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June 1, 2018

<u>VIA ELECTRONIC FILING</u>

M. Lynn Jarvis
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Re: Application of Duke Energy Carolinas, LLC for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-133.9 and NCUC Rule R8-69
Docket No. E-7, Sub 1164

Dear Ms. Jarvis:

I enclose for filing Duke Energy Carolinas, LLC's ("DEC" or the "Company") Rebuttal Testimony of Timothy J. Duff and Richard G. Stevie, Ph.D.; Rebuttal Testimony of Robert P. Evans and Evans Rebuttal Exhibits 1 and 2; and Rebuttal Testimony of Carolyn T. Miller and Miller Rebuttal Exhibits 1, 2, 6, and 8. Fifteen (15) paper copies of the Company's rebuttal testimony and exhibits will be delivered to the Commission on June 4, 2018.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

<u>Electronically submitted</u>
s/ Molly McIntosh Jagannathan
molly.jagannathan@troutmansanders.com

Enclosures

Copy: Parties of Record

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of Duke Energy Carolinas, LLC's Rebuttal Testimony and Rebuttal Exhibits, in Docket No. E-7, Sub 1164, has been served by electronic mail (e-mail), hand delivery or by depositing a copy in the United States Mail, first class postage prepaid, properly addressed to parties of record.

This, the 1st day of June, 2018.

Electronically signed
s/ Molly McIntosh Jagannathan

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ATTORNEY FOR DUKE ENERGY CAROLINAS, LLC

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1164

In the Matter of Application of Duke Energy Carolinas, LLC for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69	))))))	**REBUTTAL TESTIMONY OF TIMOTHY J. DUFF AND RICHARD G. STEVIE, PH.D. FOR DUKE ENERGY CAROLINAS, LLC**

Q. MR. DUFF, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy J. Duff. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC as General Manager, Customer Regulatory Strategy and Evaluation.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Michigan State University with a Bachelor of Arts in Political Economics and a Bachelor of Arts in Business Administration, and received a Master of Business Administration degree from the Stephen M. Ross School of Business at the University of Michigan. I started my career with Ford Motor Company and worked in a variety of roles within the company's financial organization, including Operations Financial Analyst and Budget Rent-A-Car Account Controller. After five years at Ford Motor Company, I started working with Cinergy in 2001, providing business and financial support to plant operating staff. Eighteen months later I joined Cinergy's Rates Department, where I provided revenue requirement analytics and general rate support for the company's transfer of three generating plants. After my time in the Rates Department, I spent a short period of time in the Environmental Strategy Department, and then I joined Cinergy's Regulatory and Legislative Strategy Department. After Cinergy merged with Duke

Energy Corporation ("Duke Energy") in 2006, I was employed as Managing Director, Federal Regulatory Policy. In this role, I was primarily responsible for developing and advocating Duke Energy's policy positions with the Federal Energy Regulatory Commission. I became General Manager, Energy Efficiency & Smart Grid Policy and Collaboration in 2010, was named General Manager, Retail Customer and Regulatory Strategy in 2011, and assumed my current position of General Manager, Customer Regulatory Strategy and Evaluation in 2013.

Q. PLEASE DESCRIBE YOUR DUTIES AS GENERAL MANAGER, CUSTOMER REGULATORY STRATEGY AND EVALUATION.

A. I am responsible for the development of strategies and policies related to energy efficiency and other retail products and services. I also oversee the analytics functions associated with evaluating and tracking the performance of Duke Energy's retail products and services.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER REGULATORY BODIES?

A. Yes. I testified in Duke Energy Carolinas, LLC's ("DEC" or the "Company") applications to update its demand-side management ("DSM") and energy efficiency ("EE") cost recovery rider, Rider EE, in Docket Nos. E-7, Subs 941, 979, 1001, 1031, 1050, and 1130, as well as the Company's application for approval of its new portfolio of DSM and EE program and new cost recovery mechanism in Docket No. E-7, Sub 1032. I also provided Supplemental Testimony in Duke Energy Progress, LLC's ("DEP") DSM/EE rider proceeding in Docket No. E-2, Sub 1145. In addition, I provided Rebuttal Testimony in DEP's Renewable Energy Portfolio Standard Compliance Report in Docket No. E-2, Sub 1109. In addition to testifying on behalf of DEC and DEP in North Carolina, I also testified in South Carolina in Docket 2013-298-E in support of the Company's application for approval of its new portfolio of DSM and EE programs and new cost recovery mechanism. Beyond providing testimony in the Carolinas, I also have testified in matters pertaining to DSM and EE before the state regulatory commissions in the other four states in which Duke Energy subsidiaries provide utility service: Florida, Indiana, Kentucky and Ohio.

Q. DR. STEVIE, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard G. Stevie and my business address is 123 East Fourth Street, Suite 300, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Vice President, Forecasting, by Integral Analytics, Inc. Integral Analytics is an analytical software and consulting firm focused on operational, planning, and market research solutions for the energy industry. In addition, I have been retained by Duke Energy Business Services to provide consulting support on EE issues.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor's degree in Economics from Thomas More College in May 1971. In June 1973, I was awarded a Master of Arts degree in Economics from the University of Cincinnati. In August 1977, I received a Ph.D. in Economics from the University of Cincinnati. In 2012, I was named a Research Fellow for the Economics Center at the University of Cincinnati. Prior to joining Integral Analytics, I was Chief Economist for Duke Energy. During my tenure with Duke Energy, I managed several key analytical functions including economic forecasts, projections of energy sales and peak load demands, customer research on energy usage, market research, product development analytics, evaluation of EE and DSM program cost-effectiveness, and measurement and verification of EE and DSM impacts. I have been involved in many regulatory proceedings and provided expert witness testimony on numerous utility economic issues in Ohio, Kentucky, Indiana, North Carolina, and South Carolina. The principle areas of testimony involved load forecasting, cost-effectiveness analysis of EE and DSM programs, measurement and verification plans for EE and DSM programs, market pricing for energy, regulatory recovery mechanisms for EE, weather normalization of energy sales, and assessment of economic conditions.

Before the merger with Duke Energy, I was General Manager of Market Analytics for Cinergy Corp. and prior to that Senior Economist with the Cincinnati Gas & Electric Company. In addition, I was a past Director of Economic Research for the Public Staff of the North Carolina Utilities Commission. While working at the Public Staff, I provided expert testimony on numerous issues including cost of capital, capital structure, operating ratio, and rate design.

For over twenty years, I chaired the Regional Economic Advisory Committee for the Greater Cincinnati Chamber of Commerce. As chair of the committee, I led the development and presentation of the Chamber's Annual Economic Outlook. In addition, I have appeared in numerous local forums to provide views on the economy.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes, I am a member of the American Economic Association, the National Association of Business Economists, the International Association for Energy Economics, and the Association of Energy Services Professionals.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, when I was a member of the Public Staff I testified before this Commission on numerous occasions. I also testified on behalf of DEC in the Company's original Save-a-Watt proceeding (Docket No. E-7, Sub 831), the Company's DSM/EE cost recovery mechanism review (Docket No. E-7, Sub 1032), and in several IRP proceedings (2005 IRP Docket No. E-100, Sub 103; 2007 IRP Docket E-100, Sub 114; 2008 IRP Docket E-100, Sub 118; and 2009 IRP Docket E-100, Sub 124).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of our testimony is to address the Public Staff's recommendation, as described in the testimony of Public Staff witness Eric L. Williams, that the avoided capacity cost benefits for purposes of the Portfolio Performance Incentive ("PPI") and cost-effectiveness of the Company's DSM/EE programs be calculated under the assumption that capacity avoided prior to year 2023 be assigned a zero dollar value. The Public Staff also recommends that for as long as the Docket No. E-100, Sub 148 avoided cost rates remain in effect, the Company should assign a capacity cost of zero to all kilowatt ("kW") savings occurring before year 2023 that are related to Vintage Years 2019 and afterward. As detailed in our testimony below, the Company strongly disagrees with these recommendations. Witness Duff describes the Company's agreement with the Public Staff to revise the Company's cost recovery mechanism in Docket No. E-7, Sub 1130 ("Sub 1130"), as approved by the Commission in its August 23, 2017 order in that docket ("Sub 1130 Order"), and how the agreement does not support the Public Staff's position. Dr. Stevie discusses Witness Williams' testimony with respect to his analytical process that led to the Public Staff's conclusion that all of the DSM/EE programs in the Company's resource plan should receive zero capacity value for the years 2019 through 2022. Dr. Stevie points out why this approach is inappropriate and seriously underestimates the value of the Company's DSM/EE programs.

Q. MR. DUFF, WILL YOU PLEASE SUMMARIZE THE AGREEMENT DEC REACHED WITH THE PUBLIC STAFF IN SUB 1130?

A. In pertinent part, the agreement establishes, beginning with Vintage 2019 and for all future Vintages, a uniform method for determining cost-effectiveness for DSM/EE programs and calculating the Company's PPI for the purposes of both the projection and true-up of programs offered in a given Vintage Year. Under this method, the Company uses the projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs used to determine the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider in which the Vintage was projected. The agreement specifies that the PURPA based avoided energy costs are derived by taking the difference between one production cost run that includes an assumed 24x7, 100 megawatts ("MW") of no-cost qualified facility ("QF") energy and one without the 100 MW of QF energy. The avoided energy costs used in the revised cost recovery mechanism are derived by taking a similar differencing approach except the projected hourly load shapes and load reductions associated with the proposed bundle of DSM/EE programs with the 100 MW of no-cost energy would be substituted. In order to ensure that new program requests and existing programs are being evaluated with up-to-date avoided costs, the agreement also establishes that the Company shall use projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of the date of the filing for the new program approval. The Commission approved this agreement and the resulting revisions to the Company's cost recovery mechanism in the Sub 1130 Order.

Q. WHY DID THE COMPANY AND PUBLIC STAFF PROPOSE THESE CHANGES TO THE MECHANISM?

A. One of the primary purposes for the revisions to the mechanism was to eliminate the previous "trigger" approach for updating avoided costs. Prior to the changes approved in Sub 1130, the previous version of DEC's DSM/EE cost recovery mechanism provided that the per kW avoided capacity costs used to calculate the avoided cost savings were those reflected in the filing by DEC in Docket No. E-100, Sub 136 (the 2012 Biennial Avoided Cost Proceeding). The per kilowatt-hour ("kWh") avoided energy costs were those reflected in the Company's most recent integrated resource plan ("IRP") at the time that version of the mechanism was approved (the 2012 IRP). These avoided costs were only updated if certain triggers were hit – if avoided energy costs calculated for purposes of the IRP increased or decreased by 20% or more, or if avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings increased or decreased by 15% or more.

Under the old trigger approach, if the trigger thresholds were not hit, avoided cost rates could potentially remain unchanged for years. Under the agreement and approved modifications to the mechanism, these triggers are eliminated and instead, DSM and EE programs are evaluated for cost effectiveness utilizing Commission-approved avoided cost rates that are updated every two years as part of the biennial avoided cost proceeding.

The second primary purpose of the agreement is that it changed the source and methodology for calculating avoided energy costs, which previously had been based on the IRP, so that like avoided capacity costs, they would now be derived from the biennial avoided cost proceeding. Absent the revision, the existing language in the mechanism could have resulted in DSM and EE programs being evaluated using avoided energy rates from the Company's IRP that were not based on the same fundamental assumptions used in the determination of the avoided capacity rates, which are those approved in the Company's biennial avoided cost proceeding. This potential mismatch could have undermined the validity of the cost effectiveness evaluation. The new language eliminates this potential problem by aligning the assumptions approved for both avoided energy and avoided capacity rates, as the proposed revisions to the mechanism call for using the most recently approved avoided energy cost and most recently approved avoided capacity cost from the same proceeding – i.e., the Company's biennial avoided cost proceeding.

Q. DID THE REVISIONS TO THE MECHANISM APPROVED IN SUB 1130 CHANGE THE METHODOLOGY BY WHICH THE COMPANY WAS TO CALCULATE AVOIDED CAPACITY COSTS?

A. No, aside from eliminating the trigger approach, there were no changes to the source or methodology underlying the avoided capacity calculation.

Q. WHAT WAS THE DATA SOURCE FROM WHICH THE AVOIDED CAPACITY RATE AND AVOIDED ENERGY RATE USED IN THE COMPANY'S APPLICATION IN THIS PROCEEDING WERE DERIVED?

A. Consistent with the revisions to DEC's DSM/EE cost recovery mechanism that the Commission approved in the Sub 1130 Order, the Company derived both the avoided energy and avoided capacity using the rates approved in the Company's most recent biennial avoided cost proceeding, which in this case is Docket No. E-100, Sub 148.

Q. DO YOU AGREE WITH WITNESS WILLIAMS' CONTENTION THAT THE COMPANY DID NOT USE AVOIDED CAPACITY RATES THAT WERE BASED ON ASSUMPTIONS APPROVED IN THE LAST BIENNIAL AVOIDED COST PROCEEDING?

A. No, I do not agree. The Company updated the avoided capacity rate used for estimating program cost effectiveness and the Company's projected PPI in a manner consistent with how it has always updated avoided capacity based on the biennial avoided cost proceedings. It utilized the avoided capacity value calculated using the Peaker Method consistent with the Company's understanding of the Sub 1130 settlement, which, in the Company's view, did not modify the approach used in past DSM/EE proceedings.

Q. DID THE COMPANY EXPECT THAT THE PUBLIC STAFF WOULD ADOPT THE POSITION THAT THE REVISIONS TO THE COMPANY'S DSM/EE COST RECOVERY MECHANISM APPROVED IN THE SUB 1130 ORDER WOULD ALTER THE WAY AVOIDED CAPACITY WAS TO BE UPDATED?

A. No, the Company did not believe the agreed-upon revisions to the mechanism would change how the Company should calculate the avoided capacity costs used to evaluate programs that have already been approved by the Commission and are part of the Company's existing portfolio of programs.

Q. IN SUB 1130, WHAT REVISIONS WERE PROPOSED BY THE PUBLIC STAFF AND THE COMPANY AND APPROVED BY THE COMMISSION REGARDING AVOIDED CAPACITY COSTS?

A. I am not aware of any changes contained in the revisions that pertained to avoided capacity costs. Avoided capacity costs are calculated in the same manner as they were prior to the revisions approved in Sub 1130. The revisions to paragraphs 19, 23 and 69 of the Company's cost recovery mechanism accomplished two things. First, they eliminated the trigger methodology for updating avoided energy and avoided capacity costs. Second, they changed the data source and methodology used to update the avoided *energy* rates used in the calculation of program cost-effectiveness.

Q. WITNESS WILLIAMS CITES EXCERPTS FROM YOUR SUPPLEMENTAL AND REBUTTAL TESTIMONY IN SUB 1130 AS SUPPORT FOR THE PUBLIC STAFF'S BELIEF THAT THE COMPANY WAS GOING TO UPDATE THE AVOIDED CAPACITY RATES IN A MANNER CONSISTENT WITH THE PUBLIC STAFF'S PROPOSAL IN THIS PROCEEDING. DO YOU AGREE WITH WITNESS WILLIAMS' CHARACTERIZATION OF YOUR PRIOR TESTIMONY IN SUB 1130?

A. No, I do not agree. I believe Witness Williams has selectively utilized excerpts of my prior testimony out of context to justify his contention. The statement he references from my Sub 1130 testimony was actually taken from the summary of my testimony; when reviewed in context of the entire paragraph from which they were excerpted, it is clear that I am referring to the "inconsistent assumptions" that would exist between using avoided energy rates from an IRP filing that could be based on a different resource plan than the avoided capacity rates simply due to the timing of the approval of rates in the biennial avoided cost proceeding (the source for the avoided capacity rates) and the acceptance of an IRP (previously, the source for the avoided energy rates). The language below is the entire paragraph from which Witness Williams's selectively excerpted:

> This agreement improves upon the methodology used to determine the avoided costs to be used under the Company's existing cost recovery mechanism in a number of ways. In particular, this agreement will reduce the potential for the avoided costs used to assess program cost effectiveness and establish DEC's PPI

> from becoming dated or stale, while still allowing DEC enough certainty to effectively plan its portfolio of programs. Under the old trigger approach spelled out in Paragraph 69 of the mechanism, if the trigger thresholds were not hit, avoided cost rates could potentially remain unchanged for years. Under the agreement and proposed modifications to the mechanism, DSM and EE programs will be evaluated for cost effectiveness utilizing fully-vetted and Commission-approved avoided cost rates that are essentially updated every two years as part of the biennial avoided cost proceeding. Another benefit of the agreement is that it eliminates the potential for avoided energy and avoided capacity costs to be based upon inconsistent assumptions. Absent the proposed revisions to the mechanism, DSM and EE programs could potentially be evaluated using avoided energy rates from the Company's Integrated Resource Plan that were not based on the same fundamental assumptions used in the determination of the avoided capacity rates approved in the Company's biennial avoided cost proceeding. The proposed revisions eliminate this potential problem by aligning the assumptions for both avoided energy and avoided capacity rates, as a result of using the most recently approved avoided energy and capacity costs from the same proceeding.

Q. MR. WILLIAMS' TESTIMONY FREQUENTLY REFERS TO THE TESTIMONY OF PUBLIC STAFF WITNESS JOHN R. HINTON IN SUB 1130 TO SUPPORT HIS POSITION. HAVE YOU REVIEWED WITNESS HINTON'S TESTIMONY IN THAT PROCEEDING?

A. Yes, the Company has reviewed Mr. Hinton's testimony in Sub 1130 and believes that DEC's application of avoided capacity costs in this case is entirely consistent with Mr. Hinton's testimony. Nowhere in Mr. Hinton's testimony does he indicate that the specific manner in which avoided capacity rates are to be derived from the Biennial Determination of Avoided Costs has changed as a result of the revisions to the mechanism approved in the Sub

1130 Order. In addition, Mr. Hinton does not indicate in his testimony that the avoided capacity rates to be used for existing DSM programs should be *the same* as those that would be paid to QF facilities. Instead, it should be clear from Mr. Hinton's testimony that the intent was to align the determination of both avoided energy and avoided capacity such that the resource plan used for those calculations would be based on the same plan as was used in the avoided cost filing. The key focus of the discussion was avoided energy. The process used to establish avoided capacity was not changing from what it had always been, or in Mr. Hinton's words that it was "generally" based on or "linked" to the rates paid to QFs for avoided energy and avoided capacity.

Q. AT THE TIME OF REACHING THE AGREEMENT WITH THE PUBLIC STAFF IN SUB 1130, DID THE COMPANY PROVIDE THE PUBLIC STAFF WITH ANY INFORMATION THAT WOULD HAVE DEMONSTRATED ITS INTENT TO APPLY CAPACITY VALUES BEGINNING IN YEAR 1 (VINTAGE 2019)?

A. Yes. As referenced on page 13 of Witness Maness affidavit in Sub 1130, as well as his live testimony beginning on page 267 of the transcript in Sub 1130, the Company provided the Public Staff with calculations showing that the projected PPI for 2018 would be reduced by approximately $9.5 Million if the Public Staff's interpretation of Paragraph 69 had been applied in the calculation of the Vintage 2018 PPI. In this analysis, the Company also provided a projection of what the change in Vintage 2019 PPI would be under the revisions to the mechanism if the proposed avoided costs rates pending before the Commission in Docket No. E-100, Sub 148 were approved. Specifically, the Company provided a projected stream of avoided capacity costs that reflected capacity values beginning in year one (2019). In other words, the analysis provided clearly reflected avoided capacity values in the years 2019-2022, rather than the zero value advocated by Witness Williams.

Q. DO YOU AGREE WITH WITNESS WILLIAMS' CONTENTION THAT THE COMMISSION'S ORDER IN DOCKET NO. E-100, SUB 148 JUSTIFIES THE PUBLIC STAFF'S POSITION REGARDING HOW AVOIDED CAPACITY COST SHOULD BE TREATED IN THE COMPANY'S DSM/EE APPLICATION?

A. No, I do not agree. The language that was cited from page 69 of the Commission Order in the E-100 Sub 148 case again appears to have been taken somewhat out of context. The full paragraph that was referenced by Witness Williams reads as follows:

> The Commission notes that in addition to providing the basis for electric power purchases from QFs by a utility, the Commission-determined avoided costs are utilized in, among other applications, the determination of the cost effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs, the determination of the incremental costs of compliance with REPS for cost recovery purposes; and in some ratemaking, such as determination of stand-by rates. In these contexts, it is appropriate for the rates to be reflective of the utilities' actual forecasted rates over a longer term, not based on a short-term forecast that is fixed for the duration of a longer term."

While the paragraph does reference that Commission-determined avoided costs are utilized in "the determination of the cost effectiveness of

DSM/EE programs and the calculation of the performance incentives," it in no way indicates that they are to be utilized in a manner consistent with the Public Staff's position. An even more important context to note is that the portion of the Order that contains this paragraph is specifically dealing with the Evidence and Conclusions Supporting Findings of Fact No 10, which does not deal with avoided capacity rates, but rather with the Commission's denial of DEC and DEP's request to reset energy rates utilized in a standard contract every two years. So while the language referenced clearly indicates the Commission believes that since the avoided energy rates are utilized in calculations associated with cost-effectiveness and performance incentives related to DSM/EE programs that they should not be updated every two years, it is a far cry from supporting the Public Staff's contention related the application of avoided capacity rates.

Q. DO YOU BELIEVE THAT A COMMISSION DECISION TO ADOPT THE PUBLIC STAFF'S RECOMMENDATION IS CONSISTENT WITH NORTH CAROLINA POLICY?

A. No, I do not.

Q. PLEASE EXPLAIN.

A. Witness Williams' testimony appears to imply that EE is the first capacity resource that could be cut out of the Company's resource plan, in that he states that the Company would still be able to meet its load requirement and maintain a 17% reserve margin without the projected new EE included in the plan. He then uses this logic to support his position that the Company should not recognize avoided capacity costs until a resource need exists in 2023. Unfortunately, his logic appears to ignore the fact that new EE should be viewed as a priority resource, not the first resource to be eliminated, as he fails to recognize the key role EE plays in the Company meeting its Renewable Energy Portfolio Standard. In fact, his position seems to fly directly in the face of Senate Bill 3, when one appropriately considers that the stated purpose of Senate Bill 3 was to "promote the development of renewable energy and energy efficiency in the state through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard."

Q. DR. STEVIE, WHAT IS YOUR UNDERSTANDING OF THE PUBLIC STAFF'S POSITION ON THE TREATMENT OF DSM/EE AVOIDED CAPACITY COSTS?

A. Based upon my review of Public Staff witness Williams' testimony, it is my understanding that the Public Staff's position is that:

> "DSM/EE ongoing cost-effectiveness and utility incentives should be based on consistent assumptions from the approved 2016 Biennial Avoided Cost rates which include an avoided capacity value of zero prior to 2023."
> (Witness Williams' testimony: page 7, lines 9-12).

Further, Public Staff Witness Williams states that:

> "In order to be consistent with the Sub 148 Order and the Revised Mechanism, determinations of ongoing cost-effectiveness and utility incentives of both **new** DSM/EE programs and new vintages of existing DSM/EE programs starting in vintage 2019 should be based on avoided capacity rates that reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP (2023)."
> (Emphasis added).
> (Witness Williams' testimony page 7, line 20 through page 8, line 5).

Q. WHAT IS THE IMPACT OF THIS POSITION?

A. It is my understanding that based upon this position, the Public Staff recommends that all of the DSM/EE kW impacts in the years 2019 to 2022 would have a zero capacity value for purposes of evaluating cost-effectiveness and evaluating utility incentives. To that end, the Public Staff's testimony removes the avoided capacity value for that time period for all kW impacts. Based upon the referenced DEC IRP, in 2019 this represents the removal of the capacity value for 1,119 MW of DSM impacts and 220 MW of EE impacts of summer capability from the Company's existing portfolio of approved DSM/EE programs.

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS WILLIAMS' TESTIMONY?

A. No, I do not. I have several reasons why this is not a reasonable approach.

Q. PLEASE EXPLAIN.

A. To begin, we need to parse apart the DSM/EE impacts into two components, DSM and EE. With respect to the DSM portion, the Public Staff has totally ignored the legacy aspect of the DSM programs. The DSM programs are not incremental programs. They are not new,[1] which is in direct conflict with Witness Williams' statement quoted above that his recommendation applies to **new** programs and **new** vintages of existing DSM/EE programs. The Company first initiated DSM programs at least forty years ago when I was a

[1] While of course, the Company's DSM programs qualify as "New demand-side management or energy efficiency measures" as that term is defined in Commission Rule R8-68 ("a demand-side management or energy efficiency measure that is adopted and implemented on or after January 1, 2007, including subsequent changes and modifications to any such measure."), they certainly are not "new" as the term is used by Witness Williams.

member of the Public Staff and has implemented the current set of DSM programs pursuant to Senate Bill 3. Again, these are not incremental or new programs. They are established programs that have grown over time to be a useful resource. If a power plant were designated used and useful and placed into service, but subsequently there is an unanticipated recession that caused a reduction in the projected loads, would it be reasonable to then penalize the Company for a past decision that was deemed reasonable at the time? That is similar to what the Public Staff is trying to do here and is not reasonable.

As for the usefulness of the Company's DSM programs, Public Staff witness Williams' own testimony (*see* page 16, lines 8 to 11) points out that by the year 2022, 95% of the DSM programs would be needed to defer the need for capacity to the year 2023. This should have raised an obvious question for the Public Staff. How can a resource such as the legacy DSM programs, that are in part responsible for the deferral of the need for new capacity, not receive a capacity valuation? If the Company's legacy DSM programs were closed tomorrow, there would be an immediate need for new capacity.

The Company believes it is appropriate to recognize the similarity between the continuing capacity value for these legacy DSM programs and QFs that had established legally enforceable obligations ("LEOs") or had signed power purchase agreements with the Company prior to November 15, 2016. While I am not an attorney, in order to respond to Witness Williams' testimony about the Commission's avoided cost order, I have familiarized myself at a high level with the Commission's avoided cost proceedings. It is my understanding that these legacy QFs are now receiving long-term fixed rates (up to 15 years) that included capacity values in every year based on the Commission's policies and avoided cost orders in effect prior to House Bill 589's enactment. No party has recommended a retroactive revision of existing purchase power agreements (some of which may continue until 2030 or longer under Section I.(c) of House Bill 589) entered into by the Company and these legacy QFs that contracted to sell prior to November 15, 2016 to modify the capacity payments to reflect the Commission's Sub 148 Order. Accordingly, the Company's legacy DSM programs, which are, in fact, providing capacity value in the near-term to avoid future capacity needs clearly deserve to be assigned an avoided capacity value similar to the legacy QFs, and not to have the zero value position of the Public Staff retroactively imposed upon them.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE DSM PORTION OF THE PUBLIC STAFF'S ANALYSIS?

A. Yes. In response to the Company's discovery request 1-5, Public Staff Witness Williams responded that he used Excel's solver functionality to determine the minimum DSM and EE capacity needed to maintain a 17% reserve margin for the period 2019 – 2022. This appears to be how he evaluated the capacity need for the Company. There are two things to note about his analysis. First, he ignored the fact that his own analysis demonstrated that the existing DSM resources provide real value in terms of capacity during the 2019 to 2022 time frame. Even though his own analysis showed tremendous value, the Public Staff went ahead and deleted all the value for capacity for that time period. Second, while using Excel's solver mechanism may provide the correct answer, it is impossible to know what may be overlooked by not using an IRP planning model that captures significantly more factors than just the amount of capacity. Basing capacity decisions on the use of Excel's solver software does not seem like a proper resource planning process.

Q. YOU HAVE REVIEWED THE PUBLIC STAFF'S POSITION ON THE COMPANY'S DSM PROGRAMS. WHAT COMMENTS DO YOU HAVE ABOUT THE STAFF'S POSITION ON THE EE PROGRAMS?

A. The Company's EE programs are, in some respects, different than the DSM programs in that most represent incremental new impacts in the resource plan. One could look at the EE programs and conclude that the capacity from those approved EE programs is not needed and hence should not receive a capacity value until the year 2023.

However, this overlooks the fact that one program, My Home Energy Report ("MyHER"), is effectively in the same position as the legacy DSM programs. The MW capability provided by the MyHER EE program was created in the past, prior to the establishment of the new avoided cost rates. All that is required is the expenditure of funds to maintain the impacts, just like the Company must do to maintain the availability of the impacts from the legacy DSM programs. In this case, the MyHER program impacts are also not incremental or new after November 2016. They are embedded in the resource plan, and like legacy QFs with LEOs existing prior to November 15, 2016, should receive a capacity value in the 2019 to 2022 time period. The MW impacts of the MyHER program were not included in the EE impacts shown in the Company's IRP.

With respect to the other EE programs, there is a summer capacity need of 425 MW (379 MW for the winter) from the EE programs in the year 2023. Now, anyone who has been around the implementation of EE programs for any length of time will recognize that one does not create 425 MW of EE overnight. It takes time. It takes time to build customer awareness. It takes time for equipment to wear out and be replaced or for customers to recognize that it is time to change out equipment. In addition, the Company is subject to the decisions of customers to participate in the programs. There is no control over customer decision-making when it comes to participation in EE programs. In addition, in the Company's IRP, the EE impacts are subtracted from the load forecast. As a result, there is no reserve margin for the EE impacts. The Company can only make offers that it hopes customers will embrace. But, there are no guarantees.

Looking further at the Company's IRP, Witness Williams points out in reference to the Commission approved revisions to DEC's cost recovery mechanism:

"said revisions providing that the avoided energy and capacity benefits used for program approval and the initial estimate of the PPI and any PPI true-up, as well as for the review of on-going cost-effectiveness, would use:

> 'projected avoided capacity and energy benefits specifically calculated for each program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits…'"

(Witness Williams' testimony: page 3, lines 15 to 25).

It is important to note the fact that the Company's inputs to the IRP for the cost of the DSM and EE programs include not just the implementation cost, but also the estimate of the utility's PPI, which contains a capacity value for the years 2019 through 2022. As a result, one could conclude that to be consistent with the underlying resource plan, including the cost inputs, one should be including the avoided capacity cost for DSM/EE for the years 2019 to 2022. I think when one looks at the resource planning process from this perspective, it makes good sense to recognize the capacity value of the EE programs during the 2019 to 2022 period. While the Public Staff would likely not advocate for the Company to shut down its EE programs during "gap years" until a capacity need arrives, from a financial perspective, it is effectively telling them to do just that.

Q. DO YOU HAVE ANY OTHER COMMENTS ABOUT THE PUBLIC STAFF'S POSITION ON THE DSM/EE PROGRAMS?

A. Yes. It should be very clear that the legacy DSM programs and the MyHER program deserve a full capacity value for the years 2019 to 2022 and beyond. The legacy DSM programs are not incremental and are treated as a dispatchable resource in the IRP. In addition, even the Public Staff's own analysis concluded that the legacy DSM programs provide a capacity value during the 2019 to 2022 time period.

With respect to the MyHER EE program, because its load impacts are also not incremental and existed prior to the establishment of the new avoided cost rates, I believe they also deserve a full capacity value.

For the other EE programs, while the Company believes it valued them appropriately with an avoided capacity value for all years, should the Commission agree with the Public Staff's position, then the Company would recognize that the incremental impacts from those programs could be treated the same as the incremental QF resources in the IRP. This means that, consistent with how "new" QFs with LEOs after November 15, 2016 are treated, the Company would ascribe a zero value of capacity for the years 2019 to 2022 for these other EE programs.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1164

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	**REBUTTAL TESTIMONY OF**
for Approval of Demand-Side Management	)	**ROBERT P. EVANS FOR**
and Energy Efficiency Cost Recovery Rider	)	**DUKE ENERGY CAROLINAS,**
Pursuant to N.C. Gen. Stat. § 62-133.9 and	)	**LLC**
Commission Rule R8-69	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert P. Evans. My business address is 150 Fayetteville Street, Raleigh, North Carolina 27602.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Corporation ("Duke Energy") as Senior Manager-Strategy and Collaboration for the Carolinas in the Market Solutions Regulatory Strategy Evaluation group, supporting both Duke Energy Carolinas, LLC ("DEC" or the "Company") and Duke Energy Progress, LLC ("DEP").

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN SUPPORT OF DEC'S APPLICATION IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony of Public Staff witness David M. Williamson and witness Chris Neme testifying on behalf of the North Carolina Justice Center, Natural Resources Defense Council, and Southern Alliance for Clean Energy.

Q. DO YOU HAVE COMMENTS RELATED TO PUBLIC STAFF WITNESS WILLIAMSON'S TESTIMONY?

A. Yes. These comments cover the portions of his testimony relating to: (1) his recommendations that the Company include in its 2019 Demand-Side Management ("DSM")/Energy Efficiency ("EE") rider filing its plans to incorporate the impacts identified in the lighting shelving study, including any baseline changes for non-specialty LED bulb lighting technology in its EE programs; (2) his observations concerning the Company's My Home Energy Report ("MyHER") program; and (3) his observations and recommendations related to the cost-effectiveness of the Company's DSM/EE programs.

Q. DOES THE COMPANY INTEND TO INCORPORATE IMPACTS IDENTIFIED IN ITS LIGHTING SHELVING STUDY AND ANY BASELINE CHANGES FOR NON-SPECIALTY LED BULB LIGHTING TECHNOLOGIES IN ITS 2019 DSM/EE RIDER FILING?

A. Yes. The results of the lighting shelving study will be made available to the Public Staff this summer when DEP files the Retail Lighting evaluation, which includes this study as a component, as part of its DSM/EE rider application. In addition, baselines for non-specialty bulbs will have changed to concur with applicable Energy Independence and Security Act ("EISA") standards. The impacts of the lighting shelving study and the change in baselines for non-specialty bulbs will be reflected in DEC's 2019 DSM/EE rider filing.

Q. DO YOU HAVE ANY CONCERNS REGARDING WITNESS WILLIAMSON'S OBSERVATIONS ON THE COMPANY'S MYHER PROGRAM?

A. Yes. Given that the updated customer information system and billing system will not be in service for several years, I believe that Witness Williamson's observations are premature. Nevertheless, I do feel it is necessary to express my concerns.

Witness Williamson indicated that

> As the Company moves closer to being able to provide daily information through the use of AMI and its customer information systems, there may be some redundancy in the information available through these new systems and the information provided through the MyHER program. The [Evaluation, Measurement, and Verification ("EM&V")] for the MyHER program will need to clearly isolate any savings associated with enhanced access to customer data provided through AMI and customer information systems from the impacts solely attributable to the customized suggestions for the home provided by the MyHER program.

Witness Williamson also noted that the MyHER EM&V report indicated that survey respondents reported that the most useful feature of the reports was the graphs illustrating the home's energy usage over time, and the least useful feature was the customized suggestions for the home. He concluded that the energy usage information that customers find most useful will be, or should be, available through AMI and new billing functionalities.

It appears that Witness Williamson is implying that the "least useful feature," the customized suggestions for the home to become more efficient, would be the only remaining MyHER-related source of energy savings once AMI is implemented. In doing so, he ignores the significant energy savings generated by the engagement and motivating effect created by the normative usage comparisons between the customer, peer group, and efficient home, which would not likely be available outside of the MyHER reports. While we cannot predict what an AMI-based paper billing will look like several years from now, initially I believe that it probably would be similar to the copy of my DEP bill provided as Evans Rebuttal Exhibit 1. Unlike the DEC bill, which provides a customer-specific energy comparison between the bill for the current billing month and the same billing month from the prior year, the DEP bill provides a graphic with a thirteen-month energy comparison. It is important to note that while both bills contain information illustrating the home's energy usage over time, it is only the monthly data for that specific home. In comparing my bill with a sample MyHER report, which I have included as Evans Rebuttal Exhibit 2, it is clear that the information provided is significantly different. MyHER allows a customer to compare his home's energy use with similar homes in the community based on age, square footage, and fuel type.

Witness Williamson fails to acknowledge that it is the normative psychology behind the reports that drives customers to adopt the actionable tips and take on the energy efficient behavior underlying MyHER savings. With behavioral energy reports, consumers generally adjust their attitudes and behaviors to what they comprehend as overall normal attitudes and behaviors, since few want to be considered out of the norm or an outlier. By seeing how their energy use stacks up against comparable homes, customers tend to adjust their behavior. For many, it might even be subliminal actions they might not be aware they are taking.

While it is possible to isolate savings resulting from MyHER from any impacts resulting from subsequent measures or programs that arise through the use of AMI, there is no reason to assume that AMI data will take the place of MyHER, which delivers comparative usage information through an engaging medium with information that is relevant and actionable.

Q. DO YOU HAVE ANY COMMENTS RELATING TO THE COST-EFFECTIVENESS OF THE COMPANY'S NON-RESIDENTIAL SMART $AVER CUSTOM/ASSESSMENTS, RESIDENTIAL SMART $AVER EE, ENERGYWISE FOR BUSINESS, AND NON-RESIDENTIAL SMART $AVER PERFORMANCE INCENTIVE PROGRAMS DISCUSSED IN WITNESS WILLIAMSON'S TESTIMONY?

A. Yes. Initially, I would like to indicate that the Company does not agree with the application of zero avoided capacity cost values proposed by the Public Staff for the determination of program cost-effectiveness. The impropriety of employing zero avoided capacity cost values is discussed in the testimony of Company witnesses Timothy J. Duff and Richard G. Stevie, Ph.D.

While the use of the Public Staff's proposed zero avoided capacity cost values would render the Non-Residential Smart $aver Custom/Assessments and EnergyWise for Business programs non-cost-effective, these programs are considered to be cost-effective under the avoided cost rates applied by the Company. Because these programs are cost-effective, paragraph 23B of the Company's revised cost recovery mechanism – which, for programs that are no longer cost-effective, requires the Company to provide a discussion of actions being taken to maintain or improve cost-effectiveness or, alternatively, its plans to terminate the program – does not apply.

The Company agrees with Witness Williamson that the Residential Smart $aver Energy Efficiency Program is not cost-effective at this time. However, the Company believes that suspending the only program that offers assistance for making the largest single energy user in the home, a customer's HVAC system, more energy efficient does not seem reasonable, especially when the decision to make said investment only comes around once every fifteen years. Furthermore, the recommended suspension of the program does not take into consideration the Company's relationships with HVAC contractors. This proposed suspension will likely erode trust and engagement, making it more like a termination than a suspension and also making it difficult to offer similar types of programs that would require trade ally support in the future.

In the past, when the program's cost-effectiveness has struggled due to efficiency standard changes, the Company has demonstrated the ability to effectively modify the program to restore cost-effectiveness and should have the opportunity to attempt restore to the cost-effectiveness of the program that was eroded by reduction in avoided costs. The Company is currently investigating several opportunities to increase the cost-effectiveness of the program, including the following:

1. While the Company does have some concerns with respect to the Public Staff's recommendation to move the program to an all referral

structure, the Company is not opposed to adopting this proposal so long as the Commission deems it appropriate. Irrespective of its concerns, the Company believes this structural change would result in the program passing the cost-effectiveness tests referenced in Witness Williamson's testimony;

2. Updating studies and performing cost studies of the incremental costs actually being paid by customers to adopt higher efficiency equipment, in order to ensure these costs are reflective of the current market. Such information could lead to greater TRC scores; and

3. Updating the measure mix, measure designs, and requirements that may be able to be removed/altered thus, lowering product cost to customers and increasing the TRC score.

The Company is confident that there is a solution available that will lead to a cost-effective program and that shutting down the current operations without an appropriate time frame for planning and adjustment is not the best answer for its customers.

The Non-Residential Smart $aver Performance Incentive Program has been in place since January 1, 2017. The program was intended to encompass large EE-related projects with uncertainty relative to their performance, for example, projects that employ new technologies. Related program incentives are provided in installments based on actual savings. In this manner, participants are properly incentivized for their EE-related investments and other customers are shielded from the impacts of overstated performance.

That said, very few projects are appropriate for participation in the program. The 0.81 TRC test score reflected in Evans Exhibit 7 to my Direct Testimony was based upon participation forecasts and costs used in the Company's 2016 program filing. During 2017, only two projects were involved. Currently, there are twelve projects underway in the Company's North Carolina service territory. The Company's estimated TRC score for this program, based on these and other projects under review will exceed 1.75. In short, we do not believe that this program requires additional scrutiny at this time, due to both the short time it has been in place and anticipated cost-effectiveness results.

Q. DO YOU HAVE ANY COMMENTS REGARDING WITNESS NEME'S TESTIMONY?

A. Yes. Witness Neme has brought up several issues and ideas relating to current and potential EE programs. In addition, Witness Neme discussed the employment of a Technical Resource Manual ("TRM").

Consistent with Witness Neme's suggestions, discussions relating to current and potential EE programs should be examined within the Collaborative and findings should be provided to the Commission. However, I believe that given the commonality between DEC's and DEP's programs, a combined DEC/DEP Collaborative would be preferable to a DEC-only Collaborative. Furthermore, as Witness Neme indicated, given the consideration needed to evaluate his program ideas, more than quarterly meetings will be required. I recommend that the Collaborative meetings be expanded from meeting quarterly to meeting every two months. Also, as to

Witness Neme's suggestions regarding working groups, I recommend that they should be employed when deemed beneficial by the Collaborative.

As to the employment of a TRM, a North Carolina-specific TRM working group met on several occasions during 2012, 2013, and 2014. The working group did not go forward with the establishment of a TRM. That said, given the time elapsed since the last examination of a TRM, the Company does not object to a related working group.

It is important to note that such a working group would, at a minimum, require representation by the Public Staff, Electric Membership Cooperatives, impacted municipalities, and investor owned utilities. Since part of the rationale for using a TRM is economic, such an effort should also encompass South Carolina as well.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

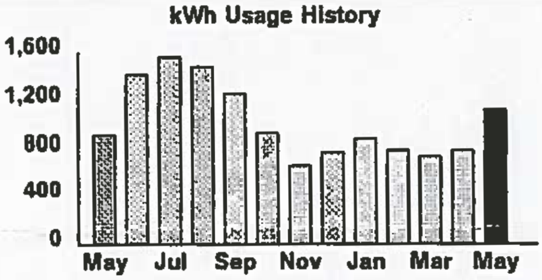
DUKE ENERGY PROGRESS

[redacted]

ROBERT P EVANS
[redacted]

Customer Bill

Account number	[redacted]
Amount due	**$116.49**
Current charges past due after	**Jun 14**
Thank you for your payment Apr 27	$116.49
Usage period	Apr 18 - May 18
This bill was mailed on	May 21, 2018



Usage

Meter number		[redacted]
Readings: May	18	91367
Apr	18	- 90226
kWh usage		**1141**
Days in period 30	Average kWh per day	38

Billing
Residential Service rate

HOUSE - 30 Days	
Electric service	125.09
Energy conservation discount	-5.20
REPS Adjustment	0.55
NC GreenPower Renewable Energy	4.00
Non-Regulated Surge Protection	6.99
7.25% North Carolina other sales tax	0.50
7% North Carolina sales tax	8.43
Current bill amount	140.36
Balance before current bill	-197.86
New account balance	-57.50
Amount due (Equal Payment Plan)	**$116.49**

Please note your electric services may not be terminated for failure to pay the non-regulated charges listed.

This bill is subject to a 1% per month late payment charge after 06/14/2018.

Please detach here. **Turn over for helpful phone numbers and customer service tips.** **PIN:** [redacted]

Return portion

ROBERT P EVANS
[redacted]

Account number
[redacted]

Amount due	**$116.49**
Current charges past due after	**Jun 14**

Make checks payable and return to:

Duke Energy Progress
PO BOX 1003
Charlotte NC 28201-1003

FORM VER. 002
11/98 REV .01/00

[redacted]

DUKE ENERGY

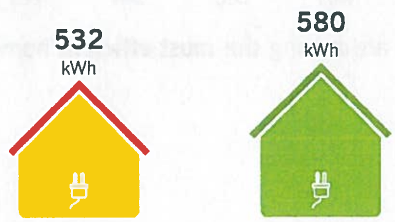
Home Energy Report

March 2018

Way to go! You are among the **most efficient** homes in your area and the envy of your neighbors. Although you're doing a great job, there still may be ways for you to save even more. Check out the tips below.

How am I doing?

My Home Comparison



Forecasted electricity use for April.

Areas you can focus on to save

Kitchen	38%
Electronics	19%
Laundry	13%
Lighting	11%
Cooling	1%
Other	18%

Who am I being compared to?

Group size	Square footage	Year built	Heating
3,893 Homes	2,350-2,950	1949-1959	Non-electric heating

We compare you to nearby similar homes based on the age, size, and heating source of your home. Update this information by completing a home profile at duke-energy.com/MyHomeEnergy or calling 888.873.3853.

Make your report more accurate. Update your profile online!

duke-energy.com/MyHomeEnergy

How can I save more?

Every little bit helps!

Store hot coffee in a thermos or carafe

Coffee - it's not just for mornings anymore. To get more out of your favorite brew, turn off the hot plate on your coffee maker and transfer your coffee to a thermos or insulated carafe. You'll save energy and your coffee will stay fresh longer. Savor the flavor AND the savings!

Save up to $23 per year.

Use energy efficient lighting indoors

Use energy efficient compact fluorescent (CFLs) bulbs or LEDs to provide quality lighting throughout your home. CFLs and LEDs use 75-90% less energy than incandescent bulbs and last 10-25 times longer. Since most electricity used by an incandescent bulb is wasted as heat, you can even save on air conditioning by switching to CFLs or LEDs.

More Savings Tips at **duke-energy.com/SavingTips**

Contact us Call **888.873.3853** Monday - Friday, 7 a.m. to 7 p.m. ET and Saturday, 8 a.m. to 1 p.m. ET Email **HomeReport@duke-energy.com**

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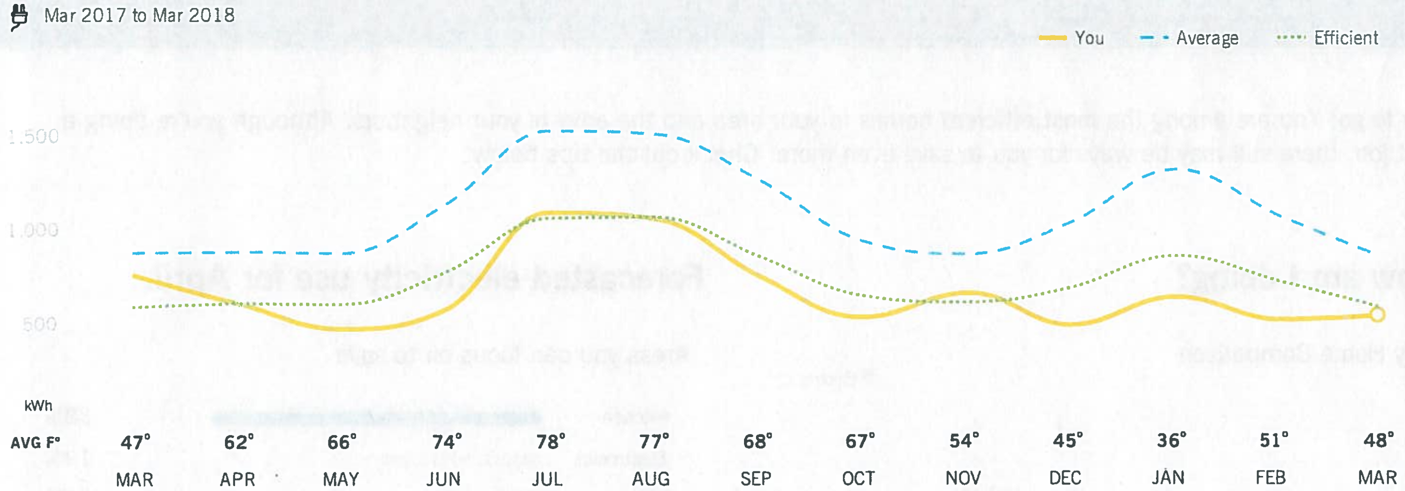
[redacted]

Reference Number: [redacted]
Account Number: [redacted]

electric use over time

Mar 2017 to Mar 2018



This month, you used **even less** electricity than last year. **Congratulations!** You are among the **most efficient** homes in your area for the year.

Take action. Reduce your use.

Earn Money. Help the environment.

Get up to $32 off your summer bills with Power Manager.
Power Manager helps:

- **Reduce waste** of natural resources
- **Delay** the need for **more power plants and transmission lines**
- **Prevent the use of** older, **less efficient** power **plants**
- **Keep energy costs low** for everyone

Learn more at **duke-energy.com/GetReward**.

Discover ways to save on your bill.

Go online to see your energy usage and identify inefficiencies in your home.

- **Review your estimated energy use** for the next month.
- **Get tips** to avoid a high bill.
- Ask our energy expert for **energy advice**.
- **Explore energy saving challenges** to save even more.

Get started at **duke-energy.com/MyHomeReport**.

DUKE ENERGY.
P.O. Box 1007
Mail Code ST29X
Charlotte, NC 28201

Call: **888.873.3853**
Email: **HomeReport@duke-energy.com**
Visit: **duke-energy.com/MyHomeEnergy**

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1164

In the Matter of Application of Duke Energy Carolinas, LLC for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69	))))))	**REBUTTAL TESTIMONY OF CAROLYN T. MILLER FOR DUKE ENERGY CAROLINAS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Carolyn T. Miller. My business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Rates Manager for Duke Energy Carolinas, LLC ("DEC" or the "Company").

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN SUPPORT OF DEC'S APPLICATION IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to support the filing of Rebuttal Exhibits which reflect revisions to Miller Exhibits 1, 2, 6 and 8 filed March 7, 2018 in this proceeding. These revisions are due to the adjustment of the opt-out forecast as recommended by Public Staff witness Michael C. Maness.

Q. WHY IS THE COMPANY REVISING THE OPT-OUT FORECAST?

A. In his testimony, Witness Maness indicated that he is concerned that the use of the 2017 actual opt-out usage experience combined with a lower projected 2019 forecast results in an understatement of participating usage for non-residential customers, resulting in a possible "rate spike." Witness Maness has proposed a 3.9% decrease to the actual 2017 opt-out usage, which corresponds to the decrease from the overall 2018 non-residential kWh forecast to the overall 2019 non-residential kWh forecast. He also proposes that the Company be allowed to recover carrying costs on any understatements of Rider 10 billing factors caused by use of the Public Staff's recommended levels of participating Rider 10 kWh sales versus the actual levels of such kWh sales, but with the understatement eligible for carrying charges limited to the difference between the Public Staff's recommended levels of participating Rider 10 kWh sales and the Company's initially proposed levels of such sales in this proceeding.

The Company disagrees with the premise that the non-residential participating sales used to calculate EE/DSM rates that the Company has proposed for Rider 10 are too low. The Company has seen an increase in the number of customers that have opted out each year, so it seems improbable that opt-out usage would decline in future periods. Using actual opt-out sales from the test period as a basis for determining projected opt-out sales has resulted in undercollection of revenue for each prior Vintage Year on a consistent basis. Further, there is no direct correlation between overall non-residential kWh sales and the level of sales associated with those customers that have opted out of EE and DSM programs.

Nevertheless, DEC is willing to make this concession in this case and agree to Witness Maness's adjustment to the opt-out sales as the Company would be made whole with the collection of any underrecovery of the non-residential revenue requirement and carrying charges on the eligible undercollected amount as described above. The Company notes that this adjustment is unique for Rider 10 and should not be used as precedent any future EE/DSM Rider filings.

Q. ARE THERE ANY OTHER ADJUSTMENTS MADE IN YOUR REBUTTAL EXHIBITS?

A. No. As discussed in DEC witnesses Timothy J. Duff and Richard G. Stevie, Ph.D.'s rebuttal testimony, the Company has not incorporated the adjustments to avoided costs as recommended by the Public Staff.

Q. HOW DO THESE CHANGES IMPACT DEC'S REQUESTED RATES?

A. The changes impact the following rates included in the initial DSM/EE filing:

Description	Filed Rate	Revised Rate
Vintage 2014 Non-Residential EMF EE Rate	(0.0063)	(0.0061)
Vintage 2014 Non-Residential EMF DSM Rate	(0.0002)	(0.0002)
Vintage 2015 Non-Residential EMF EE Rate	0.0025	0.0024
Vintage 2015 Non-Residential EMF DSM Rate	(0.0025)	(0.0024)
Vintage 2016 Non-Residential EMF EE Rate	(0.0131)	(0.0126)
Vintage 2016 Non-Residential EMF DSM Rate	(0.0015)	(0.0015)
Vintage 2017 Non-Residential EMF EE Rate	0.3032	0.2924
Vintage 2017 Non-Residential EMF DSM Rate	0.0005	0.0005
Vintage 2017 Non-Residential Prospective EE Rate	0.0831	0.0801
Vintage 2018 Non-Residential Prospective EE Rate	0.0723	0.0695
Vintage 2018 Non-Residential Prospective DSM Rate	0.0031	0.0030
Vintage 2019 Non-Residential Prospective EE Rate	0.3283	0.3158
Vintage 2019 Non-Residential Prospective DSM Rate	0.0910	0.0877

Q. WHAT REBUTTAL EXHIBITS WILL BE FILED IN CONJUNCTION WITH YOUR REBUTTAL TESTIMONY?

A. Only the exhibits impacted as a result of the changes outlined above will be filed as Rebuttal Exhibits. A description of the specific pages and contents that have been revised is provided below:

- Rebuttal Miller Exhibit 1: Summary of Rider EE Exhibits and Factors
- Rebuttal Miller Exhibit 2, page 1: True-up of Years 1 through 4 for Vintage Year 2014
- Rebuttal Miller Exhibit 2, page 2: True-up of Year 1, 2 and 3 for Vintage Year 2015
- Rebuttal Miller Exhibit 2, page 3: True-up of Year 1 and 2 for Vintage year 2016
- Rebuttal Miller Exhibit 2, page 4: Estimated Year 3 lost Revenue and True-up of Year 1 for Vintage Year 2017
- Rebuttal Miller Exhibit 2, page 5: Estimated Year 2 Lost Revenue for Vintage Year 2018
- Rebuttal Miller Exhibit 2, page 6: Estimated Program Costs, Earned Incentives and Lost Revenues for Vintage 2019
- Rebuttal Miller Exhibit 6: Revised Forecast 2019 kWh Sales for the Rate Period for Vintage Years 2014-2019
- Rebuttal Miller Exhibit 8: Revised Tariff Sheet

Q. WHAT ARE THE FINAL RATES REQUESTED IN THE

APPLICATION OF DEC FOR APPROVAL OF ITS DSM/EE RIDER FOR 2019 AS A RESULT OF THESE REVISIONS?

A. Pursuant to the provisions of N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69, the Company requests Commission approval of the following annual billing adjustments (all shown on a cents per kWh basis, including gross receipts tax and regulatory fee):

Residential Billing Factors[1]	**¢/kWh**
Residential Billing Factor for Rider 10 Prospective Components	0.4229
Residential Billing Factor for Rider 10 EMF Components	0.1091

Non-Residential Billing Factors for Rider 10 Prospective Components	**¢/kWh**
Vintage 2017 EE Participant	0.0801
Vintage 2018 EE Participant	0.0695
Vintage 2018 DSM Participant	0.0030
Vintage 2019 EE Participant	0.3158
Vintage 2019 DSM Participant	0.0877

[1] The Residential Billing Factors were not impacted by the adjustment to non-residential opt-out sales discussed herein, and are the same as those included in the Company's Application.

Non-Residential Billing Factors EMF Component	¢/kWh
Vintage 2017 EE Participant	0.2924
Vintage 2017 DSM Participant	0.0005
Vintage 2016 EE Participant	(0.0126)
Vintage 2016 DSM Participant	(0.0015)
Vintage 2015 EE Participant	0.0024
Vintage 2015 DSM Participant	(0.0024)
Vintage 2014 EE Participant	(0.0061)
Vintage 2014 DSM Participant	(0.0002)

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

Duke Energy Carolinas, LLC
DSM/EE Cost Recovery Rider 10
Docket Number E-7 Sub 1164
Exhibit Summary for Rider EE Exhibits and Factors

Residential Billing Factors

Residential Billing Factor for Rider 10 True-up (EMF) Components

Line				Adjusted
1	Year 2014 EE/DSM True-Up (EMF) Revenue Requirement	Miller Exhibit 2 pg. 1 Line 15		501,324
2	Year 2015 EE/DSM True-Up (EMF) Revenue Requirement	Miller Exhibit 2 pg. 2 Line 15		(1,014,271)
3	Year 2016 EE/DSM True-Up (EMF) Revenue Requirement	Miller Exhibit 2 pg. 3 Line 15		(2,560,305)
4	Year 2017 EE/DSM True-Up (EMF) Revenue Requirement	Miller Exhibit 2 pg. 4 Line 15		26,865,491
5	Total True-up (EMF) Revenue Requirement	Sum Lines 1-4	$	23,792,240
6	Projected NC Residential Sales (kWh) for rate period	Miller Exhibit 6 pg. 1, Line 1		21,806,637,265
7	*EE/DSM Revenue Requirement EMF Residential Rider EE (cents per kWh)*	Line 5 / Line 6 * 100		**0.1091**

Residential Billing Factor for Rider 10 Prospective Components

8	Vintage 2017 Total EE/DSM Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 4, Line 1		8,904,587
9	Vintage 2018 Total EE/DSM Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 5, Line 1		6,294,025
10	Vintage 2019 Total EE/DSM Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 6, Line 11		77,019,869
11	Total Prospective Revenue Requirement	Sum Lines 8-11	$	92,218,481
12	Projected NC Residential Sales (kWh) for rate period	Miller Exhibit 6 pg. 1, Line 1		21,806,637,265
13	*EE/DSM Revenue Requirement Prospective Residential Rider EE (cents per kWh)*	Line 12 / Line 13 * 100		**0.4229**
	Total Revenue Requirements in Rider 10 from Residential Customers			
14	Total True-up (EMF) Revenue Requirement	Line 5	$	23,792,240
15	Total Prospective Revenue Requirement	Line 12		92,218,481
16	***Total EE/DSM Revenue Requirement for Residential Rider EE***	Line 15 + Line 16	**$**	**116,010,721**
17	***Total EE/DSM Revenue Requirement for Residential Rider EE (cents per kWh)***	Line 7 + Line 14		**0.5320**

Non-Residential Billing Factors for Rider 10 True-up (EMF) Components

18	Vintage Year 2014 EE True-up (EMF) Revenue Requirement	Miller Exhibit 2 pg. 1, Line 25	$	(1,154,814)
19	Projected Year 2014 EE Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 pg. 1, Line 4		18,883,365,623
20	*EE Revenue Requirement Year 2014 EMF Non-Residential Rider EE (cents per kWh)*	Line 19/Line 20 * 100		**(0.0061)**
21	Vintage Year 2014 DSM True-up (EMF) Revenue Requirement	Miller Exhibit 2 pg. 1, Line 35	$	(39,246)
22	Projected Year 2014 DSM Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 pg. 1, Line 5		18,694,210,397
23	*DSM Revenue Requirement Year 2014 EMF Non-Residential Rider EE (cents per kWh)*	Line 22/Line 23 * 100		**(0.0002)**
24	Vintage Year 2015 EE True-up (EMF) Revenue Requirement	Miller Exhibit 2 pg. 2, Line 25	$	456,319
25	Projected Year 2015 EE Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 pg. 1, Line 6		18,763,045,012
26	*EE Revenue Requirement Year 2015 EMF Non-Residential Rider EE (cents per kWh)*	Line 25/Line 26 * 100		**0.0024**
27	Vintage Year 2015 DSM True-up (EMF) Revenue Requirement	Miller Exhibit 2 pg. 2, Line 35	$	(451,445)
28	Projected Year 2015 DSM Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 pg. 1, Line 7		18,490,935,206
29	*DSM Revenue Requirement Year 2015 EMF Non-Residential Rider EE (cents per kWh)*	Line 28/Line 29 * 100		**(0.0024)**
30	*Vintage Year 2016 EE True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 3, Line 35	$	(2,329,721)
31	*Projected Year 2016 EE Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 pg. 1, Line 8		18,489,604,035
32	*EE Revenue Requirement Year 2016 EMF Non-Residential Rider EE (cents per kWh)*	Line 31/Line 32 * 100		**(0.0126)**
33	*Vintage Year 2016 DSM True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 3, Line 35	$	(267,721)
34	*Projected Year 2016 DSM Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 pg. 1, Line 9		18,210,209,069
35	*DSM Revenue Requirement Year 2016 EMF Non-Residential Rider EE (cents per kWh)*	Line 34/Line 35 * 100		**(0.0015)**

36	*Vintage Year 2017 EE True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 3, Line 35	$	53,163,097
37	*Projected Year 2017 EE Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 pg. 1, Line 8		18,183,662,735
38	*EE Revenue Requirement Year 2017 EMF Non-Residential Rider EE (cents per kWh)*	Line 37/Line 38 * 100		**0.2924**
39	*Vintage Year 2017 DSM True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 3, Line 35	$	86,311
40	*Projected Year 2017 DSM Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 pg. 1, Line 9		18,177,460,568
41	*DSM Revenue Requirement Year 2017 EMF Non-Residential Rider EE (cents per kWh)*	Line 40/Line 41 * 100		**0.0005**

Non-Residential Billing Factors for Rider 10 Prospective Components

42	Vintage Year 2017 EE Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 4, Line 18	$	14,570,381
43	Projected Program Year 2017 EE Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 pg. 1, Line 10		18,183,662,735
44	*EE Revenue Requirement Vintage 2017 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 42/Line 43 * 100		**0.0801**
45	Vintage Year 2018 EE Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 5, Line 25	$	12,285,044
46	Projected Vintage 2018 EE Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 pg. 1, Line 12		17,670,299,445
47	*EE Revenue Requirement Vintage 2018 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 45/Line 46 * 100		**0.0695**
48	Vintage Year 2018 DSM Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 5, Line 25	$	534,763
49	Projected Vintage 2018 DSM Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 pg. 1, Line 12		18,078,506,705
50	*DSM Revenue Requirement Vintage 2018 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 48/Line 49 * 100		**0.0030**
51	Vintage Year 2019 EE Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 6, Line 25	$	55,797,199
52	Projected Vintage 2019 EE Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 pg. 1, Line 13		17,670,299,445
53	*EE Revenue Requirement Vintage 2019 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 51/Line 52 * 100		**0.3158**
54	Vintage Year 2019 DSM Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 6, Line 25	$	15,847,512
55	Projected Vintage 2019 DSM Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 pg. 1, Line 13		18,078,506,705
56	*DSM Revenue Requirement Vintage 2019 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 54/Line 55 * 100		**0.0877**
	Total EMF Rate			**0.2725**
	Total Prospective Rate			**0.5561**

<u>Total Revenue Requirements in Rider 10 from Non-Residential Customers</u>

57	Vintage Year 2014 EE True-up (EMF) Revenue Requirement	Line 18		(1,154,814)
58	Vintage Year 2014 DSM True-up (EMF) Revenue Requirement	Line 21		(39,246)
59	Vintage Year 2015 EE True-up (EMF) Revenue Requirement	Line 24		456,319
60	Vintage Year 2015 DSM True-up (EMF) Revenue Requirement	Line 27		(451,445)
61	Vintage Year 2016 EE True-up (EMF) Revenue Requirement	Line 30		(2,329,721)
62	Vintage Year 2016 DSM True-up (EMF) Revenue Requirement	Line 33		(267,721)
63	Vintage Year 2017 EE True-up (EMF) Revenue Requirement	Line 36		53,163,097
64	Vintage Year 2017 DSM True-up (EMF) Revenue Requirement	line 39		86,311
65	Vintage Year 2017 EE Prospective Amounts Revenue Requirement	Line 42		14,570,381
66	Vintage Year 2018 EE Prospective Amounts Revenue Requirement	Line 45		12,285,044
67	Vintage Year 2018 DSM Prospective Amounts Revenue Requirement	Line 48		534,763
67	Vintage Year 2019 EE Prospective Amounts Revenue Requirement	Line 51		55,797,199
68	Vintage Year 2019 DSM Prospective Amounts Revenue Requirement	Line 54		15,847,512
	Total Non-Residential Revenue Requirement in Rider 10	Sum (Lines 57-68)	**$**	**148,497,678**

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1164
True up Year 1, 2, 3 and 4 for Vintage Year 2014

RESIDENTIAL
Energy Efficiency Programs

Line		Reference	E-7 Sub 1031 Rider 5 Original Estimate	E-7 Sub 1050 Rider 6 Year 2 Lost Revenue Estimate	E-7 1073 Rider 7 - True up of Year 1	E-7 Sub 1073 Rider 7 - Estimate of Year 3 Lost Revenue	E-7 Sub 1105 Rider 8 - True up of Lost Revenues and EM&V	E-7 Sub 1105 Rider 8 - Estimate of Year 4 Lost Revenues	E-7 Sub 1130 Rider 9 True up	E-7 Sub 1164 Rider 10 True up	Year 2014
1	Residential EE Program Cost	Evans Exhibit 1 pg. 1, Line 10 * NC Alloc. Factor	$ 29,754,660		$ (1,844,170)		$ 1		$ (0)	$ -	$ 27,910,491
2	Residential EE Earned Utility Incentive	Evans Exhibit 1 pg. 1, Line 10 * NC Alloc. Factor	2,242,156		2,715,537		88,645		274	(273)	5,046,339
3	Return on undercollection of Residential EE Program Costs	Miller Exhibit 3 pg 1			53,935		140,851		71,702	(706)	265,782
4	Total EE Program Cost and Incentive Components	Line 1 + Line 2 + line 3	31,996,816		925,302		229,497		71,976	(979)	33,222,612
5	Residential DSM Program Cost	Evans Exhibit 1 pg. 1, Line 11 * NC Alloc. Factor	13,143,935		(2,535,104)		(0)		-	-	10,608,831
6	Residential DSM Earned Utility Incentive	Evans Exhibit 1 pg. 1, Line 11 * NC Alloc. Factor	3,240,520		(12,767)		(25,251)		(0)	-	3,202,502
7	Return on overcollection of Residential DSM Program Costs	Miller Exhibit 3 pg 2			(69,597)		(136,468)		(64,670)	10,071	(260,664)
8	Total DSM Program Cost and Incentive Components	Line 5 + Line 6 + Line 7	16,384,455		(2,617,468)		(161,719)		(64,670)	10,071	13,550,668
9	Total EE/DSM Program Cost and Incentive Components	Line 4 + Line 8	48,381,271		(1,692,166)		67,778		7,306	9,091	46,773,280
10	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.017953		1.001442		1.001402		1.001402	1.001402	
11	Total EE/DSM Program Cost and Incentive Revenue Requirement	Line 9 * Line 10	49,249,860		(1,694,606)		67,873		7,316	9,104	47,639,547
12	Residential Net Lost Revenues	Evans Exhibit 2 pg. 1	8,435,982	3,810,949	3,065,327	9,895,892	6,287,758	5,005,380	217,145	207,005	36,925,438
13	Total Residential EE/DSM Revenue Requirement	Line 11 + Line 12	57,685,842	3,810,949	1,370,721	9,895,892	6,355,631	5,005,380	224,462	216,109	84,564,985
14	Total Collected for Vintage Year 2014 (through estimated Rider 9)	Miller Exhibit 4 Line 1									84,063,661
15	**Total Residential EE/DSM Revenue Requirement**	Line 11 + Line 12									$ 501,324

See Miller Exhibit A for rate

NON-RESIDENTIAL
Energy Efficiency Programs

		Reference	E-7 Sub 1031 Rider 5 Original Estimate	E-7 Sub 1050 Rider 6 Year 2 Lost Revenue Estimate	E-7 1073 Rider 7 - True up of Year 1	E-7 Sub 1073 Rider 7 - Estimate of Year 3 Lost Revenue	E-7 Sub 1105 Rider 8 - True up of Lost Revenues & EM&V	E-7 Sub 1105 Rider 8 - Estimate of Year 4 Lost Revenues	E-7 Sub 1130 Rider 9 True up	E-7 Sub 1164 Rider 10 True up	Year 2014
16	Non- Residential EE Program Cost	Evans Exhibit 1 pg. 1, Line 24 * NC Alloc. Factor	16,206,358		(1,398,648)		-		1	-	14,807,711
17	Non-Residential EE Earned Utility Incentive	Evans Exhibit 1 pg. 1, Line 24 * NC Alloc. Factor	5,782,942		2,021,277		35,872		45,754	(121,883)	7,763,962
18	Return on undercollection of Non-residential EE Program Costs	Miller Exhibit 3 page 3A			94,850		130,948		73,379	(7,112)	292,065
19	Total EE Program Cost and Incentive Components	Line 16 + Line 17 + Line 18	21,989,300		717,479		166,820		119,134	(128,995)	22,863,738
20	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.017953		1.001442		1.001402		1.001402	1.001402	
21	Total Non-Residential EE Program Cost and Incentive Revenue Requirements	Line 19 * Line 20	22,384,074		718,514		167,054		119,301	(129,176)	23,259,766
22	Non-Residential Net Lost Revenues	Evans Exhibit 2 pg. 1	1,831,641	4,837,353	1,222,389	6,094,150	1,203,734	3,150,271	(853,990)	(1,483,604)	16,001,944
23	Total Non-Residential EE Revenue Requirement	Line 21 + Line 22	24,215,715	4,837,353	1,940,903	6,094,150	1,370,788	3,150,271	(734,689)	(1,612,780)	39,261,710
24	Total Collected for Year 2014 (through Estimated Rider 9)	Miller Exhibit 4 Line 7									40,416,525
25	Non-Residential EE Revenue Requirement True-Up Amount	Line 23 - Line 24									(1,154,814)
26	Projected NC Residential Sales (kWh)	Miller Exhibit 6, pg. 1, Line 4									18,883,365,623
27	**NC Non-Residential EE billing factor (Cents/kWh)**	Line 25/Line 26*100									**(0.0061)**

DSM Programs

		Reference	E-7 Sub 1031 Rider 5 Original Estimate	E-7 1073 Rider 7 - True up of Year 1	E-7 Sub 1105 Rider 8 - True up	E-7 Sub 1130 Rider 9 True up	E-7 Sub 1164 Rider 10 True up	Year 2014
28	Non-Residential DSM Program Cost	Evans Exhibit 1, pg. 1 Line 25 * NC Alloc. Factor	15,046,160	(2,195,319)	(0)	-		12,850,841
29	Non-Residential DSM Earned Utility Incentive	Evans Exhibit 1, pg. 1 Line 25 * NC Alloc. Factor	3,709,497	200,391	(30,588)	-		3,879,300
30	Return on overcollection of Non-residential DSM Program Costs	Miller Exhibit 3 page 4		(19,939)	(82,394)	(52,597)	(18,476)	(173,406)
31	Total Non-Residential DSM Program Cost and Incentive Components	Line 28 + Line 29 + Line 30	18,755,657	(2,014,867)	(112,982)	(52,597)	(18,476)	16,556,735
32	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.017953	1.001442	1.001402	1.001402	1.001402	
33	Total Non-Residential DSM Revenue Requirement	Line 31 * Line 32	19,092,377	(2,017,772)	(113,141)	(52,671)	(18,502)	16,890,292
34	Total Collected for Year 2014 (through Estimated Rider 9)	Miller Exhibit 4 Line 12						16,929,538
35	Non-Residential DSM Revenue Requirement True up Amount	Line 33- Line 34						(39,246)
36	Projected NC Non-Residential Sales (kWh)	Miller Exhibit 6 pg. 2, Line 5						18,694,210,397
37	**NC Non-Residential DSM billing factor**	Line 35/Line 36*100						**(0.0002)**

** Actual regulatory fee rate in effect in year of collection. May differ from original filed estimates.

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1164
True Up of Year 1, 2 and 3 of Vintage Year 2015

RESIDENTIAL
Energy Efficiency Programs

Line		Reference	E-7 Sub 1050 Rider 6 Original Estimate	E-7 Sub 1073 Rider 7 Year 2 Lost Revenues	E-7 Sub 1105 Rider 8 True up of Year 1	E-7 Sub 1105 Rider 8 Year 3 Lost Revenues	E-7 Sub 1130 Rider 9 True up of Lost Revenues & EM&V	E-7 Sub 1130 Rider 9 Year 4 LR Estimate	E-7 Sub 1164 Rider 10 True up	Year 2015 Year 1
1	Residential EE Program Cost	Evans Exhibit 1 pg. 2, Line 10 * NC Alloc. Factor	$ 30,685,449		$ (2,726,335)		$ -		$ -	$ 27,959,114
2	Residential EE Earned Utility Incentive	Evans Exhibit 1 pg. 2, Line 10 * NC Alloc. Factor	2,374,641		2,431,922		125,671		(0)	4,932,234
3	Return on undercollection of Residential EE Program Costs	Miller Exhibit 3 pg 5			49,064		77,792		35,939	162,795
4	Total EE Program Cost and Incentive Components	Line 1 + Line 2 + line 3	33,060,090		(245,348)		203,463		35,938	33,054,143
5	Residential DSM Program Cost	Evans Exhibit 1 pg. 2, Line 11 * NC Alloc. Factor	12,532,432		(2,137,589)		(1,252)		(0)	10,393,591
6	Residential DSM Earned Utility Incentive	Evans Exhibit 1 pg. 2, Line 11 * NC Alloc. Factor	3,275,217		(676,007)		(12,280)		(532)	2,586,398
7	Return on undercollection of Residential DSM Program Costs	Miller Exhibit 3 pg 6			(10,786)		23,451		11,838	24,503
8	Total DSM Program Cost and Incentive Components	Line 5 + Line 6 + Line 7	15,807,649		(2,824,381)		9,919		11,305	13,004,492
9	Total EE/DSM Program Cost and Incentive Components	Line 4 + Line 8	48,867,739		(3,069,730)		213,382		47,244	46,058,635
10	Revenue-related taxes and regulatory fees factor **	Miller Exhibit 2, pg. 7	1.001417		1.001402		1.001402		1.001402	
11	Total EE/DSM Program Cost and Incentive Revenue Requirement	Line 9 * Line 10	48,936,985		(3,074,034)		213,681		47,310	46,123,942
12	Residential Net Lost Revenues	Evans Exhibit 2 pg. 1	9,169,840	4,071,955	5,563,184	8,090,365	4,191,232	3,431,636	(1,336,510)	33,181,702
13	Total Residential EE/DSM Revenue Requirement	Line 11 + Line 12	58,106,825	4,071,955	2,489,151	8,090,365	4,404,913	3,431,636	(1,289,200)	79,305,645
14	Total Collected for Vintage Year 2015 (through estimated Rider 9)	Miller Exhibit 4 Line 2								80,319,916
15	**Total Residential EE/DSM Revenue Requirement**	Line 11 + Line 12								$ (1,014,271)

See Miller Exhibit A for rate

NON-RESIDENTIAL
Energy Efficiency Programs

Line		Reference	E-7 Sub 1050 Rider 6 Original Estimate	E-7 Sub 1073 Rider 7 Year 2 Lost Revenues	E-7 Sub 1105 Rider 8 True up of Year 1	E-7 Sub 1105 Rider 8 Year 3 Lost Revenues	E-7 Sub 1130 Rider 9 True up of Lost Revenues & EM&V	E-7 Sub 1130 Year 2015 Year 4 LR Estimate	E-7 Sub 1164 Rider 10 True Up	Year 2015 Year 1
16	Non- Residential EE Program Cost	Evans Exhibit 1 pg. 2, Line 24 * NC Alloc. Factor	17,348,807		11,904,051		0		-	29,252,858
17	Non-Residential EE Earned Utility Incentive	Evans Exhibit 1 pg. 2, Line 24 * NC Alloc. Factor	6,214,226		3,351,028		846,899		(594,998)	9,817,155
18	Return on undercollection of Non-residential EE Program Costs	Miller Exhibit 3 page 7			457,891		838,299		448,315	1,744,505
19	Total EE Program Cost and Incentive Components	Line 16 + Line 17 + Line 18	23,563,033		15,712,970		1,685,198		(146,683)	40,814,518
20	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.001417		1.001402		1.001402		1.001402	
21	Total Non-Residential EE Program Cost and Incentive Revenue Requirements	Line 19 * Line 20	23,596,422		15,735,000		1,687,561		(146,889)	40,872,094
22	Non-Residential Net Lost Revenues	Evans Exhibit 2 pg. 4	2,523,480	8,194,003	2,547,914	9,483,428	2,426,543	4,183,188	(3,671,147)	25,687,409
23	Total Non-Residential EE Revenue Requirement	Line 21 + Line 22	26,119,902	8,194,003	18,282,914	9,483,428	4,114,104	4,183,188	(3,818,036)	66,559,503
24	Total Collected for Year 2015 (through estimated Rider 9)	Miller Exhibit 4 Line 6								66,103,184
25	Non-Residential EE Revenue Requirement	Line 23 - Line 24								456,319
26	Projected NC Residential Sales (kWh)	Miller Exhibit 6, pg. 2, Line 6								18,763,045,012
27	**NC Non-Residential EE billing factor (Cents/kWh)**	Line 25/Line 26*100								**0.0024**

DSM Programs

Line		Reference	E-7 Sub 1050 Rider 6 Original Estimate	E-7 Sub 1005 Rider 8 Original True Up	E-7 Sub 1130 Rider 9 True Up	E-7 Sub 1164 Rider 10 True Up	Year 2015 Year 1
28	Non-Residential DSM Program Cost	Evans Exhibit 1, pg. 2 Line 25 * NC Alloc. Factor	16,493,488	(2,925,873)	(1,635)		13,565,981
29	Non-Residential DSM Earned Utility Incentive	Evans Exhibit 1, pg. 2 Line 25 * NC Alloc. Factor	4,310,397	(917,841)	(16,029)	(693)	3,375,833
30	Return on overcollection of Non-residential DSM Program Costs	Miller Exhibit 3 page 8		(107,297)	(203,069)	(128,531)	(438,897)
31	Total Non-Residential DSM Program Cost and Incentive Components	Line 28 + Line 29 + Line 30	20,803,885	(3,951,011)	(220,733)	(129,225)	16,502,917
32	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.001417	1.001402	1.001402	1.001402	
33	Total Non-Residential DSM Revenue Requirement	Line 31 * Line 32	20,833,364	(3,956,550)	(221,042)	(129,406)	16,526,366
34	Total Revenue Collected for DSM Programs Year 2015 (through estimated Rider 9)	Miller Exhibit 4 Line 10					16,977,811
35	Non-Residential EE Revenue Requirement True-up Amount	Line 33- Line 34					(451,445)
36	Projected NC Non-Residential Sales (kWh)	Miller Exhibit 6 pg. 1, Line 7					18,490,935,206
37	**NC Non-Residential DSM billing factor**	Line 35/Line 36*100					**(0.0024)**

** Actual regulatory fee rate in effect in year of collection. May differ from original filed estimates.

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1164
True Up of Year 1 and 2 for Vintage Year 2016

RESIDENTIAL
Energy Efficiency Programs

Line		Reference	E-7 Sub 1073 Rider 7 Original Estimate	E-7 Sub 1105 Rider 8 Year 2 Lost Revenues	E-7 Sub 1130 Rider 9 True up	E-7 Sub 1130 Year 2016 Yr 3 LR Estimate	E-7 Sub 1164 Rider 10 True up	Year 2016 Year 1
1	Residential EE Program Cost	Evans Exhibit 1 pg. 3, Line 10 * NC Alloc. Factor	$ 31,056,079		$ 8,965,024		$ (2)	$ 40,021,101
2	Residential EE Earned Utility Incentive	Evans Exhibit 1 pg. 3, Line 10 * NC Alloc. Factor	2,392,652		4,361,799		(52,098)	6,702,353
3	Return on undercollection of Residential EE Program Costs	Miller Exhibit 3 pg 5			272,476		710,786	983,262
4	Total EE Program Cost and Incentive Components	Line 1 + Line 2 + line 3	33,448,731		13,599,299		658,686	47,706,716
5	Residential DSM Program Cost	Evans Exhibit 1 pg. 3, Line 11 * NC Alloc. Factor	10,613,016		(1,012,441)		0	9,600,575
6	Residential DSM Earned Utility Incentive	Evans Exhibit 1 pg. 3, Line 11 * NC Alloc. Factor	2,887,418		(129,612)		(27,890)	2,729,916
7	Return on overcollection of Residential DSM Program Costs	Miller Exhibit 3 pg 6			(26,322)		(46,199)	(72,521)
8	Total DSM Program Cost and Incentive Components	Line 5 + Line 6 + Line 7	13,500,434		(1,168,375)		(74,088)	12,257,971
9	Total EE/DSM Program Cost and Incentive Components	Line 4 + Line 8	46,949,165		12,430,924		584,598	59,964,687
10	Revenue-related taxes and regulatory fees factor **	Miller Exhibit 2, pg. 7	1.001442		1.001402		1.001402	
11	Total EE/DSM Program Cost and Incentive Revenue Requirement	Line 9 * Line 10	47,016,866		12,448,352		585,417	60,050,635
12	Residential Net Lost Revenues	Evans Exhibit 2 pg. 4	11,873,767	5,723,916	4,795,359	7,765,323	(3,299,616)	26,858,749
13	Total Residential EE/DSM Revenue Requirement	Line 11 + Line 12	58,890,633	5,723,916	17,243,711	7,765,323	(2,714,199)	86,909,384
14	Total Collected for Vintage Year 2016 (through estimated Rider 9)	Miller Exhibit 4 Line 2						89,469,689
15	**Total Residential EE/DSM Revenue Requirement**	Line 11 + Line 12						$ (2,560,305)

See Miller Exhibit A for rate

NON-RESIDENTIAL
Energy Efficiency Programs

Line		Reference	E-7 Sub 1073 Rider 7 Original Estimate	E-7 Sub 1105 Rider 8 Year 2 Lost Revenues	E-7 Sub 1130 True up	E-7 Sub 1130 Year 2016 Yr 3 LR Estimate	E-7 Sub 1164 Rider 10 True up	Year 2016 Year 1
16	Non- Residential EE Program Cost	Evans Exhibit 1 pg. 3, Line 25 * NC Alloc. Factor	36,494,611		13,515,376		1	50,009,988
17	Non-Residential EE Earned Utility Incentive	Evans Exhibit 1 pg. 3, Line 25 * NC Alloc. Factor	10,105,721		4,261,607		(353,368)	14,013,960
18	Return on undercollection of Non-residential EE Program Costs	Miller Exhibit 3 page 7			378,293		1,051,375	1,429,668
19	Total EE Program Cost and Incentive Components	Line 16 + Line 17 + Line 18	46,600,332		18,155,276		698,008	65,453,616
20	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.001442		1.001402		1.001402	
21	Total Non-Residential EE Program Cost and Incentive Revenue Requirements	Line 19 * Line 20	46,667,530		18,180,730		698,987	65,547,246
22	Non-Residential Net Lost Revenues	Evans Exhibit 2 pg. 4	4,745,315	8,309,444	2,524,047	13,375,187	(4,085,026)	24,868,967
23	Total Non-Residential EE Revenue Requirement	Line 21 + Line 22	51,412,845	8,309,444	20,704,776	13,375,187	(3,386,039)	90,416,213
24	Total Collected for Vintage Year 2016 (through estimated Rider 9)	Miller Exhibit 4 Line 6						92,745,934
25	Non-Residential EE Revenue Requirement	Line 23 - Line 24						(2,329,721)
26	Projected NC Residential Sales (kWh)	Miller Exhibit 6, pg. 1, Line 8						18,489,604,035
27	**NC Non-Residential EE billing factor (Cents/kWh)**	Line 25/Line 26*100						**(0.0126)**

DSM Programs

Line		Reference	E-7 Sub 1073 Rider 7 Original Estimate	E-7 Sub 1130 Rider 9 True up	E-7 Sub 1164 Rider 10 True Up	Year 2016 Year 1
28	Non-Residential DSM Program Cost	Evans Exhibit 1, pg. 3 Line 26 * NC Alloc. Factor	12,855,910	(1,261,413)	0	11,594,497
29	Non-Residential DSM Earned Utility Incentive	Evans Exhibit 1, pg. 3 Line 26 * NC Alloc. Factor	3,497,628	(167,059)	(33,683)	3,296,886
30	Return on undercollection of Non-residential DSM Program Costs	Miller Exhibit 3 page 8		1,759	3,420	5,179
31	Total Non-Residential DSM Program Cost and Incentive Components	Line 28 + Line 29 + Line 30	16,353,538	(1,426,713)	(30,262)	14,896,563
32	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.001442	1.001402	1.001402	
33	Total Non-Residential DSM Revenue Requirement	Line 31 * Line 32	16,377,120	(1,428,713)	(30,305)	14,918,102
34	Total Collected for Vintage Year 2016 (through estimated Rider 9)	Miller Exhibit 4 Line 10				15,185,823
35	Non-Residential EE Revenue Requirement True-up Amount	Line 33- Line 34				(267,721)
36	Projected NC Non-Residential Sales (kWh)	Miller Exhibit 6 pg. 1, Line 9				18,210,209,069
37	**NC Non-Residential DSM billing factor**	Line 35/Line 36*100				**(0.0015)**

* Year 4 Projected Lost Revenue is not being requested in this filing because lost revenue through the test period of Docket E7 Sub XXXX was requested as part of base rates.

** Actual regulatory fee rate in effect in year of collection. May differ from original filed estimates.

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1164
Estimated Year 3 Lost Revenue and True Up of Year 1 for Vintage Year 2017

RESIDENTIAL
Energy Efficiency Programs

Line		Reference	Year 2017 Yr 3 LR Estimate	E-7 Sub 1105 Rider 8 Year 1 Estimate	E-7 Sub 1130 Year 2017 Yr 2 LR Estimate	E-7 Sub 1164 Rider 10 True up	Year 2017 Year 1
1	Residential EE Program Cost	Evans Exhibit 1 pg. 4, Line 10 * NC Alloc. Factor		$ 33,488,974		$ 13,998,885	$ 47,487,859
2	Residential EE Earned Utility Incentive	Evans Exhibit 1 pg. 4, Line 10 * NC Alloc. Factor		4,149,244		4,340,033	8,489,277
3	Return on undercollection of Residential EE Program Costs	Miller Exhibit 3 pg 5				522,611	522,611
4	Total EE Program Cost and Incentive Components	Line 1 + Line 2 + line 3		37,638,218		18,861,529	56,499,747
5	Residential DSM Program Cost	Evans Exhibit 1 pg. 4, Line 11 * NC Alloc. Factor		10,258,751		(176,455)	10,082,296
6	Residential DSM Earned Utility Incentive	Evans Exhibit 1 pg. 4, Line 11 * NC Alloc. Factor		2,837,134		89,061	2,926,195
7	Return on undercollection of Residential DSM Program Costs	Miller Exhibit 3 pg 6				15,015	15,015
8	Total DSM Program Cost and Incentive Components	Line 5 + Line 6 + Line 7		13,095,885		(72,379)	13,023,506
9	Total EE/DSM Program Cost and Incentive Components	Line 4 + Line 8		50,734,103		18,789,151	69,523,254
10	Revenue-related taxes and regulatory fees factor **	Miller Exhibit 2, pg. 7		1.001482		1.001402	
11	Total EE/DSM Program Cost and Incentive Revenue Requirement	Line 9 * Line 10		50,809,291		18,815,493	69,624,784
12	Residential Net Lost Revenues	Evans Exhibit 2 pg. 2	$ 8,904,587	12,699,119	4,202,002	6,456,129	23,357,250
13	Total Residential EE/DSM Revenue Requirement	Line 11 + Line 12	8,904,587	63,508,411	4,202,002	25,271,622	92,982,034
14	Total Collected for Vintage Year 2016 (through estimated Rider 9)	Miller Exhibit 4 Line 2					66,116,542
15	**Total Residential EE/DSM Revenue Requirement**	Line 11 + Line 12	$ 8,904,587				$ 26,865,491

See Miller Exhibit A for rate

NON-RESIDENTIAL
Energy Efficiency Programs

Line		Reference	Year 2017 Yr 3 LR Estimate	E-7 Sub 1105 Rider 8 Year 1 Estimate	E-7 Sub 1130 Year 2017 Yr 2 LR Estimate	E-7 Sub 1164 Rider 10 True up	Year 2017 Year 1
16	Non- Residential EE Program Cost	Evans Exhibit 1 pg. 4, Line 25 * NC Alloc. Factor		38,791,601		32,155,814	70,947,415
17	Non-Residential EE Earned Utility Incentive	Evans Exhibit 1 pg. 4, Line 25 * NC Alloc. Factor		9,347,504		9,073,243	18,420,747
18	Return on undercollection of Non-residential EE Program Costs	Miller Exhibit 3 page 7				1,588,185	1,588,185
19	Total EE Program Cost and Incentive Components	Line 16 + Line 17 + Line 18		48,139,105		42,817,241	90,956,346
20	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7		1.001482		1.001402	
21	Total Non-Residential EE Program Cost and Incentive Revenue Requirements	Line 19 * Line 20		48,210,447		42,877,271	91,087,718
22	Non-Residential Net Lost Revenues	Evans Exhibit 2 pg. 2	14,570,381	6,039,892	9,466,867	2,627,210	18,133,969
23	Total Non-Residential EE Revenue Requirement	Line 21 + Line 22	14,570,381	54,250,339	9,466,867	45,504,481	109,221,688
24	Total Collected for Vintage Year 2016 (through estimated Rider 9)	Miller Exhibit 4 Line 6					56,058,591
25	Non-Residential EE Revenue Requirement	Line 23 - Line 24	14,570,381				53,163,097
26	Projected NC Residential Sales (kWh)	Miller Exhibit 6, pg. 1, Line 8	18,183,662,735				18,183,662,735
27	**NC Non-Residential EE billing factor (Cents/kWh)**	Line 25/Line 26*100	**0.0801**				**0.2924**

DSM Programs

Line		Reference	E-7 Sub 1105 Rider 8 Year 1 Estimate		E-7 Sub 1164 Rider 10 True Up	Year 2017 Year 1
28	Non-Residential DSM Program Cost	Evans Exhibit 1, pg. 4 Line 26 * NC Alloc. Factor	13,389,985		(1,438,646)	11,951,339
29	Non-Residential DSM Earned Utility Incentive	Evans Exhibit 1, pg. 4 Line 26 * NC Alloc. Factor	3,703,101		(234,452)	3,468,649
30	Return on undercollection of Non-residential DSM Program Costs	Miller Exhibit 3 page 8	-		4,761	4,761
31	Total Non-Residential DSM Program Cost and Incentive Components	Line 28 + Line 29 + Line 30	17,093,086		(1,668,337)	15,424,749
32	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 13	1.001482		1.001402	
33	Total Non-Residential DSM Revenue Requirement	Line 31 * Line 32	17,118,418		(1,670,676)	15,447,742
34	Total Collected for Vintage Year 2016 (through estimated Rider 9)	Miller Exhibit 4 Line 10				15,361,431
35	Non-Residential EE Revenue Requirement True-up Amount	Line 33- Line 34				86,311
36	Projected NC Non-Residential Sales (kWh)	Miller Exhibit 6 pg. 1, Line 9				18,177,460,568
37	**NC Non-Residential DSM billing factor**	Line 35/Line 36*100				**0.0005**

** Actual regulatory fee rate in effect in year of collection. May differ from original filed estimates.

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1164
Estimated Year 2 Lost Revenues for Vintage Year 2018

RESIDENTIAL

Line		Reference	2018
1	Residential Net Lost Revenues	Evans Exhibit 2 pg. 3 Line 115	6,294,025
2	Projected NC Residential Sales (kWh)	Miller Exhibit 6 pg 1	$ 21,806,637,265
3	**NC Residential EE Billing Factor (Cents/kWh)**	Line 1/Line 2*100	**0.0289**

NON-RESIDENTIAL
Energy Efficiency Programs

Line		Reference	2018
4	Non-Residential Net Lost Revenues	Evans Exhibit 2 pg. 3 Line 131	10,271,966
5	Impact of Revised Forecast from Rider 9	Miller Exhibit 7 pg 1	2,013,078
6	Total Revenue Requirement	Line 4 + Line 5	12,285,044
7	Projected NC Non-Residential Sales (kWh)	Miller Exhibit 6 pg 1	17,670,299,445
8	**NC Non-Residential EE billing factor (Cents/kWh)**	Line 6/Line 7*100	**0.0695**

Demand Side Management

Line		Reference	2018
9	Impact of Revised Forecast from Rider 9	Miller Exhibit 7 page 1	534,763
10	Projected NC Non-Residential Sales (kWh)	Miller Exhibit 6 pg 1	18,078,506,705
11	**NC Non-Residential EE billing factor (Cents/kWh)**	Line 9/Line 10*100	**0.0030**

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1164
Estimated Program Costs, Earned Incentive and Lost Revenues for Vintage Year 2019

RESIDENTIAL

Line		Reference	2019
1	Residential EE Program Cost	Evans Exhibit 1, pg. 5 * NC Alloc. Factor	$ 41,002,874
2	Residential EE Earned Utility Incentive	Evans Exhibit 1, pg. 5 * NC Alloc. Factor	3,801,819
3	Total EE Program Cost and Incentive Components	Line 1 + Line 2, Evans Exhibit 1, Line 10	44,804,694
4	Residential DSM Program Cost	Evans Exhibit 1, pg. 5 * NC Alloc. Factor	10,577,352
5	Residential DSM Earned Utility Incentive	Evans Exhibit 1, pg. 5 * NC Alloc. Factor	2,773,086
6	Total DSM Program Cost and Incentive Components	Line 4 + Line 5, Evans Exhibit 1, Line 11	13,350,438
7	Total EE/DSM Program Cost and Incentive Components	Line 3 + Line 6	58,155,132
8	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.001402
9	Total EE/DSM Program Cost and Incentive Revenue Requirement	Line 7 * Line 8	58,236,665
10	Residential Net Lost Revenues	Evans Exhibit 2 pg. 3 Line 141	18,783,204
11	**Total Residential EE Revenue Requirement**	**Line 9 + Line 10**	**$ 77,019,869**

See Miller Exhibit 1
for rate

NON-RESIDENTIAL
Energy Efficiency Programs

Line		Reference	2019
12	Non- Residential EE Program Cost	Evans Exhibit 1, pg. 5 * NC Alloc. Factor	$ 41,671,833
13	Non-Residential EE Earned Utility Incentive	Evans Exhibit 1, pg. 5 * NC Alloc. Factor	8,464,629
14	Total EE Program Cost and Incentive Components	Line 12 + Line 13, Evans Exhibit 1, Line 25	50,136,461
15	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.001402
16	Total Non-Residential EE Program Cost and Incentive Revenue Requirements	Line 14 * Line 15	50,206,753
17	Non-Residential Net Lost Revenues	Evans Exhibit 2 pg. 3 Line 157	5,590,446
18	Total Non-Residential EE Revenue Requirement	Line 16 + Line 17	$ 55,797,199
19	Projected NC Residential Sales (kWh)	Miller Exhibit 6, pg. 1, Line 12	17,670,299,445
20	**NC Non-Residential EE billing factor (Cents/kWh)**	Line 18/Line 19*100	**0.3158**

DSM Programs

Line		Reference	2019
21	Non-Residential DSM Program Cost	Evans Exhibit 1, pg. 5 * NC Alloc. Factor	$ 12,538,168
22	Non-Residential DSM Earned Utility Incentive	Evans Exhibit 1, pg. 5 * NC Alloc. Factor	3,287,157
23	Total Non-Residential DSM Program Cost and Incentive Components	Line 21 + Line 22, Evans Exhibit 1, Line 26	15,825,324
24	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 7	1.001402
25	Total Non-Residential DSM Revenue Requirement	Line 23 * Line 24	15,847,512
26	Projected NC Non-Residential Sales (kWh)	Miller Exhibit 6, pg. 1, Line 13	18,078,506,705
27	**NC Non-Residential DSM billing factor**	Line 25/Line 26*100	**0.0877**

Docket No. E-7, Sub 1164
Gross Receipts Tax Years 2014 through estimated 2019

	Year		Actual GRT Rate In Effect
	2014	Jan - June	1.034554
		July - Dec	1.001352
Rider 5	2014	Weighted Average	1.017953
	2015	Jan - June	1.001352
		July - Dec	1.001482
Rider 6	2015	Weighted Average	1.001417
Rider 7	2016	Jan - June	1.001482
		July - Dec	1.001402
		Weighted Average	1.001442
Rider 8	2017		1.001402
Rider 9	2018		1.001402
Rider 10	2019		1.001402

Note: the current rate is used as the estimate for 2018 and 2019. This will be subject to true-up based on actual rates in effect.

Duke Energy Carolinas, LLC
DSM/EE Cost Recovery Rider 10
Docket Number E-7 Sub 1164
Revised Forecasted 2019 kWh Sales for Rate Period for Vintage Years 2014-2019

Line	Fall 2017 Sales Forecast - kWhs	Forecasted 2019 sales		
	North Carolina Retail:			
1	Residential	**21,806,637,265**		
2	Non-Residential	**34,250,780,653**		
3	Total Retail	**56,057,417,918**		
	NC Opt Out Sales	**Total Usage**	**Revised Opt-Outs**	**Net Usage**
	Vintage 2014 Actual Opt Out			
4	EE	34,250,780,653	15,367,415,030	18,883,365,623
5	DSM	34,250,780,653	15,556,570,256	18,694,210,397
	Vintage 2015 Actual Opt Out			
6	EE	34,250,780,653	15,487,735,641	18,763,045,012
7	DSM	34,250,780,653	15,759,845,446	18,490,935,206
	Vintage 2016 Actual Opt Out			
8	EE	34,250,780,653	15,761,176,618	18,489,604,035
9	DSM	34,250,780,653	16,040,571,583	18,210,209,069
	Vintage 2017 Actual Opt Out			
10	EE	34,250,780,653	16,067,117,918	18,183,662,735
11	DSM	34,250,780,653	16,073,320,085	18,177,460,568
	Vintage 2018 Estimated Opt Out			
12	EE	34,250,780,653	16,580,481,208	17,670,299,445
13	DSM	34,250,780,653	16,172,273,948	18,078,506,705
	Vintage 2019 Estimated Opt Out			
14	EE	34,250,780,653	16,580,481,208	17,670,299,445
15	DSM	34,250,780,653	16,172,273,948	18,078,506,705

Rider EE (NC)
ENERGY EFFICIENCY RIDER

APPLICABILITY (North Carolina Only)

Service supplied under the Company's rate schedules is subject to approved adjustments for new energy efficiency and demand-side management programs approved by the North Carolina Utilities Commission (NCUC). The Rider Adjustments are not included in the Rate Schedules of the Company and therefore, must be applied to the bill as calculated under the applicable rate.

As of January 1, 2019, cost recovery under Rider EE consists of the four year term program, years 2014-2017, as well as rates under the continuation of that program for years 2018 -2019 as outlined below. This Rider applies to service supplied under all rate schedules, except rate schedules OL, FL, PL, GL and NL for program years 2014-2019.

GENERAL PROVISIONS

This Rider will recover the cost of new energy efficiency and demand-side management programs beginning January 1, 2014, using the method approved by the NCUC as set forth in Docket No. E-7, Sub 1032, Order dated October 29, 2013, as revised by Docket No. E-7, Sub 1130, Order dated August 23, 2017.

TRUE-UP PROVISIONS

Rider amounts will initially be determined based on estimated kW and kWh impacts related to expected customer participation in the programs, and will be trued-up as actual customer participation and actual kW and kWh impacts are verified. If a customer participates in any vintage of programs, the customer is subject to the true-ups as discussed in this section for any vintage of programs in which the customer participated.

RIDER EE OPT OUT PROVISION FOR QUALIFYING NON-RESIDENTIAL CUSTOMERS

The Rider EE increment applicable to energy efficiency programs and/or demand-side management programs will not be applied to the energy charge of the applicable rate schedule for customers qualified to opt out of the programs where:

a. The customer has notified the Company that it has implemented, or has plans for implementing, alternative energy efficiency measures in accordance with quantifiable goals.
b. Electric service to the customer must be provided under:
    1. An electric service agreement where the establishment is classified as a "manufacturing industry" by the Standard Industrial Classification Manual published by the United States Government and where more than 50% of the electric energy consumption of such establishment is used for its manufacturing processes. Additionally, all other agreements billed to the same entity associated with the manufacturing industry located on the same or contiguous properties are also eligible to opt out.
    2. An electric service agreement for general service as provided for under the Company's rate schedules where the customer's annual energy use is 1,000,000 kilowatt hours or more. Additionally, all other agreements billed to the same entity with lesser annual usage located on the same or contiguous properties are also eligible to opt out.

The following additional provisions apply for qualifying customers who elect to opt out:

For customers who elect to opt out of energy efficiency programs, the following provisions also apply:

- Qualifying customers may opt out of the Company's energy efficiency programs each calendar year only during the annual two-month enrollment period between November 1 and December 31 immediately prior to a new Rider EE becoming effective on January 1. (Qualifying new customers have sixty days after beginning service to opt out).
- Customers may not opt out of individual energy efficiency programs offered by the Company. The choice to opt out applies to the Company's entire portfolio of energy efficiency programs.
- If a customer participates in any vintage of energy efficiency programs, the customer, irrespective of future opt out decisions, remains obligated to pay the remaining portion of the lost revenues for each vintage of energy efficiency programs in which the customer participated.
- Customers who elect to opt out during the two-month annual enrollment period immediately prior to the new Rider EE becoming effective may elect to opt in to the Company's energy efficiency programs during the first 5 business days of March each calendar year. Customers making this election will be back-billed retroactively to the effective date of the new Rider EE.

For customers who elect to opt out of demand-side management programs, the following provisions also apply:

- Qualifying customers may opt out of the Company's demand-side management program during the enrollment period between November 1 and December 31 immediately prior to a new Rider EE becoming effective on January 1 of the applicable year. (Qualifying new customers have sixty days after beginning service to opt out).

Rider EE (NC)
ENERGY EFFICIENCY RIDER

- If a customer elects to participate in a demand-side management program, the customer may not subsequently choose to opt out of demand-side management programs for three years.
- Customers who elect to opt out during the two-month annual enrollment period immediately prior to the new Rider EE becoming effective may elect to opt in to the Company's demand-side management program during the first 5 business days of March each calendar year. Customers making this election will be back-billed to the effective date of the new Rider EE.

Any qualifying non-residential customer that has not participated in an energy efficiency or demand-side management program may opt out during any enrollment period, and has no further responsibility to pay Rider EE amounts associated with the customer's opt out election for energy efficiency and/or demand-side management programs.

ENERGY EFFICIENCY RIDER ADJUSTMENTS (EEA) FOR ALL PROGRAM YEARS

The Rider EE amounts applicable to the residential and nonresidential rate schedules for the period January 1, 2019 through December 31, 2019 including utility assessments are as follows:

Residential	Vintage 2014, 2015[1], 2016[1], 2017[1]	0.1091¢ per kWh
	Vintage 2017[2], 2018[2], 2019[2]	0.4229¢ per kWh
	Total Residential Rate	0.5320¢ per kWh
Nonresidential		
Vintage 2014[3]		
	Energy Efficiency	(0.0061)¢ per kWh
	Demand Side Management	(0.0002)¢ per kWh
Vintage 2015[3]		
	Energy Efficiency	0.0024¢ per kWh
	Demand Side Management	(0.0024)¢ per kWh
Vintage 2016[3]		
	Energy Efficiency	(0.0126)¢ per kWh
	Demand Side Management	(0.0015)¢ per kWh
Vintage 2017[3]		
	Energy Efficiency	0.3725¢ per kWh
	Demand Side Management	0.0005¢ per kWh
Vintage 2018[3]		
	Energy Efficiency	0.0695¢ per kWh
	Demand Side Management	0.0030¢ per kWh
Vintage 2019[3]		
	Energy Efficiency	0.3158¢ per kWh
	Demand Side Management	0.0877¢ per kWh
Total Nonresidential		0.8286¢ per kWh

[1] Includes the true-up of program costs, shared savings and lost revenues from Year 1 of Vintage 2017 and Year 2 of Vintage 2016, and Year 3 of 2015.
[2] Includes prospective component of Vintage 2017, 2018 and 2019.
[3] Not Applicable to Rate Schedules OL, FL, PL, GL, and NL.

Each factor listed under Nonresidential is applicable to nonresidential customers who are not eligible to opt out and to eligible customers who have not opted out. If a nonresidential customer has opted out of a Vintage(s), then the applicable energy efficiency and/or demand-side management charge(s) shown above for the Vintage(s) during which the customer has opted out, will not apply to the bill.