utility for good cause	$ 27.00
If service discontinued at customer's request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.)

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

APPENDIX A-1
PAGE 3 OF 3

NOTE:

[1/] If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 91, on this the _24th_ day of __February_______, 2016.

APPENDIX A-2
PAGE 1 OF 2

SCHEDULE OF RATES

for

CWS SYSTEMS, INC.

for providing water utility service

in

TREASURE COVE, REGISTER PLACE ESTATES, NORTH HILLS, AND GLEN ARBOR/NORTH BEND SUBDIVISIONS

New Hanover County, North Carolina

Monthly Metered Water Rates:	
Base charge, zero usage	$ 14.53
Usage charge, per 1,000 gallons	$ 1.90
Irrigation Meter Installation:	Actual Cost
New Meter Charge:	Actual Cost
New Water Customer Charge:	$ 27.00
Meter Testing Fee: [1/]	$ 20.00
Connection Charge:	
Treasure Cove Subdivision	$ 0.00
North Hills Subdivision	$100.00
Glen Arbor / North Bend Subdivision	$ 0.00
Register Place Estates Subdivision	$500.00
Reconnection Charge:	
If water service cut off by utility for good cause	$ 27.00
If service discontinued at customer's request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.)

APPENDIX A-2
PAGE 2 OF 2

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

NOTE:

1/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 91, on this the _24th_ day of _February______, 2016.

APPENDIX A-3
PAGE 1 OF 2

SCHEDULE OF RATES

for

CWS SYSTEMS, INC.
for providing water utility service

in

FOREST HILLS SUBDIVISION

Jackson County, North Carolina

Monthly Metered Water Rates:

A. Base charge, zero usage

Residential	$ 22.50
Commercial and Other:	
5/8” meter	$ 22.50
3/4” meter	$ 33.76

1” meter	$ 56.25
1.5” meter	$ 112.50
2” meter	$ 180.00
3” meter	$ 337.50
4” meter	$ 562.50
6” meter	$1,125.00

B. Usage charge, per 1,000 gallons $ 5.25

Connection Charge:

A. 5/8” meter $ 500.00

B. All other meter sizes - actual cost of meter and installation

Irrigation Meter Installation:	Actual Cost
New Meter Charge:	Actual Cost

APPENDIX A-3
PAGE 2 OF 2

New Water Customer Charge:	$ 27.00
Meter Testing Fee: [1/]	$ 20.00

Reconnection Charge:

If water service cut off by utility for good cause	$ 27.00
If service discontinued at customer’s request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.)

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

NOTE:

[1/] If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 91, on this the _24th_ day of _February__, 2016.

APPENDIX A-4
PAGE 1 OF 4

SCHEDULE OF RATES

for

CWS SYSTEMS, INC.

for providing water and sewer utility service

in

FAIRFIELD MOUNTAINS SERVICE AREA,
HIGHLAND SHORES SUBDIVISION, APPLE VALLEY,
LAUREL MOUNTAIN ESTATES (water only)

Rutherford County, North Carolina

WATER UTILITY SERVICE

Monthly Metered Water Rates:

A. Base charge per month, zero usage	
Residential	$ 19.28
Commercial and Other:	
5/8” meter	$ 19.28
3/4” meter	$ 28.92
1” meter	$ 48.20
1.5” meter	$ 96.40
2” meter	$154.25
3” meter	$289.20
4” meter	$482.00
6” meter	$964.00
B. Usage charge, per 1,000 gallons	$ 7.12

Connection Charge: (tap-on fee)

Laurel Mountain Estates	$ 0.00
All others	$500.00

WATER AND SEWER – RATE INCREASE

APPENDIX A-4
PAGE 2 OF 4

Irrigation Meter Installation:	Actual Cost
New Meter Charge:	Actual Cost
New Water Customer Charge:	$ 27.00
Meter Testing Fee: 1/	$ 20.00

Reconnection Charge:

If water service cut off by utility for good cause	$ 27.00
If service discontinued at customer's request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.)

SEWER UTILITY SERVICE

Monthly Sewer Rates:

Residential:

Collection charge, per dwelling unit	$ 17.19
Treatment charge, per dwelling unit	$ 38.50
Total monthly flat rate, per dwelling unit	$ 55.69

Commercial and Other:

Minimum monthly collection and treatment charge	$ 55.69
Monthly collection and treatment charge for customers who do not take water service (per single family equivalent)	$ 55.69
Treatment charge, per dwelling unit	
Small (less than 2,500 gallons per month)	$ 52.50
Medium (2,500 to 10,000 gallons per month)	$105.00
Large (over 10,000 gallons per month)	$165.00

APPENDIX A-4
PAGE 3 OF 4

(Note: All treatment charges are Town of Lake Lure Charges. The treatment charges shown above are the Town of Lake Lure's inside rates and outside users are charged double the inside rates. Classification of user is determined by the Town of Lake Lure.)

Collection Charge, per 1,000 gallons	$ 12.18

WATER AND SEWER – RATE INCREASE

Connection Charge: (tap-on fee)	$550.00
New Sewer Customer Charge:	$ 27.00

(If customer also receives water service, this charge will be waived)

Reconnection Charge:

If sewer service is cut off by utility for good cause, the actual cost of disconnection and reconnection will be charged.

The utility will itemize the estimated cost of disconnecting and reconnecting service and will furnish the estimate to customer with the cut-off notice.

This charge will be waived if customer also receives water service from CWS Systems, Inc.

Customers who ask to be reconnected within nine months of disconnection will be charged the monthly flat rate for the service period they were disconnected.

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

APPENDIX A-4
PAGE 4 OF 4

NOTE:

1/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 91, on this the 24th day of February, 2016.

SCHEDULE OF RATES

for

CWS SYSTEMS, INC.

for providing water and sewer utility service

in

FAIRFIELD SAPPHIRE VALLEY SERVICE AREA

Jackson and Transylvania Counties, North Carolina

WATER UTILITY SERVICE

Monthly Metered Water Rates:

A. Base charge, zero usage	
Residential	$ 19.95
Commercial and Other:	
5/8" meter	$ 19.95
3/4" meter	$ 29.93
1" meter	$ 49.88
1.5" meter	$ 99.76
2" meter	$159.62
3" meter	$299.30
4" meter	$498.75
6" meter	$997.50
B. Usage charge, per 1,000 gallons	$ 9.20

Monthly Water Availability Rate: $ 9.10

APPENDIX A-5
PAGE 2 OF 6

Connection Charge: [1/]

All Areas Except Holly Forest XI, Holly Forest XIV, Holly Forest XV, Whisper Lake I, Whisper Lake II, Whisper Lake III, Deer Run, Lonesome Valley Phases I and II, and Chattooga Ridge
$ 0.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap-on-fee)

Holly Forest XI
$2,400.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap-on fee)

Holly Forest XIV
$ 250.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap-on fee)

Holly Forest XV
$ 500.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap-on fee)

Whisper Lake Phase I
$1,250.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap-on fee)

Whisper Lake Phases II and III
$2,450.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap-on fee)

Deer Run
$1,900.00 per tap (recoupment of capital fee)
$ 400.00 per tap (tap-on fee)

Lonesome Valley Phases I and II
$ 0.00 per tap (recoupment of capital fee)
$ 0.00 per tap (tap-on fee)

APPENDIX A-5
PAGE 3 OF 6

Chattooga Ridge
$ 0.00 per tap (recoupment of capital fee)
$ 0.00 per tap (tap-on fee)

WATER AND SEWER – RATE INCREASE

Irrigation Meter Installation:	Actual Cost
New Meter Charge:	Actual Cost
New Water Customer Charge:	$ 27.00
Meter Testing Fee: 2/	$ 20.00

Reconnection Charge:

If water service cut off by utility for good cause	$ 27.00
If service discontinued at customer's request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.)

SEWER UTILITY SERVICE

Monthly Sewer Rates:

Residential

Flat rate, per dwelling unit:	$ 35.60

(Dwelling unit shall exclude any unit which has not been sold, rented, or otherwise conveyed by the developer or contractor erecting the unit.)

Commercial and Other:

A. Minimum rate	$ 35.60
B. Customer who does not take water service (per single family equivalent)	$ 35.60

APPENDIX A-5
PAGE 4 OF 6

C. Base facility charge:

5/8" meter	$ 15.65
3/4" meter	$ 23.48
1" meter	$ 39.13
1.5" meter	$ 78.25
2" meter	$125.20
3" meter	$234.75
4" meter	$391.25
6" meter	$782.50

D. Usage charge, per 1,000 gallons	$ 7.90
Monthly Sewer Availability Rate:	$ 8.30

Connection Charge: 1/

WATER AND SEWER – RATE INCREASE

All Areas Except Holly Forest XIV, Holly Forest XV, Deer Run, and Lonesome Valley Phases I and II
$ 0.00 per tap (recoupment of capital fee)
$ 550.00 per tap (tap-on fee)

Holly Forest XIV
$1,650.00 per tap (recoupment of capital fee)
$ 550.00 per tap (tap-on fee)

Holly Forest XV
$ 475.00 per tap (recoupment of capital fee)
$ 550.00 per tap (tap-on fee)

Deer Run
$1,650.00 per tap (recoupment of capital fee)
$ 550.00 per tap (tap-on fee)

Lonesome Valley Phases I and II
$ 0.00 per tap (recoupment of capital fee)
$ 0.00 per tap (tap-on fee)

New Sewer Customer Charge: $ 27.00
(If customer also receives water service, this charge will be waived.)

Reconnection Charge:
If sewer service is cut off by utility for good cause, the actual cost of disconnection and reconnection will be charged.

The utility will itemize the estimated cost of disconnecting and reconnecting service and will furnish the estimate to customer with the cut-off notice.

This charge will be waived if customer also receives water service from CWS Systems, Inc.

Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service period they were disconnected.

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears. Availability billings semiannually in advance.

Finance Charge for Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

NOTES:

1/ The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap-on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the Company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the Company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

2/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 91, on this the _24th_ day of __February_, 2016.

SCHEDULE OF RATES

for

CWS SYSTEMS, INC.

for providing water and sewer utility service

in

FAIRFIELD HARBOUR SERVICE AREA

Craven County, North Carolina

WATER AND SEWER – RATE INCREASE

WATER UTILITY SERVICE

Monthly Metered Water Rates:

A. Base charge, zero usage	
Residential	$ 9.75
Commercial and Other:	
5/8" meter	$ 9.75
3/4" meter	$ 14.63
1" meter	$ 24.33
1.5" meter	$ 48.67
2" meter	$ 77.88
3" meter	$146.25
4" meter	$243.75
6" meter	$487.50
B. Usage charge, per 1,000 gallons	$ 2.69

Monthly Water Availability Rate: $ 3.29

Connection Charge: 1/

All Areas Except Harbor Pointe II Subdivision

$ 335.00 per tap (recoupment of capital fee)

$ 140.00 per tap (tap-on fee)

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

$ 650.00 per tap (recoupment of capital fee)

$ 320.00 per tap (tap-on fee)

Irrigation Meter Installation:	Actual Cost
New Meter Charge:	Actual Cost
New Water Customer Charge:	$ 27.00
Meter Testing Fee: 2/	$ 20.00

Reconnection Charge:

If water service cut off by utility for good cause	$ 27.00
If service discontinued at customer's request	$ 27.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service periods they were disconnected.)

WATER AND SEWER – RATE INCREASE

SEWER UTILITY SERVICE

Monthly Sewer Rates:

Residential

Flat rate, per dwelling unit	$ 38.00

Commercial and Others:

A. Customers who do not take water service

Flat monthly rate	$ 38.00

B. Monthly Metered Rates:

Base charge, zero usage

5/8” meter	$ 10.20
3/4” meter	$ 15.30
1” meter	$ 25.50
1.5” meter	$ 51.00
2” meter	$ 81.60
3” meter	$153.00
4” meter	$255.00
6” meter	$510.00

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PAGE 3 OF 4

C. Usage charge, per 1,000 gallons	$ 5.65
Monthly Sewer Availability Rate:	$ 2.65

Connection Charge: [1/]

All Areas Except Harbor Pointe II Subdivision

$ 735.00 per tap (recoupment of capital fee)
$ 140.00 per tap (tap-on fee)

Harbor Pointe Subdivision and any area where mains have been installed after July 24, 1989

$2,215.00 per tap (recoupment of capital fee)
$ 310.00 per tap (tap-on fee)

New Sewer Customer Charge: $ 27.00
(If customer also receives water service, this charge will be waived.)

Reconnection Charge:

If sewer service is cut off by utility for good cause, the actual cost of disconnection and reconnection will be charged.

The utility will itemize the estimated cost of disconnecting and reconnecting service and will furnish the estimate to customer with the cut-off notice.

This charge will be waived if customer also receives water service from CWS Systems, Inc.

Customers who ask to be reconnected within nine months of disconnection will be charged the base monthly charge for zero usage for the service period they were disconnected.

APPENDIX A-6
PAGE 4 OF 4

Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears. Availability billings semiannually in advance.
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

NOTES:

1/ The recoupment of capital portion of the connection charges shall be due and payable at such time as the main water and sewer lines are installed in front of each lot, and the tap-on fee for water and sewer shall be payable upon request by the owner of each lot to be connected to the water and sewer lines. With written consent of the company, payment of the recoupment capital portion of the connection charge may be made payable over five-year period following the installation of the water and sewer mains in front of each lot, payment to be made in such a manner and in such installments as agreed upon between lot owner and the company, together with interest on the balance of the unpaid recoupment of capital fee from said time until payment in full at the rate of 6% per annum.

2/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 91, on this the _24th_ day of _February_______, 2016.

APPENDIX B-1
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 91

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
CWS Systems, Inc., 5701 Westpark Drive, Suite 101, Charlotte, North Carolina 28217, for Authority to Adjust and Increase its Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina	)	**NOTICE TO CUSTOMERS**

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc. (CWSS) to increase rates for water utility service for the **Wake, Durham, Franklin, and Nash County systems including the Former Clearwater Systems**. The new approved rates are as follows:

WATER RATES AND CHARGES

A. Base charge per month, zero usage	
5/8” meter	$ 16.30
1” meter	$ 40.75
1.5” meter	$ 81.50
2” meter	$130.40
3” meter	$244.56
4” meter	$407.58
6” meter	$815.00
B. Usage charge, per 1,000 gallons	$ 4.51
Monthly Flat Water Rate:	
(Per residence or single family equivalent)	$ 37.25

EFFECT OF RATES:

The new rates will increase the average monthly residential water bill from $33.60 to $35.88 (approximately 6.79%), based on an average usage of 4,342 gallons.

APPENDIX B-1
PAGE 2 OF 2

RATE ADJUSTMENT MECHANISM:

The Commission has approved CWSS' request, pursuant to G.S. 62-133.12, for authority to implement a water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism. CWSS may, under rules of the Commission, initially apply for a semiannual rate surcharge in February 2016, to become effective April 1, 2016. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-778 Sub 91".

ISSUED BY ORDER OF THE COMMISSION.
This the _24th_ day of __February_________, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

APPENDIX B-2
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 91

In the Matter of		
CWS Systems, Inc., 5701 Westpark Drive,	)	
Suite 101, Charlotte, North Carolina 28217, for	)	
Authority to Adjust and Increase its Rates for	)	**NOTICE TO CUSTOMERS**
Water and Sewer Utility Service in All of its	)	
Service Areas in North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc. (CWSS) to increase rates for water utility service for the **Treasure Cove water system in New Hanover County**. The approved rates are as follows:

WATER AND SEWER – RATE INCREASE

WATER RATES AND CHARGES

Monthly Metered Water Rates:

Base charge, zero usage	$ 14.53
Usage charge, per 1,000 gallons	$ 1.90

EFFECT OF RATES:

The new rates will increase the average monthly residential water bill from $19.57 to $24.05 (approximately 22.89%), based on an average usage of 5,008 gallons.

RATE ADJUSTMENT MECHANISM:

The Commission has approved CWSS' request, pursuant to G.S. 62-133.12, for authority to implement a water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism. CWSS may, under rules of the Commission, initially apply for a semiannual rate surcharge in February 2016, to become effective April 1, 2016. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system

APPENDIX B-2
PAGE 2 OF 2

improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-778 Sub 91".

ISSUED BY ORDER OF THE COMMISSION.
This the _24th_ day of _February__, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

APPENDIX B-3
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 91

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
CWS Systems, Inc., 5701 Westpark Drive,	)	
Suite 101, Charlotte, North Carolina 28217, for	)	
Authority to Adjust and Increase its Rates for	)	**NOTICE TO CUSTOMERS**
Water and Sewer Utility Service in All of its	)	
Service Areas in North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc. (CWSS) to increase rates for water utility service for the **Forest Hills water system in Jackson County**. The new approved rates are as follows:

WATER RATES AND CHARGES

Monthly Metered Water Rates:

A. Base charge, zero usage	
Residential	$ 22.50
Commercial and Other:	
5/8” meter	$ 22.50
3/4” meter	$ 33.76
1” meter	$ 56.25
1.5” meter	$ 112.50
2” meter	$ 180.00
3” meter	$ 337.50
4” meter	$ 562.50
6” meter	$1,125.00
B. Usage charge, per 1,000 gallons	$ 5.25

APPENDIX B-3
PAGE 2 OF 2

EFFECT OF RATES:

The proposed new rates will increase the average monthly residential water bill from \$34.60 to \$40.38 (approximately 16.71%), based on an average usage of 3,405 gallons.

RATE ADJUSTMENT MECHANISM:

The Commission has approved CWSS' request, pursuant to G.S. 62-133.12, for authority to implement a water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism. CWSS may, under rules of the Commission, initially apply for a semiannual rate surcharge in February 2016, to become effective April 1, 2016. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-778 Sub 91".

ISSUED BY ORDER OF THE COMMISSION.
This the _24th_ day of __February_____, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

APPENDIX B-4
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 91

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of CWS Systems, Inc., 5701 Westpark Drive, Suite 101, Charlotte, North Carolina 28217, for Authority to Adjust and Increase its Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina	)	**NOTICE TO CUSTOMERS**

WATER AND SEWER – RATE INCREASE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc. (CWSS) to increase rates for water and sewer utility service for the **Fairfield Mountains service area in Rutherford County**. The approved rates are as follows:

FAIRFIELD MOUNTAINS (water and sewer)
HIGHLAND SHORES (water and sewer)
LAUREL MOUNTAIN ESTATES (water only)

WATER RATES AND CHARGES

Monthly Metered Water Rates:

A. Base charge, zero usage	
Residential	$ 19.28
Commercial and Other:	
5/8" meter	$ 19.28
3/4" meter	$ 28.92
1" meter	$ 48.20
1.5" meter	$ 96.40
2" meter	$154.25
3" meter	$289.20
4" meter	$482.00
6" meter	$964.00
B. Usage charge, per 1,000 gallons	$ 7.12

SEWER RATES AND CHARGES

Monthly Sewer Rates:

Residential:	
Collection charge, per dwelling unit	$ 17.19
Treatment charge, per dwelling unit	$ 38.50
Total monthly flat rate, per dwelling unit	$ 55.69
Commercial and Other:	
Minimum monthly collection and treatment charge	$ 55.69
Monthly collection and treatment charge for customers who do not take water service (per single family equivalent)	$ 55.69
Treatment charge,* per dwelling unit	
Small (less than 2,500 gallons per month)	$ 52.50
Medium (2,500 to 10,000 gallons per month)	$105.00
Large (over 10,000 gallons per month)	$165.00

WATER AND SEWER – RATE INCREASE

*All treatment charges are Town of Lake Lure Charges. The treatment charges shown above are the Town of Lake Lure's inside rates and outside users are charged double the inside rates. Classification of user is determined by the Town of Lake Lure.

Collection charge, per 1,000 gallons	$ 12.18

EFFECT OF RATES:

The new water rates will increase the average monthly residential water bill from $35.83 to $36.65 (approximately 2.29%), based on an average usage of 2,440 gallons. The new sewer rates will increase the average monthly flat sewer bill from $49.07 to $55.69 (approximately 13.49%).

RATE ADJUSTMENT MECHANISM:

The Commission has approved CWSS' request, pursuant to G.S. 62-133.12, for authority to implement a water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism. CWSS may, under rules of the Commission, initially apply for a semiannual rate surcharge in February 2016, to become effective April 1, 2016. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-778 Sub 91".

ISSUED BY ORDER OF THE COMMISSION.
This the _24th_ day of __February___, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

APPENDIX B-5
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 91

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
CWS Systems, Inc., 5701 Westpark Drive,	)	
Suite 101, Charlotte, North Carolina 28217, for	)	
Authority to Adjust and Increase its Rates for	)	**NOTICE TO CUSTOMERS**
Water and Sewer Utility Service in All of its	)	
Service Areas in North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc. (CWSS) to increase rates for water and sewer utility service for the **Fairfield Sapphire Valley service area in Jackson and Transylvania Counties**. The approved rates are as follows:

WATER RATES AND CHARGES

Monthly Metered Water Rates:	
A. Base charge, zero usage	
Residential	$ 19.95
Commercial and Other	
5/8” meter	$ 19.95
3/4” meter	$ 29.93
1” meter	$ 49.88
1.5” meter	$ 99.76
2” meter	$159.62
3” meter	$299.30
4” meter	$498.75
6” meter	$997.50
B. Usage charge, per 1,000 gallons	$ 9.20
Monthly Water Availability Rate	$ 9.10

APPENDIX B-5
PAGE 2 OF 3

SEWER RATES AND CHARGES

Monthly Sewer Rates:	
Residential	
Flat rate, per dwelling unit	$ 35.60
Commercial and Other:	
A. Minimum monthly collection and treatment charge	$ 35.60
B. Monthly collection and treatment charge for customers who do not take water service (per single family equivalent)	$ 35.60
C. Base facilities charge:	
5/8" meter	$ 15.65
3/4" meter	$ 23.48
1" meter	$ 39.13
1.5" meter	$ 78.25
2" meter	$125.20
3" meter	$234.75
4" meter	$391.25
6" meter	$782.50
D. Usage charge, per 1,000 gallons	$ 7.90
Monthly Sewer Availability Rate	$ 8.30

EFFECT OF RATES:

The new water rates will increase the average monthly residential water bill from $34.96 to $40.18 (approximately 14.93%), based on an average usage of 2,199 gallons. The new sewer rates will decrease the monthly flat sewer bill from $39.56 to $35.60 (approximately -10.01%).

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RATE ADJUSTMENT MECHANISM:

The Commission has approved CWSS' request, pursuant to G.S. 62-133.12, for authority to implement a water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism. CWSS may, under rules of the Commission, initially apply for a semiannual rate surcharge in February 2016, to become effective April 1, 2016. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-778 Sub 91".

ISSUED BY ORDER OF THE COMMISSION.
This the _24th_ day of _February_____, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 91

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
CWS Systems, Inc., 5701 Westpark Drive, Suite 101, Charlotte, North Carolina 28217, for Authority to Adjust and Increase its Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina)

NOTICE TO CUSTOMERS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc. (CWSS) to increase rates for water and sewer utility service for the **Fairfield Harbour service area in Craven County**. The approved rates are as follows:

WATER RATES AND CHARGES

Monthly Metered Water Rates:

A. Base charge, zero usage	
Residential	$ 9.75
Commercial and Other:	
5/8" meter	$ 9.75
3/4" meter	$ 14.63
1" meter	$ 24.33
1.5" meter	$ 48.67
2" meter	$ 77.88

3” meter	$146.25
4” meter	$243.75
6” meter	$487.50
B. Usage charge, per 1,000 gallons	$ 2.69
Monthly Water Availability Rate	$ 3.29

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SEWER RATES AND CHARGES

Monthly Sewer Rates:	
Residential	
Flat rate, per dwelling unit	$ 38.00
Commercial and Other:	
A. Customers who do not take water service (Flat rate)	$ 38.00
B. Monthly Metered Rate:	
Base charge, zero usage	
5/8” meter	$ 10.20
3/4” meter	$ 15.30
1” meter	$ 25.50
1.5” meter	$ 51.00
2” meter	$ 81.60
3” meter	$153.00
4” meter	$255.00
6” meter	$510.00
C. Usage charge, per 1,000 gallons	$ 5.65
Monthly Sewer Availability Rate	$ 2.65

EFFECT OF RATES:

The new water rates will increase the average monthly residential water bill from $18.54 to $20.30 (approximately 9.49%), based on an average usage of 3,922 gallons. The new sewer rates will increase the flat monthly sewer bill from $34.50 to $38.00 (approximately 10.14%).

RATE ADJUSTMENT MECHANISM:

The Commission has approved CWSS’ request, pursuant to G.S. 62-133.12, for authority to implement a water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism. CWSS may, under rules of the Commission, initially apply for a rate surcharge in February 2016, to become effective April 1, 2016. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions.

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Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-778 Sub 91".

ISSUED BY ORDER OF THE COMMISSION.
This the _24th_ day of __February___, 2016.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-778, Sub 91 and the Notice to Customers was mailed or hand delivered by the date specified in the Order.

This the ___ day of ____________________, 2016.

By: ____________________________________
Signature

____
Name of Utility Company

The above named Applicant, ________________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-778, Sub 91.

Witness my hand and notarial seal, this the ___ day of _______________, 2016.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ____________________________________
Date

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SMALL POWER PRODUCERS – Certificate

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Jackie Farm, LLC	SP-6235, SUB 0	(04/08/2016)
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Ridgeback Solar, LLC	SP-8046, SUB 0	(11/09/2016)

Allen Solar Farm, LLC -- SP-3413, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (02/03/2016)

Arthur Solar 2, LLC -- SP-7189, SUB 0; Recommended Order Granting Certificate (05/04/2016)

Calypso Farm, LLC -- SP-3716, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (10/20/2016)

Calypso Solar LLC -- SP-2042, SUB 1; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (10/20/2016)

Carolina Solar Energy II, LLC -- SP-2363,

SUB 17; Order Allowing Withdrawal of Application, Cancelling CPCN, and Closing Docket (07/12/2016)

SUB 25; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (04/08/2016)

SMALL POWER PRODUCERS – Certificate *(Continued)*

Chatham Park Solar Farm, LLC -- SP-1743, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (09/29/2016)

Columbo Farm, LLC -- SP-3830, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (09/29/2016)

Depriest Solar, LLC -- SP-5258, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (08/17/2016)

Dowtin Farm, LLC -- SP-4765, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (09/29/2016)

Fresh Air Energy II, LLC -- SP-2665, SUB 35; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (06/30/2016)

Hicone Solar, LLC -- SP-5266, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (08/17/2016)

Main Street Eden Solar, LLC -- SP-8062, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (08/17/2016)

Peanut Market Farm Solar, LLC -- SP-4342, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Registration, and Closing Docket (09/13/2016)

St. Andrews Solar Farm, LLC -- SP-3488, SUB 0; SP-3488, SUB 1; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (08/17/2016)

Stephenson Farm Solar, LLC -- SP-4343, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Registration, and Closing Docket (09/13/2016)

Wildcat Solar Farm, LLC -- SP-5343, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (02/03/2016)

510 REPP Two, LLC SP-805, SUB 1; SP-3954, SUB 0; SP-4176, SUB 1; SP-4872, SUB 0; SP-4872, SUB 1; SP-4984 SUB 0; SP-5329, SUB 0; SP-5443, SUB 0; SP-5445, SUB 0; SP-5942, SUB 0; E-100, SUB 142; Order Dismissing Without Prejudice Applications for Certificates of Public Convenience and Necessity (12/16/2016)

ORDER ISSUING CERTIFICATE

Orders Issued

Company	Docket No.	Date
Benson Solar Farm, LLC	SP-7068, SUB 0	(02/24/2016)
BRE NC SOLAR 2, LLC	SP-7095, SUB 0	(01/20/2016)
BRE NC SOLAR 4, LLC	SP-7097, SUB 0	(01/20/2016)
Chestnut Solar LLC	SP-5436, SUB 0	(10/31/2016)
Davis Lane Solar, LLC	SP-7139, SUB 0	(03/22/2016)
Enerparc Inc.	SP-6372, SUB 0	(01/05/2016)
	SP-6372, SUB 1	(01/06/2016)

ORDERS AND DECISIONS LISTED

ORDER ISSUING CERTIFICATE
Orders Issued *(Continued)*

Company	Docket No.	Date
Harrison Solar, LLC	SP-7012, SUB 0	(01/06/2016)
Hayes Solar, LLC	SP-7011, SUB 0	(01/06/2016)
HORUS North Carolina 2, LLC	SP-7168, SUB 0	(02/24/2016)
HORUS North Carolina 8, LLC	SP-7384, SUB 0	(08/10/2016)
Jackson Solar, LLC	SP-7010, SUB 0	(01/06/2016)
John Quincy Solar, LLC	SP-7014, SUB 0	(01/06/2016)
Lane Solar Farm II, LLC	SP-6936, SUB 0	(02/24/2016)
Monroe Solar, LLC	SP-7009, SUB 0	(01/06/2016)
Ruff Solar, LLC	SP-5754, SUB 0	(10/04/2016)
Sun Farm V, LLC	SP-8113, SUB 0	(10/31/2016)
Sun Farm VI, LLC	SP-8114, SUB 0	(10/18/2016)
Sun Farm X, LLC	SP-8115, SUB 0	(10/18/2016)
Sybac Solar, LLC	SP-8199, SUB 0	(12/13/2016)
	SP-8199, SUB 1	(10/18/2016)
Van Buren Solar, LLC	SP-7013, SUB 0	(01/05/2016)

Arthur Solar, LLC -- SP-5576, SUB 0; Order Issuing Amended Certificate (04/12/2016)
Auten Road Farm, LLC -- SP-3173, SUB 0; Order Issuing Amended Certificate (04/12/2016)
Barnhill Road Solar, LLC -- SP-5081, SUB 0; Order Issuing Amended Certificate (10/04/2016)
Bizzell Church Solar 1, LLC -- SP-4394, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration Statement (04/08/2016)
Bladen Solar, LLC -- SP-5220, SUB 0; Order Issuing Amended Certificate (08/16/2016)
Colonial Eagle Solar, LLC -- SP-4305, SUB 3; Order Amending Certificate of Public Convenience and Necessity and Registration (05/04/2016)
Hardison Farm Solar, LLC -- SP-4340, SUB 0; Order Issuing Amended Certificate (04/05/2016)
HXNAir Solar One, LLC -- SP-3286, SUB 0; Order Issuing Amended Certificate (04/26/2016)
Innovative Solar 31, LLC -- SP-3474, SUB 0; Order Issuing Amended Certificate (05/09/2016)
Innovative Solar 42, LLC -- SP-3477, SUB 0; Order Issuing Amended Certificate (05/23/2016)
Moore Solar, LLC -- SP-4081, SUB 0; Order Issuing Amended Certificate (07/11/2016)
Nickelson Solar 2, LLC -- SP-5523, SUB 0; Order Issuing Amended Certificate (04/12/2016)
St. Pauls Solar 2, LLC -- SP-4397, SUB 0; Order Issuing Amended Certificate (06/07/2016)
Sunbury McCoy Lane Solar, LLC -- SP-3353, SUB 0; Order Amending Certificate of Public Convenience and Necessity (07/21/2016)
Trinity Solar, LLC -- SP-5637, SUB 0; Order Issuing Amended Certificate (04/26/2016)

ORDERS AND DECISIONS LISTED

<u>SMALL POWER PRODUCERS -- Filings Due Per Order</u>

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

<u>Orders Issued</u>

Company	Docket No.	Date
Airlie Solar Farm, LLC	SP-6696, SUB 0	(09/12/2016)
Apple, Inc.	SP-1642, SUB 4	(03/09/2016)
Arthur Solar 2, LLC	SP-7189, SUB 0	(05/20/2016)
Asheville Alternative Energy, LLC	SP-895, SUB 1	(01/04/2016)
Atkinson Solar II, LLC	SP-7214, SUB 0	(01/11/2016)
Bear Creek Solar, LLC	SP-6309, SUB 0	(05/27/2016)
Bowland; Todd	SP-7379, SUB 0	(01/11/2016)
Boylston Solar, LLC	SP-7927, SUB 0	(09/12/2016)
BRE NC Solar 2, LLC	SP-7095, SUB 1	(04/13/2016)
BRE NC Solar 3, LLC	SP-6512, SUB 1	(05/05/2016)
BRE NC Solar 4, LLC	SP-7097, SUB 1	(03/09/2016)
Carnation Solar, LLC	SP-6051, SUB 0	(01/11/2016)
Carolina Poultry Power RG1, LLC	SP-7904, SUB 0	(12/22/2016)
Changeup Solar, LLC	SP-8598, SUB 0	(12/02/2016)
Charlotte Latin Schools, Inc.	SP-6994, SUB 0	(02/19/2016)
City of Charlotte	SP-1454, SUB 4	(07/27/2016)
Conetoe II Solar, LLC	SP-4483, SUB 0	(08/29/2016)
Enerparc, Inc.	SP-6372, SUB 0	(02/12/2016)
	SP-6372, SUB 4	(02/12/2016)
Facile Solar, LLC	SP-6058, SUB 0	(05/10/2016)
Faraday Farm, LLC	SP-8603, SUB 0	(12/02/2016)
Farm Credit Leasing Corporation	SP-7731, SUB 0	(05/24/2016)
Freedom Solar, LLC	SP-8023, SUB 0	(09/12/2016)
Greensboro Ecosystems, LLC	SP-7687, SUB 0	(07/29/2016)
Hardwick; Michael Dewayne	SP-8009, SUB 0	(07/06/2016)
Harrison Solar, LLC	SP-7012, SUB 0	(01/11/2016)
Hart; Robert	SP-2762, SUB 0	(01/04/2016)
Hayes Solar, LLC	SP-7011, SUB 0	(01/11/2016)
HCE Columbus I, LLC	SP-7126, SUB 0	(06/07/2016)
Hopewell Friends Solar, LLC	SP-7689, SUB 0	(05/03/2016)
Hopkins Solar, LLC	SP-7718, SUB 0	(05/17/2016)
HORUS North Carolina 6, LLC	SP-7216, SUB 0	(02/16/2016)

SMALL POWER PRODUCERS -- Filings Due Per Order *(Continued)*

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
HORUS North Carolina 7, LLC	SP-7394, SUB 0	(02/19/2016)
HORUS North Carolina 8, LLC	SP-7384, SUB 0	(02/16/2016)
Hwy 97 Solar, LLC	SP-7984, SUB 0	(09/12/2016)
Innovative Solar 18, LLC	SP-2698, SUB 0	(02/05/2016)
Innovative Solar 49, LLC	SP-5375, SUB 0	(05/27/2016)
Jackson Solar, LLC	SP-7010, SUB 0	(01/11/2016)
Jordan Solar, LLC	SP-5057, SUB 0	(03/14/2016)
Kluthe; Daniel W.	SP-5190, SUB 0	(02/22/2016)
Lucky Clays Farming and Forestry, LLC	SP-7200, SUB 0	(01/11/2016)
Member EMC Solar One, LLC	SP-4801, SUB 0	(02/04/2016)
	SP-4801, SUB 1	(02/16/2016)
	SP-4801, SUB 2	(11/18/2016)
	SP-4801, SUB 3	(02/04/2016)
Monroe Solar, LLC	SP-7009, SUB 0	(01/11/2016)
New Hope Solar, LLC	SP-7988, SUB 0	(09/12/2016)
Page Solar Farm, LLC	SP-6533, SUB 0	(02/10/2016)
Park Springs Solar, LLC	SP-8489, SUB 0	(11/18/2016)
Parker Solar Farm, LLC	SP-8583, SUB 0	(12/02/2016)
Penny Hill Solar, LLC	SP-7006, SUB 0	(01/04/2016)
Perkins Solar, LLC	SP-6846, SUB 0	(04/13/2016)
Prestage AgEnergy of North Carolina, LLC	SP-1874, SUB 0	(01/04/2016)
Princeville Solar, LLC	SP-7986, SUB 0	(09/12/2016)
Quincy; John, LLC	SP-7014, SUB 0	(01/11/2016)
Rubinow; David	SP-5701, SUB 0	(06/03/2016)
Seven Bridges Solar, LLC	SP-7964, SUB 0	(09/12/2016)
Sharpsburg Solar, LLC	SP-7985, SUB 0	(09/12/2016)
South Tarboro Solar, LLC	SP-7987, SUB 0	(09/12/2016)
Taft Farm, LLC	SP-8517, SUB 0	(11/18/2016)
Thanksgiving Fire Solar Farm, LLC	SP-8105, SUB 0	(09/23/2016)
Upper Piedmont Renewables, LLC	SP-5002, SUB 0	(01/11/2016)
URENEW Solar, LLC	SP-1757, SUB 2	(07/26/2016)
Van Buren Solar, LLC	SP-7013, SUB 0	(01/11/2016)
Violet Solar, LLC	SP-5819, SUB 0	(01/11/2016)
Viper Solar, LLC	SP-7007, SUB 0	(03/09/2016)
Washington Airport Solar, LLC	SP-3177, SUB 0	(05/16/2016)
Washington Solar, LLC	SP-6053, SUB 0	(01/11/2016)
Whiteville Solar 2, LLC	SP-7190, SUB 0	(05/20/2016)
02 emc, LLC	SP-7074, SUB 1	(08/30/2016)

<u>**SMALL POWER PRODUCERS -- Filings Due Per Order**</u> *(Continued)*

Achilles Farm, LLC -- SP-4563, SUB 0; Order Issuing Amended Certificate (06/21/2016)

Asheville Alternative Energy, LLC – SP-5573, SUB 0; Order Cancelling Registration and Closing Docket (07/13/2016)

Bacon Solar, LLC -- SP-5260, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (10/20/2016)

Bayles Farms Solar, LLC -- SP-5268, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (10/20/2016)

Bioenergy Technologies of Berkeley County, LLC -- SP-6247, SUB 0; Order Cancelling Registration and Closing Docket (03/10/2016)

Blackberry Creek Family Partners, LLC -- SP-4843, SUB 0; Order Cancelling Registration and Closing Docket (08/02/2016)

Brooke Solar, LLC -- SP-5041, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration (10/19/2016)

C M Wilson, Inc. -- SP-1487, SUB 0; Order Accepting Amended Registration of New Renewable Energy Facility (04/13/2016)

California Dairy Energy 14, LLC -- SP-5016, SUB 0; Order Accepting Amended Registration of New Renewable Energy Facility (03/15/2016)

California Energy Dairy #1 -- SP-3714, SUB 0; Order Accepting Amended Registration of New Renewable Energy Facility (07/25/2016); (12/21/2016)

Carl Friedrich Gauss Solar LLC -- SP-4824, SUB 0; Order Issuing Amended Certificate (10/18/2016)

Carter Solar, LLC -- SP-5075, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration (10/19/2016)

Cottonwood Solar, LLC -- SP-3614, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration (11/09/2016)

CREE, Inc. -- SP-4597, SUB 0; Order Cancelling Registration and Closing Docket (10/26/2016)

Creech Solar 2, LLC -- SP-4450, SUB 0; Order Issuing Amended Certificate (09/27/2016)

Cremer; Paul & Claudine -- SP-3034, SUB 0; Order Cancelling Registration and Closing Docket (09/19/2016)

Enerparc, Inc. -- SP-6372, SUB 2; Order Accepting Registration of New Renewable Energy Facility (02/12/2016)

ESA Goldsboro NC, LLC -- SP-5174, SUB 0; Order Allowing Withdrawal of Report of Proposed Construction and Registration and Closing Docket (03/01/2016)

ESA Goldsboro NC Phase 2, LLC -- SP-5254, SUB 0; Order Allowing Withdrawal of Report of Proposed Construction and Registration and Closing Docket (03/01/2016)

Fresh Air Energy II, LLC -- SP-2665,

SUB 2; SP-3556, SUB 0; Order Clarifying Record and Closing Docket (11/18/2016)

SUB 38; SP-8766, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Registration (12/07/2016)

Garland Farm, LLC -- SP-3656, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (10/20/2016)

Greenville Farm 2, LLC -- SP-2894, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (09/29/2016)

<u>**SMALL POWER PRODUCERS -- Filings Due Per Order**</u> *(Continued)*

Guernsey Holdings, LLC -- SP-3795, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Registration and Closing Docket (03/03/2016)

HCE Columbus I, LLC -- SP-7126, SUB 0; Recommended Order Granting Certificate (05/20/2016)

Hector Farm, LLC -- SP-4194, SUB 0; Order Issuing Amended Certificate (10/10/2016)

Henry Farm, LLC -- SP-5253, SUB 0; Order Issuing Amended Certificate (10/18/2016)

Holger Holdings, LLC -- SP-3655, SUB 0; Order Allowing Withdrawal of Application and Registration, Cancelling CPCN and Closing Docket (02/16/2016)

Hoosier Hydroelectric, Inc. -- SP-311, SUB 0; SP-2483, SUB 0; Order Cancelling Registration and Closing Dockets (10/13/2016)

Innovative Solar 33, LLC -- SP-3615, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (10/20/2016)

Innovative Solar 37, LLC -- SP-3617, SUB 0; Order Issuing Amended Certificate (10/04/2016)

Innovative Solar 38, LLC -- SP-3618, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (10/20/2016)

Innovative Solar 47, LLC -- SP-3621, SUB 0; Order Issuing Amended Certificate (09/06/2016)

Innovative Solar 56, LLC -- SP-5907, SUB 0; Order Allowing Withdrawal of Application, Cancelling Registration and Closing Docket (10/20/2016)

Innovative Solar 73, LLC -- SP-5471, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (10/20/2016)

Innovative Solar 79, LLC -- SP-5472, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (10/20/2016)

Jersey Holdings LLC -- SP-7017,

SUB 0; Order Allowing Withdrawal of Report of Proposed Construction and Registration and Closing Docket (05/04/2016)

SUB 1; Order Issuing Amended Certificate of Public Convenience and Necessity (11/14/2016)

Jewels Realty Investment, LLC -- SP-631, SUB 7; Order Cancelling Registration and Closing Docket (07/13/2016)

Johnson Breeders, Inc. SP-3253, SUB 1; Order Accepting Amended Registration of New Renewable Energy Facility (07/12/2016)

Jordan Solar, LLC -- SP-5057, SUB 0; Recommended Order Granting Certificate (02/11/2016)

KapStone Kraft Paper Corporation -- SP-3419, SUB 0; Order Accepting Registration of New Renewable Energy Facility and Denying Request for Waiver of Commission Rule R8-67(h)(4) (02/01/2016)

Kublickis; Peter & Judith Cestaro -- SP-595, SUB 0; Order Cancelling Registration and Closing Docket (10/21/2016)

Longhorn Holdings, LLC -- SP-3336, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (03/23/2016)

Main Street Solar, LLC -- SP-5249, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (10/20/2016)

<u>SMALL POWER PRODUCERS -- Filings Due Per Order</u> *(Continued)*

Matthews Solar Farm, LLC -- SP-6045, SUB 0; Order Amend. Certificate of Public Convenience and Necessity and Accepting Amend. Registration of New Renewable Energy Facility (08/22/2016)

McBride Place Energy, LLC -- SP-3096, SUB 0; Order Amending Certificate of Public Convenience and Necessity (12/16/2016)

Nashville Solar, LLC -- SP-4568, SUB 0; Order Cancelling Registration and Closing Docket (08/31/2016)

Old North State Solar, LLC -- SP-8219, SUB 0; SP-8616, SUB 0; Order Transferring Certificate of Public Convenience and Necessity (10/27/2016); Order Cancelling Registration of New Renewable Energy Facility and Accepting Registration of New Renewable Energy Facility (12/16/2016)

Pine Gate Holdings, LLC -- SP-3834, SUB 49; SP-8368, SUB 0: Errata Order (08/31/2016)

RESA 3 SOLAR, LLC -- SP-6228, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (10/20/2016)

Snow Hill Solar, LLC -- SP-2317, SUB 1; Order Cancelling Registration and Closing Docket (08/31/2016)

Spring Valley Farm, LLC -- SP-3931, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (09/29/2016)

Starr Farm, LLC -- SP-5816, SUB 0; Order Issuing Amended Certificate (10/18/2016)

Sunflower Solar LLC -- SP-5272, SUB 0; Order Issuing Amended Certificate and Accepting Registration of New Renewable Energy Facility (04/18/2016)

Trent River Farm, LLC -- SP-6374, SUB 0; Recommended Order Granting Certificate and Accepting Registration of New Renewable Energy Facility (10/17/2016); Order Allowing Recommended Order to Become Effective and Final (10/24/2016)

Triangle Realty Investment, LLC -- SP-630,
SUB 11; Order Cancelling Registration and Closing Docket (07/14/2016)
SUB 12; Order Cancelling Registration and Closing Docket (07/14/2016)

TWC Administration LLC -- SP-5136, SUB 0; Order Accepting Amended Registration of New Renewable Energy Facility (09/23/2016)

U. S. EcoGen Polk, LLC -- SP-7729, SUB 0; Order Accepting Registration of Renewable Energy Facility (10/13/2016)

W.E. Partners I, LLC -- SP-729, SUB 1; Order Accepting Amended Registration of New Renewable Energy Facility (10/13/2016)

Weldon Solar, LLC -- SP-3259, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (10/20/2016)

Weyerhaeuser NR Company -- SP-2285, SUB 0; SP-411, SUB 2; Order Cancelling Registrations, Closing Docket, and Accepting Registrations as a Renewable Energy Facility and as a New Renewable Energy Facility (12/02/2016)

Whitakers Farm, LLC -- SP-3147, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration (03/09/2016)

Whiteville Solar 2, LLC -- SP-7190, SUB 0; Recommended Order Granting Certificate (05/04/2016)

Wommack Farm, LLC -- SP-3025, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (09/29/2016)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS -- Filings Due Per Order *(Continued)*

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued

Company	Docket No.	Date
Aberdeen Farm, LLC	SP-8189, SUB 0	(09/27/2016)
Acme Solar, LLC	SP-8275, SUB 0	(10/25/2016)
Advanced Solar Power Holdings, Inc.	SP-6965, SUB 0	(08/31/2016)
AGA TAG Solar IV, LLC	SP-8421, SUB 0	(10/31/2016)
Airport Solar, LLC	SP-8361, SUB 0	(10/31/2016)
Alpha Value Solar, LLC	SP-8220, SUB 0	(10/26/2016)
Anjuna Solar, LLC	SP-7917, SUB 0	(09/19/2016)
Apple Pie Solar, LLC	SP-8263, SUB 0	(10/31/2016)
Armada Solar, LLC	SP-7922, SUB 0	(10/11/2016)
ATOOD Solar IV, LLC	SP-8420, SUB 0	(10/31/2016)
Badger Farm, LLC	SP-8230, SUB 0	(10/31/2016)
Badger Hill Solar, LLC	SP-8272, SUB 0	(10/18/2016)
Badger Solar, LLC	SP-8230, SUB 0	(10/31/2016)
Bakatsias Solar Farm, LLC	SP-7457, SUB 0	(09/06/2016)
Banner Solar, LLC	SP-7622, SUB 0	(06/21/2016)
Bay Branch Solar, LLC	SP-7800, SUB 0	(09/06/2016)
Bay Tree Solar, LLC	SP-7926, SUB 0	(09/06/2016)
Bayboro Solar Farm, LLC	SP-7436, SUB 0	(05/09/2016)
Bear Poplar Solar, LLC	SP-7781, SUB 0	(09/06/2016)
Beckwith Solar, LLC	SP-7918, SUB 0	(08/10/2016)
Black Bear Solar, LLC	SP-7817, SUB 0	(10/31/2016)
Bondi Solar, LLC	SP-7582, SUB 0	(04/18/2016)
Boston Farm, LLC	SP-7164, SUB 0	(01/06/2016)
Bradley Farm, LLC	SP-6426, SUB 0	(09/27/2016)
Brantley Farm Solar, LLC	SP-6532, SUB 0	(02/24/2016)
Breeden Solar, LLC	SP-8563, SUB 0	(12/13/2016)
Brewington Solar, LLC	SP-8205, SUB 0	(10/18/2016)
Brick City Solar, LLC	SP-8175, SUB 0	(10/04/2016)
Buchanan Farm, LLC	SP-8325, SUB 0	(10/31/2016)
Burgaw Solar, LLC	SP-8283, SUB 0	(10/26/2016)
Buttercup Solar, LLC	SP-8257, SUB 0	(10/25/2016)
C & C Solar	SP-8203, SUB 0	(10/31/2016)
C & S Solar, LLC	SP-5255, SUB 0	(02/24/2016)
Camel Solar, LLC	SP-8323, SUB 0	(10/31/2016)

SMALL POWER PRODUCERS -- Filings Due Per Order *(Continued)*

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Carolina Lily Solar, LLC	SP-8217, SUB 0	(10/18/2016)
Carolina Solar Energy II, LLC	SP-2363, SUB 26	(01/12/2016)
	SP-2363, SUB 27	(03/22/2016)
	SP-2363, SUB 28	(03/22/2016)
Cathcart Solar, LLC	SP-7919, SUB 0	(08/22/2016)
Catherine Lake Solar, LLC	SP-7931, SUB 0	(09/19/2016)
CB Bladen Solar II LLC	SP-8045, SUB 0	(11/07/2016)
Cell Tower Solar, LLC	SP-7665, SUB 0	(08/16/2016)
Centerville Church Solar, LLC	SP-5263, SUB 0	(09/06/2016)
Cherry Grove Solar, LLC	SP-5264, SUB 0	(09/06/2016)
Chester Lane Solar, LLC	SP-7882, SUB 0	(08/10/2016)
CL Solar, LLC	SP-8209, SUB 0	(10/18/2016)
Clarksbury Solar, LLC	SP-7797, SUB 0	(09/27/2016)
Clovelly Solar, LLC	SP-7623, SUB 0	(05/17/2016)
Coogee Solar, LLC	SP-7920, SUB 0	(09/19/2016)
Cookstown Solar Farm, LLC	SP-7853, SUB 0	(08/22/2016)
Cottontail Solar, LLC	SP-8268, SUB 0	(10/18/2016)
Country Club Solar, LLC	SP-7776, SUB 0	(09/27/2016)
County Home Solar, LLC	SP-4666, SUB 0	(08/31/2016)
Crooked Run Solar, LLC	SP-8061, SUB 0	(10/04/2016)
Cumberland Solar, LLC	SP-8316, SUB 0	(10/31/2016)
Deer Solar, LLC	SP-8300, SUB 0	(10/25/2016)
Delta Solar, LLC	SP-8280, SUB 0	(10/31/2016)
Eastway Solar, LLC	SP-7737, SUB 0	(08/31/2016)
Ebenezer Church Solar, LLC	SP-7801, SUB 0	(08/02/2016)
Eisenhower Farm, LLC	SP-8223, SUB 0	(10/25/2016)
Eisenhower Solar, LLC	SP-8285, SUB 0	(10/26/2016)
Elk Solar, LLC	SP-7465, SUB 0	(03/01/2016)
Ellisboro Solar, LLC	SP-7798, SUB 0	(08/16/2016)
Enerparc Inc.	SP-6372, SUB 3	(02/24/2016)
Ennis Solar, LLC	SP-8202, SUB 0	(10/18/2016)
Eros Solar, LLC	SP-8050, SUB 0	(10/04/2016)
ESA Albemarle NC, LLC	SP-7958, SUB 0	(09/19/2016)
ESA Boston Solar, LLC	SP-8242, SUB 0	(10/25/2016)
ESA Buies Creek, LLC	SP-8394, SUB 0	(10/31/2016)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS -- Filings Due Per Order *(Continued)*

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
ESA Goldsboro NC, LLC	SP-5174, SUB 1	(04/18/2016)
	SP-7487, SUB 0	
ESA Sherrills Ford, LLC	SP-7460, SUB 0	(04/05/2016)
	SP-7460, SUB 1	
ESA Solar Farm NC, LLC	SP-8469, SUB 0	(10/31/2016)
Eversfield Solar Farm, LLC	SP-8468, SUB 0	(11/29/2016)
Fair Bluff Solar, LLC	SP-8210, SUB 0	(10/11/2016)
Flatwood Farm, LLC	SP-8170, SUB 0	(09/27/2016)
Flying Squirrel Solar, LLC	SP-7640, SUB 0	(04/26/2016)
Fox Creek Farm Solar, LLC	SP-6050, SUB 0	(03/22/2016)
Fresh Air Energy II, LLC	SP-2665, SUB 36	(01/26/2016)
	SP-2665, SUB 38	(10/31/2016)
Fresh Air Energy XI, LLC	SP-3557, SUB 1	(10/18/2016)
Friesian Holdings, LLC	SP-8467, SUB 0	(11/07/2016)
Gamble Solar LLC	SP-8191, SUB 0	(10/04/2016)
Garfield Solar, LLC	SP-8294, SUB 0	(10/26/2016)
Gilead Farm, LLC	SP-7086, SUB 0	(01/20/2016)
Gladstone Farm, LLC	SP-7726, SUB 0	(05/23/2016)
Gray Fox Solar, LLC	SP-7635, SUB 0	(06/07/2016)
Grays Mill Solar, LLC	SP-8276, SUB 0	(10/26/2016)
Halifax Solar, LLC	SP-8224, SUB 0	(10/26/2016)
Hanover Solar, LLC	SP-7921, SUB 0	(08/22/2016)
Harding Solar, LLC	SP-7468, SUB 0	(03/01/2016)
HCE Columbus II, LLC	SP-7131, SUB 0	(04/18/2016)
HCE Moore II, LLC	SP-6832, SUB 0	(02/02/2016)
Heights Solar Farm, LLC	SP-6842, SUB 0	(09/06/2016)
Henry Gibson Solar, LLC	SP-5262, SUB 0	(08/16/2016)
Highway 16 Farm, LLC	SP-7422, SUB 0	(03/01/2016)
Homer Solar, LLC	SP-8056, SUB 0	(09/19/2016)
Hood Solar Farm, LLC	SP-7641, SUB 0	(08/10/2016)
Hoover Farm, LLC	SP-8317, SUB 0	(10/25/2016)
HORUS NORTH CAROLINA 1, LLC	SP-8576, SUB 0	(12/20/2016)
HORUS NORTH CAROLINA 3, LLC	SP-8506, SUB 0	(12/13/2016)
HORUS NORTH CAROLINA 4, LLC	SP-7550, SUB 0	(07/11/2016)
Howardtown Farm, LLC	SP-7782, SUB 0	(12/20/2016)
Jersey Holdings, LLC	SP-7017, SUB 1	(06/27/2016)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS -- Filings Due Per Order *(Continued)*

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Jester Solar, LLC	SP-6934, SUB 0	(06/21/2016)
Kendall Farm, LLC	SP-8171, SUB 0	(09/27/2016)
Lee Landing Solar, LLC	SP-8003, SUB 0	(08/31/2016)
Legion Solar, LLC	SP-7759, SUB 0	(06/27/2016)
Lexington 64, Farm, LLC	SP-7885, SUB 0	(10/31/2016)
Little Mountain Solar, LLC	SP-8125, SUB 0	(10/18/2016)
Loblolly Pine Solar, LLC	SP-8266, SUB 0	(10/31/2016)
Longleaf Pine Solar, LLC	SP-8216, SUB 0	(10/18/2016)
Longneck Solar, LLC	SP-8166, SUB 0	(10/04/2016)
Lucky Solar, LLC	SP-8148, SUB 0	(09/20/2016)
Marchpast Solar, LLC	SP-8038, SUB 0	(08/31/2016)
Marigold Solar, LLC	SP-8288, SUB 0	(10/26/2016)
Mastiff Solar, LLC	SP-8190, SUB 0	(09/26/2016)
Millers Chapel Solar Farm, LLC	SP-7433, SUB 0	(09/27/2016)
Mink Solar, LLC	SP-8303, SUB 0	(10/25/2016)
Morgan Sellers Solar, LLC	SP-8363, SUB 0	(10/31/2016)
Mount Moriah Solar, LLC	SP-8564, SUB 0	(12/13/2016)
Moyer Solar, LLC	SP-6990, SUB 0	(04/18/2016)
Mt. Olive Solar 2, LLC	SP-8427, SUB 0	(11/29/2016)
Mustang Solar, LLC	SP-7502, SUB 0	(05/09/2016)
Narwhal Solar, LLC	SP-8319, SUB 0	(10/25/2016)
Necal Farm, LLC	SP-8039, SUB 0	(09/19/2016)
NJC Solar, LLC	SP-8336, SUB 0	(11/14/2016)
Norris Solar Farm, LLC	SP-7785, SUB 0	(10/31/2016)
Oakwood Solar Farm, LLC	SP-7222, SUB 0	(02/02/2016)
Old North State Solar, LLC	SP-8219, SUB 0	(10/18/2016)
Old 421 Solar, LLC	SP-8291, SUB 0	(10/31/2016)
Orchid Solar, LLC	SP-7819, SUB 0	(10/25/2016)
Osceola Solar, LLC	SP-7976, SUB 0	(10/11/2016)
Overhill Solar, LLC	SP-8174, SUB 0	(09/27/2016)
Parkdale Solar, LLC	SP-7664, SUB 0	(05/09/2016)
Peacock Solar, LLC	SP-8567, SUB 0	(12/13/2016)
Peake Road Farm, LLC	SP-8229, SUB 0	(10/25/2016)
Pecan Grove Solar, LLC	SP-8341, SUB 0	(10/31/2016)
Perquimans Solar, LLC	SP-8284, SUB 0	(10/31/2016)
Pierce Solar, LLC	SP-7469, SUB 0	(03/01/2016)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS -- Filings Due Per Order *(Continued)*

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Pilot Mountain Solar, LLC	SP-7738, SUB 0	(08/22/2016)
Pinesage Solar Farm, LLC	SP-6225, SUB 0	(03/29/2016)
Pitt County Solar, LLC	SP-8278, SUB 0	(10/31/2016)
Plott Hound Solar, LLC	SP-8218, SUB 0	(10/18/2016)
Polk Farm, LLC	SP-8318, SUB 0	(10/25/2016)
Quail Holdings, LLC	SP-8135, SUB 0	(10/18/2016)
Quarter Horse Farm, LLC	SP-8149, SUB 0	(09/19/2016)
Quincy Farm, LLC	SP-8222, SUB 0	(10/25/2016)
Ransom Solar, LLC	SP-7762, SUB 0	(08/02/2016)
Ray Wilson Solar Farm, LLC	SP-7799, SUB 0	(10/31/2016)
Rea Magnet Farm, LLC	SP-8037, SUB 0	(09/19/2016)
Red Cedar Solar, LLC	SP-5240, SUB 0	(09/06/2016)
Red Fox Solar, LLC	SP-7467, SUB 0	(03/01/2016)
Research Station Solar, LLC	SP-6966, SUB 0	(01/27/2016)
River Forks Farm, LLC	SP-8225, SUB 0	(10/25/2016)
River Otter Solar, LLC	SP-8160, SUB 0	(09/27/2016)
Riverboat Farm, LLC	SP-7680, SUB 0	(06/07/2016)
Salisbury Solar, LLC	SP-7440, SUB 0	(02/24/2016)
Saw Solar, LLC	SP-8431, SUB 0	(10/31/2016)
Sawtell Solar, LLC	SP-7624, SUB 0	(06/21/2016)
Saxapahaw Solar, LLC	SP-7736, SUB 0	(08/22/2016)
Scotch Bonnet Solar, LLC	SP-8282, SUB 0	(10/26/2016)
Selwyn Farm, LLC	SP-7932, SUB 0	(08/31/2016)
Sheep Hill Solar, LLC	SP-8298, SUB 0	(10/25/2016)
Shieldwall Solar, LLC	SP-8102, SUB 0	(09/27/2016)
Shine Solar I, LLC	SP-5098, SUB 1	(01/26/2016)
Slender Branch Solar, LLC	SP-8116, SUB 0	(10/11/2016)
Slider Solar, LLC	SP-7625, SUB 0	(07/20/2016)
Solar Lee, LLC	SP-8200, SUB 0	(10/31/2016)
South Creek Solar, LLC	SP-5247, SUB 0	(07/20/2016)
South Hertford Solar, LLC	SP-8265, SUB 0	(10/31/2016)
Southwick Solar Farm, LLC	SP-7968, SUB 0	(08/10/2016)
Stagecoach Solar Farm, LLC	SP-7734, SUB 0	(09/27/2016)
Stallion Solar, LLC	SP-8271, SUB 0	(10/31/2016)
Storys Creek Farm Solar, LLC	SP-8130, SUB 0	(09/27/2016)
Summerset Farms Solar, LLC	SP-7712, SUB 0	(08/16/2016)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS -- Filings Due Per Order *(Continued)*

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Summit Solar, LLC	SP-8211, SUB 0	(10/11/2016)
Sun Farm VIII, LLC	SP-8254, SUB 0	(10/26/2016)
Suncaster, LLC	SP-8198, SUB 0	(10/11/2016)
Swansboro Solar, LLC	SP-8342, SUB 0	(10/31/2016)
Sweet Tea Solar, LLC	SP-8250, SUB 0	(11/14/2016)
Sykes Solar, LLC	SP-8207, SUB 0	(10/18/2016)
T-Kemp Farm, LLC	SP-8150, SUB 0	(10/31/2016)
Tamworth Holdings, LLC	SP-8025, SUB 0	(10/25/2016)
Tanager Holdings, LLC	SP-8398, SUB 0	(10/31/2016)
Tarpey Farm, LLC	SP-8213, SUB 0	(09/27/2016)
Tinker Farm, LLC	SP-8093, SUB 0	(09/19/2016)
Tomlin Mill Solar, LLC	SP-8063, SUB 0	(10/11/2016)
Traveller Solar, LLC	SP-7991, SUB 0	(09/19/2016)
Trojan Solar, LLC	SP-8051, SUB 0	(10/04/2016)
Truman Farm, LLC	SP-8226, SUB 0	(10/25/2016)
Truman Solar, LLC	SP-7466, SUB 0	(03/01/2016)
Turner Smith Solar, LLC	SP-5245, SUB 0	(09/06/2016)
Tyler Solar, LLC	SP-8320, SUB 0	(11/14/2016)
Union Chapel Solar, LLC	SP-8208, SUB 0	(10/18/2016)
Ventura Solar, LLC	SP-7894, SUB 0	(08/16/2016)
Verona Solar, LLC	SP-8182, SUB 0	(10/04/2016)
Vintage Solar2, LLC	SP-8206, SUB 0	(09/27/2016)
Wadesboro Farm 4, LLC	SP-8054, SUB 0	(09/19/2016)
Wadesboro Solar, LLC	SP-7830, SUB 0	(10/25/2016)
Wakefield Solar, LLC	SP-7473, SUB 0	(05/17/2016)
Warbler Holdings, LLC	SP-7933, SUB 0	(08/10/2016)
Warren Solar Farm, LLC	SP-8120, SUB 0	(09/27/2016)
Wedge Solar, LLC	SP-8040, SUB 0	(09/19/2016)
Wendell Solar Farm, LLC	SP-7828, SUB 0	(08/10/2016)
Wentworth Farm, LLC	SP-7758, SUB 0	(08/10/2016)
Whiskey Solar, LLC	SP-5267, SUB 0	(10/04/2016)
Whitney Solar, LLC	SP-7990, SUB 0	(08/31/2016)
Willard Solar, LLC	SP-7474, SUB 0	(05/09/2016)
Williams Solar, LLC	SP-8274, SUB 0	(10/25/2016)

SMALL POWER PRODUCERS -- Filings Due Per Order *(Continued)*

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Winters Solar, LLC	SP-8022, SUB 0	(10/31/2016)
Woodgriff Solar Farm, LLC	SP-7992, SUB 0	(08/31/2016)
Woodington Solar, LLC	SP-8162, SUB 0	(10/04/2016)
Yadkin Solar Farm, LLC	SP-7950, SUB 0	(10/31/2016)
Zuma Solar, LLC	SP-7895, SUB 0	(09/19/2016)
1073 Onslow Solar, LLC	SP-8616, SUB 0	(10/18/2016)

ORDER TRANSFERING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

Company	Docket No.	Date
Carolina Solar Energy II, LLC	SP-2363, SUB 26	(06/21/2016)
	SP-7916, SUB 0	
	SP-2363, SUB 27	(06/01/2016)
	SP-7915, SUB 0	
	SP-2363, SUB 28	(06/21/2016)
	SP-7925, SUB 0	
Lee Landing Solar, LLC	SP-8003, SUB 0	(10/19/2016)
	SP-8405, SUB 0	
Little Mountain Solar, LLC	SP-8125, SUB 0	(10/27/2016)
	SP-8408, SUB 0	
Lucky Solar, LLC	SP-8148, SUB 0	(10/19/2016)
	SP-8409, SUB 0	
Matthews Solar Farm, LLC	SP-6045, SUB 0	(10/19/2016)
	SP-8403, SUB 0	
Spencer Mountain Hydropower, LLC	SP-143, SUB 0	(05/04/2016)
	SP-143, SUB 2	
	SP-7844, SUB 0	
Tomlin Mill Solar, LLC	SP-8063, SUB 0	(10/27/2016)
	SP-8407, SUB 0	
Toprak LLC	SP-4708, SUB 1	(05/16/2016)
	E-7, SUB 1098	
Traveller Solar, LLC	SP-7991, SUB 0	(10/19/2016)
	SP-8406, SUB 0	
Whitney Solar, LLC	SP-7990, SUB 0	(10/19/2016)
	SP-8401, SUB 0	

SMALL POWER PRODUCERS -- Filings Due Per Order *(Continued)*

Catherine Lake Solar, LLC -- SP-7931, SUB 0; SP-8402, SUB 0; Order Transferring Certificate of Public Convenience and Necessity (10/19/2016)

Ebenezer Church Solar, LLC -- SP-7801, SUB 0; SP-8400, SUB 0; Order Transferring Certificate of Public Convenience and Necessity (10/19/2016)

First Solar Development, LLC -- SP-2221, SUB 0; SP-2221, SUB 1; E-7, SUB 1079; Order Transferring Certificate of Public Convenience and Necessity (05/16/2016)

SunEnergy1, LLC -- SP-751, SUB 22; SP-4396, SUB 0; Order Transfering and Amending Certificates of Public Convenience and Necessity (07/26/2016)

Wildwood Solar, LLC -- SP-5310, SUB 0; SP-5310, SUB 1; SP-5448, SUB 0; SP-8243, SUB 0; SP-8244, SUB 0; Order Amending and Transfering Certificates of Public Convenience and Necessity (08/09/2016)

SMALL POWER PRODUCERS – Registration Statements

JDC Manufacturing, LLC -- SP-845, SUB 0; SP-845, SUB 1; SP-6216, SUB 0; Order Allowing Withdrawal of Report, Cancelling Registration, Closing Dockets, and Accepting Registration of New Renewable Energy Facility (09/02/2016)

SMALL POWER PRODUCERS – Report of Proposed Construction

City View Commercial, LLC -- SP-1657, SUB 0; SP-7947, SUB 0; Order Allowing Transfer of Report of Proposed Construction (11/09/2016)

SPECIAL CERTIFICATE/PSP

SPECIAL CERTIFICATE/PSP -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE
Orders Issued

Company	Docket No.	Date
Black; Judith M.	SC-1640, SUB 1	(06/09/2016)
Johnson; Kenneth L.	SC-1805, SUB 1	(02/22/2016)
MEBTEL Communications	SC-1365, SUB 1	(09/14/2016)
Robson; Marcie	SC-1817, SUB 1	(05/03/2016)
TelSouth Incorporated of N.C.	SC-1452, SUB 3	(04/11/2016)
Town of Fletcher	SC-1734, SUB 1	(07/08/2016)

SPECIAL CERTIFICATE/PSP -- Cancellation of Certificate *(Continued)*

Clifton; Roy J. -- SC-861, SUB 2; SC-866, SUB 1; SC-1150, SUB 1; SC-1468, SUB 1; SC-1487, SUB 2; SC-1526, SUB 1; SC-1638, SUB 2; SC-1800, SUB 1; SC-1819, SUB 1; SC-1000, SUB 16 Order Affirming Previous Commission Order Cancelling Certificates (07/27/2016)

SPECIAL CERTIFICATE/PSP – Certificate

ORDER ISSUING CERTIFICATE

Orders Issued

Company	Docket No.	Date
Infinity Networks, Inc.	SC-1820, SUB 0	(05/17/2016)

TELECOMMUNICATIONS

TELECOMMUNICATIONS -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE

Orders Issued

Company	Docket No.	Date
Aero Communications, LLC	P-1393, SUB 2	(05/16/2016)
Americom Technologies, Inc., d/b/a Network Utilization Services	P-526, SUB 3	(06/29/2016)
Carolina Cable, Inc.	P-1424, SUB 1	(02/16/2016)
Global Telecom & Technology Americas, Inc.	P-1179, SUB 1	(04/11/2016)
Nexlink Wireless, LLC	P-1396, SUB 2	(03/10/2016)
NovaTel Ltd., Inc.	P-1482, SUB 1	(06/16/2016)

Alliance Group Services, Inc. -- P-801, SUB 5; Order Cancelling Certificate and Closing Docket (08/23/2016)

Cypress Communications Operating Company, LLC -- P-1027, SUB 4; Order Cancelling Certificates (02/25/2016)

Encompass Communications, L.L.P. --P-1056, SUB 1; Order Cancelling Certificate and Closing Docket (11/16/2016)

Gold Line Telemanagement, Inc. -- P-1158, SUB 1; Order Cancelling Certificate and Closing Docket (12/21/2016)

TELECOMMUNICATIONS -- Cancellation of Certificate *(Continued)*

Nexus Communications, Inc. -- P-1310, SUB 1; Order Canceling Certificate and Closing Docket (01/26/2016)

One Tone Telecom, Inc. -- P-1159, SUB 3; Order Cancelling Certificates and Closing Docket (11/04/2016)

Primus Telecommunications, Inc. -- P-451, SUB 6; Order Cancelling Certificate and Closing Docket (08/02/2016)

TeleUno, Inc. -- P-1078, SUB 1; Order Cancelling Certificate and Closing Docket (11/04/2016)

TNCI Operating Company, LLC -- P-1554, SUB 3; P-224 (Company File); Order Cancelling Certificates and Closing Docket (11/04/2016); Order Permitting Discontinuance of Service (06/02/2016)

Total Call International, Inc. -- P-940, SUB 2; Order Cancelling Certificate and Closing Docket (11/04/2016)

3U Telecom, Inc. -- P-1207, SUB 1; Order Cancelling Certificate and Closing Docket (11/17/2016)

TELECOMMUNICATIONS -- Certificate

LOCAL CERTIFICATE

Orders Issued

Company	Docket No.	Date
Airbus DS Communications, Inc.	P-1586, SUB 0	(09/20/2016)
American Cell, LLC	P-1579, SUB 0	(03/10/2016)
eNetworks, LLC	P-1587, SUB 0	(06/09/2016)
Lightrunner, LLC	P-1581, SUB 0	(03/15/2016)
Metro Fiber Networks, Inc.	P-1583, SUB 0	(03/28/2016)
Mobilitie Management, LLC	P-1585, SUB 0	(12/21/2016)
LREMC Technologies, L.L.C.	P-1575, SUB 0	(12/21/2016)
TNE Telephone, Inc.	P-1594, SUB 1	(12/22/2016)

TELECOMMUNICATIONS – Certificate *(Continued)*

LONG DISTANCE CERTIFICATE
Orders Issued

Company	Docket No.	Date
CallCatchers Inc., d/b/a FreedomVoice Systems	P-1588, SUB 0	(08/26/2016)
GoDaddy.com	P-1591, SUB 0	(09/02/2016)
Legacy Long Distance International, Inc.	P-1173, SUB 3	(12/22/2016)
Neon Phone Service, Inc.	P-1595, SUB 0	(12/08/2016)
Netcom Systems Group, LLC	P-1584, SUB 0	(03/22/2016)
Roanoke Connect Holdings, LLC	P-1582, SUB 1	(03/15/2016)
TNE Telephone, Inc.	P-1594, SUB 0	(12/21/2016)
X5 OpCo, LLC	P-1578, SUB 0	(01/07/2016)

TELECOMMUNICATIONS -- Contract/Agreements

ORDER APPROVING AGREEMENT(s) *and/or*
ORDER APPROVING AMENDMENT(s)
Orders Issued

BellSouth Telecommunications, LLC – P-55,
SUB 1460 *(Matrix Telecom, Inc.)* (02/24/2016)
SUB 1521 *(Level 3 Communications, LLC)* (11/21/2016)
SUB 1573 *(BCN Telecom, Inc.)* (02/24/2016); (11/21/2016)
SUB 1579 *(Verizon Select Services Inc.)* (12/13/2016)
SUB 1590 *(New Cingular Wireless PCS, LLC)* (04/18/2016)
SUB 1636 *(NOS Communications, Inc.)* (05/17/2016)
SUB 1642 *(Time Warner Cable Information Services (North Carolina), LLC)* (10/25/2016)
SUB 1670 *(YMax Communications Corp.)* (12/13/2016)
SUB 1676 *(EarthLink Business, LLC)* (08/31/2016)
SUB 1721 *(GC Pivotal, LLC, d/b/a Global Capacity)* (08/01/2016)
SUB 1728 *(Global Connection Inc. of America)* (05/17/2016)
SUB 1738 *(LTS of Rocky Mount, LLC)* (03/22/2016)
SUB 1749 *(Birch Communications, Inc. & Birch Telecom of the South, Inc.)* (01/12/2016)
SUB 1758 *(Budget Prepay, Inc.)* (03/22/2016)
SUB 1770 *(Tele Circuit Network Corporation)* (02/24/2016)
SUB 1772 *(Peerless Network of North Carolina, LLC)* (09/26/2016)
SUB 1779 *(Alternative Phone, Inc.)* (06/20/2016)
SUB 1811 *(Springboard Telecom, LLC and Comporium, Inc.)* (06/20/2016)
SUB 1827 *(Broadview Networks, Inc.)* (12/13/2016)

TELECOMMUNICATIONS -- Contract/Agreements *(Continued)*

ORDER APPROVING AGREEMENT(s) *and/or*
ORDER APPROVING AMENDMENT(s)
Orders Issued *(Continued)*

BellSouth Telecommunications, LLC – P-55, *(Continued)*

SUB 1849 *(Business Telecom, LLC, d/b/a EarthLink Business)* (01/12/2016); (08/31/2016)
SUB 1849; P-500, SUB 18; P-55, SUB 1676 *(Business Telecom, LLC, d/b/a EarthLink Business, DeltaCom, LLC, d/b/a EarthLink Business, and EarthLink Business, LLC)* (11/21/2016)
SUB 1860 *(DukeNet Communications, LLC)* (09/26/2016)
SUB 1870 *(OneTone Telecom, Inc.)* (08/01/2016)
SUB 1886 *(Broadvox-CLEC, LLC)* (09/26/2016)
SUB 1888 *(O1 Communications East, LLC)* (08/31/2016)
SUB 1901 *(Onvoy, LLC)* (04/18/2016)
SUB 1905 *(QuantumShift Communications, Inc.)* (08/01/2016)
SUB 1911 *(Big River Telephone Company, LLC)* (02/24/2016)
SUB 1912 *(Preferred Long Distance, Inc.)* (02/24/2016)
SUB 1913 *(RCLEC, Inc.)* (03/22/2016)
SUB 1914 *(Wide Voice, LLC)* (04/18/2016); (08/31/2016)
SUB 1915 *(RiverStreet Communications of North Carolina, Inc.)* (04/18/2016); (08/02/2016)
SUB 1916 *(Equinox Global Telecommunications, Inc.)* (05/17/2016)
SUB 1918 *(AT&T Corp.)* (08/01/2016)
SUB 1919 *(Teleport Communications America, LLC)* (08/01/2016)
SUB 1920 *(Piedmont Communications Services, Inc.)* (06/20/2016)
SUB 1921 *(Entelegent Solutions, Inc.)* (08/01/2016)
SUB 1922 *(Access Point, Inc.)* (09/26/2016)
SUB 1923 *(Ready Telecom, Inc.)* (09/26/2016)
SUB 1924 *(Wholesale Carrier Services, Inc.)* (10/25/2016)
SUB 1925 *(Airus, Inc.)* (12/13/2016)
SUB 1927 *(Budget Prepay, Inc.)* (12/13/2016)
SUB 1928 *(365 Wireless, LLC)* (12/13/2016)

TELECOMMUNICATIONS -- Contract/Agreements *(Continued)*

ORDER APPROVING AGREEMENT(s) ***and/or***
ORDER APPROVING AMENDMENT(s)
Orders Issued *(Continued)*

Carolina Telephone and Telegraph Co./Central Telephone Co. -- P-7,
SUB 1275; P-10, SUB 888 *(QuantumShift Communications, Inc.)* (02/24/2016)
SUB 1276; P-10, SUB 889 *(Randolph Telephone Telecommunications, Inc.)* (05/17/2016)
SUB 1277; P-10, SUB 890 *(RiverStreet Communications of North Carolina, Inc.)* (04/18/2016)
SUB 1278; P-10, SUB 891 *(dishNET Wireline L.L.C.)* (08/02/2016)
SUB 1280 *(Time Warner Cable Information Services, LLC)* (09/26/2016)
Central Telephone Company, d/b/a CenturyLink -- P-10, SUB 893 *(Time Warner Cable Information Services, LLC)* (09/26/2016)
MCImetro Access Transmission Services, LLC – P-474, SUB 14 *(BellSouth Telecommunications, LLC)* (05/17/2016)
Mebtel, Inc. – P-35,
SUB 135 *(Bandwidth.com CLEC, LLC)* (01/12/2016)
SUB 136 *(Time Warner Cable Information Services, LLC)* (09/26/2016)
SUB 137 *(New Cingular Wireless PCS, LLC)* (09/26/2016)
North State Telephone Company – P-42,
SUB 142; *(Level 3 Telecom of North Carolina, LP)* (11/21/2016)
SUB 144; *(Ready Telecom, Inc.)* (12/13/2016)
SUB 146; *(US LEC of North Carolina, Inc.)* (11/21/2016)
Windstream Concord Telephone, Inc. P-16,
SUB 264; P-118, SUB 199 *(Peerless Network of North Carolina, LLC)* (03/22/2016)
SUB 265; P-31, SUB 170; P-118, SUB 200 *(Randolph Telephone Telecommunications, Inc.)* (04/18/2016)
SUB 266; P-31, SUB 171; P-118, SUB 201 *(Riverstreet Communications of North Carolina, Inc.)* (04/18/2016)

TELECOMMUNICATIONS -- Discontinuance
ACN Communications Services, LLC -- P-944, SUB 2; Order Permitting Discontinuance of Certain Operator Services and Waiving Certain Requirements of Commission Rules R21-2 (06/27/2016)
BellSouth Telecommunications, LLC -- P-55, SUB 1870; Order Authorizing Termination of Services (09/02/2016)

ORDERS AND DECISIONS LISTED

TELECOMMUNICATIONS -- Miscellaneous

BellSouth Telecommunications, LLC -- P-55, SUB 1926; Order Granting Numbering Resources (10/13/2016)

North State Telephone Company -- P-42, SUB 137F; Order Permitting Discontinuance of Wholesale Lifeline Resale Services and Waiving Certain Requirements of Commission Rule R21-2 (07/29/2016)

Teleport Communications America, LLC -- P-1547, SUB 5; Order Granting Numbering Resources (08/22/2016)

Windstream North Carolina, LLC – P-118,
SUB 202; Order Granting Numbering Resources (04/21/2016)
SUB 203; Order Granting Numbering Resources (06/22/2016)

TRANSPORTATION

TRANSPORTATION -- Cancellation of Certificate

Antiques Abroad, Ltd. -- T-4267, SUB 3; Order Cancelling Certificate (06/14/2016)

Belleville; Susan Dianne, d/b/a Nelson's Delivery Service **--** T-3579, SUB 7; Order Cancelling Certificate (12/21/2016)

Campbell's Moving, LLC -- T-4592, SUB 1; Order Canceling Certificate (05/03/2016)

Movers 4 You, LLC -- T-4579, SUB 3; Order Cancelling Certificate (09/01/2016)

Open Box, LLC; The, d/b/a The Open Box Moving Solutions -- T-4431, SUB 6; Recommended Order Canceling Certificate Of Exemption (12/01/2016)

Robinson; Timothy Cobb, d/b/a Old Farm Road Moving & Storage -- T-4380, SUB 6; Order Canceling Certificate (12/02/2016)

Smooth Movin Services, Inc. -- T-4284, SUB 9; Order Canceling Certificate (09/02/2016)

TRANSPORTATION – Common Carrier Certificate

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION
Orders Issued

Company	Docket No.	Date
Browns Moving and Storage Co., LLC	T-4601, SUB 0	(07/22/2016)
Bull City Movers Plus; Juan L. Nelson, d/b/a	T-4617, SUB 0	(08/19/2016)
Carolina Hunks, Inc.	T-4620, SUB 0	(04/08/2016)
Carolina Movers, LLC, d/b/a Smooth Move	T-4645, SUB 0	(10/24/2016)
Charlotte Mobile Storage, LLC, d/b/a Zippy Shell of Charlotte	T-4628, SUB 0	(05/25/2016)
Daehan Express, LLC	T-4619, SUB 0	(04/14/2016)
Exclusive Moving and Delivery, LLC	T-4618, SUB 0	(04/04/2016)
EZZ Moving and Storage, Inc.	T-4616, SUB 0	(05/03/2016)

TRANSPORTATION – Common Carrier Certificate *(Continued)*

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION
Orders Issued (Continued)

Company	Docket No.	Date
GroveStars Moving, LLC	T-4612, SUB 0	(03/31/2016)
Herren's Carolina Moving & Storage, Inc.	T-4608, SUB 0	(01/21/2016)
Hornet Moving, LLC	T-4613, SUB 0	(03/04/2016)
J.T. Moving, Inc.	T-4627, SUB 0	(04/26/2016)
Moultrie Home Services, LLC	T-4591, SUB 0	(03/01/2016)
Movealldotcom, LLC, d/b/a A A Movers, Move Mom & More	T-4610, SUB 0	(02/23/2016)
National Budget Movers, Inc.	T-4630, SUB 0	(07/21/2016)
Relocate & Decorate Moving Services, LLC	T-4644, SUB 0	(11/03/2016)
Scallions; Kenneth J., d/b/a South Park Movers.net	T-4580, SUB 0	(07/05/2016)
Smith; Jeffery Loren, d/b/a RDU Delivered	T-4636, SUB 0	(08/22/2016)
Southeast Moving and Storage, Inc.	T-4499, SUB 1	(10/18/2016)
Stewart; Chad Raven, d/b/a Winston-Salem Moving & Storage	T-4565, SUB 0	(04/19/2016)
Titan Moving Systems, LLC	T-4638, SUB 0	(10/21/2016)
UPwright, Moving, LLC	T-4633, SUB 0	(07/15/2016)

Bellhops, Inc. -- T-4624, SUB 0; Order Dismissing Protest and Granting Application for Certificate of Exemption (09/16/2016)

Blackmon; LaKenya M., d/b/a QC Fast Moving and Storage -- T-4639, SUB 0; Order Granting Application for Certificate of Exemption (09/27/2016)

Branch Out Delivery, Inc. -- T-4631, SUB 0; Order Granting Certificate of Exemption (12/08/2016)

Coast To Coast Moving & Storage, LLC -- T-4646, SUB 0; Order Granting Application for Certificate of Exemption (11/16/2016)

Dirul Islam Henderson, d/b/a Black and White Moving Services -- T-4614, SUB 0; Order Granting Application for Certificate of Exemption (03/14/2016)

Dynamic Investment Group, Inc., d/b/a John's Moving & Storage -- T-4135, SUB 6; T-4609, SUB 0; Order Approving Sale and Transfer and Name Change (02/03/2016)

Eaker; Jamie Gordon, d/b/a Ashe Van Lines & Janitorial Services -- T-4615, SUB 0; Order Granting Certificate of Exemption (07/05/2016)

Greensboro Movers, LLC, d/b/a Two Men and A Truck of Greensboro -- T-4629, SUB 0; T-4086, SUB 5; Order Approving Sale and Transfer and Name Change (05/31/2016)

Here To There Inc., d/b/a Here to There Movers -- T-4597, SUB 0; Order Granting Application for Certificate of Exemption (02/08/2016)

Williams; Dwight Dion, d/b/a Meek Movers -- T-4569, SUB 0; Order Confirming Satisfaction and Closing Proceeding (04/08/2016)

ORDERS AND DECISIONS LISTED

TRANSPORTATION -- Miscellaneous

Rates-Truck -- T-825, SUB 351; Order Approving Fuel Surcharge (01/04/2016); (02/01/2016); (02/29/2016); (04/04/2016); (05/02/2016); (06/03/2016); (07/05/2016); (08/01/2016); (09/06/2016); (10/03/2016); (10/31/2016); (12/05/2016)

TRANSPORTATION -- Name Change

AAA Logistics, LLC -- T-4150, SUB 12; Order Approving Name Change (11/21/2016)

Armor Bearer Discount Movers, LLC -- T-4258, SUB 6; Order Approving Name Change (07/25/2016)

Bright's Moving, LLC -- T-4302, SUB 7; Order Approving Name Change (11/04/2016)

Dirul Islam Henderson, d/b/a B&W Moving -- T-4614, SUB 1; Order Approving Name Change (04/06/2016)

Eaker; Jamie Gordon, d/b/a Ashe Van Lines Moving & Storage -- T-4615, SUB 1; Order Approving Name Change (09/14/2016)

J.T. Moving, Inc., d/b/a All Ways Moving -- T-4627, SUB 1; Order Approving Name Change (05/24/2016)

Scallions; Kenneth James, d/b/a Excellence on the Move -- T-4580, SUB 1; Order Approving Name Change (09/26/2016)

TRANSPORTATION -- Sale/Transfer

Dynamic Investment Group, Inc., d/b/a John's Moving & Storage – T-4135, SUB 6; T-4609, SUB 0; Order Approving Sale and Transfer and Name Change (02/03/2016)

Weathers Bros. Moving & Storage Co., Inc. -- T-4114, SUB 8; Order Approving Stock Transfer (02/09/2016)

Weathers Bros. Transfer Co., Inc., d/b/a Weathers Moving & Distribution -- T-4194, SUB 6; Order Approving Stock Transfer (02/09/2016)

TRANSPORTATION – Show Cause

All Ways Moving, Inc. -- T-4442, SUB 3; Recommended Order Cancelling Certificate of Exemption (02/12/2016)

TRANSPORTATION -- Suspension

American Star Enterprises, Inc. -- T-3245, SUB 14; Order Granting Authorized Suspension (07/01/2016)

Coo-Lee Enterprise, Inc., d/b/a Oh My! Movers -- T-4573, SUB 1; Order Granting Authorized Suspension (04/04/2016)

Fleming-Shaw Transfer and Storage, Inc. -- T-60, SUB 4; Order Granting Authorized Suspension (01/05/2016)

Joyful Movers; Jessica Joy Hall, d/b/a-- T-4418, SUB 7; Order Granting Authorized Suspension (11/21/2016)

Pitt Movers, Inc., d/b/a A & A Moving -- T-2939, SUB 9; Order Granting Authorized Suspension (07/11/2016)

ORDERS AND DECISIONS LISTED

WATER AND SEWER

WATER AND SEWER – Adjustments of Rates/Charges

Carolina Water Service, Inc. -- W-354, SUB 344A; Order Approving Water and Sewer System Improvement Charge on a Provisional Basis and Requiring Customer Notice (09/26/2016)

WATER AND SEWER -- Bonding

Bradfield Farms Water Company -- W-1044, SUB 23; Order Accepting and Approving Bond Surety and Releasing Bond Surety (06/29/2016)

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 349; Order Approving Bond and Surety and Releasing Bond and Surety (06/29/2016)

CWS Systems, Inc. -- W-778, SUB 92; Order Accepting and Approving Bond Surety and Releasing Bond Surety (06/29/2016)

Harkers Island Sewer Company, LLC -- W-1297, SUB 6; W-1297, SUB 7; Order Accepting and Approving Bond, Releasing Bond, Granting Franchise, Approving Rates, and Requiring Customer Notice (05/06/2016)

IA Matthews Sycamore, LLC -- W-1304, SUB 2; Order Approving Name Change, Approving Bond and Surety, and Releasing Bond and Surety (04/13/2016)

JACAAB Utilities, LLC -- W-1298, SUB 3; Order Accepting Bond and Releasing Bond (06/06/2016)

JACTAW Properties, LLC -- W-1209, SUB 10; Approving Bond and Surety and Releasing Bond and Surety (09/29/2016)

Old North State Water Company, LLC -- W-1300, SUB 28; Order Approving Bond and Surety and Releasing Bond (09/19/2016)

Tanglewood Parkway Elizabeth City, LLC -- W-1310, SUB 1; Order Accepting Bond and Releasing Bond (06/06/2016)

WATER AND SEWER -- Certificate

Aqua North Carolina, Inc. -- W-218,

SUB 381; Order Granting Franchise and Approving Rates (06/28/2016)

SUB 420; W-1308, SUB 1; W-715, SUB 6; Recommended Order Approving Transfer, Granting Franchise, Approving Acquisition Adjustment, Requiring Refund, and Requiring Customer Notice (03/07/2016); Order Allowing Recommended Order to Become Effective and Final (03/07/2016); Recommended Order Approving Partial Rate Increase and Requiring Customer Notice (07/18/2016); Order Allowing Recommended Order to Become Effective and Final (07/18/2016)

WATER AND SEWER -- Certificate *(Continued)*

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 346; Order Granting Franchise, Accepting Bond, and Approving Rates (03/22/2016)

Clear Meadow Water, d/b/a; Mark Kinney -- W-1308, SUB 0; W-715, SUB 5; Order Closing Dockets (03/17/2016)

Icebreaker Development, LLC -- W-1313, SUB 0; Order Accepting and Approving Bond, Granting Certificate, Approving Rates, and Requiring Customer Notice (12/15/2016)

JACABB Utilities, LLC -- W-1298, SUB 2; Order Accepting and Approving Bond, Granting Franchise, Approving Rates, and Requiring Customer Notice (04/29/2016)

JPC Utilities, LLC -- W-1263, SUB 0; W-1263, SUB 2; W-1263, SUB 3; Order Approving Bond and Surety and Releasing Bond and Surety (08/22/2016)

Old North State Water Company, LLC – W-1300,
- SUB 13; Order Granting Franchise and Approving Rates (01/26/2016)
- SUB 14; Order Granting Franchise and Approving Rates (01/26/2016)
- SUB 16; Order Granting Franchise and Approving Rates (03/14/2016)
- SUB 17; Order Granting Franchise and Approving Rates (03/14/2016)
- SUB 18; Order Granting Franchise and Approving Rates (03/14/2016)
- SUB 19; W-888, SUB 6; Order Allowing Recommended Order to Become Effective and Final (09/19/2016)
- SUB 21; Order Granting Franchise and Approving Rates (06/28/2016)
- SUB 22; Order Granting Franchise and Approving Rates (06/28/2016)
- SUB 23; Order Granting Franchise and Approving Rates (06/28/2016)
- SUB 27; Order Granting Franchise and Approving Rates (08/15/2016)

Pluris Hampstead, LLC -- W-1305, SUB 1; Order Granting Franchise and Approving Rates (01/27/2016)

Tanglewood Parkway Elizabeth City, LLC -- W-1310, SUB 0; Order Accepting and Approving Bond, Granting Franchise, and Requiring Customer Notice (03/08/2016)

WATER AND SEWER -- Complaint

Aqua North Carolina, Inc. – W-218, SUB 426; Order Dismissing Complaint and Closing Docket *(Thomas E. Tierney)* (03/04/2016)

Carolina Water Service, Inc. -- W-354,
- SUB 347; Order Dismissing Complaint and Closing Docket *(Kevin A. Tate)* (02/03/2016)
- SUB 348; Order Dismissing Complaint and Closing Docket *(William C. & C. Suzanne Foster)* (04/27/2016)

ORDERS AND DECISIONS LISTED

WATER AND SEWER – Contiguous Water Extension

ORDER RECOGNIZING CONTIGUOUS EXTENSION AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
Aqua North Carolina, Inc.		
(West View at River Oaks Subdiv.)	W-218, SUB 289	(08/23/2016)
(MacTavish, Phase 3, Subdivision)	W-218, SUB 423	(08/02/2016)
(Smith Village at Flowers Plantation Subdivision)	W-218, SUB 424	(06/28/2016)
(The Reserve at Falls Lake Subdiv., Phase I)	W-218, SUB 425	(05/03/2016)
(Avalaire Subdivision)	W-218, SUB 427	(05/03/2016)
(Flowers Crest, Phase 4, Subdivision)	W-218, SUB 429	(06/28/2016)
(River Dell East, Phase 2, Subdiv.)	W-218, SUB 430	(08/23/2016)
(Hasentree Phase 9, Subdivision)	W-218, SUB 431	(11/01/2016)
(Miravalle Subdivision)	W-218, SUB 433	(06/28/2016)
(The Barony Overlook Subdivision)	W-218, SUB 435	(08/23/2016)
(Round Tree Ridge Subdivision)	W-218, SUB 436	(11/01/2016)
(The Village at Motts Landing, Phase 2C Subdivision)	W-218, SUB 441	(11/01/2016)
(Evergreen, Phase 2, Subdivision)	W-218, SUB 442	(11/01/2016)
JPC Utilities		
(Central Baptist Church Service Area)	W-1263, SUB 2	(08/23/2016)
(Bojangles® Service Area)	W-1263, SUB 3	(08/23/2016)
Old North State Water Company, LLC		
(Blaney South Subdivision)	W-1300, SUB 25	(06/28/2016)

KDHWWTP, LLC -- W-1160, SUB 26; Order Recognizing Contiguous Extension (01/26/2016)

WATER AND SEWER – Filings Due Per Order

Aqua North Carolina, Inc. -- W-218, SUB 363A; Order Approving Water and Sewer System Improvement Charges on a Provisional Basis and Requiring Customer Notice (06/30/2016); (12/20/2016)

Carolina Water Service, Inc. -- W-354, SUB 344A; Order Approving Water System Improvement Charge on a Provisional Basis, and Requiring Customer Notice (03/22/2016); Order Approving Water and Sewer System Improvement Charge on a Provisional Basis and Requiring Customer Notice (09/26/2016)

ORDERS AND DECISIONS LISTED

WATER AND SEWER – Merger

Carolina Water Service, Inc. -- W-354, SUB 350; W-1044, SUB 24; W-1013, SUB 11; W-778, SUB 93; W-1058, SUB 8; W-1012 SUB 16; Order Approving Merger (08/17/2016); Order Approving Bond and Surety, Releasing Bonds and Sureties, and Canceling Franchises (09/27/2016)

WATER AND SEWER – Miscellaneous

Chatham Utilities, Inc. -- W-1240, SUB 12; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice (05/13/2016); (12/06/2016)

WATER AND SEWER – Rate Increase

Carolina Water Service, Inc. -- W-354, SUB 336; W-354, SUB 336A; Order Modifying Secondary Water Quality Reporting Requirements (04/15/2016)

Conleys Creek Limited Partnership -- W-1120, SUB 8; Recommended Order Granting Partial Rate Increase and Requiring Customer Notice (10/07/2016); Order Allowing Recommended Order to Become Effective and Final (10/11/2016)

Corriher Water Service, Inc. -- W-233, SUB 26; Recommended Order Granting Partial Rate Increase and Requiring Customer Notice (09/07/2016)

Elk River Utilities, Inc. -- W-1058, SUB 7; Recommended Order Approving Amended Stipulation, Granting Partial Rate Increase, Approving Rate Adjustment Mechanisms, and Requiring Customer Notice (09/20/2016); Order Allowing Recommended Order to Become Effective and Final (09/20/2016)

GGCC Utility, Inc. -- W-755, SUB 9; Recommended Order Granting Partial Rate Increase and Requiring Rate Increase and Requiring Customer Notice (10/12/2016); Allowing Recommended Order to Become Effective and Final (10/13/2016)

Mountain Air Utilities Corporation -- W-1148, SUB 9; Order Granting MAUC's Motion to Voluntarily Withdraw Application and Closing Docket (06/02/2016)

WATER AND SEWER -- Sale/Transfer

Asheville Property Management, Inc. -- W-1145, SUB 20; Order Canceling Franchise and Releasing Bond and Surety (11/09/2016)

CBL & Associates Management, Inc. -- W-1311, SUB 0; W-1249, SUB 8; Order Accepting and Approving Bond, Granting Transfer, Approving Rates, and Requiring Customer Notice (05/04/2016)

Etowah Sewer Company, Inc. -- W-933, SUB 11; Order Approving Transfer to Owner Exempt, Canceling Franchise, Releasing Bond, and Requiring Customer Notice (11/22/2016)

Old North State Water Company, LLC -- W-1300, SUB 10; W-1082, SUB 4; Recommended Order Approving Transfer, Approving Rate Increase, and Requiring Customer Notice (02/04/2016)

ORDERS AND DECISIONS LISTED

WATER AND SEWER -- Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION
AND REQUIRING CUSTOMER NOTICE
Orders Issued

Company	Docket No.	Date
A & D Water Service, Inc.		
(Buffalo Meadows Subdivision)	W-1049, SUB 19	(05/13/2016)
	M-100, SUB 138	(12/06/2016)
Aqua North Carolina, Inc.		
(18 Subdivs. in the City of Fayetteville)	W-218, SUB 432	(06/23/2016)
(Woodland Run Subdivision)	W-218, SUB 434	(08/01/2016)
Asheville Property Management, Inc.		
(Poplar Terrace Mobile HP)	W-1145, SUB 19	(05/13/2016)
	M-100, SUB 138	
B & C Development		
(Ocean Aire Estates Subdivision)	W-924, SUB 2	(12/06/2016)
	M-100, SUB 138	
Baytree Waterfront Properties, Inc.		
(Windemere Pointe Subdivision)	W-938, SUB 5	(05/25/2016)
	M-100, SUB 138	(12/06/2016)
Beacon's Reach Master Association, Inc.		
(Beacon's Reach Development)	W-966, SUB 4	(05/24/2016)
	M-100, SUB 138	(12/06/2016)
Bear Den Acres Development, Inc.		
(Bear Den Acres Development)	W-1040, SUB 8	(12/06/2016)
	M-100, SUB 138	
Billingsley; John T.		
(Dogwood Acres)	W-632, SUB 5	(12/06/2016)
	M-100, SUB 138	
Blue Creek Utilities, Inc.		
(All Service Areas in Onslow County)	W-857, SUB 8	(05/13/2016)
	M-100, SUB 138	(12/06/2016)
Bradfield Farms Water Company		
(Bradfield Farms Subdivision)	W-1044, SUB 20	(09/08/2016)
	M-100, SUB 138	
	M-100, SUB 142	
C & P Enterprises, Inc.		
(Ocean Bay Villas &	W-1063, SUB 4	(12/06/2016)
Ocean Glen Condominuims)	M-100, SUB 138	
Carolina Trace Utilities, Inc.		
(Carolina Trace Development)	W-1013, SUB 10	(09/08/2016)
	M-100, SUB 138	
	M-100, SUB 142	

WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
AND REQUIRING CUSTOMER NOTICE
Orders Issued (Continued)

Company	Docket No.	Date
Carolina Water Service, Inc.		
(High Vista Estates)	W-354, SUB 352	(08/01/2016)
(Mt. Carmel Subdivision)	W-354, SUB 353	(08/02/2016)
Chatham Utilities, Inc.		
(Chatham Estates Manufactured Housing Community)	W-1240, SUB 13	(08/29/2016)
Clarke Utilities, Inc.		
(all Service Areas in Wake & Franklin Counties)	W-1205, SUB 8	(05/13/2016)
	M-100, SUB 138	(12/06/2016)
Conleys Creek Limited Partnership		
(All Service Areas in Swain County)	W-1120, SUB 7	(05/13/2016)
	M-100, SUB 138	(12/07/2016)
Cook; William E., Jr.		
(Green Oaks Subdivision)	W-1262, SUB 1	(05/24/2016)
	M-100, SUB 138	(12/07/2016)
Corriher Water Service, Inc.		
(All of its N.C. Service Areas)	W-233, SUB 25	(05/13/2016)
	M-100, SUB 138	(12/06/2016)
Crosby Utilities, Inc.		
(Baywood Forest Subdivision)	W-992, SUB 7	(12/07/2016)
	M-100, SUB 138	
Dillsboro Water and Sewer, Inc.		
(Dillsboro Crossing Apts.) &	W-1303, SUB 3	(11/21/2016)
(Holiday Inn Express) &		
(DRA Living Hotel) &		
(BP/Subway)		
Elk River Utilities, Inc.	W-1058, SUB 6	(09/08/2016)
(Elk River Development)	M-100, SUB 138	
	M-100, SUB 142	
Enviro-Tech of North Carolina, Inc.		
(Village at Ocean Hill Subdivision)	W-1165, SUB 4	(12/07/2016)
	M-100, SUB 138	
Etowah Sewer Company		
(Etowah Community)	W-933, SUB 10	(05/13/2016)
	M-100, SUB 138	

WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
AND REQUIRING CUSTOMER NOTICE
Orders Issued *(Continued)*

Company	Docket No.	Date
Farm Water Works		
(Winding Creek Farm Subdivision)	W-844, SUB 7	(12/06/2016)
	M-100, SUB 138	
Fearrington Utilities		
(Fearrington Village Subdivision)	W-661, SUB 8	(05/16/2016
	M-100, SUB 138	
Gensinger; John W.		
(Pineview Estates Subdivision)	W-549, SUB 9	(05/13/2016)
	M-100, SUB 138	(12/07/2016)
GGCC Utility, Inc.		
(Grandfather Golf & Country Club)	W-755, SUB 8	(05/13/2016)
	M-100, SUB 138	
Greenfield Heights Development Co., Inc.		
(Greenfield Heights Subdivision)	W-205, SUB 8	(09/12/2016)
Hawksnest Utilities, Inc.		
(Watauga County)	W-1077, SUB 1	(12/20/2016)
	M-100, SUB 138	
High Hampton, Inc.		
(High Hampton Subdivision)	W-574, SUB 3	(12/07/2016)
	M-100, SUB 138	
Hook; John D., d/b/a Whispering Pines Village		
(Whispering Pines Village MHP)	W-1042, SUB 6	(05/16/2016)
	M-100, SUB 138	(12/12/2016)
JACTAW Properties, LLC		
(Poplar Acres Mobile Home Park)	W-1209, SUB 9	(05/16/2016)
	M-100, SUB 138	(12/07/2016)
Joyceton WaterWorks, Inc.		
(Caldwell County Service Area)	W-4, SUB 18	(05/25/2016)
	M-100, SUB 138	(11/22/2016)
KDHWWTP, LLC		
(Dare County)	W-1160, SUB 24	(12/07/2016)
	M-100, SUB 138	
KRJ Utilities, Inc.		
(Southern Trace Subdivision)	W-1075, SUB 10	(12/07/2016)
	M-100, SUB 138	

WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
AND REQUIRING CUSTOMER NOTICE
Orders Issued *(Continued)*

Company	Docket No.	Date
Maxwell Water Company		
(Blawell Subdivision)	W-339, SUB 6	(12/07/2016)
	M-100, SUB 138	
MECO Utilities, Inc		
(Mobile Estates Mobile HP)	W-1166, SUB 14	(05/16/2016)
	M-100, SUB 138	(12/07/2016)
(Mobile Estates Mobile HP)	W-1166, SUB 15	(08/29/2016)
Old North State Water Company, LLC		
(Twin Lake Farm Subdivision)	W-1300, SUB 11	(12/07/2016)
	M-100, SUB 138	
Outer Banks/Kinnakeet Associates, LLC		
(Kinnakeet Shores Subdiv., etc.)	W-1125, SUB 7	(12/07/2016)
	M-100, SUB 138	
Overhills Water Company, Inc.		
(Overhills Park Subdivision)	W-175, SUB 13	(05/25/2016)
	M-100, SUB 138	(12/09/2016)
Piedmont Water & Sewer, LLC		
(All Service Areas in N.C.)	W-1294, SUB 3	(12/09/2016)
	M-100, SUB 138	
Pine Island – Currituck, LLC		
(Pine Island Subdivision &	W-1072, SUB 16	(12/09/2016)
The Currituck Club)	M-100, SUB 138	
Pluris, LLC		
(All Service Areas in Onslow County)	W-1282, SUB 11	(09/09/2016)
	M-100, SUB 138	
	M-100, SUB 142	
Ponderosa Enterprises, Inc.		
(Ponderosa Mobile Home Park)	W-1086, SUB 3	(05/25/2016)
	M-100, SUB 138	(12/12/2016)
Prior Construction Company		
(Deerfield Park, Paynes Park Landing	W-567, SUB 7	(12/09/2016)
& Little John Acres Subdivision)	M-100, SUB 138	
Riverbend Estates Water Systems, Inc.		
(Riverbend Estates Subdivision)	W-390, SUB 12	(12/12/2016)
	M-100, SUB 138	

ORDERS AND DECISIONS LISTED

WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
AND REQUIRING CUSTOMER NOTICE
Orders Issued *(Continued)*

Company	Docket No.	Date
Rock Creek Environmental Company, Inc.		
(Rock Creek Subdivision &	W-830, SUB 5	(05/16/2016)
Preps, Inc. Commercial Property)	M-100, SUB 138	(12/12/2016)
Royal Palms Water and Sewer System		
(Royal Palms Mobile HP)	W-1105, SUB 3	(05/16/2016)
	M-100, SUB 138	(12/09/2016)
Sandler Utilities at Mill Run, LLC		
(Eagle Creek Subdivision,	W-1130 SUB 9	(12/09/2016)
Mill Creek Golf Club &	M-100, SUB 138	
Moyock Middle School)		
Scientific Water and Sewerage Corporation		
(All Service Areas in Onslow County)	W-176, SUB 39	(12/09/2016)
	M-100, SUB 138	
Springdale Water and Sewer Company		
(Springdale Estates Subdivision)	W-406, SUB 5	(05/16/2016)
	M-100, SUB 138	(11/22/2016)
Sugarloaf Utility, Inc.		
(All Service Areas in Carteret County)	W-1154, SUB 9	(05/16/2016)
	M-100, SUB 138	
Total Environmental Solutions, Inc.		
(Lake Royale Subdivision)	W-1146, SUB 11	(05/16/2016)
	M-100, SUB 138	(12/12/2016)
Town and Country Mobile Home Park		
(Town and Country Mobile Home Park)	W-1193, SUB 10	(12/06/2016)
	M-100, SUB 138	
Transylvania Utilities, Inc.		
(Connestee Falls Subdivision)	W-1012, SUB 14	(09/08/2016)
	M-100, SUB 138	
	M-100, SUB 142	
Water Resources, Inc.		
(Rocky River Plantation Subdivision)	W-1034, SUB 7	(12/12/2016)
	M-100, SUB 138	
Watercrest Estates		
(Watercrest Estates Mobile HP)	W-1021, SUB 12	(08/01/2016)

WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
AND REQUIRING CUSTOMER NOTICE
Orders Issued (Continued)

Company	Docket No.	Date
Webb Creek Water and Sewage, Inc.		
(All Service Areas in N.C.)	W-864, SUB 9 M-100, SUB 138	(05/25/2016)
904 Georgetown Treatment Plant, LLC		
(Sandpiper Bay Golf & Country Club)	W-1141, SUB 6 M-100, SUB 138	(05/13/2016) (12/06/2016)

Aqua North Carolina, Inc. -- W-218, SUB 363; M-100, SUB 138; M-100, SUB 142; Order Approving Tariff Revision and Customer Notice (09/09/2016); (12/20/2016)

B & C Development -- W-924, SUB 2; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

Bear Den Acres Development, Inc. -- W-1040, SUB 8; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

Billingsley; John T. -- W-632, SUB 5; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

C & P Enterprises, Inc. -- W-1063, SUB 4; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 342; M-100, SUB 138; M-100, SUB 142; Order Approving Tariff Revision and Customer Notice (12/20/2016)

Crosby Utilities, Inc. -- W-992, SUB 7; M-100, SUB 138; Order Approving Tariff Revision and Requiring Refund (06/21/2016)

CWS Systems, Inc. - W-778, SUB 94; Order Approving Tariff Revision (07/11/2016)

Enviracon Utilities, Inc. -- W-1236, SUB 6; M-100, SUB 138; Order Requiring Refund Over Next Three Monthly Billing Cycles (06/13/2016)

Enviro-Tech of North Carolina, Inc. -- W-1165, SUB 4; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

Farm Water Works -- W-844, SUB 7; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

Fitch Creations, d/b/a Fearrington Utilities -- W-661, SUB 8; M-100, SUB 138; Order Approving Tariff Revision and Customer Notice (12/06/2016)

High Hampton, Inc. -- W-574, SUB 3; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

JL Golf Management, LLC -- W-1296, SUB 2; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016); Order Approving Tariff Revision and Customer Notice (12/06/2016)

<u>WATER AND SEWER -- Tariff Revision for Pass-Through</u> *(Continued)*

KDHWWTP, LLC -- W-1160, SUB 24; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

KRJ Utilities, Inc. -- W-1075, SUB 10; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

Mauney; William K., Jr. -- W-560, SUB 5; M-100, SUB 138; Order Approving Tariff Revision and Requiring Refund (06/21/2016)

Maxwell Water Company -- W-339, SUB 6; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/24/2016)

Mountain Air Utilities Corporation -- W-1148, SUB 14; Order Approving Tariff Revision (08/15/2016)

Outer Banks/Kinnakeet Associates, LLC -- W-1125, SUB 7; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/25/2016)

Piedmont Water & Sewer, LLC -- W-1294, SUB 3; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/25/2016)

Pine Island – Currituck, LLC -- W-1072, SUB 16; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/25/2016)

Pluris, LLC -- W-1282, SUB 11; M-100, SUB 138; Order Approving Tariff Revision and Customer Notice (11/22/2016)

Prior Construction Company -- W-567, SUB 7; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/25/2016)

Riverbend Estates Water Systems, Inc. – W-390, SUB 12; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/25/2016)

Scientific Water and Sewerage Corporation -- W-176, SUB 39; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/25/2016)

Sugarloaf Utility, Inc. -- W-1154, SUB 9; M-100, SUB 138; Order Approving Tariff Revision and Customer Notice (12/06/2016)

Town and Country Mobile Home Park -- W-1193, SUB 10; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/25/2016)

Water Resources, Inc. -- W-1034, SUB 7; M-100, SUB 138; Order Approving Tariff Revision and Requiring Customer Notice and Refund (05/25/2016)

ORDERS AND DECISIONS LISTED

RESALE OF WATER AND SEWER

RESALE OF WATER AND SEWER -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE OF AUTHORITY
Orders Issued

Company	Docket No.	Date
AERC Alpha Mill Lane, LP		
(Alpha Mill Apartments, Phases I & 2)	WR-1649, SUB 6	(10/25/2016)
Amberwood Fund IV, LLC, et al.		
(Amberwood Apartments)	WR-1574, SUB 1	(03/08/2016)
Audubon Parc Apartments, LLC		
(Audubon Parc Apartments)	WR-1662, SUB 1	(01/13/2016)
BRE Northcross Apartments, LLC		
(Marquis at Northcross Apts.)	WR-1638, SUB 1	(10/24/2016)
BVT Group, LLC		
(Bella Vista Townhomes Apts.)	WR-1396, SUB 3	(05/16/2016)
Centennial Centerview, LP		
(Century Centerview Apartments)	WR-1272, SUB 3	(06/17/2016)
CF FWB Lakeside, LLC		
(Lakeside Apartments)	WR-1720, SUB 2	(04/04/2016)
Charleston Place, LLC		
(Charleston Place Apartments)	WR-700, SUB 4	(12/22/2016)
Cogdill; Gregory Scott & Narumon Feger		
(Rockola Mobile Home Park)	WR-935, SUB 8	(09/19/2016)
CSFB 2007-C2 Summerlyn, LLC		
(Summerlyn Place Apartments)	WR-1302, SUB 3	(03/28/2016)
DMARC 2007-CD5 Riese Drive, LLC		
(Marchester on Millbrook Apartments)	WR-1593, SUB 1	(10/03/2016)
DWSS Charlotte, LLC		
(Lake Point Apartments)	WR-1330, SUB 1	(06/17/2016)
East TBR Hamptons Owner, LLC		
(The Hamptons at Research Triangle Apartments)	WR-1370, SUB 3	(01/20/2016)
Fairfield Chapel Hill, LLC		
(Bridges at Chapel Hill Apartments)	WR-1421, SUB 1	(12/22/2016)
Fairfield Waterford, LLC		
(Waterford Place Apartments)	WR-1424, SUB 2	(12/06/2016)
Fairfield Wind River, LLC		
(Bridges at Wind River Apts.)	WR-1412, SUB 1	(10/26/2016)
Fairway Apartments, LLC; The, et al.		
(The Links Apartments)	WR-565, SUB 7	(11/08/2016)

RESALE OF WATER AND SEWER -- Cancellation of Certificate *(Continued)*

ORDER CANCELING CERTIFICATE OF AUTHORITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Golden Triangle #3, LLC		
(Carmel on Providence Apartments)	WR-1439, SUB 3	(10/03/2016)
Heinmiller; Arthur E. & Florence H.		
(Apple Blossom Mobile Home Park)	WR-1094, SUB 4	(01/29/2016)
Heinmiller Investments, LLC		
(Broadview Mobile Home Park)	WR-1092, SUB 6	(01/29/2016)
Heritage Arden I, LLC, et al.		
(Arden Woods Apartments)	WR-1298, SUB 5	(10/19/2016)
Heritage Lakes I, LLC, et al.		
(The Lakes Apartments)	WR-1202, SUB 5	(10/19/2016)
Heritage Williamsburg I, LLC, et al.		
(Williamsburg Manor Apartments)	WR-1299, SUB 5	(10/05/2016)
HWY 68 APTS, LLC		
(Northpoint Apartments)	WR-1705, SUB 2	(01/04/2016)
Laurel Walk Apartments, LLC		
(Laurel Walk Apartments)	WR-1476, SUB 2	(06/17/2016)
NC Apartment Rentals, LLC		
(Medical Park West Townhomes Apts.)	WR-1237, SUB 1	(08/09/2016)
PG McAlpine Creek Apartments, LLC, et al.		
(Retreat at McAlpine Creek Apts.)	WR-1537, SUB 1	(01/13/2016)
Sagebrush Waterford Creek Apts., LLC, et al.		
(Waterford Creek Apartments)	WR-542, SUB 7	(06/17/2016)
Sides; Frank A.		
(Sunset Pines Mobile Home Park)	WR-1000, SUB 1	(04/04/2016)
Somerstone, LLC		
(Somerstone Apartments)	WR-1557, SUB 4	(12/14/2016)
Spring Ridge Apartments, LLC		
(Hawthorne Northpark Apartments)	WR-725, SUB 7	(12/09/2016)
Stoney Brook Apartments Limited Partnership		
(Stoney Brook Apartments)	WR-1848, SUB 1	(12/09/2016)
Sweetwater Meadows, LLC		
(Sweetwater Meadows MHP)	WR-1375, SUB 4	(04/18/2016)
Three Oak Property, LLC		
(The Park at Three Oaks Apts.)	WR-405, SUB 4	(10/25/2016)
VCP Birchcroft, LLC		
(Birchcroft Apartments)	WR-1888, SUB 1	(11/08/2016)

RESALE OF WATER AND SEWER -- Cancellation of Certificate *(Continued)*

ORDER CANCELING CERTIFICATE OF AUTHORITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Westdale Lenox, LLC		
(Lenox at Patterson Place Apts.)	WR-1351, SUB 4	(10/03/2016)
Williamsburg I, LLC, et al.		
(Williamsburg Manor Apartments)	WR-1299, SUB 5	(10/05/2016)
Winstead Warehousing, LLC		
(Hawthorne Crossing Apartments)	WR-1222, SUB 4	(07/18/2016)
18 Weather Hill Circle Holdings, LLC		
(The Landing Apartments)	WR-1389, SUB 3	(08/18/2016)

Bridford Parkway Apartments, LLC – WR-1363, SUB 4; Order Canceling Certificates of Authority (02/09/2016)

GCC-Courtyard, LLC -- WR-1566, SUB 1; Order Affirming Previous Commission Order Canceling Operating Authority (08/25/2016)

King James Owners, LLC -- WR-1544, SUB 1; Order Affirming Previous Commission Order Canceling Operating Authority (11/04/2016)

Pfalzgraf Communities 6, LLC -- WR-1492, SUB 1; Order Affirming Previous Commission Order Canceling Operating Authority (08/25/2016)

Spring Ridge Apartments, LLC -- WR-725, SUB 6; Order Declaring Proposed Action Moot and Closing Docket (12/09/2016)

Sureties Unlimited 2, LLC -- WR-1377, SUB 3; Order Affirming Previous Commission Order Canceling Operating Authority (08/25/2016)

Westfield Thorngrove, LLC -- WR-906, SUB 7; Order Affirming Previous Commission Order Canceling Operating Authority (08/25/2016)

RESALE OF WATER AND SEWER – Certificate

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
ACG Belmont, LLC		
(Wylie Overlook Mobile Home Park)	WR-2102, SUB 0	(06/28/2016)
Alta Berewick, LLC		
(Alta Berewick Apartments)	WR-2043, SUB 0	(05/02/2016)
Anderson Six Forks Apartments, LLC		
(Anderson Flats Apartments)	WR-2203, SUB 0	(12/13/2016)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
ARIM Williamsburg, LLC		
(Williamsburg Manor Apartments)	WR-2150, SUB 0	(10/05/2016)
ARIUM Lake Norman Owner, LLC		
(Arium Lake Norman Apartments)	WR-2084, SUB 0	(06/20/2016)
Asheville Exchange Apartments, LLC		
(Asheville Exchange Apartments)	WR-2002, SUB 0	(02/29/2016)
Bacarra, LLC		
(Bacarra Apartments)	WR-2049, SUB 0	(11/16/2016)
Bell Fund V 605 West, LP		
(Bell West End Apartments)	WR-2145, SUB 0	(09/28/2016)
Berkeley Apartments, LLC		
(Berkeley Apartments, Phase I)	WR-1985, SUB 0	(01/19/2016)
Binkley Property Management, LLC		
(Sunset Pines Mobile Home Park)	WR-2024, SUB 0	(04/04/2016)
BMA Brookwood Apartments, LLC		
(Brookwood Apartments)	WR-1987, SUB 0	(01/25/2016)
Boulevard at North Cedar Street, LLC; The		
(North Cedar Street Apartments)	WR-2079, SUB 0	(06/13/2016)
Bradley Asheboro, LLC		
(Village at Stone Creek Apartments)	WR-2126, SUB 0	(09/07/2016)
BRC Wilmington, LLC		
(Annexe at The Reserve Apartments)	WR-2172, SUB 0	(10/27/2016)
BRE Piper MF Sterling Steele Creek NC, LLC		
(Steele Creek South Apartments)	WR-2191, SUB 0	(11/21/2016)
Breckenridge Group Wilmington North Carolina, LLC		
(Aspen Heights Wilmington Apts.)	WR-2099, SUB 0	(06/28/2016)
Bridford Property Company, LLC		
(Bridford West Apartments)	WR-1994, SUB 0	(02/09/2016)
Brier Creek Investors JV, LLC		
(Bridges at Wind River Apartments)	WR-2189, SUB 0	(11/21/2016)
Bryton Residences, LLC		
(Brookson Residential Flats Apts.)	WR-2158, SUB 0	(10/13/2016)
Cambridge Park, LLC		
(Cambridge Park Townhomes Apts.)	WR-2181, SUB 0	(11/22/2016)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued (Continued)

Company	Docket No.	Date
Capital Creek Apartments, LLC		
(Capital Creek at Heritage Apts.)	WR-2218, SUB 0	(12/28/2016)
Cary Custom Investor I, LLC, et al.		
(Amberwood Apartments)	WR-2031, SUB 0	(04/11/2016)
Casa United, LLC		
(Casa Del Sol Apartments)	WR-2179, SUB 0	(11/07/2016)
Caswyck Trail, LLC		
(Caswyck Trail Apartments)	WR-1982, SUB 0	(01/13/2016)
Cates Creek Apartments, LLC		
(Ardmore Cates Creek Apartments)	WR-2148, SUB 0	(11/03/2016)
CCC Asbury Flats, LLC		
(Asbury Flats Apartments)	WR-2033, SUB 0	(04/04/2016)
CCC Bennington Woods, LLC		
(Bennington Woods Apartments)	WR-2032, SUB 0	(04/11/2016)
Chapel Hill Housing, LLC		
(1701 North Apartments)	WR-2107, SUB 0	(07/20/2016)
Church Street MHP, LLC		
(Church Street MHP)	WR-1996, SUB 0	(02/08/2016)
CN Apartments, LLC		
(Meridian at Sutton Square Apts.)	WR-2076, SUB 0	(06/06/2016)
CO-BB Audubon, LLC		
(Audubon Parc Apartments)	WR-1981, SUB 0	(01/13/2016)
CO-BB Retreat, LLC		
(Retreat at McAlpine Creek Apts.)	WR-1979, SUB 0	(01/13/2016)
Crabtree Apartments, LLC		
(Crabtree Commons Apartments)	WR-2121, SUB 0	(09/08/2016)
Crescent-Morehead Property One Venture, LLC		
(Crescent Dilworth Apartments)	WR-1993, SUB 0	(02/01/2016)
CSC Parkside, LLC		
(Parkside Five Points Apartments)	WR-1911, SUB 0	(03/28/2016)
CUOF IV Quarters at Morehead, LLC		
(Loft 135 Apartments)	WR-2054, SUB 0	(05/31/2016)
CW Alpha Mills Apartments, LLC		
(Alpha Mills Apartments)	WR-2173, SUB 0	(11/08/2016)
DD Belgate, LLC		
(Sovereign at Belgate Apartments)	WR-2170, SUB 0	(11/03/2016)

ORDERS AND DECISIONS LISTED

<u>RESALE OF WATER AND SEWER – Certificate</u> *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY
AND APPROVING RATES
<u>Orders Issued</u> (Continued)

<u>Company</u>	<u>Docket No.</u>	<u>Date</u>
DD Mellowfield II, LLC		
(Vue 64 Apartments)	WR-2171, SUB 0	(11/03/2016)
D&E Limited, LLC		
(Green Acres Mobile Home Park)	WR-2098, SUB 0	(06/28/2016)
Dilworth Apartments, LLC		
(Solis Dilworth Apartments)	WR-2083, SUB 0	(06/20/2016)
DOF IV Summerlyn, LLC		
(Summerlyn Place Apartments)	WR-2022, SUB 0	(03/29/2016)
DPR Westover, LLC		
(Cary Reserve at Reston Apartments)	WR-1989, SUB 0	(01/19/2016)
Echo Farm Apartments		
(Arbor Trace Apartments)	WR-2213, SUB 0	(12/15/2016)
Eden Chase, LLC		
(Eden Chase Apartments)	WR-1977, SUB 0	(01/12/2016)
Edison, LLC; The		
(The Edison Lofts Apartments)	WR-2053, SUB 0	(05/23/2016)
Ellis Road Apartments I, LP		
(Villages at Ellis Crossing Apts.)	WR-2078, SUB 0	(06/28/2016)
Emerald Forest Durham, LLC		
(Emerald Forest Apartments)	WR-2029, SUB 0	(04/04/2016)
First Mebane Properties, LLC		
(Alexander Pointe Apartments)	WR-2014, SUB 0	(03/21/2016)
Fountains Matthews, LLC		
(Fountains Matthews Apartments)	WR-2023, SUB 0	(03/29/2016)
Fountains Uptown, LLC		
(Presley Uptown Apartments)	WR-1992, SUB 0	(02/01/2016)
Four Hundred North Church Street Associates Master Tenant, LP		
(The RJ Reynolds Building Apts.)	WR-2114, SUB 0	(08/24/2016)
G Colonial, LLC		
(Autumn Trace Apartments, Phase 1)	WR-1829, SUB 2	(01/05/2016)
Golden Triangle #7 – Commonwealth, LLC		
(The Julien Apartments)	WR-2097, SUB 0	(06/28/2016)
Graham Street Apartments, LLC		
(Circa Uptown Apartments)	WR-2015, SUB 0	(03/22/2016)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued (Continued)

Company	Docket No.	Date
Gramercy Glenwood, LLC		
(The Gramercy Apartments)	WR-2123, SUB 0	(09/08/2016)
Grand View Holdings, LLC		
(Grand View Apartments)	WR-2042, SUB 0	(04/25/2016)
GRE JV Wilmington, LLC		
(The Park at Three Oaks Apts.)	WR-2186, SUB 0	(11/14/2016)
Greenfield Multifamily Investors, LLC		
(Deer Harbor Apartment Homes)	WR-2192, SUB 0	(11/29/2016)
Hawthorne Arden, LLC		
(Hawthorne Midtown Apartments)	WR-2156, SUB 0	(10/19/2016)
Hawthorne at Leland Apartments, LLC		
(Hawthorne at Leland Apartments)	WR-2162, SUB 0	(10/13/2016)
Hawthorne-Midway Turtle Creek Phase III, LLC, et al.		
(Hawthorne at Southside Apts., Ph. III)	WR-2077, SUB 0	(06/13/2016)
Heritage at Arlington Apts. Phase II; The		
(The Heritage at Arlington Apts., Phase II)	WR-1986, SUB 0	(01/25/2016)
Highland Park Investors II, LLC, et al.		
(Highland Park Apartments)	WR-1999, SUB 0	(02/22/2016)
I&G Direct Real Estate 41, LP		
(Residence at South Park Apartments)	WR-2025, SUB 0	(03/29/2016)
IP9 MF OAKS, LLC		
(Laurel Oaks Apartments)	WR-1990, SUB 0	(01/20/2016)
IP9 MF SPRINGS, LLC		
(Laurel Springs Apartments)	WR-1991, SUB 0	(01/26/2016)
IVY Investment III, LLC		
(Oak Court Apartments)	WR-2041, SUB 0	(04/18/2016)
J&B Development Co. of Concord, LLC		
(Rain Place Apartments)	WR-2109, SUB 0	(07/12/2016)
Jetton Apartments, LLC		
(The Linden Apartments)	WR-2185, SUB 0	(12/05/2016)
K Colonial, LLC		
(Autumn Trace Apartments, Phase 2)	WR-1943, SUB 1	(01/05/2016)
KC Realty Investments, LLC		
(Rockola Mobile Home Park)	WR-950, SUB 10	(09/19/2016)
(Hemlock Court Mobile Home Park)	WR-950, SUB 15	(09/19/2016)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Keystone at Mebane Oaks, LLC		
(Keystone at Mebane Oaks Apartments)	WR-2050, SUB 0	(05/16/2016)
King's Grant Apartments, LLC		
(Ardmore King's Grant Apartments)	WR-2120, SUB 0	(08/24/2016)
Koury Corporation		
(Yester Oaks Apartments)	WR-595, SUB 9	(11/23/2016)
Lafayette Landing Apartments and Villas, LLC		
(Lafayette Landing Apartments and Villas)	WR-2152, SUB 0	(10/19/2016)
Lakeside Property Holdings, LLC		
(Lakeside Apartments)	WR-2056, SUB 0	(05/09/2016)
Landings HC3, LLC		
(Creekside Landing Apartments)	WR-2106, SUB 0	(07/07/2016)
Latitude Davis Charlotte, LLC		
(The Hamptons Apartment Homes)	WR-2038, SUB 0	(04/18/2016)
Lawndale Associates, LLC		
(2918 North Apartments at Winstead Commons)	WR-1253, SUB 3	(01/04/2016)
Lenox at Patterson Place II, LLC		
(Lenox at Patterson Place Apartments)	WR-2182, SUB 0	(11/16/2016)
Level 51 Ten, LLC		
(Haven at Patterson Place Apts.)	WR-2110, SUB 0	(08/01/2016)
Liberty Warehouse Apartments, LLC		
(Liberty Warehouse Apartments)	WR-2209, SUB 0	(12/07/2016)
Links Raleigh, LLC		
(The Links Apartments)	WR-2144, SUB 0	(11/08/2016)
LMRF Forest, LLC		
(The Forest Apartments)	WR-2039, SUB 0	(04/18/2016)
Lynden Square, LLC		
(Reserve at Providence Apartments)	WR-2080, SUB 0	(06/20/2016)
Madison Greensboro, LLC		
(Madison Woods Apartments, Phase II)	WR-1783, SUB 2	(01/26/2016)
Matthews Lofts, LLC		
(Matthews Lofts Apartments)	WR-2064, SUB 0	(05/31/2016)
Maystone at Wakefield, LLC		
(Maystone at Wakefield Apartments)	WR-2044, SUB 0	(05/23/2016)
Meridian at Fairfield Park, LLC		
(Meridian at Fairfield Park Apts.)	WR-2101, SUB 0	(07/20/2016)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
MFREVF-Piedmont, LLC		
(The Piedmont at Ivy Meadow Apts.)	WR-1190, SUB 4	(11/03/2016)
MLK Partners II, LLC		
(Hampton Meadow Apartments)	WR-2027, SUB 0	(04/11/2016)
Monument Northpoint, LLC		
(901 Center Station Apartments)	WR-2180, SUB 0	(11/16/2016)
Mountain View of Wilkesboro, LLC		
(Mountain View Apartments)	WR-1976, SUB 0	(01/12/2016)
Mountain View Park, LLC		
(Mountain View Mobile Home Park)	WR-2051, SUB 0 W-1089, SUB 7	(05/23/2016)
Myrtle Ventures, LLC		
(Myrtle Landing Apartments)	WR-2212, SUB 0	(12/15/2016)
NCB Concord Land, LLC		
(Legacy Concord Apartments)	WR-2061, SUB 0	(05/09/2016)
NHE Tract A Residential, LLC		
(Dartmouth North Hills Apartments)	WR-2176, SUB 0	(11/08/2016)
North Wendover Partners, LLC		
(The Pines on Wendover Apartments)	WR-1998, SUB 0	(02/15/2016)
NorthPoint at 68, LLC		
(Northpoint Apartments)	WR-1907, SUB 0	(01/04/2016)
Palladium Park 2, LLC		
(Palladium Park Apts., Phase II)	WR-2184, SUB 0	(11/08/2016)
Park Place Members, LLC		
(The Reserve at Park Place Apts.)	WR-2208, SUB 0	(12/07/2016)
Patriots Apartments NC, LLC		
(Patriots Apartment Homes Apartments)	WR-2013, SUB 0	(03/21/2016)
Piedmont MMXVI, LLC		
(The Piedmont at Ivy Meadows Apts.)	WR-2175, SUB 0	(11/03/2016)
Plaza Midwood Owner, LLC		
(The Gibson Apartments)	WR-2165, SUB 0	(10/20/2016)
PMC Winston-Salem, LLC		
(Quail Lakes Apartments)	WR-2062, SUB 0	(05/16/2016)
Post Parkside at Wade II, LP		
(Post Parkside at Wade II Apts.)	WR-2103, SUB 0	(07/06/2016)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Preserve Forest, LLC		
(Preserve at Lake Forest Apts.)	WR-2108, SUB 0	(07/27/2016)
RC Acres, LLC		
(Morgan Manor Mobile Home Park)	WR-2136, SUB 0	(09/20/2016)
Retreat at the Park, LLC; The		
(The Retreat at the Park Apartments)	WR-2146, SUB 0	(09/28/2016)
Ritz Development 6, LLC		
(Castle Urban Oasis Apartments)	WR-2034, SUB 0	(04/18/2016)
Rockwood Road Apts. Phase II, LLC		
(Audubon Place Apartments, Phase II)	WR-2129, SUB 0	(09/06/2016)
Schrader Family Limited Partnership		
(Meadows Apartments)	WR-980, SUB 33	(11/23/2016)
Sea Pines Apartments, LLC		
(Braxton Place Apartments)	WR-2142, SUB 0	(09/28/2016)
Seaforth NC Partners, LLC		
(Hampton at RTP Apartments)	WR-2131, SUB 0	(09/28/2016)
Simpson Woodfield Southpark, LLC		
(The Encore Southpark Apts.)	WR-2057, SUB 0	(05/03/2016)
SK Waterford, LLC		
(Waterford Place Apartments)	WR-2197, SUB 0	(12/06/2016
SOF-X Mission Matthews Place, LP		
(Mission Matthews Place Apartments)	WR-2071, SUB 0	(06/06/2016)
SOF-X Mission Triangle Point, LP		
(Mission Triangle Point Apartments)	WR-2072, SUB 0	(06/06/2016)
SOF-X Mission University Pines, LP		
(Mission University Pines Apts.)	WR-2073, SUB 0	(06/06/2016)
Solis Ballantyne Owner, LLC		
(Solis Ballantyne Apartments)	WR-2194, SUB 0	(11/23/2016)
Solis Waverly Owner, LLC		
(Solis Waverly Apartments)	WR-2104, SUB 0	(07/27/2016)
Somerstone NC, LLC		
(Somerstone at Winding Trails Apts.)	WR-2207, SUB 0	(12/13/2016)
South Park Village, LLC		
(South Park Village Apartments)	WR-2141, SUB 0	(09/28/2016)
Southport Abbington Oaks, LLC		
(Abbington Oaks Apartments)	WR-1988, SUB 0	(02/08/2016)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued (Continued)

Company	Docket No.	Date
SP&D Mt. Pleasant, LLC		
(Barringer's Trace Apartments)	WR-2069, SUB 0	(06/06/2016)
SP&D Raleigh, LLC		
(Sycamore Run Apartments)	WR-2199, SUB 0	(12/06/2016)
SP&D Shallotte, LLC		
(River Pointe Apartments)	WR-2198, SUB 0	(12/06/2016)
SP&D Sylva, LLC		
(High Ridge Apartments)	WR-2019, SUB 0	(03/28/2016)
SRC Dilworth, Inc.		
(Dilworth Apartments)	WR-2195, SUB 0	(11/23/2016)
Stafford Place, LLC		
(Stafford Place Apartments, Phase II)	WR-1573, SUB 1	(02/08/2016)
Sterling Properties Investment Group, LLC		
(Ashley Place Apartments)	WR-2017, SUB 0	(03/22/2016)
Stoney Brook MNC, LLC		
(Stoney Brook Apartments)	WR-2202, SUB 0	(11/29/2016)
Stratford Venture, LLC		
(5115 Park Place Apartments)	WR-2117, SUB 0	(08/17/2016)
TBR 1305 Owner, LLC		
(One305 Central Apartments)	WR-2174, SUB 0	(11/03/2016)
Threshold Carolina 15 – AP, LLC		
(Alexander Place Apartments)	WR-2220, SUB 0	(12/21/2016)
Threshold Carolinas 15 – CVP, LLC, et al.		
(Crossroads at Village Park Apts.)	WR-2222, SUB 0	(12/28/2016)
Threshold Carolina 15 – FR, LLC		
(Forest Ridge Apartments)	WR-2221, SUB 0	(12/21/2016)
Threshold Carolinas 15 – VB, LLC, et al.		
(The Village at Brierfield Apartments)	WR-2223, SUB 0	(12/28/2016)
TP Ninth Street Apartments, LLC		
(Solis Ninth Street Apartments)	WR-1974, SUB 0	(01/05/2016)
Triangle Real Estate of Gastonia, Inc.		
(Hudson Woods Apartments)	WR-1125, SUB 31	(10/26/2016)
Trinity Properties, LLC		
(Georgetown Apartments)	WR-1696, SUB 10	(04/18/2016)
Uptown Court, LLC		
(Uptown Court Apartments)	WR-2016, SUB 0	(03/22/2016)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Vanguard Northlake Apartments, L.P.		
(Vanguard Northlake Apartments)	WR-2047, SUB 0	(05/02/2016)
Village Creek West Properties I, LLC		
(Village Creek West Apartments)	WR-713, SUB 4	(01/19/2016)
Village Plaza Apartments, LLC		
(Alexan Chapel Hill Apartments)	WR-2201, SUB 0	(11/29/2016)
Waterford Creek, LLC		
(Waterford Creek Apartments)	WR-2086, SUB 0	(06/20/2016)
WDF-3 Wood Oberlin Owner, LLC		
(616 Oberlin Apartments)	WR-2127, SUB 0	(09/13/2016)
Wellington West, LLC		
(Poplar Terrace Mobile Home Park)	WR-2154, SUB 0	(10/25/2016)
Wendover Axcess Apartments, LLC		
(Hawthorne Crossing Apartments)	WR-2105, SUB 0	(07/18/2016)
WF Northlake JV I, LLC		
(Woodfield Northlake Apartments)	WR-2037, SUB 0	(04/19/2016)
W-GV Greenway Village Holdings VII, LLC		
(Sojourn Lake Boone Apartments)	WR-2018, SUB 0	(03/28/2016)
Woodland Heights of Greensboro, LLC		
(Woodland Heights of Greensboro Apts.)	WR-2211, SUB 0	(12/14/2016)
WOP Waterford, LLC		
(The Waterford Apartments)	WR-2063, SUB 0	(05/16/2016)
WRPV XII Addison Park Charlotte, LLC		
(Addison Park Apartments)	WR-2035, SUB 0	(04/04/2016)
1701 E. Cornwallis, LLC		
(Emory Woods Apartments)	WR-2128, SUB 0	(09/06/2016)
1752 LLC		
(Clairmont at Perry Creek Apartments)	WR-2021, SUB 0	(03/28/2016)
3500 Spanish Quarter, LLC		
(Greenbryre Apartments)	WR-2116, SUB 0	(08/17/2016)
5920 Monroe, LLC		
(Hanover Landing Apartments)	WR-1780, SUB 0	(02/29/2016)
6300 Woodbend, LLC		
(Devonwood Apartment Homes)	WR-2149, SUB 0	(09/28/2016)
905 7TH, LLC		
(Westchester Apartments)	WR-2060, SUB 0	(08/11/2016)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

Heritage Andover I, LLC -- WR-1959, SUB 0; Errata Order *(Andover Woods Apartments)* (03/04/2016)

Lynnwood Gardens Associates, LLC, et al. -- WR-1972, SUB 0; Errata Order *(Lynnwood Park Apartments)* (01/11/2016)

Patriots Apartments NC, LLC -- WR-2013, SUB 0; Errata Order *(Patriots Apartment Homes Apartments)* (04/07/2016)

Vanguard Northlake Apartments, L.P. -- WR-2047, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates *(Vanguard Northlake Apartments, L.P)* (05/02/2016)

ORDER GRANTING HWCCWA CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued

Company	Docket No.	Date
ACH-Eagle Woods, LLC		
(Eagle Woods Apartments)	WR-2055, SUB 0	(05/03/2016)
ART IV, LLC		
(Lansdale Crossing Apartments)	WR-2008, SUB 0	(03/08/2016)
Clemmons Trace Village, LLC		
(Clemmons Trace Apartments)	WR-1995, SUB 0	(02/29/2016)
Federal Home Hardee Terrace, LLC		
(Hardee Terrace Apartments)	WR-2112, SUB 0	(08/31/2016)
Federal Home Naples Terrace, LLC		
(Naples Terrace Apartments)	WR-1956, SUB 1	(06/07/2016)
G&I VIII Midtown 501, LLC		
(The Apartments at Midtown 501)	WR-2130, SUB 0	(09/13/2016)
Hawthorne Lakes, LLC		
(Hawthorne North Ridge Apartments)	WR-2155, SUB 0	(10/19/2016)
Laurel Walk, LLC		
(Reserve at Providence Apts., Phase II)	WR-2081, SUB 0	(06/20/2016)
Schrader Family Limited Partnership		
(Tivoli Gardens Apartments)	WR-980, SUB 34	(11/23/2016)
Sterling Properties Investment Group, LLC		
(Ashley Place Apartments)	WR-2017, SUB 1	(05/23/2016)

RESALE OF WATER AND SEWER – Complaint

RP Barns, LLC -- WR-1285, SUB 2; Order Dismissing Complaint and Closing Docket *(Marry Sein)* (05/09/2016)

ORDERS AND DECISIONS LISTED

RESALE OF WATER AND SEWER -- Sale/Transfer

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
AGM Autumn Park, LLC		
(7029 West Apartments)	WR-2132, SUB 0 WR-973, SUB 5	(09/08/2016)
AGM Crystal Lake, LLC		
(The Corners at Crystal Lake Apts.)	WR-2133, SUB 0 WR-22, SUB 70	(09/08/2016)
AGM Glen Eagles, LLC		
(200 Silas Apartments)	WR-2134, SUB 0 WR-975, SUB 46	(09/20/2016)
AGM Greystone, LLC		
(The Residences at West Mint Apts.)	WR-2160, SUB 0 WR-976, SUB 13	(10/13/2016)
AGM Mill Creek, LLC		
(Mill Creek Flats Apartments)	WR-2135, SUB 0 WR-975, SUB 47	(09/07/2016)
AGM Stone Point, LLC		
(The Harlowe Apartments)	WR-2157, SUB 0 WR-975, SUB 48	(10/13/2016)
Alexandarel, LLC		
(Alexander Place Apartments)	WR-2216, SUB 0 WR-1148, SUB 2	(12/15/2016)
Avery Square, LLC		
(Avery Square Apartments)	WR-2124, SUB 0 WR-1020, SUB 17	(09/13/2016)
Baseline NC Partners, LLC		
(University Center Apartments)	WR-2085, SUB 0 WR-923, SUB 6	(06/13/2016)
Bel Thornberry, LLC		
(Thornberry Apartments)	WR-2177, SUB 0 WR-1666, SUB 1	(11/03/2016)
Bel Whitehall, LLC		
(Whitehall Parc Apartments)	WR-2140, SUB 0 WR-1338, SUB 4	(09/28/2016)
BFN Steele Creek, LLC		
(Preserve at Steel Creek Apartments)	WR-2074, SUB 0 WR-1352, SUB 3	(05/31/2016)

RESALE OF WATER AND SEWER -- Sale/Transfer *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
BMPP Dilworth Limited Partnership		
(Berkshire Dilworth Apartments)	WR-2119, SUB 0 WR-1993, SUB 1	(08/24/2016)
BPP Carlson Bay, LLC		
(Carlson Bay Apartments)	WR-2188, SUB 0 WR-585, SUB 23	(11/21/2016)
BPP Meadowbrook, LLC		
(Meadowbrook at King's Grant Apts.)	WR-2187, SUB 0 WR-585, SUB 22	(11/21/2016)
BPP Stoney Ridge, LLC		
(Stoney Ridge Apartments)	WR-2196, SUB 0 WR-585, SUB 24	(12/06/2016)
BR Ashton II Owner, LLC		
(Ashton Reserve at Northlake Apartments, Phase 2)	WR-2036, SUB 0 WR-1208, SUB 4	(04/18/2016)
BRC Alexandria Park, LLC		
(Alexandria Park Apartments)	WR-2006, SUB 0 WR-830, SUB 7	(03/07/2016)
Bridgeport LL, LLC		
(Bridgeport Apartments)	WR-2151, SUB 0 WR-751, SUB 5	(10/12/2016)
Bridges at Mallard Creek, LLC		
(Bridges at Mallard Creek Apts.)	WR-2090, SUB 0 WR-1425, SUB 3	(08/11/2016)
Brooks Property Owner, LLC; The		
(The Brook Apartments)	WR-2089, SUB 0 WR-1423, SUB 3	(08/11/2016)
Cary SPE, LLC		
(Marquis at Cary Parkway Apts.)	WR-2009, SUB 0 WR-1637, SUB 2	(03/15/2016)
CCC Mezzo1, LLC, et al.		
(Mezzo1 Apartments)	WR-2067, SUB 0 WR-1669, SUB 1	(05/31/2016)
CCC Reserve at Bridford, LLC		
(Reserve at Bridford Apartments)	WR-2143, SUB 0 WR-1120, SUB 6	(09/27/2016)

RESALE OF WATER AND SEWER -- Sale/Transfer *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
CCC Verde Vista, LLC		
(Verde Vista Apartments)	WR-2115, SUB 0 WR-1296, SUB 4	(08/24/2016)
Cedar Grove NC, LLC		
(Twin City Apartments)	WR-2163, SUB 0 WR-853, SUB 7	(10/26/2016)
Centennial Afton Ridge, LLC		
(Century Afton Ridge Apartments)	WR-2113, SUB 0 WR-1494, SUB 1	(08/11/2016)
Chapel Hill at the Pointe, LLC		
(The Pointe at Chapel Hill Apts.)	WR-2065, SUB 0 WR-1033, SUB 3	(05/16/2016)
Charlotte Northlake Multifamily DST		
(Vanguard Northlake Apartments)	WR-2193, SUB 0 WR-2047, SUB 2	(11/21/2016)
Chason Ridge Apartment Complex Operating Company, LLC		
(Chason Ridge Apartments)	WR-2118, SUB 0 WR-1414, SUB 4	(08/17/2016)
CO-BB Ashford, LLC		
(Ashford Green Apartments)	WR-1978, SUB 0 WR-1341, SUB 1	(01/13/2016)
CO-BB Atria, LLC		
(Atria at Crabtree Valley Apts.)	WR-1980, SUB 0 WR-1093, SUB 2	(01/13/2016)
Creekview Professional Centre, LLC		
(Laurel Wood Mobile Home Park)	WR-1887, SUB 0 WR-1045, SUB 5	(01/19/2016)
Crescent Oaks Partners, LLC		
(Crescent Oaks Apartments)	WR-2045, SUB 0 WR-465, SUB 9	(05/02/2016)
Duraleigh Woods LL, LLC		
(Duraleigh Woods Apartments)	WR-2210, SUB 0 WR-741, SUB 8	(12/14/2016)
EBSCO Enclave, LLC		
(The Enclave at Deep River Apts.)	WR-2020, SUB 0 WR-560, SUB 4	(03/28/2016)

RESALE OF WATER AND SEWER -- Sale/Transfer *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Edwards Mill RE II, LLC, et al.		
(The Marquis on Edwards Mill Apts.)	WR-2010, SUB 0 WR-1639, SUB 2	(03/28/2016)
Elan at Mallard Creek, LLC		
(Elan at Mallard Creek Apartments)	WR-2091, SUB 0 WR-1415, SUB 3	(08/11/2016)
Elements Property Holdings, LLC		
(Elements on Park Apartments)	WR-2059, SUB 0 WR-1719, SUB 2	(05/09/2016)
Forest at Chasewood Apartments, LLC		
(The Forest at Chasewood Apts.)	WR-1997, SUB 0 WR-1504, SUB 3	(02/22/2016)
Graybul Meadows, LP		
(The Meadows Apartments, Phase II)	WR-2030, SUB 1 WR-846, SUB 14	(04/11/2016)
Heather Park Apartments (NC) Owner, LLC		
(Heather Park Apartments)	WR-2111, SUB 0 WR-94, SUB 3	(08/11/2016)
Highland Oaks Apartments, LLC		
(Highland Oaks Apartments)	WR-2066, SUB 0 WR-1137, SUB 5	(05/16/2016)
Interurban Wellington, LLP		
(Stadler Place Apartments)	WR-2028, SUB 0 WR-701, SUB 3	(04/04/2016)
Kenton Place Operating Company, LLC		
(The Reserve at Kenton Place Apts.)	WR-2122, SUB 0 WR-1609, SUB 1	(09/08/2016)
KG Commons, LLC		
(Parkland Commons Apartments)	WR-2011, SUB 0 WR-1366, SUB 4	(03/08/2016)
KG Creek, LLC		
(Copper Creek Apartments)	WR-2012, SUB 0 WR-1367, SUB 4	(03/08/2016)
Lake Brandt I, LLC, et al.		
(Lake Brandt Apartments)	WR-2166, SUB 0 WR-1368, SUB 4	(10/13/2016)

ORDERS AND DECISIONS LISTED

<u>RESALE OF WATER AND SEWER -- Sale/Transfer</u> *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

<u>Orders Issued</u> (Continued)

Company	Docket No.	Date
LHNH-86 North DE, LLC		
(86 North Apartments)	WR-2190, SUB 0 WR-1643, SUB 3	(11/16/2016)
Madison Southpark, LLC		
(Madison Southpark Apartments)	WR-2088, SUB 0 WR-1418, SUB 4	(08/11/2016)
Magnolia Terrace, LLC		
(Magnolia Terrace Apartments)	WR-2137, SUB 0 WR-1316, SUB 4	(10/13/2016)
Morehead Apartment Homes, LLC		
(The Morehead Apartments)	WR-2075, SUB 0 WR-722, SUB 7	(06/06/2016)
MP Bridges at Southpoint, LLC		
(Bridges at Southpoint Apartments)	WR-2070, SUB 0 WR-1419, SUB 3	(05/31/2016)
Nevada Springs, LLC, et al.		
(The Marq at Weston Apartments)	WR-2159, SUB 0 WR-1837, SUB 2	(10/14/2016)
PAC Citypark View, LLC		
(City Park View Apartments)	WR-2161, SUB 0 WR-1647, SUB 1	(10/20/2016)
Paces Pointe, LLC		
(Paces Pointe Apartments)	WR-2093, SUB 0 WR-1427, SUB 3	(08/11/2016)
Parke at Trinity, LLC; The		
(The Parke at Trinity Apartments)	WR-2095, SUB 0 WR-1597, SUB 3	(08/11/2016)
Parkside REC, LLC		
(Parkside Place Apartments)	WR-2040, SUB 0 WR-1803, SUB 1	(04/19/2016)
Patterson Multifamily Durham, LP		
(Realm Patterson Place Apts.)	WR-2178, SUB 0 WR-1679, SUB 2	(11/03/2016)
PC Spring Forest, LLC		
(Spring Forest at Deerfield Apts.)	WR-2046, SUB 0 WR-450, SUB 5	(05/02/2016)

RESALE OF WATER AND SEWER -- Sale/Transfer *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
PGP Cambridge Apartment, LLC		
(Cambridge on Elm Apartments)	WR-2138, SUB 0 WR-1260, SUB 3	(09/21/2016)
Pineville Apartments, LLC		
(Pineville Apartments)	WR-2082, SUB 0 WR-1760, SUB 2	(06/20/2016)
PP TIC Owner, LLC, et al.		
(The Marq at Crabtree Apartments)	WR-2052, SUB 0 WR-1630, SUB 2	(05/16/2016)
Regency Park Property Owner, LLC		
(Regency Park Apartments)	WR-2096, SUB 0 WR-1598, SUB 3	(08/11/2016)
ROC III NC Ashford Place, LLC		
(Ashford Place Apartments)	WR-2153, SUB 0 WR-1707, SUB 3	(10/05/2016)
Runaway Bay Property Holdings, LLC		
(Runaway Bay Apartments)	WR-2058, SUB 0 WR-1728, SUB 2	(05/09/2016)
Sailboat Bay LL, LLC		
(Sailboat Bay Apartments)	WR-2214, SUB 0 WR-737, SUB 8	(12/15/2016)
Sailpointe at Lake Norman, LLC		
(Sailpointe at Lake Norman Apts.)	WR-2092, SUB 0 WR-1420, SUB 4	(08/11/2016)
Southpark Commons, LLC		
(Southpark Commons Apartments)	WR-2087, SUB 0 WR-1422, SUB 3	(08/15/2016)
Sterling Forest Associates, LLC		
(Sterling Forest Apartments)	WR-1983, SUB 0 WR-1112, SUB 6	(01/13/2016)
Sterling Forest, LLC		
(The Forest Apartments)	WR-2230, SUB 0 WR-2039, SUB 1	(12/28/2016)
Sunstone I, LLC, et al.		
(Shadowood Apartments)	WR-2164, SUB 0 WR-694, SUB 7	(10/13/2016)

ORDERS AND DECISIONS LISTED

RESALE OF WATER AND SEWER -- Sale/Transfer *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Triangle Real Estate of Gastonia, Inc.		
(Legacy of Abbington Place Apts.)	WR-1125, SUB 23 WR-596, SUB 5	(05/09/2016)
TSG Mathews, LLC		
(Matthews Lofts Apartments)	WR-2217, SUB 0 WR-2064, SUB 1	(12/15/2016)
Uncommon Raleigh, LLC, et al.		
(Millbrook Green Apartments)	WR-2000, SUB 0 WR-573, SUB 8	(02/29/2016)
Vyne on Central Partners, LLC		
(The Vyne on Central Apartments)	WR-2204, SUB 0 WR-1565, SUB 4	(12/07/2016)
Waterford Valley NC Partners, LLC		
(Arboretum at Southpoint Apts.)	WR-2183, SUB 0 WR-1340, SUB 2	(11/16/2016)
Wendover at River Oaks, LLC		
(Wendover at River Oaks Apts.)	WR-1975, SUB 0 WR-719, SUB 7	(01/11/2016)
Wilmington AR Housing, LLC		
(Abbotts Run Apartments)	WR-2048, SUB 0 WR-278, SUB 6	(05/16/2016)
WRPV XII Regatta Raleigh, LLC		
(Regatta at Lake Lynn Apartments)	WR-1984, SUB 0 WR-1318, SUB 4	(01/12/2016)
XC Apartments, LLC		
(Cross Creek Apartments)	WR-2125, SUB 0 WR-875, SUB 25	(09/13/2016)
Zell 21, LLC		
(Weaverville Commons Apts.)	WR-2100, SUB 0 WR-1646, SUB 2	(06/28/2016)
2332 Dunlavin Way, LLC		
(Country Club Apartments)	WR-1781, SUB 0 WR-1600, SUB 2	(03/07/2016)
3217 Shamrock, LLC		
(Windsor Harbor Apartments)	WR-2147, SUB 0 WR-1529, SUB 2	(09/27/2016)

RESALE OF WATER AND SEWER -- Sale/Transfer *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
5115 Park Place Owner, LLC		
(5115 Park Place Apartments)	WR-2228, SUB 0 WR-2117, SUB 1	(12/28/2016)
5625 Keyway Blvd L.P.		
(Cameron at Hickory Grove Apts.)	WR-2003, SUB 0 WR-1435, SUB 4	(03/07/2016)
5725 Carnegie Boulevard Apartment Investors, LLC		
(Crescent South Park Apartments)	WR-2001, SUB 0 WR-1895, SUB 1	(02/29/2016)
6000 Delta Crossing Lane L.P.		
(Delta Crossing Apartments)	WR-2004, SUB 0 WR-1219, SUB 4	(03/07/2016)

BFN Steele Creek, LLC -- WR-2074, SUB 0; WR-1352, SUB 4; Reissued Order Granting Transfer of Certificate of Authority and Approving Rates (05/31/2016)
MAR Flagstone, LLC -- WR-1924, SUB 0; WR-1386, SUB 4; Errata Order (09/23/2016)

ORDER GRANTING HWCCWA TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
Heritage Hanover II, LLC, et al.		
(Hanover Landing Apartments)	WR-2168, SUB 0 WR-1734, SUB 1	(11/03/2016)
Heritage Osprey II, LLC, et al.		
(Osprey Landing Apartments)	WR-2169, SUB 0 WR-1735, SUB 1	(11/03/2016)
Silverstone Partners, LLC		
(Silverstone Apartments)	WR-2026, SUB 0 WR-1355, SUB 3	(03/29/2016)
Vista Villa Holdings #1, LLC		
(Vista Villa Apartments)	WR-2139, SUB 0 WR-1711, SUB 2	(09/28/2016)
34 North Apts., LLC		
(34 North Apartments)	WR-2167, SUB 0 WR-1736, SUB 1	(11/03/2016)

RESALE OF WATER AND SEWER -- Sale/Transfer *(Continued)*

Graybul Meadows, LP -- WR-2030, SUB 0; WR-846, SUB 13; Order Granting Transfer of HWCCWA Certificate of Authority and Approving Rates *(The Meadows Apartments, Phase I)* (04/11/2016)

MP Woods Edge, LLC -- WR-2068, SUB 0; WR-1417, SUB 2; Order Granting Transfer of HWCCWA Certificate of Authority and Approving Rates (05/31/2016)

Woodlyn on the Green, LLC -- WR-2094, SUB 0; WR-1426, SUB 2; Order Granting Transfer of HWCCWA Certificate of Authority and Approving Rates *(Woodlyn on the Green Apartments)* (08/11/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION
Orders Issued

Company	Docket No.	Date
AB Merion II Thornhill, LLC		
(Thornhill Apartments)	WR-1867, SUB 1	(11/01/2016)
Abberly Green – Mooresville – Phase I, L.P.		
(Abberly Green Apts., Phase I)	WR-457, SUB 6	(03/21/2016)
Abberly Green – Mooresville – Phase II, L.P.		
(Abberly Green Apts., Phase II)	WR-686, SUB 4	(03/21/2016)
Abberly Place Place – Garner – Phase I Limited Partnership		
(Abberly Place Apartments)	WR-305, SUB 10	(07/05/2016)
Addington Ridge, LLC		
(Addington Ridge Apartments)	WR-1656, SUB 2	(12/06/2016)
Addison Point, LLC		
(Addison Point Apartments)	WR-748, SUB 8	(08/23/2016)
Admiral Pointe, LLC		
(Admiral Pointe Apartments)	WR-1205, SUB 2	(11/15/2016)
AERC Arboretum, LP		
(The Arboretum Apartments)	WR-1277, SUB 3	(11/02/2016)
AERC Blakeney, LP		
(The Apartments at Blakeney)	WR-1547, SUB 3	(10/28/2016)
AERC Crossroads, LP		
(The Park at Crossroads Apartments)	WR-1328, SUB 3	(10/27/2016)
AERC Lofts Lakeside, LP		
(Lofts at Weston Apartments)	WR-1586, SUB 4	(10/28/2016)
AERC Southpoint, LP		
(Southpoint Village Apartments)	WR-1312, SUB 3	(10/28/2016)
AERC St. Mary's, LP		
(St. Mary's Square Apartments)	WR-1587, SUB 4	(10/25/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
Allen's MHP, LLC		
(Dogwood Hills Mobile Home Park)	WR-1575, SUB 2	(09/07/2016)
Amberton at Stonewater, LLC		
(Amberton at Stonewater Apartments)	WR-1455, SUB 3	(11/03/2016)
Amelia Station, LLC		
(Amelia Station Apartments)	WR-1632, SUB 1	(02/22/2016)
Ansley Falls Apartments, LLC		
(Ansley Falls Apartments)	WR-1603, SUB 3	(11/08/2016)
Apartments at Crossroads, LLC; The		
(Legacy Crossroads Apartments)	WR-851, SUB 8	(08/15/2016)
Apex Road, LLC		
(Phillips Chatham Pointe Apts.)	WR-1103, SUB 1	(09/21/2016)
AR I Borrower, LLC		
(Ashton Reserve at Northlake Apts.)	WR-1585, SUB 3	(08/24/2016)
Arbor Steele Creek, LLC		
(Arbor Steele Creek Apartments)	WR-1499, SUB 2	(03/21/2016)
(Arbor Steele Creek Apartments)	WR-1499, SUB 3	(11/15/2016)
ARIM Crossroads, LLC		
(Crossroads North Hills Apartments)	WR-1748, SUB 2	(08/08/2016)
Arium McAlpine Creek Owner, LLC		
(Arium McAlpine Creek Apartments)	WR-1790, SUB 1	(03/15/2016)
Arium Pineville LL, LLC		
(Arium Pineville Apartments)	WR-1760, SUB 1	(03/15/2016)
Arium Pinnacle Ridge, LP		
(Pinnacle Ridge Apartments)	WR-1770, SUB 1	(03/15/2016)
ARWC – 808 Lakecrest Avenue, LLC		
(Chatham Woods Apartments)	WR-1969, SUB 1	(12/13/2016)
Asheville Apartments Investors, LLC		
(Reserve at Asheville Apartments)	WR-1327, SUB 4	(11/02/2016)
Asheville Exchange Apartments, LLC		
(Asheville Exchange Apartments)	WR-2002, SUB 1	(11/01/2016)
Asheville Housing, LLC		
(Evolve Mountain View Apartments)	WR-1916, SUB 1	(11/29/2016)
Ashley Park, LLC		
(Solis Sharon Square Apartments)	WR-1576, SUB 2	(11/21/2016)
Ashton Village Limited Partnership		
(Abberly Place Apartments, Ph. II)	WR-802, SUB 9	(07/05/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Atwood, LLC		
(Knollwood Apartments)	WR-1283, SUB 3	(08/24/2016)
Auston Grove – Raleigh Apartments, LP		
(Auston Grove Apartments)	WR-233, SUB 14	(01/25/2016)
(Auston Grove Apartments)	WR-233, SUB 15	(07/05/2016)
Auston Woods – Charlotte – Phase I Apts. L.P.		
(Auston Woods I Apartments)	WR-232, SUB 7	(03/14/2016)
(Auston Woods I Apartments)	WR-232, SUB 8	(08/08/2016)
Auston Woods – Charlotte – Phase II Apts. L.P.		
(Auston Woods II Apartments)	WR-721, SUB 7	(03/14/2016)
(Auston Woods II Apartments)	WR-721, SUB 8	(08/08/2016)
Autumn Park Owner, LLC		
(Autumn Park Charlotte Apts.)	WR-1378, SUB 4	(10/26/2016)
Autumn Ridge RS, LLC, et al.		
(Autumn Ridge Apartments)	WR-1016, SUB 2	(08/17/2016)
Avery Millbrook, LLC		
(Millbrook Apartments 2)	WR-1020, SUB 15	(08/23/2016)
(Millbrook Apartments I)	WR-1020, SUB 16	(08/23/2016)
AVR Charlotte Perimeter Lofts, LLC		
(Perimeter Lofts Apartments)	WR-1739, SUB 2	(08/24/2016)
AVR Charlotte Perimeter Station, LLC		
(Perimeter Station Apartments)	WR-1738, SUB 2	(08/24/2016)
AVR Davis Raleigh, LLC		
(Jones Grant Urban Flats Apts.)	WR-1813, SUB 1	(11/07/2016)
Barrington Apartments, LLC		
(Legacy North Pointe Apts.)	WR-384, SUB 14	(08/01/2016)
Baseline NC Partners, LLC		
(University Center Apartments)	WR-2085, SUB 1	(10/18/2016)
Battleground North Apartments, LLC		
(Battleground North Apartments)	WR-672, SUB 7	(11/02/2016)
BBR/Barrington, LLC		
(Barrington Place Apartments)	WR-619, SUB 9	(08/22/2016)
Beachwood Associates, LLC		
(Beachwood Park Apartments)	WR-880, SUB 5	(07/05/2016)
Beachwood II Associates, LLC		
(Loch Raven Pointe Apartments)	WR-1824, SUB 2	(07/05/2016)
Bel Pineville Holdings, LLC		
(Berkshire Place Apartments)	WR-1037, SUB 6	(08/09/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Bel Ridge Holdings, LLC		
(McAlpine Ridge Apartments)	WR-1053, SUB 6	(08/11/2016)
Bell Fund IV Morrisville Apartments, LLC		
(Bell Preston View Apartments)	WR-1391, SUB 4	(08/02/2016)
Bell Fund V Hawfield Farms, LP		
(Bell Ballantyne Apartments)	WR-1904, SUB 1	(08/10/2016)
Bell Fund V Wakefield, LLC		
(Bell Wakefield Apartments)	WR-1540, SUB 3	(08/10/2016)
Belle Haven Acquisition, LLC		
(Belle Haven Apartments)	WR-1822, SUB 3	(12/12/2016)
Belle Meade Development Partners, LLC		
(Belle Meade Apartments)	WR-1942, SUB 1	(09/13/2016)
Berkeley Apartments, LLC		
(Berkeley Apartments, Phase I)	WR-1985, SUB 1	(08/30/2016)
BFN Steele Creek, LLC		
(Preserve at Steele Creek Apts.)	WR-2074, SUB 1	(10/20/2016)
BHC – Hawthorne Pinnacle Ridge, LLC		
(Hawthorne Northside Apartments)	WR-1513, SUB 3	(08/17/2016)
BHI-SEI Mariners, LLC		
(Mariners Crossing Apartments)	WR-1228, SUB 3	(11/07/2016)
BIG Arbor Village NC, LLC		
(Arbor Village Apartments)	WR-1660, SUB 1	(01/19/2016)
(Arbor Village Apartments)	WR-1660, SUB 2	(08/29/2016)
BMA Bellemeade Apartments, LLC		
(Highland Ridge Apartments)	WR-814, SUB 5	(01/20/2016)
(Highland Ridge Apartments)	WR-814, SUB 6	(10/25/2016)
BMA Eden Apartments, LLC		
(Arbor Glen Apartments)	WR-728, SUB 7	(10/25/2016)
BMA Huntersville Apartments, LLC		
(Huntersville Apartments)	WR-811, SUB 8	(10/25/2016)
BMA Monroe III Apartments, LLC		
(Woodbrook Apartments)	WR-812, SUB 9	(10/25/2016)
BMA North Sharon Amity, LLC		
(Sharon Pointe Apartments)	WR-810, SUB 8	(10/25/2016)
BMA Oxford Apartments, LLC		
(Autumn Park Apartments)	WR-710, SUB 4	(11/16/2016)
BMA Wexford, LLC		
(Wexford Apartments)	WR-813, SUB 8	(10/25/2016)

ORDERS AND DECISIONS LISTED

<u>RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through</u> *(Continued)*

ORDER APPROVING TARIFF REVISION
<u>*Orders Issued*</u> *(Continued)*

Company	Docket No.	Date
BMPP Main Street Limited Partnership		
(Berkshire Main Street Apartments)	WR-1891, SUB 1	(11/21/2016)
BR Ashton II Owner, LLC		
(Ashton Reserve at Northlake Apts., Ph. 2)	WR-2036, SUB 1	(11/08/2016)
BR Park & Kingston Charlotte, LLC		
(Park and Kingston Apartments)	WR-1795, SUB 3	(08/10/2016)
BRC Abernathy, LLC, et al.		
(Abernathy Park Apartments)	WR-1057, SUB 6	(08/08/2016)
BRC Alexandria Park, LLC		
(Alexandria Park Apartments)	WR-2006, SUB 1	(10/20/2016)
BRC Charlotte 485, LLC		
(Halton Park Apartments)	WR-501, SUB 9	(08/09/2016)
BRC Knightdale, LLC		
(Berkshire Park Apartments)	WR-938, SUB 8	(08/09/2016)
BRC Majestic Apartments, LLC		
(Palladium Park Apartments)	WR-374, SUB 8	(10/20/2016)
BRC Salisbury, LLC		
(Salisbury Village Apartments)	WR-500, SUB 7	(08/08/2016)
BRC Wilson, LLC		
(Thornberry Park Apartments)	WR-502, SUB 6	(08/08/2016)
Breckenridge Group CNC, LLC		
(Aspen Charlotte Apartments)	WR-1815, SUB 2	(08/09/2016)
Brentwood Apartments of Mooresville, LLC		
(Ridgeview Apartments)	WR-1875, SUB 1	(10/19/2016)
Bridford Property Company, LLC		
(Bridford West Apartments)	WR-1994, SUB 1	(10/19/2016)
Brightwood Crossing Apartments, LLC		
(Brightwood Crossing Apartments)	WR-543, SUB 6	(09/13/2016)
BRK Kensington Place, LP		
(Kensington Place Apartments)	WR-1733, SUB 2	(08/09/2016)
BRK Matthews, LP		
(Matthews Pointe Apartments)	WR-1732, SUB 2	(08/09/2016)
BRK Waterford Hills, LP		
(Waterford Hills Apartments)	WR-1737, SUB 2	(08/09/2016)
BRNA, LLC		
(Bryn Athyn Apartments)	WR-75, SUB 16	(07/28/2016)
Brookberry Park Apartments, LLC		
(Brookberry Park Apartments)	WR-798, SUB 9	(11/02/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Brookstown Winston-Salem Apartments, LLC		
(Link Apartments Brookstown)	WR-1618, SUB 2	(09/27/2016)
BR-TBR Whetstone Owner, LLC		
(Whetstone Apartments)	WR-1881, SUB 1	(10/11/2016)
Bryant Park Apartments, LLC		
(Morehead West Apartments)	WR-1687, SUB 2	(11/07/2016)
BWP North Pointe Holdco, LLC		
(Altera North Pointe Apartments)	WR-1950, SUB 1	(11/03/2016)
Cambridge NC Warwick, LLC		
(Cambridge Apartments)	WR-514, SUB 7	(04/18/2016)
(Cambridge Apartments)	WR-514, SUB 8	(07/05/2016)
Camden Glen, LLC		
(Emerson Glen Apartments)	WR-1913, SUB 1	(10/28/2016)
Camden Summit Partnership, LP		
(Camden Simsbury Apartments)	WR-6, SUB 176	(08/15/2016)
(Camden South End Square Apts.)	WR-6, SUB 177	(08/15/2016)
(Camden Fairview Apartments)	WR-6, SUB 178	(08/15/2016)
(Camden Cotton Mills Apts.)	WR-6, SUB 179	(08/15/2016)
(Camden Touchstone Apts.)	WR-6, SUB 180	(08/15/2016)
(Camden Stonecrest Apartments)	WR-6, SUB 181	(08/15/2016)
(Camden Overlook Apartments)	WR-6, SUB 182	(08/15/2016)
(Camden Crest Apartments)	WR-6, SUB 183	(08/15/2016)
(Camden Foxcroft Apartments)	WR-6, SUB 184	(08/15/2016)
Camden USA, LLC		
(Camden Gallery Apartments)	WR-1836, SUB 2	(08/16/2016)
Carlisle at Delta Park, LLC; The		
(The Carlisle at Delta Park Apts.)	WR-388, SUB 6	(02/29/2016)
Carlyle Centennial Parkside, LLC		
(Century Parkside Apartments)	WR-942, SUB 7	(08/31/2016)
Carrington Park CAF II, LLC		
(Carrington Park Apartments)	WR-1686, SUB 2	(10/26/2016)
Carroll at Cityview, LLC		
(Carroll at Cityview Apts.)	WR-1838, SUB 1	(10/28/2016)
Cary Custom Investor I, LLC, et al.		
(Amberwood Apartments)	WR-2031, SUB 1	(08/29/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
CCC Brassfield Park, LLC		
(Brassfield Park Apartments)	WR-1619, SUB 3	(08/10/2016)
CCC Forest at Biltmore Park, LLC, et al.		
(Forest at Biltmore Park Apartments)	WR-1742, SUB 2	(08/02/2016)
(Forest at Biltmore Park Apartments)	WR-1742, SUB 3	(08/24/2016)
CCC Gallery Lofts, LLC		
(Gallery Lofts Apartments)	WR-1708, SUB 2	(12/19/2016)
CCC Mezzo1, LLC, et al.		
(Mezzo1 Apartments)	WR-2067, SUB 1	(08/09/2016)
CCC One Norman Square, LLC		
(One Norman Square Apartments)	WR-1628, SUB 2	(08/10/2016)
CCC Summerlin Ridge, LLC		
(Summerlin Ridge Apts.)	WR-1805, SUB 2	(12/19/2016)
CCC Uptown Gardens, LLC		
(Uptown Gardens Apartments)	WR-1794, SUB 2	(09/26/2016)
Cedar Trace, LLC		
(Cedar Trace Apartments)	WR-897, SUB 8	(08/23/2016)
CEG Friendly Manor, LLC		
(Legacy at Friendly Manor Apartments)	WR-266, SUB 10	(08/08/2016)
Centennial Addington Farms, LLC		
(Century Trinity Estates Apartments)	WR-1403, SUB 4	(08/16/2016)
Centennial Highland Creek, LLC		
(Century Highland Creek Apts.)	WR-1952, SUB 1	(08/15/2016)
Centennial Northlake, LLC		
(Century Northlake Apartments)	WR-1661, SUB 3	(08/16/2016)
Centennial Tryon Place, LLC		
(Century Tryon Place Apartments)	WR-1897, SUB 1	(08/16/2016)
CH Realty V/Park and Market, LLC		
(Park and Market Apartments)	WR-1303, SUB 4	(08/10/2016)
Chapman; Roy and Betty		
(Twin Willows Mobile Home Park)	WR-1035, SUB 6	(10/04/2016)
Clemmons Town Center Apartments, LLC		
(Clemmons Towncenter Apartments)	WR-1756, SUB 1	(04/18/2016)
Clover Lane, LLC		
(Mordecai on Clover Apartments)	WR-1941, SUB 1	(08/31/2016)
CND Bridgeport, LLC		
(Birdgeport Apartments)	WR-751, SUB 4	(01/12/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
CND Duraleigh Woods, LLC		
(Duraleigh Woods Apartments)	WR-741, SUB 7	(09/07/2016)
CND Sailboat Bay, LLC		
(Sailboat Bay Apartments)	WR-737, SUB 7	(08/31/2016)
Cogdill; Gregory Scott		
(Springside Mobile Home Park)	WR-1925, SUB 1	(08/29/2016)
Colonial NC, LLC		
(Colonial Townhouse Apartments)	WR-1284, SUB 5	(07/28/2016)
Commonwealth Road Properties, LLC		
(Enclave at Pamalee Square Apts.)	WR-1069, SUB 5	(06/20/2016)
Community Investments, LLC		
(Lone Pine Mobile Home Park)	WR-877, SUB 2	(12/21/2016)
(Cross Creek Pond Mobile Home Park)	WR-877, SUB 3	(12/21/2016)
Coral Stone, LLC		
(Forest Pointe 2 Apartments)	WR-1876, SUB 1	(07/26/2016)
Courtney Estates Grand, LLC		
(The Crossings at Alexander Place Apts.)	WR-729, SUB 7	(08/09/2016)
Courtney NC, LLC		
(Oakwood Raleigh at Brier Creek Apts.)	WR-1908, SUB 1	(08/24/2016)
Courtney Oaks Apartments, LLC		
(Courtney Oaks Apartments)	WR-1884, SUB 1	(08/11/2016)
Courtney Ridge H. E., LLC		
(Courtney Ridge Apartments)	WR-321, SUB 9	(01/25/2016)
(Courtney Ridge Apartments)	WR-321, SUB 10	(09/14/2016)
Creekview Professional Centre, LLC		
(Laurel Wood Mobile Home Park)	WR-1887, SUB 1	(08/29/2016)
Crestmont at Ballantyne Apartments, LLC		
(Legacy at Ballantyne Apartments)	WR-335, SUB 12	(08/01/2016)
Crescent Commons Apartment Property, LLC		
(Crescent Commons Apartments)	WR-460, SUB 9	(08/09/2016)
Cross Point NC Partners, LLC		
(Sardis Place at Matthews Apartments)	WR-1851, SUB 1	(10/18/2016)
Crossing at Chester Ridge, LLC		
(Crossing at Chester Ridge Apts.)	WR-1560, SUB 2	(12/20/2016)
CSC Parkside, LLC		
(Parkside Five Points Apartments)	WR-1911, SUB 1	(08/31/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
CSP Community Owner, LLC		
(Camden Ballantyne Apartments)	WR-909, SUB 30	(08/16/2016)
(Camden Dilworth Apartments)	WR-909, SUB 31	(08/16/2016)
(Camden Sedgebrook Apartments)	WR-909, SUB 32	(08/16/2016)
(Camden Westwood Apartments)	WR-909, SUB 33	(08/16/2016)
(Camden Manor Park Apartments)	WR-909, SUB 34	(08/16/2016)
CSP Hunt's View, LLC		
(Hunt's View Apartments)	WR-1217, SUB 5	(08/10/2016)
Cumberland Cove, LLC		
(Cumberland Cove Apartments)	WR-1771, SUB 2	(11/02/2016)
DLS Kernersville, LLC		
(Abbotts Creek Apartments)	WR-19, SUB 13	(11/02/2016)
Donathan/Briarleigh Park Properties, LLC		
(Briarleigh Park Apartments)	WR-797, SUB 9	(11/02/2016)
Donathan Cary Limited Partnership		
(Hyde Park Apartments)	WR-558, SUB 10	(08/08/2016)
Dowtin; James M.		
(Tall Pines Mobile Home Park)	WR-1577, SUB 3	(10/17/2016)
DPR Cary, LLC		
(The Reserve at Cary Park Apts.)	WR-1743, SUB 2	(12/14/2016)
DPR Parc at University Tower, LLC		
(Parc at University Tower Apts.)	WR-1384, SUB 4	(11/02/2016)
DRA Lodge at Mallard Creek, LP		
(The Lodge at Mallard Creek Apts.)	WR-854, SUB 8	(08/09/2016)
DRA Woodland Park, LP		
(Woodland Park Apartments)	WR-861, SUB 7	(08/10/2016)
Duckett, Jr.; Gordon F. & Susan C. Duckett		
(Forest Ridge Mobile Home Park)	WR-928, SUB 8	(10/04/2016)
Durham Holdings #1, LLC		
(Amber Oaks Apartments)	WR-1467, SUB 3	(10/10/2016)
Durham Mews Section II Associates, LLC		
(The Mews Apartments, Section II)	WR-884, SUB 5	(11/08/2016)
Durham Section I Associates, LLC		
(The Mews Apartments, Section I)	WR-883, SUB 5	(10/13/2016)
Eagle Point Village Apartments, LLC		
(Eagle Point Village Apartments)	WR-671, SUB 8	(11/02/2016)
EBSCO Enclave, LLC		
(The Enclave at Deep River Apts.)	WR-2020, SUB 1	(11/16/2016)
Echo Forest, LLC		
(Legacy Arboretum Apartments)	WR-368, SUB 12	(08/01/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
Edgeline Residential, LLC		
(Edgeline Flats on Davidson Apts.)	WR-1567, SUB 2	(01/26/2016)
(Edgeline Flats on Davidson Apts.)	WR-1567, SUB 3	(08/08/2016)
Edgewood Place, LLC		
(Edgewood Place Apartments)	WR-1511, SUB 1	(11/15/2016)
EEA-North Pointe, LLC		
(Sherwood Station Apartments)	WR-1028, SUB 4	(01/12/2016)
EEA-Wildwood, LLC		
(Wildwood Apartments)	WR-629, SUB 8	(09/13/2016)
El-Ad Summerlin at Concord, LLC		
(Summerlin at Concord Apartments)	WR-1056, SUB 1	(03/29/2016)
Elan Raleigh Property, LLC		
(Elan City Center Apartments)	WR-1928, SUB 1	(11/07/2016)
Ellington Farms Apartments, LLC		
(Ellington Farms Apartments)	WR-1900, SUB 1	(08/17/2016)
Elite Street Capital Lincoln Green DE, LLC		
(Lincoln Green Apartments)	WR-1936, SUB 1	(08/10/2016)
Elizabeth Square Acquisition Corp.		
(Elizabeth Square Apartments)	WR-1086, SUB 5	(09/07/2016)
Ellis Road Apartments I, LP		
(Villages at Ellis Crossing Apts.)	WR-2078, SUB 1	(08/17/2016)
Elon Crossing, LLC		
(Elon Crossing Apartments)	WR-1535, SUB 3	(07/26/2016)
ELPF Station Nine, LLC		
(Station Nine Apartments)	WR-724, SUB 7	(03/14/2016)
Emmett Ramsey		
(Emma Hills Mobile Home Park)	WR-796, SUB 7	(10/04/2016)
Enclave at Crossroads, LLC		
(Enclave at Crossroads Apartments)	WR-1922, SUB 1	(10/26/2016)
E. O. Johnson Properties Limited Partnership		
(Sedgefield Square Apartments)	WR-1191, SUB 4	(10/03/2016)
Erwin Hills Park, LLC		
(Erwin Hills Mobile HP)	WR-946, SUB 7	(08/16/2016)
Estates at Charlotte I, LLC		
(1420 Magnolia Apartments)	WR-73, SUB 8	(10/10/2016)
Everest Brampton, LP		
(Brampton Moors Apartments)	WR-1091, SUB 6	(11/03/2016)
Ewing; Roy and Frances		
(Pine Valley Mobile Home Park)	WR-994, SUB 7	(08/16/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
Fairway Apartments, LLC; The, et al.		
(The Links Apartments)	WR-565, SUB 6	(02/29/2016)
Falls River Apartments, LLC		
(Bell Falls River Apartments)	WR-1110, SUB 6	(08/10/2016)
FASF, LLC		
(Cedar Trace IV Apartments)	WR-999, SUB 7	(08/23/2016)
Featherstone Village Apartments, LLC		
(Featherstone Village Apartments)	WR-375, SUB 10	(11/02/2016)
Flat Creek Village Apartments, LLC		
(Flat Creek Village Apartments)	WR-1964, SUB 1	(09/06/2016)
Forest at Chasewood Apartments, LLC		
(The Forest at Chasewood Apts.)	WR-1997, SUB 1	(09/27/2016)
Forest MMXII, LLC		
(Copper Creek Apartments)	WR-1367, SUB 3	(02/15/2016)
Forestdale W99 LAP, LLC		
(Hawthorne at Forestdale Apartments)	WR-1847, SUB 2	(09/12/2016)
Fortune Bay Associates, LLC		
(Forest Pointe Apartments)	WR-785, SUB 10	(07/25/2016)
Franklin Ventures V, LLC		
(The Franklin Apartments)	WR-1939, SUB 1	(08/08/2016)
Free Throw NC Partners, LLC		
(The Pointe Apartments)	WR-1855, SUB 1	(10/18/2016)
Fund Asbury Village, LLC		
(Camden Asbury Village Apartments)	WR-1211, SUB 2	(08/16/2016)
Fund III Bridford Apartments, LLC		
(Bell Bridford Apartments)	WR-1120, SUB 5	(08/10/2016)
Fund III Cranbrook Apartments, LLC, et al.		
(Bell Biltmore Park Apartments)	WR-1076, SUB 6	(08/09/2016)
Fund Southline, LLC		
(Camden Southline Apartments)	WR-1789, SUB 2	(08/16/2016)
G Colonial, LLC		
(Empire Crossing Apartments)	WR-1829, SUB 3	(08/15/2016)
(Colonial Apts., Phases 5 & 6)	WR-1829, SUB 4	(08/15/2016)
(Autumn Trace Apts., Phase 1)	WR-1829, SUB 5	(08/15/2016)
G Partnership, LP		
(The Landings Apartments)	WR-1262, SUB 3	(08/17/2016)
Galleria Partners II, LLC		
(The Crest Apartments at Galleria)	WR-925, SUB 4	(08/23/2016)
Gateway West-FCA, LLC		
(Gateway West Uptown Flats Apts.)	WR-1561, SUB 2	(10/04/2016)

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ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
GECMC 2007-C1 Treetop Drive, LLC		
(Cumberland Trace Apartments)	WR-1126, SUB 4	(10/03/2016)
GF Property Funding Corp.		
(Garrett West Apartments)	WR-1534, SUB 3	(11/08/2016)
GGT Patterson Place NC Venture, LLC		
(REALM Patterson Place Apts.)	WR-1679, SUB 1	(01/11/2016)
Ginkgo Kimmerly, LLC		
(Kimmerly Glen Apartments)	WR-1729, SUB 2	(12/20/2016)
Glenhaven G, LLC		
(Glen Haven Apartments, Phase 3)	WR-1873, SUB 1	(10/19/2016)
Glenhaven K, LLC		
(Glen Haven Apartments, Phase 1 & 2)	WR-1872, SUB 1	(10/19/2016)
Glenwood Raleigh Apartments, LLC		
(Sterling Glenwood Apartments)	WR-1833, SUB 2	(11/21/2016)
Glenwood South Raleigh Apartments, LLC		
(Link Glenwood South Apartments)	WR-1877, SUB 1	(08/29/2016)
Golden Triangle #1, LLC		
(Crest at Greylyn Apartments)	WR-1400, SUB 3	(08/22/2016)
Golden Triangle #4 – 5th Street, LLC		
(Crest Gateway Apartments)	WR-1809, SUB 1	(04/11/2016)
(Crest Gateway Apartments)	WR-1809, SUB 2	(09/12/2016)
Goldsboro Properties, LLC		
(Granville Oaks Apartment Homes)	WR-1263, SUB 1	(11/01/2016)
GQ Allerton, LLC		
(Allerton Place Apartments)	WR-1608, SUB 3	(09/20/2016)
GQ Lynn Lake, LLC		
(Lynn Lake Apartments)	WR-1726, SUB 2	(10/10/2016)
GQ Millbrook, LLC		
(Millbrook Apartments)	WR-1725, SUB 2	(10/10/2016)
Graham Street Apartments, LLC		
(Circa Uptown Apartments)	WR-2015, SUB 1	(12/12/2016)
Grand View Holdings, LLC		
(Grand View Apartments)	WR-2042, SUB 1	(09/26/2016)
Granite Ridge Investments, LLC		
(Granite Ridge Apartments)	WR-295, SUB 7	(11/15/2016)
Gray Woodfield Glen, LLC		
(Woodfield Glen Apartments)	WR-1141, SUB 4	(12/05/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
Graybul Meadows, LP		
(The Meadows Apartments, Phase II)	WR-2030, SUB 3	(10/17/2016)
Graybul Woods Edge, LP		
(Woods Edge Apartments)	WR-1581, SUB 1	(10/17/2016)
Grays Land Apartments, LLC		
(Hawthorne at the Grove Apartments)	WR-1927, SUB 1	(02/08/2016)
(Hawthorne at the Grove Apartments)	WR-1927, SUB 2	(08/17/2016)
Greenway at Fisher Park, LLC		
(Greenway at Fisher Park Apts.)	WR-1322, SUB 3	(10/13/2016)
Greenway at Stadium Park, LLC		
(Greenway at Stadium Park Apartments)	WR-1909, SUB 1	(08/22/2016)
Grey Eagle MHP, LLC		
(Grey Eagle Mobile Home Park)	WR-1546, SUB 3	(10/04/2016)
Greystone WW Company, LLC		
(Greystone at Widewaters Apartments)	WR-517, SUB 9	(07/26/2016)
GS Edinborough Commons, LLC		
(Edinborough Commons Apartments)	WR-475, SUB 11	(09/27/2016)
GS Edinborough Park, LLC		
(Edinborough at the Park Apts.)	WR-476, SUB 9	(10/20/2016)
GS Village, LLC		
(The Village Apartments)	WR-564, SUB 11	(09/14/2016)
Hamilton Florida Partners, LLC		
(Hamilton Square Apartments)	WR-841, SUB 5	(11/29/2016)
Hamilton Ridge Property Corp.		
(Hamilton Ridge Apartments)	WR-1946, SUB 1	(10/20/2016)
Hanover Terrace, LLC		
(Hanover Terrace Apartments)	WR-622, SUB 9	(07/29/2016)
Happy Hill, Inc.		
(Willow Lake Mobile Home Park)	WR-512, SUB 4	(12/21/2016)
Harris Pointe, LLC		
(Harris Pointe Apartments)	WR-756, SUB 6	(05/02/2016)
Hawkins Street Holdings, LLC		
(Spectrum Apartments)	WR-1011, SUB 6	(11/02/2016)
Hawthorne-Charleston Strickland, LLC, et al.		
(Hawthorne Glen at Strickland Apts.)	WR-1778, SUB 2	(08/17/2016)
Hawthorne-Midway Cadence, LLC		
(Hawthorne at the Peak Apartments)	WR-1485, SUB 2	(09/12/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

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Company	Docket No.	Date
Hawthorne-Midway Dunhill, LLC		
(Hawthorne at the Trace Apts.)	WR-1430, SUB 3	(08/17/2016)
Hawthorne-Midway Meadows, LLC		
(Hawthorne at the Meadows Apts.)	WR-1307, SUB 4	(12/14/2016)
Hawthorne-Midway Stratford, LLC, et al.		
(Hawthorne at the Parkway Apts.)	WR-1553, SUB 3	(08/17/2016)
Hawthorne-Midway Summerwood, LLC		
(Hawthorne at the Hall Apartments)	WR-1194, SUB 6	(12/13/2016)
Hawthorne-Midway Venue, LLC, et al.		
(Hawthorne at Lake Norman Apts.)	WR-1845, SUB 1	(02/15/2016)
Hawthorne-Midway Vista Park, LLC		
(Hawthorne at the Greene Apartments)	WR-1349, SUB 2	(11/15/2016)
Hayleigh Village Apartments, LLC		
(Hayleigh Village Apartments)	WR-1152, SUB 4	(11/03/2016)
Henson Place, LLC		
(Henson Place Apartments)	WR-755, SUB 4	(11/15/2016)
Heritage Andover I, LLC, et al.		
(Andover Woods Apartments)	WR-1959, SUB 1	(07/29/2016)
Heritage Arden I, LLC, et al.		
(Arden Woods Apartments)	WR-1298, SUB 4	(07/06/2016)
Heritage at Arlington Apts., LLC; The		
(The Heritage at Arlington Apts.)	WR-1472, SUB 3	(08/31/2016)
Heritage at Arlington Apts. Phase II, LLC; The		
(The Heritage at Arlington Apts., Phase II)	WR-1986, SUB 1	(09/26/2016)
Heritage Circle Apartments, LLC		
(Heritage Circle Apartments)	WR-1625, SUB 2	(10/20/2016)
Heritage Gardens, LLC		
(Ardmore Heritage Apartments)	WR-1533, SUB 2	(09/13/2016)
Heritage Pointe NC Partners, LLC		
(Hunt Club Apartments)	WR-1852, SUB 1	(10/18/2016)
Heritage Williamsburg I, LLC, et al.		
(Williamsburg Manor Apartments)	WR-1299, SUB 4	(08/08/2016)
Hidden Creek Village Apartments, LLC		
(Hidden Creek Village Apartments)	WR-377, SUB 10	(11/02/2016)
Highland Park Investors II, LLC, et al.		
(Highland Park Apartments)	WR-1999, SUB 1	(08/16/2016)
Highland Quarters, LLC		
(Muirfield Village Apartments)	WR-520, SUB 10	(08/30/2016)
Highlands at Olde Raleigh, LLC		
(Highlands at Olde Raleigh Apts.)	WR-1443, SUB 3	(08/24/2016)

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ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Highpoint Associates, LLC		
(Laurel Bluff Apartments)	WR-570, SUB 3	(12/12/2016)
Holly NC, LLC		
(Holly Hills Apartments)	WR-1290, SUB 5	(07/27/2016)
Horizon Development Properties, Inc.		
(Mill Pond Apartments)	WR-1075, SUB 3	(08/17/2016)
HRTBH Timber Creek, LLC		
(Timber Creek Apartments)	WR-1761, SUB 2	(10/11/2016)
HTC Preston Reserve, LLC, et al.		
(Bell Preston Reserve Apartments)	WR-1180, SUB 5	(08/01/2016)
Hudson Capital Park Forest, LLC		
(Park Forest Apartments)	WR-1869, SUB 1	(08/10/2016)
Hudson Capital Steeplechase, LLC		
(Steeplechase Apartments)	WR-1868, SUB 1	(08/10/2016)
I & G Direct Real Estate 41, LP		
(Residence at South Park Apts.)	WR-2025, SUB 1	(12/05/2016)
Inman Park Investment Group, Inc.		
(Inman Park Apartments)	WR-383, SUB 13	(07/27/2016)
Innisbrook Village, LLC		
(Innisbrook Village Apartments)	WR-1278, SUB 4	(11/03/2016)
Interurban Wellington, LLP		
(Stadler Place Apartments)	WR-2028, SUB 1	(10/12/2016)
IRT Lenoxplace Apartments Owner, LLC		
(Lenoxplace at Garners Station Apts.)	WR-1713, SUB 2	(10/27/2016)
Johnston Road Apartments, LLC		
(Element South Apartments)	WR-1849, SUB 1	(11/29/2016)
Jones; Joe T. & JoAnn		
(Asbury Acres Mobile Home Park)	WR-1677, SUB 2	(08/29/2016)
Juliet Place Holdings, LLC		
(Juliet Place Apartments)	WR-1859, SUB 1	(04/11/2016)
Junction 1504, LLC		
(Junction 1504 Apartments)	WR-1559, SUB 2	(08/29/2016)
K Colonial, LLC		
(Colonial Apartments, Phase 3)	WR-1943, SUB 2	(08/15/2016)
(Autumn Trace Apts., Phases 2 & 3)	WR-1943, SUB 3	(08/15/2016)
K Partnership, LLC		
(Hampton Downs Apartments)	WR-1631, SUB 2	(08/15/2016)
KBS Legacy Partners Grand, LLC		
(Legacy Grand at Concord Apartments)	WR-1594, SUB 1	(04/11/2016)

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KBS Legacy Partners Wesley, LLC		
(Wesley Village Apartments)	WR-1379, SUB 2	(03/07/2016)
(Wesley Village Apartments)	WR-1379, SUB 3	(09/12/2016)
KC Realty Investments, LLC		
(Glimmer Mobile Home Park)	WR-950, SUB 11	(08/29/2016)
(Woodland Heights Mobile HP)	WR-950, SUB 12	(08/29/2016)
(Oteen Mobile Home Park)	WR-950, SUB 13	(08/29/2016)
KG Commons, LLC		
(Parkland Commons Apartments)	WR-2011, SUB 1	(08/02/2016)
KG Creek, LLC		
(Copper Creek Apartments)	WR-2012, SUB 1	(08/02/2016)
Kings Park, LLC		
(Redcliffe at Kenton Place Apts.)	WR-349, SUB 13	(11/22/2016)
Kip-Dell Homes, Inc.		
(Pine Winds Apartments, Phase I)	WR-341, SUB 6	(04/29/2016)
Koury Corporation		
(Village Lofts Apartments)	WR-595, SUB 8	(09/20/2016)
Lakeshore Apartments, LLC		
(The Lodge at Lakeshore Apts.)	WR-649, SUB 8	(08/23/2016)
Lancaster GCI, LLC, et al.		
(Legacy 521 Apartments)	WR-1879, SUB 1	(08/01/2016)
Landmark at Brighton Colony, LLC		
(Landmark at Brighton Colony Apts.)	WR-1488, SUB 1	(03/07/2016)
Landmark at Eagle Landing, LP		
(Landmark at Eagle Landing Apts.)	WR-1465, SUB 2	(08/30/2016)
Landmark at Watercrest, LP		
(Watercrest Apts.)	WR-1466, SUB 2	(08/30/2016)
LaSalle NC, LLC		
(Duke Manor Apartments)	WR-1286, SUB 5	(07/28/2016)
Lawndale Associates, LLC		
(2918 North Apartments at Winstead Comm.)	WR-1253, SUB 4	(08/24/2016)
LCD Properties, LLC		
(Mountain View Mobile Home Court)	WR-932, SUB 4	(08/08/2016)
LCP Durham, LLC		
(Foxfire Apartments)	WR-1914, SUB 1	(08/15/2016)
Ledges Apartments, LLC; The		
(The Ledges Apartments)	WR-1678, SUB 1	(12/20/2016)

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Company	Docket No.	Date
Lees Chapel Partners, LLC		
(Chapel Walk Apartments)	WR-875, SUB 24	(08/23/2016)
Legacy at Twin Oaks, LLC		
(Legacy at Twin Oaks Apartments)	WR-1353, SUB 4	(08/08/2016)
Legacy at Wakefield/HF, LLC, et al.		
(Legacy at Wakefield Apartments)	WR-1667, SUB 1	(03/21/2016)
(Legacy at Wakefield Apartments)	WR-1667, SUB 2	(09/14/2016)
Legacy Cornelius, LLC		
(Legacy Cornelius Apartments)	WR-1388, SUB 4	(08/01/2016)
Legacy Matthews, LLC		
(Legacy Matthews Apts.)	WR-568, SUB 10	(08/01/2016)
Legacy Oaks Apartments, LP		
(Alta Legacy Oaks Apartments)	WR-972, SUB 9	(09/14/2016)
Legends at Hickory, LLC; The		
(The Legends Apartments)	WR-1409, SUB 4	(09/14/2016)
Litchford Park, LLC		
(The Park at North Ridge Apts.)	WR-588, SUB 10	(08/10/2016)
Live Oak Apartments, LLC		
(Ashley Square at SouthPark Apts.)	WR-1041, SUB 1	(12/06/2016)
LMI-South Kings Development, LLC		
(Midtown 205 Apartments)	WR-1866, SUB 1	(10/03/2016)
Lofts at Charleston Row, LLC; The		
(The Lofts at Charleston Row Apts.)	WR-1313, SUB 3	(09/12/2016)
Lofts at Little Creek, LLC; The		
(The Lofts at Little Creek Apts.)	WR-1626, SUB 2	(11/21/2016)
Lone Oak, LLC		
(Lone Oak Mobile Home Park)	WR-1084, SUB 5	(08/31/2016)
Loray Mill Redevelopment, LLC		
(Loray Mill Lofts Apartments)	WR-1615, SUB 1	(08/17/2016)
LSREF3 Bravo (Charlotte), LLC		
(Harris Pond Apartments)	WR-1718, SUB 12	(08/03/2016)
(Mallard Creek Apartments)	WR-1718, SUB 13	(08/03/2016)
(Northlake Apartments)	WR-1718, SUB 14	(08/03/2016)
(Providence Court Apartments)	WR-1718, SUB 15	(08/03/2016)
(Sharon Crossing Apartments)	WR-1718, SUB 16	(08/03/2016)
(Harris Pond Apartments)	WR-1718, SUB 17	(08/05/2016)

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RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

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Company	Docket No.	Date
LSREF3 Bravo (Raleigh), LLC		
(Oaks at Weston Apartments)	WR-1717, SUB 13	(08/03/2016)
(The Meadows of Kildare Apartments)	WR-1717, SUB 14	(08/03/2016)
(Cooper Mill Apartments)	WR-1717, SUB 15	(08/03/2016)
(Spring Forest Apartments)	WR-1717, SUB 16	(08/09/2016)
(The Reserve at Lake Lynn Apts.)	WR-1717, SUB 17	(08/09/2016)
(Walnut Creek Apartments)	WR-1717, SUB 18	(08/09/2016)
LWH Ashley Oaks Apartments, LP		
(Ashley Oaks Apartments)	WR-1953, SUB 1	(08/29/2016)
Lynden Square, LLC		
(Reserve at Providence Apts.)	WR-2080, SUB 1	(09/13/2016)
Lynnwood Gardens Associates, LLC, et al.		
(Lynnwood Park Apartments)	WR-1972, SUB 1	(07/26/2016)
M Realty, LLC		
(Wellington Mobile Home Park)	WR-1040, SUB 5	(07/29/2016)
MA Ethan Pointe at Burlington, LLC		
(Ethan Pointe Apartments)	WR-1894, SUB 1	(09/14/2016)
Madison Greensboro, LLC		
(Madison Woods Apartments, Phase II)	WR-1783, SUB 4	(09/20/2016)
Maggard; David		
(Quiet Hollow Mobile Home Park)	WR-632, SUB 7	(10/04/2016)
Mallard Green, LLC		
(Mallard Green Apartments)	WR-1259, SUB 5	(08/30/2016)
Marsh Realty Company		
(Biscayne Apartments)	WR-1154, SUB 18	(09/26/2016)
(Briar Creek Apartments)	WR-1154, SUB 19	(09/26/2016)
(Park Place Apartments)	WR-1154, SUB 20	(09/26/2016)
Matthews Reserve, LLC		
(Matthews Reserve Apartments)	WR-557, SUB 5	(10/12/2016)
Mayfaire Apartments, LLC		
(Mayfaire Apartments)	WR-345, SUB 8	(07/07/2016)
Maystone at Wakefield, LLC		
(Maystone at Wakefield Apartments)	WR-2044, SUB 1	(11/02/2016)
Mellow Field Partners, LLC		
(The Avenues Apartments)	WR-1564, SUB 3	(10/28/2016)
Mercury NoDa Apartments, LLC		
(Mercury NoDa Apartments)	WR-1954, SUB 1	(11/16/2016)

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Company	Docket No.	Date
Meridian at Harrison Pointe, LLC		
(Meridian at Harrison Pointe Apts.)	WR-1568, SUB 2	(08/17/2016)
Meridian/H.C., LLC		
(Legacy at Meridian Apartments)	WR-1500, SUB 2	(03/07/2016)
(Legacy at Meridian Apartments)	WR-1500, SUB 3	(09/20/2016)
Metro 808 Charlotte, LLC		
(Metro 808 Apartments)	WR-1714, SUB 2	(11/29/2016)
Midtown Apartment Homes, LLC		
(One Midtown Apartments)	WR-1793, SUB 1	(02/22/2016)
Midtown Crossing PML, LLC		
(Midtown Crossing Apartments)	WR-900, SUB 3	(04/18/2016)
(Midtown Crossing Apartments)	WR-900, SUB 4	(08/11/2016)
Misty Oaks NC Partners, LLC		
(The Oaks Apartments)	WR-1856, SUB 1	(10/18/2016)
MLK Partners II, LLC		
(Hampton Meadows Apartments)	WR-2027, SUB 1	(11/07/2016)
Morehead Apartment Homes, LLC		
(The Morehead Apartments)	WR-2075, SUB 1	(07/12/2016)
Morganton Place Apartments, LLC		
(Morganton Place Apartments)	WR-782, SUB 4	(06/13/2016)
Morreene, LLC		
(Chapel Tower Apartments)	WR-1289, SUB 5	(07/27/2016)
Morrisville Associates, LLC		
(Crabtree Crossing Townhomes Apts.)	WR-879, SUB 5	(08/29/2016)
Moss; Allen H.		
(Crestview II Mobile Home Park)	WR-896, SUB 14	(08/02/2016)
(Maple Terrace Mobile Home Park)	WR-896, SUB 15	(08/02/2016)
Moss Enterprises, Inc. of Asheville		
(Crownpointe Mobile Home Park)	WR-924, SUB 16	(08/02/2016)
(Mosswood/Twin Oaks MHP)	WR-924, SUB 17	(08/02/2016)
Mosteller Apartments, LLC		
(The Estates at Legends Apartments)	WR-1404, SUB 5	(09/14/2016)
Mountain High Property Management, LLC		
(Becky's Mobile Home Park)	WR-1556, SUB 3	(10/04/2016)
MP Artisan Brightleaf Apartments, LLC		
(Artisan at Brightleaf Apartments)	WR-1478, SUB 4	(09/27/2016)
MP Beacon Glen, LLC		
(Market Station Apartments)	WR-1665, SUB 3	(10/19/2016)

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Company	Docket No.	Date
MP Bridges at Southpoint, LLC		
(Bridges at Southpoint Apts.)	WR-2070, SUB 1	(09/12/2016)
MRWR, LLC		
(Atrium Apartments)	WR-832, SUB 9	(07/28/2016)
NationsProperties, LLC		
(Arbor Crest II Apartments)	WR-821, SUB 3	(10/20/2016)
NCB Concord Land, LLC		
(Legacy Concord Apartments)	WR-2061, SUB 1	(08/15/2016)
NC2, LLC		
(Beechwood Apartments)	WR-1730, SUB 1	(03/14/2016)
New Brookstone, LLC		
(Brookstone Apartments)	WR-138, SUB 5	(08/08/2016)
New Haw Creek Associates, LLC		
(Haw Creek Mews Apts.)	WR-624, SUB 5	(08/08/2016)
New Park Ridge Associates, LLC		
(Park Ridge Estates Apartments)	WR-1225, SUB 3	(12/13/2016)
New Willow Ridge Associates, LLC		
(Willow Ridge Apartments)	WR-212, SUB 6	(12/14/2016)
Nicholas; Ruby Lea		
(Woodcrest Mobile Home Park)	WR-249, SUB 8	(02/15/2016)
NNN Enclave Apartments, LLC, et al.		
(The Enclave at Deep River Apartments)	WR-560, SUB 3	(01/20/2016)
North Carolina Rental Parks Associates, Ltd.		
(Whispering Pines MHP)	WR-1070, SUB 6	(08/16/2016)
North Wendover Partners, LLC		
(The Pines on Wendover Apartments)	WR-1998, SUB 1	(08/09/2016)
Northlake Madison Properties, LLC, et al.		
(Madison Square Apartments)	WR-1807, SUB 2	(10/27/2016)
Northland Governor's Point, LLC		
(Governor's Point Apartments)	WR-1257, SUB 5	(08/29/2016)
Northland River Birch, LLC		
(River Birch Apartments, Phase II)	WR-1258, SUB 4	(08/10/2016)
Northland River Birch I, LLC		
(River Birch Apartments, Phase I)	WR-1248, SUB 4	(08/10/2016)
Northland Windemere, LLC		
(Windemere Apartments)	WR-1369, SUB 4	(08/29/2016)
Norwalk Street Partners, LLC		
(Andover Park Apartments)	WR-653, SUB 9	(08/08/2016)
NP Six Forks, LLC		
(Junction Six Forks Apartments)	WR-1948, SUB 1	(09/08/2016)

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Company	Docket No.	Date
NR Holly Crest Property Owner, LLC		
(Holly Crest Apartments)	WR-1816, SUB 2	(11/15/2016)
NR Palladian Property Owner, LLC		
(The Apartments at Palladian Place)	WR-1721, SUB 1	(07/06/2016)
NXRTBH Radbourne Lake, LLC		
(The Apartments at Radbourne Lake)	WR-1722, SUB 2	(10/11/2016)
One Hilltop, LLC		
(Hilltop Mobile Home Park)	WR-1077, SUB 5	(12/20/2016)
P&M Winston-Salem, LLC		
(Quail Lakes Apartments)	WR-2062, SUB 1	(12/28/2016)
Paces Village, LLC		
(The Pointe at Irving Park Apts.)	WR-1554, SUB 1	(11/22/2016)
Park Commons MMXII, LLC		
(Parkland Commons Apartments)	WR-1366, SUB 3	(02/15/2016)
Parkside REC, LLC		
(Parkside Place Apartments)	WR-2040, SUB 1	(10/19/2016)
Passco Brier Creek DST		
(Carrington at Brier Creek Apartments)	WR-1614, SUB 3	(10/11/2016)
Passco Encore at the Park DST		
(Encore at the Park Apartments)	WR-1498, SUB 3	(11/01/2016)
Passco Rivergate DST		
(Enclave at Rivergate Apartments)	WR-1433, SUB 4	(10/26/2016)
Passco Wakefield Glen DST		
(Wakefield Glen Apartments)	WR-1582, SUB 3	(10/03/2016)
Pavilion Village, LLC		
(Pavilion Village Apartments)	WR-1932, SUB 1	(04/04/2016)
PC Links, LLC		
(Links at Citiside Apartments)	WR-1149, SUB 6	(08/17/2016)
PG2, LLC		
(The Gardens at Anthony House Apts., Ph. 2)	WR-1487, SUB 3	(08/23/2016)
Phillips Mallard Creek, LLC		
(Philips Mallard Creek Apartments)	WR-1310, SUB 1	(08/30/2016)
Phillips Selwyn, LLC		
(3400 Selwyn Apartments)	WR-959, SUB 3	(08/31/2016)
Piedmont Place Apts. Property Investors, LLC		
(Piedmont Place Apartments)	WR-1801, SUB 1	(08/17/2016)
Pier Properties, LLC		
(Grassy Branch Mobile Home Park)	WR-1138, SUB 3	(10/25/2016)

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Company	Docket No.	Date
Pine Knoll Mobile Home Park, LLC		
(Pine Knoll Mobile Home Park)	WR-1434, SUB 4	(08/22/2016)
Piper Station Apartments, LLC		
(Rock Creek at Ballantyne Commons Apts.)	WR-1432, SUB 6	(09/13/2016)
Plantation at Horse Pen, LLC		
(Hawthorne at Horse Pen Creek Apts.)	WR-1484, SUB 2	(09/12/2016)
Pleasant Garden Apartments, LLC		
(The Gardens at Anthony House Apts.)	WR-742, SUB 8	(08/23/2016)
POAA II, LLC		
(Pines of Ashton Apartments)	WR-1282, SUB 5	(07/29/2016)
Post Apartment Homes, LP		
(Post Uptown Place Apartments)	WR-49, SUB 20	(07/18/2016)
(Post Park at Phillips Place Apts.)	WR-49, SUB 21	(07/18/2016)
Post Ballantyne, LLC		
(Post Ballantyne Apartments)	WR-1543, SUB 3	(07/18/2016)
Post Gateway Place, LLC		
(Post Gateway Place Apartments)	WR-1542, SUB 2	(07/18/2016)
Post Parkside at Wade, LP		
(Post Parkside at Wade Apts.)	WR-1440, SUB 3	(07/18/2016)
Post South End, LP		
(Post South End Apartments)	WR-1326, SUB 4	(07/18/2016)
PR Oberlin Court, LLC		
(The Apartments at Oberlin Court)	WR-1179, SUB 4	(09/07/2016)
PRG Bainbridge Associates, LLC		
(Bainbridge in the Park Apts.)	WR-1356, SUB 2	(12/14/2016)
PRG Falls at Duraleigh Associates, LLC		
(The Falls Apartments)	WR-1800, SUB 1	(12/14/2016)
PRG Windsor Square Associates, LLC		
(South Square Townhomes Apts.)	WR-1226, SUB 3	(12/13/2016)
Privet Asheville, LLC		
(Eastwood Village Apartments)	WR-1320, SUB 4	(08/01/2016)
Providence Park Apartments I, LLC		
(Providence Park Apartments)	WR-284, SUB 13	(09/26/2016)
Quadbridge HML Owner, LLC		
(Highland Mill Lofts Apartments)	WR-1613, SUB 3	(07/26/2016)
RAIA Properties NC-2, LLC		
(Birkdale Apartment Homes)	WR-839, SUB 9	(10/26/2016)
Raleigh Multifamily Partners, LLC		
(Regency Place Apartments)	WR-1621, SUB 2	(02/01/2016)

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Company	Docket No.	Date
REEP-MF Verde NC, LLC		
(North City 6 Apartments)	WR-1087, SUB 6	(09/06/2016)
Rehobeth Pointe Holdings, LLC		
(Rehobeth Pointe Apartments)	WR-1860, SUB 1	(04/11/2016)
Research Park, LLC		
(Phillips Research Park Apartments)	WR-1470, SUB 1	(09/21/2016)
Residences at Brookline, LLC		
(Residences at Brookline Apts.)	WR-1915, SUB 1	(08/09/2016)
RFI Highlands, LLC		
(The Highlands at Alexander Point Apts.)	WR-1294, SUB 3	(04/04/2016)
(The Highlands at Alexander Point Apts.)	WR-1294, SUB 4	(10/05/2016)
Ridgeview MHP, LLC		
(Ridgeview Mobile Home Park)	WR-712, SUB 8	(08/16/2016)
Rivergate Apartment Investors, LLC		
(Tryon Park at Rivergate Apts.)	WR-1926, SUB 1	(07/26/2016)
Riverwalk Denver, LLC		
(Riverwalk Apartments)	WR-1658, SUB 1	(05/03/2016)
(Riverwalk Apartments)	WR-1658, SUB 2	(11/03/2016)
Rockwood Road Apts., LLC		
(Audubon Place Apts., Phase I)	WR-964, SUB 6	(09/06/2016)
RRE Farrington Holdings, LLC		
(4040 Crosstown at Chapel Hill Apts.)	WR-1870, SUB 1	(12/20/2016)
Ryan; Jack, LLC		
(673 Sand Hill Road Apartments)	WR-1777, SUB 1	(01/11/2016)
(673 Sand Hill Road Apartments)	WR-1777, SUB 2	(10/04/2016)
Ryder Downs, LLC		
(Ryder Downs Apartments)	WR-1830, SUB 1	(09/13/2016)
Salem Ridge Apartments, LLC		
(Salem Ridge Apartments)	WR-1096, SUB 5	(12/20/2016)
Salem Village Apartments, LLC		
(Salem Village Apartments)	WR-446, SUB 10	(09/26/2016)
SBV-Greensboro-I, LLC		
(The Retreat II Apartments)	WR-1471, SUB 9	(08/17/2016)
(The Retreat I Apartments)	WR-1471, SUB 10	(10/10/2016)
(The Retreat II Apartments)	WR-1471, SUB 11	(10/27/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
SCG/TBR Venue Owner, LLC		
(Venue Apartments)	WR-1799, SUB 2	(07/26/2016)
Schrader Family Limited Partnership		
(Green Castle Apartments)	WR-980, SUB 26	(07/25/2016)
(Dover Apartments)	WR-980, SUB 27	(07/25/2016)
(Peterson Park Apartments)	WR-980, SUB 29	(07/25/2016)
(Westcliffe Apartments)	WR-980, SUB 30	(07/25/2016)
(Woodridge Apartments)	WR-980, SUB 31	(07/25/2016)
Schrader; Michael J.		
(Campus West Apartments)	WR-795, SUB 4	(07/25/2016)
Schrader Properties, LLC		
(Campus Courtyard Apartments)	WR-1334, SUB 4	(07/25/2016)
Serenity Apartments at Greensboro, LLC		
(Serenity Apartments)	WR-1502, SUB 2	(09/07/2016)
Sherwood MHP, LLC		
(Sherwood Mobile Home Park)	WR-1044, SUB 6	(08/16/2016)
Skyhouse Raleigh, LLC		
(Skyhouse Raleigh Apartments)	WR-1784, SUB 1	(03/21/2016)
(Skyhouse Raleigh Apartments)	WR-1784, SUB 2	(09/20/2016)
Somerstone, LLC		
(Somerstone Apartments)	WR-1557, SUB 3	(08/22/2016)
South End Apartments, LLC		
(Mosaic South End Apartments)	WR-1173, SUB 5	(08/29/2016)
South LaSalle Apartments, LLC		
(The Heights at LaSalle Apartments)	WR-1629, SUB 2	(10/03/2016)
South Square Owner, LLC		
(Alden Place at South Square Apts.)	WR-1387, SUB 4	(10/26/2016)
South Terrace Apartments North Carolina, LLC		
(South Terrace Apartments)	WR-689, SUB 6	(10/27/2016)
Southport Heather Ridge, LLC		
(Heather Ridge Apartments)	WR-1082, SUB 4	(08/22/2016)
Sovereign Development Company, LLC		
(Willow Woods Apartments)	WR-784, SUB 6	(01/11/2016)
SPUS7 Tribute, LP		
(The Tribute Apartments)	WR-1846, SUB 2	(09/14/2016)
SRC Northwinds, Inc.		
(Northwinds I and II Apartments)	WR-1254, SUB 5	(09/27/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Sterling Arbor Creek, LLC		
(Arbor Creek Apartments)	WR-1906, SUB 1	(09/14/2016)
Sterling Forest Associates, LLC		
(Sterling Forest Apartments)	WR-1983, SUB 1	(11/07/2016)
Sterling Reserve at Magnolia Ridge LLC		
(Reserve at Magnolia Ridge Apts.)	WR-1949, SUB 1	(08/30/2016)
Sterling TC Property Owner, LLC		
(Sterling Town Center Apartments)	WR-1710, SUB 1	(02/01/2016)
Strawberry Hill Associates, LP		
(Strawberry Hills Apartments)	WR-293, SUB 11	(09/26/2016)
Summerlyn Holdings, LLC		
(Summerlyn Cottages Apartments)	WR-1689, SUB 2	(07/20/2016)
Summermill at Falls River Apartments, LLC		
(Summermill at Falls River Apts.)	WR-1892, SUB 1	(11/08/2016)
Summit Grandview, LLC		
(Camden Grandview Apartments)	WR-547, SUB 6	(08/16/2016)
Summit Street, LLC		
(District Flats Apartments)	WR-1741, SUB 2	(10/11/2016)
SVF Weston Lakeside, LLC		
(Weston Lakeside Apartments)	WR-601, SUB 9	(09/06/2016)
SWHR Mooresville, LLC		
(The Grove at Morrison Plantation Apts.)	WR-1599, SUB 1	(10/10/2016)
Swift Avenue-FCA, LLC		
(300 Swift Apartments)	WR-1727, SUB 2	(10/11/2016)
Tau Valley, LLC		
(Tau Valley Apartments)	WR-823, SUB 4	(03/28/2016)
Terrace Mews, LLC		
(Terrace at Olde Battleground Apts.)	WR-1394, SUB 3	(08/17/2016)
Terrace Oaks, LLC		
(Terrace Oaks Apartments)	WR-1945, SUB 1	(09/14/2016)
Tilden Legacy Beech Lake Apartments, LLC		
(Beech Lake Apartments)	WR-1947, SUB 1	(12/20/2016)
Town Square West, LLC		
(Biltmore Park Town Square Apts.)	WR-862, SUB 3	(09/07/2016)
TP Ninth Street Apartments, LLC		
(Solis Ninth Street Apartments)	WR-1974, SUB 1	(12/20/2016)
TP 1100 South Blvd, LLC		
(1100 South Apartments)	WR-1817, SUB 1	(02/15/2016)
(1100 South Apartments)	WR-1817, SUB 2	(11/28/2016)

ORDERS AND DECISIONS LISTED

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
TR Vinoy, LLC		
(The Vinoy at Innovation Park Apts.)	WR-1308, SUB 4	(10/11/2016)
Trade & Graham Associates, LLC		
(The Mint Apartments)	WR-1966, SUB 1	(10/11/2016)
Tradition at Stonewater Apartments, LLC		
(Tradition at Stonewater Apartments)	WR-1723, SUB 2	(11/08/2016)
TRB Oberlin Owner, LLC		
(401 Oberlin Apartments)	WR-1792, SUB 2	(07/05/2016)
Trellis Pointe, LLC		
(Trellis Pointe Apartments)	WR-14, SUB 3	(11/01/2016)
Treybrooke, LLC		
(Treybrooke Apartments)	WR-824, SUB 3	(03/28/2016)
Treybrooke Village Apartments, LLC		
(Treybrooke Village Apartments)	WR-379, SUB 10	(11/02/2016)
Triangle Palisades of Asheville, Inc		
(Palisades Apartments)	WR-1787, SUB 2	(08/30/2016)
Triangle Real Estate of Gastonia, LLC		
(Huntersville Commons Apartments)	WR-1125, SUB 24	(07/28/2016)
(Arborgate Apartments)	WR-1125, SUB 25	(07/28/2016)
(Eagle's Walk Apartments)	WR-1125, SUB 26	(07/28/2016)
(Lake Mist Apartments)	WR-1125, SUB 27	(07/28/2016)
(Woodbridge Apartments)	WR-1125, SUB 28	(07/28/2016)
(Pinetree Apartments)	WR-1125, SUB 29	(07/28/2016)
(Avalon at Sweeten Creek Apartments)	WR-1125, SUB 30	(08/30/2016)
Triple Overlook, LLC		
(Triple Overlook Mobile Home Park)	WR-1047, SUB 6	(08/16/2016)
Trotter Company		
(Elmsley Grove Apartments)	WR-593, SUB 2	(03/14/2016)
(Elmsley Grove Apartments)	WR-593, SUB 3	(10/03/2016)
TS Brier Creek, LLC		
(Waterstone at Brier Creek Apts.)	WR-1620, SUB 2	(10/27/2016)
TS Creekstone, LLC		
(Woodfield Creekstone Apartments)	WR-1461, SUB 4	(10/27/2016)
TS New Bern, LLC		
(Fountains Southend Apartments)	WR-1541, SUB 3	(10/27/2016)
TS Westmont, LLC		
(Westmont Commons Apts.)	WR-1462, SUB 4	(10/25/2016)
Tucker Acquisition Corporation		
(The Devon Seven 12 Apartments)	WR-1039, SUB 6	(08/31/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Tyler's Ridge Apartments, LLC		
(Tyler's Ridge Apartments)	WR-1507, SUB 1	(08/08/2016)
Umstead Raleigh Investors, LLC		
(The Seasons at Umstead Apartments)	WR-1772, SUB 2	(09/14/2016)
Uncommon Raleigh, LLC, et al.		
(North Hills Town Center Apartments)	WR-2000, SUB 1	(09/20/2016)
Uptown Court, LLC		
(Uptown Court Apartments)	WR-2016, SUB 1	(08/09/2016)
Vanstory Apartments, LLC		
(Ashbrook Pointe Apartments)	WR-126, SUB 14	(08/08/2016)
VCP Grand Oaks, LLC		
(Grand Oaks Apartments)	WR-1648, SUB 2	(08/22/2016)
VCP Lakes Meadowood, LLC		
(The Lakes on Meadowood Apartments)	WR-1810, SUB 2	(10/11/2016)
VCP The Ashland, LLC		
(The Ashland Apartments)	WR-1811, SUB 2	(10/05/2016)
Village at Cliffdale Apartments, LLC		
(Village at Cliffdale Apartments)	WR-842, SUB 4	(06/13/2016)
Village Creek West Properties I, LLC		
(Village Creek West Apartments)	WR-713, SUB 5	(09/06/2016)
Village (Locust), LLC; The		
(The Village Apartments)	WR-1008, SUB 1	(10/05/2016)
Villas at Granite Ridge, LLC		
(The Villas at Granite Ridge Apts.)	WR-1788, SUB 2	(11/15/2016)
Vinings at Morehead, LLC		
(Vinings at Wildwood Apartments)	WR-1216, SUB 2	(12/06/2016)
VR Cedar Springs Limited Partnership		
(Cedar Springs Apartments)	WR-1158, SUB 4	(07/18/2016)
VTT Carver Pond, LLC		
(Meriwether Place Apartments)	WR-1509, SUB 3	(08/10/2016)
VTT Charlotte, LLC		
(Woodland Estates Apartments)	WR-1506, SUB 2	(08/10/2016)
W-GV Greenway Village Holdings VII, LLC		
(Sojourn Lake Boone Apartments)	WR-2018, SUB 1	(08/29/2016)
Walden Court, Inc.		
(Walden Court Apartments)	WR-1878, SUB 1	(08/02/2016)
Walnut Ridge Partners Limited Partnership		
(Walnut Ridge Apartments)	WR-152, SUB 9	(10/04/2016)

ORDERS AND DECISIONS LISTED

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
Water Garden Village, LLC		
(Water Garden Village Apartments)	WR-1315, SUB 4	(07/11/2016)
Water Oak NC Partners, LLC		
(The Regency Apartments)	WR-1850, SUB 1	(10/18/2016)
Waterford Square Apartments Associates, LLC		
(Waterford Square Apartments)	WR-251, SUB 8	(08/08/2016)
Waterstone Weddington Partners, LLC		
(Waterstone at Weddington Apartments)	WR-1583, SUB 2	(03/29/2016)
Waverly Apartments, LLC		
(The Waverly Apartments)	WR-1293, SUB 5	(08/10/2016)
Waypoint Stone Hollow Owner, LLC		
(Reserve at Stone Hollow Apartments)	WR-1611, SUB 3	(08/17/2016)
WE Montclaire Estates, LLC		
(Montclaire Estates Apartments)	WR-1636, SUB 1	(02/29/2016)
Wembley Apartments, LLC		
(Wembley Apartments)	WR-1017, SUB 3	(07/29/2016)
Wendover at River Oaks, LLC		
(Wendover at River Oaks Apartments)	WR-1975, SUB 1	(08/24/2016)
West Market Partners, LLC		
(The Amesbury on West Market Apts.)	WR-749, SUB 8	(08/22/2016)
Westdale Arrowhead Crossing NC, LLC		
(Arrowhead Crossing Apartments)	WR-634, SUB 9	(10/24/2016)
Westdale Brentmoor, LLC		
(Brentmoor Apartments)	WR-1317, SUB 4	(10/24/2016)
Westdale Chase on Monroe NC, LLC		
(Chase on Monroe Apartments)	WR-635, SUB 9	(10/24/2016)
Westdale Galleria Village, LLC		
(Galleria Apartments Homes)	WR-1224, SUB 5	(10/24/2016)
Westdale NC Summit Creek, Ltd.		
(Johnston Creek Crossing Apts.)	WR-826, SUB 8	(10/24/2016)
Westdale Peppertree, Ltd.		
(Peppertree Apartments)	WR-815, SUB 8	(10/24/2016)
Westdale Sabal Point NC, LLC		
(Sabal Point Apartments)	WR-636, SUB 9	(10/24/2016)
Westdale Willow Glen NC, LLC		
(Willow Glen Apartments)	WR-633, SUB 9	(10/24/2016)
Westridge Place, LLC		
(Westridge Place Apartments)	WR-637, SUB 4	(11/15/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
Westridge Village, LLC		
(Westridge Village Apartments)	WR-1142, SUB 2	(12/06/2016)
Wilkinson High Point I, LLC		
(Fox Hollow Apartments)	WR-1670, SUB 1	(01/12/2016)
(Fox Hollow Apartments)	WR-1670, SUB 2	(12/13/2016)
Wilkinson High Point II, LLC		
(Eastchester Ridge Apartments)	WR-1762, SUB 1	(01/12/2016)
(Eastchester Ridge Apartments)	WR-1762, SUB 3	(12/13/2016)
Willow Run, LLC		
(Willow Run Apartments)	WR-1827, SUB 1	(10/03/2016)
Windridge Apartments, LLC		
(Windridge Apartments)	WR-1655, SUB 1	(04/11/2016)
(Windridge Apartments)	WR-1655, SUB 2	(10/05/2016)
Windsor Burlington, LLC		
(Windsor Upon Stonecrest Apts.)	WR-594, SUB 5	(09/14/2016)
Winter Oaks NC Partners, LLC		
(Aurea Station Apartments)	WR-1853, SUB 1	(10/18/2016)
WMCi Charlotte I, LLC		
(Bexley Commons at Rosedale Apts.)	WR-213, SUB 14	(07/19/2016)
WMCi Charlotte II, LLC		
(Bexley Creekside Apartments)	WR-230, SUB 13	(07/19/2016)
WMCi Charlotte III, LLC		
(Bexley at Lake Norman Apts.)	WR-258, SUB 13	(07/19/2016)
WMCi Charlotte IV, LLC		
(Bexley Crossing at Providence Apts.)	WR-269, SUB 13	(07/19/2016)
WMCi Charlotte V, LLC		
(Bexley at Springs Farm Apts.)	WR-340, SUB 12	(07/19/2016)
WMCi Charlotte VII, LLC		
(Bexley at Davidson Apartments)	WR-392, SUB 11	(07/19/2016)
WMCi Charlotte VIII, LLC		
(Bexley at Matthews Apartments)	WR-466, SUB 11	(07/19/2016)
WMCi Charlotte IX, LLC		
(Bexley Greenway Apartments)	WR-467, SUB 11	(07/19/2016)
WMCi Charlotte X, LLC		
(Bexley at Harborside Apts.)	WR-638, SUB 9	(07/19/2016)
WMCi Charlotte XI, LLC		
(Bexley Steelecroft Apartments)	WR-1117, SUB 6	(07/20/2016)
WMCi Charlotte XII, LLC		
(Bexley Cloisters at Steelecroft Apts.)	WR-1136, SUB 5	(07/20/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
WMCi Charlotte XV, LLC		
(Cielo Apartments)	WR-1486, SUB 3	(07/20/2016)
WMCi Raleigh I, LLC		
(Bexley at Preston Apartments)	WR-327, SUB 11	(07/26/2016)
WMCi Raleigh II, LLC		
(Bexley Park Apartments)	WR-317, SUB 11	(07/26/2016)
WMCi Raleigh III, LLC		
(Bexley at Brier Creek Apartments)	WR-754, SUB 12	(07/20/2016)
WMCi Raleigh IV, LLC		
(Bexley at Heritage Apts.)	WR-803, SUB 7	(07/20/2016)
WMCi Raleigh V, LLC		
(Bexley at Carpenter Village Apts.)	WR-949, SUB 8	(07/26/2016)
WMCi Raleigh VI, LLC		
(Bexley at Triangle Park Apartments)	WR-1311, SUB 4	(07/26/2016)
WMCi Raleigh VII, LLC		
(Bexley Panther Creek Apartments)	WR-1372, SUB 4	(07/26/2016)
WMCi Raleigh VIII, LLC		
(The Bristol at Park West Village Apts.)	WR-1693, SUB 2	(07/26/2016)
WMCi Raleigh IX, LLC		
(The Belmont Apartments)	WR-1754, SUB 2	(07/20/2016)
Woodland Estates Mobile Home Park, LLC		
(Woodland Estates Mobile Home Park)	WR-1863, SUB 1	(08/24/2016)
Woodland Heights of Burlington, LLC		
(Woodland Heights Apartments)	WR-1050, SUB 4	(03/29/2016)
WOP Cornerstone, LLC		
(Cornerstone Apartments)	WR-1905, SUB 1	(10/28/2016)
WOP Waterford, LLC		
(The Waterford Apartments)	WR-2063, SUB 1	(10/26/2016)
Worthing Meridian, LLC		
(Heights at Meridian Apartments)	WR-1627, SUB 1	(08/17/2016)
Wynslow Park, LLC		
(Gardens at Wynslow Park Apartments)	WR-128, SUB 6	(09/06/2016)
Yards at Noda, LLC		
(Yards at Noda Apartments)	WR-1640, SUB 1	(01/11/2016)
(Yards at Noda Apartments)	WR-1640, SUB 2	(10/05/2016)

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RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
YES Companies EXP, LLC		
(Woodlake M. H. Community)	WR-1336, SUB 14	(03/01/2016)
(Village Park M. H. Community)	WR-1336, SUB 15	(03/01/2016)
(Gallant Estates M. H. Community)	WR-1336, SUB 16	(03/01/2016)
(Oakwood Forest M. H. Community)	WR-1336, SUB 17	(03/01/2016)
(Foxhall Village M. H. Community)	WR-1336, SUB 18	(03/01/2016)
(Green Spring Valley M. H. Community)	WR-1336, SUB 19	(03/01/2016)
(Stony Brook North M. H. Community)	WR-1336, SUB 20	(03/01/2016)
York Ridge Associates, LP		
(York Ridge Apartments)	WR-1451, SUB 3	(09/08/2016)
100 Spring Meadow Drive Apartments, Investors, LLC		
(Alta Springs Apartments)	WR-47, SUB 11	(01/11/2016)
(Alta Springs Apartments)	WR-47, SUB 12	(09/21/2016)
102 North Elm Street Tenant, LLC		
(102 North Elm Street Apartments)	WR-1921, SUB 1	(08/01/2016)
330 West Tremont, LLC		
(335 Apartments)	WR-1548, SUB 3	(11/02/2016)
401 South Mint Street Apartment Investors, LLC		
(Element Uptown Apartments)	WR-1634, SUB 2	(09/14/2016)
425 Boylan, LLC		
(Devon 425 Apartments)	WR-1704, SUB 2	(08/31/2016)
1052, LLC		
(Clairmont at Farmgate Apts.)	WR-957, SUB 4	(07/27/2016)
1300 Knoll Circle Apartments Investors, LLC		
(The Lodge at Southpoint Apts.)	WR-268, SUB 12	(08/29/2016)
1452, LLC		
(Clairmont at Hillandale Apartments)	WR-1118, SUB 3	(08/22/2016)
1752, LLC		
(Clairmont at Perry Creek Apts.)	WR-2021, SUB 1	(07/27/2016)
2052, LLC		
(Clairmont at Brier Creek Apartments)	WR-1525, SUB 1	(07/27/2016)
4200 Investments Phase One, LLC		
(Villagio Apartments)	WR-1973, SUB 1	(05/23/2016)
4209 Lassiter Mill Road Apartments Investors, LLC		
(Alexan North Hills Apartments)	WR-571, SUB 6	(01/26/2016)
(Alexan North Hills Apartments)	WR-571, SUB 7	(11/29/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
5205 Barbee Chapel Road Apartments		
(Springs of Chapel Hill Apartments)	WR-1505, SUB 2	(01/11/2016)
(Springs of Chapel Hill Apartments)	WR-1505, SUB 3	(09/21/2016)
5725 Carnegie Boulevard Apartment Investors, LLC		
(Crescent South Park Apartments)	WR-2001, SUB 1	(08/15/2016)
6200 Raleigh Apartments, LLC		
(Andover at Crabtree Apartments)	WR-1882, SUB 1	(12/06/2016)

Aqua North Carolina, Inc. -- W-218, SUB 428; Order Approving Tariff Revision and Requiring Customer Notice *(Crestwood, Lancer Acres and Beard Acres Subdivision)* (04/29/2016); Reissued Order Approving Tariff Revision and Requiring Customer Notice *(Crestwood, Lancer Acres and Beard Acres Subdivisions)* (05/03/2016)

BMA Shelby Apartments, LLC -- WR-709, SUB 5; Errata Order *(Marion Ridge Apartments)* (03/30/2016)

Carrington Park CAF II, LLC -- WR-1686, SUB 1; Reissued Order Approving Tariff Revision *(Carrington Park Apartments)* (03/04/2016)

Ginkgo OBC, LLC -- WR-1558, SUB 3; Reissued Order Approving Tariff Revision *(Aurora Apartments)* (02/18/2016)

Ginkgo SAC, LLC -- WR-1691, SUB 1; Reissued Order Approving Tariff Revision *(Salem Crest Apartments)* (02/22/2016)

Salem Ridge Apartments, LLC -- WR-1096, SUB 4; Reissued Order Approving Tariff Revision *(Salem Ridge Apartments)* (02/22/2016)

Trinity Properties, LLC -- WR-1696,

SUB 11; Reissued[1] Order Approving Tariff Revision *(Campus Walk Apartments)* (08/10/2016)

SUB 13; Reissued[1] Order Approving Tariff Revision *(Georgetown Apartments)* (08/10/2016)

4209 Lassiter Mill Road Apartments Investors, LLC -- WR-571, SUB 6; Errata Order *(Alexan North Hills Apartments)* (09/23/2016)

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RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION (HWCCWA)
Orders Issued

Company	Docket No.	Date
Brentwood West Company, LLC		
(Brentwood West Apartments)	WR-1160, SUB 6	(07/06/2016)
Brook Dana, LLC		
(Brook Hill Apartments)	WR-1281, SUB 6	(07/28/2016)
CDC-Durham/UC, LLC		
(Duke Court Apartments)	WR-1100, SUB 11	(11/15/2016)
Clemmons Trace Village, LLC		
(Clemmons Trace Apartments)	WR-1995, SUB 1	(12/06/2016)
Fairfield Reafield Village, LLC		
(Reafield Village Apartments)	WR-1774, SUB 2	(11/01/2016)
FC Hidden Creek, LLC		
(North Oaks Landing Apartments)	WR-1724, SUB 3	(10/27/2016)
Gorman Crossing, LLC		
(Gorman Crossing Apartments)	WR-1698, SUB 2	(07/27/2016)
Graybul Meadows, LP		
(The Meadows Apartments, Phase I)	WR-2030, SUB 2	(10/17/2016)
Hawthorne-Midway Turtle Creek, LLC		
(Hawthorne at Southside Apartments)	WR-1497, SUB 2	(07/27/2016)
Heritage Lakes I, LLC, et al.		
(The Lakes Apartments)	WR-1202, SUB 4	(07/11/2016)
HR Realty Company, LLC		
(Hunting Ridge Apartments)	WR-1161, SUB 6	(07/07/2016)
Hudson Redwood Lexington, LLC		
(Lexington Farms Apartments)	WR-1823, SUB 2	(10/26/2016)
Kensington Apartments, LLC		
(Kensington Park Apartments)	WR-1692, SUB 2	(07/27/2016)
Kip-Dell Homes, Inc.		
(Pine Winds Apartments, Phase II)	WR-341, SUB 7	(04/29/2016)
(Pine Winds Apartments, Phase I)	WR-341, SUB 9	(07/29/2016)
(Pine Winds Apartments, Phase I)	WR-341, SUB 10	(07/29/2016)
Lake Clair, LLC		
(Lake Clair Apartments)	WR-1223, SUB 4	(11/03/2016)
Laurel Walk Apartments, LLC		
(Laurel Walk Apartments)	WR-1476, SUB 1	(02/29/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION (HWCCWA)
Orders Issued (Continued)

Company	Docket No.	Date
Madison Greensboro, LLC		
(Madison Woods Apts., Phase I)	WR-1783, SUB 1	(01/26/2016)
(Madison Woods Apartments, Phase I)	WR-1783, SUB 3	(10/17/2016)
Merriwood Associates Limited Partnership		
(Merriwood Apartments)	WR-1447, SUB 3	(08/30/2016)
Montecito Company, LLC		
(Montecito Apartments)	WR-1162, SUB 6	(07/11/2016)
MP Vista Villa, LLC		
(Vista Villa Apartments)	WR-1711, SUB 1	(01/20/2016)
New Cardinal Woods Associates, LLC		
(Cary Pines Apartments)	WR-1232, SUB 3	(12/13/2016)
New Woodcreek Associates, LLC		
(Woodcreek Apartments)	WR-1233, SUB 3	(12/13/2016)
PC Oxford, LLC		
(Oxford Square Apartments)	WR-1383, SUB 3	(09/26/2016)
Penrith Townhomes, LLC		
(Woodland Creek Apartments)	WR-1763, SUB 3	(07/07/2016)
PRG Clarion Crossing Associates, LLC		
(Clarion Crossing Apartments)	WR-1610, SUB 1	(12/14/2016)
PRG Lake Johnson Mews Associates, LLC		
(Lake Johnson Mews Apartments)	WR-1234, SUB 3	(12/13/2016)
Princeton Villas, LLC		
(Princeton Apartments)	WR-1971, SUB 6	(10/12/2016)
(Briarwood Apartments)	WR-1971, SUB 7	(10/12/2016)
(Rosewood Apartments)	WR-1971, SUB 8	(10/12/2016)
(Eastwood Apartments)	WR-1971, SUB 9	(10/12/2016)
(Oakwood Apartments)	WR-1971, SUB 10	(10/12/2016)
(Chesterfield Apartments)	WR-1971, SUB 11	(10/12/2016)
QR Realty Company, LLC		
(Quail Ridge Apartments)	WR-1159, SUB 6	(07/06/2016)
Redwood Landings, LLC		
(The Landing at Center Point Apts.)	WR-1681, SUB 3	(10/27/2016)

RESALE OF WATER AND SEWER -- Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION (HWCCWA)
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Company	Docket No.	Date
SBV-Greensboro-II, LLC		
(LeMans at Lawndale Apartments)	WR-1690, SUB 3	(09/06/2016)
Schmitz; Robert L.		
(1212 Chapel Hill Street Apartments)	WR-1249, SUB 5	(10/05/2016)
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(Cedar Point Apartments)	WR-980, SUB 28	(07/25/2016)
(Smithdale Apartments)	WR-980, SUB 32	(07/25/2016)
Seaboard Associates, LLC		
(Willow Ridge Apartments)	WR-1694, SUB 2	(10/12/2016)
Shellbrook Associates, LP		
(Shellbrook Apartments)	WR-1192, SUB 6	(07/11/2016)
Signature Place, LLC		
(Signature Place Apartments)	WR-1074, SUB 5	(08/08/2016)
Silverstone Partners, LLC		
(Silverstone Apartments)	WR-2026, SUB 1	(11/07/2016)
Solie; Mindy S.		
(Anderson Apartments)	WR-1700, SUB 2	(07/28/2016)
Sumare Limited Partnership		
(Sumter Square Apartments)	WR-1163, SUB 8	(07/07/2016)
TBR Lake Boone Owner, LLC		
(The Villages of Lake Boone Trail Apts.)	WR-1374, SUB 4	(07/05/2016)
Trinity Properties, LLC		
(Campus Walk Apartments)	WR-1696, SUB 11	(07/28/2016)
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(Georgetown Apartments)	WR-1696, SUB 13	(07/28/2016)
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Bruton; Debra Sue -- WR-1240, SUB 3; Order Approving Tariff Revisions *(The Family Lodge Apartments, Phase I & The Family Lodge Apartments, Phase II)* (07/11/2016)

Penrith Townhomes, LLC -- WR-1763, SUB 3; Reissued Order Approving Tariff Revision (HWCCWA) *(Woodland Creek Apartments)* (08/10/2016)

Schrader Family Limited Partnership --WR-980, SUB 19; Reissued Order Approving Tariff Revision (HWCCWA) *(Smithdale Apartments)* (03/04/2016)

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