BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1252

In the Matter of		
Application by Duke Energy Progress, LLC,	)	TESTIMONY OF
for Approval of Demand-Side Management	)	JOHN R. HINTON
and Energy Efficiency Cost Recovery Rider	)	PUBLIC STAFF –
Pursuant to N.C. Gen. Stat. § 62-133.9 and	)	NORTH CAROLINA
Commission Rule R8-69	)	UTILITIES COMMISSION

August 26, 2020

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1252

Testimony of John R. Hinton

On Behalf of the Public Staff

North Carolina Utilities Commission

August 26, 2020

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

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

Q. WHAT ARE YOUR DUTIES AT THE PUBLIC STAFF?

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

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

A. The purpose of my testimony is to discuss the appropriate avoided capacity and energy costs that should be used to evaluate the cost-effectiveness of the DSM/EE programs of Duke Energy Progress, LLC (DEP or Company), that are incorporated in the calculation of DEP's portfolio performance incentive (PPI), pursuant to the Company's cost recovery mechanism described in the Agreement and Stipulation of Settlement DEP reached with the Public Staff, the North Carolina Sustainable Energy Association, Environmental Defense Fund, Southern Alliance for Clean Energy, the South Carolina Coastal Conservation League, Natural Resources Defense Council, and the Sierra Club, which was filed with the North Carolina Utilities Commission (Commission) on, and approved in the Commission's *Order Approving DSM/EE Programs and Stipulation of Settlement* issued on June 15, 2009, in Docket No. E-2, Sub 931 (Sub 931 Mechanism). In Docket No. E-2, Sub

1145 (Sub 1145), the Commission approved certain revisions to the Mechanism relating to the methodology for determining avoided costs for purposes of the PPI calculation and determination of program cost-effectiveness in its *Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice* issued on November 27, 2017, (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 clarified the avoided energy and capacity benefits used for cost effectiveness calculations for program approval and the initial estimate of the PPI and any PPI true-up. The revisions also enabled the review of program cost-effectiveness. That review uses avoided capacity costs derived from the most recent Commission-approved Biennial Determination of Avoided Cost Rates; as of December 31 of the year immediately preceding the annual DSM/EE Rider filing date (hereafter, the “PURPA method”).

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

A. The applicable avoided cost proceeding is Docket No. E-100, Sub 158 (Sub 158), in which the Commission issued its *Notice of Decision* on October 7, 2019, ruling on issues that are relevant to the calculation of avoided capacity rates and avoided energy rates. DEP filed its compliance rates on November 1, 2019, and the Commission issued its *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* on April 15, 2020, establishing these rates.

Q. PLEASE DESCRIBE YOUR CONCERN REGARDING THE COMPANY'S APPLICATION OF AVOIDED COST RATES FROM THE SUB 158 PROCEEDING.

A. The Company has updated its underlying avoided cost inputs for both capacity and energy to be derived from the most recent avoided cost proceeding, Sub 158. The Public Staff, in this proceeding, has two concerns with the Company's application of the newly updated rates to its avoided capacity.

The first issue is with the avoided capacity component used for the

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

The second issue is with the seasonal allocation of avoided capacity cost benefits for the Company's portfolio of DSM programs, both Residential and Non-Residential. In Sub 158, the Commission approved a seasonal allocation of 100% winter, 0% summer for avoided capacity costs. However, in this proceeding the Company has proposed to use a different seasonal allocation than approved by the Commission. If the total summer based DSM capacity for Vintage year 2021 exceeds the annual DSM summer capacity as forecasted from the 2018 IRP; then, such capacity will be valued at a 100% winter and a 0% summer capacity weighting. However, the Company's application would use a 100% summer and a 0% winter allocation for any MWs less than what is forecasted by the Company's 2018 IRP.

The approved seasonal capacity weighting becomes an issue only with respect to summer-based DSM programs that offer no capacity value during the winter season; such as, with the approximately 411 MWs of load reductions in year 2021 associated with the air conditioning cycling of DEP's EnergyWise Programs for residential homes and businesses. In addition for 2021, the EnergyWise program includes approximately 18 MW of load reductions associated with its water heating load control for the western service area that receives 100% of the winter-season capacity value. Shown below is an excerpt of the reduced MW associated with the Company's DSM programs from its 2018 IRP.

	Summer DSM									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
EnergyWise Home	383	400	411	417	417	418	418	419	419	420
Demand Response Automation	32	39	46	54	57	57	57	57	57	57
Large Load Curtailable	287	290	292	295	298	300	300	300	300	300
EnergyWise Business	9	14	19	24	29	29	29	29	29	29
DSDR	213	215	215	217	218	221	224	228	231	236
Total DSM	923	958	984	1,007	1,019	1,024	1,027	1,032	1,035	1,041
	Winter DSM									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
EnergyWise Home	15	16	18	19	20	21	23	24	25	26
Demand Response Automation	15	19	23	27	31	31	31	31	31	31
Large Load Curtailable	246	249	251	254	256	259	259	259	259	259
EnergyWise Business	1	2	3	4	5	5	5	5	5	5
DSDR	213	215	215	217	218	221	224	228	231	236
Total DSM	490	501	511	521	530	537	541	546	550	557

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?

A. The remainder of my testimony is presented in the following two sections:

I. 17% Reserve Margin Adder

II. Seasonal Allocation of Capacity

I. <u>17 % RESERVE MARGIN ADDER</u>

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

A. In this proceeding, the Company proposed to increase the value of the demand reduction benefits from EE programs by 17%. The Company notes that the demand reduction benefits are accounted as a <u>reduction to its peak load</u> *(emphasis added)* in its 2018 IRP; as shown in the Company's Load, Capacity, and Reserve (LCR) Tables. Key to the Company's proposal is that the demand reduction benefits from EE programs are not viewed as supply-side resources; rather the EE demand reductions are considered as demand-side resources. The Company's argument rests on the fact that to provide adequate and reliable utility service, the Company increases the amount of supply-side resources by a 17% reserve margin to meet the projected peak load. The Company argues that their proposed reserve margin adjustment is warranted for its demand-side resources associated with EE programs. Prior to the 2012 merger of DEP's parent corporation with Duke Energy Corporation, DEP maintained that its use of the Strategist model included a reserve margin adjustment, However, since the merger, DEP's IRP process has largely followed modeling practices of

Duke Energy Carolinas, LLC (DEC), which until its 2020 DSM/EE Rider filing in Docket No. E-7, Sub 1230, had not proposed a reserve margin adjustment for demand-side resources.

Q. WILL YOU EXPLAIN THE EFFECT OF THE RESERVE MARGIN ADJUSTMENT ON THE IRP?

A. Yes. The table below is an excerpt from DEP's 2018 IRP Winter Projections from the LCR Table for years 2019-2025.[1] Lines 23-25 examine the impact of shifting 100 MW of demand-side resources to a supply side resource. In 2021, DEP projects generating reserves of 2,405 MW, for an actual reserve margin (RM) of 17.0% (lines 21 and 22). If DEP had 100 MW less EE during 2021, the load forecast would be increased by 100 MW to 14,251. By shifting to a supply side resource, DEP maintains that from a planning standpoint it would effectively increase its 2021 load serving capacity by a 117 MW to 2,522 MW, which leads to a 17.7% reserve margin; as compared to, a 17.0% reserve margin.

DEP claims that customers benefit from this, and believes its EE programs should have their capacity benefits increased to reflect the fact that its reduced load forecast through this EE program warrants a higher avoided cost valuation. The table below

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

illustrates DEP's proposal from a cost perspective with respect to shifting 100 MW of demand-side MW savings with supply-side resources:

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Progress 2018 Annual Plan

		2019	2020	2021	2022	2023	2024	2025
Load Forecast								
1	DEP System Winter Peak	14,036	14,060	14,062	14,168	14,243	14,429	14,553
2	Firm Sale	150	150	150	150	150	150	0
3	Cumulative New EE Programs	(26)	(44)	(62)	(79)	(104)	(120)	(138)
4	**Adjusted Duke System Peak**	**14,161**	**14,166**	**14,151**	**14,239**	**14,289**	**14,458**	**14,415**
18	**Cumulative Production Capacity**	**16,161**	**16,075**	**16,045**	**16,144**	**16,187**	**16,381**	**17,445**
Demand Side Management (DSM)								
19	**Cumulative DSM Capacity**	**490**	**501**	**511**	**521**	**530**	**537**	**541**
20	**Cumulative Capacity w/ DSM**	**16,651**	**16,576**	**16,555**	**16,665**	**16,718**	**16,918**	**17,985**
Reserves w/ DSM								
21	Generating Reserves	2,491	2,410	2,405	2,426	2,428	2,460	3,571
22	**% Reserve Margin**	**17.6%**	**17.0%**	**17.0%**	**17.0%**	**17.0%**	**17.0%**	**24.8%**
23	Adjusted DEP system peak w/100 MW of less demand-side EE resources	14,261	14,266	14,251	14,339	14,389	14,558	14,515
24	Genera ing Reserves w/117 MW of new demand-side EE resources	2,608	2,527	2,522	2,526	2,528	2,560	3,671
25	Effective Reserve Margin	18.3%	17.7%	17.7%	17.6%	17.6%	17.6%	25.3%

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

A. No. The Company agrees that the MW reductions from their EE program (demand-side resource) are not any greater; however, this resource is awarded a higher value from a planning perspective. This enhanced value is not realized from the customer's perspective in the short-run and it is not entirely clear whether the customer(s) will realize any value in the long-run. The Company's proposed reserve margin adder will increase the avoided cost benefits. In turn, this will increase the program's utility cost test result, leading to a higher Portfolio Performance Incentive (PPI) and higher earnings.

Irrespective of the balance of demand and supply resources at any particular point in time, a key question is what is the appropriate value customers should pay for a MW load reduction, and how is the value calculated? DEP maintains customers should pay (100 MW * approved avoided capacity rate per kW-yr. * 1.17); while, historically the value of MW reductions has been calculated (100 MW * approved avoided capacity rate per kW-yr). A weakness in DEP's argument is the inequity of asking customers to pay 17% more for the same MW reduction from an EE program, as compared to a MW reduction from a DSM program. From a resource planning perspective, DEP has a theoretical basis as shown in the above table; however, from a ratemaking perspective the logic is deficient.

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

A. It is inappropriate to include the 17% reserve margin adder because it is inconsistent with the way the Mechanism states that the avoided capacity benefits are to be determined. In Docket No.

E-2, Sub 1145, the Commission approved certain changes to the Mechanism that updated where and how these avoided capacity benefits are to be determined. The Mechanism in Paragraph 70A states that:

> "For the PPI for Vintage Years 2019 and afterwards, the program specific per kW avoided capacity benefits and per kWh avoided energy benefits…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."

This paragraph explicitly states how the rates are to be determined, however the Company is now including an additional component to the equation that does not exist in the current Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities.

Additionally, the Company's proposal effectively increases what customers will pay for the avoided capacity cost benefits of the EE programs by increasing the avoided capacity cost rate above the approved rate. This rate is comprised of an approved annual combustion turbine (CT) carrying cost and other factors including a Performance Adjustment Factor (PAF). The approved[2] PAF of 5%

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

is a multiplier that increases the annual CT carrying cost, which according to DEP should be increased by an additional 17%. From this perspective, the impact of this adjustment increases the value of the avoided demand reduction benefits by approximately 23% (1.228 = 1.05*1.17) over the cost of an avoided CT underlying the avoided capacity rates.

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

A. The Company's proposal effectively raises the dollar per kW value of the demand reduction benefits by 17% over the approved avoided capacity rates.[3] Instead of using the Sub 158 avoided capacity cost of **[BEGIN CONFIDENTIAL]** $[redacted] **[END CONFIDENTIAL]** per kW-year for 2019 and annually escalating that cost out to 2044, the Company increases that value by 17% to **[BEGIN CONFIDENTIAL]** $[redacted] **[END CONFIDENTIAL]** per kW-year for each kW of demand reduction benefits realized from its EE programs. The proposed cost per kW-yr. for the demand reductions associated with an EE program and with a DSM program is shown in Hinton Exhibit 1.

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

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

A. The Public Staff recommends that the Commission require the Company to remove the reserve margin adder it included for the demand reduction benefits associated with its EE programs. Furthermore, I believe that this is not the appropriate proceeding to evaluate such a significant change to the avoided capacity costs. In Docket No. E-2, Sub 1145, the Public Staff and the Company agreed that the PURPA-based method of calculating avoided costs was preferred over the use of the Company's IRP. In that proceeding, I testified on that,

> ...the use of PURPA-based avoided costs links the savings and financial incentives afforded the Company for its DSM/EE programs with the rates it pays QFs for avoided energy and avoided capacity. Therefore, I believe that the use of PURPA-based avoided energy and capacity costs will lead to better estimates of the costs avoided by the Company's DSM/EE programs, thereby providing a more accurate view of the value of DSM and EE.
>
> Testimony of John R. Hinton, Docket No. E-2, Sub 1145 at 7.

On November 27, 2017, in its *Order Approving DSM/EE Rider and Requiring Filing of Customer Notice* at 25, the Commission approved the Agreement and noted that,

> First, the revision to Paragraph 70 removes any ambiguity regarding the proper avoided costs to be used for calculating the PPI. The Commission finds that the

> revision to Paragraph 70 better links the savings and financial incentives for DEP's DSM/EE programs with the rates it pays QFs for avoided energy and avoided capacity, and provides for regular updating to prevent stale or outdated rates.

I believe the proposed reserve margin adjustment adds further divergence between the application of the avoided capacity rates in this proceeding and the approved avoided capacity rates in Sub 158. Furthermore, I believe that that it is inappropriate to propose such a significant change in the valuation of the avoided energy cost-benefits in this proceeding, as opposed to examining this change within the review of the Mechanism. The current cost recovery mechanism was approved in Docket No. E-2, Sub 1174, where the PPI is based on the present value of the estimated net dollar savings associated with the Company's DSM/EE programs. As such, I believe that any change to the dollar savings of avoided energy costs benefits from DSM/EE programs should be evaluated in concert with consideration of the appropriate incentive rate in a Mechanism review.

II. SEASONAL ALLOCATION OF CAPACITY

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

A. My concern stems from the need to ensure that the avoided capacity benefits or values placed on MW reductions associated with the legacy DSM programs[4] remain reasonable. Through data requests and discussions with the Company, DEP maintains that the avoided capacity benefits from the approximate 400 MW of DSM programs should continue to be valued using a 100% summer seasonal allocation weighting. The Company justifies this approach on the basis that these "legacy" measures and participation are modeled in its 2018 IRP. The Company values the "incremental" measures and participation using the seasonal allocation weightings of 100% winter and 0% summer.

DEP maintains it is a winter planning utility, as noted in its IRPs, filed reserve adequacy studies, and in its previous two Biennial Avoided Cost Proceedings.

---

[4] DEP makes a distinction between "legacy" and "incremental" DSM programs in its evaluation of the portfolio and program cost effectiveness. As understood by the Public Staff and based on the Company's responses to data requests, "Legacy" DSM is the level of DSM activation capability that was originally projected for the year 2021 in the 2018 IRP. "Incremental" means all activation capability that is above the projected MW projected in the 2018 IRP for year 2021.

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

A. The Company's recently approved avoided capacity rates were developed using seasonal weighting of 100% for the winter season and 0% for the summer season. These allocations are similar to those approved in Docket No. E-100, Sub 148, where DEP proposed and the Commission approved seasonal allocation factors of 80% for the winter season and 20% for the summer season. For Sub 158, DEP employed Astrapé Consulting to perform a Capacity Value of Solar Study that supported QFs receiving 100% of the annual avoided capacity costs during the winter season; while receiving 0% of the avoided capacity cost weighting during the summer season. The Study found a higher loss of load risk during the winter season, which the Commission approved. In addition to addressing this risk, DEC and DEP stated that these seasonal allocations provide improved price signals[5] for QFs to help the Companies meet their generation needs and appropriately pay QFs for the value they provide.

[5] Docket No. E-100, Sub 158, T., Vol. 2, page 73, lines 5-13.

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

A. No. The Public Staff believes the argument of separating legacy and incremental measures and participation in DSM/EE programs has been seriously weakened by the conclusion of another avoided cost proceeding where DEP's avoided cost rates are based on winter planning. This emphasis on winter planning is supported by the 2016 Resource Adequacy Study, which indicated that DEP's long-range planning should target the winter season, and utilize a 17% winter reserve margin. As such, the value of summer DSM is diminished and no longer has the same value for resource planning purposes in terms of a capacity resource at the expected time of peak and the dollar per kW associated with the demand reductions. In Docket No. E-100, Sub 157, the Commission directed DEC and DEP to conduct another reserve margin study for their 2020 IRPs, which is currently being developed. Based on recent discussions among the Company, Astrapé Consulting, and the Public Staff, in preparation for the 2020 IRP filing, it is my understanding that the results of the upcoming study will show that DEP remains winter planning.

Lastly, I have a concern about the emphasis that the Company places on the projected number of MWs associated with the DSM in its 2018 IRP in relation to the approved avoided costs from Sub 158. The sole use of the generation expansion plan from the 2018 IRP in the determination of the avoided energy costs using PROSYM, a production cost model, in Sub 158. Furthermore, the 2018 IRP has no role in determining the timing and the level of avoided capacity costs in this proceeding. As noted, the Company has produced reserve margin studies of its shift to winter planning. This shift to winter planning has been noted in prior IRPs and, more importantly, in its previous two Biennial Avoided Cost proceedings. As such, I believe that the approved seasonal allocation of 100% winter and 0% summer weighting should take precedence over the MW reductions that were projected in its 2018 IRP.

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

A**.** Yes, the allocation of seasonal capacity value to all of the DSM programs would appropriately direct the Company to emphasize programs that focus on reducing load during the winter season. I am aware the Company has already begun such an investigation aimed at reducing winter peak loads, and has filed modifications to its Residential Load Control Rider, Docket No. E-2, Sub 927, this week would provide a winter-focused load control program.

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

A. Yes. While the Company's Reserve Adequacy Studies provide evidence that DEP is winter planning, the fact that the Company's highest cost of generation typically occurs in the winter season provides additional support for its claim that its capacity needs are greatest in the winter season. With the peak demands for electricity, the marginal costs of fuel, variable O&M, and the occasional start costs of additional generation to serve the customers are four to five times, or more, higher than the average cost approved in rates. As such, it is in the Company's best interest to consider the activation of its DSM programs during those times. Shown below are a history of the last twelve years of DEP's day-ahead lambdas, which illustrates the relative dominance of the expected costs of generation during the winter season and the lower and less volatile day-ahead lambdas during the summer seasons relative to the winter seasons.

[BEGIN CONFIDENTIAL]

CONFIDENTIAL

DEP's 2019 Day-Ahead Lambdas

[redacted]

CONFIDENTIAL

DEP's 2018 Day-Ahead Lambdas

[redacted]

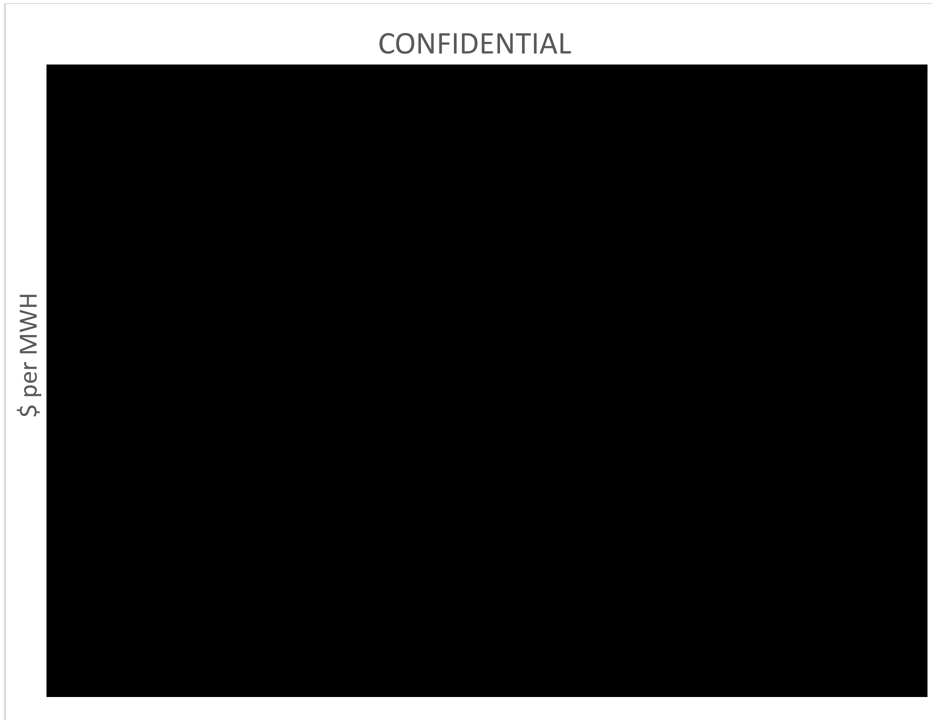
CONFIDENTIAL

[redacted]

CONFIDENTIAL

$ per MWH

[redacted]



[redacted]

[redacted]

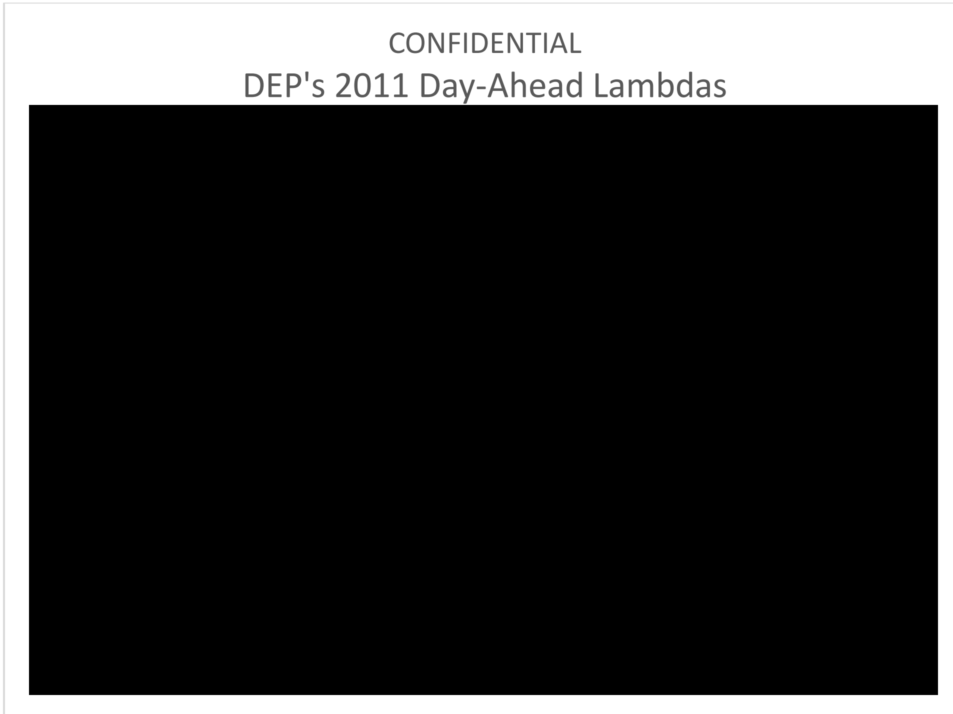
CONFIDENTIAL

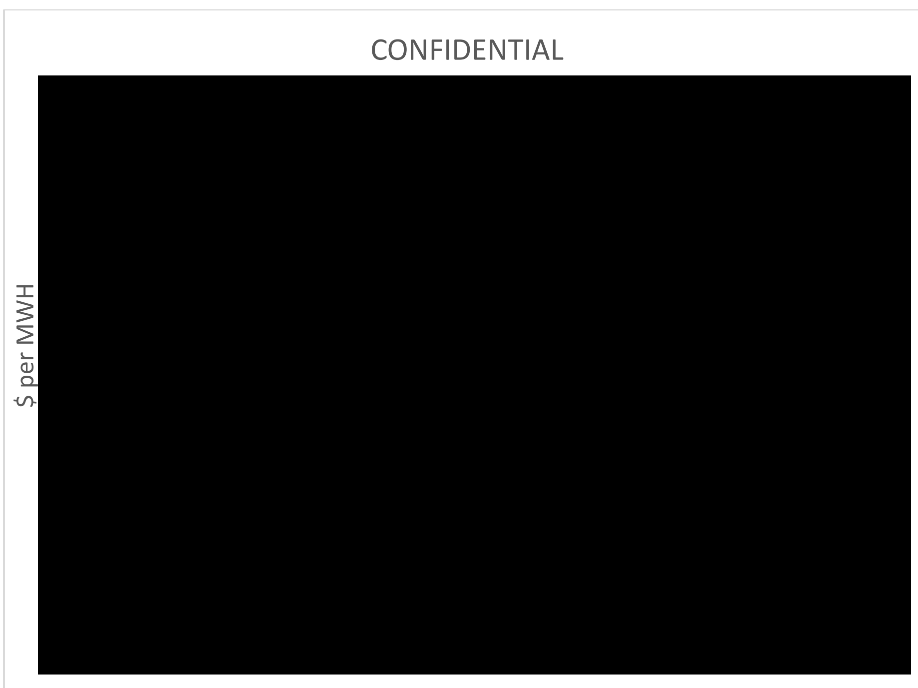
[redacted]

CONDFIDENTIAL

DEP's 2012 Day-Ahead Lambdas

[redacted]


CONFIDENTIAL
DEP's 2011 Day-Ahead Lambdas


CONFIDENTIAL
$ per MWH

[redacted]

[redacted]

CONFIDENTIAL

DEP's 2007 Day-Ahead Lambdas

[redacted]

[END CONFIDENTIAL]

While the avoided energy costs for the hour of the peak do not represent the capacity value of a DSM program, it should follow that high energy prices tend to follow constrained conditions.

Another reason for the Company's decision to activate is primarily, but not always, a function of available generation, be it an emergency condition or simply low reserves required to meet the expected load. In Hinton Exhibit 2 are exhibits from previous DSM/EE rider filings (2015-2019) on the activations of DEP's EnergyWise and other DSM programs. Exhibit 2 shows that the capacity needs and emergency events that lead to activations most often occur during the winter season. My intent in discussing DEP's historical DSM activations is to show the evolving role that these programs play in providing sufficient capacity. I do not intend to imply that these programs are not valuable; rather, I am pointing out that their capacity value has changed relative to the shifting of the seasonal weighting capacity needs from summer to winter.

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

A. The Public Staff recommends that the Commission deny DEP's proposal to give its legacy DSM/EE programs a 100% summer weighting under its current IRP winter planning scenario, and require DEP to recalculate cost effectiveness and its PPI using a 100% winter and 0% summer allocation of avoided capacity benefits. This would value the demand reduction benefits from DSM on the same basis as any other demand reductions the Company may realize from QFs. To do otherwise would have ratepayers reward the Company with a PPI that is based on over-valued kW savings via the use of DEP's proposed 100% summer seasonal capacity allocation despite its need for winter DSM. Whereas, a 100% seasonal capacity allocation for winter and 0% for seasonal capacity allocation for summer strikes a reasonable balance of the value of DSM/EE programs for ratepayers and the Company.

Furthermore, I note that my recommendation to use the Sub 158 seasonal allocation factors will not cause any legacy DSM programs to be no longer cost effective. These programs remain cost effective is, in part, due to the significant role of avoided T&D costs which provide almost the same value as 100% of the avoided capacity cost. My recommendation to use the Sub 158 seasonal weighting of avoided capacity costs reduces the cost-effectiveness of these programs and the overall cost-effectiveness of the portfolio of programs as shown in Public Staff witness Williamson Exhibit 4.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

QUALIFICATIONS AND EXPERIENCE

JOHN ROBERT HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. I joined the Public Staff in May of 1985. I filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long-range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023. I filed testimony on the level of funding for nuclear decommissioning costs in Docket Nos. E-7, Subs 1026, and 1146. I have filed testimony on the Integrated Resource Plans (IRPs) 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, 148. I have filed a Statement of Position in the arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966. I filed testimony on avoided costs in DSM/EE rider cases in Docket No.s E-7, Sub 1130, E-2, Sub 1145, E-7, Sub 1230.

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

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

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

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

CONFIDENTIAL

Year	Approved Biennial Avoided Cost Rate ($/kW-yr)	Approved Biennial Avoided Cost Rate ($/kW-yr) with 17% Adder
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]
2041	[redacted]	[redacted]
2042	[redacted]	[redacted]
2043	[redacted]	[redacted]
2044	[redacted]	[redacted]

Duke Energy Progress
System Event Based Demand Response January 1, 2018 - December 31, 2018
Docket Number E-2, Sub 1206

Date	State	Program Name	Event Trigger	Customers Notified /Switches Dispatched	MW Reduction
1/1/2018	NC and SC	DSDR	Capacity Needs	-NA-	426
1/2/2018	NC and SC	DEP DRA	Capacity Needs	14 Customers / 41 Sites	7.5
1/2/2018	NC	DEP EnergyWise Home	Capacity Needs	10,760/14,909	13.6
1/2/2018	NC and SC	DSDR	Capacity Needs	-NA-	714
1/2/2018	NC and SC	DSDR	Capacity Needs	-NA-	402
1/3/2018	NC and SC	DSDR	Capacity Needs	-NA-	1,446
1/3/2018	NC and SC	DSDR	Capacity Needs	-NA-	594
1/4/2018	NC and SC	DSDR	Capacity Needs	-NA-	487
1/4/2018	NC and SC	DSDR	Capacity Needs	-NA-	585
1/5/2018	NC	DEP EnergyWise Home	Capacity Needs	10,763/14,918	12.3
1/5/2018	NC and SC	DSDR	Capacity Needs	-NA-	867
1/5/2018	NC and SC	DSDR	Capacity Needs	-NA-	519
1/6/2018	NC and SC	DSDR	Capacity Needs	-NA-	989
1/7/2018	NC and SC	DEP DRA	Capacity Needs	14 Customers / 42 Sites	8.7
1/7/2018	NC	DEP EnergyWise Home	Capacity Needs	10,749/14,900	15
1/7/2018	NC and SC	DSDR	Capacity Needs	-NA-	1,177
1/8/2018	NC	DEP EnergyWise Home	Capacity Needs	10,749/14,900	5.6
1/8/2018	NC and SC	DSDR	Capacity Needs	-NA-	1,055
1/14/2018	NC and SC	DSDR	Capacity Needs	-NA-	617
1/15/2018	NC and SC	DEP DRA	Capacity Needs	14 Customers / 42 Sites	8.1
1/15/2018	NC	DEP EnergyWise Home	Capacity Needs	10,738/14,883	8.2
1/15/2018	NC and SC	DSDR	Capacity Needs	-NA-	633
1/16/2018	NC and SC	DSDR	Capacity Needs	-NA-	413
1/17/2018	NC and SC	DSDR	Capacity Needs	-NA-	1,005
1/18/2018	NC and SC	DEP DRA	Capacity Needs	14 Customers / 42 Sites	7.1
1/18/2018	NC	DEP EnergyWise Home	Capacity Needs	10,738/14,883	8.2
1/18/2018	NC and SC	DSDR	Capacity Needs	-NA-	899
3/9/2018	NC and SC	DSDR	Capacity Needs	-NA-	564
3/13/2018	NC and SC	DSDR	Capacity Needs	-NA-	526
3/15/2018	NC and SC	DSDR	Capacity Needs	-NA-	253
3/22/2018	NC and SC	DSDR	Capacity Needs	-NA-	189
6/18/2018	NC and SC	DSDR	Capacity Needs	-NA-	968
6/19/2018	NC and SC	DEP DRA	Tariff - Minimum Event	22 Customers / 71 Sites	22.2
6/19/2018	NC and SC	DSDR	Capacity Needs	-NA-	747
6/20/2018	NC and SC	DSDR	Capacity Needs	-NA-	1,019
8/8/2018	NC and SC	DEP DRA	Tariff - Minimum Event	22 Customers / 70 Sites	21.7
8/28/2018	NC and SC	DEP DRA	Tariff - Minimum Event	22 Customers / 70 Sites	20.7
8/28/2018	NC & SC	EnergyWise Business	Economic	3179	4
8/30/2018	NC & SC	DEP EnergyWise Home	Test	174,282/223,248	278
11/28/2018	NC	DEP EnergyWise Home	Capacity Needs	11,752/16,351	11.8
11/29/2018	NC	DEP EnergyWise Home	Capacity Needs	11,752/16,351	11
11/29/2018	NC and SC	DSDR	Capacity Needs	-NA-	516

Evans Exhibit 5

Duke Energy Progress
System Event Based Demand Response January 1, 2017 - December 31, 2017
Docket Number E-2, Sub 1174

Date	State	Program Name	Event Trigger	Customers Notified /Switches Dispatched	MW Reduction
1/8/2017	NC and SC	DSDR	Capacity Needs	-NA-	183
1/9/2017	NC	DEP EnergyWise Home	Economic Event	9,215/12,947	11.6
1/9/2017	NC and SC	DSDR	Capacity Needs	-NA-	200
3/16/2017	NC and SC	DSDR	Capacity Needs	-NA-	112
6/14/2017	NC and SC	EnergyWise Business	M&V / Economic Event	1872	2.4
7/13/2017	NC and SC	DEP DRA	Tariff - Minimum Event	19 Customers / 67 Sites	19
7/13/2017	NC and SC	EnergyWise Business	M&V / Economic Event	1915	2.9
7/21/2017	NC and SC	DEP DRA	Tariff - Minimum Event	19 Customers / 67 Sites	20
7/21/2017	NC and SC	EnergyWise Business	M&V / Economic Event	1838	2.3
8/17/2017	NC and SC	EnergyWise Business	M&V / Economic Event	1897	2.4
8/18/2017	NC and SC	DEP DRA	Tariff - Minimum Event	20 Customers / 70 Sites	22
8/18/2017	NC and SC	DSDR	Capacity Needs	-NA-	92
8/21/2017	NC and SC	DEP EnergyWise Home	Economic Event	159,244/205,016	120.5
8/22/2017	NC and SC	EnergyWise Business	M&V / Economic Event	1896	2.4
10/9/2017	NC and SC	DSDR	Capacity Needs	-NA-	144
10/11/2017	NC and SC	DSDR	Capacity Needs	-NA-	218
10/12/2017	NC and SC	DSDR	Capacity Needs	-NA-	247
10/23/2017	NC and SC	DSDR	Capacity Needs	-NA-	63

Notes:
- 'Customers Notified' is the number of participants notified to participate in the event
- 'Switches Dispatched' values represent the monthly active switch counts
- 'MW Reduction' values are based on the average across all hours of the event

Duke Energy Progress
System Event Based Demand Response January 1, 2016 - December 31, 2016
Docket Number E-2, Sub 1145

Date	State	Program Name	Event Trigger	Customers Notified /Switches Dispatched	MW Reduction
1/19/2016	NC and SC	DSDR	Economic Event	NA	82
1/20/2016	NC and SC	DSDR	Economic Event	NA	180
2/8/2016	NC and SC	DSDR	Economic, Low Reserves	NA	132
2/11/2016	NC and SC	DEP EnergyWise Home	Economic, Low Reserves	7,358 / 9,726	5.3
2/11/2016	NC and SC	DSDR	Economic, Low Reserves	NA	193
6/23/2016	NC and SC	DEP DRA	Tariff - Minimum Event	18 Customers / 59 Sites	18.6
6/23/2016	NC and SC	DEP EnergyWise Home	Economic, Low Reserves	141,195 / 162,713	143
7/8/2016	NC and SC	DEP DRA	Tariff - Minimum Event	18 Customers / 59 Sites	20.9
7/24/2016	NC and SC	DEP EnergyWise Home	Emergency, Regional Control	105,680 / 121,401	114.5
7/24/2016	NC and SC	DEP EnergyWise Home	Emergency, Regional Control	459 / 526	1
7/26/2016	NC and SC	DEP DRA	Tariff - Minimum Event	18 Customers / 59 Sites	20.9
7/26/2016	NC and SC	DSDR	Economic Event	NA	201
7/27/2016	NC and SC	DSDR	Economic Event	NA	200
7/28/2016	NC and SC	DSDR	Economic Event	NA	211
9/8/2016	NC and SC	DEP EnergyWise Home	Economic, Low Reserves	144,406 / 165,866	141.2
11/22/2016	NC and SC	DSDR	Economic, Low Reserves	NA	192

Notes:
- 'Customers Notified' is the number of participants notified to participate in the event
- 'Switches Dispatched' values represent the monthly active switch counts
- 'MW Reduction' values are based on the average across all hours of the event

Duke Energy Progress
System Event Based Demand Response January 1, 2015 - December 31, 2015
Docket Number E-2, Sub 1108

Date	State	Program Name	Event Trigger	Customers Notified /Switched Dispatched	MW Reduction
01/07/15	NC and SC	DSDR	Emergency	NA	197
01/08/15	NC and SC	DSDR	Emergency	NA	123
01/08/15	NC and SC	EnergyWise Home	Emergency	6,506/8,809	9
01/08/15	NC and SC	DRA-Curtailable	Emergency	29	8
01/09/15	NC and SC	DSDR	Emergency	NA	172
01/09/15	NC and SC	EnergyWise Home	Emergency	6,503/8,808	9
01/28/15	NC and SC	DSDR	Economic, Low Reserves	NA	141
01/29/15	NC and SC	DSDR	Economic, Low Reserves	NA	192
02/03/15	NC and SC	DSDR	Economic, Low Reserves	NA	206
02/06/15	NC and SC	DSDR	Economic, Low Reserves	NA	184
02/13/15	NC and SC	DSDR	Economic, Low Reserves	NA	192
02/15/15	NC and SC	DSDR	Economic, Low Reserves	NA	149
02/16/15	NC and SC	DSDR	Emergency	NA	226
02/19/15	NC and SC	DSDR	Emergency	NA	173
02/19/15	NC and SC	EnergyWise Home	Emergency	6,528/8,835	15
02/20/15	NC and SC	DSDR	Emergency	NA	255
02/20/15	NC and SC	Large Load Curtailable	Emergency	75	240
02/20/15	NC and SC	EnergyWise Home	Emergency	6,526/8,832	16
02/20/15	NC and SC	DRA-Curtailable	Emergency	31	9
02/20/15	NC and SC	DRA-Emergency Generator	Emergency	4	1
06/15/15	NC and SC	DSDR	Economic, Low Reserves	NA	149
06/15/15	NC and SC	EnergyWise Home	Economic, Low Reserves	126,105/161,853	144
06/16/15	NC and SC	EnergyWise Home	Economic, Low Reserves	126,254/162,033	150
06/16/15	NC and SC	DSDR	Economic, Low Reserves	NA	135
06/16/15	NC and SC	DRA-Curtailable	Rider Minimum Requirement	53	20
06/16/15	NC and SC	DRA-Emergency Generator	Rider Minimum Requirement	6	5
06/18/15	NC and SC	DSDR	Economic Event	NA	224
06/22/15	NC and SC	DSDR	Economic Event	NA	207
06/23/15	NC and SC	EnergyWise Home	Economic, Low Reserves	125,212/160,682	115
06/23/15	NC and SC	DRA-Curtailable	Rider Minimum Requirement	53	21
06/24/15	NC and SC	DSDR	Economic Event	NA	241
07/10/15	NC and SC	EnergyWise Home	100% Full Shed Test	125,754/161,357	228
07/20/15	NC and SC	DSDR	Economic Event	NA	249
07/21/15	NC and SC	DSDR	Economic Event	NA	127
07/21/15	NC and SC	EnergyWise Home	Economic Event	126,261/161,985	107
07/21/15	NC and SC	DRA-Curtailable	Rider Minimum Requirement	54	17
08/04/15	NC and SC	DSDR	Economic Event	NA	185
08/05/15	NC and SC	DSDR	Economic Event	NA	211
08/05/15	NC and SC	EnergyWise Home	Economic Event	126,763/162,638	113

Notes:
- 'Customers Notified' is the number of participants notified to participate in the event
- 'Switches Dispatched' values represent the daily active switch counts
- 'MW Reduction' values are at the generator based on the average across all hours of the event