BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1174

In the Matter of Application of Duke Energy Progress, 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 PROGRESS, LLC**

Q. 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") applications to update its demand-side management ("DSM") and energy efficiency ("EE") cost recovery rider in Docket Nos. E-7, Subs 941, 979, 1001, 1031, 1050, 1130, and 1164, as well as DEC'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" or the "Company") DSM/EE rider proceeding in Docket No. E-2, Sub 1145. In addition, I provided Rebuttal Testimony in DEP's Renewable Energy Portfolio Standard Compliance Report in Docket No. E-2, Sub 1109. In addition to testifying on behalf of DEC and DEP in North Carolina, I also testified in South Carolina in Docket 2013-298-E in support of DEC'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 recommendation, 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 DSM/EE programs be calculated under the assumption that capacity avoided prior to year 2022 be assigned a zero dollar value. The Public Staff also recommends that for as long as the Docket No. E-100, Sub 148 avoided cost rates remain in effect, the Company should assign a capacity cost of zero to all kilowatt ("kW") savings occurring before year 2022 that are related to Vintage Years 2019 and afterward. As detailed in my testimony below, the Company strongly disagrees with these recommendations. I describe the Company's agreement with the Public Staff to revise the Company's cost recovery mechanism in Docket No. E-2, Sub 1145 ("Sub 1145"), as approved by the Commission in its November 27, 2017 order in that docket ("Sub 1145 Order"), and how the agreement does not support the Public Staff's position. I also discuss Witness Hinton's testimony with respect to his analytical process that led to the Public Staff's conclusion that all of the DSM/EE programs in the Company's resource plan should receive zero capacity value for the years 2019 through 2021 and why this approach is inappropriate and seriously underestimates the value of the Company's DSM/EE programs.

Q. HAVE YOU REVIEWED 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 ("SUB 1164 ORDER")?

A. Yes. In DEC's DSM/EE cost recovery proceeding in Docket No. E-7, Sub 1164, the Commission rejected the exact same argument that the Public Staff is making in this proceeding. In particular, the Commission found that "It is inappropriate to calculate the avoided capacity cost benefits for purposes of the PPI and cost-effectiveness of the Company's DSM/EE programs under the assumption that capacity avoided prior to year 2023 be assigned a zero dollar value. The Public Staff's recommendation of such, and the corresponding reduction to the Company's Vintage 2019 PPI, is rejected."

Q. WHAT IS THE IMPACT OF THE SUB 1164 ORDER ON THE ISSUES IN THIS PROCEEDING?

A. The Company believes that the Commission's ruling in the Sub 1164 Order relating to avoided costs is dispositive of the avoided cost issue in this proceeding. The relevant language in the DEC cost recovery mechanism (Paragraph 69) is substantively identical to the relevant language in the DEP cost recovery mechanism (Paragraph 70), the agreement reached between the Public Staff and the Company which resulted in that language was substantively the same as that reached for DEC, and the rationale with which the Commission generally agreed in the Sub 1164 Order ("evaluating the contributions that DSM/EE measures make to a utility avoided future capacity needs to determine cost-effectiveness is inherently different than the evaluation undertaken to determine the capacity costs avoided through the purchase of the electric output from a QF") applies equally in this case. Accordingly, the Company believes that the Commission should reach the same result and decline to accept the Public Staff's downward adjustment to DEP's PPI in this docket.

Q. PLEASE SUMMARIZE THE AGREEMENT DEP REACHED WITH THE PUBLIC STAFF IN SUB 1145.

A. In pertinent part, the agreement establishes, beginning with Vintage 2019 and for all future Vintages, a uniform method for determining cost-effectiveness for DSM/EE programs and calculating the Company's PPI for the purposes of both the projection and true-up of programs offered in a given Vintage Year. Under this method, the Company uses the projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs used to determine the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider in which the Vintage was projected. The agreement specifies that the PURPA based avoided energy costs are derived by taking the difference between one production cost run that includes an assumed 24x7, 100 megawatts ("MW") of no-cost qualified facility ("QF") energy and one without the 100 MW of QF energy. The avoided energy costs used in the revised cost recovery mechanism are derived by taking a similar differencing approach, except the projected hourly load shapes and load reductions associated with the proposed bundle of DSM/EE programs would replace the 100 MW of no-cost QF energy. In order to ensure that new program requests and existing programs are being evaluated with up-to-date avoided costs, the agreement also establishes that the Company shall use projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of the date of the filing for the new program approval. The Commission approved this agreement and the resulting revisions to the Company's cost recovery mechanism in the Sub 1145 Order.

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

A. One of the primary purposes for the revisions to the mechanism was to eliminate the previous "trigger" approach for updating avoided costs. Prior to the changes approved in Sub 1145, the previous version of DEP'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 DEP in Docket No. E-100, Sub 140 (the 2014 Biennial Avoided Cost Proceeding). The per kilowatt-hour ("kWh") avoided energy costs were those reflected in the Company's most recent integrated resource plan ("IRP") at the time that version of the mechanism was approved (the 2015 IRP). These avoided costs were only updated if certain triggers were hit – if avoided energy costs calculated for purposes of the IRP increased or decreased by 20% or more, or if avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings increased or decreased by 15% or more.

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

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

Q. DID THE REVISIONS TO THE MECHANISM APPROVED IN SUB 1145 CHANGE THE METHODOLOGY BY WHICH THE COMPANY WAS TO CALCULATE AVOIDED CAPACITY COSTS?

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

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

A. Consistent with the revisions to DEP's DSM/EE cost recovery mechanism that the Commission approved in the Sub 1145 Order, the Company derived both the avoided energy and avoided capacity using the same fundamental assumptions approved in the Company's most recent biennial avoided cost proceeding, which in this case is Docket No. E-100, Sub 148.

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

A. No, I do not agree. The Company updated the avoided capacity rate used for estimating program cost effectiveness and the Company's projected PPI in a manner consistent with how it has always updated avoided capacity based on the biennial avoided cost proceedings. It utilized the avoided capacity value calculated using the Peaker Method consistent with the Company's understanding of the Sub 1145 agreement, which, in the Company's view, did not modify the approach used in past DSM/EE proceedings.

Q. DID THE COMPANY EXPECT THAT THE PUBLIC STAFF WOULD ADOPT THE POSITION THAT THE REVISIONS TO THE COMPANY'S DSM/EE COST RECOVERY MECHANISM APPROVED IN THE SUB 1145 ORDER WOULD ALTER THE WAY AVOIDED CAPACITY WAS TO BE UPDATED?

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

Q. IN SUB 1145, WHAT REVISIONS WERE PROPOSED BY THE PUBLIC STAFF AND THE COMPANY AND APPROVED BY THE COMMISSION REGARDING AVOIDED CAPACITY COSTS?

A. I am not aware of any changes contained in the revisions that pertained to avoided capacity costs. Avoided capacity costs are calculated in the same manner as they were prior to the revisions approved in Sub 1145. The revisions to paragraphs 18 and 70 of the Company's cost recovery mechanism accomplished two things. First, they eliminated the trigger methodology for updating avoided energy and avoided capacity costs. Second, they changed the data source and methodology used to update the avoided *energy* rates used in the calculation of program cost-effectiveness.

Q. HAVE YOU REVIEWED THE TESTIMONY OF PUBLIC STAFF WITNESS HINTON IN DOCKET NOS. E-7, SUB 1130 AND E-2, SUB 1145 THAT HE REFERENCES IN SUPPORT OF HIS TESTIMONY IN THIS PROCEEDING?

A. Yes, the Company has reviewed Mr. Hinton's testimony in Docket No. E-7, Sub 1130 ("Sub 1130") and Docket No. E-2, Sub 1145 and believes that DEP's application of avoided capacity costs in this case is entirely consistent with Mr. Hinton's testimony. Nowhere in Mr. Hinton's testimony does he indicate that the specific manner in which avoided capacity rates are to be derived from the Biennial Determination of Avoided Costs has changed as a result of the revisions to the mechanism approved in the Sub 1130 and Sub 1145 Orders. In addition, Mr. Hinton does not indicate in his testimony that the avoided capacity rates to be used for existing DSM programs should be *the same* as those that would be paid to QF facilities. Instead, it should be clear from Mr. Hinton's testimony that the intent was to align the determination of both avoided energy and avoided capacity such that the resource plan used for those calculations would be based on the same plan as was used in the avoided cost filing. The key focus of the discussion was avoided energy. The process used to establish avoided capacity was not changing from what it had always been, or in Mr. Hinton's words that it was "generally" based on or "linked" to the rates paid to QFs for avoided energy and avoided capacity.

Q. AT THE TIME OF REACHING THE AGREEMENT WITH THE PUBLIC STAFF IN SUB 1145, DID THE COMPANY PROVIDE THE PUBLIC STAFF WITH ANY INFORMATION THAT WOULD HAVE DEMONSTRATED ITS INTENT TO APPLY CAPACITY VALUES BEGINNING IN YEAR ONE (VINTAGE 2019)?

A. Yes. As referenced on page 17 of Witness Maness's affidavit in Sub 1145, the Company and the Public Staff reached an agreed upon monetary reduction to the 2018 PPI of $2.1 million to resolve the differing interpretations of Paragraph 70. In the course of reaching this agreed upon reduction to the PPI, the Company provided the Public Staff with a projection of what the change in Vintage 2019 PPI would be under the revisions to the mechanism if the proposed avoided costs rates pending before the Commission in Docket No. E-100, Sub 148 were approved. Specifically, the Company provided a projected stream of avoided capacity costs that reflected capacity values beginning in year one (2019). In other words, the analysis provided clearly reflected avoided capacity values in the years 2019-2021, rather than the zero value advocated by Witness Hinton.

Q. ASIDE FROM ITS APPLICATION IN THIS DOCKET, HAS DEP MADE ANY FILINGS IN WHICH IT USED VALUES FOR AVOIDED CAPACITY THAT WERE NOT ZERO FOR ITS DSM OR EE PROGRAMS FOLLOWING THE COMMISSION'S SUB 1145 AND SUB 148 ORDERS?

A. Yes. DEP filed for approval of the addition of the "Bring Your Own Thermostat" ("BYOT") measure to the Company's EnergyWise Program in Docket No. E-2, Sub 927. The Company filed this program modification on December 28, 2017 ("BYOT Application")[1] after both the Sub 1145 Order and Sub 148 Order had been issued. Revised Paragraph 18 of the Company's cost recovery mechanism provides that for program approval filings, like the BYOT Application, the Company shall use the same method as prescribed by revised Paragraph 70, with the avoided capacity and energy benefits derived from the most recent Commission-approved Avoided Cost Proceeding as of the date of the filing for approval. Accordingly, the Company applied this method utilizing avoided cost rates derived from the avoided capacity credits reflected in the Sub 148 Avoided Cost Proceeding to determine the cost-effectiveness of EnergyWise with the addition of BYOT.

Significantly, the Company included capacity values that were *not* zero in its filing. The Public Staff examined the cost-effectiveness evaluations the

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[1] A copy of the BYOT Application is included as Rebuttal Duff Exhibit 1 to my testimony.

Company provided in its BYOT Application and recommended approval of the program modification. As the Commission stated in its February 7, 2018 *Order Approving Program Modifications*, the Company's "application includes estimates of the Program's impacts, costs, and benefits used to calculate the cost-effectiveness of the Program. DEP's calculations indicate that the Program will remain cost-effective under the Total Resource Cost, the Utility Cost, and the Rate Impact Measure tests." The Public Staff recommended that the Commission approve the BYOT modification to the EnergyWise program, stating that "the Program has the potential to continue to encourage energy efficiency, appears to continue to be cost effective, will be included in future DEP IRPs, and is in the public interest."

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

A. No, I do not agree. The language that Mr. Hinton references in an attempt to link PURPA Rates paid to qualifying facilities to the avoided capacity recognized by Company's DSM/EE Programs does not justify the Public Staff's position. In fact, the language cited from page 69 of the Commission Order in the E-100, Sub 148 case appears to have been taken somewhat out of context. The full paragraph that was referenced by Witness Hinton reads as follows:

> The Commission notes that in addition to providing the basis for electric power purchases from QFs by a utility, the

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

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

Q. WITNESS HINTON CONTENDS THAT THE COMPANY'S EXISTING DSM PROGRAMS SHOULD BE TREATED DIFFERENTLY FROM EXISTING QFS WITH REGARDS TO RECEIVING AVOIDED

CAPACITY VALUE, SINCE EXISTING QFS ARE UNDER LONG-TERM CONTRACTS OF UP TO 10 YEARS, WHEREAS CUSTOMERS WHO PARTICIPATE IN DSM ARE UNDER A CONTRACT FOR ONE YEAR, AND THERE ARE NO EXPLICIT CONTRACTS ASSOCIATED WITH EE PROGRAMS. DO YOU AGREE?

A. No, I do not agree with his contention. First, Mr. Hinton is only partially correct when he states that customers who opt to participate in a DSM program are under a one-year contract. Residential customers do have the ability to cease participation in the residential DSM program; however, non-residential customers who elect to participate in the Company's CIG DR Program are actually agreeing to a contract period of five (5) years, with automatic extensions of two (2) years thereafter, unless terminated by either party at the end of the Contract Period by giving not less than sixty (60) days written prior notice.

Second, while it is true that the vast majority of the EE programs do not require the customer to sign a contract, however, this overlooks the fact that one program, My Home Energy Report ("MyHER"), is effectively in the same position as the legacy DSM programs. The MW capability provided by the MyHER EE program was created in the past, prior to the establishment of the new avoided cost rates. All that is required is the expenditure of funds to maintain the impacts, just like the Company must do to maintain the availability of the impacts from the legacy DSM programs. In this case, the MyHER program impacts are also not incremental or new after November 2016. They are embedded in the resource plan, and like legacy QFs with legally enforceable obligations ("LEOs") existing prior to November 15, 2016, should receive a capacity value in the 2019 to 2021 time period. The MW impacts of the MyHER program were not included in the EE impacts shown in the Company's IRP because these impacts had already impacted the overall system load forecast; however, the impacts were assumed to remain part of the system load reduction. Otherwise, the load forecast would have needed to be increased by the amount of load reduction from MyHER already included in the system load prior to the IRP modeling.

With respect to the other EE programs, there is a summer capacity need of 216 MW (166 MW for the winter) from the EE programs in the year 2022. Those familiar with the implementation of EE programs will recognize that one does not create 216 MW of EE overnight. It takes time. It takes time to build customer awareness. It takes time for equipment to wear out and be replaced or for customers to recognize that it is time to change out equipment. In addition, the Company is subject to the decisions of customers to participate in the programs. There is no control over customer decision-making when it comes to participation in EE programs. In addition, in the Company's IRP, the EE impacts are subtracted from the load forecast. As a result, there is no reserve margin for the EE impacts. The Company can only make offers that it hopes customers will embrace. But, there are no guarantees.

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

A. No, I do not.

Q. PLEASE EXPLAIN.

A. Witness Hinton's testimony appears to imply that existing QFs are somehow a superior resource compared to on-going participation in existing DSM/EE Programs because they are based on a long term contract. He then uses this logic to support his position that the Company should not recognize avoided capacity costs until a resource need exists in 2022. Unfortunately, his logic appears to ignore the fact that incremental new EE impacts from existing approved programs should be viewed as a priority resource and not an inferior resource, as he fails to recognize the key role EE plays in the Company meeting its Renewable Energy Portfolio Standard. In fact, his position seems to fly directly in the face of Senate Bill 3, when one appropriately considers that the stated purpose of Senate Bill 3 was to "promote the development of renewable energy and energy efficiency in the state through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard."

Q. WHAT IS THE IMPACT OF THE PUBLIC STAFF'S POSITION?

A. It is my understanding that based upon this position, the Public Staff recommends that all of the DSM/EE kW impacts in the years 2019 to 2021 would have a zero capacity value for purposes of evaluating cost-effectiveness and evaluating utility incentives. To that end, the Public Staff's testimony removes the avoided capacity value for that time period for all kW impacts. Based upon the referenced DEP IRP, in 2019 this represents the removal of the capacity value for 951 MW of DSM impacts and 128 MW of EE impacts of summer capability from the Company's existing portfolio of approved DSM/EE programs.

Q. DO YOU AGREE WITH MR. HINTON'S TESTIMONY THAT THE COMPANY AGREES THAT ZERO CAPACITY VALUES ARE APPROPRIATE FOR ALL NEW PROGRAMS JUST AS NEW QFS?

A. No, I do not completely agree with his statement. The Company does agree that zero avoided capacity value should be assigned to new DSM/EE Programs to the extent they represent capacity reductions over and above those necessary to meet the EE/DSM capacity that is included in the IRP.

In contrast to this position, however, the fact that DSM/EE capacity savings from existing approved programs are included in the IRP forecast are a critical part of the very reason why there is not a capacity need until 2022. Thus, if a new program is needed for the Company to meet the EE/DSM forecast that was included in the IRP, then the Company believes this new program should receive avoided capacity value in years 2019-2021.

Q. LOOKING AT THE COSTS OF EE/DSM PROGRAMS THAT WERE INCLUDED IN THE IRP, DO THEY SUPPORT THE COMPANY'S POSITION?

A. Yes, the Company's inputs to the IRP for the cost of the DSM and EE programs include not just the implementation cost, but also the estimate of the utility's PPI, which contains a capacity value for the years 2019 through 2021. As a result, one could conclude that to be consistent with the underlying resource plan, including the cost inputs, one should be including the avoided capacity cost for DSM/EE for the years 2019 to 2021. I think when one looks at the resource planning process from this perspective, it makes good sense to recognize the capacity value of the EE programs during the 2019 to 2021 period.

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

A. Yes. It should be very clear that incremental additions to the legacy DSM programs and the annual participation in the MyHER program deserve a full capacity value for the years 2019 to 2021 and beyond. With respect to the MyHER EE program, because its load impacts are also not incremental and existed prior to the establishment of the new avoided cost rates, I believe they also deserve a full capacity value.

For the other EE programs, while the Company believes it valued them appropriately with an avoided capacity value for all years, should the Commission agree with the Public Staff's position, then the Company would recognize that the incremental impacts from those programs, over and above the impacts already included in the forecast used in the IRP and Avoided Cost filing resource plans, could be treated the same as the incremental QF resources in the IRP. This means that, consistent with how "new" QFs with LEOs after November 15, 2016 are treated, the Company would ascribe a zero value of capacity for the years 2019 to 2021 for these other EE programs.

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

A. Yes.

Bring Your Own Thermostat / EnergyWise Home (Summer)

R8-68 Filing Requirements	
Bring Your Own Thermostat ("BYOT") / EnergyWise Home (Summer)	
Filing Requirements	
(c)(2)(i)(a)	**Measure / Program Name**
	Bring Your Own Thermostat ("BYOT") Measure / EnergyWise Home (Summer)
(c)(2)(i)(b)	**Consideration to be Offered**
	<u>BYOT Measure Related Program Modifications:</u> Residential customers of Duke Energy Progress, LLC ("DEP" or "Company"), by enrolling in the EnergyWise Home program, agree to allow the Company to temporarily remotely control their eligible thermostats via the internet as a means of direct load control at any time the Company has capacity problems, including generation, transmission or distribution capacity problems or reactive power problems. • Residential customers who meet specific criteria (see (c)(2)(ii)(c) below) will receive an invitation via a third-party vendor on behalf of the Company to enroll in the BYOT measure. • Enrollees are compensated for their voluntary participation in the program and retain the ability to override (opt-out of) individual events or exit the program.
(c)(2)(i)(c)	**Anticipated Total Cost of the Measure / Program**
	See Attachment B, Line 12.
(c)(2)(i)(d)	**Source and Amount of Funding Proposed to be Used**
	All program costs will be funded from the Company's general funds, consisting of all sources of capital. • These costs will be subject to cost recovery through a DSM/EE annual cost recovery rider consistent with Commission Rule R8-69(b). • See Attachment B, line 12 for the estimated level of required funding.
(c)(2)(i)(e)	**Proposed Classes of Persons to Whom This Will be Offered**
	The BYOT measure is available to residential customers served by the Company in single-family homes, condos or townhomes who already possess, have installed and have registered/ activated one or more of the supported smart thermostat devices. Customer must own or occupy the residence or occupy and provide owner's consent.
(c)(2)(ii)(a)	**Describe the Measure / Program's Objective**
	<u>BYOT Measure Related Program Modifications:</u> BYOT provides the Company with an additional Demand Response ("DR") measure for its EnergyWise Home (Summer) program. Rather than utilizing traditional paging or cellular load control switches which must be installed at the customer's residence, BYOT manages load by remotely accessing the customers' eligible thermostats and by making automated adjustments to reduce kW demand in near-real time.

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Bring Your Own Thermostat / EnergyWise Home (Summer)

(c)(2)(ii)(b)	**Describe the Measure / Program Duration**
	Duration – see Attachment A, line 1.

(c)(2)(ii)(c)	**Describe the Measure / Program Sector and Eligibility Requirements**
	<u>BYOT Measure Related Program Modifications:</u> DEP residential customers as described in (c)(2)(i)(e) above with active accounts and eligible thermostats will be invited to participate in the Program. Customers that are already enrolled in EnergyWise® will not be actively recruited at this time.
(c)(2)(ii)(d)	**Examples of Communication Materials and Related Cost**
	<u>BYOT Related Program Modifications:</u> The Company will engage a BYOT vendor (third-party aggregator) to provide, implement and support a BYOT measure which includes marketing and recruitment services provided by the vendor (subject to the Company's branding and messaging policies). Charges for these services are typically included in specified program fees, paid to the vendor by the utility. Methods of recruitment may include, but are not limited to: • Direct customer engagement via the thermostat manufacturer's online web portal • Invitation to enroll by direct email, interactive PDF or link to enrollment portal • Invitation to enroll by text or other mobile application • Company public website (at a later time in the program)
(c)(2)(ii)(e)	**Estimated Number of Participants**
	Estimated DEP Participation – see Attachment A, lines 3 - 12.
(c)(2)(ii)(f)	**Impact that each measure or program is expected to have on the electric public utility or electric membership corporation, its customer body as a whole, and its participating North Carolina customers**
	Estimated DEP Impact – see Attachment A, lines 13 - 49.
(c)(2)(ii)(g)	**Any other information the electric public utility or electric membership corporation believes is relevant to the application, including information on competition known by the electric public utility or the electric membership corporation**
	Not applicable.
(c)(2)(iii)(a)	**Proposed Marketing Plan Including Market Barriers and how the Electric Public Utility Plans to Address Them**
	<u>BYOT Measure Related Program Modifications:</u>

BYOT vendors typically establish direct relationships with selected thermostat manufacturers, who in turn notify the vendor when a customer within a specified territory (usually identified by zip code) has activated his/her thermostat via the manufacturer's online activation portal.

- Upon validation by the utility, the customer is then extended an invitation by the vendor (on behalf of the utility) to enroll in the BYOT measure and participate in DR "events" as initiated by the utility. Invitations are extended via the methods listed in section (c)(2)(ii)(d) above.

Bring Your Own Thermostat	
Market Barrier	**Actions to Address**
Lack of awareness/understanding on the part of the customer regarding DR programs in general, how they work and what the benefits are (for the customer, the utility and the community).	Ensure that messaging includes clear, easy to understand information regarding the program and DR as a whole. Provide clear channels to customer support via phone, email or direct online chat.
Fear on the part of the customer that the utility may be eavesdropping on them, controlling their thermostat against their will, damaging the thermostat device, causing discomfort to the customer or some other unwanted intrusive action.	These concerns should be anticipated when third parties such as utilities request remote access to appliances within customers' homes. All messaging and customer support must proactively provide assurance and education about each issue, including the customers' right to opt-out or exit the program at any time, and after the first year of participation without penalty.
Disruptive or competing programs/incentives on the part of the thermostat manufacturer(s) that may lessen or adversely affect the utility's DR capabilities/efforts.	Partnering with BYOT vendors allows the utility to leverage the vendors' relationships with the thermostat manufacturers and to cooperatively design DR programs that are to everyone's benefit. The utility is also in the position to cross-market additional energy efficiency measures or programs to the customers which thermostats manufacturers cannot provide.

(c)(2)(iii)(b) Total Market Potential and Estimated Market Growth throughout the Duration of the Program

BYOT Measure Related Program Modifications:

Market potential represents the number of eligible customers based on eligibility requirements defined in the program tariff. There are approximately 74,000 residential customers that meet the criteria for this program as of 2017.

Estimated Market Growth (Participation) – see Attachment A, lines 3 - 12.

(c)(2)(iii)(c) Estimated Summer and Winter Peak Demand Reduction by Unit Metric and in the Aggregate by Year

Estimated Summer and Winter Peak Demand Reduction – see Attachment A, lines 13 - 17 and lines 23 – 24, and Attachment E, lines 1 - 10.

Bring Your Own Thermostat / EnergyWise Home (Summer)

(c)(2)(iii)(d)	**Estimated Energy Reduction per Appropriate Unit Metric and in the Aggregate by Year**
	Estimated Energy Reduction – see Attachment A, lines 18 - 22 and lines 25 - 29.
(c)(2)(iii)(e)	**Estimated Lost Energy Sales per Appropriate Unit metric and in the Aggregate by Year**
	Not applicable.

(c)(2)(iii)(f)	**Estimated Load Shape Impacts**
	See sections (c)(2)(iii)(c) and (c)(2)(iii)(d).
(c)(2)(iv)(a)	**Estimated Total and Per Unit Cost and Benefit of the Measure / Program and the Planned Accounting Treatment for Those Costs and Benefits**
	Costs associated with this program will be subject to deferral and amortization. DEP is also eligible to recover a return on any outstanding deferred balance [R8-69(b)(6)]. Total estimated cost by category – see Attachment B, lines 6 - 9. Total estimated benefit – see Attachment B line 11. Total estimated per unit cost by category – see Attachment D, lines 1 - 25. Data shown on Attachment B represents present value of cost and benefits over the life of the program.
(c)(2)(iv)(b)	**Type, Amount, and Reason for Any Participation Incentives and Other Consideration and to Whom They Will be Offered, Including Schedules Listing Participation Incentives and Other Consideration to be Offered**
	<u>BYOT Measure Related Program Modifications:</u> Participants in the BYOT measure will receive a one-time enrollment incentive of $75 at the time of enrollment. • Participants who continue to remain in the program will also receive an annual incentive of $25, paid at the end of each completed year of participation.
(c)(2)(iv)(c)	**Service Limitations or Conditions Planned to be Imposed on Customers Who do not Participate in the Measure / Program**
	<u>BYOT Measure Related Program Modifications:</u> There are no service limitations or conditions to be imposed on customers who do not participate in the measure/program. Program participants who voluntarily opt-out of a maximum of 2 (two) DR events within a

	peaking season may be asked to leave the program and, as such, receive no further compensation from that point onward. • Additionally, participants whose thermostat remains chronically offline or unavailable for any reason will be notified by the Company of the situation and provided with an opportunity to remedy. Failure to remedy the situation allows the Company to ask the customer to leave the program, as above. • If the Company is unable to communicate with the Customer's thermostat(s) during a load control event, it will be counted as a control event override.
(c)(2)(v)	**Cost-Effectiveness Evaluation (including the results of all cost-effectiveness tests and should include, at a minimum, an analysis of the Total Resource Cost Test, the Participant Test, the Utility Cost Test, and the Ratepayer Impact Measure Test) Description of the Methodology Used to Produce the Impact Estimates, as well as, if Appropriate, Methodologies Considered and Rejected in the Interim Leading to the Final Model Specification**
	See Attachment B**,** line 13.
(c)(2)(vi)	**Commission Guidelines Regarding Incentive Programs (provide the information necessary to comply with the Commission's Revised Guidelines for Resolution of Issues Regarding Incentive Programs, issued by Commission Order on March 27, 1996, in Docket No. M-100, Sub 124, set out as an Appendix to Chapter 8 of these rules)**
	The EnergyWise Home program and the BYOT measure do not provide any inducement or incentive affecting participant's decision to install or adopt natural gas or electric service.
(c)(2)(vii)	**Integrated Resource Plan (explain in detail how the measure is consistent with the electric public utility's or electric membership corporation's integrated resource plan filings pursuant to Rule R8-60)**
	Energy and capacity reductions from this program will be included for planning purposes in future integrated resource plans.
(c)(2)(viii)	**Other (any other information the electric public utility or electric membership corporation believes relevant to the application, including information on competition known by the electric public utility or the electric membership corporation)**
	Not applicable.
Additional Filing Requirements	
(c)(3)(i)(a)	**Costs and Benefits- Any Costs Incurred or Expected to be Incurred in Adopting and Implementing a Measure / Program to be Considered for Recovery Through the Annual Rider Under G.S. 62-133.9**
	See Attachment C, lines 11 - 35.
(c)(3)(i)(b)	**Estimated total costs to be avoided by the measure by appropriate capacity, energy and measure unit metric and in the aggregate by year**

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	See Attachment A, lines 40 - 49.
(c)(3)(i)(c)	**Estimated participation incentives by appropriate capacity, energy, and measure unit metric and in the aggregate by year**
	Incentive per cumulative kW – see Attachment E, lines 21 - 25. Incentive per cumulative kWh – see Attachment F, lines 16 - 20. Incentive per participant – see Attachment D, lines 11 - 15.
(c)(3)(i)(d)	**How the electric public utility proposes to allocate the costs and benefits of the measure among the customer classes and jurisdictions it serves**
	The program costs for DSM/DR programs targeted at North Carolina and South Carolina residential customers are allocated to North Carolina retail jurisdiction based on the ratio of North Carolina one-hour coincident peak. Rate Class Allocation (allocated jurisdictional costs will be further allocated to all rates classes, based upon one-hour coincident peak) then recovered only from North Carolina residential customers.
(c)(3)(i)(e)	**The capitalization period to allow the utility to recover all costs or those portions of the costs associated with a new program or measure to the extent that those costs are intended to produce future benefits as provided in G.S. 62-133.9(d)(1)**
	No costs from this program will be capitalized.
(c)(3)(i)(f)	**The electric public utility shall also include the estimated and known costs of measurement and verification activities pursuant to the Measurement and Verification Reporting Plan described in paragraph (ii)**
	The Company's estimated evaluation, measurement and verification ("EM&V") costs for this program is estimated to be 5% of total portfolio costs.
(c)(3)(ii)(a)	**Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures: Describe the industry-accepted methods to be used to evaluate, measure, verify, and validate the energy and peak demand savings estimated in (2)(iii)c and d above**
	The Company will use an independent, third-party evaluator specializing in the EM&V of demand reduction program impacts to provide the appropriate EM&V support. The independent, third-party consultant will customize an EM&V plan with specific activities to carry out the evaluation approach described below. **Objectives** Impact evaluation activities verify demand reduction impacts attributable to the program. Process evaluation activities assess the effectiveness of program processes and their impact on the broader program market. Specific objectives for the evaluation of the program include the following:

- Estimate the average (kW) and aggregate (MW) load reductions that are achieved during load control events and the overall average event.
- Forecast load impacts under different event conditions (i.e., time of day, temperature) to create a time/temperature matrix for use by the program.
- Evaluate effectiveness of program design and processes.

Impact Evaluation

The goal of the impact evaluation is to assess the average (kW) and aggregate (MW) load reductions attributable to the program. The independent, third-party EM&V consultant will determine the detailed analysis methodologies, sample design and data collection activities. The target level for precision is 90/10.

For the impact evaluation, the consultant will utilize data loggers that will be installed on air conditioning units to estimate end use load impacts during load control events. Load impact estimation will be accomplished using regression models in order to obtain accurate and precise estimates.

Process Evaluation

The goal of the process evaluation is to assess program design and implementation processes to improve effectiveness or operational efficiencies. Through the process evaluation, the evaluation contractor will document significant components of the program including program accomplishments, administrative processes and participant experiences during load events, customer satisfaction, program successes and opportunities for improvement to program design and delivery. Ultimately, the process evaluation will provide guidance regarding opportunities for more effective program implementation.

Process Evaluation Activities

The evaluation team will complete in-depth interviews with participant households and program staff and implementers to understand program processes.

Process Evaluation Interviews/Surveys

Market Actor	Research Issues (Illustrative)	Approximate Sample Size
Program Implementers and Associated Staff Interviews	• Understand program processes, particularly event notification procedures, how incentives are paid and how the program is communicated to customers • Develop a program logic model that depicts program processes • Identify areas where processes could be improved	TBD*
Participant Households Surveys	• Determine participant satisfaction, particularly post-event • Determine participation satisfaction,	TBD*

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	particularly during non-events		

**Sample size will be determined based on the number of program participants.*

(c)(3)(ii)(b)	**Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures: Provide a schedule for reporting the savings to the Commission**
	The schedule for the EM&V actions will begin after the program has a sufficient amount of participation from which to draw a statistically significant sample. The evaluation plan may be modified based on the actual participation in the Program, as needed to provide a cost effectiveness evaluation, and as agreed to by the independent third-party.
(c)(3)(ii)(c)	**Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures: describe the methodologies used to produce the impact estimates, as well as, if appropriate, the methodologies it considered and rejected in the interim leading to final model specification**
	Please refer to section R8-68 (c)(3)(ii)a which provides information regarding the methodologies used to produce impact estimates associated with this program.

(c)(3)(ii)(d)	**Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures: Identify any third party and include all of the costs of that third party, if the electric public utility plans to utilize an independent third party for purposes of measurement and verification**
	An independent, third-party consultant will be engaged to provide EM&V services.
(c)(3)(iii)	**Cost Recovery Mechanism- Describe the Proposed Method of Cost Recovery From its Customers**
	The Company seeks to recover program costs and a utility incentive pursuant to the approved cost recovery mechanism in Commission Docket No. E-2, Sub 931.
(c)(3)(iv)	**Tariffs or Rates- Provide Proposed Tariffs or Modifications to Existing Tariffs That Will be Required to Implement Each Measure / Program**
	The tariff proposed by the Company for this program is included as Attachment G.
(c)(3)(v)	**Utility Incentives- Indicate Whether it Will Seek to Recover Any Utility Incentives, Including, if Appropriate, Net Lost Revenues, in Addition to its Costs**
	The Company seeks a utility incentive pursuant to the approved cost recovery mechanism approved by the North Carolina Utilities Commission in Docket No. E-2, Sub 931 on January 20, 2015.

Bring Your Own Thermostat / EnergyWise Home (Summer)

Attachment A
Participation

	Bring Your Own Thermostat / EnergyWise® Home	
1	Measure Life (Average)	1
2	Free Rider % (Average)	0%
3	Incremental Participants Year 1	21,944
4	Incremental Participants Year 2	51,544
5	Incremental Participants Year 3	79,062
6	Incremental Participants Year 4	105,351
7	Incremental Participants Year 5	133,428
8	Cumulative Participation Year 1	21,944
9	Cumulative Participation Year 2	51,544
10	Cumulative Participation Year 3	79,062
11	Cumulative Participation Year 4	105,351
12	Cumulative Participation Year 5	133,428
13	Cumulative Summer Coincident kW w/ losses (net free) Year 1	35,963
14	Cumulative Summer Coincident kW w/ losses (net free) Year 2	78,576
15	Cumulative Summer Coincident kW w/ losses (net free) Year 3	117,658
16	Cumulative Summer Coincident kW w/ losses (net free) Year 4	154,242
17	Cumulative Summer Coincident kW w/ losses (net free) Year 5	191,358
18	Cumulative kWh w/ losses (net free) Year 1	0
19	Cumulative kWh w/ losses (net free) Year 2	0
20	Cumulative kWh w/ losses (net free) Year 3	0
21	Cumulative kWh w/ losses (net free) Year 4	0
22	Cumulative kWh w/ losses (net free) Year 5	0
23	Per Participant Weighted Average Coincident Saved Winter kW w/ losses	0.05
24	Per Participant Weighted Average Coincident Saved Summer kW w/ losses	1.64
25	Per Participant Average Annual kWh w/ losses (net free) Year 1	0
26	Per Participant Average Annual kWh w/ losses (net free) Year 2	0
27	Per Participant Average Annual kWh w/ losses (net free) Year 3	0
28	Per Participant Average Annual kWh w/ losses (net free) Year 4	0
29	Per Participant Average Annual kWh w/ losses (net free) Year 5	0
30	Cumulative Lost Revenue (net free) Year 1	$0
31	Cumulative Lost Revenue (net free) Year 2	$0
32	Cumulative Lost Revenue (net free) Year 3	$0
33	Cumulative Lost Revenue (net free) Year 4	$0
34	Cumulative Lost Revenue (net free) Year 5	$0
35	Average Lost Revenue per Participant (net free) Year 1	$0
36	Average Lost Revenue per Participant (net free) Year 2	$0
37	Average Lost Revenue per Participant (net free) Year 3	$0
38	Average Lost Revenue per Participant (net free) Year 4	$0
39	Average Lost Revenue per Participant (net free) Year 5	$0
40	Total Avoided Costs/MW saved Year 1	$109,196
41	Total Avoided Costs/MW saved Year 2	$111,652
42	Total Avoided Costs/MW saved Year 3	$114,311
43	Total Avoided Costs/MW saved Year 4	$117,152
44	Total Avoided Costs/MW saved Year 5	$120,084
45	Total Avoided Costs/MWh saved Year 1	N/A
46	Total Avoided Costs/MWh saved Year 2	N/A
47	Total Avoided Costs/MWh saved Year 3	N/A
48	Total Avoided Costs/MWh saved Year 4	N/A
49	Total Avoided Costs/MWh saved Year 5	N/A

Attachment B
Cost-Effectiveness Evaluation

Bring Your Own Thermostat / EnergyWise® Home

		UCT	TRC	RIM	Participant
1	Avoided T&D Electric	$66,828,683	$66,828,683	$66,828,683	$0
2	Cost-Based Avoided Elec Production	$0	$0	$0	$0
3	Cost-Based Avoided Elec Capacity	$86,687,111	$86,687,111	$86,687,111	$0
4	Participant Elec Bill Savings (gross)	$0	$0	$0	$0
5	Net Lost Revenue Net Fuel	$0	$0	$0	$0
6	EM&V Costs	$2,812,872	$2,812,872	$2,812,872	$0
7	Implementation Costs	$30,747,601	$30,747,601	$30,747,601	$0
8	Incentives	$21,803,002	$0	$21,803,002	$21,803,002
9	Other Utility Costs	$6,478,144	$6,478,144	$6,478,144	$0
10	Participant Costs	$0	$0	$0	$0
11	Total Benefits	$153,515,794	$153,515,794	$153,515,794	$21,803,002
12	Total Costs	$61,841,619	$40,038,617	$61,841,619	$0
13	**Benefit/Cost Ratios**	**2.48**	**3.83**	**2.48**	

Data represents present value of costs and benefits over the life of the program.

Attachment C

Program Costs by Year

	Bring Your Own Thermostat / EnergyWise® Home	
1	Incremental Participants Year 1	21,944
2	Incremental Participants Year 2	51,544
3	Incremental Participants Year 3	79,062
4	Incremental Participants Year 4	105,351
5	Incremental Participants Year 5	133,428
6	Total Participant Costs Year 1	$0
7	Total Participant Costs Year 2	$0
8	Total Participant Costs Year 3	$0
9	Total Participant Costs Year 4	$0
10	Total Participant Costs Year 5	$0
11	EM&V Costs Year 1	$288,751
12	EM&V Costs Year 2	$290,381
13	EM&V Costs Year 3	$329,540
14	EM&V Costs Year 4	$390,996
15	EM&V Costs Year 5	$422,300
16	Implementation Costs Year 1	$5,820,093
17	Implementation Costs Year 2	$5,637,636
18	Implementation Costs Year 3	$5,361,095
19	Implementation Costs Year 4	$5,235,508
20	Implementation Costs Year 5	$5,185,952
21	Total Incentives Year 1	$1,167,712
22	Total Incentives Year 2	$1,736,556
23	Total Incentives Year 3	$2,558,717
24	Total Incentives Year 4	$3,122,237
25	Total Incentives Year 5	$3,884,601
26	Other Utility Costs Year 1	$384,451
27	Other Utility Costs Year 2	$508,400
28	Other Utility Costs Year 3	$646,050
29	Other Utility Costs Year 4	$710,556
30	Other Utility Costs Year 5	$820,327
31	Total Utility Costs Year 1	$7,661,007
32	Total Utility Costs Year 2	$8,172,973
33	Total Utility Costs Year 3	$8,895,402
34	Total Utility Costs Year 4	$9,459,297
35	Total Utility Costs Year 5	$10,313,180

Attachment D
Program Costs per Participant

Bring Your Own Thermostat / EnergyWise® Home		
1	Average Per Participant EM&V Costs Year 1	$13
2	Average Per Participant EM&V Costs Year 2	$6
3	Average Per Participant EM&V Costs Year 3	$4
4	Average Per Participant EM&V Costs Year 4	$4
5	Average Per Participant EM&V Costs Year 5	$3
6	Average Per Participant Implementation Costs Year 1	$265
7	Average Per Participant Implementation Costs Year 2	$109
8	Average Per Participant Implementation Costs Year 3	$68
9	Average Per Participant Implementation Costs Year 4	$50
10	Average Per Participant Implementation Costs Year 5	$39
11	Average Per Participant Incentives Year 1	$53
12	Average Per Participant Incentives Year 2	$34
13	Average Per Participant Incentives Year 3	$32
14	Average Per Participant Incentives Year 4	$30
15	Average Per Participant Incentives Year 5	$29
16	Average Per Participant Other Utility Costs Year 1	$18
17	Average Per Participant Other Utility Costs Year 2	$10
18	Average Per Participant Other Utility Costs Year 3	$8
19	Average Per Participant Other Utility Costs Year 4	$7
20	Average Per Participant Other Utility Costs Year 5	$6
21	Average Per Participant Total Utility Costs Year 1	$349
22	Average Per Participant Total Utility Costs Year 2	$159
23	Average Per Participant Total Utility Costs Year 3	$113
24	Average Per Participant Total Utility Costs Year 4	$90
25	Average Per Participant Total Utility Costs Year 5	$77

Attachment E
Program Costs per kW

Bring Your Own Thermostat / EnergyWise® Home		
1	Cumulative Winter Coincident kW w/ losses (net free) Year 1	1,189
2	Cumulative Winter Coincident kW w/ losses (net free) Year 2	2,469
3	Cumulative Winter Coincident kW w/ losses (net free) Year 3	3,661
4	Cumulative Winter Coincident kW w/ losses (net free) Year 4	4,793
5	Cumulative Winter Coincident kW w/ losses (net free) Year 5	5,861
6	Cumulative Summer Coincident kW w/ losses (net free) Year 1	35,963
7	Cumulative Summer Coincident kW w/ losses (net free) Year 2	78,576
8	Cumulative Summer Coincident kW w/ losses (net free) Year 3	117,658
9	Cumulative Summer Coincident kW w/ losses (net free) Year 4	154,242
10	Cumulative Summer Coincident kW w/ losses (net free) Year 5	191,358
11	EM&V Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 1	$8
12	EM&V Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 2	$4
13	EM&V Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 3	$3
14	EM&V Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 4	$3
15	EM&V Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 5	$2
16	Implementation Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 1	$162
17	Implementation Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 2	$72
18	Implementation Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 3	$46
19	Implementation Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 4	$34
20	Implementation Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 5	$27
21	Incentives / Cumulative Summer Coincident kW w/ losses (net free) Year 1	$32
22	Incentives / Cumulative Summer Coincident kW w/ losses (net free) Year 2	$22
23	Incentives / Cumulative Summer Coincident kW w/ losses (net free) Year 3	$22
24	Incentives / Cumulative Summer Coincident kW w/ losses (net free) Year 4	$20
25	Incentives / Cumulative Summer Coincident kW w/ losses (net free) Year 5	$20
26	Other Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 1	$11
27	Other Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 2	$6
28	Other Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 3	$5
29	Other Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 4	$5
30	Other Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 5	$4
31	Total Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 1	$213
32	Total Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 2	$104
33	Total Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 3	$76
34	Total Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 4	$61
35	Total Utility Costs / Cumulative Summer Coincident kW w/ losses (net free) Year 5	$54

Attachment F

Program Costs per kWh

Bring Your Own Thermostat / EnergyWise® Home		
1	Cumulative kWh w/ losses (net free) Year 1	0
2	Cumulative kWh w/ losses (net free) Year 2	0
3	Cumulative kWh w/ losses (net free) Year 3	0
4	Cumulative kWh w/ losses (net free) Year 4	0
5	Cumulative kWh w/ losses (net free) Year 5	0
6	EM&V Costs / Cumulative kWh w/ losses (net free) Year 1	N/A
7	EM&V Costs / Cumulative kWh w/ losses (net free) Year 2	N/A
8	EM&V Costs / Cumulative kWh w/ losses (net free) Year 3	N/A
9	EM&V Costs / Cumulative kWh w/ losses (net free) Year 4	N/A
10	EM&V Costs / Cumulative kWh w/ losses (net free) Year 5	N/A
11	Implementation Costs / Cumulative kWh w/ losses (net free) Year 1	N/A
12	Implementation Costs / Cumulative kWh w/ losses (net free) Year 2	N/A
13	Implementation Costs / Cumulative kWh w/ losses (net free) Year 3	N/A
14	Implementation Costs / Cumulative kWh w/ losses (net free) Year 4	N/A
15	Implementation Costs / Cumulative kWh w/ losses (net free) Year 5	N/A
16	Incentives / Cumulative kWh w/ losses (net free) Year 1	N/A
17	Incentives / Cumulative kWh w/ losses (net free) Year 2	N/A
18	Incentives / Cumulative kWh w/ losses (net free) Year 3	N/A
19	Incentives / Cumulative kWh w/ losses (net free) Year 4	N/A
20	Incentives / Cumulative kWh w/ losses (net free) Year 5	N/A
21	Other Utility Costs / Cumulative kWh w/ losses (net free) Year 1	N/A
22	Other Utility Costs / Cumulative kWh w/ losses (net free) Year 2	N/A
23	Other Utility Costs / Cumulative kWh w/ losses (net free) Year 3	N/A
24	Other Utility Costs / Cumulative kWh w/ losses (net free) Year 4	N/A
25	Other Utility Costs / Cumulative kWh w/ losses (net free) Year 5	N/A
26	Total Utility Costs / Cumulative kWh w/ losses (net free) Year 1	N/A
27	Total Utility Costs / Cumulative kWh w/ losses (net free) Year 2	N/A
28	Total Utility Costs / Cumulative kWh w/ losses (net free) Year 3	N/A
29	Total Utility Costs / Cumulative kWh w/ losses (net free) Year 4	N/A
30	Total Utility Costs / Cumulative kWh w/ losses (net free) Year 5	N/A

Duke Energy Progress, LLC RP-7
(North Carolina Only)

RESIDENTIAL SERVICE - LOAD CONTROL
RIDER LC-SUM-5

AVAILABILITY

This Rider is available in conjunction with all residential service schedules. Participating Customers may choose to employ (1) Company-provided Load Control Device(s) or (2) eligible Customer-owned thermostat(s) to interrupt service to each installed, approved electric central air conditioning unit and/or electric heat pump and to monitor their operation under the provisions of this Rider.

Customers choosing to employ Company-provided Load Control Device(s) contracts for Company or its representative to install and operate the necessary control equipment in a location provided by Customer and suitable to Company in or about the residential dwelling unit. This option is only available where Company has the necessary communications equipment installed and where load control signal can be satisfactorily received at Company's specified location on Customer's residence.

Customers choosing to employ their own eligible thermostat(s), listed on the Company's website, must have the thermostat(s) configured in a manner which allows the Company to remotely communicate and control Customer's equipment.

Company shall be allowed to monitor Customer's load or any part thereof and the operation of controlled appliances, at no charge, to Customer under the provisions of this Rider. To participate in the program, Customer must either own and occupy the residence or occupy and provide Company with owner-consent.

PARTICIPATION INCENTIVES

Customer shall receive an Initial Incentive Payment following the successful installation and testing of the Load Control Device(s). Following each twelve months of continuous participation on the program Customer shall receive an additional Annual Incentive. Customer leaving the program may return anytime to the program, but shall not receive the Initial Incentive Payment and must complete a twelve-month continuous participation on the program to receive an additional Annual Incentive.

REFERRAL INCENTIVE

A participating Customer shall receive a $25 Incentive for each new program participant that provides a referral code and successfully enrolls in either Rider LC-WIN or Rider LC-SUM, or both. Successful enrollment shall include installation of the necessary control equipment in or about the new Customer's residential dwelling unit, to interrupt service to each installed, approved electric central air conditioning unit and/or electric heat pump. The maximum referral Incentive available to any participating Customer shall not exceed $100 (or four referrals) per calendar year. The participating Customer will be provided the referral Incentive within 30 days of successful installation at the new Customer's premise. Company will verify and track referrals by unique referral codes provided to participating Customers. New Customers will be required to provide a referral code at the time of enrollment.

PAYMENT OF INCENTIVES

The Company's payment of Incentives may be offered in a variety of ways, including, but not limited to, bill credits, checks, and prepaid credit cards as follows:

- Initial Incentive for Company-provided Load Control Device(s) - $25 per residence
- Initial Incentive for Customer-provided eligible Thermostat(s) - $75 per residence

- Annual Incentive for Company-provided Load Control Device(s) - $25 per residence
- Annual Incentive for Customer-provided eligible Thermostat(s) - $25 per residence

APPROVED CENTRAL AIR CONDITIONING UNIT

An approved electric central air conditioning and/or electric heat pump unit is a central electric air conditioning unit used to cool the residence through a ducted system. All central air conditioning and/or electric heat pump units installed at the residence must participate in load control in order to receive the Annual Incentive.

INTERRUPTION

Company shall be allowed, at its discretion, to interrupt service to each air conditioner for up to four hours during each day of the summer control season months of May through September. Company reserves the right for longer interruption in the event continuity of service is threatened. Air conditioner interruptions shall be limited to a total of 60 hours during any one summer season. The Company reserves the right to test the load control equipment at any time, and such test periods shall be counted towards the maximum hourly interruption limit. Customer shall have the option to override an air conditioner based control event; however, if Customer exceeds two (2) control event overrides in a single control season of May through September, Customer may be subject to removal from the program and shall forfeit the next subsequent Annual Incentive for that controlled device. A control event override is defined as Customer requesting exemption from part or whole of the interruption time period. If Company is unable to communicate with Customer's thermostat(s) during a load control event, it will be counted as a control event override.

EQUIPMENT INSPECTION AND SERVICING

Company or its agents shall have the right of ingress and egress to Customer's premises at all reasonable hours for the purpose of inspecting Company's wiring and apparatus; changing, exchanging, or repairing its property, as necessary; or removing its property after termination of service. Company and Customer shall schedule a convenient time for such purposes whenever it is necessary to service Company's equipment installed inside the residence. If any tampering with Company-owned equipment occurs, Company may adjust the billing and take other action in accordance with the Rules and Regulations of the North Carolina Utilities Commission and the laws of the State of North Carolina as applicable to meter tampering.

CONTRACT PERIOD

The Contract Period shall not be less than one year. Customer or Company may terminate participation under the Rider by providing 30 days prior notice to the other party. If within the first year, the Customer wishes to discontinue participation in this Program, the Customers using Company provided Load Control Device(s) will pay a $25 service charge and Customers who have received initial thermostat based incentive will pay a $75 service charge. Upon termination, the load control device(s), at Customer's residence will be remotely disabled to prevent further load control.

SALES TAX

To the above charges will be added any applicable North Carolina Sales Tax.

COMPANY RETENTION OF PROGRAM BENEFITS

Incentives and other considerations offered under the terms of this Program are understood to be an essential element in the recipient's decision to participate in the Program. Upon payment of these considerations, Company will be entitled to any and all environmental, energy efficiency, and demand reduction benefits and attributes, including all reporting and compliance rights, associated with participation in the Program.

Supersedes LC-SUM-3B
Effective for service rendered on and after
NCUC Docket No. E-2, Sub 927