NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

May 22, 2020

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-7, Sub 1230 – Application Pursuant to N.C.G.S. 62-133.9 and Commission Rule R8-69 for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider

Dear Ms. Campbell:

In connection with the above-referenced docket, I transmit herewith for filing on behalf of the Public Staff the following:

1. Testimony and exhibits of David M. Williamson, Utilities Engineer, Electric Division;

2. Confidential Testimony and confidential exhibit of John R. Hinton, Director, Economic Research Division; and

3. Testimony and exhibit of Michael C. Maness, Director, Accounting Division.

By copy of this letter, I am forwarding a copy of the redacted version to all parties of record by electronic delivery. The confidential version will be provided to those parties that have entered into a confidentiality agreement.

Sincerely,

/s Lucy E. Edmondson
Staff Attorney
lucy.edmondson@psncuc.nc.gov

Attachments

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1230

In the Matter of		
Application by 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	)))))))	TESTIMONY OF DAVID M. WILLIAMSON PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

May 22, 2020

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1230

Testimony of David M. Williamson

On Behalf of the Public Staff

North Carolina Utilities Commission

May 22, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is David M. Williamson. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Utilities Engineer with the Electric Division of the Public Staff, North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations with respect to the following aspects of the February 25, 2020 application and May 11, 2020 supplemental testimony and exhibits of Duke Energy Carolinas, LLC (DEC), for approval of its demand-side management (DSM) and energy efficiency (EE) cost recovery rider for 2021 (Rider 12).

This testimony discusses: (1) the portfolio of DSM/EE programs included in the proposed Rider 12, including modifications of those programs made pursuant to the joint motion regarding program modifications approved on July 16, 2012, in Docket No. E-7, Sub 831 (Flexibility Guidelines); (2) the ongoing cost-effectiveness of each DSM/EE program; (3) the concerns of the Public Staff with various DSM/EE programs going forward, with regard to regulatory and grid related activities; and (4) the evaluation, measurement, and verification (EM&V) studies filed as Exhibits A through E to the testimony of Company witness Robert P. Evans.

Q. WHAT DOCUMENTS HAVE YOU REVIEWED IN YOUR INVESTIGATION OF DEC'S PROPOSED RIDER 12?

A. I reviewed the application and supporting testimony and exhibits, the Company's supplemental testimony and exhibits, and DEC's responses to Public Staff data requests. In addition, the following documents remain pertinent to Rider 12:

1. The Agreement and Joint Stipulation of Settlement (Sub 831 Agreement) approved on February 9, 2010, in Docket No. E-7, Sub 831;

2. The agreement regarding EM&V approved on November 8, 2011, in Docket No. E-7, Sub 979 (EM&V Agreement);

3. The Flexibility Guidelines; and,

4. The Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs approved on October 29, 2013, in Docket No. E-7, Sub 1032 (Sub 1032 Order), as revised in the 2017 DSM/EE rider proceeding, Docket No. E-7, Sub 1130 (Revised Mechanism).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The Public Staff makes the following recommendations to the Commission:

1. That, beginning in 2021, only specialty light emitting diode (LED) lighting be considered for recognition as an EE measure eligible for cost recovery;

2. That the Company, in the next rider proceeding, assess the costs and benefits of continuing to offer the MyHER program, which is a comparison of energy consumption and EE tips, versus providing the same comparison and tips through another channel;

3. That the Company perform an analysis of the Grid Improvement Plan (GIP) to explain how it will affect the ability

of DSM/EE programs to produce peak demand and energy savings;

4. That the Company, in the next rider proceeding, explain how it will distinguish peak demand and energy savings between GIP and DSM and EE programs; and

5. That the Company provide in its next rider filing a list of GIP projects that have been implemented and how those projects have affected the performance of the Company's DSM/EE portfolio, if at all. The Company should be prepared to discuss any impacts the GIP projects have had on day-to-day system operations, as well as customer expectations for utility service in general, DSM/EE program performance, and the availability of customer data.

Q. ARE YOU PROVIDING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I have three exhibits, described below:

- Exhibit 1: Three year cost benefit analysis (CBA) projections
- Exhibit 2: Three year CBA actuals
- Exhibit 3: Net effects on Cost-Effectiveness tests applying Public Staff's position regarding avoided capacity issues

DSM/EE Programs in Rider 12

Q. PLEASE IDENTIFY THE DSM/EE PROGRAMS FOR WHICH DEC IS SEEKING COST RECOVERY THROUGH THE DSM/EE RIDER IN THIS PROCEEDING.

A. In its proposed Rider 12, DEC included the costs and incentives associated with the following programs:

- Energy Assessments;
- EE Education;
- Residential Smart $aver® Energy Efficient Appliances and Devices;
- Residential Smart $aver® EE (formerly the HVAC EE Program);
- Multi-Family EE;
- My Home Energy Report (MyHER);
- Residential Neighborhood Energy Saver (formerly Income-Qualified Energy Efficiency and Weatherization Assistance);
- Power Manager;
- Nonresidential Smart $aver® Energy Efficient Products and Assessments Program:
    - Energy Efficiency Food Service Products;
    - Energy Efficiency HVAC Products;

- Energy Efficiency IT Products;
- Energy Efficiency Lighting Products;
- Energy Efficiency Process Equipment Products;
- Energy Efficiency Pumps and Drives;
- Custom Incentive and Energy Assessments;

- PowerShare®;
- Small Business Energy Saver;
- EnergyWise for Business; and,
- Nonresidential Smart $aver® Performance Incentive.

Each of these programs has received Commission approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under N.C. Gen. Stat. § 62-133.9, subject to certain program-specific conditions imposed by the Commission.

Since initial program approval, DEC has modified several of these programs to add or remove measures, consistent with the Flexibility Guidelines, to enhance the programs' cost-effectiveness and address changing market conditions and technologies. In each case, DEC either sought Commission approval or provided notice of those modifications in compliance with those guidelines.

I also note that since the last rider proceeding, DEC has received Commission approval to modify the Residential Energy Saver and Residential Neighborhood Energy Saver programs.

<u>Changes to the DSM/EE Rider since last Rider Proceeding</u>

Q. PLEASE DISCUSS THE CHANGES THAT HAVE OCCURRED SINCE THE LAST RIDER PROCEEDING, IN DOCKET NO. E-7, SUB 1192 (RIDER 11).

A. In the Rider 11 proceeding, the Company utilized the avoided cost rates approved in the Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2016, Docket No. E-100, Sub 148, to determine the avoided benefits that would be generated for each of the Company's DSM/EE programs within its portfolio.

On October 7, 2019, and supplemented on October 17, 2019, the Commission issued a Notice of Decision in Docket No. E-100, Sub 158, regarding the Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018 (Sub 158 proceeding).

Pursuant to the Mechanism, the Company has updated its underlying input source for both avoided capacity and avoided energy in this proceeding to reflect the methodology used in the Sub 158 proceeding.

The Public Staff agrees with the Company's decision to update its underlying inputs to reflect those approved in the Sub 158 proceeding, pursuant to the Mechanism. However, as discussed later in my testimony and in more detail in Public Staff witness Hinton's testimony, the Public Staff has two concerns with the Company's application of the inputs from the Sub 158 proceeding.

Additionally, since the Rider 11 proceeding, the various parties to this proceeding, including the Public Staff, have jointly filed proposed modifications to the Revised Mechanism.[1] These proposed modifications are still pending before the Commission.

<u>Cost Effectiveness</u>

Q. HOW IS THE COST EFFECTIVENESS OF DEC'S DSM/EE PROGRAMS EVALUATED?

A. The Public Staff reviews the cost-effectiveness of the individual DSM/EE programs when they are proposed for approval and then annually in the rider proceedings. Pursuant to the Revised

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[1] The proposed modifications to the Revised Mechanism were filed in Docket No. E-7, Sub 1032.

Mechanism, cost-effectiveness is evaluated at both the program and portfolio levels. The Public Staff reviews cost-effectiveness using the Utility Cost (UC), TRC, Participant, and Ratepayer Impact Measure (RIM) tests. Under each of these four tests, a result above 1.0 indicates that a program is cost-effective.

A program may be above 1.0 on one or more tests, and below 1.0 on other tests. The Public Staff, as well as the Revised Mechanism, places greater weight on the UC and TRC tests.

The TRC test represents the combined utility and participant benefits that will result from implementation of the program; a result greater than 1.0 indicates that the benefits outweigh the costs of a program to both the utility and the program's participants. A UC test result greater than 1.0 means that the program is cost beneficial[2] to the utility (the overall system benefits are greater than the utility's costs, including incentives paid to participants). The Participant test is used to evaluate the benefits against the costs specific to those ratepayers who participate in a program. The RIM test is used to understand

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[2] "Cost beneficial" in this sense represents the net benefit achieved by avoiding the need to construct additional generation, transmission, and distribution facilities related to providing electric utility service, and/or avoiding energy generation from existing or new facilities or purchased power.

how ratepayers who do not participate in a program will be impacted by the program.

Q. HOW IS COST-EFFECTIVENESS EVALUATED IN DSM/EE RIDER PROCEEDINGS?

A. In each DSM/EE rider proceeding, DEC files the projected cost-effectiveness of each program and for the portfolio as a whole for the upcoming rate period (Evans Exhibit 7). Subsequently, when new DSM/EE programs are approved under Commission Rule R8-68, potential cost-effectiveness is evaluated over a three to five year period using estimates of participation and measure attributes that can be reasonably expected over that period. The evaluations in DSM/EE rider proceedings look more specifically at the actual performance of a typical measure, providing an indication of what to expect over the next year. Each year's rider filing is updated with the most current EM&V data and other program performance data.

Q. HOW DOES THE PUBLIC STAFF ASSESS COST-EFFECTIVENESS IN EACH RIDER?

A. The Public Staff compares the cost-effectiveness test predictions in previous DSM/EE proceedings to the current filing, and develops a trend of potential cost-effectiveness that serves as the basis for the Public Staff's recommendation on whether a program should: (1)

continue as currently implemented, (2) be watched for signs of continued decreasing cost-effectiveness combined with Company efforts to improve cost-effectiveness, or (3) be terminated.

Q. HOW DO THE FORWARD-LOOKING COST-EFFECTIVENESS TEST SCORES FILED IN THIS RIDER COMPARE TO SCORES IDENTIFIED IN PREVIOUS RIDERS?

A. While many programs continue to be cost effective, the TRC and UC scores as filed by the Company for all programs have a natural ebb and flow over the years of DSM/EE rider proceedings, mainly due to the changes in avoided cost rate determinations. In addition, decreasing cost-effectiveness is partially attributable to a reduction in the unit savings from the original estimates of savings as determined through EM&V of the program. As programs mature, baseline standards increase, or avoided cost rates decrease, it becomes more difficult for a program to produce cost-effective savings. On the other hand, some programs have experienced greater than expected participation, which usually results in greater savings per unit cost, generally increasing cost-effectiveness.

These changes are shown for Vintage years 2019, 2020, and 2021 in Williamson Exhibit No. 1.

In addition to the forward looking cost-effectiveness test results, as most of the EM&V reports for the Company's portfolio of programs are completed, the Company has been able to provide the Public Staff with updated, actual cost-effectiveness test results for each program, and program year, over the Vintage years 2017, 2018, and 2019.

Q. HOW DO THE ACTUAL COST-EFFECTIVENESS TEST SCORES COMPARE TO THE FORWARD-LOOKING SCORES IDENTIFIED IN PREVIOUS RIDERS?

A. Understanding that the incorporation period of EM&V within the portfolio may be different from one program to another, having a rolling record of actual cost-effectiveness results provides the Public Staff with confirmation that the activities within the portfolio have been and continue to be worthwhile. On the other hand, actual test results highlight programs that ultimately do not perform at or above the original projection. The actual cost-effectiveness results for DEC's portfolio of programs are shown in Williamson Exhibit 2. These test results are a reflection of the annual updates in cost-effectiveness due to completed EM&V and finalized participation numbers.

Program Performance

Q. PLEASE DISCUSS THE PERFORMANCE OF THE PORTFOLIO.

A. The Company's DSM/EE portfolio offers a wide variety of measures to support everyday activities of its customers. Our review of program performance involves: (1) reviewing cost-effectiveness trends; and (2) reviewing Evans Exhibit 6, which provides specific information on each program's marketing strategy, potential areas of concern, and an overall qualitative analysis.

The Public Staff also uses its involvement in the Company's bi-monthly EE collaborative meetings to determine how a program is performing. During these meetings, the Collaborative discusses program performance (participation, customer engagement, and potential barriers regarding continuation and entry to the program), recently completed EM&V and market potential study activities, and potential new program offerings.

Relying on all of the resources mentioned above, the Public Staff believes that the historical performance of the Company's programs, as previously described, is reasonable. However, I have a number of concerns with the portfolio that I wish to bring to the Commission's attention for consideration in future rider proceedings.

Public Staff's Concerns

Q. PLEASE DISCUSS THE PUBLIC STAFF'S CONCERNS REGARDING THE PORTFOLIO.

A. I have the following areas of concern regarding DEC's DSM/EE portfolio:

a. The federal guidelines relevant to the production of lighting-related measures, and the North Carolina market in which these measures are offered;

b. The potential impacts of the Company's proposed GIP on the performance of current and future DSM/EE programs;

c. The Company's incorrect application of the Sub 158 avoided cost rates in the DSM/EE Rider calculations; and

d. Changes to the Company's Referral Channel for its Residential Smart Saver EE program to incorporate referrals to services unrelated to DSM/EE.

Lighting

Q. PLEASE DISCUSS YOUR OBSERVATIONS CONCERNING LIGHTING-RELATED MEASURES.

A. Over the years and in various dockets before the Commission,[3] and extensively in the Public Staff's testimony regarding Evans Exhibit C in the Docket No. E-7, Sub 1192 proceeding, we have highlighted several trends surrounding the adoption of EE lighting measures, specifically, that the EE lighting market for North Carolina is being transformed and that non-specialty LED lighting will likely become the baseline standard for general service bulb technologies by January 2020, thereby decreasing savings from any EE program that continues to include general service bulb technologies.

On January 19, 2017, the U.S. Department of Energy (DOE) published final rules for its second phase of the 2007 Energy Independence and Security Act (EISA). The rules, otherwise known as EISA 2020, adopted revised definitions for the general service lamp (GSL) and the general service incandescent lamp (GSIL), which were to become effective January 1, 2020.[4]

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[3] See Comments of the Public Staff filed February 6, 2019, in Docket No. E-100, Sub 159; Testimony of Jack L. Floyd filed May 23, 2017, in Docket No. E-7, Sub 1130; Testimony of David M. Williamson filed May 22, 2018, in Docket No. E-7, Sub 1164, May 20, 2019, in Docket No. E-7, Sub 1192, September 5, 2017, in Docket No. E-2, Sub 1145, September 4, 2018, in Docket No. E-2, Sub 1174, and August 9, 2019, in Docket No. E-2, Sub 1206.

[4] Energy Conservation Program: Conservation Standards for General Service Lamps, 82 Fed. Reg. 7276-7322 (January 19, 2017).

However, on February 11, 2019, DOE issued a notice of proposed rulemaking and request for comment to withdraw the current definitions of GSL and GSIL.[5]

On September 5, 2019, the DOE published a notice of proposed determination in which it initially determined that energy conservation standards for GSILs do not need to be amended.

On December 27, 2019, the DOE published a final determination in which it responded to comments received in September of 2019 and determined that amending the energy conservation standards for GSILs would not be economically justified.[6]

The Public Staff continues to believe that the EE lighting market in North Carolina has transformed at a faster rate than was initially recognized. This transformation has been a result of changes to federal lighting standards since 2007 resulting from the EISA, and customer preference for LEDs. Both of these factors have substantially transformed the lighting market to the point that non-

[5] Energy Conservation Program: Conservation Standards for General Service Lamps, 84 Fed. Reg. 3120-3131 (February 2, 2019), https://www.federalregister.gov/documents/2019/02/11/2019-01853/energy-conservation-program-energy-conservation-standards-for-general-service-lamps

[6] Energy Conservation Program: Conservation Standards for General Service Lamps, 84 Fed. Reg. 71626-71671 https://www.federalregister.gov/documents/2019/12/27/2019-27515/energy-conservation-program-energy-conservation-standards-for-general-service-incandescent-lamps

specialty LED lighting should be considered the baseline standard for general service bulb technologies.[7]

One of the goals of utility-sponsored EE programs is to build customer awareness of, and confidence in, EE technologies, and to encourage consumers to adopt EE measures on their own. As technologies become more energy efficient, costs decrease, and consumer acceptance increases, adoption of EE measures should become routine, at which point "market transformation" results, as has been seen in the lighting markets.

Q. PLEASE DESCRIBE THE ACTIONS THAT THE COMPANY IS TAKING WITH REGARD TO TRANSFORMATION OF LIGHTING IN NORTH CAROLINA.

A. The Company, in last year's rider proceeding, acknowledged the changes and impacts proposed by the EISA 2020 rules and began making strides to minimize those impacts. The Company has been updating all of its programs that incorporate lighting-related products to offer specialty LED bulb technologies as the only lighting offering. Based on the Public Staff's review in this case, we can confirm that

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[7] The Public Staff is aware of Duke Energy's work to finalize an EE and DSM market potential study in time for submission with their 2020 Integrated Resource Plans.

the Company's portfolio is focusing on specialty LED bulb technologies.

The Public Staff agrees with this approach.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR THE COMMISSION WITH REGARD TO LIGHTING TRANSFORMATION IN NORTH CAROLINA?

A. Yes. Based on the Public Staff's review of lighting-related EM&V reports over the last three years, and the Company's acknowledgement of upcoming lighting standard changes as they alter their program offerings, I recommend that the Commission require that, beginning in 2021, only specialty LED lighting be considered for recognition as energy efficiency.

<u>DEC's GIP Impacts</u>

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S CONCERNS WITH THE IMPACT OF THE COMPANY'S GIP ON DSM/EE PROGRAMS.

A. Since the last rider proceeding, the Company has filed a general rate case in Docket No. E-7, Sub 1214 (Sub 1214 proceeding), in which, among other things, it has proposed a GIP, along with deferral of associated investments, which is still pending before the

Commission at this time. The GIP, as proposed, would drive enhancements to capacity, data analytics/collection, and power flow capabilities on almost all of the circuits within its service territory. The Public Staff believes that the GIP proposal will have an impact on the savings achieved through the DSM/EE portfolio due to improvements in the areas of utility operation listed above.

Q. WHY IS IT IMPORTANT TO DISCUSS THE GIP IN THE CONTEXT OF THE DSM/EE RIDER?

A. As discussed in the Sub 1214 proceeding, the Company is planning to make improvements to its ability to provide customer-specific information and reliability through data analytics, all designed to help bring the grid up to a new level of operation. The Company has also acknowledged that its customer’s needs and expectations are evolving.

As more data analytics and technology enhancements are made to the Company’s day-to-day operations, the base level impacts and offerings of DSM/EE programs will be impacted.

Q. WHICH PROGRAMS WILL BE MOST IMPACTED BY THE COMPANY’S GIP PROPOSAL?

A. I believe that that the MyHER and DSM programs will be impacted the most by the GIP proposal. These programs rely heavily on data analytics and base level system capacity on the Transmission and Distribution (T&D) grid. As the Company deploys GIP, with particular regard to the availability of customer data and demand reduction, these programs will need to be re-evaluated (both internally by the Company and through EM&V) to ensure that they remain cost effective offerings, and to determine whether or not they have become standard operating procedures (i.e., part of the Company's day-to-day operations).

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE MYHER PROGRAM WILL BE IMPACTED BY THE COMPANY'S GIP PROPOSAL.

A. The success of the MyHER program relies on the Company's collection of individual customers' data, and then analyzing this data in relation to similar nearby customers.

The Company, for a number of years, has been deploying Advanced Metering Infrastructure (AMI) meters throughout its service territory. That deployment was for the most part completed[8] in 2019, with a large majority of customers now being served by AMI meters. This deployment is expected to be used to provide new opportunities for

[8] Customers currently have the ability to opt out of having an AMI meter installed at their residence. As long as this AMI opt-out tariff is offered to customers, the Company will likely never see a completion of its AMI rollout across the entirety of its service territory.

better rate design and to provide customers with interval usage data. These meters will be a crucial component of the Company's GIP data collection infrastructure.

In Exhibit 6, page 11, DEC witness Evans discusses the impact AMI meters have on the MyHER program:

> In 2019, the [MyHER] program launched into the Duke Energy Mobile App. Participants in the MyHER program are now able to see their usage comparison and disaggregation in the mobile app. With the deployment of AMI meters throughout DEC, the program began sending AMI data to Tendril. Customers with AMI meters can see their interval energy usage on the MyHER interactive experience. In 2019, the program also launched new AMI usage charts on the eHERs which show customers the difference in average weekly usage by hour from one month to the next.

Additionally, the Company's investment in its AMI meters provides its customers with more direct access to their customer data than previously available. This comes in the form of a Smart Meter Usage App as well as a means of allowing third parties to analyze a particular customer's usage data.[9]

In response to a Public Staff data request, the Company acknowledged that:

[9] See Smart Meter Usage App approved September 4, 2019, in Docket No. E-7, Sub 1209.

> The Company has very recently made available to customers functionality similar to the functionality provided by Green Button Download, enabling customers to download their usage data in a standard format. A customer may then share this data at their discretion.

The Public Staff believes that with these services and access to data, the MyHER program will simply be a duplicate provision of the same data to the customer in one form or another. The only incremental difference would be the energy efficiency tips that would be offered through the MyHER report. If offering EE tips is the only additional item offered by a MyHER report that is not already provided by other potentially less costly channels (e.g., the Company's website, bill inserts, or information printed on the monthly bill that a customer receives), then the Public Staff is skeptical that the cost and utility incentives associated with the MyHER program are justified. The Public Staff believes it would be appropriate for the Commission to require Duke to assess the costs and benefits of continuing to offer the MyHER program, which is a comparison of energy consumption and EE tips, versus providing the same comparison and tips through another channel such as those identified above.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE DSM PROGRAMS WILL BE IMPACTED BY THE COMPANY'S GIP PROPOSAL.

A. The Company's DSM programs rely on the level of system demand that is on the grid at the time that the particular DSM program is called upon by system operations.[10] If the base level of demand on the T&D grid changes, then the level of demand response from DSM programs could potentially be impacted as well.

The Public Staff believes that the Company's plan to build grid infrastructure to enable Integrated Volt/Var Controls (IVVC), which is part of the Company's GIP proposal, will emphasize this concern. As explained in further detail in the Company's general rate case[11] application, DEC witness Mark Oliver's Exhibit 4, pages 3 through 5, explains that IVVC will allow the distribution system to optimize voltage and reactive power needs.

Additionally, in response to a Public Staff data request, the Company acknowledged that:

> . . . voltage reduction impacts will likely vary amongst measures, it is anticipated that the Company's DSM/EE portfolio savings, in aggregate, would be reduced to a level less than or equal to the approximate reduction in load associated with IVVC. Thus, with all

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[10] Data from the Company suggests that DSM programs may or may not be called upon during a peak demand event when system conditions require load reductions.

[11] Docket No. E-7, Sub 1214.

> other things being equal, a greater number of DSM/EE measures would need to be installed to obtain savings equivalent to those that would be realized without the IVVC program. Hence, the implementation of IVVC will likely slightly diminish projected cost effectiveness of the Company's portfolio of EE and DSM Programs.

As the Company begins to implement the GIP, this implementation will likely result in reduced demand savings from the Company's DSM programs.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE MYHER AND DSM PROGRAMS GOING FORWARD.

A. As the Company continues to implement its GIP, the continuation of savings and offerings for DSM/EE programs will need to be reviewed to ensure that peak demand and energy savings are not being either double-counted or offered in other rate base related channels.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE COMPANY'S GIP AND ITS INFLUENCE ON THE DSM/EE RIDER?

A. Yes. With regards to the Company's pending GIP proposal, the Public Staff recommends that the Commission require the Company to:

1. Perform an analysis of GIP to explain how GIP will affect the performance of DSM/EE programs to produce peak demand and energy savings. In other words, if a GIP project will reduce T&D losses or impact the operational capability of a DSM or

EE program to produce savings, the Company should seek to quantify those impacts;

2. In the next rider proceeding, explain how the Company will distinguish peak demand and energy savings between GIP and DSM and EE programs; and,
3. Provide in its next rider filing a list of GIP projects that have been implemented and how those projects have affected the performance of the Company's DSM/EE portfolio, if at all. The Company should be prepared to discuss any impacts the GIP projects have had on day-to-day system operations, as well as customer expectations for utility service in general, DSM/EE program performance, and the availability of customer data.

<u>Avoided Cost</u>

Q. PLEASE DESCRIBE YOUR CONCERNS REGARDING THE COMPANY'S USE OF AVOIDED COST RATES.

A. The Company, as noted above, has updated its underlying avoided cost inputs for both capacity and energy to be derived from the Sub 158 avoided cost proceeding, in Docket No. E-100, Sub 158 (Sub 158), pursuant to the Revised Mechanism. While the Public Staff agrees with this update, we have two concerns with the Company's application of avoided capacity derived from the Sub 158 rates. Public Staff witness John R. Hinton goes into further discussion on these two concerns in his testimony, but I summarize his concerns as the following:

1. That the Company's incorporation of a 17% reserve margin adder to all avoided capacity benefits associated with its EE programs, beginning in Vintage year 2021, is inappropriate; and,
2. That the Company's allocation of 100% of avoided capacity benefits to summer capacity for DEC's legacy[12] DSM programs is inappropriate.

Q. WHAT IS THE IMPACT OF IMPLEMENTING PUBLIC STAFF WITNESS HINTON'S POSITION ON THE FIRST CONCERN?

A. The impact associated with this issue on the cost effectiveness of the portfolio is seen in Williamson Exhibit 3, under the column labeled "Removing 17% Reserve Margin Adder." The impacts expressed in this column are only associated with this adjustment because only the Energy Efficiency programs are impacted by this adjustment.

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[12] "Legacy," as understood by the Public Staff and based on the Company's responses to data requests, is the level of DSM activation capability that was originally projected for the year 2021 in the 2018 IRP.

The impacts with regard to the NPV of system avoided cost benefits that are included in Evans Exhibit 1 and used in the calculation of the revenue requirement for the prospective rate for Vintage year 2021 amount to a decrease in the amount of approximately $7.5 million for both residential and non-residential programs combined.

Q. WHAT IS THE IMPACT OF IMPLEMENTING PUBLIC STAFF WITNESS HINTON'S POSITION ON THE SECOND CONCERN?

A. The impact on the cost effectiveness of the portfolio is seen in Williamson Exhibit 3, under the column labeled "Applying 90%W/10%S Seasonal Allocation." The impacts expressed in this column are only associated with this adjustment because only the DSM programs are impacted by this adjustment.

The impacts with regard to the NPV of system avoided cost benefits that are included in Evans Exhibit 1 and used the calculation of the revenue requirement for the prospective rate for Vintage year 2021 amounts to a decrease in amount of approximately $59.7 million for both residential and non-residential programs combined.

Q. WHAT ARE THE NET IMPACTS TO THE PROJECTED COST-EFFECTIVENESS SCORES FOR THE PORTFOLIO OF THE PUBLIC STAFF'S POSITION ON BOTH CONCERNS?

A. The impact on the cost effectiveness of the portfolio of both of these adjustments is seen in Williamson Exhibit 3, under the column labeled "Total Net Impacts."

In addition to the net impacts to cost-effectiveness, I have calculated the percent change to both the TRC and UC tests from the originally filed scores to the "Total Net Impacts" scores. As seen in Williamson Exhibit 3, the greatest impacts to cost-effectiveness occur with the DSM programs. This is because the Company does not currently have activations of its DSM programs during the winter time, where the majority of potential avoided benefits reside.

The total net impacts with regard to the NPV of system avoided cost benefits that are included in Evans Exhibit 1 and used in the calculation of the revenue requirement for the prospective rate for Vintage year 2021 amount to a decrease in the amount of approximately $67.2 million for both residential and non-residential programs combined.

These impacts have been provided to Public Staff witness Maness for his incorporation in the appropriate revenue requirement for this proceeding.

Residential Smart Saver EE Program – Referral Channel

Q. WHAT IS THE PURPOSE OF THE RESIDENTIAL SMART SAVER PROGRAM?

A. The Company's Residential Smart Saver (SmartSaver) program, which was originally known as the HVAC EE program, is designed to offer rebate options to customers for a variety of EE measures related to home heating and cooling[13] to encourage greater energy efficiency.

On February 9, 2016, in Docket No. E-7, Sub 1032, the Commission approved the Company's request to implement a referral channel to offset some of the costs associated with the program. The Company expected that this modification would bolster the cost-effectiveness of the HVAC EE program.

On September 11, 2017, in the same docket, the Commission approved the conversion of the HVAC EE program into what is now

[13] For example, HVAC equipment (heat pumps and central air conditioning), attic insulation, duct sealing, etc.

known as the SmartSaver program. This program modification expanded the program to include additional household-related measures, as well as an online store option. These changes were intended to make the DEC SmartSaver program match the SmartSaver program of Duke Energy Progress, LLC.

Q. DID THE RESIDENTIAL HVAC EE REFERRAL CHANNEL CONTINUE AFTER THE PROGRAM CHANGES APPROVED ON SEPTEMBER 11, 2017?

A. Yes. The Company's referral channel continues to be a part of the SmartSaver program. However, the Company has expanded the original scope of the referral channel to include a variety of items and services beyond its original focus on HVAC equipment-related contractor referrals. The referral channel now also provides customers with contractor referrals related to rooftop solar systems, plumbing, and tree removal services.

For marketing purposes, the Company uses the name "FindItDuke" to provide the contractor referral information.[14] This portal is accessible to the general public, and is accessible without having to log into the Company's customer account system. The Company

[14] https://www.duke-energy.com/find-it-duke

includes a disclaimer on its portal to explain this accessibility. It reads that "[w]hile non-Duke Energy customers are eligible to use the referral service and receive special contractor discounts and financing, only Duke Energy customers are eligible to receive Duke Energy rebates."

The referral services currently available from the "FindItDuke" portal include:

- Heating and Air Conditioning;
- Insulation;
- Plumbing;
- Electrical;
- Pool;
- Solar; and
- Tree Removal.

Q. WHERE ARE THE REVENUES RECEIVED FROM CONTRACTORS PARTICIPATING IN THE REFERRAL CHANNEL BOOKED?

A. All funds that DEC receives from contractors participating in the referral channel are used to offset the program costs for the SmartSaver program. This includes funds associated with rooftop solar and tree service contractors, which at this time represent only a very small portion of the overall revenues received.

Q. WITH RESPECT TO THE EXPANSION OF THE REFERRAL CHANNEL AND THE "FINDITDUKE" WEB PORTAL, DOES THE PUBLIC STAFF HAVE ANY CONCERNS WITH THE COMPANY MAKING THIS TYPE OF PROGRAM MODIFICATION?

A. The Public Staff does not believe that the Company has violated any Commission rules or the Flexibility Guidelines that address how program modifications are to be handled. While the Flexibility Guidelines have generally worked well to provide the appropriate notice to the Commission and parties of upcoming or past changes to the programs, the expansion of the referral channel into areas not specifically related to DSM and EE programs, or that may be otherwise recovered through base revenues, does seem to be the type of program change that should be brought to the Commission's attention for approval in advance of the change. This would be particularly applicable to any change that would give the appearance of impacting the performance or cost recovery of a particular DSM or EE program. The Public Staff will continue to discuss this matter with the Company, and such discussions could include the potential for revisions to the Flexibility Guidelines to specifically address this type of program modification.

EM&V

Q. HAVE YOU REVIEWED THE EM&V REPORTS FILED BY DEC?

A. Yes. The Public Staff contracted the services of GDS Associates, Inc. (GDS), to assist with review of EM&V. With GDS's assistance, I have reviewed the EM&V reports filed in this proceeding as Evans Exhibits A through E.

I also reviewed previous Commission orders to determine if DEC complied with provisions regarding EM&V contained in those orders. My review leads me to conclude that the Company is complying with the various Commission orders regarding EM&V of their DSM/EE portfolio.

Q. DO YOU HAVE ANY CONCERNS REGARDING THE EM&V REPORTS YOU REVIEWED?

A. I have reviewed the testimony and exhibits of DEC witness Evans concerning the EM&V of DEC's DSM/EE programs. Based upon my review and upon the analysis performed by GDS, I have recommendations regarding the EM&V report for the Residential Income-Qualified EE (Neighborhood Energy Saver or NES) Program (Evans Exhibit A).

Evans Exhibit A evaluated the performance of the NES program over the period from June 1, 2017, through June 30, 2018, and included approximately 8,900 customers in the DEC portion of the study. As discussed by the evaluator of the NES program, a billing analysis was not used in this case to determine program savings. Rather, the evaluator used an engineering analysis that relied on information from other sources (namely technical reference manuals from other states). The evaluator states that a billing analysis was not appropriate in this evaluation because of differences in usage patterns between the treatment group and control group, and the differences in weather patterns between pre- and post-treatment periods.[15]

The use of an engineering analysis is an appropriate analytical approach for the NES program. However, a billing analysis is preferable because it provides a more accurate representation of the actual program performance.[16] The Public Staff has recommended in past DSM/EE rider proceedings,[17] and the Company and Commission have agreed, that billing analyses of EE programs were

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[15] See Section 4.3 of Evans Exhibit A.

[16] A billing analysis provides net program savings. An engineering analysis does not include a net-to-gross analysis and therefore must rely on numerous measure assumptions, and less on empirical customer consumption data.

[17] Docket Nos. E-7, Subs 1105 and 1130, and E-2, Subs 1145 and 1174.

preferable. The engineering analysis in this case produces per participant savings that are double the savings from the previous evaluation.[18]

A second issue relates to the evaluation of the net-to-gross ratio (NTGR). The engineering analysis assumes a NTGR of 1.0, which is standard practice for income-qualified programs. While the Public Staff recognizes this to be a standard practice, we also note that lighting accounts for 38% of the program's gross savings and that there have been significant changes in the lighting market in recent years. The evaluation indicates that many bulbs could not be installed because efficient bulbs were already present, which suggests a NTGR of less than 1.0 for lighting measures. The issue is further complicated by the fact that the engineering analysis assumes the baseline wattage is equal to the federal standard (equivalent to a halogen bulb) when at the time of the evaluation, halogen bulbs likely only represented a small fraction of shelf space at stores selling bulbs to prospective lighting purchasers. During 2017-2018, LEDs and CFLs were already occupying much of the available shelf-space at big box retailers like Home Depot and

[18] The previous evaluation reported 347 kWh per participant (Table 1-2 of Evans Exhibit A in Docket No. E-7, Sub 1130). The current evaluation reports 676 kWh per participant (Table 1-3 of Evans Exhibit A).

Lowes. This suggests that the NTGR assumption as well as the presumed baseline wattage in the engineering analysis may over-estimate the LED bulb savings component of the program. The concern we have over the NTGR for the lighting component of the program adds emphasis to my recommendation that the next evaluation rely on a billing analysis for assessing the savings attributable to the program.

Consistent with the EM&V agreement contained in the Mechanism, the results in Evans Exhibit A would apply to participation from June 30, 2018, through the end of the sampling period associated with the next evaluation. Based on past scheduling of evaluations, this could be two to three years, which likely puts the next evaluation in 2021. Evans Exhibit A is acceptable for purposes of verifying the NES program savings. However, the Public Staff also believes it would be appropriate to perform the next evaluation of the NES program as soon as possible, and incorporate a billing analysis in that evaluation. The Company has represented to the Public Staff that it will initiate the next evaluation very soon.

Q. DO YOU HAVE ANY OTHER EM&V CONCERNS?

A. Yes. There are some cases in which a similar or identical measure is offered across multiple programs. For example, the low-flow showerhead is offered through the Neighborhood Energy Saver program as well as the Energy Efficiency Education in Schools program. DEC used different contractors in the evaluations of these two programs. The evaluators made different assumptions with respect to the assumed baseline flow of an existing showerhead in the calculation of the low-flow showerhead measure savings. The assumptions and sources cited by both evaluators are reasonable. However, unless there is a compelling reason to have different assumptions for the same measure (other than the use of different contractors to evaluate different programs), the Public Staff recommends that DEC work to ensure that these measures be evaluated consistently. When such recommendations are not consistent across the programs, the Company should explain the differences justifying each case.[19]

Q. SHOULD THE EM&V REPORTS FILED IN THIS PROCEEDING BE ACCEPTED AS COMPLETE?

A. Yes. The reports filed in this proceeding, labeled as Evans Exhibits A through E, should be considered complete.

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[19] This is similar to the Public Staff's recommendations in Docket No. E-2, Sub 1145 regarding differently methodologies that were used to evaluate different programs offering the same measures.

Q. HAVE YOU CONFIRMED THAT THE COMPANY'S CALCULATIONS INCORPORATE THE VERIFIED SAVINGS OF THE VARIOUS EM&V REPORTS?

A. Yes. As in previous cost recovery proceedings, I was able, through sampling, to verify that the changes to program impacts and participation were appropriately incorporated into the rider calculations for each DSM/EE program, as well as the actual participation and impacts calculated with EM&V data. I reviewed: (1) workpapers provided in response to data requests; (2) a sampling of the EE programs; and, (3) Evans Exhibit 1, which incorporates data from various EM&V studies. I also met with DEC personnel to review the calculations, EM&V, DSMore, and other data related to the program/measure participation and impacts. Based on my ongoing review of this data, I believe DEC has appropriately incorporated the findings from EM&V studies and annual participation into its rider calculations consistent with Commission orders and the Revised Mechanism. I will continue to review this information and, if necessary, file further information with the Commission should my review reveal any relevant issues that would cause me to alter my recommendations or conclusions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

DAVID M. WILLIAMSON

I am a 2014 graduate of North Carolina State University with a Bachelor of Science Degree in Electrical Engineering. I began my employment with the Public Staff's Electric Division in March of 2015. My current responsibilities within the Electric Division include reviewing applications and making recommendations for certificates of public convenience and necessity of small power producers, master meters, and resale of electric service; reviewing applications and making recommendations on transmission proposals for certificates of environmental compatibility and public convenience and necessity; and also interpreting and applying utility service rules and regulations. Additionally, I am currently serving as a co-chairman on the National Association of State Utility and Consumer Advocates' (NASUCA) DER and EE Committee.

My primary responsibility within the Public Staff is reviewing and making recommendations on DSM/EE filings for initial program approval, program modifications, EM&V evaluations, and on-going program performance of DEC, DEP, and DENC's portfolio of programs. I have filed testimony in various DEC, DEP, and DENC Demand Side Management/Energy Efficiency rider proceedings, as well as recent general rate case proceedings.

WilliamsonExhibit 1

Docket Number E-7, Sub ___ Projected Program/Portfolio Cost Effectiveness	2018 vintage 2019 Evans Exhibit 7 in Sub 1164				2019 vintage 2020 Evans Exhibit 7 in Sub 1192				2020 vintage 2021 Evans Exhibit 7 in Sub 1230				Percent change from last year	
Program	UCT	TRC	RIM	PCT	UCT	TRC	RIM	PCT	UCT	TRC	RIM	PCT	UCT	TRC
Residential Programs														
Appliance Recycling Program	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency Education	1.22	1.69	0.53	-	1.32	1.32	0.54	7.68	1.40	1.41	0.53	8.97	6%	7%
Energy Efficient Appliances & Devices	2.4	2.17	0.42	6.11	3.27	3.54	0.70	7.50	2.64	2.20	0.60	4.96	-19%	-38%
HVAC Energy Efficiency/Smart Saver EE	0.94	0.59	0.45	1.52	1.31	0.95	0.60	1.84	0.81	0.67	0.49	1.68	-38%	-29%
Income-Qualified Energy Efficiency and Weatherization Assistance	0.19	0.83	0.16	-	0.21	0.35	0.17	2.80	0.70	0.72	0.44	2.09	235%	107%
Multi-Family Energy Efficiency	2.82	4.71	0.59	-	2.97	2.97	0.61	22.81	3.14	3.16	0.66	20.52	6%	6%
My Home Energy Report	1.56	1.56	0.57	-	1.89	1.89	0.61	-	1.89	1.89	0.66		0%	0%
Power Manager	4.33	8.86	4.33	-	4.22	8.72	4.22	-	4.33	9.80	4.33		3%	12%
Residential Energy Assessments	1.41	1.56	0.54	-	1.36	1.34	0.49	30.23	1.33	1.28	0.48	19.95	-2%	-4%
Residential Total	2.22	2.60	0.70	7.69	2.5	3.02	1.04	6.61	2.50	2.82	1.04	6.18	0%	-6%
Non-Residential Programs														
Business Energy Report	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non Residential Smart Saver Custom Energy Assessments	2.17	0.89	0.68	1.78	3.07	1.08	0.84	1.99	2.70	0.80	0.84	1.38	-12%	-26%
Non Residential Smart Saver Custom	2.38	1.07	0.67	2.18	3.42	1.79	0.84	3.38	3.07	1.18	0.87	1.97	-10%	-34%
EnergyWise For Business	0.83	1.21	0.68	-	0.72	1.25	0.61		0.63	1.26	0.55	-	-13%	1%
Non Residential Smart Saver Energy Efficient Food Service Products	2.68	1.95	0.61	3.18	1.40	0.81	0.51	2.02	1.45	0.79	0.45	2.38	4%	-3%
Non Residential Smart Saver Energy Efficient HVAC Products	2.04	1.63	0.88	1.82	1.57	1.24	0.70	2.06	1.47	1.12	0.64	2.05	-6%	-10%
Non Residential Smart Saver Energy Efficient Lighting Products	3.48	1.44	0.74	2.17	4.29	2.00	0.80	3.75	4.19	2.14	0.78	4.08	-3%	7%
Non Residential Smart Saver Energy Efficient Pumps and Drives Products	2.54	2.45	0.54	3.56	3.68	2.63	0.86	5.38	3.11	2.41	0.82	4.99	-15%	-8%
Non Residential Smart Saver Energy Efficient IT Products	2.36	1.77	0.59	3.79	0.60	0.46	0.31	2.55	0.65	0.47	0.31	2.26	8%	2%
Non Residential Smart Saver Energy Efficient Process Equipment Products	2.13	2.23	0.47	4.21	2.14	1.85	0.70	3.86	3.50	2.26	0.97	3.66	63%	22%
Non Residential Smart Saver Performance Incentive	2.7	0.81	0.69	1.50	3.29	1.06	0.83	1.79	3.22	1.06	0.86	1.79	-2%	0%
Small Business Energy Saver	2.59	1.61	0.77	3.00	2.70	1.67	0.80	2.93	2.32	1.43	0.76	2.60	-14%	-14%
Smart Energy in Offices	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PowerShare Call Option	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PowerShare	2.9	41.14	2.90	-	3.35	112.28	3.35	-	3.37	137.02	3.37	-	1%	22%
Non-Residential Total	2.69	1.67	0.85	2.41	3.28	2.13	0.94	3.34	3.12	2.03	0.93	3.16	-5%	-5%
Overall Portfolio total	2.46	1.98	0.78	3.48	2.90	2.43	0.98	4.00	2.81	2.32	0.98	3.83	-3%	-5%

Public Staff
Williamson Exhibit 1

Williamson Exhibit 2

Docket Number E-7, Sub ___
Current Actual YTD Program/Portfolio Cost Effectiveness

	2016				**2017**				**2018**					
	vintage 2017				vintage 2018				vintage 2019					
	Evans Exhibit 7 in Sub 1105				Evans Exhibit 7 in Sub 1130				Evans Exhibit 7 in Sub 1164				Percent change from last year	
Program	UCT	TRC	RIM	PCT	UCT	TRC	RIM	PCT	UCT	TRC	RIM	PCT	UCT	TRC
Residential Programs														
Appliance Recycling Program	-	-	-	-	-	-	-	-	-	-	-	-		
Energy Efficiency Education	1.73	2.47	0.73	-	1.36	1.85	0.60	-	1.50	1.48	0.48	10.39	10%	-20%
Energy Efficient Appliances & Devices	3.46	4.53	0.88	7.19	3.17	5.29	0.78	9.62	2.47	3.06	0.60	6.97	-22%	-42%
HVAC Energy Efficiency	1.00	0.54	0.59	0.91	1.05	0.69	0.57	131.00	0.96	0.77	0.50	1.82	-9%	11%
Income-Qualified Energy Efficiency and Weatherization Assistance	0.58	2.32	0.38	-	0.54	2.61	0.42	-	0.50	0.49	0.30	2.14	-7%	-81%
Multi-Family Energy Efficiency	4.21	6.74	0.81	-	3.79	5.66	0.70	-	3.23	3.09	0.55	22.13	-15%	-45%
My Home Energy Report	1.57	1.57	0.63	-	1.60	1.78	0.63	-	2.21	2.21	0.66	-	38%	24%
Power Manager	4.36	8.39	4.36	-	4.31	8.59	4.29	-	5.21	12.18	5.21	-	21%	42%
Residential Energy Assessments	2.27	2.44	0.80	-	2.03	7.27	0.68	-	1.38	1.35	0.49	22.86	-32%	-81%
Residential Total	2.80	3.38	1.02	6.56	2.73	4.08	0.91	9.30	2.54	3.00	0.80	6.79	-7%	-26%
Non-Residential Programs														
Business Energy Report	0.01	0.01	0.01	-	-	-	-	-	-	-	-	-	-	-
Non Residential Smart Saver Custom Energy Assessments	4.80	1.88	1.22	2.30	0.17	0.16	0.16	1.25	2.34	0.78	0.52	2.33	1276%	388%
Non Residential Smart Saver Custom	4.75	1.30	1.43	1.25	3.84	1.49	1.18	1.84	4.04	1.72	0.83	3.22	5%	15%
EnergyWise For Business	1.02	1.18	0.72	-	0.73	0.92	0.59	-	0.74	0.97	0.60	-	1%	5%
Non Residential Smart Saver Energy Efficient Food Service Products	3.13	1.99	0.93	3.06	3.15	1.09	0.78	1.82	1.07	0.64	0.57	1.32	-66%	-41%
Non Residential Smart Saver Energy Efficient HVAC Products	1.90	1.48	0.99	1.70	1.73	1.67	0.89	2.09	2.03	1.74	0.53	3.79	17%	4%
Non Residential Smart Saver Energy Efficient Lighting Products	3.60	1.68	1.09	1.98	5.66	2.54	1.17	3.06	4.70	2.48	0.89	4.12	-17%	-2%
Non Residential Smart Saver Energy Efficient Pumps and Drives Products	5.80	4.69	1.17	6.26	5.82	3.89	1.03	5.88	2.70	2.08	0.77	4.81	-54%	-47%
Non Residential Smart Saver Energy Efficient IT Products	0.01	0.01	0.01	2.16	0.08	0.08	0.08	2.79	0.02	0.04	0.02	11.82	-75%	-50%
Non Residential Smart Saver Energy Efficient Process Equipment Products	3.27	2.83	1.50	2.56	3.36	3.48	1.16	4.58	2.59	2.09	0.74	3.97	-23%	-40%
Non Residential Smart Saver Performance Incentive	0.03	0.03	0.03	0.87	3.48	1.03	0.96	1.59	2.85	1.07	0.63	2.78	-18%	4%
Small Business Energy Saver	3.64	2.35	1.10	2.95	2.93	1.95	0.89	3.07	2.25	1.49	0.70	3.03	-23%	-24%
Smart Energy in Offices	1.20	1.29	0.72	-	0.65	0.65	0.49	-	-	-	-	-	-	-
PowerShare Call Option	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PowerShare	3.12	65.75	3.12	-	2.78	50.77	2.79	-	3.23	57.56	3.23	-	16%	13%
Non-Residential Total	3.54	1.92	1.19	2.09	3.90	2.48	1.18	2.99	3.44	2.43	0.96	3.78	-12%	-2%
Overall Portfolio total	3.24	2.27	1.13	2.87	3.22	3.08	1.03	5.02	2.91	2.69	0.87	5.14	-10%	-13%

Public Staff
Williamson Exhibit 2

Williamson Exhibit 3

Program/Portfolio Cost Effectiveness - Program Year 2021

	ORIGINAL				Removing 17% Reserve Margin Adder				Applying 90%W/10%S Seasonal Allocation				Total Net Impacts				Percent Change of "Total Net Impacts" from "Original"	
Program	**UCT**	**TRC**	**RIM**	**PCT**	**UCT**	**TRC**	**RIM**	**PCT**	**UCT**	**TRC**	**RIM**	**PCT**	**UCT**	**TRC**	**RIM**	**PCT**	**UCT**	**TRC**
Residential Programs																		
· **Energy Education Program for Schools**	1.40	1.41	0.53	8.97	1.35	1.37	0.51	8.97	1.40	1.41	0.53	8.97	1.35	1.37	0.51	8.97	-3%	-3%
· **Energy Efficient Appliances & Devices**	2.64	2.20	0.60	4.96	2.58	2.15	0.59	4.96	2.64	2.20	0.60	4.96	2.58	2.15	0.59	4.96	-2%	-2%
· **HVAC EE Products & Services**	0.81	0.67	0.49	1.68	0.78	0.65	0.47	1.68	0.81	0.67	0.49	1.68	0.78	0.65	0.47	1.68	-4%	-4%
· **Income-Qualified EE Products & Services**	0.70	0.72	0.44	2.09	0.68	0.70	0.42	2.09	0.70	0.72	0.44	2.09	0.68	0.70	0.42	2.09	-4%	-4%
· **Multi-Family EE Products & Services**	3.14	3.16	0.66	20.52	3.04	3.06	0.64	20.52	3.14	3.16	0.66	20.52	3.04	3.06	0.64	20.52	-3%	-3%
· **My Home Energy Report**	1.89	1.89	0.66		1.81	1.81	0.63		1.89	1.89	0.66		1.81	1.81	0.63		-4%	-4%
· **Power Manager**	4.33	9.80	4.33		4.33	9.80	4.33		2.25	5.10	2.25		2.25	5.10	2.25		-48%	-48%
· **Residential Energy Assessments**	1.33	1.28	0.48	19.95	1.30	1.26	0.47	19.95	1.33	1.28	0.48	19.95	1.30	1.26	0.47	19.95	-2%	-2%
Residential Total	**2.50**	**2.82**	**1.04**	**6.18**	**2.46**	**2.78**	**1.02**	**6.18**	**1.90**	**2.15**	**0.79**	**6.18**	**1.86**	**2.10**	**0.77**	**6.18**	**-25%**	**-25%**
Non-Residential Programs																		
· **Custom Assessment**	2.70	0.80	0.84	1.38	2.63	0.78	0.82	1.38	2.70	0.80	0.84	1.38	2.63	0.78	0.82	1.38	-3%	-3%
· **Custom Incentive**	3.07	1.18	0.87	1.97	2.98	1.14	0.84	1.97	3.07	1.18	0.87	1.97	2.98	1.14	0.84	1.97	-3%	-3%
· **EnergyWise for Business**	0.63	1.26	0.55		0.63	1.26	0.55		0.41	0.83	0.36		0.41	0.83	0.36		-34%	-34%
· **Food Service Products**	1.45	0.79	0.45	2.38	1.43	0.78	0.44	2.38	1.45	0.79	0.45	2.38	1.43	0.78	0.44	2.38	-1%	-1%
· **HVAC**	1.47	1.12	0.64	2.05	1.44	1.09	0.63	2.05	1.47	1.12	0.64	2.05	1.44	1.09	0.63	2.05	-2%	-2%
· **Lighting**	4.19	2.14	0.78	4.08	4.05	2.07	0.76	4.08	4.19	2.14	0.78	4.08	4.05	2.07	0.76	4.08	-3%	-3%
· **Motors, Pumps & VFDs**	3.11	2.41	0.82	4.99	3.01	2.33	0.79	4.99	3.11	2.41	0.82	4.99	3.01	2.33	0.79	4.99	-3%	-3%
· **Non Res Information Technology**	0.65	0.47	0.31	2.26	0.65	0.47	0.31	2.26	0.65	0.47	0.31	2.26	0.65	0.47	0.31	2.26	0%	0%
· **Process Equipment**	3.50	2.26	0.97	3.66	3.36	2.18	0.93	3.66	3.50	2.26	0.97	3.66	3.36	2.18	0.93	3.66	-4%	-4%
· **Performance Incentive**	3.22	1.06	0.86	1.79	3.13	1.03	0.83	1.79	3.22	1.06	0.86	1.79	3.13	1.03	0.83	1.79	-3%	-3%
· **Small Business Energy Saver**	2.32	1.43	0.76	2.60	2.26	1.40	0.74	2.60	2.32	1.43	0.76	2.60	2.26	1.40	0.74	2.60	-3%	-3%
· **PowerShare**	3.37	137.02	3.37		3.37	137.02	3.37		1.92	78.06	1.92		1.92	78.06	1.92		-43%	-43%
Non-Residential Total	**3.12**	**2.03**	**0.93**	**3.16**	**3.05**	**1.98**	**0.91**	**3.16**	**2.83**	**1.83**	**0.84**	**3.16**	**2.75**	**1.79**	**0.82**	**3.16**	**-12%**	**-12%**
Overall Portfolio Total	**2.81**	**2.32**	**0.98**	**3.83**	**2.76**	**2.27**	**0.95**	**3.83**	**2.37**	**1.95**	**0.82**	**3.83**	**2.31**	**1.90**	**0.80**	**3.83**	**-18%**	**-18%**

Public Staff
Williamson Exhibit 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1230

In the Matter of		
Application by 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	)))))	TESTIMONY OF JOHN R. HINTON PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

May 22, 2020

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1230

Testimony of John R. Hinton
On Behalf of the Public Staff
North Carolina Utilities Commission

May 22, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is John R. Hinton. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Economic Research Division of the Public Staff - North Carolina Utilities Commission. My qualifications are included in Appendix A to this testimony.

Q. WHAT ARE YOUR DUTIES AT THE PUBLIC STAFF?

A. My duties with the Public Staff include conducting financial studies on the investor-required rate of return for water, natural gas, and electric utilities and reviewing issues involving nuclear decommissioning plans, weather normalization of energy sales, electric utility meter sampling plans, the electric utilities' long-range peak demand and energy forecasts, and the integration aspect of the electric utilities' integrated resource plans (IRPs). I also review electric utilities' avoided cost biennial filings, as well as avoided cost issues for fuel cases and annual rider proceedings involving renewable energy and demand-side management and energy efficiency (DSM/EE).

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

A. The purpose of my testimony is to discuss the appropriate avoided capacity and energy costs that should be used to evaluate the cost-effectiveness of the DSM/EE programs of Duke Energy Carolinas, LLC (DEC), that are incorporated in the calculation of DEC's portfolio performance incentive (PPI), pursuant to the Company's cost recovery mechanism described in the Agreement and Stipulation of Settlement DEC reached with the Public Staff, the North Carolina Sustainable Energy Association, Environmental Defense Fund, Southern Alliance for Clean Energy, the South Carolina Coastal Conservation League, Natural Resources Defense Council, and the Sierra Club, which was filed with the Commission on August 19, 2013, and approved in the Commission's *Order Approving DSM/EE Programs and Stipulation of Settlement* issued on October 29, 2013, in Docket No. E-7, Sub 1032 (Sub 1032 Mechanism). In Docket No. E-7, Sub 1130 (Sub 1130), the Commission approved certain revisions to the Sub 1032 Mechanism relating to the methodology for determining avoided costs for purposes of the PPI calculation and determination of program cost-effectiveness in its *Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice* issued on August 23, 2017, (Revised Mechanism).

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

A. The Public Staff and DEC proposed and the Commission approved revisions to Paragraphs 19 and 69 of the Sub 1032 Mechanism that provided for the avoided energy and capacity benefits used for cost effectiveness calculations for program approval and the initial estimate of the PPI and any PPI true-up. The revisions also provided for the review of ongoing cost-effectiveness. That review uses avoided capacity costs derived from the most recent Commission-approved Biennial Determination of Avoided Cost Rates as of December 31 of the year immediately preceding the annual DSM/EE Rider filing date (hereafter, the “PURPA method”).

Q. WHAT IS "THE MOST RECENT COMMISSION-APPROVED BIENNIAL DETERMINATION OF AVOIDED COSTS FOR ELECTRIC UTILITY PURCHASES FROM QUALIFYING FACILITIES" FOR PURPOSES OF THIS DSM/EE RIDER PROCEEDING?

A. The applicable avoided cost proceeding is Docket No. E-100, Sub 158, in which the Commission issued its Notice of Decision on October 7, 2019, ruling on issues that are relevant to the calculation of avoided capacity rates and avoided energy rates. DEC filed its compliance rates on November 1, 2019, and the Commission issued its Final Order on April 15, 2020, establishing these rates.

Q. PLEASE DESCRIBE YOUR CONCERN REGARDING THE COMPANY'S APPLICATION OF AVOIDED COST RATES.

A. The Company has updated its underlying avoided cost inputs for both capacity and energy to be derived from the avoided cost proceeding, in Docket No. E-100, Sub 158. The Public Staff, in this proceeding, has two concerns with the Company's application of avoided capacity derived from the newly updated rates.

The first issue applies to the avoided capacity component used for the Company's Residential and Non-Residential energy efficiency programs. The Company applied a 17% reserve margin value adder to all of the megawatt (MW) reductions (demand reduction benefits) associated with the Company's EE programs beginning with vintage year 2021.

The second issue applies to the seasonal allocation of avoided capacity cost benefits for the Company's entire portfolio of programs, both Residential and Non-Residential. For DSM programs for vintages 2021 and beyond, the Company has applied avoided capacity benefits using a seasonal capacity allocation factor of 90% for the winter season and 10% seasonal allocation factor for the summer season. However, for existing or legacy DSM programs, the Company proposes to apply 100% of the value of capacity to the summer season. DEC associates its legacy programs for the Vintage 2021 period as the level of MW reduction capability that was calculated in the 2018 IRP and projected out to 2021. Using this as the baseline, DEC's total retail DSM projected load reductions[1] up to the level of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MW, as identified in year 2021 of the 2018 IRP, will receive a seasonal allocation of 100% summer and 0% winter avoided capacity benefits and the remaining **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** incremental MW of reductions to get to the identified 1,060 in 2022 will receive the 10%

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[1] Docket No. E-100, Sub 157, confidential support for the 2018 Summer LCR Table, p. 62.

summer seasonal avoided capacity allocation. Likewise, the incremental **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MW reductions in 2023 will receive 10% summer seasonal avoided capacity allocation. The Company did not apply the same reserve margin value adder to the avoided capacity cost benefits associated with its DSM programs.

Q. WHY HAS THE COMPANY INCLUDED A 17% RESERVE MARGIN ADDER FOR THE DEMAND REDUCTION BENEFITS ASSOCIATED WITH ENERGY EFFICIENCY PROGRAMS?

A. In this proceeding, the Company has proposed to increase the value of the demand reduction benefits from EE programs by 17%. The Company notes that the demand reduction benefits are accounted for in its Integrated Resource Plan (IRP) as a <u>reduction to its peak load</u> *(emphasis added)* as shown in the Company's Load, Capacity, and Reserve (LCR) Tables in its 2018 IRP. A key to the Company's position is that the demand reduction benefits from EE programs are not viewed as supply-side resources; rather the EE demand reductions are considered as a demand-side resource. Given that to provide adequate and reliable utility service, the Company increases the amount of supply-side resources required to meet the projected peak load by a 17% reserve margin, the Company argues that a similar reserve margin adjustment is warranted with demand-side resources. Previously, DEC has not employed a reserve margin adjustment for MW reductions associated with EE programs.

Q. WILL YOU EXPLAIN THE BASIS FOR THE COMPANY'S ARGUMENT?

A. Yes. The table below is an excerpt from DEC's 2019 IRP Winter Projections from the Load, Capacity, and Reserves (LCR) Table for years 2020-2022.[2] Lines 21-27 examine the impact of reducing peak demand by 100 MW of EE programs. In 2020, DEC projects generating reserves of 3,591 MW, for a reserve margin (RM) of 19.3% (lines 19 and 20) ("Actual Reserve Margin"). If DEC had 100 MW more EE during this year, the load forecast would be reduced by 100 MW (line 21), which increases the reserve margin to 3,691 MW, or 20.0% (lines 22 and 23) ("New Reserve Margin").

DEC's position supporting the reserve margin adder is essentially stating that due to that 100 MW load reduction from EE, it is able to reduce its existing generating capacity by 119 MW to maintain the Actual Reserve Margin that it held before the 100 MW of EE was added (lines 25-26). DEC claims that customers benefit from this, and believes its EE programs should have their capacity benefits increased to reflect this benefit. Thus, the 100 MW of

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[2] The 2019 IRP is used here for illustrative purposes.

demand-side EE programs equates to 119 MW of supply-side resource. The table below illustrates DEC's proposal with respect to balancing demand-side MW savings with supply-side resources:

Winter Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2019 Annual Plan

		2020	2021	2022
Load Forecast				
4	**Adjusted Duke System Peak**	**18,589**	**18,531**	**18,611**
18	**Cumulative Capacity w/ DSM**	**22,180**	**22,173**	**22,263**
Reserves w/ DSM				
19	Generating Reserves	3,591	3,642	3,651
20	**% Reserve Margin**	**19.3%**	**19.7%**	**19.6%**
21	**Adjusted Duke System Peak w/ 100 MW EE added**	**18,489**	**18,431**	**18,511**
22	RM w/ 100 MW EE added (MW)	3,691	3,742	3,751
23	RM w/ 100 MW EE added (%)	**20.0%**	**20.3%**	**20.3%**
24	Change in RM Held (MW)	(100)	(100)	(100)
25	Required Reserves to Maintain Actual RM (after adding EE)	3,571	3,623	3,631
26	Required Reduc ion in Existing Capacity to Reach Actual RM	(119)	(120)	(120)
27	Effective PRMR - ONLY IF "Actual RM" is maintained	**19.3%**	**19.7%**	**19.6%**

Q. DO YOU BELIEVE THAT DEC'S CUSTOMERS WILL REALIZE THIS CLAIMED VALUE?

A. No. The above example suggests that DEC's customers will ultimately see a benefit of the 100 MW of load reductions due to an EE program. The above example from the 2019 IRP has DEC with reserves above its 17% target level. It is likely in the future that supply side resources will be below the 17% margin and the customer would see the value of 100 MW of added demand reduction from EE programs. Almost irrespective of the balance of demand and supply at any particular point in time, a key question is what is the appropriate value customers should pay for a MW load reduction, and how is the value calculated? DEC maintains customers should pay (100 MW * approved avoided capacity rate per kW-yr. * 1.17); while, historically the value of MW reductions has been calculated (100 MW * approved avoided capacity rate per kW-yr.). A weakness in DEC's argument is the inequity of asking customers to pay 17% more for the same MW reduction from an EE program, as compared to a MW reduction from a DSM program. From a resource planning perspective, DEC has a theoretical basis as shown in the above table; however, from a ratemaking perspective the logic is deficient.

Q. ARE THERE OTHER REASONS WHY YOU BELIEVE IT IS INAPPROPRIATE TO INCLUDE THE 17% RESERVE MARGIN ADDER WITH EE PROGRAMS?

A. The Company's proposal effectively increases what customers will pay for the avoided capacity cost benefits of the EE programs by increasing the avoided capacity cost rate above the approved rate. This rate is comprised of an approved annual combustion turbine (CT) carrying cost and other factors including a Performance Adjustment Factor (PAF). The approved[3] PAF of 5% is a multiplier that increases the annual CT carrying cost, which according to DEC should be increased by an additional 17%. From this perspective, the impact of this adjustment increases the value of

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[3] Approved in Docket No. E-100, Sub 158.

the avoided demand reduction benefits by approximately 23% (1.228 = 1.05*1.17) over the cost of an avoided combustion turbine (CT) underlying the avoided capacity rates.

Q. PLEASE PROVIDE A BRIEF HISTORY OF THE PAF.

A. Prior to the 1991 Biennial Avoided Cost Proceeding, Docket No. E-100, Sub 59, a reserve margin of 20% was an accepted margin for long-range planning, and was the basis for the Reserve Margin Adjustment of 20% applied to avoided capacity payments made to Qualifying Facilities (QFs). In the 1991 Biennial Avoided Cost Proceeding the 20% Reserve Margin Adjustment was renamed the PAF, which was represented numerically as 1.20. The rationale for the 1.20 PAF was to allow a QF to experience a reasonable number of outages and still receive its full capacity payment. Without a PAF, the QF would have to operate 100% of its on-peak hours throughout the year in order to receive its full capacity payment. The 1.20 PAF was based on a 0.83 availability factor or 1.20 = 1 / 0.83. The 1.20 PAF withstood over 20 years of direct challenges by the utilities who argued for a lower PAF of 1.129 based on a 0.886 availability factor. On October 11, 2017, in Docket No. E-100, Sub 148, the Commission approved a lower PAF of 1.05 that was based on an equivalent forced outage rate for all of its generation resources.

Q. CAN YOU ILLUSTRATE THE AVOIDED CAPACITY COST-BENEFITS WITH AND WITHOUT THE PROPOSED RESERVE MARGIN ADJUSTMENT?

A. The Company's proposal effectively raises the dollar per kW value of the demand reduction benefits by 17% over the approved avoided capacity rates.[4] Instead of using the Sub 158 avoided capacity cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW-year for 2019 and annually escalating that cost out to 2044, the Company increases that value by 17% to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW-year for 2019 to value each kW of demand reduction benefits realized from its EE programs. The proposed cost per kW-yr. for the demand reductions associated with an EE program and with a DSM program is shown in Hinton Exhibit 1.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING DEC'S PROPOSED RESERVE MARGIN ADDER?

A. The Public Staff recommends that the Company not use the reserve margin adder for the demand reduction benefits associated with its EE programs. Furthermore, I believe that this is not the appropriate proceeding to evaluate such a significant change to the avoided energy cost rates. In Docket No. E-7, Sub 1130, the Public

[4] As approved in Docket No E-100, Sub 158.

Staff and the Company agreed that the PURPA-based method of calculating avoided costs was preferred over the use of the Company's IRP. In that proceeding, I testified that,

> "...the use of the PURPA-based avoided costs links the savings and financial incentives afforded the Company for its DSM/EE programs with the rates it pays QFs for avoided energy and avoided capacity. Therefore, I believe that the use of PURPA-based avoided energy and capacity costs will lead to better estimates of the costs avoided by the Company's DSM/EE programs thereby providing a more accurate view of the value of DSM and EE."

On August 27, 2017, the Commission approved the Agreement and noted that,

> "First, the revision to Paragraph 69 removes any ambiguity regarding the proper avoided costs to be used for calculating the PPI. The Commission finds that the revision to Paragraph 69 better links the savings and financial incentives for DEC's DSM/EE programs with the rates it pays QFs for avoided energy and avoided capacity, and provides for regular updating to prevent stale or outdated rates."

I believe the proposed reserve margin adjustment adds further divergence between the application of the avoided energy rates in this proceeding and the approved avoided cost energy rates in Docket No. E-100, Sub 158. Furthermore, I believe that that it is inappropriate to propose such a significant change in the valuation of the avoided energy cost-benefits in this proceeding, as opposed to examining this change within the review of the Mechanism. The current cost recovery mechanism was approved in Docket No. E-7, Sub 1032, where the Portfolio Performance Incentive (PPI) is based on the present value of the estimated net dollar savings associated with the Company's DSM/EE programs. As such, I believe that any change to the dollar savings of avoided energy costs benefits from DSM/EE programs should be evaluated in concert with consideration of the appropriate incentive rate in a Mechanism review. Per Public Staff witness Maness, the NC retail impact of the Public Staff's removal of the reserve margin adder on the PPI is $618,791.

Q. PLEASE DESCRIBE YOUR CONCERN REGARDING THE COMPANY'S USE OF SEASONAL ALLOCATION FACTORS FOR LEGACY DSM PROGRAMS.

A. My concern stems from the need to ensure that the avoided capacity benefits or values placed on MW reductions associated with the legacy DSM programs[5] remain reasonable. Through data requests and discussions with the Company, DEC maintains that

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[5] DEC makes a distinction between "legacy" and "incremental" DSM programs in its evaluation of the portfolio and program cost effectiveness. As understood by the Public Staff and based on the Company's responses to data requests, "Legacy" DSM is the level of DSM activation capability that was originally projected for the year 2021 in the 2018 IRP. "Incremental" means all activation capability that is above the projected levels of the 2018 IRP for year 2021. DEC makes a distinction between "legacy" and "incremental" DSM programs in its evaluation of the portfolio and program cost effectiveness. "Legacy" measures and participation represent those measures and participants who were enrolled and active in the program in 2018. "Incremental" means any measure installed and participation occurring after 2018.

the avoided capacity benefits from “legacy” DSM programs should continue to be valued using a 100% summer seasonal allocation weighting. The Company justifies this approach on the basis that these “legacy” measures and participation are included in its IRP. The Company values the “incremental” measures and participation using the seasonal allocation weightings of 90% winter and 10% summer.

While the Company’s 2018 IRP predicts that its summer peaks are 300 to 400 MW greater than the winter peaks throughout most of the planning period, reaching over 500 MW in 2030, the Company maintains that it is winter planning. DEC has maintained it is a winter planning utility, as noted in its IRPs, filed reserve adequacy studies, and in its previous two Biennial Avoided Cost Proceedings.

A similar issue was addressed in Docket No. E-7, Sub 1164, where DEC made the argument that capacity from legacy DSM programs should not receive the same treatment as capacity from QFs given that the MW reductions from these legacy programs are already included in the IRP. The Commission in its Order noted:

> “…the Commission concludes that the capacity value provided by additional solar PV does not necessarily help the utilities offset or avoided their next capacity need. However, DEC contends that DSM/EE is different from solar QF’s, and that none of the policy reasons behind the Commissions shift in avoided costs methodology articulated in Sub 148 Order apply to

> DSM/EE. DEC states, for example, that there is no evidence in this proceeding that there is an over-supply of DSM/EE that customers are paying artificially high prices for DSM/EE, or that DSM/EE is burdening the system.[6]"

Q. HOW DOES THE FACT THAT DEC IS WINTER PLANNING AFFECT THE SEASONAL ALLOCATION OF THE VALUE OF AVOIDED CAPACITY WITH ITS DSM/EE PROGRAMS?

A. The Company's recently approved avoided capacity rates were developed using seasonal weighting of 90% for the winter season and 10% for the summer season. These allocations are similar to those approved in Docket No. E-100, Sub 148, where DEC proposed and the Commission approved seasonal allocation factors of 80% for the winter season and 20% for the summer season. For Docket No. E-100, Sub 158, DEC employed Astrapé Consulting to perform a Capacity Value of Solar Study that supported QFs receiving only 10% of the annual avoided capacity costs during the summer season; while receiving 90% of the avoided capacity cost weighting during the winter season. The Study found a higher loss of load risk during the winter season, which the Commission approved. In addition to addressing this risk, DEC and DEP stated that these seasonal allocations provide improved price signals[7] for QFs to help the Companies meet their

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[6] NCUC Final Order in Docket e-2, Sub 1164, page 43.
[7] Docket No. E-100, Sub 158, T., Vol. 2, page 73, lines 5-13.

generation needs and appropriately pay QFs for the value they provide.

Q. DO YOU AGREE WITH THE COMPANY'S TREATMENT OF INCREMENTAL AND LEGACY DSM SEASONAL CAPACITY IN THIS PROCEEDING?

A. No. The Public Staff believes the argument of separating legacy and incremental measures and participation in DSM/EE programs has been seriously weakened by the conclusion of another avoided cost proceeding where DEC's avoided cost rates are based on winter planning. This emphasis on winter planning is supported by the 2016 Resource Adequacy Study, which indicated that DEC's long-range planning should target the winter season, and utilize a 17% winter reserve margin. As such, the value of summer DSM is diminished and no longer has the same value for resource planning purposes in terms of a capacity resource at the expected time of peak and the dollar per kW associated with the demand reductions.

In Docket No. E-100, Sub 157, the Commission directed DEC and DEP to conduct another reserve margin study for their 2020 IRPs, which are currently being developed. Based on recent discussions among the Company, Astrapé Consulting, and the Public Staff, in preparation for the 2020 IRP filing, it is my understanding that DEC's summer peak load forecast could increase by approximately

400 MW, and yet DEC would still be considered a winter planning utility. The Study has yet to be completed, but this observation underscores the Company's claims that DEC is winter planning.

Q. WILL YOUR PROPOSAL PROVIDE ADDED MOTIVATION FOR THE COMPANY TO FIND WAYS TO REDUCE THE WINTER PEAKS?

A**.** Even though none of the legacy DSM programs would cease to be cost effective under the Public Staff's proposal, the application of the allocation of seasonal capacity value to these legacy DSM programs would appropriately direct the Company to emphasize programs that focus on reducing load during the winter season. I am aware the Company has already begun such an investigation aimed at reducing winter peak loads. In DEC's last general rate case decision in Docket No. E-7, Sub 1146, the Final Order expressed some of the Commission's concerns about the growth of the Company's winter peaks as follows:

> The Commission is, however, concerned that discontinuing programs that can be used to effectively clip winter peaks is moving in the wrong direction. This is especially true given the fact that the Company has moved to "winter planning."[8]

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[8] NCUC Order in Docket no. E-7, Sub 1146, p. 101.

Similar concerns were expressed by the Commission in Docket No. E-100, Sub 147[9] and Docket No. E-100, Sub 158.[10] As such, it is my belief that the use of a 90% winter and 10% summer allocation for both legacy programs and new programs sends an appropriate signal to the Company to devote less resources toward mitigating summer peak load growth while at the same time increasing the incentives with the pursuit of reducing the growth of winter peak demands.

Q. ARE OTHER REASONS WHY YOU DO NOT SUPPORT THE COMPANY'S USE OF A 100% SUMMER SEASON CAPACITY ALLOCATION FOR LEGACY DSM PROGRAMS?

A. Yes. It is an underlying premise of DSM programs is that it typically costs the utility more to serve the customer during capacity constrained hours, than the Company recovers in rates. Often, the marginal costs of fuel, variable O&M, and the occasional start costs of additional generation to serve the customers are four to five times, or more, higher than the approved cost of fuel. As such, it is in the Company's best interest to consider the activation of its DSM programs during those times. Shown below are the last three years of DEC's day-ahead lambdas, which illustrate the relative lower

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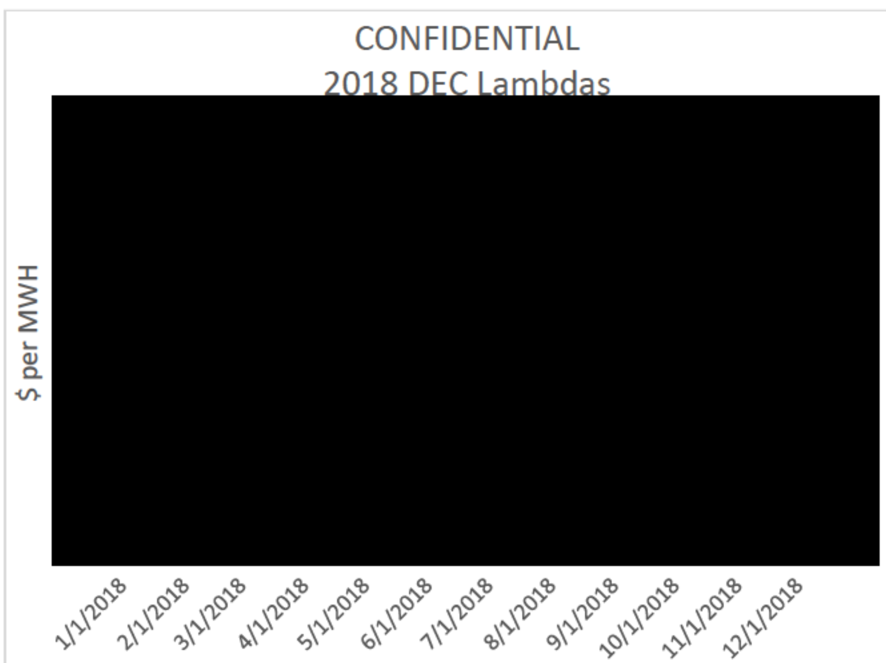
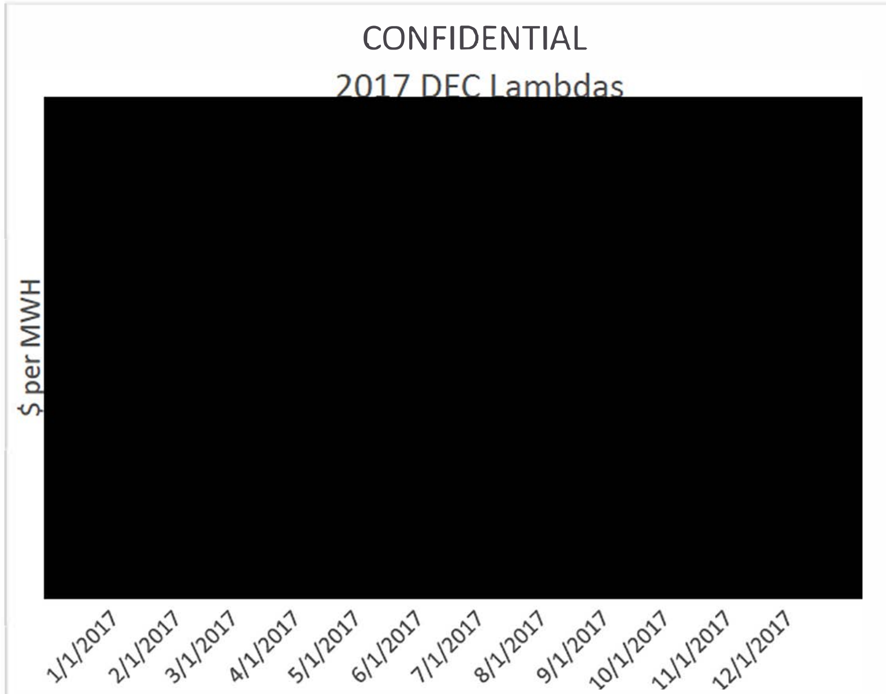
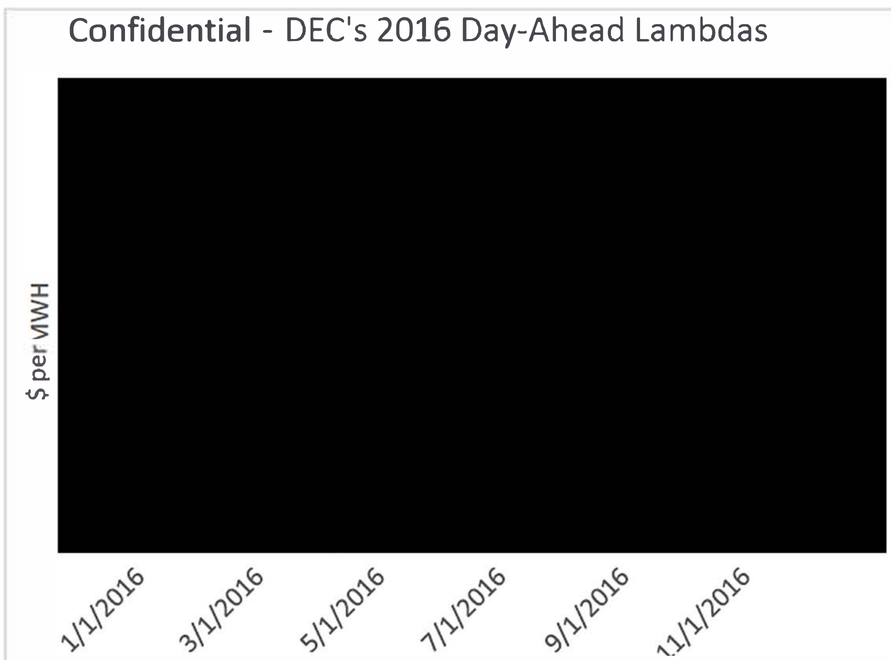
[9] NCUC Commission Order in Docket No. E-100, Sub 147, p. 7.
[10] NCUC Commission Order in Docket No. E-100, Sub 158, pp. 28-29.

and less volatile day-ahead lambdas or expected marginal costs during the summer seasons relative to the winter seasons.







While the avoided energy costs for the hour of the peak do not represent the capacity value of a DSM program, it should follow that high energy prices tend to follow constrained conditions. As the graphs illustrate, the expected avoided energy costs experienced due to activations of DEC's EnergyWise program have tended to decrease from the early year of the deployment of these summer related DSM programs. However, the Company's decision to activate is primarily; but not always, a function of available generation, be it an emergency condition or simply low reserves required to meet the expected load. In Hinton Exhibit 2 are exhibits from previous DSM/EE rider filings on the activations of DEC's Power Share and Power Manager programs. Exhibit 2 shows that the frequency of summer emergency events has lessened (2017 – 2019). The intent of discussing DEC's historical DSM activations is merely to show the evolving role that these programs play in providing sufficient capacity, which is not to say that these programs are not valuable; rather, that the capacity value has changed on par with the shifting of the seasonal weighting capacity needs from summer to winter.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING DEC'S PROPOSED SEASONAL ALLOCATION OF CAPACITY VALUE FOR ITS LEGACY DSM PROGRAMS?

A. The Public Staff recommends that the Commission deny DEC's proposal to give its legacy DSM/EE programs a 100% summer weighting under its current IRP winter planning scenario, and require DEC to recalculate cost effectiveness using a 90% winter and 10% summer allocation of avoided capacity benefits. This would value the demand reduction benefits from DSM on the same basis as any other demand reductions the Company may realize from QFs. To do otherwise would have ratepayers reward the Company with a PPI that is based on over-valued kW savings via the use of DEC's proposed 100% summer seasonal capacity allocation despite its need for winter DSM. Whereas, a 90% seasonal capacity allocation for winter and 10% for seasonal capacity allocation for summer strikes a reasonable balance of the value of DSM/EE programs for ratepayers and the Company. Per Public Staff witness Maness, the NC retail impact of the Public Staff's recommended adjustment to the seasonal allocations on the PPI is $5,093,947.

Furthermore, the use of these proposed seasonal allocation factors will not cause any legacy DSM programs to fail cost effectiveness. The fact that these programs remain cost effective is, in part, due to the significant role of avoided T&D cost which provide almost the same beneficial value that 100% of the avoided capacity cost. As such, the use of the approved seasonal weighting of avoided capacity costs simply reduces the cost-effectiveness of these programs and the overall cost-effectiveness of the portfolio of programs as shown in Public Staff witness Williamson Exhibit 3.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

QUALIFICATIONS AND EXPERIENCE

JOHN ROBERT HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. I joined the Public Staff in May of 1985. . I filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. . In 1986, 1989, and 1992, I developed the long-range forecasts of peak demand for electricity in North Carolina. . I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. . I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023. . I filed testimony on the level of funding for nuclear decommissioning costs in Docket Nos. E-7, Sub 1026, and E-7, Sub 1146. . I have filed testimony on the Integrated Resource Plans (IRPs) filed in Docket No. E-100, Subs 114 and 125, and I have reviewed numerous peak demand and energy sales forecasts and the resource expansion plans filed in electric utilities' annual IRPs and IRP updates.

I have been the lead analyst for the Public Staff in numerous avoided cost proceedings, filing testimony in Docket No. E-100, Subs 106, 136, 140, and 148. . I have filed a Statement of Position in the arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966.

I have filed testimony on the issuance of certificates of public convenience and necessity (CPCN) in Docket Nos. E-2, Sub 669; SP-132, Sub 0; E-7, Sub 790; E-7, Sub 791; and E-7, Sub 1134.

I have filed testimony on the issue of fair rate of return in Docket Nos. E-22, Sub 333; E-22, Sub 412; P-26, Sub 93; P-12, Sub 89; G-21, Sub 293; P-31, Sub 125; G-5, Sub 327; G-5, Sub 386; G-9, Sub 351; P-100, Sub 133b; P-100, Sub 133d (1997 and 2002); G-21, Sub 442; W-778, Sub 31; and W-218, Sub 319 and E-22, Sub 532; and several smaller water utility rate cases. . I have filed testimony on credit metrics and the risk of a credit downgrade in Docket No. E-7, Sub 1146. .

I have filed testimony on the hedging of natural gas prices in Docket No. E-2, Subs 1001 and 1018. . I have filed testimony on the expansion of natural gas in Docket No. G-5, Subs 337 and 372. . I performed the financial analysis in the two audit reports on Mid-South Water Systems, Inc., Docket No. W-100, Sub 21. I testified in the application to transfer of the CPCN from North Topsail Water and Sewer, Inc. to Utilities, Inc., in Docket No. W-1000, Sub 5. . I have filed testimony on weather normalization of water sales in Docket No. W-274, Sub 160.

With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency. . I have published an article in the National Regulatory Research Institute’s Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

CONFIDENTIAL

Year	Approved Biennial Avoided Cost Rate ($/kW-yr.)	Approved Biennial Avoided Cost Rate ($/kW-yr.) with 17% Adder
2019	$ [redacted]	$ [redacted]
2020	$ [redacted]	$ [redacted]
2021	$ [redacted]	$ [redacted]
2022	$ [redacted]	$ [redacted]
2023	$ [redacted]	$ [redacted]
2024	$ [redacted]	$ [redacted]
2025	$ [redacted]	$ [redacted]
2026	$ [redacted]	$ [redacted]
2027	$ [redacted]	$ [redacted]
2028	$ [redacted]	$ [redacted]
2029	$ [redacted]	$ [redacted]
2030	$ [redacted]	$ [redacted]
2031	$ [redacted]	$ [redacted]
2032	$ [redacted]	$ [redacted]
2033	$ [redacted]	$ [redacted]
2034	$ [redacted]	$ [redacted]
2035	$ [redacted]	$ [redacted]
2036	$ [redacted]	$ [redacted]
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2038	$ [redacted]	$ [redacted]
2039	$ [redacted]	$ [redacted]
2040	$ [redacted]	$ [redacted]
2041	$ [redacted]	$ [redacted]
2042	$ [redacted]	$ [redacted]
2043	$ [redacted]	$ [redacted]
2044	$ [redacted]	$ [redacted]

Evans Exhibit 5

Duke Energy Carolinas
System Event Based Demand Response January 1, 2019 - December 31, 2019
Docket Number E-7, Sub 1230

Date	State	Program Name	Event Trigger	High / Low System Temp (F)	Customers Notified /Switches Dispatched	MW Reduction
7/15/2019	NC and SC	Power Manager	M&V Event	91 / 74	226,600 / 272,600	275.0
7/19/2019	NC and SC	Power Manager	M&V Event	94 / 74	23,800 / 28,700	n/a
8/9/2019	NC and SC	Power Manager	M&V Event	93 / 70	238,400 / 286,700	302.3
8/19/2019	NC and SC	Power Manager	M&V Event	92 / 73	Tests across different hours with different subgroups	n/a
9/9/2019	NC and SC	Power Manager	M&V Event	93 / 68	226,800 / 272,700	182.9
9/12/2019	NC and SC	Power Manager	M&V Event	96 / 71	226,800 / 272,700	230.0
9/17/2019	NC and SC	Power Manager	M&V Event	91 / 69	226,600 / 272,500	200.0
9/26/2019	NC and SC	Power Manager	M&V Event	92 / 65	226,500 / 272,300	227.3

Notes:

- The 'High / Low System Temperature' is the average of the daily high & low temperatures from 3 weather stations (Charlotte, Greensboro, Greenville/Spartanburg)
- 'Customers Notified' is the number of participants notified to participate in the event
- 'Switches Dispatched' values represent the monthly active switch counts
- 'MW Reduction' values are based on the average across all hours of the event
- A loss adjustment of 1.0622 has been included in the 'MW Reduction' values.
- Customer and switch counts are estimated and rounded to nearest 100 due to not all customers being controlled in M&V events - some were left out as part of an uncontrolled control group.
- There were no PowerShare curtailment events in 2019

Duke Energy Carolinas
System Event Based Demand Response January 1, 2018 - December 31, 2018
Docket Number E-7, Sub 1192

Date	State	Program Name	Event Trigger	High / Low System Temp (F)	Customers Notified /Switches Dispatched	MW Reduction
1/2/2018	NC and SC	PowerShare	Emergency, Low Reserves	32/10	163	282.1
1/7/2018	NC and SC	PowerShare	Emergency, Low Reserves	29/12	163	210.0
8/30/2018	NC and SC	Power Manager	Test Event	91 / 72	225,210 / 270,511	184.1

Notes:

- The 'High / Low System Temperature' is the average of the daily high & low temperatures from 3 weather stations (Charlotte, Greensboro, Greenville/Spartanburg)
- 'Customers Notified' is the number of participants notified to participate in the event
- 'Switches Dispatched' values represent the monthly active switch counts
- 'MW Reduction' values are based on the average across all hours of the event
- A loss adjustment of 1.0622 has been included in the 'MW Reduction' values.

Evans Exhibit 5

Duke Energy Carolinas
System Event Based Demand Response January 1, 2017 - December 31, 2017
Docket Number E-7, Sub 1164

Date	State	Program Name	Event Trigger	High / Low System Temp (F)	Customers Notified /Switches Dispatched	MW Reduction
7/13/2017	NC and SC	Power Manager	Emergency, Low Reserves	92 / 78	208,330 / 248,954	220.5

Notes:

- The 'High / Low System Temperature' is the average of the daily high & low temperatures from 3 weather stations (Charlotte, Greensboro, Greenville/Spartanburg)
- 'Customers Notified' is the number of participants notified to participate in the event
- 'Switches Dispatched' values represent the monthly active switch counts
- 'MW Reduction' values are based on the average across all hours of the event
- A loss adjustment of 1.0622 has been included in the 'MW Reduction' values.

Duke Energy Carolinas
System Event Based Demand Response January 1, 2016 - December 31, 2016
Docket Number E-7, Sub 1130

Date	State	Program Name	Event Trigger	High / Low System Temp (F)	Customers Notified /Switches Dispatched	MW Reduction
6/23/2016	NC and SC	Power Manager	Economic, Low Reserves	94 / 76	185,744 / 222,898	219.9
7/13/2016	NC and SC	PowerShare Mandatory	Emergency, Low Reserves	93 / 71	168	302.2
7/13/2016	NC and SC	PowerShare Generator	Emergency, Low Reserves	93 / 71	13	11.9
7/13/2016	NC	Interruptible Service (IS)	Emergency, Low Reserves	93 / 71	50	115.1
7/13/2016	NC	Standby Generator (SG)	Emergency, Low Reserves	93 / 71	24	10.7
7/14/2016	NC and SC	Power Manager	Emergency, Low Reserves	96 / 72	186,504 / 223,788	220.8
7/14/2016	NC and SC	PowerShare Mandatory	Emergency, Low Reserves	96 / 72	168	315.8
7/14/2016	NC and SC	PowerShare Generator	Emergency, Low Reserves	96 / 72	13	11.8
7/14/2016	NC	Interruptible Service (IS)	Emergency, Low Reserves	96 / 72	50	122.8
7/14/2016	NC	Standby Generator (SG)	Emergency, Low Reserves	96 / 72	24	8.6
7/25/2016	NC and SC	PowerShare Mandatory	Emergency, Low Reserves	97 / 76	168	326.5
7/25/2016	NC and SC	PowerShare Generator	Emergency, Low Reserves	97 / 76	13	10.2
7/25/2016	NC	Interruptible Service (IS)	Emergency, Low Reserves	97 / 76	50	121.4
7/25/2016	NC	Standby Generator (SG)	Emergency, Low Reserves	97 / 76	24	8.5
7/26/2016	NC and SC	PowerShare Mandatory	Emergency, Low Reserves	94 / 76	168	328.8
7/26/2016	NC and SC	PowerShare Generator	Emergency, Low Reserves	94 / 76	13	10.1
7/26/2016	NC	Interruptible Service (IS)	Emergency, Low Reserves	94 / 76	50	121.6
7/26/2016	NC	Standby Generator (SG)	Emergency, Low Reserves	94 / 76	24	8.1
9/8/2016	NC and SC	Power Manager	Economic, Low Reserves	93 / 68	189,396 / 227,222	179.9
9/19/2016	NC and SC	Power Manager	Economic, Low Reserves	87 / 73	190,306 / 228,381	150.2

Notes:
- The 'High Temperature' is the average of the daily high temperatures from 3 weather stations (Charlotte, Greensboro, Greenville/Spartanburg)
- 'Customers Notified' is the number of participants notified to participate in the event
- 'Switches Dispatched' values represent the monthly active switch counts
- 'MW Reduction' values are based on the average across all hours of the event
- A loss adjustment of 1.0622 has been included in the 'MW Reduction' values.

Duke Energy Carolinas
System Event Based Demand Response January 1, 2015 - December 31, 2015
Docket Number E-7, Sub 1105

Date	State	Program Name	Event Trigger	High / Low Temperature	Customers Notified /Switched Dispatched	MW Reduction
1/8/2015	NC and SC	IS	Emergency	H 28 L 9	56	115.7
1/8/2015	NC and SC	SG	Emergency	H 28 L 9	30	14.7
1/8/2015	NC and SC	PowerShare Mandatory	Emergency	H 28 L 9	169	318.3
1/8/2015	NC and SC	PowerShare Voluntary	Emergency	H 28 L 9	3	-
1/9/2015	NC and SC	IS	Emergency	H 44 L 24	56	118.2
1/9/2015	NC and SC	SG	Emergency	H 44 L 24	30	14.5
1/9/2015	NC and SC	PowerShare Mandatory	Emergency	H 44 L 24	169	303.4
1/9/2015	NC and SC	PowerShare Voluntary	Emergency	H 44 L 24	3	-
2/19/2015	NC and SC	IS	Emergency	H 24 L 12	56	102.8
2/19/2015	NC and SC	SG	Emergency	H 24 L 12	30	15.2
2/19/2015	NC and SC	PowerShare Mandatory	Emergency	H 24 L 12	168	331.6
2/19/2015	NC and SC	PowerShare Voluntary	Emergency	H 24 L 12	3	-
2/20/2015	NC and SC	Power Share Generator	Emergency	H 30 L 8	33	32.7
2/20/2015	NC and SC	IS	Emergency	H 30 L 8	56	87.3
2/20/2015	NC and SC	SG	Emergency	H 30 L 8	30	15.5
2/20/2015	NC and SC	PowerShare Mandatory	Emergency	H 30 L 8	168	304.1
2/20/2015	NC and SC	PowerShare Voluntary	Emergency	H 30 L 8	3	-
6/16/2015	NC and SC	Power Manager	Economic	H 96 L73	163,633/196,105	284.2
6/23/2015	NC and SC	Power Manager	Economic	H 96 L73	163,716/196,267	276.3
7/20/2015	NC and SC	Power Manager	Economic	H 96 L73	121,245/144,208	207.3
8/5/2015	NC and SC	Power Manager	Economic	H 95 L 72	166,697/199,615	266.8

Notes:
- The 'High Temperature' is the average of the daily high temperatures from 3 weather stations (Charlotte, Greensboro, Greenville/Spartanburg)
- 'Customers Notified' is the number of participants notified to participate in the event
- 'Switches Dispatched' values represent the monthly active switch counts
- 'MW Reduction' values are based on the average across all hours of the event
- A loss adjustment of 1.0622 has been included in the 'MW Reduction' values.

Duke Energy Carolinas, LLC
System Event Based Demand Response January 1, 2014 - December 31, 2014
Docket Number E-7, Sub 1073

Date	State	Program Name	Event Trigger	Weather Conditions	Numbers of Customers Notified / Enrolled	MW Reduction
1/7/2014	NC and SC	PowerShare Generator	Emergency	H 25 L 5	9	12.60
1/7/2014	NC and SC	IS	Emergency	H 25 L 5	61	145.51
1/7/2014	NC and SC	SG	Emergency	H 25 L 5	80	30.16
1/7/2014	NC and SC	PowerShare Mandatory	Emergency	H 25 L 5	184	284.50
1/8/2014	NC and SC	PowerShare Generator	Emergency	H 44 L 14	9	14.46
1/8/2014	NC and SC	IS	Emergency	H 44 L 14	61	151.42
1/8/2014	NC and SC	SG	Emergency	H 44 L 14	80	36.18
1/8/2014	NC and SC	PowerShare Mandatory	Emergency	H 44 L 14	184	358.72
1/23/2014	NC and SC	PowerShare Voluntary	Economic	H 40 L 18	134	3.32
6/5/2014	NC and SC	Power Manager	SOC Test Event	H 90 L 70	156,650	M&V impacts not available at the time of this filing.
6/10/2014	NC and SC	Power Manager	SOC Test Event	H 90 L 67	183,683	
6/18/2014	NC and SC	Power Manager	Economic	H 93 L 70	183,683	
9/2/2014	NC and SC	Power Manager	Economic	H 94 L 70	183,117	
9/11/2014	NC and SC	Power Manager	Economic	H 89 L 66	183,117	
9/16/2014	NC and SC	Power Manager	Economic	H 85 L 66	183,117	

Notes:
- 'Weather Conditions' is the averaged daily high/low temperature from 3 weather stations (Charlotte, Greensboro, Greenville/Spartanburg).
- 'Numbers of Customers Notified/Enrolled' is the number of participants notified to participate in the event. For Power Manager events, this is the monthly active switch count.
- 'MW Reduction' values are based on the average MW reduction across all hours of the event.
- A loss adjustment of 1.08 has been included in the 'MW Reduction' values to reflect "at the plant" values.

Duke Energy Carolinas
System Event Based Demand Response January 1, 2013 - December 31, 2013
Docket Number E-7, Sub 1050

Date	State	Program Name	Event Trigger	High Temperature	Customers Notified	Customers Enrolled	MW Reduction
7/18/2013	NC	Power Manager	High Prices	89.7	N/A	129,398	115.9
7/19/2013	NC	Power Manager	High Prices	89.7	N/A	129,398	112.3
7/24/2013	NC and SC	Power Manager	High Prices	90.0	N/A	178,289	150.4
8/12/2013	NC and SC	Power Manager	High Prices	91.0	N/A	177,924	157.6
8/29/2013	NC and SC	Power Manager	High Prices	91.0	N/A	178,283	157.4
9/10/2013	NC and SC	Power Manager	High Prices	88.3	N/A	178,109	142.5
9/11/2013	NC and SC	Power Manager	High Prices	88.7	N/A	178,109	123.0

Note:
A loss adjustment has been included in the MW values.
The high temperature is the average of the daily high temperatures from 3 weather stations (Charlotte, Greensboro, Greenville/Spartanburg).
The values for MW reduction are based on the average across the hours of the event.
Customers Notified is the number of participants notified that they should participate or have the opportunity to participate in the event.
For Power Manager events, the Customer Enrolled value represents the load control devices activated for the event.

Duff Exhibit 5

Duke Energy Carolinas
System Event Based Demand Response January 1, 2012 - December 31, 2012
Docket Number E-7 Sub 1031

Date	State	Program Name	Event Trigger	High Temperature	Customers Notified	Customers Enrolled	MW Reduction
6/29/2012	NC and SC	Power Manager	High Prices	103	N/A	172,232	152.1
7/9/2012	NC and SC	Power Manager	High Prices	94	N/A	172,232	113.4
7/17/2012	NC and SC	Power Manager	High Prices	93	N/A	171,531	141.5
7/26/2012	NC and SC	Power Manager	High Prices	95	N/A	171,531	142.9
7/27/2012	NC and SC	Power Manager	High Prices	95	N/A	171,531	152.1
7/27/2012	NC and SC	PowerShare CallOption	High Prices	95	1	1	0.2

Note:

A loss adjustment has been included in the MW values.

The high temperature is the average of the high temperatures from 3 weather stations.

The values for MW reduction are based on the average across the hours of the event.

Customers Notified is the number of participants notified that they should participate or have the opportunity to participate in the event.

For Power Manager events, the Customer Enrolled value represents the load control devices activated for the event.

Duff Exhibit 5

Duke Energy Carolinas
System Event Based Demand Response January 1, 2011 - December 31, 2011
Docket Number E-7 Sub 1001

	Date	State	Program Name	Event Trigger	High Temperature	Customer Notified	Customers Enrolled	MW Reduction
1	6/1/2011	NC and SC	PowerShare Mandatory	Reliability	94	139	139	333.6
2		NC and SC	PowerShare Generator	Reliability		8	8	16.5
3		NC and SC	PowerShare Voluntary	Reliability		100	100	1.6
4		NC	IS	Reliability		66	66	156.4
5		NC	SG	Reliability		93	93	54.6
6	6/2/2011	NC and SC	PowerShare Voluntary	High Prices	92	100	100	16.1
7	6/21/2011	NC and SC	Power Manager	High Prices	95	N/A	165,953	100.6
8	7/11/2011	NC and SC	Power Manager	High Prices	92	N/A	165,955	101.1
9	7/12/2011	NC and SC	PowerShare Mandatory	Reliability	96	141	141	338.6
10		NC and SC	PowerShare Generator	Reliability		8	8	12.5
11		NC	IS	Reliability		66	66	132.5
12		NC	SG	Reliability		93	93	44.9
13	7/13/2011	NC and SC	Power Manager	High Prices	95	N/A	165,956	101.7
14	7/20/2011	NC and SC	Power Manager	High Prices	94	N/A	165,957	107.5
15		NC and SC	PowerShare Voluntary	High Prices		101	101	1.8
16	7/21/2011	NC and SC	Power Manager	High Prices	96	N/A	165,957	114.6
17		NC and SC	PowerShare Voluntary	High Prices		101	101	1.9
18	7/22/2011	NC and SC	PowerShare Voluntary	High Prices	96	101	101	3.6
19	7/29/2011	NC and SC	Power Manager	High Prices	97	N/A	165,969	110.4
20	8/2/2011	NC and SC	Power Manager	High Prices	96	N/A	166,006	115.3
21	8/3/2011	NC and SC	PowerShare Voluntary	High Prices	96	101	101	2.1
22	8/25/2011	NC and SC	Power Manager	Test	92	N/A	192,261	183.3

Note:

The loss factor has been included in the MW values.

The high temperature is the average of the high temperatures from 3 weather stations.

The values for MW reduction are based on the average across the hours of the event.

Customers Notified is the number of participants notified that they should participate or have the opportunity to participate in the event.

For Power Manager events, the Customer Enrolled value represents the load control devices activated for the event.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1230

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	))))))	TESTIMONY OF MICHAEL C. MANESS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

May 22, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Michael C. Maness. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am Director of the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. A summary of my qualifications and duties is set forth in Appendix B of this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present my recommendations regarding the overall Demand-Side Management/Energy Efficiency (DSM/EE) rider (Rider 12) proposed by Duke Energy Carolinas, LLC (DEC or the Company), in its Application filed in this docket on February 25, 2020, pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69, as revised by the Supplemental Testimony and Supplemental Exhibits of DEC witness Carolyn T. Miller and the Supplemental Exhibits of DEC witness Robert P. Evans, filed on May 11, 2020.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony begins with a review of the statutory framework for

DSM/EE cost recovery by electric utilities and the historical background of DEC's Application in this docket. I then discuss the Company's proposed billing factors and other aspects of its filing. Following a summary of my investigation, I present my findings, conclusions, and recommendations regarding approval of proposed Rider 12.

THE RATE-SETTING PROCESS FOR DEC'S DSM/EE REVENUE REQUIREMENTS

Q. PLEASE DESCRIBE THE BASIS FOR THE COMPANY'S FILING.

A. N.C. Gen. Stat. § 62-133.9(d) allows a utility to petition the Commission for approval of an annual rider to recover: (1) the reasonable and prudent costs of new DSM and EE measures; and (2) other incentives to the utility for adopting and implementing new DSM and EE measures. However, N.C. Gen. Stat. § 62-133.9(f) allows industrial and certain large commercial customers to opt out of participating in the power supplier's DSM/EE programs or paying the DSM/EE rider, if each such customer notifies its electric power supplier that it has implemented or will implement, at its own expense, alternative DSM and EE measures. Commission Rule R8-69, which was adopted by the Commission pursuant to N.C. Gen. Stat. § 62-133.9(h), sets forth the general parameters and procedures governing approval of the annual rider, including but not limited to: (1) provisions for both (a) a DSM/EE rider to recover the estimated costs and utility incentives applicable to the “rate period” in which that DSM/EE rider will be in effect; and (b) a DSM/EE experience modification factor (EMF) rider to recover the difference between the DSM/EE rider in effect for a given test period (plus a possible extension) and the actual recoverable amounts incurred during that test period; and (2) provisions for interest or return on amounts deferred and on refunds to customers.

The costs and utility incentives proposed to be recovered via Rider 12 are all related to DSM and EE measures actually or expected to be installed or implemented during calendar years 2016-2021 (Vintage Years 2016 through 2021). Therefore, DEC has calculated each proposed Rider 12 billing factor by use of the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs approved on October 29, 2013, in Docket No. E-7, Sub 1032 (the Sub 1032 Order), as revised in the 2017 DSM/EE rider proceeding, Docket No. E-7, Sub 1130 (Revised Mechanism). In the following paragraphs, I will describe the essential characteristics of the Revised Mechanism; however, the Revised Mechanism includes and is subject to many additional and more detailed criteria than are set forth in this testimony.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE REVISED MECHANISM AND ITS MAJOR COMPONENTS.

A. In the Sub 1032 Order, the Commission approved an Agreement and Stipulation of Settlement, filed on August 19, 2013, and amended on September 23, 2013, by and between DEC, the Public Staff, and certain other intervenors[1] (Sub 1032 Settlement), which incorporated the mechanism at that time. However, as the result of discussions that took place during the Company's 2017 Sub 1130 proceeding, the Company and the Public Staff recommended certain changes to Paragraphs 19, 23, and 69 of the mechanism, and the addition of new Paragraphs 23A through 23D. These revisions were set forth in Public Staff witness Maness Exhibit II filed in Sub 1130, and were approved as set forth therein by the Commission in its *Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice*, issued August 23, 2017 (Sub 1130 Order).

The overall purpose of the Revised Mechanism is to: (1) allow DEC to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and new EE measures; (2) establish certain requirements, in addition to those of Commission Rule R8-68, for

[1] The parties to the Sub 1032 Settlement were DEC; the North Carolina Sustainable Energy Association; the Environmental Defense Fund; the Southern Alliance for Clean Energy; the South Carolina Coastal Conservation League; the Natural Resources Defense Council; the Sierra Club; and the Public Staff.

requests by DEC for approval, monitoring, and management of DSM and EE programs; (3) establish the terms and conditions for the recovery of certain utility incentives - net lost revenues (NLR) and a Portfolio Performance Incentive (PPI) to reward DEC for adopting and implementing new DSM and EE measures and programs; and (4) provide for an additional incentive to further encourage kilowatt-hour (kWh) savings achievements. The Revised Mechanism includes provisions addressing mechanism continuity and review, program modification flexibility, and the treatment of opted-out and opted-in customers, as well as provisions directly affecting the calculation of the DSM/EE and DSM/EE EMF riders. A summary of these provisions is set forth in Appendix A of this testimony.[2] The Revised Mechanism adopted and continued certain requirements from several prior Commission orders.

THE COMPANY'S PROPOSED BILLING FACTORS AND OTHER ASPECTS OF ITS FILING

Q. PLEASE DESCRIBE THE BILLING FACTORS AND VINTAGE YEARS BEING CONSIDERED IN THIS PROCEEDING.

A. In witnesses Miller's and Evans's Supplemental Testimony and Exhibits, DEC has requested approval of 15 billing factors [including

[2] A consolidated version of the entire Revised Mechanism was filed on May 22, 2018 as Maness Exhibit II in DEC's 2018 DSM/EE rider proceeding, Docket No. E-7, Sub 1164.

the North Carolina Regulatory Fee (NCRF)] comprising Rider 12, which is to be charged for service rendered during the rate period January 1, 2021, through December 31, 2021. These proposed billing factors are set forth on Supplemental Miller Exhibit 1, Pages 1 and 2.

For purposes of the Company's filing, the identified vintage years correspond to the following time periods:

Vintage Year 2016:	The year ended December 31, 2016.
Vintage Year 2017:	The year ended December 31, 2017.
Vintage Year 2018:	The year ended December 31, 2018.
Vintage Year 2019:	The year ended December 31, 2019.
Vintage Year 2020:	The year ended December 31, 2020.
Vintage Year 2021:	The year ended December 31, 2021.

Q. WHAT ARE THE GENERAL CHARACTERISTICS OF DEC'S PROPOSED DSM/EE BILLING FACTORS?

A. DEC's proposed billing factors have the following general characteristics[3]:

1. For Vintage Year 2021, proposed Rider 12 includes billing factors (or components of billing factors) intended to recover estimated program costs and a PPI, as well as estimated

[3] In addition to the Revised Mechanism, particular billing factors may also be subject to Commission rulings in Docket No. E-7, Subs 831, 938, 979, and 1032, as well as DEC's various annual DSM/EE cost and incentive recovery proceedings and individual program approval proceedings.

calendar year 2021 NLR, applicable to DSM and EE measures projected to be installed or implemented during Vintage Year 2021, all subject to future true-up;

2. For Vintage Year 2020, the proposed Rider includes billing factors (or components of billing factors) intended to prospectively recover estimated calendar year 2021 NLR associated with Vintage Year 2020 installations, subject to future true-up;

3. For Vintage Year 2019, the proposed Rider includes billing factors (or components of billing factors) intended to: (a) prospectively recover estimated calendar year 2021 NLR associated with Vintage Year 2019 installations, subject to future true-up; and (b) true up 2019 program cost and, to the extent evaluation, measurement, and verification (EM&V) of these results has been completed, Vintage Year 2019 participation and per-participant avoided cost savings and calendar year 2019 NLR;

4. For Vintage Year 2018, the proposed Rider includes billing factors (or components of billing factors) intended to: (a) prospectively recover estimated calendar year 2021 NLR associated with Vintage Year 2018 installations, subject to future true-up; and (b), to the extent EM&V of these results

has been completed, true up Vintage Year 2018 participation and per-participant avoided cost savings and calendar years 2018 and/or 2019 NLR;

5. For Vintage Year 2017, the proposed Rider includes billing factors intended to, to the extent EM&V of these results has been completed, true up calendar years 2017, 2018, and/or 2019 NLR; and

6. For Vintage Year 2016, the proposed Rider includes billing factors intended to true up calendar year 2019 NLR.

The calculations of the billing factors for each vintage year may also include adjustments to the return on undercollections or overcollections of DSM/EE revenue requirements, as well as to amounts to be collected to compensate DEC for the NCRF.

Q. COULD THERE BE FUTURE TRUE-UPS OF THE DSM/EE REVENUE REQUIREMENTS?

A. Certain components of the revenue requirements related to certain prior, current, and future years will remain subject to prospective update adjustments and/or retrospective true-ups in the future. The various types of other expected or possible adjustments to the revenue requirements for these vintage years include prospective recovery of NLR requirements; true-ups of program cost; and true-ups of the PPI and NLR requirements to reflect the results; and possible adjustments to participation and EM&V analyses.

Q. WHAT IS THE IMPACT OF THE COMPANY'S PROPOSED BILLING FACTORS IN THIS PROCEEDING ON CUSTOMERS' RATES?

A. Based on the pro forma kWh sales used by the Company to calculate the DSM/EE riders in this case, the Company-proposed Residential DSM/EE combined prospective and EMF revenue requirement is approximately $114.8 million, an approximate $8.0 million increase over the revenue that would be produced by the rates currently in effect. The increase in the monthly bill of a Residential customer using 1,000 kilowatt-hours of energy resulting from this revenue requirement increase would be $0.36. For the Non-Residential class, the proposed overall combined revenue requirement is approximately $101.2 million, an approximate $12.6 million reduction. The change in a Non-Residential customer's bill would depend on which particular Vintage Years of DSM and/or EE rates for which the customer is opted out or opted in.

INVESTIGATION AND CONCLUSIONS

Q. PLEASE DESCRIBE YOUR INVESTIGATION OF DEC'S FILING.

A. My investigation of DEC's filing in this proceeding focused on whether the Company's proposed DSM/EE billing factors were: (a) calculated in accordance with the Sub 1032 Settlement, the Sub 1130 Order, and the Revised Mechanism; and (b) otherwise adhered to sound ratemaking concepts and principles. The procedures I and other members of the Public Staff's Accounting Division utilized included a review of the Company's filing, relevant Commission proceedings and orders, and workpapers and source documentation used by the Company to develop the proposed billing factors. Performing the investigation required the review of responses to written and verbal data requests, as well as discussions with Company personnel. As part of its investigation, the Public Staff performed a review of the DSM/EE program costs incurred by DEC during the 12-month period ended December 31, 2019. To accomplish this, the Public Staff selected and reviewed samples of source documentation for test year costs included by the Company for recovery through the DSM/EE riders. Review of this sample, which is still underway as of the filing date of this testimony, is intended to test whether the costs included by the Company in the DSM/EE riders are valid costs of approved DSM and EE programs.

Q. WHAT ARE YOUR FINDINGS AND CONCLUSIONS?

A. With the exception of items specifically described later in this testimony, as well as subject to the outcome of the Public Staff's program cost review described above, I am of the opinion that the Company has calculated the Rider 12 billing factors in a manner consistent with N.C. Gen. Stat. § 62-133.9, Commission Rule R8-69, the Sub 1032 Settlement, the Sub 1130 Order, the Revised Mechanism, and other relevant Commission Orders. However, this conclusion is subject to the caveat that the Public Staff is still in the process of reviewing certain data responses recently received from the Company, including documentation of costs selected for review in the Public Staff's sample; once this review is complete, the Public Staff will file with the Commission any findings not already set forth in testimony.

I would like to note the following regarding the Public Staff's investigation:

1 Review of Vintage Year 2019 Program Costs – The Public Staff's review of the selected sample items from the population of 2019 DSM/EE program costs resulted in one exception. This exception is related to certain adjustments that the Company made to its DSM/EE program costs in last year's DSM/EE rider proceeding, Docket No. E-7, Sub 1192.

In that proceeding, both the Company and the Public Staff made adjustments to the program costs included in the calculation of Rider 11 to incorporate certain credits to Vintage Year 2018 North Carolina retail program costs that were not actually recorded in the Company's general ledger until 2019. Thus, when the time came to calculate Vintage Year 2019 North Carolina retail program costs for purposes of Rider 12 to be set in this proceeding, the Company rightly undertook to reverse the credits recorded in the general ledger in 2019 that had already been reflected in the Rider 11 calculation. However, during the course of its investigation in this case, the Public Staff determined that the Company had inadvertently calculated a greater reversal than it should have, thus overstating North Carolina retail Vintage Year 2019 program costs by approximately $725,000. After discussion, the Company informed the Public Staff that it agreed with the adjustment, and subsequently incorporated it into witnesses Evans and Miller's Supplemental Testimony and Exhibits. It should be noted that these reductions in Vintage Year 2019 program costs will also result in an approximate $83,000 increase in the Vintage Year 2019 PPI.

As noted previously, the Public Staff's review of samples of Vintage Year 2019 program costs is not yet completed. Once the review is completed, the Public Staff will file supplemental information in this proceeding setting forth the results of the review, including any concerns, issues, or necessary adjustments found; and

2 <u>Return on Deferred Program Costs and Interest on Overrecoveries</u> – As stated in past proceedings, the Public Staff reserves the right to raise the issue of the appropriate interest rate on <u>overrecoveries</u> of utility incentives in future proceedings.

Q. WHAT IS THE IMPACT OF THE TESTIMONY OF PUBLIC STAFF WITNESSES WILLIAMSON AND HINTON ON YOUR CONCLUSIONS REGARDING THE DSM/EE RIDERS IN THIS PROCEEDING?

A. Public Staff witnesses Williamson and Hinton have each filed testimony and exhibits in this proceeding that recommend certain changes to the calculations of avoided cost savings for estimated Vintage 2021 DSM/EE participation. The first change involves the elimination of a reserve margin that the Company has added to the avoided capacity benefits for Vintage 2021 EE measures. The second involves the allocation of avoided capacity benefits between summer and winter for the Company's Vintage 2021 DSM measures. These changes affect the PPI recommended by the Public Staff in this proceeding. Mr. Williamson has calculated the system-level impacts of these avoided cost savings recommendations and provided them to me. I have taken his calculations and calculated their impact on the Vintage 2021 DSM/EE riders. The results of my calculations are set forth in Maness Exhibit I.

Mr. Williamson has also filed testimony in this proceeding discussing several other topics related to the Company's filing. None of the matters discussed by Mr. Williamson necessitate an adjustment in this particular proceeding to the Company's billing factor calculations, although some of them may affect the determination of the factors in future proceedings.

Q. WHAT ARE THE IMPACTS OF THE PUBLIC STAFF'S RECOMMENDATIONS ON THE COMPANY'S PROPOSED VINTAGE 2021 DSM AND EE RIDERS?

A. The table below sets forth the Public Staff's recommended Vintage 2021 prospective factors, as calculated in Maness Exhibit I, and the Company's proposed factors, as set forth in Company witness Miller's Exhibit 1:

Billing Factor	Proposed by Company	Recommended by Public Staff
	(In cents per kWh)	
Res. DSM/EE factor	0.4184	0.4068
Non-Res. EE factor	0.3522	0.3495
Non-Res. DSM factor	0.1200	0.1037

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE RIDER 12 BILLING FACTORS.

A. In summary, I have identified one program cost adjustment that should be made to the Rider 12 DSM/EE revenue requirement and flowed through to the DSM/EE billing factors; the Company has reflected this adjustment in its Supplemental Testimony and Exhibits. Additionally, I have calculated the effects on the Vintage 2021 DSM and EE Riders of the adjustments to avoided cost savings recommended by Public Staff witnesses Williamson and Hinton. Other than these adjustments, the Public Staff has found no errors or other issues necessitating an adjustment to the Rider 12 billing factors, subject to completion of our program cost sample review.

RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDATION IN THIS PROCEEDING?

A. Based on the results of the Public Staff's investigation (subject to completion of its review of 2018 program costs), I recommend that the adjustments I have recommended be incorporated into the DSM/EE billing factors. These factors should be approved subject to any true-ups in future cost recovery proceedings consistent with the Sub 1032 Settlement, the Sub 1130 Order, and the Revised Mechanism, as well as other relevant orders of the Commission, including the Commission's final order in this proceeding. In making this recommendation, the Public Staff notes that reviewing the calculation of the DSM/EE rider is a process that involves reviewing numerous assumptions, inputs, and calculations, and its recommendation with regard to this proposed rider is not intended to indicate that the Public Staff will not raise questions in future proceedings regarding the same or similar assumptions, inputs, and calculations.

Q. DO YOU HAVE ANY OTHER COMMENTS?

A. Yes. As explained in Public Staff witness Williamson's testimony, as part of the Company's Residential SmartSaver Program, it operates a referral channel (entitled "FinditDuke" for marketing purposes). This referral channel enables DEC customers and others to locate contractors who may be able to provide certain services. The contractors pay a fee to DEC for performing referrals, and this fee is used to offset some of the program costs of the SmartSaver program. The referable services include those that are associated with measures under the SmartSaver Program, but have been expanded since the referral channel began to include other services, including

Plumbing, Solar, and Tree Removal unrelated to DSM/EE. It appears possible that some of the services that could be referred through FinditDuke are services that are not regulated by the Commission. Thus, DEC may be operating a referral service that includes referrals for non-regulated services to be performed by third parties. The Public Staff is not making a recommendation for any adjustment related to the possible non-regulated service-related component of the referral program, but has begun and will continue to examine and review it, and reserves the right to address it in a future proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SUMMARY OF CERTAIN PORTIONS OF DEC'S DSM/EE MECHANISM

1. With the exception of Low-Income Programs or certain other societally beneficial non-cost-effective programs approved by the Commission, all programs submitted for approval will have an estimated Total Resource Cost (TRC) and Utility Cost (UC) test result greater than 1.00. For purposes of calculating cost-effectiveness for program approval, 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 as of the date of the program approval filing, but using, for program-specific avoided energy benefits, the projected EE portfolio hourly shape rather than an assumed 24x7 100 MW reduction.

2. In each annual DSM/EE cost recovery filing, DEC shall perform and file (a) prospective cost-effective test evaluations for each of its approved DSM and EE programs, and (b) prospective aggregated portfolio-level cost-effectiveness test evaluations for its approved DSM/EE programs, using the same methodology for determining avoided capacity and energy benefits as set forth in the Revised Mechanism for program approval, except that the reference Commission-approved avoided cost credits shall be derived from those approved as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. For any program that initially demonstrates a TRC result, determined pursuant to paragraph 23A above, of less than 1.00, the Company shall either terminate the program or undertake a process over the next two years to improve program cost-effectiveness. For programs that demonstrate a prospective TRC result of less than 1.00 in a third DSM/EE rider proceeding after the initial non-cost-effective result, the Company shall terminate the program effective at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission.

3. Industrial and large commercial customers have the flexibility to opt out of either or both of the DSM and EE categories of programs for one or more vintage years, as well as the ability to opt back into either or both the categories for a later vintage year. If a customer opts back into the DSM category, it cannot opt out again for three years; however, a customer has the freedom to opt in or out of the EE category for each vintage year. Additionally, if a customer opts out of paying the rider for a vintage year after one or more years in which the customer was "opted in," DEC may charge

the customer subsequent DSM/EE and DSM/EE EMF riders only for those vintage years in which the customer actually participated in a DSM/EE program.

4. DSM/EE and DSM/EE EMF riders will be calculated on a vintage year basis, with separate riders being calculated for the Residential customer class and for those rate schedules within the Non-Residential customer class that have DEC DSM/EE program options in which they can participate.

5. Incurred DSM and EE program costs will be directly recovered as part of the annual riders. Deferral accounting for over- and underrecoveries of costs is allowed, and the balance in the deferral account(s), net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in DEC's then most recent general rate case.

6. DEC will be allowed to recover NLR as an incentive (with the exception of those amounts related to research and development or the promotion of general awareness and education of EE and DSM activities), but will be limited for each measurement unit installed in a given vintage year to those dollar amounts resulting from kWh sales reductions experienced during the first 36 months after the installation of the measurement unit. NLR related to pilot programs are subject to additional qualifying criteria.

7. The eligibility of kWh sales reductions to generate recoverable NLR during the applicable 36-month period will cease upon the implementation of a Commission-approved alternative recovery mechanism that accounts for NLR, or new rates approved by the Commission in a general rate case or comparable proceeding.

8. NLR will be reduced by net found revenues (as defined in the Revised Mechanism) that occur in the same 36-month period. Net found revenues will continue to be determined according to the "Decision Tree" process approved by the Commission on February 8, 2011, in Docket No. E-7, Sub 831.[1]

9. DEC will be allowed to recover a PPI for its DSM and EE portfolio based on a sharing of actually achieved and verified energy and peak demand

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[1] Additionally, in its Order issued on August 21, 2015, in Docket No. E-7, Sub 1073, the Commission found that "it is reasonable, for purposes of this proceeding, for DEC to include negative found revenues associated with its current initiative to replace mercury vapor (MV) lighting with light emitting diode (LED) fixtures in the calculation of net found revenues used in the Company's calculation of NLR."

savings (excluding those related to general programs and measures and research and development activities). Any PPI related to pilot programs is subject to additional qualifying criteria. Unless the Commission determines otherwise in an annual DSM/EE rider proceeding, the amount of the pre-income-tax PPI initially to be recovered for the entire DSM/EE portfolio for a vintage year will be equal to 11.5% multiplied by the present value of the estimated net dollar savings associated with the DSM/EE portfolio installed in that vintage year. Low-income programs with expected UC test results less than 1.00 and other non-cost-effective programs with similar societal benefits as approved by the Commission will not be included in the portfolio for purposes of the PPI calculation. The PPI for each vintage year will ultimately be trued up based on net dollar savings as verified by the EM&V process and approved by the Commission. For Vintage Years 2019 and afterwards, the program-specific per kilowatt (kW) avoided capacity benefits and per kWh avoided energy benefits used for the initial estimate of the PPI and any PPI true-up will be 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 as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing, but using, for program-specific avoided energy benefits, the projected EE portfolio hourly shape rather than an assumed 24x7 100 MW reduction.

10. If the Company achieves incremental energy savings of 1% of its prior year's system retail electricity sales in any year during the five-year 2014-2018 period, the Company will receive a bonus incentive of $400,000 for that year.

APPENDIX B

QUALIFICATIONS AND EXPERIENCE

MICHAEL C. MANESS

I am a graduate of the University of North Carolina at Chapel Hill with a Bachelor of Science degree in Business Administration with Accounting. I am a Certified Public Accountant and a member of both the North Carolina Association of Certified Public Accountants and the American Institute of Certified Public Accountants.

As Director of the Accounting Division of the Public Staff, I am responsible for the performance, supervision, and management of the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties under the jurisdiction of the Commission or involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings. I have been employed by the Public Staff since July 12, 1982.

Since joining the Public Staff, I have filed testimony or affidavits in a number of general, fuel, and demand-side management/energy efficiency rate cases of the utilities currently organized as Duke Energy Carolinas, LLC, Duke Energy Progress, LLC., and Virginia Electric and Power Company (Dominion Energy North Carolina) as well as in several water and sewer general rate cases. I have also filed testimony or affidavits in other proceedings, including applications for certificates of public convenience and necessity for the construction of generating facilities, applications for approval of self-generation deferral rates, applications for approval of cost and incentive recovery mechanisms for electric utility demand-side management and energy efficiency (DSM/EE) efforts, and applications for approval of cost and incentive recovery pursuant to those mechanisms.

I have also been involved in several other matters that have come before this Commission, including the investigation undertaken by the Public Staff into the operations of the Brunswick Nuclear Plant as part of the 1993 Carolina Power & Light Company fuel rate case (Docket No. E-2, Sub 644), the Public Staff's investigation of Duke Power's relationship with its affiliates (Docket No. E-7, Sub 557), and several applications for business combinations involving electric utilities regulated by this Commission. Additionally, I was responsible for performing an examination of Carolina Power & Light Company's accounting for the cost of Harris Unit 1 in conjunction with the prudence audit performed by the Public Staff and its consultants in 1986 and 1987.

I have had supervisory or management responsibility over the Electric Section of the Accounting Division since 1986, and also was assigned management duties over the Water Section of the Accounting Division during the 2009-2012 time frame. I was promoted to Director of the Accounting Division in late December 2016.

Public Staff
Maness Exhibit I
Schedule 1

Supplemental Miller Exhibit 1, page 1 (unless otherwise noted)

Duke Energy Carolinas, LLC
DSM/EE Cost Recovery Rider 12
Docket Number E-7 Sub 1230
Exhibit Summary of Rider EE Exhibits and Factors

Residential Billing Factor for Rider 12 True-up (EMF) Components

Line				
1	Year 2016 EE/DSM True-up (EMF) Revenue Requirement	Miller Exhibit 2, pg 1a, Line 15	$	(57,239)
2	Year 2017 EE/DSM True-Up (EMF) Revenue Requirement	Miller Exhibit 2 pg.1 Line 15		(4,091,589)
3	Year 2018 EE/DSM True-Up (EMF) Revenue Requirement	Miller Exhibit 2 pg 2 Line 15		2,645,710
4	Year 2019 EE/DSM True-Up (EMF) Revenue Requirement	Miller Exhibit 2 pg 3 Line 15		23,835,420
5	Total True-up (EMF) Revenue Requirement	Sum Lines 1-3	$	22,332,301
6	Projected NC Residential Sales (kWh) for rate period	Miller Exhibit 6 pg. 1, Line 1		22,092,324,452
7	*EE/DSM Revenue Requirement EMF Residential Rider EE (cents per kWh)*	Line 4 / Line 5 * 100		**0.1011**

Residential Billing Factor for Rider 12 Prospective Components

Line				
8	Vintage 2018 Total EE/DSM Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 2, Line 15		-
9	Vintage 2019 Total EE/DSM Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 3, Line 15		5,292,331
10	Vintage 2020 Total EE/DSM Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 4, Line 1		4,495,479
11	Vintage 2021 Total EE/DSM Prospective Amounts Revenue Requirement	**Maness Exhibit I, Schedule 2**		80,087,298
12	Total Prospective Revenue Requirement	Sum Lines 7-10	$	89,875,108
13	Projected NC Residential Sales (kWh) for rate period	Miller Exhibit 6 pg. 1, Line 1		22,092,324,452
14	*EE/DSM Revenue Requirement Prospective Residential Rider EE (cents per kWh)*	Line 11 / Line 12 * 100		**0.4068**

<u>Total Revenue Requirements in Rider 12 from Residential Customers</u>

Line				
15	Total True-up (EMF) Revenue Requirement	Line 4	$	22,332,301
16	Total Prospective Revenue Requirement	Line 11		89,875,108
17	***Total EE/DSM Revenue Requirement for Residential Rider EE***	Line 14 + Line 15	**$**	**112,207,409**
18	***Total EE/DSM Revenue Requirement for Residential Rider EE (cents per kWh)***	Line 6 + Line 13		**0.5079**

Non-Residential Billing Factors for Rider 12 True-up (EMF) Components

Line				
19	*Vintage Year 2016 EE True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 1a, Line 25	$	3,217,376
20	*Projected Year 2016 EE Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 Line 4		16,670,610,353
21	*EE Revenue Requirement Year 2016 EMF Non-Residential Rider EE (cents per kWh)*	Line 18/Line 19 * 100		**0.0193**
22	*Vintage Year 2016 DSM True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 1a, Line 35	$	(18,608)
23	*Projected Year 2016 DSM Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 Line 5		16,964,126,808
24	*DSM Revenue Requirement Year 2016 EMF Non-Residential Rider EE (cents per kWh)*	Line 21/Line 22 * 100		**(0.0001)**
25	*Vintage Year 2017 EE True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 1, Line 25	$	5,650,795
26	*Projected Year 2017 EE Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 Line 4		16,498,870,944
27	*EE Revenue Requirement Year 2017 EMF Non-Residential Rider EE (cents per kWh)*	Line 18/Line 19 * 100		**0.0342**
28	*Vintage Year 2017 DSM True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 1, Line 35	$	6,539
29	*Projected Year 2017 DSM Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 Line 5		16,933,914,400
30	*DSM Revenue Requirement Year 2017 EMF Non-Residential Rider EE (cents per kWh)*	Line 21/Line 22 * 100		**-**

31	*Vintage Year 2018 EE True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 2, Line 25	$	(784,173)
32	*Projected Year 2018 EE Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 Line 6		15,929,504,199
33	*EE Revenue Requirement Year 2018 EMF Non-Residential Rider EE (cents per kWh)*	Line 24/Line 25 * 100		**(0.0049)**
34	*Vintage Year 2018 DSM True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 2, Line 35	$	(243,015)
35	*Projected Year 2018 DSM Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 Line 7		16,832,538,740
36	*DSM Revenue Requirement Year 2018 EMF Non-Residential Rider EE (cents per kWh)*	Line 27/Line 28 * 100		**(0.0014)**
37	*Vintage Year 2019 EE True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 3, Line 25	$	(3,527,723)
38	*Projected Year 2019 EE Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 Line 8		15,707,415,542
39	*EE Revenue Requirement Year 2019 EMF Non-Residential Rider EE (cents per kWh)*	Line 30/Line 31 * 100		**(0.0225)**
40	*Vintage Year 2019 DSM True-up (EMF) Revenue Requirement*	Miller Exhibit 2 pg. 3, Line 35	$	312,940
41	*Projected Year 2019 DSM Participants NC Non-Residential Sales (kwh) for rate period*	Miller Exhibit 6 Line 9		16,897,018,794
42	*DSM Revenue Requirement Year 2019 EMF Non-Residential Rider EE (cents per kWh)*	Line 33/Line 34 * 100		**0.0019**

Non-Residential Billing Factors for Rider 12 Prospective Components

43	Vintage Year 2018 EE Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 2, Line 25	$	2,182,027
44	Projected Program Year 2018 EE Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 Line 6		15,929,504,199
45	*EE Revenue Requirement Vintage 2018 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 36/Line 37 * 100		**0.0137**
46	Vintage Year 2019 EE Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 3, Line 25	$	10,794,655
47	Projected Vintage 2019 EE Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 Line 8		15,707,415,542
48	*EE Revenue Requirement Vintage 2019 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 39/Line 40 * 100		**0.0687**
49	Vintage Year 2020 EE Prospective Amounts Revenue Requirement	Miller Exhibit 2 pg. 4, Line 4	$	9,376,721
50	Projected Vintage 2020 EE Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 Line 10		15,330,345,599
51	*EE Revenue Requirement Vintage 2020 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 42/Line 43 * 100		**0.0612**
52	Vintage Year 2021 EE Prospective Amounts Revenue Requirement	**Maness Exhibit I, Schedule 2**	$	53,575,595
53	Projected Vintage 2021 EE Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 Line 12		15,330,345,599
54	*EE Revenue Requirement Vintage 2021 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 45/Line 46 * 100		**0.3495**
55	Vintage Year 2021 DSM Prospective Amounts Revenue Requirement	**Maness Exhibit I, Schedule 2**	$	17,522,052
56	Projected Vintage 2021 DSM Participants NC Non-Residential Sales (kwh) for rate period	Miller Exhibit 6 Line 13		16,898,362,794
57	*DSM Revenue Requirement Vintage 2021 Prospective Component for Non-Residential Rider EE (cents per kWh)*	Line 48/Line 49 * 100		**0.1037**
	Total EMF Rate			**0.0265**
	Total Prospective Rate			**0.5968**

Total Revenue Requirements in Rider 12 from Non-Residential Customers

58	Vintage Year 2016 EE True-up (EMF) Revenue Requirement	Line 19	3,217,376
59	Vintage Year 2016 DSM True-up (EMF) Revenue Requirement	Line 22	(18,608)
60	Vintage Year 2017 EE True-up (EMF) Revenue Requirement	Line 25	5,650,795
61	Vintage Year 2017 DSM True-up (EMF) Revenue Requirement	Line 28	6,539
62	Vintage Year 2018 EE True-up (EMF) Revenue Requirement	Line 31	(784,173)
63	Vintage Year 2018 DSM True-up (EMF) Revenue Requirement	Line 34	(243,015)
64	Vintage Year 2019 EE True-up (EMF) Revenue Requirement	Line 37	(3,527,723)
65	Vintage Year 2019 DSM True-up (EMF) Revenue Requirement	Line 40	312,940
66	Vintage Year 2018 EE Prospective Amounts Revenue Requirement	Line 43	2,182,027
67	Vintage Year 2019 EE Prospective Amounts Revenue Requirement	Line 46	10,794,655
68	Vintage Year 2020 EE Prospective Amounts Revenue Requirement	Line 49	9,376,721
69	Vintage Year 2021 EE Prospective Amounts Revenue Requirement	Line 52	53,575,595
70	Vintage Year 2021 DSM Prospective Amounts Revenue Requirement	Line 55	17,522,052
	Total Non-Residential Revenue Requirement in Rider 12	Sum (Lines 58-70)	**98,065,181**

Public Staff
Maness Exhibit I
Schedule 2

Supplemental Miller Exhibit 2, page 5 (unless otherwise marked)

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1230
Estimated Program Costs, Earned Incentive and Lost Revenues for Vintage Year 2021

RESIDENTIAL

Line		Reference	2021
1	Residential EE Program Cost	Evans Exhibit 1, pg. 4 * NC Alloc. Factor	$ 37,155,471
2	Residential EE Earned Utility Incentive	**Maness Exhibit I, Schedule 3 * NC Alloc. Factor**	2,774,995
3	Total EE Program Cost and Incentive Components	Line 1 + Line 2, Evans Exhibit 1, Line 10	39,930,466
4	Residential DSM Program Cost	Evans Exhibit 1, pg. 4 * NC Alloc. Factor	13,699,485
5	Residential DSM Earned Utility Incentive	**Maness Exhibit I, Schedule 3 * NC Alloc. Factor**	1,180,685
6	Total DSM Program Cost and Incentive Components	Line 4 + Line 5, Evans Exhibit 1, Line 12	14,880,170
7	Total EE/DSM Program Cost and Incentive Components	Line 3 + Line 6	54,810,636
8	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 6	1.001302
9	Total EE/DSM Program Cost and Incentive Revenue Requirement	Line 7 * Line 8	54,881,999
10	Residential Net Lost Revenues	Evans Exhibit 2 pg. 3	25,205,298
11	**Total Residential EE Revenue Requirement**	**Line 9 + Line 10**	**$ 80,087,298**
			See Miller Exhibit 1 for rate

NON-RESIDENTIAL
Energy Efficiency Programs

Line		Reference	2021
12	Non- Residential EE Program Cost	Evans Exhibit 1, pg. 4 * NC Alloc. Factor	$ 38,264,959
13	Non-Residential EE Earned Utility Incentive	**Maness Exhibit I, Schedule 3 * NC Alloc. Factor**	8,888,527
14	Total EE Program Cost and Incentive Components	Line 12 + Line 13, Evans Exhibit 1, Line 27	47,153,486
15	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 6	1.001302
16	Total Non-Residential EE Program Cost and Incentive Revenue Requirements	Line 14 * Line 15	47,214,880
17	Non-Residential Net Lost Revenues	Evans Exhibit 2 pg. 3	6,360,715
18	Total Non-Residential EE Revenue Requirement	Line 16 + Line 17	$ 53,575,595
19	Projected NC Residential Sales (kWh)	Miller Exhibit 6, pg. 1, Line 12	15,330,345,599
20	**NC Non-Residential EE billing factor (Cents/kWh)**	Line 18/Line 19*100	**0.3495**

DSM Programs

Line		Reference	2021
21	Non-Residential DSM Program Cost	Evans Exhibit 1, pg. 4 * NC Alloc. Factor	$ 16,110,767
22	Non-Residential DSM Earned Utility Incentive	**Maness Exhibit I, Schedule 3 * NC Alloc. Factor**	1,388,501
23	Total Non-Residential DSM Program Cost and Incentive Components	Line 21 + Line 22, Evans Exhibit 1, Line 29	17,499,268
24	Revenue-related taxes and regulatory fees factor	Miller Exhibit 2, pg. 6	1.001302
25	Total Non-Residential DSM Revenue Requirement	Line 23 * Line 24	17,522,052
26	Projected NC Non-Residential Sales (kWh)	Miller Exhibit 6, pg. 1, Line 13	16,898,362,794
27	**NC Non-Residential DSM billing factor**	Line 25/Line 26*100	**0.1037**

Public Staff
Maness Exhibit I
Schedule 3

Supplemental Evans Exhibit 1, page 4 (unless otherwise marked)

Duke Energy Carolinas
Evans Exhibit 1
Vintage 2020 Estimate - January 1, 2021 to December 31, 2021
Docket Number E-7, Sub 1230
Load Impacts and Estimated Revenue Requirements by Program

	Residential Programs	System kW Reduction - Summer Peak	System kW Reduction - Winter Peak	System Energy Reduction (kWh)	A System NPV of Avoided Costs (PER PUBLIC STAFF WITNESS WILLIAMSON)	B Total Cost	C Shared Savings %	D =(A-B)*C Incentive	E = (B+D) System Revenue Requirement	F NC Retail kWh Sales Allocation Factor	G NC Allocation Factor (2)		H NC Residential Revenue Requirement
	EE Programs												
1	Energy Efficiency Education Program for Schools	997	1,407	7,951,567	$ 2,918,117	$ 2,315,055	11.5%	$ 69,352	$ 2,384,407	73.0903918%		E2 * F2	$ 1,742,772
2	Energy Efficient Appliances and Devices	9,790	5,988	56,621,851	$ 25,500,983	$ 10,615,734	11.5%	$ 1,711,804	$ 12,327,538	73.0903918%		E3 * F3	$ 9,010,246
3	HVAC Energy Efficiency	1,347	1,284	5,570,374	$ 4,340,717	$ 5,936,054	11.5%	$ (183,464)	$ 5,752,590	73.0903918%		E4 * F4	$ 4,204,591
4	Income Qualified Energy Efficiency and Weatherization Assistance	1,635	1,798	8,977,504	$ 5,103,548	$ 8,077,022	0.0%	$ -	$ 8,077,022	73.0903918%		E5 * F5	$ 5,903,527
5	Multi-Family Energy Efficiency	2,983	4,947	28,264,645	$ 13,755,026	$ 4,853,158	11.5%	$ 1,023,715	$ 5,876,873	73.0903918%		E6 * F6	$ 4,295,429
6	Energy Assessments	1,778	1,264	14,921,390	$ 7,393,282	$ 6,105,383	11.5%	$ 148,108	$ 6,253,491	73.0903918%		E7 * F7	$ 4,570,701
7	Total for Residential Conservation Programs	18,528	16,688	122,307,332	$ 59,011,672	$ 37,902,406		$ 2,769,515	$ 40,671,921				$ 29,727,266
8	My Home Energy Report (1)	94,985	39,714	342,160,803	$ 21,864,262	$ 12,932,554	11.5%	$ 1,027,146	$ 13,959,700	73.0903918%		E9 * F9	$ 10,203,200
9	Total Residential Conservation and Behavioral Programs	113,514	56,402	464,468,135	$ 80,875,934	$ 50,834,960		$ 3,796,662	$ 54,631,621				$ 39,930,466
										NC Residential Peak Demand Allocation Factor			
10	PowerManager	658,987	-	-	$ 43,182,806	$ 20,427,903	11.5%	$ 2,616,814	$ 23,044,717	74.2414264%	45.9556149%	(E11+E29) *F11 *G11	$ 14,880,170
11	Total Residential	772,501	56,402	464,468,135	$ 124,058,740	$ 71,262,862		$ 6,413,475	$ 77,676,338				$ 54,810,636

	Non-Residential Programs	System kW Reduction - Summer Peak	System kW Reduction - Winter Peak	System Energy Reduction (kWh)	System NPV of Avoided Costs	Total Cost	Shared Savings %	Incentive	System Revenue Requirement	NC Retail kWh Sales Allocation Factor			NC Non-Residential Revenue Requirement
	EE Programs												
12	Non Residential Smart Saver Custom Technical Assessments	626	626	5,482,371	$ 2,707,586	$ 1,106,646	11.5%	$ 184,108	$ 1,290,754	73.0903918%		E13 * F13	$ 943,417
13	Non Residential Smart Saver Custom	7,579	7,579	53,115,768	$ 28,307,620	$ 10,192,972	11.5%	$ 2,083,185	$ 12,276,156	73.0903918%		E14 * F14	$ 8,972,691
14	Non Residential Smart Saver Energy Efficient Food Service Products	212	196	4,280,461	$ 1,411,005	$ 1,057,658	11.5%	$ 40,635	$ 1,098,293	73.0903918%		E16 * F16	$ 802,747
15	Non Residential Smart Saver Energy Efficient HVAC Products	1,118	439	3,698,306	$ 2,321,340	$ 1,732,792	11.5%	$ 67,683	$ 1,800,475	73.0903918%		E17 * F17	$ 1,315,975
16	Non Residential Smart Saver Energy Efficient Lighting Products	27,805	26,034	156,866,525	$ 91,636,893	$ 24,280,837	11.5%	$ 7,745,946	$ 32,026,783	73.0903918%		E18 * F18	$ 23,408,501
17	Non Residential Smart Saver Energy Efficient Pumps and Drives Products	429	424	2,717,418	$ 1,194,746	$ 424,983	11.5%	$ 88,523	$ 513,506	73.0903918%		E19 * F19	$ 375,324
18	Non Residential Energy Efficient ITEE	-	-	272,355	$ 28,640	$ 47,381	11.5%	$ (2,155)	$ 45,226	73.0903918%		E20 * F20	$ 33,056
19	Non Residential Energy Efficient Process Equipment Products	186	206	877,998	$ 368,355	$ 117,383	11.5%	$ 28,862	$ 146,245	73.0903918%		E21 * F21	$ 106,891
20	Non Residential Smart Saver Performance Incentive	1,701	1,701	14,901,572	$ 6,902,827	$ 2,365,586	11.5%	$ 521,783	$ 2,887,368	73.0903918%		E22 * F22	$ 2,110,389
21	Small Business Energy Saver	9,404	5,944	50,790,447	$ 23,221,797	$ 11,026,688	11.5%	$ 1,402,438	$ 12,429,125	73.0903918%		E23 * F23	$ 9,084,496
22	Total for Non-Residential Conservation Programs	49,060	43,150	293,003,221	$ 158,100,809	$ 52,352,927		$ 12,161,006	$ 64,513,933				$ 47,153,486
										NC Non-Residential Peak Demand Allocation Factor			
23	EnergyWise for Business	20,801	-	2,557,568	$ 2,295,637	$ 5,981,812	11.5%	$ (423,910)	$ 5,557,902				
24	PowerShare	344,454	664	-	$ 24,766,708	$ 13,743,409	11.5%	$ 1,267,679	$ 15,011,089				
25	Total for Non-Residential DSM Programs	365,255	664	2,557,568	$ 27,062,345	$ 19,725,221		$ 843,769	$ 20,568,990	74.2414264%	54.0443851%	(E11+E29) *F29 *G29	$ 17,499,268
26	Total Non Residential	414,316	43,814	295,560,789	$ 185,163,154	$ 72,078,147		$ 13,004,776	$ 85,082,923				$ 64,652,755
27	Total All Programs	1,186,817	100,217	760,028,924	$ 309,221,894	$ 143,341,010		$ 19,418,251	$ 162,759,261				$ 119,463,391

(1) My Home Energy Report impacts reflect cumulative capability as of end of vintage year, including impacts for participants from prior vintages
(2) Total System DSM programs allocated to Residential and Non-Residential based on contribution to retail system peak