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Jun 01 2020

June 1, 2020

VIA ELECTRONIC FILING

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

Re: Duke Energy Carolinas, LLC's DSM/EE Cost Recovery Rider – Rebuttal Testimony
Docket No. E-7, Sub 1230

Dear Ms. Campbell:

Enclosed for filing is Duke Energy Carolinas, LLC's Rebuttal Testimony of Robert P. Evans and Timothy J. Duff for filing in connection with the referenced matter.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's DSM/EE Cost Recovery Rider – Rebuttal Testimony of Robert P. Evans and Timothy J. Duff, in Docket No. E-7, Sub 1230, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 1st day of June, 2020.

Kendrick C. Fentress

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1230

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

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITH DUKE ENERGY.

A. My name is Robert P. Evans, and my business address is 410 S. Wilmington Street, Raleigh, North Carolina. I am employed by Duke Energy Corporation as Senior Manager-Strategy and Collaboration for the Carolinas in the Portfolio Analysis and Regulatory Strategy group**.**

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN SUPPORT OF DUKE ENERGY CAROLINAS, LLC'S ("COMPANY") APPLICATION IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to portions of the testimony of David Williamson filed on behalf of the Public Staff and Forest Bradley-Wright filed on behalf of the North Carolina Justice Center ("NCJC"), the North Carolina Housing Coalition, and the Southern Alliance for Clean Energy ("SACE").

Q. WILL YOU DESCRIBE THE PORTIONS OF WITNESS DAVID WILLIAMSON'S TESTIMONY TO WHICH YOU ARE RESPONDING?

A. Yes. There are several portions of Witness Williamson's testimony that cause concerns, specifically, those portions related to witness Williamson's recommendation regarding lighting transformation in North Carolina and his recommendations concerning the Company's Grid Improvement Plan ("GIP").

Q. WHAT ARE YOUR CONCERNS RELATING TO WITNESS WILLIAMSON'S RECOMMENDATION REGARDING LIGHTING TRANSFORMATION IN NORTH CAROLINA?

A. Starting on line 7 on page 19 of his testimony, witness Williamson recommended the following:

> *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.*

Although the Company agrees in part with witness Williamson that significant market transformation with respect to LED non-specialty lighting has taken place, this transformation has not been universal, particularly with respect to low-income and multifamily residences. The Company still sees an ongoing need for non-specialty energy efficient A-line bulbs in both low income and multifamily residences to enable those customers to participate in the benefits of energy efficient lighting. For this reason, the Company intends to continue providing A-line bulbs to low income customers through its direct install Neighborhood Energy Saver Program and provide them through outlets such as Good Will, Dollar General, Dollar Tree and Habitat stores. In addition, the Company intends to continue replacing inefficient lighting through its Multifamily direct install program. Future needs in low income and multifamily residences will be closely monitored as independent EM&V

studies for these programs determine their saturation with standard high efficiency lighting.

Q. DO YOU AGREE WITH WITNESS DAVID WILLIAMSON'S RECOMMENDATIONS THAT AN ANALYSIS BE PERFORMED BY THE COMPANY TO EXPLAIN HOW GIP WILL AFFECT THE PERFORMANCE OF DSM/EE PROGRAMS?

A. No, I do not. In response to Public Staff and other intervenors' data requests, the Company has provided voluminous amounts of data, analyses, and general information regarding the Company's GIP program, including its Integrated Volt/Var Controls ("IVVC") program, as part of Docket No. E-7, Sub 1214 and Duke Energy Progress, LLC's Docket No. E-2, Sub 1219, which are both pending general rate cases. Specifically, information has been shared regarding the Company's IVVC program. Although the Company is certainly not opposed to reporting information about IVVC, as it has stated in Witness Jay W. Oliver's testimony in the Company's pending rate case, the additional analysis recommended by witness Williamson is not necessary. Any influence or interaction between GIP and DSM/EE programs will be evaluated and captured in the existing reporting protocols.

Q. HOW DOES THE COMPANY RESPOND TO WITNESS WILLIAMSON'S RECOMMENDATIONS THAT THE NEXT DSM/EE RIDER FILING INCLUDE REPORTING ON GIP IMPLEMENTATION AND ITS IMPACTS ON THE COMPANY'S DSM/EE PORTFOLIO?

A. I do not agree with Witness Williamson's recommendation. As previously mentioned, recommendations on reporting on the GIP status are addressed extensively in testimony filed in the pending rate cases, including in the direct and rebuttal testimony of Witness Jay W. Oliver. Accordingly, integrating additional GIP status reporting in the separate DSM/EE proceedings is unnecessary and will likely lead to confusion because the programs are separate initiatives designed to accomplish clearly defined, distinguishable goals. Because the Company (or any other party for that matter) has not recommended to have any of the programs in the GIP be filed or considered as part of the DSM/EE rider recovery proceeding, the DSM/EE rider recovery docket is not the appropriate forum for the types of information witness Williamson is recommending for reporting. Once again, any influence or interaction between GIP and DSM/EE program will be evaluated and captured in the existing reporting protocols.

Q. WHAT IS YOUR RESPONSE TO WITNESS BRADLEY-WRIGHT'S ASSERTION THAT DUKE SHOULD FIND ADDITIONAL SAVINGS IN AN EFFORT TO REACH THE 1% EVEN IF THOSE SAVINGS ARE DIFFICULT TO ACHIEVE?

A. I find Mr. Bradley-Wright's insinuation that the Company's projected decline in savings is the result of a lack of effort is disappointing. Program or measure ideas that may garner additional savings must sometimes be set aside because the benefits will not exceed the costs, but they are not set aside because they are "difficult." He knows from his active participation in the Collaborative that the Company's approach to program development and design is what has made

DEC the leader in EE savings across the Southeast, that the program managers actively seek ways to improve and expand their programs, and that the Company is committed to offering all cost-effective energy efficiency opportunities.

Q. DO DEC'S PROJECTIONS OF SAVINGS BELOW PREVIOUS YEARS DEMONSTRATE A LACK OF COMMITMENT TO OFFERING ROBUST PROGRAMS ACROSS CUSTOMER CLASSES?

A. No, the lower projections reflect market conditions and projected participation. DEC remains committed to offering robust programs across customer classes. The Company continues to seek opportunities for new and improved programs within the cost effectiveness guidelines approved by this Commission.

Q. SHOULD DEC SET HIGHER PROJECTIONS TO INDICATE ITS ASPIRATION TO ACHIEVE MORE SAVINGS?

A. No, it should not. Projections in the Rider filings are used to set rates. Therefore, the Company is often conservative to avoid raising rates unnecessarily and over-collecting from customers. The Company does not use projections as a cap, as Witness Bradley-Wright's acknowledges when he notes that Duke exceeded its projections in 2019.

Q. DOES DEC NEED TO PREPARE A PLAN OUTLINING TARGETED EE PROGRAMS TO ADDRESS THE EFFECTS OF THE PANDEMIC ON CUSTOMERS?

A. Because Duke has launched a corporate strategy to address the needs of customers during the pandemic, DEC does not plan to file an EE-specific plan. The corporate strategy to aid customers includes initiatives that DEC has brought to the Commission beginning in early March, such as the moratorium on disconnections; the suspension of all fees associated with connection, reconnection and payments, and Duke Foundation financial support for food banks and agencies that provide bill assistance. Although the Company has had to suspend programs that require in-home consultations or installations temporarily, it has updated its customer communication with more tips related to working from home, and it continues to offer energy saving kits and free LEDs by mail to qualifying customers. Additionally, all programs will resume once the Company is confident that the safety of its customers and employees can be ensured.

Q. WHAT IS YOUR RESPONSE TO WITNESS BRADLEY-WRIGHT'S RECOMMENDATION THAT THE COMMISSION REQUEST A REPORT DIRECTLY FROM THE COLLABORATIVE?

A. The Collaborative's formation by this Commission in Docket No. E-7, Sub 831 was as an advisory group to provide "an important forum for Duke to receive input from a variety of stakeholders." Witness Bradley-Wright acknowledges throughout his testimony that DEC is receiving input on new programs, discussing potential program modifications with members, and sharing information freely on a variety of topics from program performance to the IRP. If members feel it necessary to communicate directly with the Commission, they can do so by intervening in this or future dockets, as the organizations for which Witness Bradley-Wright represents did. I do not think it is necessary or consistent with the purpose of the Collaborative to assign a written report to organizations which choose not to intervene.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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	))))))	**REBUTTAL TESTIMONY OF TIMOTHY J. DUFF FOR DUKE ENERGY CAROLINAS, LLC**

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

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

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Michigan State University with a Bachelor of Arts in Political Economics and a Bachelor of Arts in Business Administration, and received a Master of Business Administration degree from the Stephen M. Ross School of Business at the University of Michigan. I started my career with Ford Motor Company and worked in a variety of roles within the company's financial organization, including Operations Financial Analyst and Budget Rent-A-Car Account Controller. After five years at Ford Motor Company, I started working with Cinergy in 2001, providing business and financial support to plant operating staff. Eighteen months later I joined Cinergy's Rates Department, where I provided revenue requirement analytics and general rate support for the company's transfer of three generating plants. After my time in the Rates Department, I spent a short period of time in the Environmental Strategy Department, and then I joined Cinergy's Regulatory and Legislative Strategy Department. After Cinergy merged with Duke Energy Corporation ("Duke Energy") in 2006, I was employed as Managing Director, Federal Regulatory

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

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

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

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

A. Yes. I testified in Duke Energy Carolinas, LLC's ("DEC" or the "Company") applications to update its demand-side management ("DSM") and energy efficiency ("EE") cost recovery rider, Rider EE, in Docket Nos. E-7, Subs 941, 979, 1001, 1031, 1050, 1130, and 1164, as well as the Company's application for approval of its new portfolio of DSM and EE program and new cost recovery mechanism in Docket No. E-7, Sub 1032. I also provided Supplemental Testimony in Duke Energy Progress, LLC's ("DEP") DSM/EE rider proceeding in Docket No. E-2, Sub 1145 and Rebuttal Testimony in Docket E-2, Sub 1174. In addition, I provided Rebuttal Testimony in DEP's

Renewable Energy Portfolio Standard Compliance Report in Docket No. E-2, Sub 1109. In addition to testifying on behalf of DEC and DEP in North Carolina, I also testified in South Carolina in Docket 2013-298-E in support of the Company's application for approval of its new portfolio of DSM and EE programs and new cost recovery mechanism. Beyond providing testimony in the Carolinas, I also have testified in matters pertaining to DSM and EE before the state regulatory commissions in the other four states in which Duke Energy subsidiaries provide utility service: Florida, Indiana, Kentucky and Ohio.

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

A. The purpose of my testimony is to address the Public Staff's recommendations, as described in the testimony of Public Staff witness John R. Hinton, that the avoided capacity cost benefits for purposes of the Portfolio Performance Incentive ("PPI") and cost-effectiveness of the Company's legacy DSM programs be calculated using a seasonal allocation of avoided capacity value. Witness Hinton's testimony also disagrees with the Company's application of a reserve margin factor in calculating the avoided cost value of energy efficiency programs. In my testimony, I will discuss why the Company's allocation of 100% of avoided capacity to legacy summer DSM resources is reasonable, consistent with past Commission Orders, and aligns with both North Carolina public policy and resource planning assumptions. I will also discuss why the Company's application of a reserve margin to the avoided capacity costs for EE programs is consistent with past Commission approved practices and how EE resources are treated in the Company's approved Integrated Resource Plan.

Q. MR. DUFF, WILL YOU PLEASE SUMMARIZE THE AGREEMENT DEC REACHED WITH THE PUBLIC STAFF IN DOCKET NO. E-7, SUB 1130 ("SUB 1130 AGREEMENT")?

A. In pertinent part, the Sub 1130 Agreement establishes, beginning with Vintage 2019 and for all future Vintages, a uniform method for determining cost-effectiveness for DSM/EE programs and calculating the Company's PPI for the purposes of both the projection and true-up of programs offered in a given Vintage Year. Under this method, the Company uses the projected avoided capacity and energy benefits specifically calculated for each EE or DSM program, as derived from the underlying resource plan, production cost model, and cost inputs used to determine the avoided capacity and avoided energy credits reflected in the most recent Commission-approved biennial determination of avoided cost rates for electric utility purchases from qualifying facilities ("Avoided Cost Proceeding") as of December 31 of the year immediately preceding the date of the annual DSM/EE rider in which the Vintage was projected. The Sub 1130 Agreement specifies that the Public Utility Regulatory Policies Act ("PURPA") -based avoided energy costs are derived by taking the difference between one production cost run that includes an assumed 24x7, 100 megawatts ("MW") of no-cost qualified facility ("QF") energy and one without the 100 MW of QF energy. The avoided energy costs used in the revised cost recovery mechanism are derived by taking a similar differencing approach, except that the projected hourly load shapes and load reductions associated with the proposed bundle of DSM/EE programs are used rather than the 24x7 100 MW reduction typically used to represent a QF. To ensure that new program requests and existing programs are being evaluated with up-to-date avoided costs, the Sub 1130 Agreement also establishes that the Company shall use projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits approved in the most recent Commission-approved Avoided Cost Proceeding as of the date of the filing for the new program approval. The Commission approved the Sub 1130 Agreement and the resulting revisions to the Company's cost recovery mechanism in the *Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, And Requiring Filing of Proposed Customer Notice* in Docket No. E-7, Sub 1130 ("Sub 1130 Order").

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

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

Under the old trigger approach, if the trigger thresholds were not hit, avoided cost rates could potentially remain unchanged for years. Under the Sub 1130 Agreement and approved modifications to the mechanism, these triggers are eliminated and instead, DSM and EE programs are evaluated for cost effectiveness utilizing Commission-approved avoided cost rates that are updated every two years as part of the biennial avoided cost proceeding.

The second primary purpose of the revisions in the Sub 1130 Agreement was to update the source and methodology for calculating avoided energy costs, which previously had been based on the IRP. Under the Sub 1130 Agreement, avoided energy costs are now derived similarly to avoided capacity costs - from the biennial Avoided Cost Proceedings. Absent the revision, the existing language in the mechanism could have resulted in DSM and EE programs being evaluated using avoided energy rates from the Company's IRP that were not based on the same fundamental assumptions used in the determination of the avoided capacity rates, which are those approved in the Company's Avoided Cost Proceedings. This potential mismatch could have undermined the validity of the cost effectiveness evaluation. The new language eliminates this potential problem by aligning and updating the assumptions approved for both avoided energy and avoided capacity rates, as the proposed revisions to the mechanism call for using the most recently approved avoided energy cost and most recently approved avoided capacity cost from the same proceeding – i.e., the Company's biennial avoided cost proceeding.

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

A. Consistent with the revisions to DEC's DSM/EE cost recovery mechanism that the Commission approved in Sub 1130 Order, the Company derived both the avoided energy and avoided capacity using the underlying resource plan, production cost model, and cost inputs approved in the Company's most recent Avoided Cost Proceeding, which in this case is Docket No. E-100, Sub 158. Notably, the final order from the Commission in Docket No. E-100, Sub 158 was not issued until April 15, 2020, after the required December 31 deadline; however, the Company chose to implement the final proposed values in anticipation of the final approval and consistent with the Commission's October 2019 Notice of Decision in Docket No. E-100, Sub 158.

Seasonal Allocation Factor

Q. FOR PURPOSES OF THIS DISCUSSION, WHAT DOES THE COMPANY MEAN WHEN IT REFERS TO ITS "LEGACY" DSM PROGRAMS?

A. "Legacy" in this context and for this proceeding means the capacity resource that has been built from historic and planned DSM programs, or, in other words, the amount of DSM capacity included in the Company's 2018 IRP forecast as a load serving resource. Incremental or new DSM capacity refers to capacity resources that are built from new participation in DSM programs that were not factored into the Company's IRP as a load serving resource.

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATED THE AVOIDED CAPACITY COST RATE ASSOCIATED WITH ITS LEGACY DSM PROGRAMS.

A. The Company utilized the avoided capacity value calculated using the Peaker Method consistent with the Sub 1130 Agreement and the Commission's recent DSM/EE cost-recovery orders, including the Commission's *Order Approving DSM/EE Rider and Requiring Filing of Customer Notice*, issued on September 11, 2018 in Docket No. E-7, Sub 1164.

Q. DO YOU AGREE WITH WITNESS HINTON THAT THE COMPANY ACTED INCONSISTENTLY WITH THE COMMISSION'S ORDER IN DOCKET NO. E-7, SUB 1130 IN NOT APPLYING A 10% SEASONAL ALLOCATION FACTOR TO THE AVOIDED COST ASSOCIATED WITH ITS LEGACY DSM PROGRAMS?

A. No, I do not agree. The Company updated the avoided capacity cost rate used for estimating program cost effectiveness and the Company's projected PPI consistently with the method agreed upon and approved in Docket No. E-7, Sub 1130.

Q. DID THE COMPANY EXPECT THE PUBLIC STAFF TO ADOPT THE POSITION THAT THE REVISIONS TO THE COMPANY'S DSM/EE COST RECOVERY MECHANISM APPROVED IN THE DOCKET NO. E-7, SUB 1130 ORDER WOULD ALTER THE WAY AVOIDED CAPACITY ASSOCIATED WITH LEGACY DSM RESOURCES WAS TO BE UPDATED?

A. No, the Company did not believe the Sub 1130 Agreement's revisions to the mechanism would amend how the Company calculates the avoided capacity costs used to evaluate existing programs that have already been approved by the Commission and are part of the Company's existing portfolio of programs.

Q. DO YOU BELIEVE THAT THE COMPANY'S APPLICATION OF THE UPDATED AVOIDED CAPACITY RATES APPROVED IN DOCKET NO. E-100 SUB 158 IS CONSISTENT WITH THE AGREEMENT IN DOCKET NO. E-7, SUB 1130 AND VALIDATED AND APPROVED IN DOCKET NO. E-7, SUB 1164?

A. Yes, the avoided capacity cost used in determining the projected Vintage 2021 cost effectiveness and PPI was calculated consistently with both the Company's most recent annual DSM/EE cost recovery proceeding in Docket No. E-7, Sub 1164 and with the Sub 1130 Agreement. To recognize the growing need for winter capacity and to encourage EE and DSM programs that will provide winter capacity savings, however, the Company made one change to its application of avoided capacity costs in this proceeding from previous proceedings. Beginning with Vintage 2021, the Company voluntarily applied the 90% Winter/10% Summer allocation approved in the most recent Avoided Cost Proceeding to avoided capacity savings for all new incremental participation in both EE and DSM programs. The Company believes this approach is consistent with the treatment of new QF capacity as discussed in the Commission's Notice of Decision and April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 158 ("Sub 158 Order"). Furthermore, although the Commission's discussion of its findings and conclusions in the Sub 158 Order were not before the Company when it filed this DSM/EE application, the Company's adjustment to its avoided capacity savings in this proceeding is consistent with the Commission's encouraging Duke to place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands.

Q. WHAT DID THE COMMISSION CONCLUDE ABOUT SEASONAL ALLOCATIONS IN THE PREVIOUS AVOIDED COST PROCEEDING?

A. The Commission concluded that DEC's seasonal allocation weightings for future capacity need of 90% for winter and 10% for summer were appropriate for use in weighting capacity value between winter and summer.[1] In so concluding, the Commission acknowledged that the currently high solar penetrations in Duke's service territory that it expects to continue in the future will have different impacts on summer versus winter loads net of solar contribution than in the past.[2]

Q. WAS THE COMPANY REQUIRED TO ADOPT THIS SEASONAL ALLOCATION TO NEW INCREMENTAL PROGRAMS AND PARTICIPATION BY THE COMMISSION'S SUB 158 ORDER AND SUB 1130 ORDER?

A. No, neither the Commission's previous avoided cost order or the Sub 1130 Agreement expressly required adoption of this seasonal allocation for purposes of this cost-recovery proceeding. As I mentioned previously, the Company *voluntarily* adopted the recently approved seasonal allocation of avoided capacity values for new incremental programs and participation in this proceeding to encourage the development and specific promotion of EE and DSM programs that provide winter capacity savings. Additionally, the Company feels that adopting this seasonal allocation approach better aligns with how new QFs receive capacity value consistent with the Sub 158 Order. Although this is the first time the Company has applied a seasonal allocation factor to new incremental programs and participation for this purpose, the reality is that the Commission's order in the Docket No. E-100, Sub 148

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[1] Sub 158 Order at 28.

[22] *Id.*

Avoided Cost Proceeding also included a seasonal allocation for capacity of 80% for winter and 20% for summer. Neither the Company nor any party to the previous DSM/EE proceedings, however, raised the argument after the Docket No. E-100, Sub 148 Avoided Cost Proceeding that the Sub 1130 Agreement required the Company to apply those Sub 148 seasonal allocations to the EE and DSM programs. The Company voluntarily applied the seasonal allocation to incremental new participation in both EE and DSM programs for the first time in this proceeding for the reasons previously mentioned.

Q. DO YOU BELIEVE THAT THE COMPANY'S APPLICATION OF THE SEASONAL ALLOCATION FACTOR ONLY TO NEW AND INCREMENTAL DEMAND RESPONSE PROGRAMS IS APPROPRIATE?

A. Yes, the Company believes that it is appropriate and consistent to only apply the seasonal allocation factor to new and incremental program participation while at the same time continuing to recognize 100% of the avoided capacity value of the Company's legacy summer demand response programs.

Q. WHY DOES THE COMPANY BELIEVE THAT LINKING TREATMENT OF LEGACY DSM PROGRAMS AND TREATMENT OF EXISTING QFS WITH RESPECT TO APPLICATION OF THE COMMISSION'S AVOIDED COST DETERMINATIONS IS APPROPRIATE IN THIS PROCEEDING?

A. The Commission has previously concluded that the net benefits and financial incentives for DEC's DSM/EE programs are linked (although not identical) to the avoided cost rates DEC pays QFs for avoided energy and capacity. As the Commission itself noted in its Sub 158 Order, seasonal allocation factors may change based on the then prevailing circumstances reviewed in biennial avoided cost proceedings.[3] Therefore, just as the Commission approved applying the seasonal allocation factors of 90% winter and 10% summer to future QF capacity in its order in Docket No. E-100, Sub 158, the Company applied the approved seasonal allocation factors to new and incremental demand response programs in this proceeding. As a corollary, just as the Commission did not retroactively apply its Sub 158 seasonal allocation factors to QFs that had previously established power purchase agreements ("PPAs") at avoided cost rates that were approved based on past prevailing circumstances, the Company did not retroactively apply the seasonal allocations approved in Sub 158 to its legacy DSM programs.

Additionally, the Commission's review of the Company's 2018 DSM/EE application is supportive of the Company's treatment of its legacy DSM/EE in this proceeding. In the 2018 DSM/EE cost recovery proceeding, Docket No. E-7, Sub 1164, the Public Staff asserted that legacy DSM programs should receive zero capacity value until the year of first need shown in the Company's most recent IRP, based on the Commission's avoided cost determination in Docket No. E-100, Sub 148 and House Bill 589's recent amendments to N.C. Gen. Stat. §62-156(b)(3). The Company opposed this recommendation and argued, among other things, that the MW reductions of those programs were

[3] Sub 158 Order at 28.

already included in the IRP and that the policy reasons behind this shift in the Commission's PURPA implementation in Docket No. E-100, Sub 148 did not likewise compel the Commission to duplicate application of the zero capacity value to existing DSM/EE programs. The Company also noted that its DSM programs had been established over a number of years and were a useful resource and that legacy DSM programs should be treated similarly to QFs that had established legally enforceable obligations ("LEOs") or had signed PPAs prior to November 15, 2016. Company witness Steve argued in his testimony that, as the Commission or House Bill 589 had not retroactively ended the capacity payments for those QFs, the Commission should not discontinue attributing capacity value to legacy DSM programs.[4] The Commission declined to accept the Public Staff's recommendation and ruled that the Company's method of assigning full avoided capacity cost value in every year was correct. Thus, one of the main arguments that the Commission reviewed in its conclusion was that the treatment of existing legacy DSM programs as a resource could be linked to treatment of existing PPAs with QFs. Just as it would be incorrect to change the avoided capacity value for an existing QF, it would likewise be incorrect to change the avoided capacity value for an existing DSM resource. Accordingly, the Company continues to believe that, for purposes of this proceeding, it is appropriate to recognize the similarity between the continuing capacity value for these legacy summer DSM programs and QFs that had established LEOs or had signed PPAs with the Company.

[4] NCUC Final Order, Docket No. E-7, Sub 1164 at 40-41

Q. PLEASE DESCRIBE HOW FROM AN INTEGRATED RESOURCE PLANNING STANDPOINT THE LEGACY DSM PROGRAMS, SPECIFICALLY THE POWER MANAGER PROGRAM, ARE VIEWED?

A. From the perspective of the Company's IRP, the Company's Legacy DSM Programs are considered a dispatchable resource that is available for the entire fifteen-year IRP planning horizon. In particular, the Power Manager Program resource has the flexibility to dispatch any time throughout the day depending on the net load on the system after accounting for must-take solar output onto the grid. As such, Power Manager is available to dispatch into the evening hours when net load is still high due to diminished solar output, a phenomenon often referred to as the "duck-curve." Conversely, if solar is lost due to mid-afternoon cloud cover, DR can be utilized earlier to make up for diminished irradiance. As an IRP resource, both existing AC DR and existing solar resources are oriented toward summer peak demand reduction helping to meet consumer peak demand in the summer. This summer capacity value from these resources, at least in part, is why incremental resource decisions are now geared toward winter peak demand needs. Importantly, this does not imply that existing summer-oriented resources such as AC DR and QF solar are not valuable, but rather implies that incremental additions to such resources would have diminished incremental value.

Q. DO YOU AGREE WITH WITNESS HINTON'S CONTENTION THAT THE LEGACY DSM PROGRAMS ARE SHORT-LIVED AND HENCE

EACH YEAR'S CUSTOMER PARTICIPATION IS NEW AND INCREMENTAL?

A. No, I do not agree with his contention. While the Company recognizes a one-year measure life associated with its demand response programs, this is purely a function of its recovery mechanism rather than a representation of the projected program participation and impact. The fact is that while the Company recognizes one year of participation at a time in its cost recovery, the legacy DSM resource has been built over time, and the term of implicit contract with customers likely more closely resembles the life of the load control switch than it does a one-year measure life. Based on the Company's experience, the Company's legacy DSM program experiences about a 1% annual net attrition rate after factoring in that in the vast majority of the residences where an existing DSM-participating customer moves out, the new customer in that residence chooses to continue participation in the DSM program.

In addition, from a system planning perspective, the peak MW capability of the DSM programs is included for all 15 years of the IRP. In fact, as noted in the Commission Order in Docket No. E-7, Sub 1164, Public Staff Witness Williams acknowledged that the DSM programs in the DSM/EE IRP block are "stable and expected to continue for the foreseeable future".

Finally, the fallacy of Mr. Hinton's argument is even more obvious, when one observes that for DEP, the Company recognizes 25 years of peak reduction impacts at the point a new customer signs up for DSM; however, customers in

DEP have the same ability to drop out of the program as those in DEC's DSM programs.

Q. WITNESS HINTON STATES THAT HE BELIEVES THAT THE CAPACITY VALUE OF SUMMER DSM RESOURCES HAS CHANGED DUE TO CHANGES IN THE COMPANY'S SYSTEM LAMBDA. DO YOU AGREE WITH THIS ASSESSMENT?

A. No, I do not. With his confidential testimony on the Company's system lambda, it appears that Witness Hinton is attempting to show that during the most recent four years of actual DSM activations, the Company has had fewer activations of summer DSM programs, which he attributes to a change in the Company's system lambda. Although it is true that the metric Mr. Hinton is using, the Company's system lambda, appears to show that the expected avoided energy costs during peak summer hours have become lower over time, this type of behavior in avoided energy costs does not clearly refute the Company's legacy DSM summer capacity value or justify reducing its value now. This change in the summer avoided costs could just as easily be explained by the milder 2017-19 summers when compared to the summer of 2016 where the DSM programs were activated a significant number of times. The Company has not performed a rigorous analysis of the Cooling Degree Days during these summer periods versus a weather normal period. A cursory examination of historical temperatures, however, indicates that the summer of 2016 was much hotter than normal. In contrast, the 2017-19 summers were very close to normal summer periods.

Additionally, the full value of a summer DSM resource occurs during extreme weather days where that ability to dispatch a summer DSM program provides peak load reduction that is less expensive than starting up and running more expensive peaking generation. Thus attempting to show that summer DSM has become less valuable over time by highlighting system lambdas during normal weather years (2017-19) when compared to an extremely hot summer year, is misleading.

Q. DO YOU AGREE WITH WITNESS HINTON'S CONTENTION THAT RECOGNIZING THE SEASONAL ALLOCATED CAPACITY VALUE OF 10% ON ITS LEGACY DEMAND RESPONSE PROGRAMS WOULD BETTER ENCOURAGE THE COMPANY TO PROMOTE WINTER CAPACITY FOCUSED EE AND DSM PROGRAMS?

A. No. While as stated previously, the Company agrees that recognizing a seasonal capacity allocation factor applied to new and incremental EE and DSM programs and participation will encourage the Company's portfolio to achieve more winter capacity savings, it struggles to understand how devaluing an existing approved summer resource that is heavily relied upon in system planning in any way encourages more winter capacity savings. The reality is that the recognition of full capacity value for an existing legacy resource has virtually no influence on the value or emphasis placed on a promoting new participation and savings; they are in fact independent of each other.

Q. DO YOU AGREE WITH WITNESS HINTON'S CONTENTION THAT APPLYING THE SEASONAL ALLOCATION FACTOR TO LEGACY

DSM PROGRAMS SHOULD NOT MATTER BECAUSE THE PROGRAMS STILL PROJECT TO BE COST EFFECTIVE EVEN AFTER SUCH AN APPLICATION WOULD OCCUR?

A. No, I do not agree. While Mr. Hinton is correct that the Company's legacy DSM program still project to be cost effective for Vintage Year 2021 if it applied the 10% seasonal allocation factor, that does not mean it is appropriate now and would not have negative longer-term impacts on this important legacy summer capacity resource.

First, as discussed earlier, failure to factor in the full avoided capacity is simply not correct, as the legacy DSM programs were implemented assuming that the avoided capacity value would exist beyond the one year measure life assumed for the purposes of cost recovery, as is clearly shown in the Company's IRP documents where the contribution from DSM programs is included in all 15 years of system planning analysis.

Second, as acknowledged by Mr. Hinton, with only 10% of the avoided capacity value being recognized, the majority of the avoided costs associated with the legacy resource comes from avoided Transmission and Distribution ("T&D") value. The avoided T&D rates are required by the Commission to be studied and updated prior to 2022. Given the uncertainty regarding the avoided T&D values beyond 2021, the Company does not believe it is appropriate to adopt Mr. Hinton's short-sighted justification that the unwarranted application of the seasonal allocation factor to the avoided capacity associated with legacy DSM resources is appropriate because the programs project to be cost effective in

2021. By establishing a precedent that the avoided capacity value for these existing summer DSM resources is arbitrarily reduced to only 10%, this could easily create a situation where these programs are no longer cost effective if there is a drop in the value of avoided T&D values.

Finally, in the Commission's final order in Docket No. E-7, Sub 1164, the Commission stated that it was "persuaded by the arguments of DEC, [the North Carolina Sustainable Energy Association] NCSEA and NC Justice Center that assigning a zero-capacity value to DSM programs would under-value the contributions of those programs and send the wrong pricing signal." In the same way, it logically follows that assigning a 10% value for avoided capacity to an existing summer DSM resource would under-value the value of this capacity resource.

Q. IF THE COMPANY DID AGREE WITH WITNESS HINTON AND THE PUBLIC STAFF'S POSITION REGARDING THE APPLICATION OF THE SEASONAL ALLOCATION FACTORS TO THE AVOIDED CAPACITY VALUES ASSOCIATED WITH LEGACY DSM PROGRAM, DO YOU AGREE WITH THE FINANCIAL ADJUSTMENT ASSOCIATED WITH THE PUBLIC STAFF' POSITION DISCUSSED IN WITNESS MANESS TESTIMONY?

A. No. The proposed reduction in the Company's PPI of $5,093,947 discussed in Witness Maness's testimony was based on an Company response to Data Request that contained a scrivener error in one of the formulas related to the Power Share Program which resulted in the net present value of avoided capacity being understated. The Company notified the Public Staff of a corrected response on May 18, 2020; however, it appears that the correction was not incorporated into Witness Maness's Testimony. Upon correction of this error, the updated difference in the PPI resulting from assigning the 90%/10% seasonal allocation of avoided capacity would be $3,624,753.

Reserve Margin

Q. DO YOU AGREE WITH WITNESS HINTON'S CONTENTION THAT IT IS INAPPROPRIATE FOR THE COMPANY TO APPLY A RESERVE MARGIN FACTOR IN THE DETERMINATION OF THE AVOIDED COST VALUE ASSOCIATED WITH THE COMPANY'S EE PROGRAMS FOR VINTAGE 2021?

A. No, I do not agree. Because EE is treated as a load reduction resource in the IRP, rather than like a load serving resource, it is appropriate that it should have a 17% reserve margin factor applied to it just as it would be appropriate to apply a 17% planning reserve margin factor to an increase to the system load. For every KW of load reduction that comes from EE, the Company does not need to plan for 1.17 KW of load serving capacity. For this reason, it is both mathematically logical and prudent from a planning standpoint to apply a 17% reserve margin factor to the avoided capacity associated with EE programs.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING WITNESS HINTON'S DISCUSSION OF THE APPLICATION OF A 17% RESERVE MARGIN TO THE AVOIDED CAPACITY ASSOCIATED WITH EE PROGRAMS?

A. Yes. I have several additional comments and concerns with witness Hinton's testimony.

First, Mr. Hinton states on Page 5 lines 19 through Page 6, line 2 that the reserve margin adjustment was applied by the Company to "all of the megawatt (MW) reductions (demand reduction benefits) associated with the Company's EE programs beginning with vintage year 2021." This statement requires clarification that the Company only applied the adjustment to the avoided capacity benefits, not the avoided T&D benefits. Technically, a reduction in avoided T&D costs could also be considered a demand reduction benefit, and the Company wants to clarify that the reserve margin adjustment is only applied to the reduction in avoided capacity.

Second, on Page 8, line 4 of Mr. Hinton's testimony, he provides a table showing an example for a 100 MW reduction in peak demand from EE. However, this table is not entirely representative of the way in which the Company applied the reserve margin adjustment. The concept is correct; however, the result in row 26 of his table does not accurately reflect DEC's proposal. DEC is proposing that a hypothetical 100 MW customer load reduction from EE program should be increased by the planning reserve margin of 17%, not the actual reserve margin in any given year. In this case, a 100 MW load reduction would yield a 117 MW reduction in generating capacity needs, rather than the 119 MW shown for the year 2020 in row 26. Thus, it is not "DEC's position . . . 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," as stated on page 8, lines 14-18 of Mr. Hinton's testimony. Third, Mr. Hinton states on Page 9, lines 5-7 of his testimony that "DEC's customers will not realize this claimed value." This statement is not correct. Just because the 2019 IRP shows DEC's actual reserve margin is greater than 17% in the near-term is no reason to assume that there is no capacity value to building new EE resources several years before the in-service date of a new generating unit. The EE measures in DEC's vintage 2021 portfolio have a life greater than 6 years, which is about the time DEC's 2019 IRP demonstrates the need for new combustion turbine generation, so those EE measures with longer lives directly contribute peak load, and reserve margin, savings during and after the in-service date of the next planned generating unit. Even Mr. Hinton recognizes that " . . . DEC's customers will ultimately see a benefit of the 100 MW of load reduction due to an EE program" (page 9, lines 7-9) and "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." (page 9, lines 10-13). EE programs are built one customer or one measure (e.g., one LED light bulb) at a time, so it typically takes several years to build a significant amount of peak load savings from EE resources. As such, EE needs to start being implemented well in advance of when it is needed.

Fourth, Mr. Hinton states on page 9, line 16 through page 10, line 4 that "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.)." This statement is not accurate. The appearance is that the two calculations only differ by the inclusion of a 1.17 reserve margin adjustment factor in the DEC proposal, which is generally correct. However, there is more information in the "approved avoided capacity rate per kW-yr" term that needs to be considered. For example, the "approved avoided capacity cost rate" from Docket E-100, Sub 158 can also be viewed as (Avoided Capacity Rate * Performance Adjustment Factor).

As Mr. Hinton notes on page 11, lines 9-22, the Performance Adjustment Factor (PAF) was 1.20 from the 1991 Avoided Cost Proceeding (Docket No. E-100, Sub 59) up until October 11, 2017 when the Commission approved a lower PAF of 1.05. Mr. Hinton also explained on page 11 that the 1.20 PAF was originally based on a 20% reserve margin, which at that point in time was an accepted margin for long-range planning. At that time, it was also known as a 20% Reserve Margin Adjustment that was applied to avoided capacity payments made to QFs, until it was renamed the PAF in the 1991 Avoided Cost Proceeding. This means that, prior to October 11, 2017, the value of a 100 MW load reduction was calculated as (100 MW * avoided capacity rate per kW-yr. * 1.20), which is very close to, and greater than, DEC's proposed calculation of (100 MW * avoided capacity rate per kW-yr. * 1.17). In essence, therefore, DEC's proposed reserve margin adjustment factor of 1.17, which reflects the current 17% margin used for long-term planning, is no different than the application of the 1.20 PAF that existed for the roughly 15-year historical period ending October 11, 2017. The outliers are the last two years when the PAF was changed to 1.05 so that it no longer represents a reserve margin adjustment.

Fifth, on page 10, lines 4-6 of Mr. Hinton's testimony, he states that, "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." The Company disagrees with this statement because the IRP addresses EE programs differently than DSM programs. Because the IRP treats EE program as a reduction to the load forecast, EE programs also eliminate the need to build a reserve, which is why EE programs should include the 1.17 reserve margin adjustment factor. DSM programs, on the other hand, are treated as a dispatchable resource, much like a generating unit. As such, DSM programs are recognized within the IRP as additional supply-side capacity, not as a peak load reduction to the load forecast. If there is no load forecast reduction, then there is also no reserve margin savings. Thus, DEC's proposal is both the correct and equitable solution and the fact that it properly recognizes this important distinction is a strength, not a weakness.

Finally, Mr. Hinton argues that "…this is not the appropriate proceeding to evaluate such a significant change to the avoided energy rates" as stated on Page 12, lines 19-21. The Company assumes that Mr. Hinton intended to use the term "avoided capacity rates" rather than "avoided energy rates" in his testimony because there was a significant drop in the avoided energy cost rates for vintage 2021 based on the new results from Docket E-100, Sub 158 and the Company has applied those rates appropriately in this proceeding.

Q. IF ONE WERE TO AGREE WITH WITNESS HINTON'S CONTENTION THAT THE PAF UTILIZED IN THE DETERMINATION OF THE COMPANY'S AVOIDED CAPACITY RATES APPROPRIATELY REFLECTS A RESERVE MARGIN, AND NOT SIMPLY AN EFFECTIVE FORCED OUTAGE RATE, SHOULD THE COMPANY BE REQUIRED TO REMOVE THE 17% RESERVE MARGIN ADDER IT APPLIED TO AVOIDED CAPACITY ASSOCIATED WITH EE PROGRAMS?

A. No, even in the case that someone agreed that the PAF included in avoided capacity calculations was equivalent to a reserve margin adjustment, it would only account for part of an appropriate adjustment for the reserve margin associated with avoided capacity coming from EE programs. In other words, an appropriate adjustment would be to only apply an 11.429% reserve margin adder to the avoided capacity to make the capacity reduction reflect a 17% reserve margin after factoring the 5% PAF already factored into the Company's approved avoided capacity rated in Docket No. E-100, Sub 158.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.