PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, September 18, 2018

TIME: 9:47 a.m. - 10:00 a.m.

DOCKET NO: E-2, Sub 1174

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding
Chairman Edward S. Finley, Jr.
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter
Commissioner Charlotte A. Mitchell

IN THE MATTER OF:

Application of Duke Energy Progress, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69.

VOLUME: 1

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P R O C E E D I N G S

COMMISSIONER BROWN-BLAND: Good morning again. Let's come to order and proceed with Docket Number E-2, Sub 1174. I'm Commissioner ToNola D. Brown-Bland with the North Carolina Utilities Commission, the presiding Commissioner for this hearing. With me this morning are Chairman Edward S. Finley, Jr.; Commissioners Jerry C. Dockham, James G. Patterson, Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell.

I now call for hearing Docket Number E-2, Sub 1174, In the Matter of Application by Duke Energy Progress, LLC, hereafter DEP, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69.

On June 20, 2018, DEP filed its annual application for approval of its Demand-Side Management, hereafter DSM, and Energy Efficiency, hereafter EE, Cost Recovery Rider. Filed with the application were the direct testimony, exhibits and workpapers of witnesses Robert P. Evans and Carolyn T. Miller.

On July 2, 2018, the Commission issued an

Order Scheduling Hearing, Establishing Discovery Guidelines and Requiring Public Notice. The Order set the hearing in this docket for today, Tuesday, September 18, 2018, following the hearing in Docket E-2, Sub 1175.

The Commission granted Petitions to Intervene timely filed by North Carolina Sustainable Energy Association, Carolina Industrial Group for Fair Utility Rates II, and Carolina Utility Customers Association, Inc.

The Commission also granted the joint Petition to Intervene filed by North Carolina Justice Center, Southern Alliance for Clean Energy and, Natural Resources Defense Council, and the North Carolina Housing Coalition, collectively, hereafter referred to as North Carolina Justice Center.

The Public Staff's participation is recognized pursuant to G.S. 62-15.

On September 4, 2018, the Public Staff filed the testimony and exhibits of Michael C. Maness, David M. Williamson and John R. Hinton.

On September 5, 2018, the North Carolina Justice Center filed the testimony and exhibits of Chris Neme.

On September 10, 2018, DEP filed the supplemental testimony of Carolyn T. Miller and Robert P. Evans.

On September 10, 2018, DEP filed a Motion for Additional Public Hearing and Public Notice of Revised Proposed Rates, which was granted by Order dated September 11, 2018. That Order Scheduled an Additional Public Hearing to be held in this docket on Monday, October 8, 2018.

On September 12, 2018, the North Carolina Justice Center filed a Motion requesting that Witness Neme be excused from attending the hearing and his prefiled testimony be received into evidence at this hearing.

On September 13, 2018, DEP filed Affidavits of Publication of notice of today's hearing in this docket. Also, on September 13th, DEP and the Public Staff filed a joint Motion requesting their witnesses be excused and their prefiled testimony be entered into evidence at this hearing. The Motion was granted by Order entered on the same day.

In compliance with the requirements of Chapter 138A of the State Government Ethics Act, I remind members of the Commission of our responsibility to avoid conflicts of interest, and inquire at this time whether any member has a known conflict of interest with respect to the matter before us this morning?

(No response)

Let the record reflect that I have no such conflict and my fellow Commissioners have not identified any such conflict.

I now call for appearances of counsel, beginning with the Applicant, DEP.

MS. FENTRESS: Good morning, Madam Chair and Members of the Commission. I'm Kendrick Fentress appearing on behalf of Duke Energy Progress.

COMMISSIONER BROWN-BLAND: Good morning.

MS. WARREN: Good morning. Warren Hicks appearing on behalf of the Carolina Industrial Group for Fair Utility Rates.

COMMISSIONER BROWN-BLAND: Good morning, Ms. Hicks.

MR. PAGE: Good morning. Robert Page appearing on behalf of Carolina Utility Customers Association, Inc.

COMMISSIONER BROWN-BLAND: Good morning.

MR. NEAL: Good morning. David Neal with

the Southern Environmental Law Center appearing on behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, and Natural Resources Council.

COMMISSIONER BROWN-BLAND: Good morning.

MS. EDMONDSON: Good morning. Lucy Edmondson with the Public Staff, and Heather Fennell appearing on behalf of the Using and Consuming Public.

COMMISSIONER BROWN-BLAND: All right. Good to have all of you with us. And, Ms. Edmondson, have you identified any public witnesses?

MR. SMITH: Commissioner, I'm sorry.

COMMISSIONER BROWN-BLAND: Oops! I'm sorry.

MR. SMITH: I'm hiding back here.

COMMISSIONER BROWN-BLAND: I forget you're not at the table over there.

MR. SMITH: I know it. Ben Smith on behalf of North Carolina Sustainable Energy Association.

COMMISSIONER BROWN-BLAND: Good morning, Mr. Smith. You're welcome despite my quickness there.

Ms. Edmondson, have you identified any public witnesses who wish to give testimony?

MS. EDMONDSON: I have not.

COMMISSIONER BROWN-BLAND: All right. Just to be clear, if there's anyone out in the audience who wishes to provide public witness testimony come forth now. And the record will reflect that no one came forward.

Is there anything else that we need to take up before we move on to the Applicant?

MS. EDMONDSON: Presiding Commissioner, I wanted to note, yesterday the Public Staff filed the supplemental testimony and Exhibit 2 of Michael C. Maness.

COMMISSIONER BROWN-BLAND: All right.

MS. EDMONDSON: It put into -- it was where Mr. Maness, he had in his initial testimony, he'd said once the Company filed its supplemental testimony he would file rates that showed the impact of the Public Staff's adjustments as well as the Company's adjustments, and so it's five pages and an Exhibit 2. All parties have agreed to waive cross examination of him on the supplemental testimony.

COMMISSIONER BROWN-BLAND: All right. And, Ms. Edmondson, with that filing of that testimony, then outside of the public hearing, the evidentiary record can be closed; is that correct?

MS. EDMONDSON: Yes.

COMMISSIONER BROWN-BLAND: Thank you. I'll hear from the Applicant.

MS. FENTRESS: Thank you. Madam Chair, as you have indicated the parties, and as Ms. Edmondson has indicated, the parties have agreed to waive cross examination of all the witnesses who have prefiled testimony in this docket and have asked that their prefiled testimony be entered into the record as if given orally from the stand, and that their exhibits which have been premarked also be entered into evidence. With that, I will begin by entering the testimony of Carolyn Miller into the record. I would move that Carolyn Miller's direct testimony filed June 20, 2018, consisting of 18 pages be entered into the record as if given orally from the stand, and that the six exhibits attached to her direct testimony be admitted into evidence. I would also move that Carolyn Miller's supplemental testimony filed September 10, 2018, consisting of nine pages be entered into the record as if given orally from the stand, and that Supplemental Miller Exhibits 1, 2, 3 and 7 be admitted as evidence.

COMMISSIONER BROWN-BLAND: All right. There being no objection, that motion will be allowed and the exhibits that were filed with the prefiled testimony will be marked as they were when filed and received into evidence noting, in particular, on the supplemental testimony of Carolyn T. Miller the exhibits admitted are 1, 2, 3 and 7.

MS. FENTRESS: Yes.

(WHEREUPON, Miller Exhibits 1 - 6 are admitted into evidence.)

(WHEREUPON, the prefiled direct testimony of CAROLYN T. MILLER is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1174

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Carolyn T. Miller, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Manager, Rates & Regulatory Strategy for Duke Energy Corporation ("Duke Energy"), supporting both Duke Energy Progress, LLC ("DEP" or the "Company") and Duke Energy Carolinas, LLC ("DEC").

Q. PLEASE BRIEFLY STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from the College of New Jersey in Trenton, New Jersey with a Bachelor of Science in Accountancy. I am a certified public accountant licensed in the State of North Carolina. I began my career in 1994 with Ernst & Young as a staff auditor. In 1997, I began working with Duke Energy as a senior business analyst and have held a variety of positions in the Finance organization. I joined the Rates Department in 2014 as Manager, Rates and Regulatory Strategy.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN MATTERS BROUGHT BEFORE THIS COMMISSION?

A. Yes. I provided testimony in support of DEC's applications for approval of its demand-side management ("DSM") and energy efficiency ("EE") cost recovery rider in Docket No. E-7, Subs 1073, 1105, 1130, and 1164, as well as

DEP's application for approval of its DSM/EE cost recovery rider in Docket No. E-2, Subs 1070, 1108, and 1145.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. I am responsible for providing regulatory support for retail rates and providing guidance on DEP's DSM/EE cost recovery process.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain and support DEP's proposed DSM/EE cost recovery rider and Experience Modification Factor ("EMF") and provide information required by Commission Rule R8-69.

Q. PLEASE DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. Miller Exhibit 1 provides a summary of the proposed annual rates by customer class. Miller Exhibit 2, pages 1 through 3, shows the calculation of the DSM and EE rates for the rate period, as well as the breakdown by program of the various components of the estimated revenue requirement. Miller Exhibit 2, pages 4 through 6, presents the calculation of the DSM EMF and EE EMF rates for the test period, as well as the breakdown by program of the various components of the final revenue requirement. Adjustments resulting from Evaluation, Measurement and Verification ("EM&V") of the Company's DSM/EE programs are also presented in Miller Exhibit 2, page 7. Miller Exhibit 3, pages 1 through 4, calculates the amount of interest or return due on over- and under-collections for Vintage 2017. Miller Exhibit 4 shows a summary of revenue collected during calendar year 2017 by program type and customer class. Miller Exhibit 5, pages 1 through 7, presents the allocation factors used in the development of the rider, including the energy allocation factors applicable to DSM and EE program costs, the North Carolina and South Carolina retail allocation factors, and the lighting allocation factors. Miller Exhibit 6 includes both forecasted 2019 sales from the Spring 2018 forecast and the impact of opt-outs.

Q. WERE MILLER EXHIBITS 1-6 PREPARED BY YOU OR AT YOUR DIRECTION AND SUPERVISION?

A. Yes.

II. SUMMARY OF DSM/EE COSTS

Q. CAN YOU PROVIDE A SUMMARY OF THE COSTS FOR WHICH DEP IS REQUESTING RECOVERY IN THIS PROCEEDING?

A. Yes. The DSM/EE costs DEP is requesting to recover through the rates proposed in this proceeding are associated with the costs incurred during the test period, as well as the costs forecasted to be incurred during the rate period. The test period utilized in the development of the DSM/EE EMF is January 1, 2017 through December 31, 2017. The North Carolina allocated share of recoverable DSM/EE costs for the test period is $180,805,498. For the rate period of January 1, 2019 through December 31, 2019, the North Carolina allocated share of forecasted DSM/EE costs is $173,203,629. The total North Carolina allocated share of DSM/EE costs for the test period plus the rate period is $354,009,127.

A summary of the costs associated with DEP's recovery request by period and by DSM/EE program/measure is provided in the following table:

Program/Measure	Test Period 1/1/17 through 12/31/17	Rate Period 1/1/19 through 12/31/19
CIG DR	$1,488,540	$3,052,617
EnergyWise	$15,769,318	$17,723,656
EnergyWise for Business	$1,185,120	$2,059,581
DSDR Implementation	$25,490,210	$23,699,090
Residential Home Advantage	$176,476	$168,458
Home Energy Improvement	$7,113,193	$4,278,348
Residential Low Income – NES	$1,738,167	$1,798,481
CIG EE/EE For Business	$33,588,505	$7,241,363
Energy Efficient Lighting	$26,695,371	$20,644,474
Appliance Recycling	$520,771	$120,467
My Home Energy Report	$11,557,818	$13,647,883
Small Business Energy Saver	$15,215,157	$15,279,529
Residential New Construction	$11,650,143	$12,937,198
Multi-Family EE	$4,617,270	$4,309,031
Energy Education Program for Schools	$1,018,817	$878,941
Save Energy & Water Kit	$3,186,004	$6,355,307
Residential Energy Assessments	$2,009,382	$1,576,899
Business Energy Report	$17,193	$0
Smart $aver Prescriptive	N/A	$16,943,719
Smart $aver Custom	N/A	$1,923,951
Smart $aver Performance Incentive	$16,146	$267,143
Administrative & General Costs	$3,488,434	$4,338,927
Carrying Cost on Balances	$14,449,660	$14,289,019
Found Revenue (total)	$(186,197)	$(330,453)
Total Cost	$180,805,498	$173,203,629

In addition to the summary table above, Miller Exhibit 2, page 3, and Miller Exhibit 2, page 6, provide additional categorizations by cost element.

Q. ARE DEP'S PROPOSED RATES DESIGNED TO RECOVER THE TOTAL NORTH CAROLINA ALLOCATED SHARE OF $354,009,127?

A. No. Because many of the expenses incurred during the current test period to develop and implement DEP's DSM/EE programs produce benefits covering several years, a significant portion of those expenses will be deferred and recovered over varying amortization periods. A summary of the amortization periods for program expenses and Program/Portfolio Performance Incentive ("PPI")[1] is shown below:

Length of Amortization Period				
Program Name	Program Cost – batches prior to 2016	Program Cost – 2016 - present	PPI – vintages prior to 2016	PPI – 2016 - present
CIG DR	10	3	10	3
EnergyWise	10	10	10	10
EnergyWise for Business	N/A	3	N/A	3
DSDR Implementation	10	10	10	10
Residential Home Advantage	10	N/A	10	N/A
Home Energy Improvement	10	10	10	10
Residential Low Income - NES	10	10	10	10
Energy Efficient Lighting	5	5	10	5
Appliance Recycling	10	10	10	10
My Home Energy Report	1	1	1	1
Residential New Construction	10	10	10	10
CFL Pilot	10	N/A	10	N/A
Solar Hot Water Pilot	10	N/A	10	N/A
Multi-Family EE	5	5	5	5
Energy Education	5	5	5	5
CIG EE	10	3	10	3
Save Water & Energy Kit	N/A	5	N/A	5
Residential Energy Assessments	N/A	5	N/A	5
Small Business Energy $aver	10	3	10	3
Smart $aver Prescriptive	3	3	3	3
Smart $aver Custom	3	3	3	3

[1] As explained further below, for vintages prior to 2016, incentives are calculated on a program basis. Pursuant to the Commission's *Order Approving Revised Cost Recovery Mechanism and Granting Waivers* issued January 20, 2015 in Docket No. E-2, Sub 931 ("Order Approving Revised Mechanism"), which applies to Vintages 2016 and forward, incentives under the Company's revised cost recovery mechanism are calculated on a portfolio basis. For ease of reference, I will refer to both incentives as "PPI."

Business Energy Report	3	3	1	1
Admin. & General	3	3	3	3

In addition to the aforementioned deferrals, DEP's proposed rates include the recognition and amortization of prior period deferrals. In total, the EMF-related calculations based on test period costs reflect an estimated under-recovery of $10,783,557. The DSM/EE rate calculations associated with rate period estimates are based on a revenue requirement of $176,171,947. The rate period and EMF revenue requirements produce a combined revenue requirement of $186,955,504. Miller Exhibit 2, page 3, and Miller Exhibit 2, pages 4 and 5, detail the calculation of these amounts.

III. EMF REVENUE REQUIREMENT

Q. HOW WAS THE DSM/EE EMF UNDER-RECOVERY OF $10,783,557 DETERMINED?

A. The EMF under-recovery is a function of the sum of test period costs, including amounts relating to the amortization of deferred costs from prior periods, and credits for actual DSM/EE rider revenues for the period January 1, 2017 through December 31, 2017. The following table illustrates the relationship of these elements with respect to the determination of the DSM/EE EMF:

Rate Element	Amounts
Test Period Revenue Requirement	$168,088,803
Net DSM/EE Rate Revenue	$155,003,924
Add: Other Adjustments	$2,301,322
Total EMF Adjustments	$157,305,246
Adjusted DSM/EE EMF Revenue Requirement	$10,783,557

Miller Exhibit 2, pages 4 through 7, provides additional details associated with the development of these amounts.

Q. PLEASE DESCRIBE THE $2,301,322 THAT HAS BEEN CATEGORIZED AS "OTHER ADJUSTMENTS."

A. The $2,301,322 in "Other Adjustments" is the sum of lines 2 through 8 on page 7 of Miller Exhibit 2. Lines 2 and 3 are reserved for prospective uncollectible allowances in DEP's DSM/EE rates. DEP is not requesting an uncollectible adjustment as a part of its cost recovery request in this proceeding. In addition, the adjustments found on lines 4 through 7 reflect the true-up of PPI and net lost revenues for the 2015 and 2016 vintages. The last of these adjustments, found on line 8, recognizes estimated interest owed and return earned for revenue over- and under-collections during the period extending from January 1, 2017 through December 31, 2017. The Direct Testimony of Company witness Robert P. Evans provides further detail on program-specific impacts to PPI and net lost revenues.

IV. RATE PERIOD REVENUE REQUIREMENT

Q. PLEASE DESCRIBE THE BASIS FOR THE RATE PERIOD REVENUE REQUIREMENT.

A. As indicated previously, the estimated revenue requirement for the rate period is $176,171,947. This amount reflects the anticipated costs and necessary recoveries for the rate period, which extends from January 1, 2019 through December 31, 2019. The $176,171,947 revenue requirement includes: (1) $22,722,598 for anticipated rate period program expenses; (2) amortizations and carrying costs associated with deferred prior period costs totaling $77,083,142; (3) recovery of Distribution System Demand Response ("DSDR") depreciation and capital costs totaling $18,019,811; (4) net lost revenues for the rate period totaling $32,348,840 for vintage years 2017 through 2019; and (5) PPI totaling $25,997,556 associated with vintage years 2010 through 2019.

V. JURISDICTIONAL COST ALLOCATION

Q. HOW ARE DSM AND EE PROGRAM COSTS ALLOCATED TO THE NORTH CAROLINA RETAIL JURISDICTION?

A. DEP determines the total amount of recoverable costs and separates these costs into three categories: (1) DSM-related costs, (2) EE-related costs, and (3) costs that provide a system benefit in support of both DSM and EE programs. For each of these categories, different allocation methods are employed to assign those costs to the appropriate jurisdiction.

Q. HOW ARE COSTS IDENTIFIED AS EE-RELATED ALLOCATED TO NORTH CAROLINA?

A. Any program costs that are identified as being EE-related, including administrative and general ("A&G") costs, are allocated to the North Carolina retail jurisdiction based upon the ratio of North Carolina retail sales to DEP system retail sales at the point of generation. For calendar year test periods beginning in year 2016, the allocation percentage for the entire calendar year test period is based on the latest cost of service study available at the time of filing.

Q. HOW ARE DSM-RELATED COSTS ALLOCATED TO NORTH CAROLINA?

A. Any program costs that are identified as being DSM-related, including A&G costs, are allocated to the North Carolina retail jurisdiction based upon the ratio of the North Carolina retail demand to the DEP system retail demand at the hour of the annual summer system peak. For calendar year test periods beginning in year 2016, the allocation percentage for the entire calendar year test period is based on the latest cost of service study available at the time of filing.

Q. PLEASE ELABORATE ON THE METHODOLOGY USED TO ALLOCATE DSM/EE COSTS THAT OFFER A SYSTEM BENEFIT.

A. Certain A&G costs provide a system benefit in support of both DSM and EE programs and, therefore, are allocated in both categories. The allocation of these costs into either the DSM or EE category is based upon the percentage of program costs for each type of expenditure anticipated during the next forecast calendar year. For example, if 30% of direct program costs in the forecast period are EE-related, then 30% of these A&G costs will be considered EE-related costs for allocation purposes. The use of a forecast period recognizes the types of new programs DEP will offer in the immediate future that will be supported by these administrative costs. The assignment of A&G costs as either DSM- or EE-related is reviewed annually based upon forecasted program costs for the next calendar year. The A&G costs in this proceeding have been assigned to these categories based upon forecasted DSM and EE costs for 2019.

Q. IN MILLER EXHIBIT 2, PAGE 3, AND MILLER EXHIBIT 2, PAGE 6, THE DSDR PROGRAM IS SEPARATED FROM THE OTHER DSM/EE PROGRAMS. HOW IS THE DSDR PROGRAM CLASSIFIED?

A. The DSDR program has been classified by the Commission, for purposes of ratemaking, as an EE program. Due to the scope and nature of DSDR, its costs are being tracked separately. This separate tracking includes both direct costs and A&G costs associated with the program.

VI. PORTFOLIO PERFORMANCE INCENTIVE AND NET LOST REVENUES

Q. HOW IS THE PPI CALCULATED?

A. The PPI is calculated pursuant to the Order Approving Revised Mechanism and is based on the savings achieved by the portfolio of PPI-eligible DSM/EE programs. Under the terms of the Order Approving Revised Mechanism, the amount of PPI to be recovered during the rate period is 11.75 percent of the net benefits produced by the portfolio of PPI-eligible programs. Estimated net savings for all periods are determined by multiplying the number of measurement units projected to be installed for a specific program or measure in a vintage year by the most current estimate of the annual per installation kilowatt ("kW") and kilowatt-hour ("kWh") savings over the measurement unit's life and by the annual kW and kWh avoided costs. DEP then subtracts the estimated utility costs over the measurement unit's life related to the projected installations in that vintage year and discounts the result to determine a net present value.

The PPI for each program vintage is converted into a stream of up to ten levelized annual payments. DEP's overall weighted average net-of-tax rate of return approved in DEP's most recent general rate case is used as the appropriate discount rate. Pursuant to the Order Approving Revised Mechanism, PPI recoveries are subject to true-up on the basis of future EM&V results. PPI calculations are based on calendar year vintages. The PPI vintage assigned to the test period in this filing encompasses calendar year 2017. These values will be trued-up on the basis of future EM&V results. The estimated PPI for the rate period used in this filing is based on calendar year 2019 and will be trued-up as a part of DEP's 2020 DSM/EE cost recovery proceeding. Please see Evans Exhibit 1 for additional detail by program.

Q. HOW WERE NET LOST REVENUES DETERMINED?

A. The Company determines net lost revenues, which are applicable to both DSM and EE programs, by multiplying the estimated reduction in kWh sales associated with a program or measure by a margin-based net lost revenue rate. The following formula illustrates the basic components of the net lost revenue calculations: Net Lost Revenues ($) = Lost Sales (kWh) x Net Lost Revenue Rate ($/kWh).

Lost Sales are those sales that do not occur as a result of implementation of DEP DSM/EE measures. These values are initially based on engineering estimates and/or past impact evaluations. Future periods are based on updated impact evaluations resulting from EM&V activities and are applied prospectively and in conjunction with applicable net lost revenue true-ups. The net lost revenue rate represents the difference between the average retail rate applicable to the customer class impacted by the measure and the sum of (1) the embedded regulatory fees, (2) the related average customer charge component of that rate, (3) the average fuel component of the rate, and (4) the incremental variable operations and maintenance (O&M) rate as filed in DEP's last Cogeneration and Small Power Producer tariff. When multiple customer classes are impacted by a DSM/EE measure, as with the DSDR program, a weighted or system-wide net lost revenue rate is employed.

Pursuant to the Order Approving Revised Mechanism, DEP may only recover net lost revenues for up to 36 months of an installed measure's life, and as with the PPI, recoveries are subject to true-up on the basis of future EM&V results.

VII. COST ALLOCATION METHODOLOGY

Q. HOW ARE DSM- AND EE-RELATED COSTS ALLOCATED TO EACH RATE CLASS?

A. Costs are assigned to customer classes based on program design and participation. In other words, residential program costs are allocated solely to residential customers, general service program costs are allocated solely to general service customers, and lighting program costs are allocated solely to lighting customers. Where programs benefit multiple customer groups, the costs are allocated directly to groups receiving benefits or by employing annual energy- and/or coincident peak demand-based allocation factors.

Miller Exhibit 2, pages 1 and 2, and Miller Exhibit 2, pages 4 and 5, demonstrate the manner in which the costs associated with a specific program have been assigned to customer groups.

Q. HOW ARE SALES AND DEMAND ADJUSTED FOR THE IMPACT OF OPT-OUT CUSTOMERS?

A. Commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers who implement or will implement alternative DSM/EE measures may elect not to participate in DEP's DSM and/or EE programs. DEP reviewed its customer records and identified that commercial and industrial customers choosing to opt out of EE programs consumed 11,445,011,475 kWh during the year ended December 31, 2017. In addition, DEP identified that commercial and industrial customers choosing to opt out of DSM programs consumed 11,560,314,862 kWh during the year ended December 31, 2017.

DEP developed rate class allocation factors based on the assumption that customers that have elected to opt out of the Company's DSM/EE rider will remain opted out. If customers decide to change their opt-out status, revenue gains or losses will be recognized in subsequent DSM/EE EMF calculations.

Sales for the year ended December 31, 2017 for all customers electing to opt out of the DSM/EE rate are provided in Miller Exhibit 6.

Q. THE SALES FOR OPT-OUT CUSTOMERS ARE EASILY IDENTIFIED, BUT HOW IS THE COINCIDENT PEAK OF THESE CUSTOMERS ESTIMATED?

A. Currently installed metering for a great number of opt-out customers does not provide sufficient detail to determine their contribution to the system coincident peak hour load. Instead, the impact is estimated based upon the ratio of opt-out sales to total sales for the rate class multiplied by the rate class peak demand. This approach should accurately approximate the demand of opt-out accounts.

Q. AFTER ADJUSTING ENERGY AND DEMAND FOR OPT-OUT CUSTOMERS, HOW ARE THE RESULTING ALLOCATION FACTORS THEN USED TO DETERMINE THE REVENUE REQUIREMENT FOR EACH RATE CLASS?

A. Energy- and demand-based allocators are used in cases where programs or measures directly benefit multiple rate groups. When a DSM or EE program benefits multiple rate groups, DEP multiplies EE costs by rate class energy allocation factors and multiplies any associated DSM costs by rate class demand allocation factors for purposes of cost assignment.

Since usage for opt-out customers is not forecasted, the rate class energy allocation factors were developed from the forecasted rate class usage after subtracting actual sales for opt-out customers for the year ended December 31, 2017. Miller Exhibit 5, page 5, provides the energy allocation factors applicable to each rate class based upon the forecast of rate class sales for the rate period of January 1, 2019 through December 31, 2019.

The allocation rate class demand allocation factors are based on the summer coincident peak demand for 2017 after subtracting the estimated demand for opt-out customers as discussed above. The forecast does not provide rate class coincident peak demands; therefore, the most recent historic data was deemed to be representative of future demand impacts. Miller Exhibit 5, page 6, shows the demand allocation factors applicable to each rate class for the rate period.

Q. WHICH OF DEP'S PROGRAMS OR MEASURES BENEFIT MULTIPLE CUSTOMER CLASSES?

A. The Company's DSDR program benefits all customer classes. To allocate DSDR costs, DEP employs rate class energy allocation factors. These allocation procedures are elements of Miller Exhibit 2, pages 1 and 4. In addition, DEP's Energy Efficient Lighting Program provides benefits to both the residential and general service customer classes. These costs were allocated on the basis of bulbs provided to those classes using EM&V results as shown in Miller Exhibit 5, page 7.

Q. HOW DOES DEP DETERMINE RATE CLASS DSM/EE RATES?

A. The calculated rate class DSM and EE revenue requirements are divided by forecasted rate class sales, after adjustment for opt-out customers, to establish the rate class DSM/EE rate. Miller Exhibit 2, page 1, provides the derivation of the EE rate. Miller Exhibit 2, page 2, provides the derivation of the DSM rate.

Q. HOW DOES DEP DETERMINE RATES FOR THE DSM/EE EMF?

A. As with DSM/EE rate determination, the calculated rate class DSM and EE EMF revenue requirements, adjusted for cost recoveries, are divided by forecasted rate class sales, after adjustment for opt-out customers, to establish the rate class DSM/EE EMF rate. Miller Exhibit 2, page 4, provides the derivation of the EE EMF rate. Miller Exhibit 2, page 5, provides the derivation of the DSM EMF rate.

VIII. PROPOSED RATES

Q. WHAT RATES ARE PROPOSED FOR EACH RATE CLASS?

A. Miller Exhibit 1 is populated with the DSM/EE rates and EMF rates proposed in this proceeding. The DSM/EE rates recover costs forecasted to be incurred from January 1, 2019 through December 31, 2019. The DSM/EE EMF is a true-up mechanism recognizing costs and recoveries for the test period of January 1, 2017 through December 31, 2017. DEP proposes the following rates, exclusive of North Carolina regulatory fees, for each rate class:

Rate Class	DSM Rate (¢/kWh)	EE Rate (¢/kWh)	DSM EMF (¢/kWh)	EE EMF Rate (¢/kWh)	DSM/EE Annual Rider (¢/kWh)
Residential	0.120	0.530	0.009	(0.006)	0.653
General Service EE		0.684		0.122	0.806
General Service DSM	0.062		(0.018)		0.044
Lighting		0.099		0.001	0.100

Q. WHAT ARE THE RATES INCLUDING NORTH CAROLINA REGULATORY FEES?

A. The following table reflects the proposed billing rates, including North Carolina regulatory fees, for each rate class:

Rate Class	DSM Rate (¢/kWh)	EE Rate (¢/kWh)	DSM EMF (¢/kWh)	EE EMF (¢/kWh)	Annual DSM/EE Rider (¢/kWh)
Residential	0.120	0.531	0.009	(0.006)	0.654
General Service EE		0.685		0.122	0.807
General Service DSM	0.062		(0.018)		0.044
Lighting		0.099		0.001	0.100

Q. HOW WILL DEP REVISE ITS TARIFFS TO RECOVER THESE RATES?

A. The Company will update its Annual Billing Adjustment, Rider BA, to recognize these rates, adjusted for the North Carolina regulatory fees.

IX. CONCLUSION

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

A. Yes.

(WHEREUPON, Supplemental Miller Exhibits 1, 2, 3 and 7 are admitted into evidence.)

(WHEREUPON, the prefiled supplemental testimony of CAROLYN T. MILLER is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1174

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am a Rates & Regulatory Strategy Manager for Duke Energy Carolinas, LLC ("DEC"), supporting both DEC and Duke Energy Progress, LLC ("DEP" or the "Company").

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

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my Supplemental Testimony is to support the filing of Supplemental Exhibits which reflect revisions to Miller Exhibits 1, 2, and 3 and Evans Exhibits 1 and 2 filed June 20, 2018 in this proceeding. These revisions are due to the following:

1. Adjustments to the Portfolio Performance Incentive ("PPI") relating to Vintage 2016 and Vintage 2017 of the EnergyWise for Business program;

2. Adjustments to Vintage 2016 and Vintage 2017 lost revenues to align with the final outcome of DEP's most recent general rate case in Docket No. E-2, Sub 1142; and

3. Adjustments to the valuation of Vintage 2017 lost revenues allocated to the non-residential lighting program.

Q. WHY IS THE COMPANY REVISING THE VINTAGE 2016 AND VINTAGE 2017 PPI FOR THE ENERGYWISE FOR BUSINESS PROGRAM?

A. As mentioned in the Testimony of Public Staff Witness Michael C. Maness (*see* p. 21), the Company is recommending an adjustment relating to Evaluation, Measurement, & Verification ("EM&V") results. During the course of the Company's review of its DSM/EE filing in this docket, DEP discovered that, although the EM&V results received in 2017 for the EnergyWise for Business program had been appropriately applied prospectively, these results had not been included in calculation of the filed EMF rate. The Company is updating Vintages 2016 and Vintage 2017 to reflect the revised kW savings included in the EnergyWise for Business EM&V report, which results in a reduction of PPI for non-residential customers in the amount of ($8,468) for Vintage 2016 and a reduction in PPI for non-residential customers in the amount of ($47,721) for Vintage 2017. The Company is revising Evans Exhibit 1, pages 3 through 6 and the corresponding interest calculation on Miller Exhibit 3, page 2 to reflect this adjustment.

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT TO THE LOST REVENUE CALCULATION.

A. During the Public Staff's review of DEP's Application in this docket, the Public Staff and the Company discussed how the Company should determine lost revenue recovered in DEP's most recent general rate case (Docket No. E-

2, Sub 1142) pursuant to Paragraph 58 of DEP's approved DSM/EE cost recovery mechanism. Paragraph 58 reads as follows:

> 58. Notwithstanding the allowance of 36 months' Net Lost Revenues associated with eligible kWh sales reductions, the kWh sales reductions that result from measurement units installed shall cease being eligible for use in calculating Net Lost Revenues as of the effective date of (a) a Commission-approved alternative recovery mechanism that accounts for the eligible Net Lost Revenues associated with eligible kWh sales reductions, or (b) <u>the implementation of new rates approved by the Commission in a general rate case or comparable proceeding to the extent the rates set in the general rate case or comparable proceeding are set to explicitly or implicitly recover the Net Lost Revenues associated with those kWh sales reductions.</u> [Emphasis added].

As Witness Maness noted in his testimony, although the test period in Docket No. E-2, Sub 1142 was January 1, 2016 through December 31, 2016, the Agreement and Stipulation of Partial Settlement agreed to between the Public Staff and the Company in that proceeding included updated revenues that reflected changes in the number of customers and, for the residential class, changes in weather-normalized usage per customer through October 31, 2017.

The Public Staff and the Company discussed the methodology that should be used to incorporate these revenue adjustments from E-2, Sub 1142 into this filing. Based on these discussions, the Company will do the following:

a. For residential customers, the Company will extend the rate case test period to October 31, 2017 as the customer growth adjustment used in the rate case also included updated actual kWh sales through that time period; and

b. For non-residential customers, the Company will continue to utilize the rate case test period January 1, 2016 through December 31, 2016 as no adjustments were made to incorporate actual kWh sales past that date.

In addition, the following modification will be made to calculate how much lost revenue is included in kWh sales for the test period. Since the twelve-month rate case test period uses actual kWh sales, and participation in EE measures occurs throughout the year, in any given twelve-month period, a full year of lost revenues are not captured in test period kWh sales as all measures were not in place at the beginning of the test period. The Company believes it is appropriate to quantify the actual incremental savings by month during that twelve-month rate case test period to calculate the amount of lost revenues that is truly being reflected in the new base rates that will be recovered from customers. The difference between the annualized amount of energy savings and the actual amount of energy savings should be recovered through the Company's DSM/EE rider. Supplemental Miller Exhibit 7 provides an example of this methodology.

This update has been made to Evans Exhibit 2, pages 1 and 2 and impacts Vintage Years 2016 and 2017 for lost revenue recognized in 2018[1] and 2019. The final result of the adjustment for the 2019 rate period is a

[1] Only lost revenues projected to be recognized in 2019 are included in projected rates in this proceeding; as noted by Witness Maness (*see* p. 20), the adjustment for 2018 will be made when Vintage 2018 is trued up in next year's DSM/EE proceeding.

reduction in lost revenue requested for residential customers in the amount of ($1,669,505) and an increase in lost revenue requested for non-residential customers in the amount of $1,361,119.[2] There is no impact to the interest calculation.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO VINTAGE 2017 NON-RESIDENTIAL LIGHTING LOST REVENUES.

A. As mentioned in Witness Maness' testimony (*see* p. 21), the Company is recommending a further adjustment to non-residential lost revenues. During the analysis to determine the appropriate Vintage 2017 lost revenues for non-residential customers, the Company determined that there were certain non-residential customers in the lighting program whose benefits were inadvertently calculated using the *residential* lost revenue rate. This adjustment corrects that error. The impact on net lost revenues for Vintage 2017 Non-Residential Energy Efficient Lighting is ($33,469) for Vintage 2017 and ($93,299) for Vintage 2019. The Company is revising Evans Exhibit 2, page 2 to reflect this adjustment. There was no impact to the interest calculation.

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

A. The changes I have outlined above result in revisions to the following rates

[2] As Witness Maness testified (*see* pp. 19-20), the net of these adjustments for the 2019 rate period is a reduction in retail NLR of approximately ($308,000). Though the net result is a reduction, because the adjustment results in an increase to the prospective non-residential rates as compared to those originally filed in the Application, the Company is filing a Motion for Additional Public Hearing and Public Notice of Revised Proposed Rates, simultaneously herewith.

included in the initial DSM/EE filing (all shown on a cents per kWh basis, including regulatory fee):

Description	Filed Rate	Revised Rate
Residential Prospective Rate	0.651	0.641
Non-Residential EE Prospective Rate	0.685	0.698
Non-Residential DSM Prospective Rate	0.062	0.063

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

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

- Supplemental Miller Exhibit 1: Summary of Rider EE Exhibits and Factors
- Supplemental Miller Exhibit 2, page 1: Energy Efficiency Rate Derivation
- Supplemental Miller Exhibit 2, page 2: Demand-Side Management Rate Derivation
- Supplemental Miller Exhibit 2, page 3: Rate Period Revenue Requirement Summary
- Supplemental Miller Exhibit 2, page 4: Energy Efficiency Experience Modification Factor Rate Derivation
- Supplemental Miller Exhibit 2, page 5: Demand-Side

Management Experience Modification Factor Rate Derivation

- Supplemental Miller Exhibit 2, page 6: EMF Period Revenue Requirement Summary
- Supplemental Miller Exhibit 2, page 7: EMF Adjustment Summary
- Supplemental Miller Exhibit 3, page 2: Vintage 2017 Interest Calculations for Non-Residential DSM
- Supplemental Miller Exhibit 7: Calculation of % of Lost Revenues Included in Base Rates
- Supplemental Evans Exhibit 1, pages 3 through 6: Vintage 2016 and Vintage 2017 Load Impacts and Estimated Revenue Requirements
- Supplemental Evans Exhibit 2, pages 1 and 2: North Carolina Lost Revenue Summary and True up

Q. WHAT ARE THE FINAL RATES REQUESTED IN THE APPLICATION OF DEP FOR APPROVAL OF ITS DSM/EE RIDER FOR 2019 AS A RESULT OF THESE REVISIONS?

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

Residential Billing Factors	**¢/kWh**
Residential Billing Factor for Prospective Components	0.641
Residential Billing Factor for EMF Components	0.003

Non-Residential Billing Factors	**¢/kWh**
EE EMF Rate	0.122
EE Prospective Rate	0.698
DSM EMF Rate	(0.018)
DSM Prospective Rate	0.063
Lighting EE EMF Rate	0.001
Lighting EE Prospective Rate	0.099

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

A. No. As Company Witnesses Timothy J. Duff and Robert P. Evans will explain in their Rebuttal Testimony to be filed on September 12, 2018, the Company does not agree with and has not incorporated the Public Staff's recommended adjustment to avoided costs nor its adjustment relating to its recommended termination of the Residential Smart $aver EE program.

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

A. Yes.

MS. FENTRESS: And I'll continue with the other witnesses then. I would move that Robert Evans direct testimony filed June 20, 2018, consisting of 29 pages be entered into the record as if given orally from the stand, and that his Exhibits 1 through 11 and A through K supporting that testimony be admitted as evidence. I would also move that Supplemental Evans Exhibits 1 and 2 filed September 10th be admitted as evidence. And finally with Mr. Evans I would move that Robert Evans rebuttal testimony consisting of 14 pages be entered into the record as if given orally from the stand. That testimony was filed September 12, 2018.

COMMISSIONER BROWN-BLAND: Is that rebuttal in addition to what was filed on September 10th?

MS. FENTRESS: Yes, it is.

COMMISSIONER BROWN-BLAND: So that motion will be allowed and the testimonies will be received as if given orally from the witness stand, with the identified exhibits received into evidence and identified as they were marked when prefiled.

MS. FENTRESS: Thank you.

(WHEREUPON, Evans Exhibits 1 - 11 and A - K are admitted into evidence.)

(WHEREUPON, the prefiled direct testimony of ROBERT P. EVANS is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1174

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Robert P. Evans, and my business address is 150 Fayetteville Street, Raleigh, North Carolina 27602. I am employed by Duke Energy Corporation ("Duke Energy") as Senior Manager-Strategy and Collaboration for the Carolinas in the Market Solutions Regulatory Strategy and Evaluation group.

Q. PLEASE BRIEFLY STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Iowa State University ("ISU") in 1978 with a Bachelor of Science Degree in Industrial Administration and a minor in Industrial Engineering. As a part of my undergraduate work, I participated in graduate level regulatory studies programs sponsored by American Telephone and Telegraph Corporation, as well as graduate level study programs in Engineering Economics. Subsequent to my graduation from ISU, I received additional Engineering Economics training at the Colorado School of Mines, completed the National Association of Regulatory Utility Commissioners Regulatory Studies program at Michigan State, and completed the Advanced American Gas Association Ratemaking program at the University of Maryland. Upon graduation from ISU, I joined the Iowa State Commerce Commission (now known as the Iowa Utility Board ("IUB")) in the Rates and Tariffs Section of the Utilities Division. During my tenure with the IUB, I held several positions, including Senior Rate Analyst in charge of Utility Rates and Tariffs and Assistant Director of the Utility Division. In those positions, I provided testimony in gas, electric, water, and telecommunications proceedings as an expert witness in the areas of rate design, service rules, and tariff applications. In 1982, I accepted employment with City Utilities of Springfield, Missouri, as an Operations Analyst. In that capacity, I provided support for rate-related matters associated with the municipal utility's gas, electric, water, and sewer operations. In addition, I worked closely with its load management and energy conservation programs. In 1983, I joined the Rate Services staff of the Iowa Power and Light Company, now known as MidAmerican Energy, as a Rate Engineer. In this position, I was responsible for the preparation of rate-related filings and presented testimony on rate design, service rules, and accounting issues before the IUB. In 1986, I accepted employment with Tennessee-Virginia Energy Corporation (now known as the United Cities Division of Atmos Energy) as Director of Rates and Regulatory Affairs. While in this position, I was responsible for regulatory filings, regulatory relations, and customer billing. In 1987, I went to work for the Virginia State Corporation Commission in the Division of Energy Regulation as a Utilities Specialist. In this capacity, I worked on electric and natural gas issues and provided testimony on cost of service and rate design matters brought before that regulatory body. In 1988, I joined North Carolina Natural Gas Corporation ("NCNG") as its Manager of Rates and Budgets. Subsequently, I was promoted to Director-Statistical Services in

NCNG's Planning and Regulatory Compliance Department. In that position, I performed a variety of work associated with financial, regulatory, and statistical analysis and presented testimony on several issues brought before the North Carolina Utilities Commission ("Commission"). I held that position until the closing of NCNG's merger with Carolina Power and Light Company, the predecessor of Progress Energy, Inc. ("Progress"), on July 15, 1999.

From July 1999 through January 2008, I was employed in Principal and Senior Analyst roles by the Progress Energy Service Company, LLC. In these roles, I provided NCNG, Progress Energy Carolinas, Inc. (now Duke Energy Progress, LLC ("DEP" or the "Company")), and Progress Energy Florida, Inc. with rate and regulatory support in their state and federal venues. From 2008 through the merger of Duke Energy and Progress, I provided regulatory support for demand-side management ("DSM") and energy efficiency ("EE") programs. Subsequent to the Progress merger with Duke Energy, I obtained my current position.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN MATTERS BROUGHT BEFORE THIS COMMISSION?

A. Yes. I have provided testimony to this Commission in matters concerning revenue requirements, avoided costs, cost of service, rate design, and the recovery of costs associated with DSM/EE programs and related accounting matters.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. I am responsible for the regulatory support of DSM/EE programs in North Carolina for both DEP and Duke Energy Carolinas, LLC ("DEC").

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

A. The purpose of my testimony is to explain and support DEP's proposed DSM/EE Cost Recovery Rider and Experience Modification Factor ("EMF"). My testimony provides: (1) a discussion of items the Commission specifically directed the Company to address in this proceeding; (2) an overview of the Commission's Rule R8-69 filing requirements; (3) a synopsis of the DSM/EE programs included in this filing; (4) a discussion of program results; (5) an explanation of how these results have affected DSM/EE rate calculations; (6) information on DEP's Evaluation Measurement & Verification ("EM&V") activities; and (7) an overview of the calculation of the Portfolio Performance Incentive ("PPI").

Q. PLEASE DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. Evans Exhibit 1 supplies load impacts, program costs, and avoided costs for each program, which are used in the calculation of the PPI and revenue requirements by vintage. Evans Exhibit 2 contains a summary of net lost revenues for the period January 1, 2014 through December 31, 2017. Evans Exhibit 3 contains the actual program costs for North Carolina for the period January 1, 2013 through December 31, 2017. Evans Exhibit 4 contains the found revenues used in the net lost revenues calculations. Evans Exhibit 5 supplies evaluations of event-based programs. Evans Exhibit 6 contains information about the results of DEP's programs and a comparison of actual impacts to previous estimates. Evans Exhibit 7 contains the projected program and portfolio cost-effectiveness results for DEP's approved programs. Evans Exhibit 8 contains a summary of 2017 program performance and an explanation of the variances between the expected program results and the actual results. It is designed to create more transparency with regard to the factors that have driven these variances. Evans Exhibit 9 is a list of DEP's industrial and large commercial customers that have opted out of participation in the Company's DSM and/or EE programs and a listing of those customers that have elected to participate in new measures after having initially notified the Company that they declined to participate, as required by Commission Rule R8-69(d)(2). Evans Exhibit 10 provides a summary of the estimated activities and timeframe for completion of EM&V by program. Evans Exhibit 11 provides the actual and expected dates when the EM&V for each program or measure will become effective.

Evans Exhibits A through K provide detailed EM&V reports, completed or updated since DEP's DSM/EE Cost Recovery Rider Filing in Docket No. E-2, Sub 1145, for the following programs: Demand Response Automation – 2016 (Evans Exhibit A); EE Education Program – 2015 & 2016 (Evans Exhibit B); EnergyWise Home Demand Response Program – Summer 2016 (Evans Exhibit C); EnergyWise Home Demand Response Program – Winter 2016 & 2017 (Evans Exhibit D); Residential Multi-Family EE

Program – 2015 & 2016 (Evans Exhibit E); Non-Residential Smart $aver Program (Prescriptive) – 2016 & 2017 (Evans Exhibit F); EnergyWise for Business Program – 2016 (Evans Exhibit G); Energy Efficient Lighting Program – 2016 & 2017 (Evans Exhibit H); My Home Energy Report (MyHER) Program – 2016 (Evans Exhibit I); Small Business Energy Saver Program – 2015 & 2016 (Evans Exhibit J); and Residential Save Energy and Water Program – 2016 (Evans Exhibit K).

Q. WERE EVANS EXHIBITS 1-11 PREPARED BY YOU OR AT YOUR DIRECTION AND SUPERVISION?

A. Yes, they were.

II. ACTIONS ORDERED BY THE COMMISSION

Q. PLEASE DESCRIBE THE ACTIONS THE COMMISSION DIRECTED DEP TO TAKE IN THE COMMISSION'S ORDER IN DOCKET NO. E-2, SUB 1145.

A. In its November 27, 2017 *Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice* in Docket No. E-2, Sub 1145 ("Sub 1145 Order"), the Commission ordered that: (1) the Appliance Recycling Program shall be canceled as of December 31, 2017; (2) in its next DSM/EE rider filing, DEP should address the continuing cost-effectiveness of the Smart $aver Performance (Custom) Program, Smart $aver Performance (Prescriptive) Program, the Smart $aver Performance Incentive Program, and the Home Energy Improvement Program; (3) with respect to the Smart $aver Performance (Custom) Program and the Smart $aver Performance

(Prescriptive) Program, the Company should include a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program(s) in its next DSM/EE rider filing; (4) if the Commission-approved modifications to the Residential Home Energy Improvement Program do not maintain or improve the program's cost-effectiveness by the Company's next DSM/EE rider proceeding, the program should be terminated at the end of 2018; (5) the EM&V reports for the Small Business Energy Saver Program (Evans Exhibit D) and the Multi-Family EE Program (Evans Exhibit E) should be revised as discussed by Public Staff witness Williamson and refiled in the next rider proceeding and their respective program approval dockets; (6) the Company should, when feasible and not cost prohibitive, incorporate the recommendations made by Public Staff witness Williamson regarding EM&V into future EM&V reports filed with the Commission in subsequent DSM/EE rider proceedings; and (7) the issues raised in Southern Alliance for Clean Energy ("SACE") and North Carolina Justice Center ("NC Justice Center") witness James Grevatt's testimony shall be discussed in the DEP Collaborative as addressed herein, and the results of such discussions shall be reported in the Company's application in the next DSM/EE rider proceeding. In addition, the Commission directed DEP to file updated cost-effectiveness scores for its Distribution System Demand Response ("DSDR") Program in each of DEP's DSM/EE rider proceedings.

Q. DID THE COMPANY CANCEL ITS APPLIANCE RECYCLING PROGRAM AS OF DECEMBER 31, 2017?

A. Yes.

Q. PLEASE ADDRESS THE CONTINUING COST-EFFECTIVENESS OF THE SMART $AVER PERFORMANCE (CUSTOM) MEASURE, THE SMART $AVER PERFORMANCE (PRESCRIPTIVE) MEASURE, THE SMART $AVER PERFORMANCE INCENTIVE PROGRAM, AND THE HOME ENERGY IMPROVEMENT PROGRAM.

A. Both the Smart $aver Custom and Prescriptive measures are not programs but rather subsets of the Nonresidential Smart $aver Energy Efficient Products and Assessment Program. This program, formerly known as EE for Business, is estimated to produce a Utility Cost Test ("UCT") cost-effectiveness score of 2.45 and a Total Resource Cost ("TRC") cost-effectiveness score of 1.07. These resulting scores indicate that the program has exceeded the standard cost-effectiveness thresholds.

DEP's Non-Residential Smart $aver Performance Incentive Program is not expected to have a TRC score exceeding 1.0 in 2019. The forecasted 2019 TRC score is 0.92, and the UCT score is 3.75. These scores are significantly greater than the 0.40 TRC and 0.54 UCT scores submitted in the Company's 2017 cost recovery request. While the 0.92 TRC score may be viewed as slightly less than optimal in isolation, it is important to note that this program is largely an extension of the Non-Residential Smart $aver Program. In particular, the Performance Incentive Program encompasses energy saving measures related to new technologies, unknown building conditions and system constraints, as well as uncertain operating circumstances, occupancy, or production schedules. In these cases, energy savings are difficult to project with any level of accuracy. Due to the scope of projects envisioned, the Company also believes that the program could impact a customer's decision to opt into the EE portion of the rider; in other words, if this program were no longer offered as part of the Company's EE portfolio, additional customers may elect to opt out as a result. Another important element of this program is that it limits the prospects of overcompensating participants, at the expense of other customers, or undercompensating participants for their EE improvements. The Company believes that this program is an important element of its non-residential portfolio of programs and that its cost-effectiveness results will continue to improve as more customers become familiar with it and participation increases.

DEP's Home Energy Improvement Program has been renamed the "Residential Smart $aver EE Program" and modified in several ways. However, this program continues to struggle to maintain cost-effectiveness. During 2016 and 2017, the Company made a number of changes to the program to address the erosion in the program's cost-effectiveness caused by advancements in efficiency standards and the associated lower incremental savings associated with exceeding the new standards. These program changes, which were highlighted by the redesign of the program to include a referral channel that reduced program costs, proved successful in returning the program to cost-effectiveness in 2017 and 2018. Unfortunately, with the application of the new lower avoided costs in 2019, the program is again projecting to no longer be cost-effective. For this reason, the Company is actively working to evaluate additional programmatic changes, such as the Public Staff's recommendation to eliminate all non-referral channel measures, that would offset the decline in avoided costs and make this critical residential program cost-effective in 2019 and beyond.

While the Residential Smart $aver EE Program is not assumed to be cost-effective at this time, the Company believes that suspending or terminating the only program that offers assistance for making the largest single energy user in the home, a customer's HVAC system, more energy efficient does not seem reasonable, especially when the decision to make said investment only comes around once every fifteen years. A suspension of this program would also impact the Company's relationships with HVAC contractors and could erode trust and engagement, which would make it difficult to offer similar types of programs that would require trade ally support in the future.

In the past, when the program's cost-effectiveness has struggled due to efficiency standard changes, the Company has demonstrated the ability to effectively modify the program to restore cost-effectiveness and should have the opportunity to attempt to restore the cost-effectiveness of the program that was eroded by reduction in avoided costs.

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

Q. HAS THE COMPANY RE-FILED REVISED EM&V REPORTS FOR THE SMALL BUSINESS ENERGY SAVER PROGRAM (EVANS EXHIBIT D) AND THE MULTI-FAMILY EE PROGRAM (EVANS EXHIBIT E), AS RECOMMENDED BY PUBLIC STAFF WITNESS WILLIAMSON?

A. Yes. The revised EM&V report for the Small Business Energy Saver Program is included as Evans Exhibit J, and the revised EM&V report for the Residential Multi-Family EE Program is included as Evans Exhibit E.

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS MADE BY PUBLIC STAFF WITNESS WILLIAMSON REGARDING FUTURE EM&V REPORTS FILED WITH THE COMMISSION IN SUBSEQUENT DSM/EE RIDER PROCEEDINGS.

A. Witness Williamson recommended that: (1) future EM&V reports should describe any key methodological changes or differences between past and present studies, including differences in methodologies across multiple programs that offer similar or identical measures; (2) if feasible, future evaluations of the Residential Multi-Family EE Program should include a billing analysis and more specific data on bulbs being replaced (if it is not feasible to do so, then the evaluator should address what limitations in program design or evaluation resources would prevent a billing analysis from being conducted); (3) future evaluations of the Small Business Energy Saver program should update the coincidence factors for lighting measures, incorporate HVAC interactive effects, and begin tracking the heating and cooling types of participants to improve estimates of the HVAC interaction factors; and (4) future evaluations of the Neighborhood Energy Saver Program and similar programs should consider utilizing state-level specific data when providing estimates in the program's EM&V review, unless cost-prohibitive.

Q. HAS THE COMPANY ADOPTED WITNESS WILLIAMSON'S RECOMMENDATIONS?

A. Yes. The Company has notified its third-party evaluators of Witness Williamson's recommendations and such recommendations are being adopted to the extent that they are both feasible and cost-effective.

Q. CAN YOU SUMMARIZE THE NEW PROGRAMS AND ENHANCEMENTS TO EXISTING PROGRAMS RECOMMENDED BY SACE AND NC JUSTICE CENTER WITNESS GREVATT?

A. The Commission's Sub 1145 Order provided that the issues raised in witness Grevatt's testimony shall be discussed in the DEP Collaborative. Witness Grevatt recommended that DEP work with the Collaborative to: (1) consider the potential for comprehensive program approaches with longer measure lives, such as home retrofits and HVAC system improvements; (2) consider the maximization of cross-program marketing in behavior, audit, and kit programs; (3) examine opportunities to save more energy in multi-family housing, including in common areas and for commonly-metered systems; (4) consider the expansion of the Company's low-income program offerings; (5) examine ways to continue to promote adoption of a greater range of measures through the Company's Small Business Energy Saver Program; (6) discuss ways to encourage participation of non-residential customers who are eligible to opt out, including making sure that the available programs meet these customers' needs and by providing personalized outreach to engage them; and (7) discuss the use of Advanced Metering Infrastructure ("AMI") technology to drive more EE and DSM for customers if DEP launches a large-scale deployment of AMI.

Q. HAVE THE RECOMMENDATIONS BY WITNESS GREVATT BEEN CONSIDERED BY THE COLLABORATIVE?

A. Yes. Witness Grevatt's proposals have been discussed in the combined DEP and DEC Collaboratives. As previously noted to the Commission, the Collaborative continues to consider ways to improve current residential and non-residential programs and to develop new programs. In addition to originating its own new program proposals, the Company is receptive to ideas for new programs from Collaborative members and has developed a New Program Assumptions Template so that Collaborative members can gather the necessary data for the Company to evaluate their new program ideas. The Company continues to look forward to receiving completed New Program Assumptions Templates from Collaborative members which would provide sufficient data from which the Company can evaluate the viability of new program ideas.

Q. HAS THE COMPANY ANALYZED THE COST-EFFECTIVENESS SCORES FOR ITS DSDR PROGRAM?

A. Yes. The Company has determined that the TRC and UCT cost-effectiveness scores are both 1.204. In addition, the present value of DSDR Program net benefits is approximately $60,567,000.

Q. HAS THE COMPANY MADE ANY CHANGES TO ITS ANNUAL RATIOS OF ALLOCATIONS BETWEEN NON-DSDR AND DSDR EQUIPMENT?

A. DEP reviews the allocation ratios annually each summer and implements any necessary updates the following year. The Company reviewed 2016 units during the summer of 2017 and determined that no change in the 20.12 percent allocation ratio applicable to capacitors was necessary for 2018; however, the allocation ratio applied to regulators was elevated from 77.79 to 79.45 percent. The 2017 units will be reviewed this summer, and any further changes will be communicated to the Public Staff and implemented on January 1, 2019.

III. <u>RULE R8-69 FILING REQUIREMENTS</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE INFORMATION DEP IS PROVIDING IN RESPONSE TO THE COMMISSION'S FILING REQUIREMENTS.

A. The information for this filing is provided pursuant to the Commission's filing requirements contained in R8-69(f)(1) and can be found in my testimony and exhibits, as well as the testimony and exhibits of Company witness Carolyn T. Miller as follows:

R8-69(f)(1)		Items	Location in Testimony
(i)		Projected NC retail sales for the rate period	Miller Exhibit 6
(ii)		For each measure for which cost recovery is requested through DSM/EE rider:	
(ii)	a.	Total expenses expected to be incurred during the rate period	Evans Exhibit 1
(ii)	b.	Total costs savings directly attributable to measures	Evans Exhibit 1
(ii)	c.	EM&V activities for the rate period	Evans Exhibit 10
(ii)	d.	Expected summer and winter peak demand reductions	Evans Exhibit 1
(ii)	e.	Expected energy reductions	Evans Exhibit 1
(iii)		Filing requirements for DSM/EE EMF rider, including:	
(iii)	a.	Total expenses for the test period in the aggregate and broken down by type of expenditure, unit, and jurisdiction	Evans Exhibit 3
(iii)	b.	Total avoided costs for the test period in the aggregate and broken down by type of expenditure, unit, and jurisdiction	Evans Exhibit 1
(iii)	c.	Description of results from EM&V activities	Testimony of Robert Evans and Evans Exhibits A-K
(iii)	d.	Total summer and winter peak demand reductions in the aggregate and broken down per program	Evans Exhibit 1
(iii)	e.	Total energy reduction in the aggregate and broken down per program	Evans Exhibit 1
(iii)	f.	Discussion of findings and results of programs	Testimony of Robert Evans and Evans Exhibit 6

(iii)	g.	Evaluations of event-based programs	Evans Exhibit 5
(iii)	h.	Comparison of impact estimates from previous year and explanation of significant differences	Testimony of Robert Evans and Evans Exhibits 6 and 8
(iv)		Determination of utility incentives	Testimony of Robert Evans and Evans Exhibit 1
(v)		Actual revenues from DSM/EE and DSM/EE EMF riders	Miller Exhibit 3
(vi)		Proposed DSM/EE rider	Testimony of Carolyn Miller and Miller Exhibit 1
(vii)		Projected NC sales for customers opting out of measures	Miller Exhibit 6
(viii)		Supporting work papers	Flash drive accompanying filing

IV. PROGRAM OVERVIEW

Q. WHAT ARE DEP'S CURRENT DSM AND EE PROGRAMS?

A. The Company's current DSM and EE programs are as follows:

RESIDENTIAL CUSTOMER PROGRAMS

- Appliance Recycling Program
- EE Education Program
- Multi-Family EE Program
- My Home Energy Report Program
- Neighborhood Energy Saver Program
- Residential Smart $aver EE Program (formerly known as the Home Energy Improvement Program)
- New Construction Program
- Load Control Program (EnergyWise)
- Save Energy and Water Kit Program

- Energy Assessment Program

NON-RESIDENTIAL CUSTOMER PROGRAMS

- Non-Residential Smart$aver Energy Efficient Products and Assessment Program (formerly known as the EE for Business Program)
- Non-Residential Smart$aver Performance Incentive Program
- Small Business Energy Saver Program
- CIG Demand Response Automation Program
- EnergyWise for Business

COMBINED RESIDENTIAL/NON-RESIDENTIAL PROGRAMS

- Energy Efficient Lighting Program
- DSDR

Q. PLEASE DESCRIBE ANY UPDATES MADE TO THE UNDERLYING ASSUMPTIONS FOR DEP'S PROGRAMS THAT HAVE ALTERED PROJECTIONS FOR VINTAGE 2019.

A. EM&V results were used to update the savings impacts for those programs for which DEP received EM&V results after it prepared its application in Docket No. E-2, Sub 1145. Updating programs for EM&V results changes the projected avoided cost benefits associated with the projected participation and, hence, impacts the calculation of the specific program and overall portfolio cost-effectiveness, as well as the calculation of DEP's projected shared savings incentive.

Q. AFTER FACTORING THESE UPDATES INTO DEP'S PROGRAMS FOR VINTAGE 2019, DO THE RESULTS OF DEP'S PROSPECTIVE COST-EFFECTIVENESS TESTS INDICATE THAT IT SHOULD DISCONTINUE OR MODIFY ANY OF ITS PROGRAMS?

A. DEP performed a prospective analysis of each of its programs and the aggregate portfolio for the Vintage 2019 period. The results of this prospective analysis are contained in Evans Exhibit 7. This exhibit shows that there are three programs which do not pass the TRC and/or UCT thresholds of 1.0. These programs are: (1) the Neighborhood Energy Saver Program, which was not cost-effective at the time of Commission approval (but was approved based on its societal benefits); (2) the Residential Smart $aver EE Program, formerly known as the Home Energy Improvement Program; (3) My Home Energy Report; (4) the Non-Residential Smart$aver Performance Incentive Program; and (5) the EnergyWise for Business Program. In the aggregate, DEP's portfolio of programs continues to project cost-effectiveness.

As discussed earlier in my testimony, DEP continues its efforts to make the Residential Smart $aver EE Program cost-effective and believes it should continue to be included in the Company's portfolio. The Non-Residential Smart$aver Performance Incentive Program was also discussed earlier in my testimony, and the Company believes that its TRC value will increase in the future in part due to increased scrutiny in the project selection process. As to the MyHER results, while the Company is concerned by the program's projected marginally negative cost-effectiveness, it believes that it is merely a short-term issue that will resolve itself over time. The program is still relatively young (launched in March 2015), with an evaluation period of January 2016 through December 2016. In effect, the Company believes that this first evaluation may not provide a complete picture of the savings that can be realized from participants over time. Based on the MyHER results the Company has experienced in other jurisdictions where the program has been in the market longer (including DEC), the Company believes that as the customer engagement becomes more established that the savings realized by participants will increase. In addition, the Company continues to work with the program vendor to identify potential cost savings associated with offering the program. The cost-effectiveness of the Company's EnergyWise for Business Program was negatively impacted by lower than anticipated participation. The Company believes that the program's 0.72 UCT score will elevate as participation increases.

V. DSM/EE PROGRAM RESULTS TO DATE

Q. HOW MUCH ENERGY, CAPACITY AND AVOIDED COST SAVINGS DID DEP DELIVER AS A RESULT OF ITS DSM/EE PROGRAMS DURING VINTAGE 2017?

A. During Vintage 2017, DEP's DSM/EE programs delivered over 416 million kilowatt hours ("kWh") of energy savings and over 450 megawatts ("MW") of capacity savings, which produced a net present value of avoided cost savings of close to $287 million. The 2017 performance results for individual programs are provided in Evans Exhibits 6 and 8.

Q. DID ANY PROGRAMS SIGNIFICANTLY OUT-PERFORM RELATIVE TO THEIR ORIGINAL ESTIMATES FOR VINTAGE 2017?

A. Yes. In the residential market, two programs did significantly out-perform compared to their original energy savings estimates: the Residential Energy Assessment Program and the Residential Smart $aver EE Program. When compared to estimates originally filed for Vintage 2017, the programs exceeded projections by 174 percent and 295 percent, respectively. Both programs achieved these increases largely through higher participation levels.

The non-residential program with the largest percentage increase in expected energy savings from those forecasted for 2017 is the Small Business Energy Saver Program. This program produced energy savings that exceeded DEP's projections by 162 percent.

Q. HAVE ANY PROGRAMS SIGNIFICANTLY UNDERPERFORMED RELATIVE TO THEIR ORIGINAL ESTIMATES IN VINTAGE 2016?

A. Yes. In the residential market, three programs did not achieve energy savings in excess of those forecasted for 2017. These were: (1) the Energy Efficient Lighting Program; and (2) the My Home Energy Report Program. These programs achieved 70 percent and 88 percent of projected energy savings, respectively. The primary drivers for the underperformance of these programs are changes in estimated impacts and changes in the mix of program measures.

In the non-residential market, the Energy Efficient Lighting Program failed to meet energy savings expectations. The primary drivers for the underperformance of the Energy Efficient Lighting Program were changes to the estimated impacts and changes in the mix of program measures.

VI. PROJECTED RESULTS

Q. PLEASE PROVIDE A PROJECTION OF THE RESULTS THAT DEP EXPECTS TO SEE FROM IMPLEMENTATION OF ITS PORTFOLIO OF PROGRAMS.

A. DEP will update the actual and projected DSM/EE achievement levels in its annual DSM/EE cost recovery filing to account for any program or measure additions based on the performance of programs, market conditions, economics, and consumer demand. The actual results for Vintage 2017 and projection of the results for the next two years, as well as the associated projected program expenses, are summarized in the table below:

DEP System (NC & SC) DSM/EE Portfolio 2017 Actual Results and 2018-2019 Projected Results			
	2017	2018	2019
Annual System MW	450	426	461
Annual System Net Gigawatt-Hours	416	374	385
Annual Program Costs (Millions)	$97	$90	$100

VII. EM&V ACTIVITIES

Q. CAN YOU PROVIDE INFORMATION ON THE COMPANY'S EM&V ACTIVITIES?

A. Yes. Evans Exhibit 10 provides a summary of the estimated activities and timeframe for completion of EM&V by program. Evans Exhibit 11 provides the actual and expected dates of when the EM&V for each program or measure will become effective. Evans Exhibits A through K provide the completed EM&V reports or updates for the following programs:

Evans Exhibit	EM&V Reports	Report Finalization Date
A	Demand Response Automation – 2016	6/19/2017
B	EE Education Program – 2015 & 2016	7/28/2017
C	EnergyWise Home Demand Response Program – Summer 2016	6/5/2017
D	EnergyWise Home Demand Response Program – Winter 2016 & 2017	7/6/2017
E	Residential Multi-Family Efficiency Program – 2015 & 2016	6/27/2017
F	Non-Residential Smart $aver Program (Prescriptive) – 2016 & 2017	3/25/2018
G	EnergyWise for Business Program – 2016	6/12/2017
H	Energy Efficient Lighting Program – 2016 & 2017	4/26/2018
I	My Home Energy Report (MyHER) Program - 2016	7/31/2017
J	Small Business Energy Saver Program – 2015 & 2016	6/6/2017
K	Residential Save Energy and Water Program – 2016	11/29/2017

Q. HOW WERE EM&V RESULTS UTILIZED IN DEVELOPING THE PROPOSED RATES?

A. The Company has applied EM&V in accordance with the process approved by the Commission in its Order Approving Revised Cost Recovery Mechanism and Granting Waivers issued January 20, 2015 in Docket No. E-2, Sub 931 ("Order Approving Revised Mechanism").

The level of EM&V required varies by program and depends upon that program's contribution to the total portfolio, the duration the program has been in the portfolio without material change, and whether the program and administration is new and different in the energy industry. DEP estimates, however, that no additional costs above five percent of total program costs will be associated with performing EM&V for all measures in the portfolio.

Q. WHICH PROGRAMS CONTAIN IMPACT RESULTS BASED ON CAROLINAS-BASED EM&V?

A. All of the impact results included in the Company's filing (Evans Exhibits A through K) are based on Carolinas-based EM&V.

VIII. RATE IMPACTS

Q. HAVE THE PARTICIPATION RESULTS AFFECTED THE VINTAGE 2017 EMF?

A. Yes. The EMF accounts for changes to actual participation relative to the forecasted participation levels utilized in DEP's 2017 DSM/EE rider. As DEP receives actual participation information, it is then able to update participation-driven actual avoided cost benefits and the net lost revenues derived from its DSM and EE programs. For example, with all other things being equal, for programs that underperform relative to their original participation targets, the EMF will be reduced to reflect lower costs, net lost revenues, and shared savings incentives. On the other hand, higher-than-expected participation in programs causes the EMF to reflect higher program costs, net lost revenues, and shared savings incentives. In addition, the EMF is impacted by the application of EM&V results.

Q. HOW WILL EM&V BE INCORPORATED INTO THE VINTAGE 2016 EMF COMPONENT OF ITS RATES?

A. All of the final EM&V results that were received by DEP as of December 31, 2017 have been applied prospectively from the first day of the month immediately following the month in which the study participation sample for the EM&V was completed. Accordingly, for any program for which DEP has received EM&V results, the per participant impact applied to the projected program participation in Vintage 2017 is based upon the actual EM&V results that have been received.

Q. HAS THE OPT-OUT OF NON-RESIDENTIAL CUSTOMERS AFFECTED THE RESULTS OF APPROVED PROGRAMS?

A. Yes, the opt-out of qualifying non-residential customers has had a significant effect on DEP's overall non-residential participation and the associated impacts. For Vintage 2017, DEP had 4,165 eligible customer accounts opt out of participating in DEP's non-residential portfolio of EE programs and had 4,099 eligible customer accounts opt out of participating in DEP's non-residential portfolio of DSM programs. This is an increase from the 3,869 EE accounts and 3,919 DSM opt-outs reported for 2016.

Q. IS THE COMPANY CONTINUING ITS EFFORTS TO ATTRACT THE PROGRAM PARTICIPATION OF OPT-OUT ELIGIBLE CUSTOMERS?

A. Yes. Increasing the participation of opt-out eligible customers in DSM and EE programs is very important to the Company. DEP continues to evaluate and revise its non-residential programs to accommodate new technologies, eliminate product gaps, remove barriers to participation, and make its programs more attractive. It also continues to leverage its Large Account Management Team to make sure customers are informed about product offerings. Forty-four customers did opt in to participate in programs during 2017.

IX. NET LOST REVENUES

Q. IS DEP REQUESTING RECOVERY OF NET LOST REVENUES FOR ALL OF ITS PROGRAMS?

A. No. At this time, DEP is not requesting recovery of net lost revenues for its EnergyWise or CIG Demand Response Automation programs.

Q. IS THE COMPANY REQUESTING THE RECOVERY OF NET LOST REVENUES ASSOCIATED WITH ITS DSDR PROGRAM IN THIS PROCEEDING?

A. Yes. The Company has recognized net lost revenues for the test period based on its analysis of energy savings impacts related to DSDR activations occurring between January 1 and May 31, 2017.

Q. HAS THE COMPANY RECOGNIZED FOUND REVENUES IN ITS CALCULATION OF NET LOST REVENUES?

A. Yes. The recognized found revenues are provided in Evans Exhibit 4.

Q. PLEASE DESCRIBE HOW DEP DETERMINES ITS FOUND REVENUES.

A. Consistent with the Commission's Order Approving Revised Mechanism, DEP has adopted the "Decision Tree" located in Attachment C of the approved revised cost recovery mechanism. Consistent with the methodology employed by DEP, found revenue activities are identified, categorized, and netted against the net lost revenues created by DEP's EE programs. Found revenues, as calculated, result from DEP's activities that are perceived to directly or indirectly result in an increase in customer demand or energy consumption within DEP's service territory. However, revenues resulting from load-building activities would not be considered found revenues if they (1) would have occurred regardless of DEP's activity, (2) were a result of a Commission-approved economic development activity not determined to produce found revenues, or (3) were part of an unsolicited request for DEP to engage in an activity that supports efforts to grow the economy. DEP also adjusts the calculation of found revenues to account for the impacts of activities outside of its DSM/EE programs that it undertakes that reduce customer consumption – i.e., "negative found revenues." Based on the results of this work, all potential found revenue-related activities are identified and categorized in Evans Exhibit 4.

Q. PLEASE DISCUSS THE ADJUSTMENT THAT DEP MAKES TO ITS FOUND REVENUE CALCULATION TO ACCOUNT FOR NEGATIVE FOUND REVENUES.

A. DEP continues to aggressively pursue, with its outdoor lighting customers, the replacement of aging Mercury Vapor lights with Light Emitting Diode

("LED") fixtures. By moving customers past the standard High Pressure Sodium ("HPS") fixture to an LED fixture in this replacement process, DEP is generating significant energy savings. These energy savings, since they come outside of DEP's EE programs, are not captured in DEP's calculation of lost revenues. Since one of the activities that DEP includes in the calculation of found revenues is the increase in consumption from new outdoor lighting fixtures added by DEP, it is logical and symmetrical to count the energy consumption reduction realized in outdoor lighting efficiency upgrades. The Company does not take credit for the entire efficiency gain from replacing Mercury Vapor lights, but rather only the efficiency gain from replacing HPS with LED fixtures. Also, DEP has not recognized any negative found revenues in excess of the found revenues calculated; in other words, the net found revenues number will never be negative and have the effect of increasing net lost revenue calculations.

X. PPI CALCULATION

Q. PLEASE PROVIDE AN OVERVIEW OF THE SHARED SAVINGS RECOVERY MECHANISM APPROVED IN THE ORDER APPROVING REVISED MECHANISM.

A. Pursuant to the Commission's Order Approving Revised Mechanism, for Vintage Year 2017 and subsequent vintage years, DEP's revised cost recovery mechanism allows it to (1) recover the reasonable and prudent costs incurred for adopting and implementing DSM and EE measures in accordance with N.C. Gen. Stat. § 62-133.9 and Commission Rules R8-68 and R8-69; (2)

recover net lost revenues incurred for up to 36 months of a measure's life for DSM and EE programs; and (3) earn a PPI based upon the sharing of 11.75% of the net savings achieved through DEP's DSM/EE programs on an annual basis.

Q. IS DEP REQUESTING PPI FOR ALL OF ITS PROGRAMS?

A. No. The Company is not requesting PPI recovery for its Residential Low-Income Program or its EE Education Program. In addition, under the terms of the revised cost recovery mechanism, DEP is not eligible for a PPI for its DSDR Program.

Q. PLEASE EXPLAIN HOW DEP DETERMINES THE PPI.

A. First, DEP determines the net savings eligible for incentive by subtracting the present value of the annual lifetime DSM/EE program costs (excluding low-income programs or other programs with societal benefits which are explicitly approved with expected UCT results less than 1.0) from the net present value of the annual lifetime avoided costs achieved through the Company's programs (again, excluding approved low-income and societal programs). The Company then multiplies the net savings eligible for incentive by the 11.75% shared savings percentage to determine its pretax incentive.

XI. CONCLUSION

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

A. Yes.

(WHEREUPON, Supplemental Evans Exhibits 1 and 2 are admitted into evidence.)

(WHEREUPON, the prefiled rebuttal testimony of ROBERT P. EVANS is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1174

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

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

A. Yes.

Q. DID YOU ALSO CAUSE TO BE FILED SUPPLEMENTAL EVANS EXHIBITS 1 AND 2?

A. Yes. As a result of the adjustments discussed in the Supplemental Testimony of Carolyn T. Miller, Evans Exhibits 1 and 2 were updated and filed on September 10, 2018 as Supplemental Evans Exhibits 1 and 2.

Q. WERE SUPPLEMENTAL EVANS EXHIBITS 1 AND 2 PREPARED BY YOU OR AT YOUR DIRECTION AND SUPERVISION?

A. Yes, they were.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

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

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

A. My rebuttal testimony addresses: (1) Mr. Williamson's comments on the appropriate avoided capacity rates to be utilized in DEP's calculation of cost effectiveness; (2) his recommendation regarding the Company's programs that include lighting measures; (3) his observations relating to the Company's My Home Energy Report ("MyHER") program; (4) his recommendation for closure of the Company's Residential Smart $aver Program; (5) his comments regarding the cost effectiveness of certain Demand-Side Management ("DSM") and Energy Efficiency ("EE") programs; and (6) his recommendations relating to the Company's Evaluation, Measurement, and Verification ("EM&V") reports.

Q. WILL YOU SUMMARIZE WITNESS WILLIAMSON'S POSITION ON THE AVOIDED COSTS USED TO DETERMINE THE COST EFFECTIVENESS OF THE COMPANY'S PROGRAMS?

A. In summary, Witness Williamson indicates that the Public Staff believes DEP should reflect zero avoided capacity value for its DSM/EE programs in years prior to the identified need for new capacity in the Company's IRP.

Q. WHAT IS THE COMPANY'S VIEW OF WITNESS WILLIAMSON'S POSITION?

A. The Company does not agree with the application of zero avoided capacity cost values proposed by the Public Staff for the determination of DSM/EE program cost-effectiveness or calculation of the Company's Portfolio Performance Incentive ("PPI"). The impropriety of employing zero avoided capacity cost values is discussed in the rebuttal testimony of Company witness Timothy J. Duff.

In addition, as discussed later in my testimony, use of zero avoided capacity values has a major impact on the cost-effectiveness of the Company's existing and future DSM/EE portfolios.

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. As explained in Witness Duff's testimony, 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. 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 and accept the Company's calculations of cost-effectiveness for purposes of this rider proceeding.

Q. WILL YOU DESCRIBE WITNESS WILLIAMSON'S RECOMMENDATION CONCERNING EE PROGRAMS THAT INCLUDE LIGHTING MEASURES?

A In light of the likely implementation of phase 2 of the Energy Independence and Security Act ("EISA") standards in January 2020, Witness Williamson recommends that DEP include in its 2019 DSM/EE cost recovery filing its plans for general use lighting measures in all of its EE programs that include lighting measures.

Q. IS THE COMPANY AMENABLE TO SUBMITTING ITS PLANS FOR EE PROGRAMS THAT CONTAIN GENERAL USE LIGHTING MEASURES IN ITS 2019 DSM/EE COST RECOVERY FILING?

A. Yes.

Q. DO YOU HAVE ANY CONCERNS REGARDING WITNESS WILLIAMSON'S OBSERVATIONS ON ADVANCED METERING INFRASTRUCTURE ("AMI") AND THE UPDATED BILLING/

INFORMATION SYSTEM WITH RESPECT TO THE COMPANY'S MYHER PROGRAM?

A. Yes. Given that the updated customer information system and billing system will not be in service for several years, I believe that Witness Williamson's observations are premature. That being said, the Company will work with the Public Staff to evaluate the MyHER Program's energy savings, recognizing the impacts of AMI and the updated billing/information system.

Q. DO YOU HAVE ANY COMMENTS RELATING TO THE PUBLIC STAFF'S RECOMMENDATION THAT THE RESIDENTIAL SMART $AVER EE PROGRAM BE CLOSED AT THE END OF 2018?

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

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

1. While the Company does have some concerns with respect to the Public Staff's recommendation to move the program to an all-referral structure, the Company is not opposed to adopting this proposal so long as the Commission deems it appropriate. However, in lieu of moving to a referral only approach, the program management team has developed a number of potential revisions to the referral program that will improve cost-effectiveness and lead to a more gradual transition to a referral only approach. The Company believes that these modifications would result in improving the program and the cost-effectiveness tests referenced in Witness Williamson's testimony;
2. The Company has been reevaluating and updating the cost studies of the incremental costs actually being paid by customers to adopt higher efficiency equipment. This work will ensure that the Company's cost-effectiveness analysis is consistent with the current market conditions and reflects the changes in equipment pricing that occur as the new higher efficiency standards have been in place for a longer period of time. Such information could lead to improvements in the program's TRC scores; and

3. Finally, the program management team has been working with the third-party vendor used in program administration (payment processing) to further reduce program costs and increase the TRC score.

The Company is confident that the combination of these actions will allow it to again result in a cost-effective program and that shutting down the current operations without an appropriate time frame for planning and adjustment is not the best answer for its customers.

Based on the Company's persistent efforts to maintain the viability of the program through program modifications, as well as the negative impact on the Company's PPI if the program continues to struggle to maintain cost-effectiveness, it is clear that DEP is highly motivated to continue to find ways to improve cost-effectiveness. As approved in the Sub 1164 Order for DEC's companion Residential Smart $aver EE Program, given the importance of the program to DEP's residential portfolio and the Company's relationships with its trade allies, DEP would appreciate the opportunity to propose modifications to this program with the goal of restoring the TRC score to 1.0 or greater.

Q. DO YOU HAVE ANY COMMENTS RELATING TO THE COST-EFFECTIVENESS OF THE RESIDENTIAL NEW CONSTRUCTION, ENERGYWISE FOR BUSINESS, AND NON-RESIDENTIAL SMART $AVER PROGRAMS DISCUSSED IN WITNESS WILLIAMSON'S TESTIMONY?

A. Witness Williamson has indicated that these programs are not cost-effective when the Public Staff's proposed zero avoided capacity values are employed. However, these programs are all cost-effective under the Company's calculations. As the application of zero avoided capacity cost values is not appropriate, as discussed by Witness Duff and as decided by the Commission in the Sub 1164 Order, these programs are, in fact, cost-effective and therefore do not fall under paragraphs 22B or 22C of the Mechanism. It is important to recognize that these programs constitute a significant portion of the Company's DSM/EE portfolio, which demonstrates the devastating impact that the Public Staff's position on avoided costs could have on the Company's portfolio.

Q. DO YOU HAVE ANY CONCERNS RELATING TO WITNESS WILLIAMSON'S COMMENTS RELATING TO THE COST-EFFECTIVENESS OF THE COMPANY'S MYHER AND NON-RESIDENTIAL SMART $AVER PERFORMANCE INCENTIVE PROGRAMS?

A. As filed, the Company's MyHER program has EM&V cost-effectiveness UCT/TRC results of 0.96. For practical purposes, a score of 0.96 is essentially 1.0. It is important to note that there has only been a single EM&V study performed on the MyHER Program and that this single program constitutes a significant portion of the Company's portfolio. Given the closeness of the applicable cost-effectiveness tests to 1.0 and the importance of the program, I would not recommend that MyHER fall under the provisions of paragraph 22B of the Mechanism at this time.

The Non-Residential Smart $aver Performance Incentive Program has been in place since January 1, 2017. The program was intended to encompass large EE-related projects with uncertainty relative to their performance (e.g., projects that employ new technologies). Related program incentives are provided in installments based on actual savings. In this manner, participants are properly incentivized for their EE-related investments, and other customers are shielded from the impacts of overstated performance. That said, very few projects are appropriate for participation in the program. The 0.92 TRC test score reflected in Evans Exhibit 7 to my Direct Testimony was based upon participation forecasts and costs used in the Company's 2016 program filing. During 2017, only five projects were involved. Currently, there are seventy-four projects underway in the DEP service territory. The Company's estimated TRC score for this program, based on these and other projects under review, should exceed 1.5. In short, we do not believe that this program requires additional scrutiny at this time, due to both the short time it has been in place and its anticipated cost-effectiveness results.

Q. DO YOU HAVE ANY OBSERVATIONS WITH RESPECT TO WITNESS WILLIAMSON'S POSITIONS RELATED TO THE COMPANY'S EM&V REPORTS?

A. Yes. Witness Williamson recommended that future evaluations of the Residential Multi-Family EE Program should include a billing analysis, if feasible, and more specific data on bulbs being replaced. The Company is unable to determine at this time if such a billing analysis would be feasible. The Company agrees that it will include such a billing analysis if feasible; if a billing analysis is not feasible, the evaluation results will indicate the rationale as to why it was not feasible.

Witness Williamson recommended for future evaluations of the Energy Efficient Lighting Program that the program evaluator should include the basis for the selected weighting methodology (weightings based on bulb sales, measure savings, or other metric) when assessing program savings. The Company agrees to ensure that in future evaluations, the evaluator will detail rationale for selected weighting methodology and indicate the reasons why it was chosen over other weighting methodologies.

Also with respect to the Energy Efficient Lighting Program, Witness Williamson recommended that the program evaluator should, in future evaluations, provide further clarity into the sales of incentivized bulbs at dollar/discount stores to determine the income levels of customers purchasing these bulbs. This information would be used as an element in the determination of Net-to-Gross ("NTG") levels. The Company recognizes that in-store intercepts are the most reliable method to estimate NTG among dollar/discount stores. With the use of in-store intercepts, there is no need to determine the income levels of customers purchasing these bulbs, since the NTG would be determined by customers' responses to the NTG battery of questions. That said, evaluators initially planned to conduct in-store intercepts for the Program Year 2015 evaluation; however, the evaluators could not gain access to the retail stores. Even if retailer access was provided, the cost of such an endeavor would be prohibitive, considering generally low LED sales volume at each individual store. In order to satisfy confidence and precision requirements around the NTG estimate, the evaluators would have to either spend a lot of time at each store, or conduct intercepts in many stores – or more likely, both. No other options exist to determine the income levels of customers purchasing these bulbs at dollar/discount stores. A weighted NTG value could be determined for the dollar/discount segment that is based on the assumption of a 1.0 NTG for the dollar/discount stores located in low-income neighborhoods, and a NTG of other retailers (established through sales data modeling or supply-side interviews) for dollar/discount stores located in non-low-income neighborhoods. It is possible, however, that this option would unfairly penalize the program since even in non-low-income neighborhoods, customers who choose to shop at dollar/discount stores may be more price-sensitive, and in the absence of the program discounts at those stores, could show a higher propensity to purchase the least costly alternative.

Witness Williamson also recommended for future evaluations of the Energy Efficient Lighting Program that the program should update its study on the percentage of bulb sales to residential and non-residential customers. The Company believes that in-store intercepts are the only method that would allow evaluators to update an estimate of bulb sales share between residential and non-residential customers. As noted above, without access to participating retailers to conduct intercepts, the evaluator is unable to develop an updated estimate. The Company will continue to work with Lighting Program Management to identify alternative methods to potentially update the residential/non-residential sales split.

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

A. Yes. Witness Neme has brought up several issues and ideas relating to EE programs and their relative mix. In addition, Witness Neme discussed the employment of a Technical Resource Manual ("TRM") as well as issues associated with determination of cost-effectiveness. He also indicated that proper venues to examine these issues would be the DEC/DEP Collaborative and associated working groups.

Q. DO YOU AGREE WITH WITNESS NEME'S RECOMMENDATION THAT THE ISSUES BROUGHT UP IN HIS TESTIMONY BE DISCUSSED IN THE DEC/DEP COLLABORATIVE AND ASSOCIATED WORKING GROUPS?

A. While the Company does not necessarily agree with all of the recommendations included in Witness Neme's testimony, it does agree that it is appropriate for the recommendations to be discussed at the DEC/DEP Collaborative.

As mentioned in my rebuttal testimony in DEC's DSM/EE cost recovery proceeding in Docket No. E-7, Sub 1164, I believe that given the commonality between DEC's and DEP's programs, a combined DEC/DEP

Collaborative would be preferable to a DEC-only Collaborative. Furthermore, as Witness Neme indicated, given the consideration needed to evaluate his program ideas, more than quarterly meetings will be required. Accordingly, I recommend that the Collaborative meetings be expanded from meeting quarterly to meeting every two months, as approved in the Sub 1164 Order.

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

A. Yes.

MS. FENTRESS: I would also move that Timothy Duff's rebuttal testimony consisting of 20 pages be entered into the record as if given orally from the stand, and that Rebuttal Duff Exhibit 1 be admitted as evidence. This was filed September 12, 2018.

COMMISSIONER BROWN-BLAND: And that motion will also be allowed.

MS. FENTRESS: Thank you.

(WHEREUPON, Rebuttal Duff Exhibit 1 is admitted into evidence.)

(WHEREUPON, the prefiled rebuttal testimony of TIMOTHY DUFF is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1174

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is 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

[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.

MS. FENTRESS: Finally, I move that the Company's Application filed on June 20, 2018, in this docket be admitted as evidence into the record as well.

COMMISSIONER BROWN-BLAND: There being no objection, that motion is also granted.

(WHEREUPON, Application of Duke Energy Progress, LLC is admitted into evidence.)

MS. FENTRESS: Thank you. That is all from the Company.

COMMISSIONER BROWN-BLAND: Thank you.

MR. NEAL: Good morning. David Neal again. The North Carolina Justice Center would move at this time to have the prefiled testimony of Chris Neme of the Energy Futures Group filed on September 4, 2018, consisting of 66 pages be entered into the record as if given orally from the stand, and move that his two exhibits marked as CN-1 and CN-2 be admitted into evidence.

COMMISSIONER BROWN-BLAND: And that motion will be allowed and the testimony of Witness Neme will be received as well as his two exhibits identified as they were marked when prefiled are received into evidence. Thank you.

(WHEREUPON, Exhibits CN-1 and CN-2 are admitted into evidence.)

(WHEREUPON, the prefiled testimony of CHRIS NEME is copied into the record as if given orally from the stand.)

I. Introduction and Qualifications

Q: PLEASE STATE YOUR NAME, EMPLOYER, AND BUSINESS ADDRESS.

A: My name is Chris Neme. I am a co-founder and Principal of Energy Futures Group, a consulting firm that provides specialized expertise on energy efficiency and renewable-energy markets, programs, and policies. My business address is P.O. Box 587, Hinesburg, VT 05461.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A: I received a Master of Public Policy degree from the University of Michigan (Ann Arbor) in 1986. That is a two-year, multi-disciplinary degree focused on applied economics, statistics, and policy development. I also received a Bachelor's degree in Political Science from the University of Michigan (Ann Arbor) in 1985. My first year of graduate school counted towards both my Master's and Bachelor's degrees.

Q: PLEASE SUMMARIZE YOUR BUSINESS AND PROFESSIONAL EXPERIENCE.

A: As a Principal of Energy Futures Group, I play lead roles in a variety of energy-efficiency consulting projects. Recent examples include:

- Representing the Natural Resources Defense Council (NRDC) in Illinois, Michigan, and Ohio consultations with utilities (including Duke Energy Ohio) and other parties on efficiency-program and portfolio design, cost-effectiveness screening, evaluation, shareholder incentive structures, and other related topics;

- Helping the National Association of Regulatory Utility Commissioners and the Michigan Public Service Commission staff assess the relative merits of alternative approaches to defining savings goals for utility-efficiency programs (focusing on lifetime rather than just first-year savings);
- Serving as an appointed expert representative on the Ontario Energy Board's Evaluation and Audit Committee for natural gas demand-side management, as well as on related committees to provide expertise on the conduct of gas and electric efficiency-potential studies;
- Serving on the Management Committee and leading strategic planning and program design for a team of firms, led by Applied Energy Group, that was hired by the New Jersey Board of Public Utilities to deliver the electric and gas utility-funded New Jersey Clean Energy Programs;
- Serving on a five-person national drafting committee for development of a new National Standard Practice Manual for cost-effectiveness screening of energy-efficiency measures, programs, and portfolios, which was published in May 2017;
- Providing technical support to the Arkansas energy-efficiency collaborative (commonly known as the "Parties Working Collaboratively") in assessing (at the Arkansas Commission's direction) how well the State's current practices in assessing cost-effectiveness aligns with national best practices; and
- Drafting policy reports for the Regulatory Assistance Project on a variety of energy-efficiency and related regulatory policy issues, such as whether 30% electric savings is achievable in 10 years, the history of efforts across the

United States to use geographically targeted efficiency programs to cost-effectively defer transmission and distribution system investments, and the history of bidding of efficiency resources into the PJM and New England capacity markets.

Prior to co-founding Energy Futures Group in 2010, I worked for 17 years for the Vermont Energy Investment Corporation ("VEIC"), the last 10 as Director of its Consulting Division managing a group of 30 professionals with offices in three states. Most of our consulting work involved critically reviewing, developing, and/or supporting the implementation of electric, gas, and multi-fuel energy-efficiency programs for clients across North America and beyond.

During my more than 25 years in the in the energy-efficiency industry, I have worked in numerous jurisdictions to develop or review energy-efficiency potential studies; develop or review Technical Reference Manuals ("TRM") of deemed savings assumptions; support utility-stakeholder collaboratives; negotiate or support development of efficiency-program performance incentive mechanisms; review or develop efficiency programs; and/or review or develop energy-efficiency evaluation frameworks and related studies. All told, I have worked on these and/or other policy and program issues for clients in more than 30 states, half a dozen Canadian provinces, and several European countries. I have also led courses on efficiency program design, published widely on a range of efficiency topics, and served on numerous national and regional efficiency committees, working groups, and forums. A copy of my curriculum vitae is attached as Exhibit CN-1.

Q: HAVE YOU PREVIOUSLY FILED EXPERT WITNESS TESTIMONY IN OTHER PROCEEDINGS BEFORE THE NORTH CAROLINA COMMISSION?

A: Yes, I filed testimony in May of 2018 in a similar proceeding regarding Duke Energy Carolinas' request for Approval of a Demand-Side Management and Energy Efficiency Cost Recovery Rider (Docket No. E-7, Sub 1164).

Q: HAVE YOU BEEN AN EXPERT WITNESS ON ENERGY-EFFICIENCY MATTERS BEFORE OTHER REGULATORY COMMISSIONS?

A: Yes, I have filed expert witness testimony on approximately 50 occasions before similar regulatory bodies in 10 other states and provinces, including most recently in Michigan, Ohio, Illinois, and Ontario.

Q: ARE YOU SPONSORING ANY EXHIBITS?

A: Yes.

- CN-1 Christopher Neme CV
- CN-2 Advanced Energy, Duke Energy, Lockheed Martin, and North Carolina Community Action Association, *Evaluation of Duke Energy's Helping Home Fund*, p. 2 (October 2017) (hereinafter "Helping Home Fund Evaluation")

II. Testimony Overview

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: My testimony addresses three issues:

1. the reasonableness of Duke Energy Progress' (DEP's) energy-efficiency savings estimates;
2. the completeness of DEP's assessment of the cost-effectiveness of its efficiency programs; and
3. the proposed 2019 energy-efficiency program portfolio, particularly the sufficiency of its savings goals, the extent of its reliance on short-lived savings and the level of resources devoted to serving low income customers.

Q: WHAT ARE YOUR SUMMARY FINDINGS WITH REGARD TO DEP'S ENERGY-EFFICIENCY SAVINGS ESTIMATES?

A: While I have not reviewed every detail of each of the program evaluation studies upon which most of DEP's savings estimates are based, my high-level review of the evaluation studies DEP has filed in this proceeding suggests that they have been conducted professionally.

That said, I have a few concerns:

- **No published Technical Reference Manual ("TRM")**. Most jurisdictions have a TRM to publicly document all current assumptions regarding efficiency-measure energy savings, peak-demand savings, savings life, and incremental costs – as well as references for the sources of those assumptions. When evaluation studies suggest that an assumption needs to be updated, the TRM is also updated. The absence of such a single reference document makes it more difficult to review the reasonableness of DEP's savings and net-benefits claims properly.

- **Potential for overstating of My Home Energy Report savings**. DEP is assuming that My Home Energy Report program savings last only as long as a residential customer is enrolled in the program. As a result, DEP effectively assumes that those savings are reacquired by re-running the program each year for the same participants. However, there is evidence that a significant portion of the savings produced from any set of customers participating in year one would continue to persist in subsequent years even if program delivery were ended for those customers. Thus, DEP may be significantly over-estimating the *new* savings this program produces each year. The persistence of savings and implications for annual savings claims and future program design and delivery strategy are issues that should be evaluated.
- **Potential for overstating lifetime savings (and economic net benefits) of residential lighting measures.** DEP is assuming that the annual savings produced by a residential LED light bulb installed as a result of its efficiency programs will be realized every year—at the same level experienced in the first year—for each of the next 20 years. These projections do not take into account new federal efficiency standards imposed by the Energy Independence and Security Act (EISA) for most residential light bulbs. Those standards will essentially mean roughly 80% of the savings realized from most LED light bulbs installed before 2020 will not be attributable to utility programs after 2020.

I discuss each of these issues in greater detail in Section III of my testimony.

Q: PLEASE SUMMARIZE YOUR ASSESSMENT OF DEP'S APPROACH TO ASSESSING COST-EFFECTIVENESS OF ITS PROGRAMS.

A: While DEP includes all of the costs that should be included under the Utility Cost Test (UCT) and the Total Resource Cost (TRC) test, it does not include all of the benefits that should be included under each test.

To begin with, and as made clear in the *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM), all utility system benefits should be included in both the UCT and TRC (and all other tests for that matter). While DEP includes avoided energy, avoided capacity, and avoided transmission and distribution system costs, it does not include any value for avoided ancillary service costs, avoided credit and collection costs or the value of risk mitigation that efficiency resources provide. Also, DEP has accounted for reduced line losses using its average annual line loss rate, rather than the more appropriate (and higher) average annual *marginal* line loss rate for valuing energy savings and the (even higher) average *peak marginal* line loss rate for valuing peak savings. The combination of these shortcomings leads to a likely average understatement of utility system benefits from its efficiency program portfolio on the order of 20%. For individual programs, the understatement could be higher (especially for low income programs and programs promoting air conditioning efficiency) or lower.

In addition, under the TRC, DEP has not accounted for the value of avoided gas costs (for measures saving both electricity and gas), avoided water costs (for measures that reduce electricity use through water conservation) and/or other participant non-energy benefits. This is important because the TRC is supposed to be an assessment of cost-effectiveness from the combined perspective of the utility system and program participants. While DEP's TRC analysis appropriately includes both all utility system costs and all participant costs, on the benefits side, it includes only utility system benefits. The result is a structurally biased test.

I discuss each of these issues in greater detail in Section IV of my testimony.

Q: PLEASE SUMMARIZE YOUR ASSESSMENT OF DEP'S PROPOSED 2019 EFFICIENCY PROGRAM PORTFOLIO.

A: There are a number of admirable elements in DEP's 2019 planned portfolio. First, DEP's efficiency program portfolio is forecast to be very cost-effective, producing $2.63 in supply-cost savings for every dollar DEP is projecting it will spend.[1] And that may be conservatively low, as the portfolio produced $3.50 in supply-cost savings for every dollar DEP actually spent in 2017.[2] In just the three years from 2015 through 2017, DEP's efficiency programs have saved enough energy at the time of system peak to eliminate the need for the equivalent of approximately two and a half natural gas "peaker" power plants. Second, the portfolio includes a wide range of efficiency measures and programs. Third, there are some national state-of-the-art program design features, particularly the

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[1] DEP reports that the UCT benefit-cost ratio for its combined portfolio of efficiency and demand response programs was 2.63 (Evans Exhibit 7). This includes the effects of three demand response programs, one of which has a UCT benefit-cost ratio greater than the portfolio average (EnergyWise Home) and two of which are less cost-effective than the portfolio average (EnergyWise for Business and Commercial Industrial Governmental Demand Response).

[2] Response to SACE DR Item No. 1-1.

Company's recent launch of a midstream channel for promoting non-residential HVAC, lighting, food service, and IT measures.

That said, I also have some over-arching concerns about the portfolio:

- **Projected savings are below the target of 1.0% of total sales**. DEP is proposing to acquire first year savings equal to 0.84% of total sales. Though substantial, that is still appreciably below the 1.00% annual target that the Company agreed to reach in a 2015 settlement in the then-proposed merger of Duke Energy and Progress Energy ("Merger Settlement"), let alone the 1.40% average annual savings level that would have been required for the Company to reach a cumulative 7.00% over five years (2014 through 2018) to which it also agreed in the same settlement.[3] Further, there is no evidence in this proceeding to suggest that the Company's proposed 2019 savings target is close to the level at which all cost-effective savings are being acquired. That should be the Company's ultimate goal. Otherwise, DEP customers will be unnecessarily investing in more expensive supply options.
- **Too much emphasis on short-lived savings**. About 55% of residential annual savings and 31% of the total portfolio savings in 2019 are forecast to come from DEP's My Home Energy Report program. Savings from such behavioral programs are very short-lived, though longer than the one year DEP is currently assuming. The short-lived programs generally provide less economic value to participating customers, as well as to the grid.

[3] The Merger Settlement with SACE, South Carolina Coastal Conservation League, and Environmental Defense Fund calls for annual energy savings of at least 1% of prior-year retail sales beginning in 2015 and cumulative savings of at least 7% over the period from 2014 through 2018. The Merger Settlement was approved by the Public Service Commission of South Carolina ("PSCSC") in Docket No. 2011-158-E.

- **Inadequate promotion of longer-lived major measures or comprehensive treatment of buildings**. The Residential Smart$aver Energy-Efficiency Program (historically called the Home Energy Improvement program), through which DEP promotes major measures such as heat pumps, central air conditioners, heat pump water heaters, attic insulation, and duct sealing, is forecast to produce only about 2% of its total residential sector savings.
- **Insufficient planning to offset what will be a significant loss of residential-lighting savings potential once the 2020 federal EISA efficiency standards go into effect.** DEP's filing does not demonstrate how the Company will make up for the loss of lighting savings following full implementation of the federal efficiency standards for lightbulbs. DEP's over-emphasis on short-term savings and under-emphasis on longer-lived major measures is a structural problem with the Company's portfolio. Greater promotion of longer-lived measures will diversify DEP's program portfolio, which will be an acute need following the loss of lighting savings.
- **Need for increased investment in lower-income communities.** Nearly one-third of North Carolina households have incomes at or below 200% of the Federal Poverty Guideline. In contrast, DEP is forecasting that in 2019 it will spend only $2 million, or about 4.5% of its residential efficiency program budget, on its only program specifically designed to reach low income customers (targeted to customers with incomes at or below 200% of Federal Poverty Guidelines), the Neighborhood Energy Savings Program. Even when DEP's shareholder contribution to the Helping Homes Fund is considered, the

Company's investment in dedicated low income programs is small in comparison to the proportion of its customers who would benefit from such programs, and far less than that of most other major utilities.

Q: HOW COULD DEP MODIFY ITS 2019 PORTFOLIO OF PROGRAMS TO ADDRESS THESE SHORTCOMINGS?

A: I have four recommendations for improvement:

- First, DEP should endeavor to improve participation in its Residential Smart$aver (historically known as Home Energy Improvement) program significantly through establishment of a midstream channel for promoting specified measures through equipment distributors (and possibly retailers and/or other parts of the supply chain), increasing incentives, enhancing marketing, and/or other means to reach more customers. This should also improve the program's cost-effectiveness, both by spreading fixed program costs over a larger volume of participants and savings and also by ultimately reducing administrative costs.
- Second, DEP should consider greater promotion of whole-building retrofits, including support for both (A) improvements to building envelopes (e.g. installing insulation and air leakage reduction); and (B) retrofitting single-family and multi-family buildings that currently have electric-resistance heating with high-efficiency heat pumps. Such efforts could also be targeted to lower-income communities, but should ultimately aim to address all such cost-effective opportunities within the residential sector. One option would be to emulate an Entergy Arkansas program that is weatherizing

manufactured homes. Another would be to consider a new pilot-program (such as one in Illinois) that is promoting heat-pump retrofits in electric-resistance-heated multi-family buildings.

- Third, DEP should build on recent success in promoting efficiency measures for non-residential customers through the midstream channel of its non-residential Smart$aver prescriptive rebate program.
- Fourth, DEP should assess the potential to reduce the number of non-residential customers who opt out of its programs by both improving their understanding of its programs and improving the designs of its programs to make them more attractive to such customers.

Q: HOW DO YOU RECOMMEND THAT THE UTILITIES COMMISSION ADDRESS YOUR RECOMMENDATIONS?

A: All of the EM&V issues, cost-effectiveness analysis issues, and efficiency-portfolio design issues that I raise are complicated and would probably best be addressed, at least initially, through in-depth discussions between the utilities and other parties, with solutions ultimately brought back to the Utilities Commission. Thus, I recommend that the Utilities Commission refer the issues to the DEP-DEC Collaborative, with a requirement that DEP report back on decisions in their 2019 Rider proceeding. Note that this will require more intensive engagement between DEP and other parties than has historically been the case, or than is even possible through quarterly Collaborative meetings alone. However, my experience with collaboratives in other jurisdictions suggests that this can be accomplished by establishing subcommittees or working groups that meet as often as required to reach resolution on specific issues and to identify any points of disagreement that cannot be bridged. In his rebuttal testimony in Docket No. E-7, Sub 1164, DEP witness Evans also suggested that a more intensive Collaborative process could be appropriate.

III. DEP's Energy-Efficiency Savings Estimates

Q: BASED ON YOUR REVIEW, ARE YOU IN A POSITION TO ENDORSE THE SAVINGS ESTIMATES PUT FORWARD BY DEP IN THIS PROCEEDING?

A: No, but not because I have reason to think that there are widespread problems. Such a thorough review is beyond the scope of my engagement with NC Justice Center, et al., and would take more time and resources than I could devote to this case. It would be a less burdensome task to undertake such a review, however, if DEP or the State as whole made use of a Technical Reference Manual ("TRM").[4]

1. Value of Technical Reference Manual (TRM)

Q: WHAT IS A TRM?

A A TRM publicly documents all current estimates of efficiency-measure energy-savings, peak-demand savings, other fuel savings, savings life, incremental costs and, other related assumptions – as well as references for the sources of each assumption. When evaluation studies suggest that an assumption needs to be updated, the TRM is also updated. This typically takes place annually. TRMs also sometimes document protocols and/or EM&V methods that should be used to estimate savings from custom projects for which prescriptive assumptions are not appropriate.

Q: WHAT IS THE VALUE OF A TRM?

A: TRMs provide a single reference that regulators and other parties can use to ensure that utility savings estimates are based on correct assumptions. They also

[4] Note that in some jurisdictions, this is called a Technical *Resources* Manual instead of Technical *Reference* Manual.

provide transparency for regulators and other parties regarding the basis for all utility-savings estimates, as well as other key inputs to cost-effectiveness calculations. That makes it easier for all parties to identify quickly when key assumptions may be outdated and/or when targeted evaluation activity may be needed to update assumptions. That includes assumptions, such as savings life and incremental cost, that are often not addressed by impact evaluations. Such assumptions are important inputs to cost-effectiveness calculations and shareholder-incentive calculations.

Q: DO MOST STATES HAVE A TRM?

A: Yes. In my experience, most states – especially those with fairly robust efficiency-program offerings – have TRMs. For example, in the South there are TRMs currently in use in Arkansas (currently on its seventh iteration),[5] New Orleans (currently on its first iteration),[6] Texas (currently on its fifth iteration),[7] and by TVA (currently on its seventh iteration).[8] TRMs have also been developed and used by utilities in Illinois, Indiana, Michigan, Ohio, Pennsylvania, Missouri, New Jersey, other mid-Atlantic states, New York, the New England states, the Pacific Northwest states, California, and at least half a dozen other states.[9]

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[5] http://www.apscservices.info/EEInfo/TRMv7.0.pdf.
[6] No on-line link is available.
[7] http://www.texasefficiency.com/index.php/emv.
[8] https://www.tva.gov/Energy/EnergyRightSolutions.
[9] For a list of jurisdictions with TRMs as of a year ago see U.S. Department of Energy, *SEE Action Guide for States: Guidance on Establishing and Maintaining Technical Reference Manuals for Energy Efficiency Measures*, Evaluation, Measurement and Verification Working Group, June 2017 (https://www4.eere.energy.gov/seeaction/system/files/documents/TRM%20Guide_Final_6.21.17.pdf).

Q: WHAT DO YOU RECOMMEND THAT THE UTILITIES COMMISSION DO TO ADDRESS YOUR CONCERNS REGARDING THE ABSENCE OF A NORTH CAROLINA TRM?

A: I recommend that the Commission instruct the DEP-DEC Collaborative to discuss the merits of and process for developing a North Carolina TRM. I further recommend that the Commission instruct DEP to report back in its 2019 Rider filing on either (1) the process and timeline by which a TRM will be developed; or (2) why a decision was made to not pursue development of a North Carolina TRM, including whether that was a consensus decision of the Collaborative as well as the arguments presented in favor of a TRM, the arguments against a TRM, and why DEP concluded the disadvantages of a TRM outweighed the advantages.

2. My Home Energy Report Program Savings Life

Q: WHAT IS YOUR UNDERSTANDING OF DEP'S ASSUMPTION REGARDING THE LIFE OF SAVINGS FROM ITS MY HOME ENERGY REPORT PROGRAM?

A: DEP is assuming that the savings from this program last one year.[10]

Q: WHAT ARE THE IMPLICATIONS OF THAT ASSUMPTION?

A: DEP assumes that in each year, in addition to sometimes reaching new participants, it needs to "re-reach" the previous year's participants in order to reacquire savings procured the previous year, which are assumed to have "expired." Thus, each year, DEP counts the savings from all program

[10] Response to SACE DR Item 1-14.

participants, regardless of the year in which they started participating, as part of its estimates of the *new* annual savings it is producing each year.

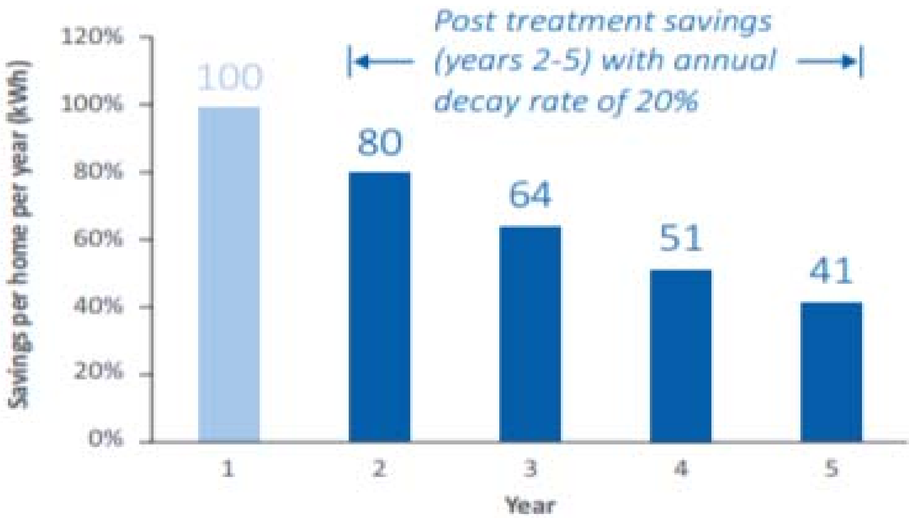
Q: IS THAT A REASONABLE ASSUMPTION?

A: Probably not. A number of studies of residential behavior programs have shown that savings produced from a given year of program delivery do not expire after one year if the program is stopped. Instead, a significant portion of the savings will persist into the years following program termination, though the amount that persists declines over the course of several years. One commonly referenced study suggests that, on average, savings achieved during a program year decay (or decline) by about 20% every year following program termination.[11] As Figure 1 illustrates, that would mean that 80% of the program-year savings persist into the first year following program termination, 64% persist into the second year following program termination, 51% persist into the third year following program termination, etc.

Figure 1: Home Energy Report Savings Persistence 20% Annual Decay Rate[12]

[11] Khawaja, Sami and James Stewart, Long-Run Savings and Cost-Effectiveness of Home Energy Report Programs, published by The Cadmus Group, Inc., Winter 2014/2015 (http://www.cadmusgroup.com/wp-content/uploads/2014/11/Cadmus_Home_Energy_Reports_Winter2014.pdf).

[12] This is a copy of Figure 3 from the Cadmus paper.



Q: DO ANY OTHER JURISDICTIONS ADJUST SAVING ASSUMPTIONS TO ACCOUNT FOR THIS UNDERSTANDING OF SAVINGS PERSISTENCE FROM RESIDENTIAL BEHAVIOR PROGRAMS?

A: Some states have adjusted the way that they estimate savings from such programs. For example, the Illinois TRM now requires electric utilities in the state to assume that 80% of savings achieved in a program-participation year persist into the first year following program termination, 54% into the second year, 31% into the third year and 15% into the fourth year.[13] Thus, if a utility's residential behavior program achieves annual savings of 100 kWh per participating customer each year, it can only claim 20 kWh of new incremental annual savings in the second consecutive year of delivery to the same set of customers.[14]

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[13] Illinois TRM Version 6.0, Volume 4, p. 9 (http://ilsagfiles.org/SAG_files/Technical_Reference_Manual/Version_6/Final/IL-TRM_Effective_010118_v6.0_Vol_4_X-Cutting_Measures_and_Attach_020817_Final.pdf).

[14] Unless savings per customer increase, which they sometimes do after more than one year of participation. For example, if average savings per customer were 100 kWh in the first year and grew to 120 kWh in the second year, the utility could claim 40 kWh of new incremental annual savings per

Q: CAN THAT APPROACH TO ACCOUNTING FOR THE PERSISTENCE OF SAVINGS FROM RESIDENTIAL BEHAVIOR PROGRAMS AFFECT PROGRAM-DELIVERY STRATEGY?

A: Yes, it can, for a couple of related reasons. First, it significantly reduces the amount of *new* annual savings a utility can count from repeat participants towards any annual savings goals. And because the cost of the program per participant does not change, the cost per unit of new annual savings from repeat participants goes up considerably. That, in turn, has the potential to make program delivery to repeat participants comparatively more expensive per new annual kWh saved than other programs to which efficiency portfolio budgets can be allocated. Second, it can even render it not cost-effective to deliver the program to repeat participants.[15]

As a result, it may make sense to adjust program design and delivery strategy. One option is to rotate delivery of residential behavior programs to different sets of customers each year, and not return to a group of customers until at least three or four years have passed since they last received the My Home Energy Report. That is the strategy that Ameren Illinois has adopted for its 2018-2021 plan. There are undoubtedly other options that merit consideration as well.

Q: ARE YOU SUGGESTING THAT DEP NEEDS TO CHANGE ITS ASSUMPTION OF A ONE-YEAR LIFE FOR SAVINGS FROM ITS MY

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repeat participant, or the difference between the 120 kWh measured in the second year and the 80 kWh that would have persisted into the second year had the program not been offered again to the same customers.

[15] On the other hand, for customers to whom the program is delivered for just one year, cost-effectiveness could improve substantially – relative to DEP's current program cost-effectiveness estimates – because significant portions of the savings will persist into future years whereas DEP is assuming savings have just a one year life.

HOME ENERGY REPORT PROGRAM, WITH ATTENDANT CHANGES IN THE AMOUNT OF NEW SAVINGS IT COUNTS EACH YEAR?

A: I think it likely that it will be appropriate to change that assumption. However, I would recommend that more analysis be done, considering the applicability of the results of other studies' estimates of savings decay/persistence to DEP's program, before making any specific changes. It may also be appropriate to stop delivering the program for a set of participants and to perform an evaluation of savings persistence over time for those participants in order to refine any changes in savings assumptions. Finally, it will be important to consider the extent to which any change in assumption regarding measure life – as well as other concerns I discuss further below – supports changes to program emphasis and delivery strategy. This is an issue that the Utilities Commission should refer to the DEP-DEC Collaborative for discussion, analysis, and ultimate recommendations on how to proceed.

3. EISA Impact on Residential Light Bulb Savings Life

Q: WHAT MEASURE-LIFE ASSUMPTION IS DEP USING FOR RESIDENTIAL LED LIGHT BULBS ITS PROGRAMS ARE CURRENTLY PROMOTING?

A: Based on the evaluation report for DEP's Free LED program, it appears as if DEP is assuming that LED light bulbs promoted through its retail-based Energy Efficient Lighting Program have a savings life of 20 years.[16]

Q: IS 20 YEARS A REASONABLE ASSUMPTION FOR THE MEASURE LIFE OF AN LED LIGHT BULB?

[16] Response to SACE DR Item 1-13.

A: 20 years appears to be an optimistic assumption, even for the technical life of an LED light bulb. Most jurisdictions that I am familiar with assume somewhere between 10 and 15 years. That is also consistent with the Energy Star requirement for minimum hours of use for the most common (omni-directional) LEDs (15,000)[17] and DEP's most recent evaluation estimate of average daily hours of use of LEDs (2.88 hours)[18].[19] Moreover, as noted in my recent testimony in Docket E-7 Sub 1174, Duke Energy Carolinas typically assumes 12 years.

More importantly, for most LEDs it is not reasonable to assume that the technical life or equipment life of an LED is equal to its *savings life*. Put another way, multiplying the first-year savings of a standard LED by its assumed 20-year technical measure life – or even an assumed 14-year technical measure life – will produce an unrealistically high estimate of lifetime savings for the measure.

Q: WHY IS THE SAVINGS LIFE SHORTER THAN THE TECHNICAL LIFE OR EQUIPMENT LIFE?

A: For most measures they are the same. But they can be different when the equipment life of the efficiency measure and the equipment life of the baseline measure being replaced or displaced are different. That is the case with LED light bulbs.

An LED light bulb that is purchased today – or next year – is assumed to be purchased instead of a halogen light bulb. The electricity savings produced by an

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[17] https://www.energystar.gov/products/lighting_fans/light_bulbs/key_product_criteria
[18] Evans Exhibit H.
[19] At 2.88 hours of use per day, the average LED purchased through DEP's residential lighting program will be used 1052 hours per year. Thus, a product meeting the Energy Star minimum criteria would last about 14 years (15,000 hours life divided by 1052 hours of use per year).

LED in its first year of operation will therefore be equal to the difference between its electricity consumption and that of the halogen that would have otherwise been purchased and installed. In addition to consuming less energy, LEDs last a lot longer – whether 10 years, 20 years, or something in between – than the halogens that they replace, which typically last only a year or two.[20] Thus, in the baseline scenario, the customer would be buying a new light bulb roughly every year or every other year, for as long as the baseline product remains a halogen bulb. If it were reasonable to assume that the baseline product would remain a halogen bulb for the next 14 years, the savings in each of the next 14 years of the LED equipment life would be the same as in the first year. In that case, the LED savings life would be equal to the LED equipment life. But that is not a reasonable assumption for standard LEDs because federal efficiency standards under the Energy Independence and Security Act (EISA) that will go into effect in 2020 will effectively require all new general service, screw-based lamps – i.e., those that "standard LEDs" would replace – to be as efficient as compact fluorescent light bulbs (CFLs). Thus, the annual savings estimated for standard LEDs will decline significantly starting in 2020. Put another way, rather than assuming that the current annual savings of an LED will last 14 years, the annual savings for an LED installed in 2017 should only have been assumed to continue at the 2017 level for three or four years, followed by 10 or 11 years of much lower levels of savings. Similarly, for a standard LED light bulb installed in 2019, the current annual savings estimate may be appropriate for only the first

[20] Based on review of a variety of screw based halogen light bulbs for sale from Home Depot (https://www.homedepot.com/s/halogen%2520light%2520bulb?NCNI-5).

year or two of the LED bulb's physical life, with lower savings assumed for the remaining 12 or 13 years.[21]

Q: IS THAT KIND OF ADJUSTMENT APPROPRIATE FOR ALL LED LIGHT BULBS?

A: No, this kind of adjustment is only appropriate for the kinds of light bulbs that are governed by the EISA product-efficiency standards. That means all of what are commonly known in the industry as "standard LEDs," particularly "A-Line LEDs," but also likely directional and decorative lamps that are included in a recently expanded definition of "general service lamp" adopted by the U.S. Department of Energy. DEP's programs may include savings from both LEDs that are covered by EISA and LEDs that are not. The savings from the LEDs not covered by EISA would be unaffected by the shifting baseline efficiency associated with EISA. It appears as if all of the bulbs proposed to be promoted in 2019 through DEP's Residential Energy Efficient Lighting program will be affected by EISA.[22]

Q: IS THE KIND OF ADJUSTMENT TO STANDARD LED SAVINGS LIVES THAT YOU ARE SUGGESTING CONSISTENT WITH NATIONAL BEST PRACTICE?

A: Yes. This is kind of savings adjustment was recommended a couple of years ago by the national "Uniform Methods Project," a national effort designed to bring best practice consistency to energy-savings estimation and evaluation:

[21] The savings for any standard LED installed in 2020 or later will be much smaller in every year of its operation (i.e. requiring a lower first year savings value as well as lower savings in subsequent years).
[22] Based on my review of product types listed in DEP's Excel attachment to its response to SACE 1-10, all would be governed by the U.S. Department of Energy's expanded definition of a general service lamp.

> *Bulbs expected to be in use in 2020 and beyond will be affected by the EISA backstop provision mentioned in Section 1. The life cycle savings of CFLs, therefore, should either terminate for any remaining years in the expected life beginning in mid-2020, or be substantially reduced after 2020 to account for the backstop provision. Similarly, the life cycle savings for LEDs should incorporate this upcoming baseline change.*[23]

Q: ARE THERE OTHER STATES THAT MAKE SUCH SAVINGS ADJUSTMENTS FOR STANDARD LEDS STARTING IN OR AROUND 2020?

A: Yes. Illinois is an example of a state that makes this adjustment. The Illinois TRM explains the LED "mid-life baseline adjustment" as follows:

> *During the lifetime of a standard Omnidirectional LED, the baseline incandescent/halogen bulb would need to be replaced multiple times. Since the baseline bulb changes over time (except for <300 and >2600+ lumen lamps) the annual savings claim must be reduced within the life of the measure to account for this baseline shift. For example, for 60W equivalent bulbs installed in 2014, the full savings…should be claimed for the first six years, but a reduced annual savings (…[initial first year energy savings]…multiplied by the*

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[23] Dimetrosky, Scott, Katie Parkinson and Noah Lieb, "Chapter 21: Residential Lighting Evaluation Protocol," The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures, published by the National Renewable Energy Laboratory, February 2015, http://energy.gov/sites/prod/files/2015/02/f19/UMPChapter21-residential-lighting-evaluation-protocol.pdf.

adjustment factor in the table below) claimed for the remainder of the measure life.[24]

Minimum Lumens	Maximum Lumens	LED Wattage (WattsEE)	Delta Watts 2014-2019 (WattsEE)	Delta Watts Post 2020 (WattsEE)	Mid Life adjustment(made from June 2020) to first-year savings
1490	2600	37.2	34.8	8.3	23.8%
1050	1489	23.1	29.9	5.1	17.1%
750	1049	16.4	26.6	3.6	13.5%
310	749	9.6	19.4	2.1	10.8%

As one can see from the table, the portion of initial LED savings that no longer apply after 2020 varies by lamp light output level. The average remaining savings across the four categories shown is 16%, representing an 84% reduction from pre-2020 annual savings levels.

The Arkansas TRM uses the same conceptual approach, but with slightly different assumptions. Specifically, it assumes that the baseline shift for standard LEDs does not change until 2022 instead of after 2020, so it assumes that there are a couple more years of the higher levels of savings and a couple fewer years of lower levels of savings.[25] That difference is a function of different assumptions regarding the average life of a current baseline halogen lamp.

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[24] Illinois Statewide Technical Reference Manual for Energy Efficiency, Version 5.0, Volume 3: Residential Measures, Final; February 11th, 2016; effective June 1st, 2016; p. 261, http://ilsagfiles.org/SAG_files/Technical_Reference_Manual/Version_5/Final/IL-TRM_Effective_060116_v5.0_Vol_3_Res_021116_Final.pdf.f

[25] Arkansas Public Service Commission, Arkansas Technical Reference Manual, Version 7.0, Approved in Docket 10-100-R, filed 8/31/2017 (http://www.apscservices.info/EEInfo/TRMv7.0.pdf).

Q: WHAT ARE THE IMPLICATIONS OF ACCOUNTING FOR THIS EISA-DRIVEN BASELINE SHIFT WHEN ESTIMATING SAVINGS FROM LED LIGHT BULBS?

A: The EISA-driven baseline shift, by definition, does not affect estimated first year savings from LEDs, at least not until 2020 when the prohibition on sale of products not meeting EISA standards goes into effect. However, because it affects estimated savings for a significant portion of the assumed physical life of the average LED governed by such standards, it will reduce estimates of the economic net benefits of such light bulbs.

Q: ARE YOU SUGGESTING THAT ANY PART OF DEP'S APPLICATION IN THIS PROCEEDING BE ADJUSTED TO ACCOUNT FOR SUCH IMPACTS?

A: No. There are several issues that would need to be worked out in detail before making adjustments to DEP's economic net benefit calculations, including the nature of the specific baseline shifts to be made, assumptions regarding the products for which they should be made,[26] assumptions regarding the assumed life of the average halogen baseline lamp being displaced today (the longer the halogen life, the longer the average period before the baseline shift occurs), etc. That said, this is an important issue for a measure that accounts for a significant portion of DEP's estimated annual savings. Thus, as with the issue of the My Home Energy Report program savings decay/persistence, the Utilities

[26] The U.S. Department of Energy's expanded definition of general service lamp is being challenged by some parties. While it appears likely to withstand such challenges, it may be appropriate to assess that likelihood thoroughly before making definitive decisions regarding the products for which adjustments should be made.

Commission should consider referring this issue to the DEC-DEP Collaborative for discussion, analysis, and ultimate recommendations on how to proceed.

IV. DEP's Cost-Effectiveness Analyses

Q: WHAT IS THE NATURE OF YOUR REVIEW OF DEP'S APPROACH TO ASSESSING THE COST-EFFECTIVENESS OF ITS EFFICIENCY PROGRAMS?

A: I have reviewed the range of avoided costs and other related assumptions used by DEP to estimate the benefits of its programs under the Utility Cost Test (UCT) and the Total Resource Cost (TRC) test. My review has focused principally on whether the proper categories or types of impacts – both costs and benefits – have been included in each test. In other words, I have focused on whether DEP has applied the tests in a manner that is consistent with the conceptual constructs of the tests and with national best practices, as outlined in the *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM).[27] I have not assessed the reasonableness of the specific values for such things as avoided energy or avoided capacity costs that have been provided by DEP.

Q: WHAT ARE THE CONCEPTUAL CONSTRUCTS OF THE UCT AND TRC TESTS AND WHAT DOES THAT IMPLY REGARDING THE CATEGORIES OF IMPACTS THAT SHOULD BE INCLUDED IN EACH OF THEM?

A: As explained in the NSPM, the UCT examines cost-effectiveness from the perspective of the utility system. It answers the question of whether utility

[27] Woolf, Tim et al., *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, Edition 1, Spring 2017 (https://nationalefficiencyscreening.org/national-standard-practice-manual/).

system costs will be reduced through utility investment in efficiency resources. Thus, a UCT analysis should include only the costs incurred by the utility and only the benefits that accrue to the utility system.[28] When analyzing cost effectiveness of an electric utility's efficiency program, that means the cost is the program budget and the benefit is the net present value (NPV) of the sum of all electric system benefits.

Conceptually, the TRC examines cost-effectiveness from the combined perspective of the utility system and efficiency program participants. In other words, it adds participant impacts to the utility system impacts included in the UCT. On the cost side, that means adding any contributions program participants make to the cost of efficiency measures.[29] On the benefit side, it means adding any non-electric benefits that those participants receive. That can be the value of gas savings (from measures like attic insulation in homes that have central air conditioning and gas heating), water savings (from measures like low flow showerheads that save electricity by reducing hot water consumption), and other non-energy benefits such as improved comfort, improved health and safety, improved building durability, and improved business productivity.

1. DEP's UCT Analysis

Q: HAVE YOU IDENTIFIED ANY WAYS IN WHICH DEP'S UCT COST-EFFECTIVENESS ANALYSIS DEVIATES FROM NATIONAL BEST PRACTICES?

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[28] NSPM, Appendix A.

[29] For example, if a utility efficiency program offers a $200 rebate for an efficient central air conditioner that has an incremental cost of $500, then the additional $300 paid by the customer is a TRC cost.

A: Yes. DEP appears to include all of the costs of its programs in its UCT cost-effectiveness analyses. However, there are categories of benefits that it does not include. For example, DEP does not include any avoided ancillary services costs, any avoided credit and collection costs or any value to reflect the risk mitigating benefits of efficiency (e.g. by reducing customers' exposure to future fuel price volatility).[30]

In addition, though DEP adjusts its estimated savings to account for line losses between its customers' meters and generators, its adjustments are based on average loss rates rather than marginal loss rates. Efficiency programs reduce loads on the order of just 1% per year, so their impact on line losses are – almost by definition – equal to marginal loss rates. This is important because line losses grow (largely) exponentially with load,[31] meaning that marginal line loss rates are much higher than average line loss rates.

Q: ARE THERE OTHER UTILITIES THAT INCLUDE AVOIDED ANCILLARY SERVICES COSTS, AVOIDED CREDIT AND COLLECTION COSTS AND THE VALUE OF RISK MITIGATION

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[30] In response to SACE DR 1-9, DEP indicated that avoided costs of compliance with renewable energy requirements were "not applicable". It is not clear whether that is because the costs of compliance with North Carolina's Renewable Portfolio Standard are already captured in the way that the Company's avoided energy and avoided capacity costs are estimated, or whether the Company has simply not accounted for the benefits of avoiding such costs. If it is the latter, that would be another category of utility system benefits not included. Counsel for DEP have confirmed that that this reference to avoided costs of compliance with renewable energy requirements being "not applicable" is not confidential information, even though it was produced in data request responses that otherwise include confidential information.

[31] Lazar, Jim and Xavier Baldwin, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, published by the Regulator Assistance Project, August 26, 2011 (https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/?sf_data=results&_sf_s=lazar+line+loss).

PROVIDED BY EFFICIENCY INVESTMENTS IN COST-EFFECTIVENESS ANALYSES?

A: I have not attempted to conduct an exhaustive review of which jurisdictions currently account for which categories of utility system benefits in their cost-effectiveness analyses.

That said, I am aware of several efficiency program administrators – including Commonwealth Edison in Illinois, DTE in Michigan and the New Jersey Clean Energy Program – that include avoided ancillary services costs in their cost-effectiveness analyses.

I am not aware of another utility that currently separately accounts for reduced credit and collection costs in its cost-effectiveness screening. However, Commonwealth Edison is currently in the process of having its independent evaluator quantify the effect that its low-income programs are having on the Company's credit and collection costs, with the objective of including such benefits in future cost-effectiveness analyses.[32] In addition, I am aware of a number of jurisdictions that include a non-energy benefits "adder" to account for a range of impacts in their cost-effectiveness analyses, including reduced utility credit and collection costs.

I am also aware of several jurisdictions that assign value to the risk-mitigating benefits of efficiency. For example, an avoided cost study completed for the New England states estimated that there is a wholesale risk premium of 8% that

[32] See Draft ComEd NEI Research Plan (particularly Task 6) at http://www.ilsag.info/nei-working-group.html.

should be added to avoided wholesale energy prices and avoided wholesale capacity prices. In essence, this increase in avoided costs accounts for the fact that a fixed price contract for multiple years is more expensive (an indicator of greater value) than the sum of the forecast future annual costs of energy and capacity.[33] Put another way, since efficiency measures effectively function like a fixed price contract because they "lock in" a certain amount of annual savings for a fixed period of time (for example, a rebate for an efficient central air conditioner is buying 15 years of a fixed level of savings), thereby insulating a customer for a number of years from future fuel price volatility. As a result, they have greater value than just the best estimate of future annual energy prices. Note that this only accounts for a portion of the risk-mitigating value of efficiency resources. Investment in efficiency resources also mitigate risk by generally being more flexible,[34] requiring less lead time to deploy, being available in smaller increments, and being better able to grow with load[35] than supply resources. These factors have been cited in the past as the basis for making efficiency resources a priority for acquisition by the Northwest Power Planning Council (now called the Northwest Power and Conservation Council) and were largely the basis for the Vermont Public Service Board's decision to

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[33] Synapse Energy Economics et al., *Avoided Energy Supply Components in New England: 2018 Report*, prepared for AESC 2018 Study Group, Amended June 1, 2018, pp. 253-254.

[34] For example, many efficiency programs are relatively easy to ramp up and down as needed. Efficiency resources can also be relatively easily shifted from one type of program to another to address shifting customer or system needs.

[35] For example, when the economy is booming and more buildings are being constructed and more products are being purchased, there are more opportunities for efficiency programs targeted at new construction and equipment purchases to gain participants and savings – just when such additional savings are more likely to be needed. Conversely, when the economy is stagnating and fewer buildings are being built and less energy consuming equipment is being sold – i.e. when less energy savings may be needed for the system – efficiency program participation and savings tend to be lower.

assign efficiency measures a 10% cost reduction (the equivalent of an 11.1% avoided cost adder) when conducting cost-effectiveness assessments.[36]

Q: ARE THERE OTHER UTILITIES THAT USE MARGINAL LINE-LOSS RATES RATHER THAN AVERAGE LINE LOSS RATES IN COST-EFFECTIVENESS ANALYSES?

A: Yes, both Illinois utilities – Commonwealth Edison and Ameren Illinois – use estimates of marginal line losses for energy and for peak capacity.[37] Similarly, the statewide New Jersey Clean Energy Program uses marginal line-loss rates.[38] In Arkansas, regulators have mandated the use of marginal line-loss rates.

Q: WHAT ARE THE POTENTIAL IMPACTS ON DEP'S UCT COST-EFFECTIVENESS SCREENING OF ITS PROGRAMS OF (1) EXCLUDING AVOIDED ANCILLARY SERVICES; (2) EXCLUDING AVOIDED CREDIT AND COLLECTION COSTS; (3) EXCLUDING THE RISK MITIGATING BENEFITS OF EFFICIENCY; AND (4) USING AVERAGE LINE-LOSS RATES RATHER THAN MORE APPROPRAITE MARGINAL LINE-LOSS RATES?

A: I would characterize the impacts of these four items as follows:

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[36] State of Vermont Public Service Board, Board Decision Adopting (as Modified) Hearing Officer's Report and Proposal for Decision, Docket No. 5270, 4/16/90.

[37] For example, see Commonwealth Edison's 2018-2021 Energy Efficiency Plan, Docket 17-0312, Exhibit 1.0 Appendix A (at https://www.icc.illinois.gov/docket/files.aspx?no=17-0312&docId=254601).

[38] http://www.njcleanenergy.com/files/file/Library/Market%20Research/Avoided%20Cost%20Memo%20(3-13-18).pdf).

1. **Excluding avoided ancillary service costs**. Estimates of avoided ancillary service costs vary: about 2% of utility system benefits for Commonwealth Edison in Illinois; 4% for New Jersey; and 13% for DTE in Michigan.[39]
2. **Excluding credit and collection costs**. This is likely to have a modest impact at the portfolio level, but may have a much more substantial impact on DEP's low-income program (Neighborhood Energy Savers) and possibly some other programs.[40]
3. **Excluding the risk mitigating benefits of efficiency**. As suggested in the discussion above, consideration of this benefit would increase the value of avoided energy and avoided capacity benefits by 8 to 11%.
4. **Using marginal line loss rates rather than average line loss rates**. DEP is using a single average annual loss rate of 5.1% in assessing the value of both avoided energy and avoided peak capacity.[41] My review of studies on this issue suggests that marginal loss rates are about 50% higher than average loss rates and that marginal loss rates at the time of system peak are on the order of three times higher than average annual loss rates.[42] Thus, I would expect

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[39] For example, New Jersey estimate that avoided ancillary services costs are $0.96/MWh in 2016. Their avoided wholesale energy costs for the same year ranged from $18.83 to $28.24 per MWh, depending on the costing period (http://www.njcleanenergy.com/files/file/Library/Market%20Research/Avoided%20Cost%20Memo%20(3-13-18).pdf).

[40] I recognize that income-qualified programs designed to reach DEP's low-income customers are not required to achieve cost-effectiveness. However, it is always useful to understand the full benefits that low-income programs provide to the system and to customers as a whole as well to low-income customers themselves.

[41] Confidential response to SACE DR 1-9.a.viii.1 and 1-9.a.viii.2. Counsel for DEP have confirmed that that this line-loss value is not confidential information, even though it was produced in data request responses that otherwise include confidential information.

[42] See: Lazar, Jim and Xavier Baldwin, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, published by the Regulator Assistance Project, August 26, 2011 (https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/?sf_data=results&_sf_s=lazar+line+loss).

the value of DEP's avoided energy costs to increase by about two and a half percent, and the value of its avoided capacity and avoided T&D costs to increase by about 10% if it were to more appropriately use marginal-loss rates instead of a single average-annual-loss rate.

The combined, compound effect of addressing these issues would likely increase the UCT estimates of benefits by on the order of 20%. However, the impacts would be bigger on some programs (e.g. the low income program because of bigger credit and collection cost impacts and programs promoting efficient air conditioning because of the greater impact of marginal line losses at the time of system peak) than others.

2. DEP's TRC Analysis

Q: HAVE YOU IDENTIFIED ANY WAYS IN WHICH DEP'S APPLICATION OF THE TRC TEST DIFFERS FROM NATIONAL BEST PRACTICES?

A: Yes. Consistent with the conceptual construct of the TRC, DEP appears to include all utility system costs and all participant costs in its TRC analyses. However, it does not include all benefits that should be included in the TRC.

First, all of the omitted utility system benefits discussed in the previous sub-section, as well as the use of lower average line loss rates rather than more

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and Commonwealth Edison's 2018-2021 Energy Efficiency Plan, Docket 17-0312, Exhibit 1.0 Appendix A (at https://www.icc.illinois.gov/docket/files.aspx?no=17-0312&docId=254601).

[42] http://www.njcleanenergy.com/files/file/Library/Market%20Research/Avoided%20Cost%20Memo%20(3-13-18).pdf).

accurate marginal loss rates discussed in the previous sub-section, result in understating TRC as well as UCT benefits estimates.

Second, it appears that DEP does not include the benefit of avoided gas costs for measures that save both electricity and gas.

Third, DEP also does not include the benefit of avoided water consumption for electric efficiency measures that save both electricity and water.

Fourth, DEP does not include any other non-energy participant benefits, such as improved comfort, improved health for residents (e.g., reduced asthma and improved mold control by weatherization and better air conditioning in low-income residences),[43] improved safety, improved building durability and improved business productivity.

Q: ARE THERE OTHER UTILITIES THAT INCLUDE AVOIDED GAS COSTS, AVOIDED WATER COSTS AND/OR OTHER NON-ENERGY PARTICIPANT BENEFITS IN THEIR TRC COST-EFFECTIVENESS ANALYSES?

A: I have not conducted an exhaustive review of which jurisdictions currently account for these benefits in their TRC cost-effectiveness analyses. However, I know that many do. I'll discuss each of these categories of TRC benefits separately.

[43] For examples of recent reports regarding how efficiency investments can improve the health of residential customers see: https://payforsuccess.org/project/baltimore-asthma-pay-success-project; https://www.greenandhealthyhomes.org/wp-content/uploads/GHHI-and-PFS.pdf; and https://www.southface.org/the-journal/healthy-evaluator-launches/.

- **Gas savings**. In my experience, the vast majority of jurisdictions that use the TRC test include other fuel savings (e.g. gas savings for an electric utility TRC calculation and vice versa). The only jurisdiction that I know of that does not is Ohio. Among the jurisdictions that use the TRC test as their primary test and that include other fuel savings in the test are Arkansas, New Orleans, Maryland, Illinois, California, Massachusetts, and New Jersey.
- **Water savings**. Many states include the value of water savings in their TRC test calculations. Examples, include Arkansas, Maryland, Illinois, and Massachusetts.
- **Other Participant non-energy benefits**. A growing number of jurisdictions include at least some value for other participant non-energy benefits. This is done in several different ways. For example, a number of different jurisdictions, including Colorado, Oregon, Washington, Vermont, DC, and New York, use generic non-energy benefits adders, ranging from 7.5% to 25% of utility system benefits,[44] applied to all programs, sometimes with even higher values for low-income programs. Some states, like Massachusetts, have invested in evaluations to develop program specific adders that currently equate to an average portfolio level adder of about 20%.[45] In contrast, Arkansas[46] and Illinois currently account for just

[44] Skumatz, Lisa (Skumatz Economic Research Associates), Non-Energy Benefits/Non-Energy Impacts (NEBs/NEIs) and their Role & Values in Cost-Effectiveness Tests: State of Maryland, March 31, 2014 (http://energyefficiencyforall.org/resources/non-energy-benefitsnon-energy-impacts-nebsneis-and-their-role-values-cost-effectiveness).
[45] Currently non-energy impacts account for 17% of total electric and gas system benefits, which is equivalent to 20.5% adder (0.17/0.83). Tetra Tech, Non-Energy Impact Framework Study Report, January 23, 2018 (http://ma-eeac.org/studies/special-cross-sector-studies/).
[46] Arkansas TRM Protocol L3 (http://www.apscservices.info/EEInfo/TRMv7.0.pdf).

operation and maintenance cost savings (in addition to other fuels and water), though Illinois utilities are currently in the process of evaluating participant non-energy impacts with the objective of using those local data-based estimates in future cost-effectiveness analyses. Similarly, Maryland assigns value only to commercial lighting operation and maintenance cost savings and the value of improved comfort for residential weatherization programs.

Q: GIVEN THAT THESE ADDITIONAL BENEFITS ARE, BY DEFINITION, NON-ELECTRIC BENEFITS, WHY IS IT APPROPRAITE TO INCLUDE THEM IN A COST-EFFECTIVENESS TEST USED TO DETERMINE WHICH EFFICIENCY RESOURCE MERIT INVESTMENT BY ELECTRIC RATEPAYERS?

A: It is important to separate two issues here: (1) whether a resource is cost-effective and therefore merits ratepayer investment; versus (2) how much ratepayers should be expected to invest in an efficiency resource. It is often appropriate to use different tests to answer these two questions. For example, a properly structured TRC test could be used alongside the UCT to inform the answer to the first question, without being used to answer the second question. Absent compelling public policy decisions to the contrary, the UCT is the best (and perhaps only) test for answering the second question because it is the only test that ensures that the amount of benefits electric ratepayers receive from efficiency programs is greater than the cost they incur. In other words, if a program passes the TRC because of a lot of non-electric benefits, and it is important to the state that electric ratepayers are not subsidizing gas savings or water savings or improved comfort or improved business productivity for efficiency program participants, use of the UCT will ensure such concerns are addressed.

The bottom line with respect to the TRC is this: if it is going to be used to inform efficiency investment decisions, it should be conducted in a way that reflects its underlying purpose – to assess combined impacts on the utility system and program participants in a balanced and unbiased manner (consistent with national best practices). Otherwise, there is no point to conducting the test at all, because an unbalanced and biased TRC does not provide any useful information regarding the economics of efficiency investments.

Q: WHAT ARE THE POTENTIAL IMPACTS OF THESE OMISSIONS ON DEP'S TRC COST-EFFECTIVENESS SCREENING OF ITS PROGRAMS?

A: The potential impacts are likely quite large. Remember that the approximately 20% addition to utility system impacts addressed in the UCT discussion applies equally to the TRC benefits calculation. Adding to that (A) gas and other fuel savings (which I have not quantified), (B) water savings (which I have also not quantified) and (C) other participant non-energy benefits (which are likely to be on the order of at least 20% of utility system impacts on average), and the combined effect is that DEP's TRC benefits estimates would likely be increased, on average, by more than 50%. To determine how much more would require a more detailed analysis – including quantification of other fuel and water benefits – that I have not had the time or resources to undertake for this proceeding.

Q: WHAT ARE THE IMPLICATIONS OF REDUCING THE BIASES INHERENT IN DEP'S CURRENT APPLICATION OF THE UCT AND TRC COST-EFFECTIVENESS TESTS?

A: Both DEP's portfolio of programs as a whole and each of its individual programs are unquestionably more cost-effective than DEP's current cost-effectiveness analyses suggest. Showing the true cost-effectiveness of the portfolio of programs would allow for better informed discussion regarding the potential for expanding the ambition of the program portfolio. It would show that more savings could be acquired because those savings are less expensive than alternative resources. In addition, it may become apparent that some of the individual programs that DEP is modifying or terminating to address concerns about cost-effectiveness do not actually require termination or modification. Indeed, it may be that termination and/or modification of those programs will ultimately result in lowering economic net benefits for DEP's customers. Ensuring that cost-effectiveness tests more fully capture all relevant benefits (including those currently omitted from the tests) as well as all relevant costs will enable a more informed assessment of such programs.

Q: HOW DO YOU RECOMMEND THAT YOUR CONCERNS REGARDING DEP'S COST-EFFECTIVENESS CALCUATIONS BE ADDRESSED?

A: As with some of the other issues raised in my testimony, these calculation issues are complex and arcane. Thus, I would recommend that they be addressed in the DEP-DEC Collaborative, with DEP required to report back to the Commission on the results of those Collaborative discussions in its filing next year.

V. DEP's Efficiency Program Mix

1. Overview

Q: WHAT IS YOUR VIEW OF DEP'S PLANNED ENERGY-EFFICIENCY PROGRAM PORTFOLIO FOR 2019?

A: There are some admirable elements to the portfolio:

- First, the efficiency-program portfolio is very cost-effective, demonstrating that efficiency programs are a least-cost resource for meeting consumers' electricity needs. For every dollar that DEP spends on its programs, it is eliminating the need to spend $2.63 on new power plants, the fuel to run those power plants, new power lines, and other investments otherwise needed to supply electricity to inefficient homes and businesses. This calculation is based on DEP's estimated UCT benefit-cost ratio as reported in Evans Exhibit 7. DEP's analysis also suggests that the programs are very cost-effective under the TRC test (benefit-cost ratio of roughly 2.1 to 1). As discussed above, these are likely to be very conservative estimates of the Company's programs because of the omission of key categories of benefits under both the UCT and TRC calculations. It is notable that in just the three years from 2015 through 2017, DEP's efficiency programs provided enough peak demand savings to eliminate the need for about two and a half natural gas "peaker" power plants.[47]

[47] The sum of the incremental annual peak savings for each year for all DEP's efficiency programs other than the My Home Energy Report program is 132 MW. Since virtually all of the savings from those programs are likely to have a life of at least three years, that is a reasonable estimate of the persisting peak savings after three years. On top of that, the My Home Energy Report program had a peak savings of 20 MW in 2017 (since this is a program that is estimated to have just a one-year life, I only include the peak savings from 2017), bringing the total for the efficiency program portfolio to 152 MW by the

- Second, DEP's efficiency program portfolio is fairly broad. That is, it promotes a fairly wide range of efficiency measures through a range of programs that at least theoretically could be accessed a by wide range of residential and non-residential customers.
- Third, I am impressed by the sophistication and advanced nature of some of the DEP programs or program elements. In particular, the Company deserves great credit for initiating a new midstream channel to its Non-Residential Smart$aver Prescriptive program for promoting a range of efficient products (HVAC, lighting, food service, and IT measures) to non-residential customers. This is a national state-of-the-art practice.

That said, I do have several concerns regarding the composition of the portfolio of programs and, perhaps even more importantly, the relative contributions of different programs to the Company's estimated savings.

Q: WHAT ARE THOSE CONCERNS?

A: I have several inter-related concerns:

- Insufficiently aggressive energy-savings targets.
- Too much relative emphasis on programs that deliver only very short-lived savings.
- Insufficient promotion of long-lived major measures and comprehensive treatment of buildings. This is a corollary to the point above.

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end of 2017. Note that this analysis is for efficiency programs only; the peak savings from DEP's demand-response programs are additional to that amount. According to U.S. Energy Information Administration data (Form EIA-860 Data-Schedule 3, 'Generator Data' (Proposed Units Only)), in 2016 DEP had 2 proposed natural-gas-fired combustion turbines, each with a summer capacity of 60.5 MW.

- Insufficient planning to offset what will be a significant loss of residential-lighting savings potential once the 2020 federal EISA efficiency standards go into effect.
- Need for expanded focus on delivering energy-saving programs in lower-income communities.

Though I express these concerns at the portfolio level, they are most pronounced for the residential sector.

2. Insufficiently Aggressive Savings Targets

Q: WHAT LEVEL OF SAVINGS IS DEP PLANNING TO ACHIEVE IN 2019?

A: DEP is planning to achieve annual energy savings of about 313 GWh from its North Carolina customers in 2019. That represents about 0.84% of its total annual retail sales and 1.21% of its retail sales to eligible customers (i.e. those that have not opt out of its programs).[48]

Q: HOW DOES THAT COMPARE TO PAST SAVINGS TARGETS TO WHICH THE COMPANY AGREED?

A: In a settlement to the then-proposed merger of Duke Energy and Progress Energy, the Company agreed to achieve annual energy savings of at least 1.0% of retail sales in 2015 and at least 7.0% cumulative annual savings – or an average

[48] The Company is forecasting that it will achieve 385 GWh of total efficiency program savings at the generator in 2019 (Evans Exhibit 1, p. 7). Approximately 85.56% of those savings – or 329 GWh – is allocated to North Carolina. Adjusted for 5.10% line losses (DEP response to SACE 1-9), the North Carolina savings are about 313 GWh at customers' meters. DEP's forecast 2019 North Carolina sales are 37,417 GWh (Miller Exh. 6). DEP is forecasting that non-residential customers with annual sales of 11,462 GWh will opt out of its programs (Miller Exh. 6), so sales to non-opt-out customers will be 25,954 GWh in 2019.

annual savings level of at least 1.4% – over the five year period of 2014-2018. The 0.84% proposed for 2019 is clearly well below those historic benchmarks.

Q: WHAT SAVINGS LEVEL SHOULD THE COMPANY BE PLANNING TO ACHIEVE IN 2019?

A: The Company should ideally be pursuing all cost-effective efficiency investments. By definition, to do anything less than that is to impose higher than necessary electricity costs on the Company's customers.

Q: HAS THE COMPANY PROVIDED ANY EVIDENCE TO SUGGEST THAT THE PROPOSED SAVINGS LEVEL FOR 2019 IS THE ECONOMICALLY OPTIMAL LEVEL – I.E. THAT IT CAPTURES ALL COST-EFFECTIVE EFFICIENCY?

A: No. The Company has provided no evidence in this proceeding to suggest that their proposed savings level for 2019 is even close to an "all cost-effective" standard.

Q: IS THERE REASON TO BELIEVE THAT HIGHER LEVELS OF SAVINGS COULD BE COST-EFFECTIVELY ACHIEVED IN 2019?

A: Yes, to begin with, the actual savings level achieved in 2017 was higher than what DEP is proposing in 2019; and the 2017 program portfolio had an actual benefit-cost ratio that was higher (substantially higher in the case of the UCT) than the Company has estimated for its 2019 portfolio.

Second, as I discuss in more detail below, the midstream channel for promoting efficient products to non-residential customers – particularly lighting products – proved to be more successful than the Company anticipated in 2017. Given my experience with these types of programs, I would expect that momentum to continue and lead to even greater levels of savings in subsequent years. Generally speaking, increasing participation will improve program cost-effectiveness because it allows for relatively fixed program costs to be spread across a larger volume of savings.

Third, also as I discuss further below, there are opportunities to expand the use of the midstream approach to increase residential program participation, savings and cost-effectiveness.

Finally, again as I discuss further below, there are some other program options that could allow for acquisition of additional cost-effective savings.

Q: HAVE YOU QUANTIFIED THE AMOUNT BY WHICH DEP COULD INCREASE ITS 2019 SAVINGS COST-EFFECTIVELY?

A: No, I have not. That level of analysis would take more time and resources than I could devote to this case.

Q: HOW DO YOU RECOMMEND THIS CONCERN BE ADDRESSED?

A: I recommend the Commission instruct DEP to engage with stakeholders in the Collaborative to explore the question of how much savings could be increased cost-effectively, and to reflect the results of those discussions in increased proposed savings targets for 2020.

3. Short-Lived Savings vs. Longer-Lived Savings

Q: WHAT DO YOU CONSIDER TO BE "SHORT-LIVED" SAVINGS?

A: If I had to draw a line, it would be savings from measures with a life of less than 7 to 10 years. However, I think it is more appropriate to take a more nuanced view by looking at the mix of savings lives.[49]

Q: WHAT IS THE BASIS FOR YOUR CONCERN REGARDING DEP'S LEVEL OF EMPHASIS ON SHORT-LIVED SAVINGS?

A: To begin with, 55% of DEP's residential annual savings and 31% of the DEP's *total* forecast 2019 incremental annual savings are forecast to come from just its Residential My Home Energy Report behavioral program. Those are extremely high percentages.

Second, a large fraction of other savings DEP is forecasting to acquire from the residential sector is lighting savings.[50] As I discussed in a previous section to this testimony, most residential lighting savings will not persist past 2020 (or maybe 2021) because of the baseline shift resulting from the 2020 federal EISA efficiency standards.

Finally, data from the American Council for an Energy Efficient Economy's (ACEEE's) 2017 Utility Energy Efficiency Scorecard, which rated the efficiency performance of 51 utilities across the country, also suggest that the average savings life of DEP's efficiency programs is much lower than average. Specifically, though DEP's average *annual* savings was only just below average

[49] For example, if 60% of savings are from measures that have a life of less than seven years, but most of those have lives of six years, that would be much better than if 50% of savings are from measures that have a life of less than seven years, but most of those have a life of one year.

[50] DEP is forecasting to acquire 98.7 GWh of annual savings in 2019 from other (non-My Home Energy Report) residential programs. Roughly one-quarter of that amount (24.9 GWh) is associated with its residential retail lighting program (Evans Exh. 1, p. 7). Another 15% is forecast to come from DEP's Multi-Family program (15.2 GWh) – with over half of those savings also being associated with lighting measures (DEP response to SACE 1-16). There are also lighting savings associated with the Energy Education, Neighborhood Energy Saver and Residential Energy Assessments programs (Excel file attachment to DEP response to SACE 1-16).

for the 51 utilities analyzed, its average *lifetime* savings was only about half of the average lifetime savings achieved by the same utilities.[51]

Q: HOW DOES THE 31% OF TOTAL PORTFOLIO SAVINGS THAT DEP IS FORECASTING TO ACHIEVE THROUGH ITS RESIDENTIAL BEHAVIOR (MY HOME ENERGY REPORTS) PROGRAM COMPARE TO OTHER UTILITIES?

A: I am not aware of any other investor-owned electric utility (other than DEP's affiliated companies, Duke Energy Carolinas and Duke Ohio) that is planning to get that much of its total savings from a residential behavior program. To illustrate that point, I have compiled estimates of the percentage of both residential and total savings that residential-behavior programs provide for 19 electric utilities in the eastern half of the United States, including nine Southern utilities. Though this is not an exhaustive review, I have endeavored to collect data for the largest (non-Duke) utilities in most Southern, mid-Atlantic and Midwestern states. Those estimates are provided in Table 1 below. Where possible, I have provided planned numbers to compare to DEP's plan for 2019; otherwise I have provided actual performance numbers for a recent year (mostly 2017). None of these utilities are planning to achieve (or did achieve in the most recent year for which data are available) as large a portion of total electric portfolio savings from their Residential Behavior programs as does DEP. In fact, the average non-DEP utility is getting only 9% of total portfolio electric savings from its residential behavior programs – less than one-third as much as DEP –

[51] Relf, Grace et al., 2017 Utility Energy Efficiency Scorecard, ACEEE Report U1707, June 2017 (https://aceee.org/research-report/u1707).

and the average of the other southern utilities for which I obtained data is even lower. Only one utility – Baltimore Gas & Electric – is planning to get close to as much of its savings from its Residential Behavior program as DEP.[52]

Table 1: Percentage of Total Savings from Residential Behavior Programs[53]

				MWh Savings			Behavior Savings %	
Utility	State	Plan or Actual	Year	Res. Behavior Program	All Res. Sector Programs	All Programs, All Sectors	% of Res. Sector Savings	% of Total Savings (All Sectors)
Duke Energy Progress	**NC/SC**	**Plan**	**2019**	**119,273**	**217,997**	**384,711**	**55%**	**31%**
Entergy New Orleans	LA	Plan	2019	8,000	19,416	53,894	41%	15%
Entergy Gulf States	LA	Actual	2017	0	10,419	17,057	0%	0%
Entergy Louisiana	LA	Actual	2017	0	18,101	28,456	0%	0%
Entergy Mississippi	MS	Actual	2017	0	13,227	26,294	0%	0%
Mississippi Power	MS	Actual	2017	3,421	7,611	18,333	45%	19%
Entergy Arkansas	AR	Actual	2017	7,901	104,051	264,992	8%	3%
SWEPCO	AR	Actual	2017	0	12,617	33,667	0%	0%
Georgia Power	GA	Actual	2017	12,366	94,119	375,375	13%	3%
Florida Power and Light	FL	Actual	2017	0	23,600	71,400	0%	0%
PEPCO	MD	Plan	2019	48,710	130,189	262,357	37%	19%
Baltimore Gas & Electric	MD	Plan	2019	138,200	335,267	500,267	41%	28%
PECO	PA	Plan	2016-20	304,999	844,412	2,091,301	36%	15%
All MA Utilities	MA	Actual	2016	140,547	723,392	1,569,661	19%	9%
Commonwealth Edison	IL	Plan	2018	275,502	575,606	1,619,028	48%	17%
Ameren Illinois	IL	Plan	2018	6,290	92,971	347,176	7%	2%
First Energy	OH	Plan	2017-19	125,788	632,302	1,781,833	20%	7%
American Electric Power	OH	Plan	2019	75,000	212,600	611,500	35%	12%
DTE	MI	Plan	2019	73,668	291,013	702,850	25%	10%
Consumers Energy	MI	Plan	2019	31,442	157,846	479,471	20%	7%
Avg of non-Duke Utilities								
Other Southern Utilities							**12%**	**4%**
All Utilities							**21%**	**9%**

Q: YOU TESTIFIED THAT THE AMOUNT OF NEW INCREMENTAL ANNUAL SAVINGS PRODUCED BY DEP'S MY HOME ENERGY

[52] The 28% provided in the table for BG&E includes only efficiency programs designed to promote efficiency actions by customers. BG&E also gets significant customer savings from conservation voltage regulation, which I did not include in the total savings into which I divided their residential-behavior program savings. If CVR savings were included, the BG&E average would drop to 21%.
[53] All values are from publicly available sources, either filed utility plans or utility annual reports. Specific references are available upon request.

REPORT PROGRAM MAY BE OVER-STATED. IF THAT PROVES TO TRUE, AND PERSISTENT SAVINGS WERE INSTEAD ACCOUNTED FOR, WOULD THAT ELIMINATE YOUR CONCERN ABOUT TOO MUCH OF THE COMPANY'S SAVINGS BEING SHORT-LIVED SAVINGS?

A: No. Though it is true that such an adjustment would reduce the percentage of annual portfolio savings coming from the My Home Energy Report program, this isn't just an accounting issue. As I note above, I have a corollary concern that DEP is not acquiring enough longer-lived savings. Moreover, if the My Home Energy Report *annual* savings declined because it was determined to be more appropriate to account for persistence of savings from participants over multiple years, DEP would need to acquire additional savings from other measures and programs in order to meet (or exceed) the 1.0% of prior-year sales target that it is already planning to fall short of achieving without such adjustments. Those additional savings should ideally come from longer-lived measures because they provide more lasting benefits both to consumers and to the utility system.

Q: CAN YOU GIVE EXAMPLES OF THE KINDS OF ADDITIONAL LONGER-LIVED SAVINGS DEP COULD ACQUIRE IN THE RESIDENTIAL SECTOR?

A: I would begin by suggesting efforts to increase significantly the number of customers participating in rebate offers for high-efficiency heat pumps, central air conditioners, heat-pump water heaters, pool pumps, attic insulation, air sealing, and duct sealing. There should be significant savings potential from these measures as they address the largest electricity end-uses in homes. However, DEP's Residential Smart$aver Energy Efficiency Program – the program through which all of these measures are promoted – is forecast to produce only about 2% of the Company's annual residential savings in 2019. The Company has implied that its 2019 savings forecast for this program is low because the forecast was developed early in 2017, before the market had reacted to some program design changes the Company had put in place, and that the changes were better received than expected.[54] Indeed, the 2017 level of actual savings was 76% higher than forecast for 2019. However, I believe participation rates for these measures could potentially be increased even beyond levels realized in 2017. Perhaps most notably, they could likely be dramatically increased by moving some of the measure incentives (e.g., those for heat pumps, central air conditioners, and heat pump water heaters) upstream to distributors, as the Company has recently done for a number of non-residential prescriptive incentives. Utilities that have made such transitions have achieved dramatic increases in participation. For example, United Illuminating in Connecticut saw a more than six-fold increase in participation in its heat pump water heater rebates when it moved rebates upstream to distributors.[55] Changes in rebate levels, marketing strategies, paperwork requirements, options for financing investments (for example, through on-bill financing), and/or other program elements may also enable increases in participation.

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[54] Response to SACE 1-21.

[55] Jennifer Parsons (UI, SCG and CNG), "Energize Connecticut Upstream Residential HVAC Program," presented at the 2015 ACEEE National Conference on Energy Efficiency as a Resource in Little Rock, Arkansas, September 2015 (http://aceee.org/sites/default/files/pdf/conferences/eer/2015/Jennifer_Parsons_Session4A_EER15_9.22.15.pdf). For other examples see: Merson, Howard et al., Five Years and Beyond with Supply Side Engagement: What's Next with Upstream and Midstream?", ACEEE 2018 Summer Study Conference on Energy Efficiency in Buildings, pp. 7-1 to 7-12 (http://aceee.org/files/proceedings/2018/index.html#/paper/event-data/p218).

In addition, the Company could increase longer-lived savings through greater promotion of whole-building retrofits. Such whole-building retrofits should include both (A) improvements to building envelopes (e.g. insulation and air leakage reduction), and (B) retrofitting efficient heat pumps in single-family and multi-family homes currently using inefficient electric-resistance heat. There may be quite a large number of such inefficiently electrically heated housing units.[56]

Q: CAN YOU GIVE EXAMPLES OF THE KINDS OF ADDITIONAL LONGER-LIVED SAVINGS DEP COULD ACQUIRE IN THE NON-RESIDENTIAL SECTOR?

DEP reports that in 2017, incentive payments in its prescriptive rebate program increased (relative to 2016 levels) by 57% for lighting, 54% for food service equipment, and 89% for HVAC equipment.[57] One key reason for the growth is the increased interest in LED lighting, which is likely tied to both fast improving product quality and declining costs. Another key to the increase was improvements to the midstream channel through which 67% of program savings were processed in 2017.[58] Absent any changes to the program to dampen participation, I would expect participation and savings to increase further in the

[56] I do not have statistics specific to DEP's North Carolina service territory. However, 62% of North Carolina homes use electricity as their primary heating fuel [U.S. Census, Selected Housing Characteristics, 2012-2016 American Community Survey 5-Year Estimates (https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk)]. Census data also suggest that more than half of electrically heated homes in the South Atlantic region rely upon some form of electric-resistance heating system, whether a furnace, electric baseboard, or portable electric heaters (U.S. Energy Information Administration, Residential Energy Consumption Survey, Table HC6.8: "Space heating in homes in the South and West Regions, 2015" (https://www.eia.gov/consumption/residential/data/2015/#sh)).
[57] Evans Exhibit 6, p. 33.
[58] Evans Exhibit 6, p. 34.

future as LED lighting products become even more attractive and as distributors' comfort with the midstream channel continues to increase.[59]

Q: COULD ADDRESSING COMMERCIAL AND INDUSTRIAL OPT-OUTS ALSO HELP DEP ACHIEVE LONGER-LIVED SAVINGS.

A: Yes. Customers responsible for approximately half of DEP's forecast commercial and industrial sales have opted out and/or are forecast to opt out of its efficiency programs for 2019. In my experience, non-residential customers opt out of efficiency-program offerings (when they have the option) for a variety of reasons. Some of those reasons are outside the control of the utility. Others are not. For example, some non-residential customers opt out because they do not feel that the utility's efficiency-program offerings adequately address their needs. Sometimes this feeling is a function of the business customer not fully understanding the efficiency programs that the utility offers. Other times, non-residential customers have legitimate concerns about the structure and nature of available program designs. I cannot speak to the extent to which either of those issues exists with respect to DEP's programs. However, if DEP could improve awareness of how its programs can help non-residential customers while also improving its offerings to better serve customers that are otherwise inclined to opt out, the Company could tap into another source of substantial energy savings.

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[59] DEP's filed 2019 savings forecast (Evans Exhibit 1, p. 7) shows a nearly 25% reduction in total non-residential savings relative to 2017 (Evans Exhibit 1, p. 5), which appears to be entirely a function of a nearly 50% decline in non-residential prescriptive savings – from 93 GWh in 2017 to just 48 GWh in 2019 (DEP Response to SACE DR 1-19). The Company appears to be suggesting that reduction is outdated because it was developed in early 2017, before it realized trade allies had a growing interest in promoting lighting measures and before the much more positive than expected market reaction to the Company's promotion of its midstream channel was realized (DEP response to SACE DR 1-18). Thus, there are indications that the Company itself believes greater savings – potentially significantly greater savings – are possible from continued promotion of the midstream channel for non-residential prescriptive measure savings.

Many of these savings would likely be long-lived and very cost-effective and would further reduce the amount of more expensive supply-side resources the Company would need to procure.

I understand that last year the Utilities Commission instructed DEP to explore how it could reduce opt-outs. DEP witness Evans very briefly discusses this issue in his testimony, noting that it was discussed in the Collaborative, but concrete and actionable solutions have not yet been identified. It appears as if additional Collaborative discussions, perhaps informed by some surveys of opt-out customers, would be warranted.

4. Preparing for the Impact of the 2020 EISA Federal Lighting Efficiency Standards

Q: WOULD THESE KINDS OF CHANGES TO THE COMPANY'S PROGRAM PORTFOLIO THAT YOU HAVE IDENTIFIED ADDRESS YOUR CONCERN REGARDING THE COMING 2020 EISA STANDARDS AND THE NEED TO REPLACE RESIDENTIAL LIGHTING AS A SIGNIFICANT SOURCE OF ENERGY SAVINGS?

A: Yes. The kinds of program additions, changes, and enhancements I have suggested should not only lead to longer-lasting savings and benefits, but also help diversify the sources of DEP's energy savings.

Q: WHY IS SUCH DIVERSIFICATION IMPORTANT?

A: As I noted earlier, the 2020 EISA standards are going to eliminate much of the residential energy savings that appears to currently make up a large majority of DEP's non-behavior program savings in the residential sector. There is unlikely to be a single measure or even a single program that, by itself, could fill the "savings gap" that EISA will create – at least not in the residential sector. Thus, it is important that DEP consider several different new programs and/or changes to existing programs that may collectively fill the gap.

Q: IS IT IMPORTANT THAT SUCH DIVERSIFICATION EFFORTS BEGIN SOON?

A: Yes, it is very important. 2020, when the new lightbulb standards go into effect, is only two years away. Depending on the program and market, it can take a year or two to launch new initiatives and then begin to gain significant traction in the market with them. Thus, the Company should be ramping up efforts now to acquire other important sources of savings.

5. Equitably Serving Lower Income Communities

Q: WHY IS IT IMPORTANT FOR DEP'S ENERGY-EFFICIENCY PROGRAM PORTFOLIO TO INCLUDE AN EXPANDED FOCUS ON LOW-INCOME COMMUNITIES?

A: There are at least three related reasons:

- **Equity**. Low-income customers are generally less likely to participate in programs marketed to the entire residential sector, both because such programs generally are designed for owner-occupied single-family detached homes and because they usually offer financial incentives to defray, but not eliminate, the cost of efficiency measures. Low income customers are also more likely to be renters. Renters face greater barriers to efficiency program participation than home owners, both because (A) they are typically not permitted to make decisions about envelope weatherization or replacement of energy-consuming appliances and related equipment; and because (B) the landlord who would incur the cost of making any major investments in building envelope, HVAC and appliance measures has reduced incentives to do so if s/he is not paying the energy bills.[60]

- **Need**. Low-income customers need energy-efficiency improvements more than other customers. This is because the portion of their income devoted to paying for energy tends to be much higher than for non-low-income customers. In addition, because of their limited means, paying their energy bills can force trade-offs with other necessities of life like food and health care.
- **Utility System Benefits**. Because of their financial constraints, low-income households are generally more likely to have problems paying their bills. DEP, like all utilities, incurs costs managing relationships with customers with bill-payment problems. As noted in Section IV of my testimony on cost-effectiveness issues, to the extent that low-income efficiency programs can lower such costs, there are added utility-system benefits that do not accrue to other programs (at least not to the same level).

Q: WHAT EFFICIENCY PROGRAMS DOES DEP OFFER TO LOW INCOME CUSTOMERS IN ITS SERVICE TERRITORY?

[60] This commonly referred to as the "split incentive" barrier.

A: DEP has one program in its filed efficiency program portfolio that appears targeted specifically to low income households: Neighborhood Energy Savers. Approximately 4.0% of its 2017 residential energy efficiency spending was on that program. In 2019, that is forecast to modestly increase to 4.5% of residential spending.

Q: IS THAT SUFFICIENT TO ADDRESS CONCERNS REGARDING EQUITY?

A: No. The Neighborhood Energy Savings program is targeted to neighborhoods where at least half of the households have income levels at or below 200% of the Federal Poverty Guideline.[61] While I have not seen data specific to just DEP's service territory, 31% of North Carolina households have incomes at that level.[62] Thus, if statewide poverty levels are a reasonable proxy for poverty levels in DEP's service territory, the size of the target market is roughly seven times the portion of residential program spending being devoted to it.[63] Put another way, although all DEP residential customers contribute to the DSM/EE rider, low-income customers are unlikely to benefit as much as non-low income customers.[64]

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[61] DEP response to SACE 1-24.

[62] Kaiser Family Foundation, Distribution of the Total Population by Federal Poverty Level (above and below 200% FPL), https://www.kff.org/other/state-indicator/population-up-to-200-fpl/?currentTimeframe=0&selectedRows=%7B%22states%22:%7B%22north-carolina%22:%7B%7D%7D%7D&sortModel=%7B%22colId%22:%22Location%22,%22sort%22:%22asc%22%7D.

[63] And this could be a conservatively low multiplier because DEP's Neighborhood Energy Saver program, though targeted at communities in which at least 50% of households are at or below 200% of the Federal Poverty Guideline, can treat customers in those neighborhoods that have incomes above that threshold.

[64] Low income customers, like all customers, can still benefit from the effects all of DEP's programs have on reducing utility system costs. They just cannot benefit as much as others if they cannot participate at levels commensurate with those of non-low income customers.

Q: IS IT POSSIBLE THAT THE DIFFERENCE IS MADE UP BY LOW INCOME PARTICIPATION IN OTHER DEP RESIDENTIAL EFFICIENCY PROGRAMS?

A: That is highly unlikely. There is probably some low income participation in some other residential programs. The My Home Energy Report program, for which there is no cost barrier to participation and for which DEP itself ultimately determines who will participate, is one possible example. The Residential Energy Efficient Lighting program, particularly if explicitly designed to target low income customers (which the Company's program summary suggests is a potential future change),[65] could be another. However, it is likely that low income customers disproportionately fail to participate in most other programs. Put simply, low-income customers rarely have the financial means to make contributions to efficiency-measure costs – especially major measures with significant costs such as water heaters, HVAC equipment, appliances and insulation – let alone to buy the new homes which are forecast to receive nearly 30% of DEP's residential efficiency program spending in 2019.[66]

Q: DO DEP'S CONTRIBUTIONS TO THE HELPING HOME FUND HELP ALLEVIATE LOW INCOME EQUITY CONCERNS?

A: They help, but more is needed to fully address the equity gap. For example, it is my understanding that earlier this year DEP committed to provide another $2.5 million in shareholder contributions to the Helping Home Fund. It is unclear what the expectations are regarding the period of time over which those funds will be spent. However, if that amount of money was committed and expected to

[65] Evans Exhibit 6, p. 6.
[66] Evans Exhibit 1, p. 7.

be spent every year, it would have the effect of a little more than doubling the Company's spending dedicated to low income customers – from about 4½ percent of total residential spending to a little more than 9½ percent. That is still much less than the 31% of the state's households with incomes at or below 200% of the Federal Poverty Guideline.

Q: HOW DOES DEP'S LEVEL OF EFFICIENCY PROGRAM SPENDING COMPARE TO OTHER UTILITIES?

A: Not very well. For example, in the American Council for an Energy Efficient Economy's (ACEEE's) 2017 Utility Energy Efficiency Scorecard, that ranked the 51 largest electric utilities on a variety of energy efficiency metrics, DEP (Progress NC in the ACEEE report) ranked near the bottom for low income programs.[67] The biggest reason is that it spent only 2.06% of its total efficiency program budget on dedicated low income programs.[68] One third of the other utilities were spending more than 10% of their efficiency program funds – i.e. at least five times as much as DEP – on low income programs. The median low income spending percentage was 6.23% - or about three times the DEP level.[69] Even if DEP spent an additional $2.5 million per year through its contributions to the Helping Home Fund (whose effects may not have been captured in the ACEEE utility scorecard), its low income spending as a percent of total efficiency program spending would still be well below the median utility in ACEEE's scorecard.

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[67] Relf, Grace et al., 2017 Utility Energy Efficiency Scorecard, ACEEE Report U1707, June 2017 (https://aceee.org/research-report/u1707).
[68] The forecast for 2019 is 2.4% (Evans Exhibit 1, p. 7).
[69] Commonwealth Edison (ComEd) of Illinois was the median utility. Coincidentally, in its most recent efficiency program plan filing (for 2018 through 2021), ComEd has increased its low income spending to about 14% of its total portfolio budget.

Q: COULD ANY OF THE IDEAS YOU PUT FORWARD IN YOUR TESTIMONY FOR INCREASING LONGER-LIVED SAVINGS ALSO BE TAILORED TO ADDRESS THE NEEDS OF LOWER INCOME CUSTOMERS?

A: Yes. For example, a new residential, whole-building retrofit program could be targeted first to electrically heated residential properties in low-income neighborhoods[70] and/or offered with a tiered incentive structure, with income-eligible customers receiving the retrofit services for free when necessary to enable them to participate.[71] Depending on capabilities, relationships, and other factors, such a program could even be delivered on DEP's behalf by community action agencies (CAAs) that already perform low-income home retrofits using federal and/or state dollars. Again, DEP has experience with this kind of partnership following its investment in the Helping Home Fund.[72]

There are a variety of other options that could also be considered. Later this year, Commonwealth Edison will launch a pilot program promoting heat-pump retrofits exclusively in electric-resistance-heated, low-income, multi-family buildings in the Chicago area.[73] Entergy Arkansas is currently running a program weatherizing manufactured homes, 37% of which were occupied by low-income households and another 29% either "likely" to be or "potentially"

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[70] Although for equity reasons, there would be value to initially targeting such a program offering to electrically heated low-income customers, such a program should ultimately aim (over time) to address all cost-effective opportunities for all customers, regardless of income.

[71] There can be situations, particularly in the case of multi-family rental buildings, where it may not be necessary to offer efficiency upgrades for free (e.g., where building owners are paying the energy bills and/or when building owners see enough value in lowering energy costs, reducing turnover rates, etc., that they are willing to bear a portion of the cost).

[72] CN Ex. 2, Helping Home Fund Report.

[73] Illinois Commerce Commission, Order, Docket 17-0312, September 11, 2017 (https://www.icc.illinois.gov/docket/files.aspx?no=17-0312&docId=256554).

low-income.[74] That program had a remarkable 8.56-to-1 TRC benefit-to-cost ratio in 2017. These programs could be models for similar future DEP initiatives.

6. Process for Consideration of New Program Ideas

Q: ARE YOU SUGGESTING THAT THE UTILITIES COMMISSION REQUIRE DEP TO LAUNCH SPECIFIC NEW EFFICIENCY PROGRAMS IN THE AREAS YOU HAVE IDENTIFIED?

A: No. Before a commitment to new program design or even a significant change to an existing program design is made, one would need to: flesh out the details of the proposed approach; assess the market; estimate likely participation and savings; develop a specific budget; and conduct a cost-effectiveness analysis.[75]

Q: WHAT DO YOU SUGGEST THE UTILITIES COMMISSION DO WITH RESPECT TO THE NEED FOR CHANGES TO DEP'S EFFICIENCY-PROGRAM PORTFOLIO?

A: As with the potential concerns I have raised regarding DEP's current savings assumptions and cost-effectiveness practices, I suggest that the Utilities Commission direct DEP to explore program options for decreasing emphasis on short-lived savings, increasing investment in longer-lived measures, filling the "savings gap" that will be created by the elimination of most residential-lighting savings potential in 2020, and increasing program offerings to low-income communities. This direction should include, but not be limited to, a requirement

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[74] Energy Arkansas, Arkansas Energy Efficiency Program Portfolio Annual Report, Docket No. 07-085-TF, 2017 Program Year, May 1, 2018 (http://www.apscservices.info/EEInfo/EEReports/Entergy%202017.pdf).

[75] The program concepts that I have proposed have been shown to be quite cost-effective in other jurisdictions, including jurisdictions in the South. That is a good indicator that they could be cost-effective in DEP's North Carolina service territory. However, a DEP-specific analysis should ultimately be required.

to consider the program ideas I have put forward. Analysis and consideration of all such program ideas should be pursued through the DEP-DEC Collaborative in order to involve stakeholders. Note that this will require more than a quarterly meeting; it will likely require significant subcommittee or "working group" discussions in between such meetings.

Q: HAVE YOU PARTICIPATED IN UTILITY-STAKEHOLDER COLLABORATIVE PROCESSES?

A: Yes. I have participated as a technical advisor in numerous utility-stakeholder collaborative processes in a wide range of jurisdictions. For example, since 2010, I have actively participated in virtually every collaborative meeting of Illinois's Stakeholder Advisory Group (SAG), which typically meets monthly, as well as in much more numerous and more regular SAG subcommittee or working-group discussions. In recent years, I have also participated in a number of similar regular collaborative discussions in Michigan, the Canadian province of Ontario, and, to a lesser degree, in Ohio. I am also currently working with the Arkansas collaborative, called the "Parties Working Collaboratively" ("PWC"), to support an effort that the Arkansas Commission directed to assess how its current cost-effectiveness test aligns with the best practice principles of the *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*.

Q: IN YOUR EXPERIENCE, CAN SUCH COLLABORATIVE DISCUSSIONS BETWEEN UTILITIES AND STAKEHOLDERS EFFECTIVELY ADDRESS COMPLEX PROGRAM DESIGN AND EM&V ISSUES?

A: Yes. In fact, they are often much more effective venues for addressing such issues than regulatory proceedings.

Q: WHY IS THAT?

A: Because the complex and often arcane nature of the issues demands both specialized expertise and significant "back-and-forth" dialogue to fully explore concerns and options for addressing them. In jurisdictions where well-functioning collaborative processes have become institutionalized, regulators often choose to focus their efforts on higher-level policy issues, such as savings targets and budgets, and direct the collaboratives to work out EM&V, program design, and other operational issues.

Q: CAN YOU ELABORATE ON THE KINDS OF ISSUES THAT COMMISSIONS HAVE DEFERRED TO COLLABORATIVES TO RESOLVE?

A: Because I am most familiar with Illinois, I will use it as an example. The Illinois Commerce Commission ("ICC") has directed the Illinois SAG to address the following issues, among others:

- **Statewide TRM**. Development of a statewide TRM that documents all savings, cost, measure life, and other relevant assumptions for estimating savings from the two electric utilities' and three gas utilities' efficiency programs. The SAG developed the first such statewide TRM in 2012. It also developed a process for annually updating and filing the TRM with the ICC.[76]

[76] For the current version (6.0), which is in four volumes, see (http://www.ilsag.info/il_trm_version_6.html).

To date, every TRM filed has been a consensus document. However, the SAG also has a process for filing any updates when there is disagreement.

- **Net-to-gross (NTG) program assumptions**. The SAG has a similar annual process for engaging with all parties, including the utilities' independent evaluators, to develop NTG assumptions for every program the utilities are operating.
- **Energy-Efficiency Policy Manual**. A couple of years ago, the SAG developed a policy manual which it now also updates annually and files with the ICC. The policy manual explains how the SAG works as well as the TRM and NTG processes discussed above. The manual also spells out how TRC cost-effectiveness calculations are to be performed; sets forth schedules and processes for developing EM&V plans and reviewing and finalizing EM&V reports; dictates consistent statewide utility quarterly and annual reporting requirements; and covers related issues.
- **Cost-effectiveness testing parameters**. In the past, when there were disagreements between parties over the parameters of cost-effectiveness analyses, the ICC directed the SAG to flesh out the issues and attempt to resolve them. There was partial resolution with a couple of remaining disagreements that the ICC was going to address (but subsequent legislation addressed them first).
- **Large industrial self-direct program design**. Several years ago there was disagreement in a contested proceeding over the effectiveness of a utility's program offerings for large industrial customers. Following a directive from

the ICC, the SAG worked by consensus to develop a self-direct program for large industrial customers.

- **Low-income program design and delivery**. The ICC has directed the SAG to work to identify ways to increase the effectiveness (particularly savings) of low-income efficiency programs.
- **Calculation of weighted average measure life (WAML)**. Illinois's electric utilities now amortize the cost of their efficiency programs over the weighted average life of the efficiency measures installed. Interestingly, three different parties initially put forward three different ways of calculating WAML. The ICC directed the SAG to attempt to reach consensus on the most appropriate way to calculate WAML.
- **Program budget reallocations**. The ICC has required that whenever a utility plans to change an approved program budget by more than 20%, it must report and discuss that proposed change to the SAG, with the goal that consensus on such changes (and the rationale for them) be reached without requiring Commission involvement.

The SAG has also taken upon itself efforts to negotiate details of the utilities' multi-year plans prior to their filing with the ICC. In the vast majority of cases in the last two multi-year planning cycles, consensus plan filings have been achieved.

Q: IN YOUR EXPERIENCE, WHAT FACTORS ALLOW THE ILLINOIS SAG, AND OTHER WELL-FUNCTIONING COLLABORATIVES, TO SUCCEED?

A: In my experience, there are several key factors that allow collaboratives to function well:

- **A genuine willingness on the part of all parties to work together**. That does not mean that there will be no disagreement. There will be. But in my experience, the number and importance of such disagreements decline over time as parties work together, begin to appreciate the others' perspectives, and look to find compromises that work for everyone.
- **A commitment to meet often enough to effectively work through complex issues**. In my experience, this means eight to 10 times a year, almost monthly, for larger group discussions, as well as more numerous sub-group working sessions focused on specific topics (for example, examination and analysis of a particular program design, or updating the TRM).
- **All parties having a voice in establishing priorities for discussion**, including specific meetings agendas.
- **Independent facilitation of Collaborative meetings**. In Illinois, an independent facilitator has been hired to manage the SAG process. In Arkansas, an individual hired by the Commission to serve as an Independent Evaluation Monitor facilitates the Collaborative meetings. In Michigan, a Commission staff person manages the monthly Collaborative meetings and related subcommittee or working-group meetings. An independent facilitator ensures that all voices are heard, including in the setting of agendas for meetings, and enables participants in the Collaborative to focus on the topic at hand rather than the actual running of meetings.

- **Institutionalization of working processes**. This starts with simple things like establishing a schedule for meetings and what those meetings will cover; distributing agendas; and distributing meeting notes, summaries of agreements/ disagreements, and lists of next steps. All of these steps must be taken with enough advance notice for parties to be able to meaningfully prepare and participate in the meetings. Over time, more formal processes should be developed (e.g., annual processes for reviewing and updating and documenting savings assumptions – ideally in a TRM). The institutionalization evolves over time as the collaborative parties get used to working together and develop an increasing list of work products that require periodic updating.
- **Accountability**. Well-functioning collaboratives are expected to produce results and to report back to regulators, increasingly in the form of consensus filings, on progress made on key issue

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. EDMONDSON: Presiding Commissioner, in regard to the Public Staff's testimony, first I would move that the testimony of Michael C. Maness filed September 4th consisting of 24 pages and a two-page Appendix, and his supplemental testimony filed September 17th consisting of five pages be entered into the record as if given orally from the stand, and that his Exhibit I filed with his initial testimony and his Exhibit II filed yesterday with his supplemental testimony be admitted as evidence.

COMMISSIONER BROWN-BLAND: There being no objection, that motion is allowed and all is received into evidence, the testimony being treated as if given orally from the witness stand.

MS. EDMONDSON: Thank you.

(WHEREUPON, Maness Exhibit I is admitted into evidence.)

(WHEREUPON, the prefiled direct testimony of MICHAEL C. MANESS is copied into the record as if given orally from the stand.)

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	)))))	TESTIMONY OF MICHAEL C. MANESS Public Staff – North Carolina Utilities Commission

September 4, 2018

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

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

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present my recommendations regarding the Demand-Side Management (DSM) and Energy Efficiency (EE) cost and incentive recovery rider (DSM/EE Rider),[1] proposed by Duke Energy Progress, LLC (DEP or the Company), in its Application filed in this docket on June 20, 2018 (Application). The DSM/EE Rider is authorized by N.C. Gen. Stat. § 62-133.9 and implemented pursuant to Commission Rule R8-69.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

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[1] The DSM/EE Rider is comprised of various class-based DSM, EE, DSM Experience Modification Factor (DSM EMF), and Energy Efficiency Experience Modification Factor (EE EMF) billing rates.

A. My testimony begins with a review of the regulatory framework for DSM/EE cost recovery by electric utilities and the historical background of DEP's Application in this docket. I then discuss the Company's proposed billing rates and other aspects of its filing. Following a summary of my investigation, I present my conclusions and recommendations regarding the proposed billing rates and the overall DSM/EE Rider.

THE PROCESS FOR SETTING DEP'S DSM/EE REVENUE REQUIREMENTS

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

A. N.C. Gen. Stat. § 62-133.9(d) allows a utility to petition the Commission for approval of an annual rider to recover (1) the reasonable and prudent costs of new DSM and EE measures and (2) other incentives to the utility for adopting and implementing new DSM and EE measures. However, N.C. Gen. Stat. § 62-133.9(f) allows industrial and certain large commercial customers to opt out of participating in the power supplier's DSM/EE programs or paying the DSM/EE rider, if an eligible customer notifies its electric power supplier that it has implemented or will implement, at its own expense, alternative DSM and EE measures. Commission Rule R8-69 sets forth the general parameters and procedures governing approval of the annual rider.

In this proceeding, DEP has calculated its proposed DSM/EE Rider (incorporating both prospective and Experience Modification Factor (EMF) DSM and EE billing rates) using two "mechanisms" previously approved by the Commission. To calculate the billing rates related to DSM and EE measures installed or implemented in Vintage Years prior to 2016, DEP has used the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Initial Mechanism) approved by the Commission on June 15, 2009, in its *Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required Modifications*, in Docket No. E-2, Sub 931, as modified by the Commission's November 25, 2009, *Order Granting Motions for Reconsideration in Part*, in the same docket. To calculate the billing rates related to DSM and EE measures actually or expected to be installed or implemented on and after January 1, 2016, the Company has used the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Revised Mechanism) approved by the Commission on January 20, 2015, in its *Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waivers*, in Docket No. E-2, Sub 931 (2015 Sub 931 Order). The Revised Mechanism was subsequently amended as approved by the

Commission in the Company's 2017 DSM/EE rider proceeding, Docket No. E-2, Sub 1145 (Sub 1145).

Q. WHAT DID THE INITIAL MECHANISM PROVIDE AS TO RECOVERY OF COSTS AND UTILITY INCENTIVES?

A. The Initial Mechanism approved by the Commission provided for recovery of program and common costs, as well as Net Lost Revenues (NLR) in a manner similar to that set forth in the Revised Mechanism, as further explained below. Additionally, the Initial Mechanism provided that DEP would be allowed to recover, subject to certain exceptions, a performance incentive (the Program Performance Incentive, or PPI$_1$[2]) for the implementation and operation of cost-effective new DSM and EE programs that achieve verified energy and peak demand savings. The PPI$_1$ is based on the net savings of each program or measure, as calculated using the Utility Cost Test (UCT), and is equal to 8% of net savings for DSM programs and measures and 13% for EE programs and measures.

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[2] In the Initial Mechanism, DEP was eligible for a <u>Program</u> Performance Incentive, based on the performance of each individual DSM/EE program (with a floor of $0 for the incentive related to each program). I refer to the Program Performance Incentive as PPI$_1$. Effective January 1, 2016, the Revised Mechanism replaced the calculation of an incentive for individual programs with a single net <u>Portfolio</u> Performance Incentive calculation, which I refer to as PPI$_2$.

The Initial Mechanism's terms and procedures were to be reviewed by DEP and other parties at least every three years.

On January 15, 2015, the Commission issued the 2015 Sub 931 Order, approving the Revised Mechanism. However, as the result of discussions that took place during the Company's 2017 Sub 1145 proceeding, the Company and the Public Staff recommended certain changes to Paragraphs 18, 22, and 70 of the Revised Mechanism, and the addition of new Paragraphs 22A through 22D and 70A. These revisions were set forth in Public Staff witness Maness Exhibit II filed in Sub 1145, and were approved by the Commission in its *Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice*, issued November 27, 2017. For purposes of clarity and convenience, a copy of the entire Revised Mechanism is attached to my testimony in this docket as Maness Exhibit I.

Q. PLEASE DESCRIBE THE REVISED MECHANISM (INCLUDING THE 2017 CHANGES) AND ITS MAJOR COMPONENTS.

A. The overall purpose of the Revised Mechanism, as amended, is to (1) allow DEP to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and new EE measures; (2) establish the terms, conditions, and methodology for the recovery of certain utility incentives - NLR and a PPI[2] - to reward

DEP for adopting and implementing DSM and EE measures and programs; (3) provide for an additional incentive to further encourage kilowatt-hour (kWh) savings achievements; and (4) establish certain requirements and guidelines to guide requests by DEP for approval, monitoring, and management of DSM and EE programs. The Revised Mechanism includes many provisions that indirectly influence the ratemaking process for DSM and EE costs and incentives, including provisions that address program approval, management, and modification; evaluation, measurement, and verification (EM&V) of program results; operation of a Stakeholder Collaborative; procedural matters and the general structure of the DSM/EE billing rates; allocation methodologies; reporting requirements; and provisions for the term and future review of the Revised Mechanism itself. Additionally, the provisions that most directly address the determination of the annual DSM/EE Rider include the following:

1. Eligible non-residential customers may opt out of either or both of the DSM and EE categories of programs, as well as opt back into either or both. Beginning on January 1, 2016, separate DSM and EE billing rates became available to Non-Residential opt-out-eligible customers. A customer receiving program incentives from either a DSM or an EE program will be required to pay the respective portion(s) of the DSM/EE and DSM/EE EMF billing rates for a period of not less than 36 months.

2. In general, DEP shall be allowed to recover, through the DSM/EE and DSM/EE EMF rates, all reasonable and prudent costs of Commission-approved DSM/EE programs.

However, any of the Stipulating Parties may propose a procedure for the deferral and amortization over a maximum of ten years of all or a portion of DEP's non-capital program costs to the extent those costs are intended to produce future benefits, and may propose to defer and amortize related non-incremental administrative and general (A&G) costs over a maximum of three years. Deferred program and A&G costs shall be allowed to accrue a return at the overall weighted average net-of-tax rate of return approved in DEP's most recent general rate case (net of income taxes). For program costs not deferred for amortization in future DSM/EE riders, the accrual of a return on any under-recoveries or over-recoveries of cost will follow the requirements of Commission Rule R8-69(b), subparagraphs (3) and (6), unless the Commission determines otherwise.

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

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

5. NLR will be reduced by net found revenues, as defined in the Revised Mechanism, occurring in the same 36-month period. Net found revenues will be determined according to the "Decision Tree" process included in the Revised Mechanism.

6. DEP shall be allowed to recover a PPI_2 per vintage year for its DSM and EE portfolio based on a sharing of actually achieved and verified energy and peak demand savings (excluding those related to general programs and measures and research and development activities). The inclusion of pilot programs in any PPI_2 calculation is subject to additional qualifying criteria. Unless the Commission determines otherwise in an annual DSM/EE rider proceeding, the

amount of the pre-income-tax PPI_2 to be recovered for the entire allowable DSM/EE portfolio for a vintage year shall be equal to 11.75% multiplied by the present value of the estimated net dollar savings associated with the DSM/EE portfolio installed in that vintage year (as determined by the UCT). Low-income programs or other programs approved with expected UCT results less than 1.00 shall not be included in the portfolio for purposes of the PPI_2 calculation; nor shall the Demand Side Distribution Response (DSDR) program. The PPI_2 for each vintage year shall ultimately be trued up based on net dollar savings as verified by the EM&V process and approved by the Commission. Unless the Commission determines otherwise, the PPI_2 shall be converted into a stream of no more than ten levelized annual payments, incorporating the overall weighted average net-of-tax rate of return approved in DEP's most recent general rate case as the appropriate discount rate.

7. For Vintage Years 2019 and afterwards, the program-specific per kilowatt (kW) avoided capacity benefits and per kWh avoided energy benefits used for the initial estimate of the PPI_2 and any PPI_2 true-up will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing, but using, for program-specific avoided energy benefits, the projected EE portfolio hourly shape rather than an assumed 24x7 100 megawatt (MW) reduction.

8. If the Company achieves incremental energy savings of 1% of its prior year's system retail electricity sales in any year during the five-year 2015-2019 period, the Company will receive a bonus incentive of $400,000 for that year.

THE COMPANY'S PROPOSED BILLING RATES

Q. PLEASE DESCRIBE THE BILLING FACTORS, VINTAGE YEARS, RATE PERIOD, AND TEST PERIOD BEING CONSIDERED IN THIS PROCEEDING.

A. In its Application in this proceeding, DEP requested approval of prospective and EMF DSM and EE billing rates that would result in annual North Carolina retail revenue of approximately $187 million [including a revenue adder for the North Carolina Regulatory Fee (regulatory fee)]. DEP's request would be an increase of approximately $ 29 million from the annual revenues that would be produced by the rates currently in effect. These proposed billing rates are set forth on DEP witness Miller's Exhibit 1. The rates, as applicable to each class, are proposed by the Company to be charged to all participating North Carolina retail customers [i.e., those who have not opted out pursuant to N.C. Gen. Stat. § 62-133.9(f)] served during the rate period.

The rate period for this proceeding is the twelve-month period from January 1, 2019, through December 31, 2019. This is the period over which the prospective DSM and EE billing rates and the DSM and EE EMF billing rates determined in this proceeding will be charged. It is also the period for which the estimated revenue requirements to be recovered through the prospective DSM/EE rates are determined.

The test period applicable to this proceeding is the twelve-month period ended December 31, 2017. This is the presumptive period for which the under- or overrecovery of DSM/EE revenue requirements is measured for purposes of determining the DSM and EE EMF billing rates. Actual program costs considered for true-up in this proceeding are either costs actually incurred during the test period, or amortizations, depreciation, and/or return associated with costs incurred in prior test periods.

NLR, PPI_1, and PPI_2 reflected in the EMF revenue requirements being set in this proceeding are associated with Vintage Years 2015, 2016, and 2017.

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

A. The prospective DSM and EE billing rates incorporate several cost recovery elements as estimated for the rate period, including amortizations of operations and maintenance and A&G costs, capital costs of DSDR, carrying costs (return on deferred costs), NLR, and levelized PPI_1 and PPI_2 incentives. The test period true-up DSM and EE EMF billing rates contain test period actual amounts of the same types of costs and incentives as do the prospective rates. The DSM and EE EMF billing rates also include adjustments to the 2015 and 2016 NLR, PPI_1, and PPI_2, a reduction for the DSM/EE billing rate amounts billed during the test period, and interest on overcollections and undercollections.

NLR amounts included in the DSM and EE billing rates have also been affected by the Company's recently concluded general rate case (Docket No. E-2, Sub 1142). The revenue requirement filed by the Company in that case took into account DEP's total net revenue losses through December 31, 2016, and further residential losses through October 31, 2017. The effective date of the rates set in the case was March 16, 2018. Therefore, NLR being requested in this proceeding should exclude, effective March 16, 2018, any net revenue losses due to DSM/EE measures installed or implemented on or prior to December 31, 2016, for all customers, and on or prior to October 31, 2017, for residential customers. This matter is further addressed later in my testimony.

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

A. The finalization of the true-ups of NLR, PPI_1, and PPI_2 sometimes tends to lag behind the true-ups of program costs and A&G expenses subject to amortization. This feature of the true-up process is due to the fact that while cost amounts are typically known and determinable very soon after they are incurred, it can take several months to complete the applicable EM&V process and to refine and adjust the cost savings results for a given vintage year so that the final actual incentives payable to the utility can be determined. Therefore, while the cost amounts to be trued up as part of the test period DSM/EE EMF revenue requirement in a given annual proceeding typically correspond very closely to the actual costs incurred during the test period, the test period revenue requirement often contains incentives related to more than one vintage year. Additionally, certain components of the revenue requirements related to prior years will remain subject to prospective update adjustments and retrospective true-ups in the future, as participation and EM&V analyses are finalized, reviewed, and perhaps refined.

INVESTIGATION AND CONCLUSIONS

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

A. My investigation of DEP's filing in this proceeding focused on determining whether the proposed DSM/EE Rider (a) was calculated in accordance with the Initial or Revised Mechanisms, as applicable, and (b) otherwise adhered to sound ratemaking concepts and principles. The procedures I and other members of the Public Staff's Accounting Division acting under my supervision utilized included a review of the Company's filing, relevant prior Commission proceedings and orders, and workpapers and source documentation used by the Company to develop the proposed billing rates. Performing the investigation required the review of responses to written and verbal data requests, as well as discussions with Company personnel. As part of its investigation, the Accounting Division performed a review of the actual DSM/EE program costs incurred by DEP during the 12-month period ended December 31, 2017. To accomplish this, the Accounting Division selected and reviewed samples of source documentation for test year costs included by the Company for recovery through the DSM/EE Rider. Review of this sample, which is still underway as of the date of pre-filing of this testimony, is intended to test whether the actual costs included by the Company in the DSM and EE billing rates are either valid costs of approved DSM and EE programs or administrative costs supporting those programs.

My investigation, including the sampling of source documentation, concentrated primarily on costs and incentives related to the January through December 2017 test period, which will begin to be trued up through the DSM and EE EMF billing rates approved in this proceeding. The Public Staff also performed a more general review of the prospective billing rates proposed to be charged for Vintage Year 2019, which are subject to true-up in future proceedings.

Q. WHAT ARE YOUR FINDINGS AND CONCLUSIONS?

A. With the exception of items specifically described later in this testimony, I am of the opinion that the Company has calculated its proposed DSM, EE, DSM EMF, and EE EMF billing rates in a manner consistent with N.C. Gen. Stat. § 62-133.9, Commission Rule R8-69, and the Initial and Revised Mechanisms. However, this conclusion is subject to the caveat that the Public Staff is still in the process of reviewing certain data responses received from the Company in the last few days, including documentation of costs selected for review in the Public Staff's sample; should this review result in any further issues, the Public Staff will file additional information with the Commission.

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

(1) Avoided Costs to be Used in the Determination of the PPI – In his testimony in this proceeding, Public Staff witness Hinton recommends that the avoided capacity cost benefits used to determine the PPI_2 should be consistent with the avoided cost rates for capacity set by the Commission for Qualifying Facilities (QFs) under PURPA,[3] as provided for in the Revised Mechanism, as amended. Per Mr. Hinton, maintaining this consistency requires

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[3] The Public Utility Regulatory Policy Act of 1978.

that beginning with Vintage Year 2019, avoided capacity cost benefits for purposes of the PPI[2] be calculated under the assumption that generation kW (capacity) avoided prior to year 2022 be assigned a zero dollar value, consistent with the Commission's Order in Docket No. E-100, Sub 148 (Sub 148), for QFs under PURPA. Mr. Hinton testifies that instead of assigning a zero dollar value to such avoided generation kW, the Company has assigned full capacity value to them.

I concur with Mr. Hinton's recommendation. Paragraph 70A of the Revised Mechanism, as amended, reads as follows:

> 70A. For the PPI for Vintage Years 2019 and afterwards, the program-specific per kW avoided capacity benefits and per kWh avoided energy benefits used for the initial estimate of the PPI and any PPI true-up will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. However, for the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100 MW reduction typically used to represent a qualifying facility.

Pursuant to Paragraph 70A, for purposes of this proceeding, the treatment recommended by Mr. Hinton should be applied to calculate the estimated (and the eventually trued-up) PPI_2 for Vintage Year 2019. Since the Company did not do so, it is appropriate and necessary to make an adjustment to the estimated Vintage Year 2019 PPI_2 proposed in this case by DEP to bring it into compliance with the Revised Mechanism. It is particularly important to note that Paragraph 70A states that the avoided capacity benefits "will be derived from the … cost inputs that generated the avoided capacity and avoided energy credits", thus, it is not just the methodology from the biennial proceeding that is to be used, but the cost inputs themselves, including, in the Public Staff's opinion, the zero avoided cost inputs for the years 2019 through 2021 mandated in Sub 148.

In the course of its investigation, the Public Staff asked the Company to provide a calculation of estimated avoided cost benefits related to Vintage Year 2019 under the assumption that avoided capacity kW occurring prior to year 2022 is assigned a zero dollar value.[4] According to the Company's calculation, making this assumption reduces the estimated Vintage Year 2019 system-

[4] Certain DSM/EE measures installed or implemented in Vintage Year 2019 have lives extending into and beyond 2022, meaning that assigning an avoided capacity cost benefit of $0 to kW savings achieved before 2022 does not reduce the avoided capacity cost benefit for the entire Vintage Year to $0.

level PPI_2 (before levelization) from $14,913,197 to $13,404,068, a decrease of $1,509,129.

(2) Cut-Off of NLR to Reflect Outcome of General Rate Case – Paragraph 58 of the Revised Mechanism reads as follows:

> 58. Notwithstanding the allowance of 36 months' Net Lost Revenues associated with eligible kWh sales reductions, the kWh sales reductions that result from measurement units installed shall cease being eligible for use in calculating Net Lost Revenues as of the effective date of (a) a Commission-approved alternative recovery mechanism that accounts for the eligible Net Lost Revenues associated with eligible kWh sales reductions, or (b) <u>the implementation of new rates approved by the Commission in a general rate case or comparable proceeding to the extent the rates set in the general rate case or comparable proceeding are set to explicitly or implicitly recover the Net Lost Revenues associated with those kWh sales reductions.</u> [Emphasis added].

The effective date of the rates approved in DEP's most recent general rate case, Docket No. E-2, Sub 1142, was March 16, 2018. In its *Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase*, issued on February 23, 2018, the Commission stated in the Evidence and Conclusions for Findings of Fact Nos. 10-15 that "DEP witness Bateman testified that as part of the settlement, the Stipulating Parties agreed to update revenues to reflect changes in number of customers and, for the residential class, changes in weather-normalized usage per customer through October 31, 2017," and further, in Finding of Fact No. 36, "The provisions of the Stipulation are just and reasonable to all parties to this proceeding and serve the public interest. Therefore, the Stipulation should be approved in its entirety."

In its filing in this proceeding, the Company cut off NLR, as of the March 16, 2018 effective date of the Sub 1142 general rate increase, associated with DSM/EE measures installed through December 31, 2016, the end of the nominal Sub 1142 test year. However, it did not further reduce NLR to reflect the update adjustment made in Sub 1142 to capture changes in residential per customer usage through October 31, 2017. After discussions with the Public Staff, the Company agreed to make an adjustment to remove from residential NLR the impacts of the measures installed/implemented through October 31, 2017. However, the Company has also indicated to the Public Staff that in calculating this adjustment related to 2017, it has also determined that it initially overstated the amount of residential and nonresidential NLR related to 2016 that should be removed. The Company has provided workpapers to the Public Staff that indicate that the net of the two corrections for the 2019 rate period is a reduction in N.C.

retail NLR of approximately $308,000[5]; I am in the process of reviewing the Company's adjustments. It is the Public Staff's understanding that the Company will incorporate this adjustment in a supplemental filing to be made in this case. Once it has reviewed the Company's supplemental filing, the Public Staff will inform the Commission as to whether it believes that the adjustment has been made correctly.

(3) <u>Recommended Termination of Residential Smart $aver EE Program</u> – In his testimony, Public Staff witness Williamson has recommended that the Residential Smart $aver EE Program be terminated as of the end of 2018. Consistent with his recommendation, I conclude that all associated Vintage 2019 program costs, NLR, and PPI_2 should be removed from the calculated billing factors. The N.C. retail impacts of this removal (applied to the Company's filing) are (a) a reduction in estimated 2019 program costs of approximately $322,000, (b) a reduction in estimated Vintage 2019 NLR of approximately $110,000, and (c) an increase in Vintage 2019 levelized PPI_2 of approximately $8,000.

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[5] For rate period 2018, the net adjustment is estimated to be an increase of approximately $1,022,000; however, this adjustment would not be reflected in the rates until rate period 2018 is trued up in a future proceeding.

(4) Other Adjustments to Rate Calculations – The Company has provided workpapers to the Public Staff indicating that, in addition to the adjustment regarding the general rate case cut-off of NLR described above, it recommends two further adjustments, one to EM&V results and one to non-residential lost revenues. It is my understanding that the Company intends to make a supplemental filing in this proceeding that will incorporate these adjustments. Once it has reviewed the Company's supplemental filing, the Public Staff will inform the Commission as to whether it believes that the adjustments have been made correctly.

Q. DO YOU PLAN TO PRESENT TO THE COMMISSION THE OVERALL EFFECT OF THESE THE DSM/EE BILLING RATES?

A. Yes. I plan to incorporate each adjustment described above into an exhibit that will set forth the overall billing factors recommended by the Public Staff, to be filed prior to or at the time of the hearing in this case, subsequent to the supplemental exhibit that the Company has indicated to the Public Staff that it intends to file.

Q. WHAT IS THE IMPACT OF RECOMMENDATIONS MADE BY PUBLIC STAFF WITNESS WILLIAMSON IN HIS TESTIMONY ON YOUR CONCLUSIONS REGARDING THE DSM/EE REVENUE REQUIREMENTS IN THIS PROCEEDING?

A. Public Staff witness Williamson has filed testimony in this proceeding discussing several topics and issues related to the Company's filing. Except as noted above, none of these topics and issues necessitates an adjustment in this particular proceeding to the Company's billing factor calculations, although some of the recommendations made by Mr. Williamson may affect the revenue requirements in future proceedings.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING DEP'S BILLING RATES.

A. In summary, other than the issues identified above, the Public Staff has found no errors or other issues necessitating an adjustment to DEP's proposed billing rates.

RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDATION IN THIS PROCEEDING?

A. Based on the results of the Public Staff's investigation (subject to completion of its review of 2017 program costs and further review of Company-provided information), I recommend that the adjustments I have set forth earlier in my testimony be made to the calculation of the DSM/EE billing rates proposed in this proceeding. To summarize, these recommended adjustments are in the following areas:

(1) Avoided costs to be used in the determination of the PPI.
(2) Cut-off of NLR to reflect outcome of general rate case.
(3) Recommended termination of Residential Smart $aver EE Program.
(4) Other Adjustments to Rate Calculations.

As stated previously, I plan to incorporate these adjustments into an exhibit that will set forth the overall billing factors recommended by the Public Staff, to be filed prior to or at the time of the hearing in this case.

I also recommend that the $1,509,129 reduction in the system PPI[2] related to avoided capacity costs be included in all future true-ups of the Vintage 2019 DSM/EE revenue requirement and billing factors. Furthermore, I recommend that for as long as the Sub 148 avoided cost rates remain in effect, the Company continue to assign a capacity cost value of zero to all kW savings occurring before year 2022 that are related to Vintage Years 2019 and afterwards, consistent with Paragraph 70A of the Revised Mechanism.

The billing rates ultimately found reasonable and appropriate by the Commission should be approved subject to any true-ups in future cost recovery proceedings consistent with the Initial or Revised Mechanisms as applicable, as well as other relevant orders of the Commission.

In making its recommendation, the Public Staff notes that reviewing the calculation of the DSM/EE rider is a process that involves reviewing numerous assumptions, inputs, and calculations, and its recommendation with regard to this proposed rider is not intended to indicate that the Public Staff will not raise questions in future proceedings regarding the same or similar assumptions, inputs, and calculations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

MICHAEL C. MANESS

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

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

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

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

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

(WHEREUPON, Maness Exhibit II is admitted into evidence.)

(WHEREUPON, the prefiled supplemental testimony of MICHAEL C. MANESS is copied into the record as if given orally from the stand.)

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	)))))	SUPPLEMENTAL TESTIMONY OF MICHAEL C. MANESS Public Staff – North Carolina Utilities Commission

September 17, 2018

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

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

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed my initial direct testimony in this proceeding on September 4, 2018.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. The purpose of my supplemental testimony is, first, to present Maness Exhibit II, which quantifies the impacts of the Public Staff's recommended adjustments on the Demand-Side Management (DSM) and Energy Efficiency (EE) billing rates proposed by Duke Energy Progress, LLC (DEP or the Company), in the Supplemental Testimony and Exhibits of Carolyn T. Miller and the Supplemental Exhibits of Robert P. Evans filed in this proceeding on September 10, 2018. Second, I am presenting the Public Staff's conclusions regarding certain adjustments proposed by the Company in its September 10 filing.

Q. PLEASE ELABORATE.

A. In my September 4, 2018 testimony, I indicated that I planned to incorporate the effects of the following Public Staff recommended adjustments in an exhibit to be filed later:

(1) Avoided costs to be used in the determination of the Portfolio Performance Incentive (PPI).
(2) Recommended termination of Residential Smart $aver EE Program.

Additionally, I indicated that I planned to present the Public Staff's conclusions regarding the following three adjustments that the Company had indicated that it planned to make in its supplemental filing (the first of which was also recommended by the Public Staff):

(1) Cut-off of net lost revenues (NLR) to reflect outcome of general rate case.
(2) Company adjustment to evaluation, measurement, and verification (EM&V) results.
(3) Company adjustment to non-residential lost revenues.

The final two adjustments are described in more detail in the Supplemental Testimony of Company witness Miller; the first deals with the appropriate inclusion in the DSM/EE experience modification factor (EMF) of the Vintage 2016 and 2017 impacts of the Company's EM&V of the EnergyWise for Business Program, while the second corrects the Vintage 2017 and 2019 NLR rates used for the Non-Residential Energy Efficient Lighting Program from residential rates to non-residential rates.

Finally, I indicated in my testimony that I would present the overall billing factors recommended by the Public Staff.

Q. HAVE ALL OF THESE IMPACTS BEEN INCLUDED IN MANESS EXHIBIT II?

A. Yes. Any unadjusted amounts set forth in Maness Exhibit II as part of the basis for the Public Staff's recommended billing factors have as their source the amounts set forth in DEP witness Miller's supplemental exhibits, which reflect the three additional adjustments proposed by the Company. I have adjusted these amounts to reflect the two additional adjustments recommended by the Public Staff. The overall DSM/EE billing factors recommended by the Public Staff are set forth on Maness Exhibit II, Schedule 1.

Q. WHAT ARE THE REVENUE REQUIREMENT IMPACTS OF THE TWO ADJUSTMENTS RECOMMENDED BY THE PUBLIC STAFF?

A. As set forth in the footnotes on Schedules 2, 3-1, and 3-2 of Maness Exhibit II, the rate period 2019 revenue requirement impact of the Public Staff's recommended adjustment to terminate the Residential Smart $aver EE Program is a reduction of $512,494. The rate period 2019 revenue requirement impact of the Public Staff's recommended adjustment to reduce the avoided costs used in the determination of the PPI to reflect a value of zero for appropriate years is a reduction of $488,550. However, if accepted by the Commission, the long-term impacts of this second adjustment will be significantly greater, in total, because a given Vintage Year's PPI is typically amortized over several years into the future; the $488,550 represents only one of those years.

Q. WHAT IS THE PUBLIC STAFF'S CONCLUSION REGARDING THE THREE ADJUSTMENTS PROPOSED BY THE COMPANY IN WITNESS MILLER'S SUPPLEMENTAL TESTIMONY AND EXHIBITS?

A. The Public Staff is of the opinion that the Company's three additional adjustments are reasonable for purposes of this proceeding.

Q. WHAT IS THE STATUS OF THE PUBLIC STAFF'S REVIEW OF 2017 DSM/EE PROGRAM COSTS?

A. The review is nearing completion. When it is complete, the Public Staff will file the results with the Commission. To date, the Public Staff has found no exceptions.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

MS. EDMONDSON: I also move that the testimony of John R. Hinton filed September 4th, consisting of 15 pages and a two-page appendix be entered into the record as if given orally from the stand, and that his confidential Exhibit 1 be admitted as evidence.

COMMISSIONER BROWN-BLAND: That motion is allowed and the evidence is received into the record as if given orally from the witness stand, with the confidential exhibit remaining as filed and remaining confidential and it, of course, will be identified as it was marked when prefiled.

(WHEREUPON, Confidential Exhibit JRH-1 is identified as premarked and admitted into evidence.)

(WHEREUPON, the prefiled direct testimony and Appendix A of JOHN R. HINTON is copied into the record as if given orally from the stand.)

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.
>
> 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.

APPENDIX A
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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.

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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.

MS. EDMONDSON: And, finally, I move that the testimony of David M. Williamson filed September 4th, consisting of 32 pages and a one-page appendix be entered into the record as if given orally from the stand, and that his Exhibits 1, 2 and 3 to his testimony be admitted as evidence.

COMMISSIONER BROWN-BLAND: And that motion is allowed and all is received into evidence.

(WHEREUPON, Williamson Exhibits 1, 2 and 3 are admitted into evidence.)

(WHEREUPON, the prefiled direct testimony of DAVID M. WILLIAMSON is copied into the record as if given orally from the stand.)

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	)))))	TESTIMONY OF DAVID M. WILLIAMSON Public Staff – North Carolina Utilities Commission

September 4, 2018

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

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

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations with respect to the following aspects of the June 20, 2018, application of Duke Energy Progress, LLC (DEP), for approval of its demand-side management (DSM) and energy efficiency (EE) cost recovery rider for 2019 (2019 Rider Rates): (1) the portfolio of DSM and EE programs included in the proposed 2019 Rider Rates; (2) the ongoing cost-effectiveness of each DSM and EE program; and (3) the evaluation, measurement, and verification (EM&V) studies filed as Exhibits A through K to the testimony of Company witness Robert P. Evans.

Q. WHAT DOCUMENTS HAVE YOU REVIEWED IN YOUR INVESTIGATION OF DEP'S PROPOSED 2019 RIDER RATES?

A. I reviewed the application and supporting testimony and exhibits, as well as DEP's responses to Public Staff data requests. In addition, I reviewed previous Commission orders related to DEP's DSM and EE programs and cost recovery rider proceedings, including the Commission's *Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice* issued November 27, 2017, in Docket No. E-2, Sub 1145 (Sub 1145 Order), that approved revisions to the Mechanism approved in Docket No. E-2, Sub 931 (Revised Mechanism).

Q. DO YOU HAVE ANY EXHIBITS?

A. Yes. I have three exhibits to my testimony. Williamson Exhibit No. 1 provides a historical look at the cost-effectiveness of the Company's Residential Smart $aver EE Program (formerly known as the Home Energy Improvement Program, or HEIP). Williamson Exhibit No. 2 shows the changes in the cost-effectiveness of the Company's programs as calculated by the Company in its 2016, 2017, and current DSM/EE rider proceedings. Williamson Exhibit No. 3 shows the difference between the cost-effectiveness calculations of each program using the Company's methodology of determining avoided capacity benefits and the methodology that the Public Staff believes is required by the Revised Mechanism.

DSM and EE Programs in DEP's 2019 Rider Rates

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

A. In its proposed 2019 Rider Rates, DEP included the costs and incentives associated with the following programs:

- Residential
  - Appliance Recycling Program (Sub 970)
  - EE Education Program (Sub 1060)
  - Multi-Family EE Program (Sub 1059)
  - My Home Energy Report (MyHER) Program (formerly the EE Benchmarking Program) (Sub 989)
  - Neighborhood Energy Saver (Low Income) Program (Sub 952)
  - Residential Smart $aver EE Program (formerly HEIP) (Sub 936)
  - New Construction Program (Sub 1021)
  - Load Control Program (EnergyWise Home) (Sub 927)
  - Save Energy and Water Kit Program (Sub 1085)
  - Energy Assessment Program (Sub 1094)

- <u>Non-Residential</u>
  - Non-Residential Smart $aver Energy Efficient Products and Assessment Program (formerly Energy Efficiency for Business Program) (Sub 938)[1]
  - Non-Residential Smart $aver Performance Incentive Program (Sub 1126)[2]
  - Small Business Energy Saver Program (Sub 1022)
  - CIG Demand Response Automation (CIG DRA) Program (Sub 953)
  - EnergyWise for Business (Sub 1086)
- <u>Combined Residential and Non-Residential</u>
  - Energy Efficient Lighting Program (EE Lighting) (Sub 970)
  - Distribution System Demand Response (DSDR) Program (Sub 926)

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

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[1] The Non-Residential Smart $aver EE Products and Assessment program encompasses its own sub-portfolio of programs, which include the Smart $aver Performance (Custom) and Smart $aver Performance (Prescriptive) programs. These programs are listed under the same tariff in Docket No. E-2, Sub 936, but are reflected separately in Evans Exhibit 7 because of the unique nature of each program.

[2] Approved December 20, 2016.

the recovery of net lost revenues (NLR) and portfolio performance incentives (PPI).

Program Performance

Q. PLEASE DISCUSS THE PERFORMANCE OF THE PORTFOLIO.

A. While the testimony and exhibits of DEP witness Evans provides information regarding the performance of each program in DEP's portfolio, I want to bring certain information to the Commission's attention regarding the performance of particular programs, as well as the performance of DEP's overall portfolio. While the portfolio of programs seems generally to be performing satisfactorily, the level of savings obtained from non-specialty light-emitting diode (LED) lighting-related measures and the MyHER program merit further discussion. I also discuss the performance of the Residential Smart $aver EE Program, and its struggles to remain cost-effective.

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

A. As seen in Evans Exhibit 1 in this rider and past riders, savings from lighting-related measures continue to provide a significant portion of the savings in the portfolio. The two lighting profiles, residential and non-residential, are comprised of both specialty and non-specialty bulbs. I have serious concerns about the future of the non-specialty bulbs incorporated in the Company's portfolio, which I discuss below.

In various recent dockets[3] over the past two years, including the Sub 1145 proceeding, the Public Staff has highlighted trends that we are seeing in North Carolina regarding the adoption of EE lighting measures. The EE lighting market in North Carolina appears to be transforming at a faster rate than the rest of the country, and non-specialty LED lighting will likely become the baseline standard for general service bulb technologies[4] by January 2020 as phase 2 of the federal government's Energy Independence and Security Act (EISA) goes into effect. This will result in decreased savings from EE lighting programs. Furthermore, I am not aware of any new information that would suggest that federal proposals to revise lighting standards[5] are being delayed or modified. Accordingly, the new EE Lighting EM&V (Evans Exhibit H) states that "under this new phase of EISA, energy-efficient lighting programs, such as the DEP EEL [EE Lighting] program, will no longer be cost-effective or needed."[6]

Evans Exhibit H provides strong evidence that lighting-related programs have assisted in transforming the lighting market in DEP's

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[3] DSM/EE Rider proceedings and within the discussion of EE Credits as part of the North Carolina Renewable Energy Portfolio Standard (REPS) Compliance reports and plans.

[4] General service bulbs refer to the general use bulb technologies found in residential lamp shade fixtures.

[5]https://www.federalregister.gov/documents/2017/01/19/2016-32012/energy-conservation-program-energy-conservation-standards-for-general-service-lamps

[6] p. 11.

service territory such that consumers have begun adopting EE on their own without the need for incentives. Market transformation is difficult to determine because the associated metrics are subjective. However, one of the purposes of utility EE programs, including the EE Lighting Program, is market transformation. As technologies become more energy efficient, costs decrease, and consumer acceptance increases, adoption of EE measures should become more the norm.

The Net-to-Gross Ratio (NTGR) for a program can show the degree of consumer acceptance. The NTGR of the EE Lighting Program, as shown in Evans Exhibit H, uses a triangulation approach that takes into account sales data, retailer interviews, and manufacturer interviews. The report concluded that the NTGR for DEP's lighting program is 0.40, which is applicable to all bulb types.[7] However, when looking specifically at the sales data[8] for DEP's LED bulbs, the weighted average of all types of LED bulbs has a NTGR of 0.10, which means that 90% of the LED bulbs in the market during the time-frame of January 1, 2016, through March 12, 2017, would have been purchased even if the program did not exist.

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[7] All Bulb types for purposes of this report refers to CFL and LED bulbs.

[8] Sales Data represents the customers who are actually buying the bulb in the stores and not manufacturer/retailer sale records to the stores.

Regardless of the new standard and barring any new technology for lighting, it appears that the lighting market in North Carolina has been transformed, and that further incentives for certain EE lighting measures for certain customers may not be necessary after January 1, 2020.[9] In DEP's 2019 rider proceeding, the Company will file for rider rates that will be effective for the 2020 rate period. I recommend that the Company include in its 2019 DSM/EE rider filing its plans for general service lighting measures in all of its EE programs that include lighting measures.

Q. PLEASE DISCUSS YOUR OBSERVATIONS CONCERNING THE MYHER PROGRAM.

A. The MyHER program provides periodic reports to customers that compare their household energy consumption patterns to those of other similarly situated, nearby households. The reports provide a summary of energy use compared to the customer's neighbors, and also provide energy savings tips to encourage customers to reduce energy consumption. As illustrated on page 5 of Evans Exhibit 1, for Vintage Year 2017, approximately one-half of the energy savings and one-quarter of the peak demand savings of the residential portfolio were derived from the MyHER program.

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[9] http://www.nmrgroupinc.com/wp-content/uploads/2017/09/Davids-poster-description.pdf

As indicated in its recent general rate case (Docket No. E-2, Sub 1142), the Company is modernizing its electric grid, in part by updating its metering technology and billing software to allow its customers to access their energy consumption data in a more manageable and timely format. The Company is currently replacing its existing billing meters with Advanced Metering Infrastructure (AMI) meters, as well as replacing and updating its customer information and billing systems.

DEP's AMI deployment and its new customer billing/information software should both be fully implemented by the end of 2021. While both the AMI meters and billing/information software are being deployed in stages over the next three years, customers should begin to experience the benefits of these newer technologies prior to their final completion dates.

To the extent that there is any redundancy in the information (primarily energy saving recommendations and shifting energy use from on- to off-peak periods) available through these new systems and the information provided through the MyHER program, the EM&V for the MyHER program will need to clearly isolate any savings associated with enhanced access to customer data provided through AMI and customer information systems from the impacts solely attributable to the customized energy-saving suggestions provided by the MyHER program.

The current MyHER EM&V report, filed in this proceeding as Evans Exhibit I, contains a list of key findings,[10] two of which I note: (1) 87% of respondents recalled receiving at least one MyHER, with 98% of those that recalled receiving a MyHER indicating that they "always" or "sometimes" read the reports; (2) respondents reported that the most useful feature of the reports was the graphs illustrating the home's energy usage over time, and the least useful feature was the customized suggestions for the home. Thus, while respondents appear to generally read their MyHER, much of the energy usage information that they find most useful will be, or at least should be, available through AMI and new billing functionalities.

The Public Staff will continue to work with DEP to evaluate the MyHER program to ensure that it produces verifiable and cost effective energy savings as the Company develops its technology base and provides customers with new functionalities.

Q. PLEASE DISCUSS YOUR OBSERVATIONS CONCERNING THE RESIDENTIAL SMART $AVER EE PROGRAM.

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[10] Section 4.3 of the report, page 59 of 123.

A. The Residential Smart $aver EE program has struggled to achieve cost-effectiveness for several years because of: 1) higher efficiency standards mandated by the federal government that have increased baselines against which savings impacts have been measured, and 2) the need for large participant incentives to overcome the upfront out-of-pocket costs to participants. Williamson Exhibit No. 1 provides the history of TRC test performance for this program, consisting of Company-filed TRC scores for rider filings, modification filings, and actual year-ending TRC scores. This exhibit shows that the actual TRC test results for this program have not been positive since Vintage Year 2013. Additionally, as illustrated by Evans Exhibit 7, the program is not expected to be cost effective, as measured by the TRC test for Vintage Year 2019.

DEP has consistently advocated the need to offer a residential HVAC (heating, ventilation, and air conditioning) replacement program. Because HVAC is one of the largest energy-consuming users in homes, I agree that a well-designed, cost effective program that encourages adoption of higher efficiency HVAC equipment is fundamental for any utility EE portfolio. DEP has also indicated the importance of maintaining its trade ally network. While it is desirable to maintain a good vendor network that provides customers with accurate, reliable information on HVAC energy consumption and other assistance, ratepayers should not be required to pay for a program year after year where the costs of the program outweigh the benefits ratepayers receive from the program.

Further, the cost-effectiveness projections continue on a downward trend, forcing ratepayers to shoulder more of the costs but receiving less benefit. While the Company asserts that this program is a necessary and fundamental EE program for an electric utility to offer its customers, the Public Staff continues to believe that N.C. Gen. Stat. § 62-133.9, and the Commission rules implementing this statute, require DEP to offer EE programs that are cost effective. Ratepayers should not be forced to pay for an EE program that has demonstrated over multiple years that it cannot attain and maintain cost effectiveness.

Q. PLEASE PROVIDE YOUR RECOMMENDATION FOR THE RESIDENTIAL SMART $AVER EE PROGRAM.

A. In the Sub 1145 proceeding, the Commission's Order stated that "if the [upcoming] modifications do not maintain or improve the program's cost-effectiveness by the next DSM/EE rider proceeding, the program should be terminated at the end of 2018." The Residential Smart $aver EE Program's performance has not improved.

Therefore, based on the continuing performance of the program, the Sub 1145 Order requiring termination at the end of 2018 if performance is not improved, and to protect ratepayers from continuing to pay for a program that is not cost-effective, I recommend that the program be closed at the end of 2018.

Q. WHAT ARE THE IMPACTS TO THE REVENUE REQUIREMENT BY CLOSING THE RESIDENTIAL SMART $AVER EE PROGRAM?

A. The impact to the North Carolina revenue requirement is a savings to customers of approximately $424,000 for Vintage Year 2019.

<u>Cost Effectiveness</u>

Q. HOW IS THE COST EFFECTIVENESS OF DEP'S DSM AND EE PROGRAMS EVALUATED?

A. The Public Staff reviews the cost-effectiveness of the individual DSM/EE programs to determine if their benefits outweigh the costs when they are proposed for approval, and on an ongoing basis in the annual DSM/EE rider proceedings. Pursuant to the Revised Mechanism, cost-effectiveness is evaluated at both the program and portfolio levels. The Public Staff reviews cost-effectiveness using the Utility Cost (UC), TRC, Participant, and Ratepayer Impact Measure (RIM) tests. Under each of these four tests, a result above 1.0 for any one test indicates that a program is cost-effective from the perspective of that particular test.

The TRC test represents the overall net system and participant benefits that will result from implementation of the program; a result greater than 1.0 indicates that these overall benefits outweigh the costs of a program to both the utility and the program's participants. A UC test result greater than 1.0 means that the program is cost beneficial[11] to the utility system (the overall system benefits are greater than the utility's costs, including incentives paid to participants). The Participant test is used to understand how ratepayers who do participate in a program will be impacted by the program, and conversely, the RIM test is used to understand how ratepayers who do not participate in a program will be impacted by the program.

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

A. In each DSM/EE rider proceeding, DEP files the projected cost-effectiveness of each program and the portfolio as a whole for the upcoming rate period (Evans Exhibit 7). New DSM/EE programs are approved under Commission Rule R8-68, which evaluates cost-effectiveness over a three- to five-year period using estimates of participation and measure attributes that can be reasonably

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

expected over that period. The evaluations in DSM/EE rider proceedings look more specifically at the expected performance of a typical measure in the next year. Each year's rider filing is updated with the most current EM&V data and other program performance data.

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

A. The Public Staff compares the cost-effectiveness test results in previous DSM/EE proceedings to the current filing, and develops a trend of cost-effectiveness that serves as the basis for the Public Staff's recommendation on whether a program should (1) continue as it is currently implemented, (2) be placed under watch for signs of decreasing cost-effectiveness and be modified to sustain cost-effectiveness, or (3) be terminated.

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

A. While many programs continue to be cost effective, the TRC scores as filed by the Company for the majority of the programs have decreased since the 2017 DSM/EE rider proceeding, mainly due to the change in avoided cost rate determinations, but also due to updated EM&V and program participation. These changes are shown in Williamson Exhibit No. 2.

Q. UNDER DEP'S CALCULATION OF COST-EFFECTIVENESS, ARE THERE ANY PROGRAMS THAT ARE NOT PROJECTED TO BE COST-EFFECTIVE FOR VINTAGE 2019?

A. Yes. Evans Exhibit 7 indicates that the following programs are not cost-effective under either the TRC or UC test, or both:

Program	TRC	UC
Residential Smart $aver EE Program	0.57	0.91
Neighborhood Energy Saver program (low-income)	1.55	0.46
My Home Energy Report program	0.96	0.96
Non-Residential Smart $aver Performance Incentive	0.92	3.75
EnergyWise for Business program	1.07	0.72

<u>Revisions to the Mechanism Approved in Sub 1145</u>

Q. PLEASE DISCUSS THE REVISIONS TO THE SUB 931 MECHANISM THAT WERE APPROVED IN THE SUB 1145 ORDER.

A. As proposed by DEP and the Public Staff, and approved by the Commission in Sub 1145, revisions to the DEP DSM/EE Mechanism were made to better align the avoided cost rates used for DSM/EE PPI calculations, PPI true-up, and program cost-effectiveness evaluations with the current avoided cost rates being implemented by the Company.[12] These changes are discussed in more detail in the testimonies of Public Staff witnesses Hinton and Maness.

Impact on Portfolio Cost-Effectiveness

from the Mechanism Revisions

Q. PLEASE DISCUSS THE IMPACTS TO THE PORTFOLIO AS A RESULT OF THE REVISIONS TO THE MECHANISM APPROVED IN THE SUB 1145 ORDER.

A. In the last rider proceeding, the underlying avoided costs utilized for calculation of avoided energy and avoided capacity values were derived from the 2015 IRP[13] and the 2014 Avoided Cost proceeding,[14] respectively. Under the Revised Mechanism, the underlying avoided costs utilized for the calculation of avoided energy and capacity values in this proceeding are derived from the Avoided Cost Proceeding approved as of December 31, 2017, in Docket No. E-100, Sub 148 (Sub 148).

While the changes in program cost effectiveness from last year's to the current year's rider filing are not solely attributable to the changes in avoided cost rates, the impact of the changes is significant. As

[12] Similar changes were made to the evaluation process for new programs in the Revised Mechanism, but are not an issue in this proceeding. However, the Commission's decision in this proceeding should apply to the evaluation of avoided capacity values for new programs.

[13] Docket No. E-100, Sub 137

[14] Docket No. E-100, Sub 136

calculated by the Company, these changes decreased the dollar impacts on a net present value basis by approximately 35% for avoided energy rates and approximately 15% for avoided capacity rates.[15] Williamson Exhibit No. 2 shows the aggregate impact on program cost-effectiveness, which includes updates to avoided cost rates, EM&V, and program participation.

Q. DOES THE PUBLIC STAFF AGREE WITH DEP'S CALCULATION OF COST-EFFECTIVENESS FILED IN THIS PROCEEDING?

A. No. Based on the information provided in response to the Public Staff's data requests and in conversations with the Company representatives who perform the DSMore modeling,[16] the Public Staff believes that the Company's calculations of cost-effectiveness were not appropriately based on the avoided capacity rates approved by the Sub 148 Avoided Cost Order. The Public Staff believes the Revised Mechanism requires the Company to use avoided capacity rates consistent with Sub 148 Avoided Cost Order and should reflect zero avoided capacity value in years prior to the

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[15] The calculations of the decreases in avoided cost were provided to the Public Staff in the Sub 1145 proceeding. These percentages were Company projections of avoided energy and avoided capacity values that could result from the Sub 148 avoided cost proceeding, since an Order by the Commission had not been issued at the time of that rider proceeding.

[16] DSMore is a modeling tool that simulates the impacts (in terms of both energy and demand savings, and avoided cost benefits) that an EE or DSM measure could contribute to a program over a period of time. Usually the model provides projections for the upcoming year. This model takes into account the market potential, current participation, costs, and benefits, along with other economic factors.

identified need for new capacity in the underlying IRP (which in this case is the 2016 IRP) that serves as the basis for the avoided capacity rate calculations.

Q. WHY DO THE PUBLIC STAFF AND THE COMPANY HAVE DIFFERING OPINIONS ON THE USE OF ZEROS IN THE AVOIDED CAPACITY PAYMENTS?

A. From conversations with the Company and responses to Public Staff data requests, the Company believes that there are fundamental differences between a Qualified Facility (QF) and a DSM/EE measure and that the avoided benefits were not intended to be the same for these two sources of non-traditional capacity.

Q. DOES THE PUBLIC STAFF CONTEND THAT THE AVOIDED COST METHODOLOGY USED FOR CAPACITY PAYMENTS TO QFS AND FOR MEASURING COST EFFECTIVENESS OF DSM/EE MEASURES SHOULD BE IDENTICAL?

A. Yes. The basis behind the methodology for calculating these measures should be the same. Through the plain language of the Revised Mechanism, the calculations for both capacity payments and measurements of cost effectiveness should utilize the same methodology and approach as approved by the Commission in its last avoided cost proceeding.

The avoided cost proceeding establishes the avoided cost capacity and energy rates that are applicable to the rates used for payments made to QFs, and the valuation of kWh and kW savings for DSM and EE program. These are separate purposes and one does not have influence on the other. However, both use the same methodology that is the basis of the avoided cost proceeding. DSM/EE impacts do not influence the payments to QFs, and vice versa. The language of the Revised Mechanism that was agreed to by DEP and the Public Staff acknowledges this application of the avoided cost methodology derived from the avoided cost proceeding.

Q. IS THE APPLICATION OF ZEROS IN DETERMINING AVOIDED CAPACITY COSTS, AS DEFINED BY THE SUB 148 ORDER, AN INAPPROPRIATE METHOD FOR ASSESSING THE PERFORMANCE OF DSM/EE PROGRAMS NOW AND GOING FORWARD?

A. No. The Public Staff believes that the Sub 148 Order establishes the methodology by which all other proceedings that incorporate the findings and conclusions represented in the Sub 148 Order should be applied. This includes DEP's DSM/EE portfolio as provided in the Revised Mechanism.

Q. WHEN DID THE PUBLIC STAFF FIRST LEARN THAT THE COMPANY'S CALCULATIONS FOR COST-EFFECTIVENESS

MAY NOT INCLUDE THE USE OF ZEROS FOR CAPACITY IN YEARS WHERE THE IRP DID NOT REFLECT A NEED FOR CAPACITY?

A. In February of this year, while reviewing the results of the cost effectiveness tests for the Prepaid Advantage Energy Efficiency Pilot proposed by Duke Energy Carolinas, LLC, (DEC) the Public Staff realized that the calculations provided by DEC included payments for capacity in years when its 2016 IRP did not reflect a need for capacity. As noted in our comments filed in E-7, Sub 1167, the Public Staff and DEC did not agree on how to calculate the avoided capacity cost rates used in the cost effectiveness tests. Considering the language in DEC and DEP mechanisms for DSM/EE cost recovery regarding the calculation of cost effectiveness is the same, the Public Staff realized that the calculation would likely be an issue in both the DEC and DEP DSM/EE rider proceedings.

Impacts of the Public Staff's Position

Q. WHAT ARE THE IMPACTS ON PORTFOLIO COST-EFFECTIVENESS OF APPLYING ZERO CAPACITY VALUES FOR YEARS PRIOR TO 2022?

A. Williamson Exhibit 3 shows the change in cost-effectiveness scores for each program when no capacity value is given for years that DEP's 2016 IRP does not show a capacity need. I note that programs with measures having lives extending to 2022 and beyond do include a capacity payment for those periods when the IRP shows a capacity need.

Q. UNDER THE PUBLIC STAFF'S CALCULATION OF COST-EFFECTIVENESS, ARE THERE ANY ADDITIONAL PROGRAMS THAT ARE NOT COST-EFFECTIVE FOR VINTAGE 2019?

A. Yes. In addition to the programs that I listed earlier that had a TRC score of less than 1.0, the TRC test scores for the Residential New Construction, EE for Business, and the EnergyWise for Business programs drop below 1.0 after incorporating zeros for the value for capacity in the appropriate years when in calculating cost-effectiveness. Williamson Exhibit No. 3 highlights the programs that had a TRC score of less than 1.0 as filed by DEP, as well as the additional programs that have a TRC score of less than 1.0 under the Public Staff's position.

Q. WHAT ACTIONS DO YOU RECOMMEND THAT THE COMMISSION TAKE REGARDING PROGRAMS THAT ARE NOT COST EFFECTIVE PURSUANT TO THE REVISED MECHANISM?

A. As part of the Revised Mechanism, the Company and the Public Staff agreed on a procedure for programs that are not cost effective. Under Paragraph 22 and Paragraphs 22A-D of the Revised Mechanism, for any program that initially demonstrates a TRC score less than 1.00, the Company will include in its annual DSM/EE rider filing a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program. If a program demonstrates a prospective TRC score of less than 1.00 in a second DSM/EE rider proceeding, the Company will include a discussion of what actions it has taken to improve cost-effectiveness. If a program demonstrates a prospective TRC score of less than 1.00 in a third DSM/EE rider proceeding, the Company will terminate the program at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission. This approach provides ample time for program modifications to improve cost-effectiveness. I discuss below my recommendations regarding the programs in this rider proceeding that have a projected ongoing TRC score of less than 1.0:

1. The Residential Smart $aver EE program. My recommendation, as stated earlier in this testimony, should be to close the program at the end of 2018, pursuant to the Commission's order in the Sub 1145 proceeding.
2. The MyHER, Residential New Construction, EE for Business, and Non-Residential Smart $aver Performance Incentive programs fall under Paragraph 22B of the Mechanism,[17]

[17] This is the second year the Non-Residential Smart $Aver Performance Incentive Program has not been cost-effective. The program was launched in January 2017. The Public Staff prefers to give new programs a year to get established before directing the Company to take action to improve cost effectiveness.

which requires that the Company provide a discussion in the next proceeding on the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate these programs.

3. The EnergyWise for Business program is a demand-side management program that draws the majority of its avoided benefits from capacity and (T&D) cost reductions. Using the Company's application of avoided capacity costs, this program is cost effective under the TRC test; however, when using the Public Staff's methodology, this program is no longer cost effective, as illustrated in Williamson Exhibit No. 3. Pursuant to Paragraph 23B, the Company should provide a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program. Pursuant to Paragraph 23C of the Revised Mechanism, if this program shows a prospective TRC of less than 1.0 in next year's DSM/EE rider proceeding, the Company should include a discussion of what actions it has taken to improve cost-effectiveness.

EM&V

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

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

I also reviewed previous Commission orders to determine if DEP complied with provisions regarding EM&V contained in those orders. In the Sub 1145 proceeding, the Commission approved my recommendations that:

1. Future evaluations of the Residential Multi-Family Energy Efficiency program should include a billing analysis and more specific data on bulbs being replaced.
2. Future evaluations of the Small Business Energy Saver program should (a) incorporate HVAC interactive effects and update the coincidence factors for lighting measures, and (b) begin tracking the heating and cooling types of participants to improve estimates of the HVAC interaction factors.
3. Future evaluations of the Neighborhood Energy Saver program, and similar programs, should consider utilizing state-level specific data in its evaluations when providing estimates in the program's EM&V review, unless cost-prohibitive.
4. Future DEP evaluation reports should include a discussion of key methodological differences between past and present evaluations, including differences in methodologies across multiple programs that offer similar or identical measures.

Q. DID DEP ADOPT THE PUBLIC STAFF'S RECOMMENDATIONS IN ITS EM&V REPORTS?

A. Yes. To the extent these recommendations are applicable to the EM&V reports filed in this proceeding, the reports incorporated my recommendations. I understand that the Company's EM&V evaluator intends to incorporate these recommendations in future EM&V reports as well.

Q. DO YOU HAVE ANY RECOMMENDATIONS CONCERNING THE EM&V REPORTS YOU REVIEWED?

A. Yes. I have reviewed the testimony and exhibits of DEP witness Evans concerning the EM&V of DEP's DSM and EE programs. Based upon my review, I have three recommendations that will impact any future analysis of the EE Lighting program (Exhibit H) and one recommendation for the MyHER program (Exhibit I) that will impact current and future analyses.

Q. PLEASE EXPLAIN YOUR EM&V-RELATED RECOMMENDATION REGARDING THE EE LIGHTING PROGRAM.

A. Unless DEP or the program evaluator can demonstrated the following recommendations are cost-prohibitive, in future evaluations of the EE Lighting program, I recommend:

1. The program evaluator should include the basis for the selected weighting methodology (weightings based on bulb

sales, measure savings, or other metric) when assessing program savings. The program evaluator should also indicate what other weighting methodologies were considered and why they were rejected, and why the selected methodology is preferable;

2. The program evaluator should provide further clarity into the sales of incentivized bulbs at dollar/discount stores to determine the income levels of customers purchasing these bulbs. This information would be useful in determining the appropriate NTGR applicable to this category of sales. The program evaluation in Evans Exhibit H asserts a NTGR of 1.00 for these sales, assuming that many of the sales are made by low income customers, who typically would not participate in the program without the incentive. Higher income customers who also shop at dollar/discount stores usually show NTGRs of less than 1.00. The volume of sales from the dollar/discount stores and the potential impacts that result justify my recommendation for further study; and,

3. The program evaluator should update its study on the percentage of bulb sales to residential and non-residential customers.

Q. PLEASE EXPLAIN YOUR EM&V-RELATED RECOMMENDATION REGARDING THE MYHER PROGRAM.

A. The savings and impacts of the MyHER program were evaluated by Nexant, (Evans Exhibit I) for the period of program participation spanning calendar year 2016. Nexant relied upon a randomized control trial (RCT) to determine the savings of program participants. An RCT compares observed differences in energy consumption between the treatment group (program participants) and a control group (non-participants). A benefit of the use of an RCT is that it can isolate the observed differences between the treatment and control group to those which must be attributable to the program. In other words, the only difference in the change in consumption patterns between the treatment and control groups over time is that one group is exposed to the home energy reports and the other is not. The Public Staff recognizes this approach to be a standard and best practice for the evaluation of residential behavioral programs that are similar or identical in nature to the MyHER program.

Nexant evaluated the program savings based on the timing of participation of different groups of customers called "cohorts." As the report describes, a cohort is a group of accounts that are added to the program at a given time. For this evaluation, there were five cohorts: the first included customers who began participating in 2014, the second included those who began participating in 2015, the third included those who began participating in June 2016, the fourth, or Cohort R, included those who began participating in

October of 2015, and the fifth, or Cohort X, included those who began participating in June of 2015.

The annual kWh savings were found to vary by cohort as follows:

Cohort 1 (2014)	-123.8 kWh
Cohort 2 (2015)	-0.4 kWh
Cohort 3 (June 2016)	-2 kWh
Cohort R (October 2015)	-7.7 kWh
Cohort X (June 2015)	-15.5 kWh

Source: Table 3-10 of Evans Exhibit I shows point estimates for each cohort for the 2016 calendar year.

While the Public Staff has confidence in the methodology applied to complete this evaluation and believes that the overall savings appear to be reasonable and in line with the findings of other similar evaluations of residential behavioral savings in the United States, the Public Staff is unable to conclude its review of the overall findings and savings estimates put forth in the evaluation report. The Public Staff will continue to evaluate Evans Exhibit I and will coordinate with DEP to conduct additional review of the data used in the evaluation. As a result, the Public Staff is not able to make a definitive recommendation on Evans Exhibit I in this proceeding and bring its review to a conclusion. Therefore, it is my recommendation is to postpone acceptance of the results of the MyHER program evaluation for the purposes of this EE Rider proceeding. However, the Public Staff will continue to review this report and offer further recommendations in the next DSM/EE rider proceeding.

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

A. With the exception of Evans Exhibit I as discussed above, the program vintages for which the remaining EM&V reports were filed in this proceeding should be considered complete and do not require any adjustment to the impacts at this time. With respect to Evans Exhibit I, I believe it is appropriate to postpone accepting Evans Exhibit I until the Public Staff can conclude its review, which would be addressed in DEP's 2019 DSM/EE rider proceeding.

Q. WERE THERE ANY EM&V REPORTS THAT WERE CARRIED OVER FROM LAST YEAR'S RIDER PROCEEDING AND LEFT OPEN FOR REVISION?

A. Yes. In the Sub 1145 proceeding, I recommended that the EM&V reports for the Small Business Energy Saver and the Multi-Family EE programs (Evans Exhibits D and E, respectively, filed in the Sub 1145 proceeding) be revised before accepting them as complete. These reports have been revised and submitted as Evans Exhibits J and E, respectively, in this proceeding. The Public Staff's review indicates that the Company appropriately incorporated the Public Staff's previous recommendations into these EM&V reports. Therefore, I recommend that Evans Exhibits J and E be considered complete for purposes of calculating program impacts in this proceeding.

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

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

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

DAVID M. WILLIAMSON

I am a 2014 graduate of North Carolina State University with a Bachelor of Science Degree in Electrical Engineering. I began my employment with the Public Staff's Electric Division in March of 2015. My current responsibilities within the Electric Division include reviewing applications and making recommendations for certificates of public convenience and necessity of small power producers, master meters, and resale of electric service; reviewing applications and making recommendations on transmission proposals for certificates of environmental compatibility and public convenience and necessity; and also interpreting and applying utility service rules and regulations.

My primary responsibility within the Public Staff is reviewing and making recommendations on DSM/EE filings for initial program approval, program modifications, EM&V evaluations, and on-going program performance of DEC, DEP, and DENC's portfolio of programs. I filed an affidavit in DEP's 2016 DSM/EE rider proceeding in Docket No. E-2, Sub 1108. I have filed testimony in DEP's 2017 DSM/EE rider proceeding in Docket No. E-2, Sub 1145 and also in DEC's 2018 DSM/EE rider proceeding in Docket No. E-7, Sub 1164.

MS. EDMONDSON: Thank you. That's all from the Public Staff.

COMMISSIONER BROWN-BLAND: Is there anything else to come before the Commission on this DSM/EE matter?

MS. FENTRESS: Not from the Company.

COMMISSIONER BROWN-BLAND: And with regard to proposed orders, 30 days from today's date; is that good with everybody?

MS. FENTRESS: Yes.

MS. EDMONDSON: Yes.

COMMISSIONER BROWN-BLAND: Then it shall be so ordered.

MS. FENTRESS: Thank you.

COMMISSIONER BROWN-BLAND: Thank you. And we will take a little time to switch around and take care of the last one.

(WHEREUPON, the proceedings were adjourned.)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell

Kim T. Mitchell
Court Reporter II