OCC EXHIBIT NO. _____

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)	Case No. 14-841-EL-SSO
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)	Case No. 14-842-EL-ATA

DIRECT TESTIMONY
of
ANTHONY J. YANKEL

On Behalf of the
Office of the Ohio Consumers' Counsel
10 West Broad Street, 18th Floor
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September 26, 2014

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Attachment –AJY-1

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, ADDRESS, AND EMPLOYMENT.

A1. I am Anthony J. Yankel. I am President of Yankel and Associates, Inc. My address is 29814 Lake Road, Bay Village, Ohio, 44140.

Q2. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A2. I received a Bachelor of Science Degree in Electrical Engineering from Carnegie Institute of Technology in 1969 and a Master of Science Degree in Chemical Engineering from the University of Idaho in 1972. From 1969 through 1972, I was employed by the Air Correction Division of Universal Oil Products as a product design engineer. My chief responsibilities were in the areas of design, start-up, and repair of new and existing product lines for coal-fired power plants. From 1973 through 1977, I was employed by the Bureau of Air Quality for the Idaho Department of Health & Welfare, Division of Environment. As Chief Engineer of the Bureau, my responsibilities covered a wide range of investigative functions. From 1978 through June 1979, I was employed as the Director of the Idaho Electrical Consumers Office. In that capacity, I was responsible for all organizational and technical aspects of advocating a variety of positions before various governmental bodies that represented the interests of the consumers in the State of Idaho. From July 1979 through October 1980, I was a partner in the firm of Yankel, Eddy, and Associates. Since that time, I have been in business for myself. I am a registered Professional Engineer in Ohio. I have presented testimony before the Federal Energy

Regulatory Commission, as well as the State Public Utility Commissions of Idaho, Montana, Ohio, Pennsylvania, Utah, and West Virginia.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A3. I am testifying on behalf of the Ohio Consumers' Counsel ("OCC").

II. SUMMARY AND RECOMMENDATIONS

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A4. The purpose of my testimony is to address certain of Duke Energy Ohio's ("Duke" or "the Utility") proposed changes and/or additions to its riders as a part of its Standard Service Offer ("SSO") filing at the Public Utilities Commission of Ohio ("PUCO" or "Commission"). I will primarily address the various changes and/or additions from the perspective of cost-of-service principles.

Q5. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A5. I start off by addressing the Utility's proposed allocation of costs associated with Rider RC ("Retail Capacity"). The Utility asserts that:

> On the basis of traditional cost-causation principles, it is reasonable to allocate the capacity cost on the basis of each class's contribution to the total Five Coincident Peak ("5-CP")[1]

[1] See direct testimony of Company witness Ziolkowski at page 9.

But, these costs are charged to the Utility on an energy basis and the Utility does not pay any directly-billed capacity costs in order to supply its SSO load. Thus, it is not appropriate to charge customers for these costs on any basis other than the manner in which they are charged to the Utility, i.e. as energy charges ($/MWh. Additionally, even if one were to accept the incorrect notion that the Utility incurs capacity costs apart from capacity built into the competitively bid auction prices, the Utility's calculation of the capacity costs is overstated for several reasons. First, the Utility calculates a total value for Duke Energy Ohio and Duke Energy Kentucky combined and then allocates those hypothetical dollars to only the Ohio jurisdictional customers. Second, the Utility has not demonstrated that this allocation is consistent with cost-causation principles. Furthermore, the underlying data used to allocate these hypothetical costs to the Ohio Jurisdiction have not been produced, and the most recent underlying data from PUCO Case No. 12-1682-EL-AIR ("12-1682") indicates that the Company's data is not reliable and is also biased.

Next, I address the Utility's proposed allocation of a new Distribution Capital Rider ("DCI"). The Utility has proposed this rider to collect costs associated with "incremental distribution capital investment." However, it does not propose to allocate these costs on **distribution capital investment**. Instead, Duke proposes to allocate these capital costs on total distribution revenue, which not only covers capital costs, but customer accounting and service costs as well. It is inappropriate to use such things as meter reading and billing expenses as a basis

for spreading unassociated capital costs. I recommend allocating these capital costs on the basis of "total distribution revenue less customer accounting and service expenses."

Next, I address the Utility's proposed allocation of a new Distribution Storm Rider ("DSR"). The Utility has proposed this rider to collect costs associated with "storm restoration expenses." However, it does not propose to allocate these costs on **capital investment being repaired**. Instead, Duke proposes to allocate these storm restoration expenses on total distribution revenue. As with the problem associated with the way Duke proposed to allocate its incremental distribution cost investments, this method also includes expenses associated with customer accounting and service costs as well. It is inappropriate to use such things as meter reading and billing expenses as a basis for spreading unassociated storm restoration expenses. I also recommend allocating these capital costs on the basis of "total distribution revenue less customer accounting and service expenses."

Next, I address the Utility's proposed allocation of a new Price Stabilization Rider ("PSR"). If the Commission authorizes this rider, the Utility has proposed that these costs be allocated on the basis of energy ($/kWh). I agree that an energy allocation factor is the only thing that makes sense.

Finally, I address Duke's proposal to withdrawn its interruptible service. I concur with the Utility's proposal. Given the fact that it will no longer be a Fixed Resource Requirements ("FRR") entity under PJM Interconnection, L.L.C.'s ("PJM") Reliability Assurance Agreement, it has no need for any interruptible loads. Duke's SSO capacity requirement will be satisfied by the winners of an auction-based procurement process.

III. RETAIL CAPACITY RIDER (RC)

Q6. PLEASE SUMMARIZE THE UTILITY'S PROPOSAL WITH RESPECT TO THE RETAIL CAPACITY ("RC") RIDER.

A6. There is a RC Rider in the current ESP. The Utility proposes to allocate what it **assumes** to be the "underlying"[2] generation-related capacity costs, based on the manner in which Duke assumes that these capacity costs arise. In the last ESP case (Case No.-11-3549-EL-SSO), the Utility initially proposed that generation-related capacity costs be allocated on the basis of a 12 Coincident Peak ("12-CP") method. The resulting allocation percentage from the Utility's initial proposal for residential[3] customers was 46.76%.[4] As a result of the Stipulation in Case No.-11-3549-EL-SSO, this allocation factor for the residential customers was heavily weighted on energy usage. The allocation factor for capacity charges that came

[2] See testimony of Company witness Ziolkowski at page 9.
[3] This includes rates RS (Residential Service), TD (Optional Time-of-Day), and ORH (Optional Residential Service with Electric Space Heating).
[4] See attachment JRB-1, page 1 of 10, of Company witness Jeffrey Bailey in Case No.-11-3549-EL-SSO.

out of the Stipulation for the residential customers was 39.12%.[5] Thus, the Stipulation provided Residential customers a reduction of 16 percent[6] in RC Rider costs compared to Duke's initially proposed capacity charges in its Application.

In this case, the Utility is proposing to use a 5-CP method to allocate similar "underlying" generation-related capacity costs to the various customer classes. The resulting share of these costs that is proposed to be allocated to the residential customers is 45.37 percent--slightly lower than the Utility proposed in the last case.

Q7. WAS THERE SOME BASIS IN THE LAST CASE FOR DEVELOPING A CAPACITY COST RIDER AND ALLOCATING IT ON SOME BASIS OF DEMAND?

A7. Yes, there was some basis in the last case to have a capacity cost rider, **but not in this case**. Under the existing rates from the last ESP case, Duke was self-supplying its own capacity requirements under what is referred to as a FRR Plan. As stated in the last case:[7]

> … the FRR, presents options for the Company in respect of capacity pricing. Again, the price could be based on market, cost, some combination thereof, or a state determination. By electing the FRR option, the Company is seeking a capacity rate that is

[5] See workpapers to Attachment B and Attachment and B-1, page 1, of the Stipulation.

[6] (1 – (39.12% / 46.76%)) = 0.1634.

[7] See direct testimony of Company witness Trent at page 18.

largely predicated upon its costs, thereby shielding retail customers from the volatile capacity market without adversely affecting competitive suppliers.

Notably, the Utility's witness in the last case made no mention, let alone recommendation, of using a 5-CP method in spite of the fact that, at the time, PJM was using a 5-CP demand to define the capacity requirement for Duke Energy Ohio's service footprint.

In the current ESP, the Utility is terminating its FRR and is fully going to market for both energy and capacity. There is no state regulation or specific cost structure and/or allocation that can be made on the basis of demand—capacity and energy come as a package, and are simply sold on the basis of energy. Any attempt to try to relate these all-inclusive energy prices to the previous FRR is meaningless.

Q8. IS THE UTILITY'S LOGIC FOR DEVELOPMENT AND EMPLOYMENT OF RIDER RC APPROPRIATE IN THIS CASE?

A8. No. The Utility is proposing a rider for capacity costs and its allocation to customer classes in order to reflect "the underlying cost in the SSO auction based on the manner in which the capacity costs arise."[8] In fact, Duke does not incur any direct or known generation-related capacity costs. Duke holds a competitively-bid auction where energy and capacity are procured from wholesale

[8] See testimony of Company witness Ziolkowski at page 9.

suppliers on an energy only basis. Consequently, because Duke incurs no direct generation-related capacity costs, there are no generation-related capacity costs to be allocated.

Q9. IF THE COMPETITIVELY-BID WHOLESALE RATE IS CHARGED TO DUKE'S CUSTOMERS ON AN ENERGY BASIS, WHY HAS DUKE PROPOSED TO SPLIT THESE COSTS INTO CAPACITY AND ENERGY COMPONENTS AND CHARGED CUSTOMERS BASED ON THE PJM 5-CP METHOD?

A9. There is not a good reason for this and it is inconsistent with the manner in which wholesale costs are passed through to the Utility and the way the Utility passes those costs to retail customers. What the Utility is calling "underlying" costs is based upon a hypothetical calculation that Mr. Ziolkowski supports as follows:

> The PJM capacity requirement for Duke Energy Ohio's service footprint is determined on the basis of the total 5CP demand. **On the basis of traditional cost-causation principles**, it is therefore reasonable to allocate the capacity cost on the basis of each class's contribution to the total 5CP. (Emphasis added.)

Mr. Ziolkowski bases his support for the use of the 5-CP method on "traditional cost-causation principles." But this contravenes the manner in which wholesale costs are passed through to the Utility in this case.

Q10. ARE THERE OTHER INCONSISTENCIES BETWEEN MR. ZIOLKOWSKI'S PROPOSED ALLOCATION IN THIS CASE AND THE MANNER IN WHICH GENERATION-RELATED CAPACITY COSTS WERE PROPOSED BY HIM TO BE ALLOCATED IN THE PAST?

A10. Yes. In the last ESP case, Mr. Ziolkowski proposed the use of a 12-CP method, when at that time PJM was setting the generation-related capacity requirements for Duke Energy Ohio's service footprint on the basis of the 5-CP demand. It is significant that while PJM has consistently used the 5-CP method to set the capacity requirement for the Utility, Duke has not previously suggested that generation-related capacity costs passed through to customers at the retail level should track PJM's 5-CP approach. Duke's argument for a different allocation method in this proceeding as compared to the last proceeding is indicative of the fact that it is not seeking a method that follows cost-causation principles. As I will point out later with respect to other riders, Mr. Ziolkowski ignores "traditional cost-causation principles."

Q11. WHAT "TRADITIONAL COST-CAUSATION PRINCIPLES" IS MR. ZIOLKOWSKI ADDRESSING?

A11. Mr. Ziolkowski appears to be addressing the most fundamental cost-causation principle—that cost should be allocated/recovered in direct relationship to the manner in which costs are incurred. There is nothing wrong with following such cost-causation principles. The fallacy with Mr. Ziolkowski's statement is that he is suggesting that there is a one-to-one relationship between PJM's wholesale

generation capacity requirement for Duke Energy Ohio and the costs that the Utility pays to wholesale suppliers for its competitively-bid supply. In fact, the Utility pays no separate capacity charge for the SSO power that is brought into the system. **The Utility pays only energy ($/MWh) charges.**

Q12. IS IT TRUE THAT THE VARIOUS ENTITIES THAT SUPPLY THE GENERATION FOR THE SSO LOAD INCUR CAPACITY COSTS BASED UPON PJM'S 5-CP METHOD?

A12. Yes, but these costs are only passed on to Duke through an energy charge. If the Utility is interested in following "traditional cost-causation principles," it should allocate costs on the same basis that it incurs those costs. "Traditional cost-causation principles" never included trying to figure out how a supplier incurred costs and then allocating accordingly—ignoring how the supplier passed those costs on to the customers.

Additionally, the capacity cost that suppliers incur as a result of their sales to Duke is only one of several broad factors built into the flat energy rate that is ultimately charged. For example, an SSO supplier's labor costs, its operations and facilities costs, its profit, and many other costs go into the competitively-bid price charged to customers on an energy basis. Should these costs be allocated on the basis of capacity, energy, or some other factor? Duke's attempt to separate out one cost factor from the flat energy price that is paid is inappropriate and runs

counter to well-established cost causation principles, which charge retail costs to customers in the manner they are charged to the Utility.

Q13. WOULD THE ALLOCATION OF RETAIL CAPACITY COSTS ON A 5-CP METHOD, AS PROPOSED BY DUKE, BE APPROPRIATE?

A13. No. First, Duke is proposing to allocate costs on the basis of a 5-CP method. According to Utility witness Ziolkowski's testimony:

> The PJM capacity requirement for Duke Energy Ohio's service footprint is determined on the basis of the total 5CP demand.[9]

However, unlike the traditional 12-CP method (which used the peak hour of each month) that the Utility proposed to allocate its RC Rider costs in the last case, the 5-CP method used by PJM is simply the five days with the highest peaks during the year. In the case of 2013, these five days occurred consecutively on July 15 through July 19.[10]

Historically, the allocation of generation-related capacity costs has not adhered to the strictest interpretation of cost-causation. For example, generation capacity has historically been built to satisfy the single, maximum hourly load during a year, plus a reserve margin. In spite of the building of this plant for one specific hour,

[9] See direct testimony of Company witness Ziolkowski at page 9.

[10] See Company response to OCC-POD-06-052.

historically Duke has used a 12 monthly coincident peaks method for allocating these costs to customer classes and even proposed its use in the last ESP case.

Where a utility is charging retail customers for generation capacity it owns, I agree with the use of the 12-CP method, and the Commission has traditionally used it for generation cost allocation purposes—in spite of the specific cost-causation involved. Although in this case Duke is proposing the use of a 5-CP allocation method, the Utility has not offered any basis why the allocation of generation-related capacity costs, if it were appropriate (and it is not), should be treated any differently than in prior cases.

Given the fact that the five days of the highest peaks in 2013 were consecutive days (or even if they were within a seven- or 10-day window), the 5-CP method is little different than a 1-CP method where costs are allocated only on the basis of the single highest peak of the year. Although demand resources must be acquired to meet that single hourly peak, the cost of the resource(s) is not proportional to the size (MW) of the resource(s). What needs to be allocated is the cost ($) and not size (MW). The 12-CP method has been recognized for decades as a way to more closely reflect the cost of generation resources that produce both capacity and energy as well as operating requirements of these facilities such as maintenance schedules. To my knowledge, the Commission has never used a single peak in order to allocate generation capacity costs. For as long as I can remember, the Commission has used the peak hour over multiple months in order

to allocate generation capacity costs to customer groups. There is no reason to deviate from that policy in this case if the Commission finds it appropriate to allocate wholesale energy charges from SSO suppliers to retail customers as capacity and energy charges.

Q14. ARE THERE OTHER REASONS WHY DUKE'S PROPOSED ALLOCATION OF RETAIL CAPACITY RIDER COSTS IS INAPPROPRIATE?

A14. The data used to develop the allocation factors proposed by the Utility come from load research sample data. In other words, the allocation factors are merely estimates, and those estimates are only as good as the samples represent the population of the customers as a whole. And the Utility has failed to produce the underlying data necessary to support its 5-CP analysis.[11]

Q15. IS THERE A WAY TO ASSESS THE ADEQUACY OF DUKE'S LOAD RESEARCH DATA IN SPITE OF THE FACT THAT IT WAS NOT PROVIDED IN THIS CASE?

A15. Yes. Duke did not provide of its underlying load research data used to develop its allocation factors for its proposed Retail Capacity Rider costs in this case.

[11] Notably, OCC attempted to obtain the detailed data that came from the specific samples. In OCC-POD-06-049, the OCC sought the specific hourly raw load research data (as well as rate schedule, stratum to which the sample customers belonged and stratum weight) associated with each customer sampled. This is the exact underlying data that the Utility gathered and used to develop its estimate of the contribution of each rate group to the 5-CP that were used for allocation purposes. However, the Utility did not provide the requested data, claiming that this was an undue burden and would put the Utility to undue expense. The Utility also took issue with the relevance of the discovery request.

However, the accuracy of the Utility's load research data was assessed in the Utility's most recent distribution rate case.

The generally accepted minimum standard for "adequate" load research data is that it must be at least 90 percent accurate (within +/- 10 percent) on at least 90 percent of the occasions. The data presented in Duke's most recent distribution rate case fell far short of this minimum standard. In that case, (Case No. 12-1682-EL-AIR) on workpaper WPE-3.2b pages 2 and 3, the Utility listed its calculated peak loads for each of the 12 monthly peaks of 2011 for each customer group. The load research data results predicted total loads that differed from the actual total load by the following percentages:

Table 1

Jan	**116.6%**	Jul	105.9%
Feb	105.2%	Aug	**110.1%**
Mar	**117.7%**	Sep	108.0%
Apr	**114.9%**	Oct	**111.7%**
May	109.1%	Nov	**116.4%**
Jun	108.7%	Dec	**113.3%**

As can be seen from Table 1 above, the 2011 load research data was only within the +/- 10 percent accuracy limit on 42 percent of the days tested (five out of 12). Of even more concern is the fact that all of the load research data is biased to be higher than actual usage. The load research data never predicted a level of usage that was less than what actually occurred. The percentages in Table 1 reflect the inaccuracy of the entire load research for all customer classes combined. Mathematically, this means that the inaccuracies within each rate group are even

higher than the overall averages. Very simply, the 2011 load research data was highly inaccurate, and the Utility has failed to present any evidence that the load research data it relied upon in this case is any more "accurate." The Commission should recognize that the Utility has no reliable way to allocate Retail Capacity Rider costs and therefore, the Commission should simply reject the idea of the request for a Retail Capacity Rider.

Q16. ARE THERE OTHER INACCURACIES OR INAPPROPRIATE CALCULATIONS IN THE UTILITY'S PROPOSED RC RIDER?

A16. Yes. The inaccuracy can be seen in Attachment AJY-1 which shows how Duke developed its "Capacity Cost to Recover" in its last ESP case.[12] That methodology appears to have been utilized by Duke in this case as well. The "Capacity Cost to Recover" is calculated by multiplying the PJM assigned demand of 4,732 MW, times the "Final Zonal Capacity Price" (FZCP), times the number of days in the period. This calculation results in the Capacity Cost that Duke claims it needs to recover. The Utility then divides that "Capacity Cost to Recover" by the MWh in the period in order to come up with an "Average Capacity Price" in $/MWh that needs to be collected from the customers.

The inaccuracy comes about because of the values used in this calculation. First of all, the PJM assigned capacity footprint of 4,732 MW for Duke: "includes

[12] Attachment AJY-1 is a copy of Attachment B, Exhibit 1, page 2 from the Stipulation in the last ESP case. Although that Stipulation reflected a compromise of the parties' position in such proceeding, the Capacity Cost to Recover used in that Stipulation is not appropriate for setting rates going forward.

Duke Energy Ohio and Duke Energy Kentucky retail loads and all other wholesale loads served on the DEOK system."[13] In other words, the theoretical "Capacity Cost to Recover" that are being assigned to the Ohio customers is based upon the footprint of not only Ohio customers, but Kentucky customers and wholesale loads for Ohio and Kentucky as well. These theoretical capacity costs are then divided by only the Ohio jurisdictional load in order to develop the "Average Capacity Price" to be charged to Ohio customers. Duke is not only developing a theoretical cost that it is not specifically paying (capacity cost), but it is also assigning to Ohio far more than its share of those theoretical costs.

Q17. IF ONE WERE TO ALLOCATE GENERATION-RELATED CAPACITY COSTS TO CUSTOMERS, SHOULD THE ALLOCATION OF THOSE GENERATION-RELAT ED CAPACITY COSTS TO THE OHIO JURISDICTION BE REDUCED TO REMOVE THE COSTS ASSOCIATED WITH KENTUCKY USAGE?

A17. Yes. Capacity costs should be reduced to reflect the allocation of Ohio-jurisdictional capacity among Ohio-jurisdictional customers. The Utility has not made that calculation in this case and has not provided the information necessary to make that calculation.

[13] See response to OCC-INT-11-322-F.

Q18. WHAT IS YOUR RECOMMENDATION AS TO THE TREATMENT OF THE RC RIDER COSTS THAT DUKE PROPOSES TO CHARGE ITS CUSTOMERS?

A18. As pointed out above, Duke does not incur any generation-related capacity charges and therefore should not be assigning some theoretical level of capacity costs to its customers. Additionally, Duke failed to provide the underlying data showing how it developed the RC Rider rates. The appropriate thing to do is to reject Duke's proposed capacity cost rider.

IV. DISTRIBUTION CAPITAL RIDER (DCI)

Q19. PLEASE SUMMARIZE THE UTILITY'S PROPOSAL WITH RESPECT TO THE DISTRIBUTION CAPITAL INVESTMENT RIDER (DCI).

A19. At page 16 of his direct testimony in this case, Duke witness Arnold outlines the general purpose of the DCI rider:

> In summary, the rider will recover the Company's **incremental distribution capital investment**, including, but not limited to ongoing maintenance capital, as well as the cost to implement various specific programs or initiatives designed to maintain and/or enhance the safety and reliability of the Company's distribution system. (Emphasis added.)

Q20. ARE YOU ADDRESSING THE APPROPRIATENESS OF THE UTILITY'S PROPOSAL WITH RESPECT TO THE DISTRIBUTION CAPITAL INVESTMENT RIDER?

A20. No, the appropriateness of the proposed DCI Rider will be addressed by OCC witnesses Mierzwa and Williams. My testimony will only address how the costs and revenue requirement from the DCI Rider should be allocated among customer groups—assuming that the Commission adopts some form of Distribution Capital Investment Rider.

Q21. WHAT FEDERAL ENERGY REGULATORY COMMISSION ("FERC") ACCOUNTS DOES THE UTILITY PROPOSE BE USED TO DETERMINE THE OVERALL REVENUE REQUIREMENT OF THE DCI RIDER AND HOW HAS THE UTILITY PROPOSED TO ALLOCATE THIS REVENUE REQUIRMENT BETWEEN CUSTOMER GROUPS?

A21. The Utility proposes only that FERC Plant accounts 360 through 374 would be included, as well as portions of common general plant FERC accounts 389 through 398.[14] Looked at from "the other side of the coin," this means that the calculation of the revenue requirement of the DCI rider would not include (at a minimum) expenses for the following FERC accounts:

Distribution Operation Expense	Accounts 580-589
Distribution Maintenance Expense	Accounts 590-598
Customer Accounts Expense	Accounts 901-905

[14] See direct testimony of Company witness Laub at page 3.

Customer Service Expense	Accounts 909-912
Sales and Promotion Expense	Accounts 915-918

Furthermore, it would not include a portion of the expenses from the following FERC accounts:

A & G Operation Expense	Accounts 920-931
A & G Maintenance Expense	Account 932

However, the Utility proposes to allocate the revenue requirement for the DCI rider on the basis of "total distribution revenue".

Q22. IS THE UTILITY'S ALLOCATION OF DCI RIDER RESPONSIBILITY CONSISTENT WITH COST-CAUSATION PRINCIPLES IN RELATIONSHIP TO THE FERC ACCOUNTS THAT ARE PROPOSED TO BE INCLUDED IN THE DCI RIDER BY THE UTILITY?

A22. No. Obviously, "total distribution revenue" captures the capital costs of the distribution equipment costs to be allocated, but it also captures a great deal more, specifically FERC expense accounts 580-932. But such expenses as meter reading and billing have nothing to do with the distribution plant investment costs that are the subject of the Utility's proposed DCI Rider. "Total distribution revenue" may produce a simply developed allocation factor, but it is clearly flawed by including a host of expenses that are not related to the allocation task at hand.

Q23. IS THERE A SIMPLE ALTERNATIVE TO THE UTILITY'S PROPOSAL TO USE TOTAL DISTRIBUTION REVENUE TO ALLOCATE DCI RIDER COSTS?

A23. Yes. The capital costs that would be allocated with respect to this rider should follow the same cost causation principles that are incorporated in the Utility's cost of service study for similar capital costs. For the sake of simplicity, I recommend that the net plant allocation factors for each customer grouping that came out of the Utility's cost-of-service study in its last distribution rate case (12-1682-EL-AIR) be utilized.

Q24. WHAT IS THE IMPACT ON THE VARIOUS CUSTOMER GROUPS OF CHANGING FROM THE UTILITY'S PROPOSED USE OF A "TOTAL DISTRIBUTION REVENUE" ALLOCATOR TO A "NET DISTRIBUTION PLANT" ALLOCATOR FROM CASE 12-1682-EL-AIR?

A24. The "total distribution revenue" allocator/percentages are listed on Attachment PAL-1 page 1 of Duke witness Laub's direct testimony. The "net distribution plant" ratios come out of Duke's most recent distribution case (Case No. 12-1682-EL-AIR) Schedule E-3.2 page 20, line 38. A comparison of the Utility's proposed "total distribution revenue" allocation/percentages and my recommended "net distribution plant" allocation/percentages is as follows:

Rate	Group	Distribution Revenue	Net Distribution Plant
RS	Residential	56.4%	51.7%
DS	Sec. Distribution	29.4%	30.9%
GSFL	Small Fixed	0.2%	0.2%

EH	Electric Heat	0.3%	0.6%
DM	Sec. Small	5.1%	3.9%
DP	Dist. Primary	6.1%	8.3%
TS	Transmission	0.0%	0.0%
SL	Lighting	2.3%	4.4%

V. DISTRIBUTION STORM RIDER (DSR)

Q25. DO YOU HAVE ANY SPECIFIC COMMENTS REGARDING THE APPROPRIATENESS OF THE DISTRIBTION STORM RIDER (DSR) PROPOSED BY THE UTILITY IN THIS CASE?

A25. Yes. My testimony does not address the mechanics or the appropriateness of the DSR proposed by Duke. However, I do have comments regarding the allocation to customer classes of any DSR costs that are approved by the Commission.

Q26. HOW HAS THE UTILITY PROPOSED TO ALLOCATE THE RIDER DSR COSTS BETWEEN CUSTOMER GROUPS?

A26. The Utility proposes that the DSR costs:

> … be allocated to all rate classes in proportion to their respective base revenue contributions approved in the most recent rate case, Case No. 12-1682-EL-AIR, et al.[15]

This allocation method is inappropriate because it is not consistent with cost-causation principles. For purposes of allocating DSR costs, it is inappropriate to

[15] See response to OCC-INT-02-024 (b).

include Customer Accounts Expenses and Customer Service Expenses associated with FERC Accounts 901-912, which includes meter reading and billing. Additionally there are a portion of A&G expenses that are associated with FERC Accounts Customer Accounts Expenses and Customer Service Expenses that should not be included in the development of an allocation factor. Because DSR cost are all distribution O&M expenses related, the inclusion of distribution plant costs in the development of an allocation factor is equally inappropriate.

Q27. WHAT ALLOCATION METHOD WOULD BETTER REFLECT THE COST-CAUSATION ASSOCIATED WITH RIDER DSR?

A27. Simply put, the allocation method proposed by Duke for DSR costs is the same allocation method that the Utility proposed for Rider DCI—"total distribution revenue." Once again, "total distribution revenue" means that the Utility is proposing to allocate the costs associated with a minimum number of FERC account costs (operations and maintenance ["O&M"] expenses associated with DSR as opposed to capital costs associated with DCI) on the basis of the total cost of all FERC Distribution accounts (capital and expense). Once again, the most obvious Distribution accounts that do not belong in a determination of O&M costs associated with the repair of the various facilities that were damaged due to one or more storms are FERC Accounts 901-912, which include all meter reading and billing expense (as well as all associated A&G expenses).

Essentially, the Utility's proposed use of "total distribution revenue" to allocated DSR Rider costs is inappropriate. Once again, at a minimum, the Account 901-912 and a portion of A&G costs do not belong in the allocation of DSR Rider costs. They must be removed. I recommend the use of the "Distribution O&M Expense Ratios" from Duke's cost of service study in its last Distribution Rate case (12-1682) as a basis for allocating any DSR Rider costs that the Commission may approve. This makes far more sense and is better reflective of cost-causation than using only "total distribution revenue" and it is easily calculated.

Q28. WHAT IS THE IMPACT ON THE VARIOUS CUSTOMER GROUPS OF CHANGING FROM THE UTILITY'S PROPOSED USE OF A "TOTAL DISTRIBUTION REVENUE" ALLOCATOR TO A "DISTRIBUTION O&M EXPENSE" ALLOCATOR FROM CASE 12-1682-EL-AIR?

A28. The "total distribution revenue" allocator/percentages are listed on Attachment PAL-1 page 1 of Duke witness Laub's direct testimony. The "distribution O&M expense" ratios come out of Duke's most recent distribution case (Case No. 12-1682-EL-AIR) Schedule E-3.2 page 20, line 8. A comparison of the Utility's proposed "total distribution revenue" allocation/percentages and my recommended "distribution O&M expense" allocation/percentages is as follows:

Rate	Group	Distribution Revenue	Distribution O&M Expense
RS	Residential	56.4%	46.2%
DS	Sec. Distribution	29.4%	33.2%
GSFL	Small Fixed	0.2%	0.2%

EH	Electric Heat	0.3%	0.5%
DM	Sec. Small	5.1%	3.7%
DP	Dist. Primary	6.1%	12.9%
TS	Transmission	0.0%	0.0%
SL	Lighting	2.3%	3.3%

VI. PRICE STABILIZATION RIDER (PSR)

Q29. ARE YOU ADDRESSING THE APPROPRIATENESS OF THE UTILITY'S PROPOSAL WITH RESPECT TO THE PRICE STABILIZATION RIDER ("PSR")?

A29. No. The appropriateness of the proposed PSR will be addressed by OCC witness Wilson. My testimony will only address how the costs and revenue requirement from the PSR rider should be allocated between customer groups—assuming that the Commission adopts some form of a PSR.

Q30. HOW DOES THE UTILITY PROPOSE TO ALLOCATE THE PRICE STABILIZATION RIDER AMONG CUSTOMER CLASSES AND AMONG CUSTOMERS WITHIN A CLASS?

A30. According to Mr. Wathen's direct testimony at page 16, the revenues/costs associated with the PSR Rider will be allocated on "a "$/kWh" rate applicable to all customers." I fully agree with this approach for allocating these revenues/costs, should the Commission authorize some form of a PSR.

Q31. WHY DO YOU SUPPORT THE USE OF AN ENERGY BASIS FOR ALLOCATING PSR REVENUE/COSTS AMOUNG CUSTOMERS?

A31. Although I am not supporting the Utility's proposal to establish a PSR, I do agree that if the Commission adopts a PSR, that the appropriate way to allocate these revenues/costs is on the basis of kWh (energy) for all customers. As the Utility perceives the PSR, it is designed to be essentially a "profit (or loss) sharing mechanism." As stated by Mr. Wathen:

> The capacity and energy available from OVEC will not displace any of the capacity and energy procured for SSO service and will not displace any of the capacity and energy provided by CRES providers.[16]

If revenues/costs are not displacing any of the capacity procured for SSO service or provided by Competitive Retail Electric Service ("CRES") providers, there is clearly no association/basis to allocate these revenues/costs on the basis of capacity.

Although Mr. Wathen continues to talk about selling capacity and energy out of the Ohio Valley Electric Company ("OVEC"), his testimony makes it clear that the hedging would work by selling energy, but not necessarily capacity. He states that the hedge would work against volatility in market prices:

[16] See direct testimony of Company witness Wathen at page 12.

> At times of very low prices, there may be a charge flowing through to customers as the output of OVEC will have less value vis-à-vis market prices. But when market prices are very high, such as the prices seen in PJM during the recent polar vortex, the profits from OVEC would serve to benefit customers by reducing overall rates.[17]

This language fits what historically has been known as "opportunity sales," which are essentially made with no long-term commitment, but are "as, if and when" energy sales and prices. This type of sale has always been allocated on the basis of energy.

VII. INTERRUPTION SERVICE

Q32. DUKE HAS PROPOSED TO ELIMINATE ITS INTERRUPTIBLE SERVICE. DO YOU AGREE WITH THIS PROPOSAL?

A32. Given the specifics of this case, it is appropriate to eliminate the Interruptible Service as the Company has proposed. For a fully-integrated utility, the use of interruptible load can help to address operational and cost issues, especially during period of high demand. These problems would include everything from unexpected heavy load, extremely high cost of marginal generation, or problems with generation facilities not being able to fully operate. Interruption of load can

[17] See direct testimony of Company witness Wathen at page 14.

be used as an economic solution to these problems of matching needed supply with load. However, in this case, Duke's need for interruptible load is basically non-existent.

Q33. WHY IS IT APPROPRIATE TO ELIMINATE DUKE'S INTERRUPTIBLE SERVICE?

A33. The present interruptible program for transmission voltage customers with loads greater than 10 MW came about as a result of the Stipulation in the last ESP—Case No. 11-3549-EL-SSO.[18] But it is clear from that stipulation that the interruptible program was only to exist until May 31, 2015.

There are two statements in that Stipulation that make it clear that Duke would terminate its interruptible program at the conclusion of the present ESP—May 31, 2015. First, Section **IX**-N of the Stipulation goes on to declare that:

> The customer acknowledges that Duke Energy Ohio may use such interruptible load in Duke Energy Ohio's FRR plan …

As an FRR entity, Duke had accepted the PJM capacity supply obligation for all electric distribution customers and PJM will not procure capacity on behalf of these customers. The Stipulation points out that the interruptible load can be used to meet a segment of the Utility's capacity obligation.

[18] See Stipulation in Case No. 11-3549-EL-SSO at pages 32 and 33.

However, the Stipulation also declared that Duke:

> … **will terminate** its election of an FRR plan and provide written notice by March 2, 2012, to the PJM Office of the Interconnection of its intent to participate in the RPM and BRA for the 2015/2016 planning year. (Emphasis added.)[19]

Given the fact that Duke was an FRR entity at the signing of the Stipulation in the last case, and the fact that the Utility was using interruptible load to meet a portion of its capacity obligation, it should have been obvious to all that with the Stipulation requiring that Duke terminate its FRR election, that the need for interruptible load would terminate at the same time.

Second, Section **IX**-N of the Stipulation starts out with the declaration that:

> **During the term of this ESP**, transmission voltage customers, whether shopping or non-shopping, with loads in excess of 10 MW at a single site shall have the option to annually nominate any part of their load as being subject to interruptions through Duke Energy Ohio. (Emphasis added.)

This clear language conveys that the interruptible program was only intended to continue under the current tariff until May 31, 2015. Additionally, between

[19] See Stipulation in Case No. 11-3549-EL-SSO at page 13.

October 2013 and January 2014, individual customers were notified that Duke planned to terminate the program on May 31, 2015.[20]

Q34. INTERRUPTIBLE LOADS HAVE HISTORICALLY BEEN CONSIDERED TO BE BENEFICIAL TO A UTILITY SYSTEM. HAS THIS CHANGED?

A34. Interruptible loads have been beneficial almost exclusively to the generation arm of a utility. This is still the case. However, the distribution Utility, Duke Energy Ohio, is no longer in the generation business. With Duke Energy Ohio giving up its FRR status, it will no longer be responsible for meeting its own generation capacity needs. In such a situation, an interruptible load has essentially no value to the Utility.

Q35. IF DUKE ENERGY OHIO NO LONGER HAS A NEED TO HAVE INTERRUPTIBLE LOAD, DOES THIS MEAN THAT INTERRUPTIBLE LOADS HAVE NO VALUE?

A35. No. Interruptible loads are still of value to generation and transmission utilities—they are essentially of no value to distribution-only utilities. A distribution-only utility has basically no need to interrupt a customer, when its generation capacity needs have already been addressed through contracts. Any "interruption credit" that would be given by a distribution-only utility should only be viewed as a subsidy, as the distribution-only utility has no requirement for the interruption.

[20] See Response to OEG –DR-02-011.

Very simply, with the termination of Duke's FRR status, the interruptible customers now need to go elsewhere to sell their benefit.

Q36. IF DUKE ENERGY OHIO NO LONGER OFFERS CUSTOMERS INTERRUPTIBLE SERVICE, WILL THAT HAVE AN ADVERSE IMPACT UPON THE RELIABILITY OF THE UTILITY'S SYSTEM?

A36. No. It must be remembered that Duke Energy Ohio is a wires-only utility with no generation responsibility. The overall need for reliability is just as great now as it was with Duke being an FRR entity. The difference is that the responsibility no longer falls on Duke Energy Ohio, but on its suppliers. Interruptible loads are just as important now, within the PJM system, as they were before—it is just a question of who has the responsibility for meeting the reliability requirements and who is going to pay for this reliability. Duke no longer has that responsibility and therefore Duke's customers should not pay for interruptible load that provides little, if any, value to the Utility.

VIII. CONCLUSION

Q37. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A37. Yes. However, I reserve the right to supplement my testimony in the event that Duke, the PUCO Staff or other parties submit additional testimony, or if new information or data in connection with this proceeding becomes available.

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of Anthony J. Yankel on Behalf of the Office of the Ohio Consumers' Counsel* was served via electronic transmission to the persons listed below on this 26th day of September 2014.

/s/ *Maureen R. Grady*_____
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Duke Energy Ohio
Convert Capacity and Energy Prices for Proposed Delivery Periods

	Methodology for Calculating Average Price for Rider RC					
	Underlying Capacity Price					
Period	Demand [1]	FZCP [2]	Days in Period	Capacity Cost To Recover [3]	Projected MWh in Period [4]	Average Capacity Price [5]
Jan '12 - May '12	4,732	$116.16	152	$88,980,437	8,533,333	$4.11
Jun '12 - May '13	4,732	16.46	365	30,277,293	20,473,777	
Jun '13 - May '14	4,732	27.73	365	51,007,857	20,810,354	2.45
Jun '14 - May '15	4,732	125.99	365	231,751,890	21,177,162	10.94

Note: [1] Reliability Obligation as reported to PJM. (Will need to update future years for any growth).
[2] PJM's Final Zonal Capacity Price. Prices shown for June 2012 through May 2015 are based on the results of the Base Residual Auctions for those delivery periods.
[3] FZCP Prices are at load zone. Gross up by 6.5% for average T&D losses.
[4] Estimated MWh sales as shown in Attachment WDW-2.
[5] Assumes first delivery period is January 2012 through May 2014.

	Calculate Average Price for Rider RE		
Calendar Year	Mkt Price [1]	Avg Cap Price [2]	Avg Energy
Jan '12 - Dec '12	$61.40	$5.21	$56.19
Jan '13 - Dec '13	66.30	1.95	64.35
Jan '14 - Dec '14	78.70	7.08	71.62
Jan '15 - Dec '15 [3]	90.40	10.94	79.46

Delivery Period	Wtd Energy [4]	Avg Cap	Price for Period
Jan '12 - May '13	$58.59	$4.11	$62.70
Jun '13 - May '14	68.59	2.45	71.04
Jun '14 - May '15	76.19	10.94	87.13

[1] Total Projected Retail Market Price from JLR Testimony, Exhibit W. At the meter. Figures in Exhibit W are in Calendar Year.
[2] Weighted average capacity price converted to average per MWh.
[3] ESP ends on May 31, 2015.
[4] Weighted by months of calendar year prices from Exhibit W in each delivery period.

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in

Case No(s). 14-0841-EL-SSO, 14-0842-EL-ATA

Summary: Testimony Direct Testimony of Anthony J. Yankel on Behalf of the Office of the Ohio Consumers' Counsel electronically filed by Ms. Deb J. Bingham on behalf of Grady, Maureen R. Ms.