BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1174

In the Matter of		
Application of Duke Energy Progress, LLC,	)	TESTIMONY OF
for Approval of Demand-Side Management	)	JOHN R. HINTON
and Energy Efficiency Cost Recovery Rider	)	Public Staff – North Carolina
Pursuant to N.C. Gen. Stat. § 62-133.9 and	)	Utilities Commission
Commission Rule R8-69	)	

September 4, 2018

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 ongoing cost-effectiveness of the DSM/EE programs of Duke Energy Progress, LLC (DEP), as well as to calculate DEP's portfolio performance incentive (PPI) pursuant to the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs agreed upon in Docket No. E-2, Sub 1145 (Revised Mechanism).

Q. IN SUB 1145, 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 DEP proposed and the Commission approved revisions to Paragraphs 18 and 70 of the Sub 1145 Mechanism that provided that 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, as well as for review of ongoing cost-effectiveness, would use 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 148 (Sub 148), in which the Commission issued an order establishing rates on October 11, 2017.

Q. WHAT DID THE COMMISSION ORDER IN DOCKET NO. E-100, SUB 148, REGARDING AVOIDED CAPACITY COSTS AND RESULTING RATES?

A. The Commission stated:

> PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need. Changes experienced in the marketplace for QF-supplied power in North Carolina challenge many of the assumptions regarding the application of the peaker method, as well as threaten to obligate customers to pay for capacity well in excess of what may actually be avoided. While the Utilities' IRPs all continue to show additional need for capacity, the mere presence of QF capacity including solar nameplate capacity, does not always translate into an avoidance of capacity needs by the utility.[1]

In the Sub 148 Order, the Commission concluded:

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[1] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 148, October 11, 2017 (Sub 148 Order), pp. 48-49.

> N.C. Gen. Stat. § 62-156(b)(3) requires that when calculating avoided capacity rates using the peaker method, a utility's standard offer to purchase should include a capacity credit for those years when the utility's most recent IRP demonstrates a need for capacity.[2]

Q. WHAT WAS THE IMPACT OF THE COMMISSION'S CONCLUSIONS ON QUALIFYING FACILITY (QF) CAPACITY RATES?

A. The result is that for at least as long as the Sub 148 Order is in effect, "new" QFs seeking to sell their energy and capacity to DEP will not be paid capacity payments until new capacity is needed in 2022, as identified in the Company's 2016 IRP.[3] The zero avoided capacity costs for the years through 2021 are combined with positive capacity payments in 2022 and beyond, and levelized such that the avoided capacity cost rates are reduced to reflect a zero dollar value for capacity for years prior to 2022.

Q. IN THE SUB 148 ORDER, DID THE COMMISSION NOTE THE LINK BETWEEN PURPA-BASED AVOIDED COSTS AND THE COMPANY'S DSM/EE PROGRAMS?

A. Yes. The Commission Order notes that

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[2] Sub 148 Order, p. 48.

[3] "New" QFs would consist of those facilities that had not previously established a legally enforceable obligation with DEP to sell their energy and capacity to the utility under a prior avoided cost rate structure.

> … in addition to providing the basis for electric power purchases from QFs by a utility, the Commission-determined avoided costs are utilized in, among other applications, the determination of the cost-effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs…[4].

Q. WHAT IS THE PUBLIC STAFF'S POSITION ON HOW DSM/EE CAPACITY COSTS SHOULD BE TREATED UNDER THE REVISED MECHANISM?

A. The Public Staff's position is that the avoided costs for capacity used in the calculation of ongoing cost-effectiveness and utility incentives for DSM/EE programs should be consistent with the avoided cost rates for capacity for PURPA-based QFs, as provided in the Revised Mechanism and noted above in the Sub 148 Order. As such, DSM/EE ongoing cost-effectiveness and utility incentives should be based on consistent assumptions from the approved 2016 Biennial Avoided Cost rates, which include avoided capacity credits of zero for years prior to 2022.[5]

Q. PURSUANT TO PARAGRAPHS 18 AND 70 OF THE REVISED MECHANISM, SHOULD ONGOING COST-EFFECTIVENESS AND UTILITY INCENTIVES FOR DSM/EE PROGRAMS BE DETERMINED BASED ON AVOIDED CAPACITY COSTS

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[4] Sub 148 Order, p. 69.

[5] Actual DSM/EE avoided capacity rates would be levelized across the life of a given measure, with the levelized calculation including zeros for years prior to 2022. For measure lives that end before 2022, the avoided capacity rate would be zero.

GREATER THAN ZERO IN THE YEARS PRIOR TO AN IDENTIFIED NEED FOR NEW CAPACITY IN THE COMPANY'S IRP?

A. No. In order to be consistent with the Sub 148 Order and the Revised Mechanism, determinations of ongoing cost-effectiveness and utility incentives of both new DSM/EE programs and new vintages of existing DSM/EE programs starting in vintage 2019 should be based on avoided capacity costs and the ensuing rates that reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP (2022). This approach of attaching zero capacity values for years until the need for a generating unit is pushed out in time is referred to as the deferred unit method.

Q. DID THE COMPANY USE AVOIDED COST CAPACITY RATES THAT WERE BASED ON CONSISTENT ASSUMPTIONS AS APPROVED IN THE LAST BIENNIAL AVOIDED COST PROCEEDING?

A. No, the Company applied the approved avoided capacity rate in all years of the measure lives for their programs. In assessing the ongoing cost-effectiveness of its DSM/EE programs and the appropriate level of utility incentives, the Company used avoided cost rates that reflected the full value regardless of DEP's need for additional capacity. Public Staff witness Williamson discusses the

Public Staff's proposal in regard to cost-effectiveness and Public Staff witness Maness discusses the proposal impact on the PPI in more detail.

Q. HAS THE COMPANY EXPLAINED WHY IT INCLUDED FULL AVOIDED COST CAPACITY VALUE FOR DSM/EE PROGRAMS BEGINNING IN YEAR 1?

A. Yes. In response to Data Request 1-2, the Public Staff inquired how this approach, which forces customers to pay for avoided capacity that is not avoided, is consistent with the Sub 148 Order. The Company noted the applicable language of the Revised Mechanism and then responded:

> Due to fundamental differences between a Qualifying Facility (QF) and a DSM/EE measure, the avoided cost benefits for EE and DSM programs should not be, and were not intended to be, exactly the same as those used to establish QF payments. For example, the currently approved DEP DSM/EE mechanism specifically allows avoided energy rates to be modeled differently for DSM/EE programs (which uses the projected hourly EE portfolio) than for QF's (which uses a flat 100 MW [megawatt] power purchase). In this case, the resulting avoided energy rates for DSM/EE are different than for QF purchases, while being "derived from" the same underlying data and models.
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> The mechanism, however, does not address the specifics required to properly determine the avoided capacity costs of DSM/EE programs. DSM/EE measures are different and must be evaluated differently than Qualifying Facilities. The Public Staff questions appear to contend that because avoided capacity credits for a QF are calculated based upon the projected in-service date for the next avoidable

> generating unit, then that same assumption should also be applied to the calculation of avoided capacity costs for DSM/EE measures. If indeed the case, that contention fails to recognize that the capacity credits for a QF were derived after inclusion of the DSM/EE portfolio in the resource plan. The very fact that the DSM/EE portfolio has been included in the resource plan is why the QF capacity credit is zero for the period 2018-2021. The valuation of QF capacity credits is incremental to a resource plan which already includes the DSM/EE portfolio. If the DSM/EE portfolio had not been included in the resource plan, then the QF capacity credits would have been the same as those used in the DSM/EE valuation of cost effectiveness because the removal of the DSM/EE portfolio would have resulted in an immediate resource need.

The Company also argues that DSM/EE programs are unlike natural gas units, solar facilities, and other supply-side options; in that, DSM/EE MW impacts depend on short-term and long-term forecasts of customer adoption rates, market potential studies, and experience of program managers. The Company's argument could be interpreted as contending that a utility-sponsored "negawatt"[6] is more valuable than a QF generated megawatt.

Q. ARE THERE ANY CASES WHERE THE COMPANY HAS AGREED THAT THE USE OF ZERO FOR CAPACITY VALUES OR CREDITS IS REASONABLE?

A. Yes, the Company has indicated previously to the Public Staff that it believes that it is wholly consistent to apply zero capacity credits

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[6] A negawatt is a term used to represent an amount of electrical power (measured in watts) that is avoided.

to only new programs approved after the Sub 148 Order. The Company maintains that zero capacity values are acceptable for new programs just as for new QF contracts. However, the Company maintains that as the Sub 148 Order did not change the rate structures for existing QFs, therefore, it should not be used as a justification to change the rate structure for existing DSM/EE programs. As such, it appears that a key difference between the Public Staff and the Company is whether it is appropriate to apply zeros for avoided capacity credits to new measures associated with programs that already existed at the time of the Sub 148 Order, or only for new measures of new programs that are coming into existence after the date of that Order.

Q. DO YOU AGREE WITH THE COMPANY'S BASIS FOR INCLUDING FULL AVOIDED COST CAPACITY VALUE FOR APPROVED DSM/EE PROGRAMS BEGINNING IN YEAR 1?

A. No. The Company maintains that all measures associated with existing programs, regardless of the vintage year of a measure, ought to receive a full capacity payment that is based upon the approved levelized cost per kilowatt (kW) of a peaker unit as determined in the 2016 avoided cost proceeding. In contrast, my position is that for all measures installed or otherwise implemented (for any program) while the Sub 148 Order is in effect, the 2019-2021 avoided capacity savings should be credited with a value of zero dollars. Consistent with the Public Staff's testimony in Docket No. E-7, Sub 1130, the avoided costs' value to customers associated with the demand reductions with the Company's DSM/EE programs should not be set at a higher rate than paid to QF generators for their capacity that is not considered "avoided." Thus, customers should not pay for QF capacity or DSM/EE capacity when that capacity has not yet allowed the utility to avoid a generating unit in its IRP. Secondly, while it is correct that the emphasis of my testimony in DEP's last DSM/EE rider proceeding, Docket No. E-2, Sub 1145, was on the recommended use of PURPA-based models to determine the appropriate avoided energy cost, I testified in a parallel 2017 rider proceeding with DEC in Docket No. E-7, Sub 1130, that

> "the use of PURPA-based avoided costs appropriately links the Company's DSM/EE savings and <u>*financial incentives*</u> with the avoided cost rates it <u>*pays qualified facilities*</u>, will lead to better estimates of the costs avoided by the Company's DSM/EE programs, and will provide a more accurate view of the *value* of DSM and EE."[7] *(emphasis added)*

The Company also argues that previously approved DSM/EE programs should be exempt from the use of zeros just like previous avoided cost proceedings are exempt from the Sub 148 Order. However, I would point out that a key difference is that QFs are

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[7] T. p. 257.

under long-term contracts of up to 10 years to supply energy and capacity, whereas, the customers who opt for a DSM program are under contract for one year; there are no explicit contracts associated with EE programs.

Q. IS THE COMPANY CORRECT IN SAYING THAT REMOVING THE BLOCK OF DSM/EE PROGRAMS FROM THE IRP WOULD RESULT IN A MORE IMMEDIATE NEED FOR NEW CAPACITY?

A. Yes, the Company is correct in its contention that removing the block of DSM/EE programs from the IRP would result in a more immediate need for new capacity. However, I disagree with DEP's contention that the avoided capacity benefits of DSM/EE are unique. The same argument holds with respect to QFs in the IRP; in that, removing existing and future QF capacity would also leave the Company with a more immediate need for new capacity. Within IRP modeling, expected QF capacity and demand reductions associated with DSM/EE differ from traditional generation alternatives, in part, because the impacts on its load and DEP's generation requirements are impacted by factors outside of the utilities' control. Thus, if the Company argues that removing the block of existing DSM/EE is appropriate, then the removal of existing QF capacity should also be appropriate, which is inconsistent with the Order in Docket No. E-100, Sub 148. In my opinion, the utilization of the existing DSM/EE block of programs in the IRP does not justify an exception from the use of zero capacity values. Additionally, this Company's position is inconsistent with the Sub 148 Order, in that it would require customers to pay for avoided capacity before a DEP generation unit is deferred in 2022.

Q. WILL THE USE OF ZERO CAPACITY VALUE RESULT IN ZERO CREDITS IN YEARS 2019 – 2021 FOR AVOIDED CAPACITY IN THE CALCULATIONS OF DSM/EE COST EFFECTIVENESS TESTS AND PPI?

A. No, the Company's cost effectiveness tests include avoided transmission and distribution (T&D) costs, which are based on the amount of a program's kW demand reductions for all years of its measure life per the California Standards Manual.[8] A second reason is related to the Company's measure lives for its DSM programs. DEP utilizes lives of several years for its DSM measures. For instance, the present value of future avoided capacity benefits of each of DEP's air conditioning (AC) cycling measures includes the value of kW savings over the approximately 25-year-long life of the AC control equipment. Thus, the Public Staff's proposed use of zero capacity payments for years 2019

[8] Docket No. E-100, Sub 58, Duke's Least Cost Integrated Resource Plan - Stipulation Agreement Status Report for May 1992, p. 5.

through 2021 results in only a slightly lower present value of avoided capacity benefits for the 2019 vintage year programs.

Q. WHY DOES THE PUBLIC'S STAFF'S PROPOSED USE OF ZERO CAPACITY VALUE CAUSE DEP'S AVOIDED CAPACITY COST BENEFITS TO FALL LESS RELATIVE TO DEC'S AVOIDED CAPACITY COST BENEFITS?

A. There are several factors that may have contributed to the Vintage 2019 adjustment recommended by the Public Staff for DEP to be lower than that recommended for DEC. Certainly one of the most important is the differing assumptions made by the two companies with regard to the lives of its DSM measures. As previously noted, DEP uses measure lives that reflect the expected life of each measure's underlying physical equipment. In contrast, DEC uses a measure life of one year for its DSM measures.[9] Therefore, for a given vintage year (e.g. Vintage 2019), each of the companies will have a differing mix of measures and savings. DEP's measures will consist of all participants added in only that year, with estimates of associated savings for many years in the future; DEC's measures will consist of all participants during that year (including those first added in previous years), but will utilize savings

[9] If the participant in the measure chooses to remain on the program for one or more subsequent years, each such year is treated as a new measure with a life of one year.

occurring only during that year. Other factors that can contribute to the difference between DEP's and DEC's net savings and PPI may be differing mixes of measures and measure characteristics, including participants, cost structures, and Evaluation, Measurement, and Verification results. Exhibit JRH-1 illustrates the calculation of DEC's and DEP's avoided cost benefits under the Company's filed position and the Public Staff's recommended use of zero capacity values for the first three years of the vintage 2019 programs. The Exhibit also illustrates that avoided T&D cost benefits and avoided energy cost benefits will continue to provide incentives to DEP to pursue DSM even when there is no IRP-based need for additional capacity during years 2019 through 2021.

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.

Exhibit JRH- 1

Confidential Exhibit