BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for the Establishment of a Charge Pursuant to Revised Code Section 4909.18.	))))	Case No. 12-2400-EL-UNC
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	)))	Case No. 12-2401-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., for the Approval of a Tariff for a New Service.	)))	Case No. 12-2402-EL-ATA

DIRECT TESTIMONY OF

WILLIAM DON WATHEN JR.

ON BEHALF OF

DUKE ENERGY OHIO, INC.

__________ Management policies, practices, and organization

___X___ Operating income

___X___ Rate base

__________ Allocations

__________ Rate of return

__________ Rates and tariffs

___X___ Other: Drivers for rate request

March 1, 2013

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Don Wathen Jr., and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director of Rates and Regulatory Strategy for Ohio and Kentucky. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., (Duke Energy Ohio or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received Bachelor Degrees in Business and Chemical Engineering, and a Master of Business Administration Degree, all from the University of Kentucky. After completing graduate studies, I was employed by Kentucky Utilities Company as a planning analyst. In 1989, I began employment with the Indiana Utility Regulatory Commission as a senior engineer. From 1992 until mid-1998, I was employed by SVBK Consulting Group, where I held several positions as a consultant focusing principally on utility rate matters. I was hired by Cinergy Services, Inc., in 1998 as an Economic and Financial Specialist in the Budgets and Forecasts Department. In 1999, I was promoted to the position of Manager, Financial Forecasts. In August 2003, I was named to the position of Director - Rates. On December 1, 2009, I took the position of General Manager and Vice President of Rates, Ohio and Kentucky. On July 3, 2012, as a result of the merger between Duke Energy and Progress

Energy Corp., my title changed to Director of Rates and Regulatory Strategy for Ohio and Kentucky.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR OF RATES AND REGULATORY STRATEGY FOR OHIO AND KENTUCKY.

A. As Director of Rates and Regulatory Strategy for Ohio and Kentucky, I am responsible for all state and federal rate matters involving Duke Energy Ohio and Duke Energy Kentucky, Inc.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A. Yes. I have previously testified in a number of cases before the Public Utilities Commission of Ohio (Commission) and other regulatory commissions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. I am supporting the calculation of the cost-based rate for capacity committed to satisfying Duke Energy Ohio's fixed resource requirement (FRR) obligation under the Reliability Assurance Agreement (RAA) of PJM Interconnection, L.L.C. (PJM) and PJM Tariff. The calculations I am supporting result in the rate for the period August 1, 2012, through May 31, 2015. My testimony introduces the formula that the Company is proposing, describes the sources of the data supporting the calculations, and describes the manner in which the Company proposes to recover such costs. I will also describe the basis for using the formula rate and the basis for the proposed manner of collecting the cost-based rates. Finally, I will provide a preview of the Company's upcoming filing regarding itsCompany's actual earnings for 2012, as required by the Significantly Excessive Earnings Test (SEET).

I sponsor the following attachments in support of my testimony:

- Attachment WDW-1 (Formula Rate for Calculating Duke Energy Ohio's Cost-Based Rate for Capacity)
- Attachment WDW-2 (Summary of Financials)
- Attachment WDW-3 (Calculation of AEP Ohio Capacity Rate)

II. CALCULATION OF COST-BASED CAPACITY RATE – OVERVIEW

Q. PLEASE DESCRIBE THE FORMULA THAT DUKE ENERGY OHIO PROPOSES FOR CALCULATING ITS COST OF CAPACITY.

A. Duke Energy Ohio witness Scott W. Niemann discusses the capacity construct in PJM. Briefly, as I understand, Duke Energy Ohio is currently obligated to self supply all of the capacity needs of the Duke Energy Ohio Load Zone, pursuant to Section D.8 of Schedule 8.1 of the RAA, included in the Open Access Transmission Tariff of PJM. This obligation, or "fixed resource requirement," obligates the Company to commit sufficient capacity to ensure that it meets all load and reserve requirements of PJM. And Duke Energy Ohio is fulfilling its FRR obligation through its own resources, including generation, and market purchases. The provision of this electric generating capacity is effectively a fixed cost inasmuch as the cost associated with this service is a cost that the Company must incur, regardless of the amount of energy produced. Thus, depreciation expense, carrying costs, property taxes, and significant operating and maintenance (O&M) expenses are incurred by the Company, independent of the energy output from its plants included in the FRR plan.

The formula proposed by Duke Energy Ohio in these proceedings mirrors the formula approved by the Commission in setting the cost-based capacity rate for Ohio

Power Company (AEP Ohio) in Case No. 10-2929-EL-UNC (Case No. 10-2929).[1] It is worth noting that the formula is also similar to the formula used by many transmission-owning utilities to set their revenue requirements for network integrated transmission service[2] and it follows traditional concepts of calculating revenue requirements for electric service.

As I discuss in greater detail below, in order to minimize the potential for controversy regarding the development of Duke Energy Ohio's cost-based capacity rate, nearly all of the recommendations made by the Commission Staff and adjustments made by the Commission as described in its order in Case No. 10-2929 were incorporated into the calculation that I sponsor herein.

Q. WHAT EFFORTS HAS THE COMPANY MADE TO REPRODUCE, FOR THE SAKE OF CONSISTENCY AND RELIABILITY, THE METHODOLOGY THAT THE COMMISSION FOUND REASONABLE IN ARRIVING AT A COST-BASED CAPACITY RATE FOR AEP OHIO?

A. Before describing the methodology underlying Duke Energy Ohio's calculation, I believe it is important to first recognize that the formula being proposed here is no different than any other, traditional revenue requirement calculation. The revenue requirement is the sum of (1) all applicable O&M expenses, (2) depreciation expense, (3) return required on the investment (*i.e.*, to compensate shareholders and bondholders for the use of their money), and (4) income and other taxes, including property taxes.

[1] *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC.
[2] All investor-owned electric utilities in Ohio collect unbundled transmission rates from SSO customers based on rates approved by the FERC using formula rates filed with PJM under its OATT.

Starting with this well established framework, consideration was given to the debate that oftentimes occurs in ratemaking with regard to the cost items that should, or should not, be included in a revenue requirement calculation. As is often the case, a utility may suggest that certain costs be included in the revenue requirement calculation while other parties, whether Staff or intervenors, may disagree. Such differences of opinion between the utility and Staff were evident in Case No. 10-2929, as Staff recommended a number of adjustments and exclusions to AEP Ohio's calculation of its cost-based capacity rate. The Commission resolved the dispute by adopting a formula that produced a particular charge for AEP Ohio, reflective of its own embedded costs for providing FRR capacity service.

For purposes of quantifying its embedded costs for fulfilling its FRR capacity obligations, Duke Energy Ohio has incorporated here the same formula that the Commission found reasonable in respect of AEP Ohio. And similar to what the Commission has determined appropriate for arriving at the actual cost for providing capacity service, the revenue requirement was offset by projected revenues earned (*e.g.*, market sales of capacity and energy) as a result of Duke Energy Ohio's ownership of the assets committed to its FRR plan. Furthermore, Duke Energy Ohio also incorporated into its calculation certain of the adjustments recommended by Staff in Case No. 10-2929. Importantly, as some of Staff's recommended adjustments are not applicable to Duke Energy Ohio, they are not relevant to the calculation in these proceedings. I provide details of such adjustments later in my testimony. The schedules provided in Attachment WDW-1 provide the details of the revenue requirement calculation associated with Duke Energy Ohio's FRR obligation. Attachment WDW-2 is a different view of the results from Attachment WDW-1 insofar as it represents a calculation of how much revenue it will take just to be able to earn $0 return on equity and then shows the value of the return required to go from $0 to a reasonable rate of return as proposed by the Company.

Q. PLEASE IDENTIFY THE STAFF-RECOMMENDED ADJUSTMENTS IN CASE NO. 10-2929 THAT WERE NOT INCORPORATED INTO DUKE ENERGY OHIO'S CALCULATION.

A. Unlike AEP Ohio, Duke Energy Ohio does not operate its facilities under a system-wide agreement with its affiliates. Further, Duke Energy Ohio does not have a comparable arrangement with its affiliates. As such, any adjustments that Staff may have recommended to the energy margins included in AEP Ohio's revenue requirement analysis and that the Commission approved in respect of AEP Ohio are not applicable here.

There were two other adjustments proposed by Staff that the Commission rejected. These adjustments were for cost items such as prepaid pension and severance costs that are not being included in the Company's calculation in the first place.

III. CALCULATION OF COST-BASED CAPACITY RATE – RATE BASE

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE RATE BASE ASSOCIATED WITH THE COMPANY'S FRR CAPACITY OBLIGATION.

A. Using the most recent FERC Form 1 at the time the Application was filed, the calculation of rate base started with Net Plant, as of December 31, 2011, which is defined as Gross Production Plant, including allocated Common and General Plant, less Accumulated Depreciation on the same Gross Plant. Rate base also includes Accumulated Deferred Income Taxes (ADITs) associated with actual cash inflows or outflows owing to differences in current and deferred tax liabilities driven by the Tax Code. ADITs associated with non-cash items are not included in the rate base calculation as these ADITs do not represent any increase or decrease in the investment required from shareholders in the rate base.

The only other item included in the Rate Base calculation being proposed by the Company is for non-fuel Materials and Supplies. Recognizing the adjustments recommended by Staff in Case No. 10-2929, the Company excluded any investment in Plant Held for Future Use, Construction Work in Progress, Prepayments, and Cash Working Capital. The Company does not concede that these items should not earn a return. Rather it is only in the interest of minimizing disagreement over the Company's revenue requirement calculation that these items were excluded from the calculation of the cost-based rate.

Q. IS THE RATE BASE THAT IS ALLOCATED TO PRODUCTION PLANT ALL ASSOCIATED WITH THE FIXED COST OF OPERATION?

A. Not necessarily. Pages 5 through 8 of Attachment WDW-1 provide the basis for allocating rate base associated with General Plant and Common Plant between costs associated with the fixed cost of capacity (designated as the "demand cost" in the schedules) and the costs associated with providing energy. In these proceedings and thus in the formula rate, the only issue is the fixed cost of capacity. This is reflected by the costs in the formula allocated to "demand." It should be noted that the general allocation process used here is modeled on the allocation process already approved by the Commission in Case No. 10-2929.

Q. WHAT IS YOUR SOURCE FOR GROSS PLANT IN SERVICE AND ACCUMULATED DEPRECIATION?

A. The FERC Form 1 for 2011 includes a detailed summary of all Gross Production Plant at the end of the year. All of the figures underlying rate base are referenced in the formula rate schedules. It also includes values for General Plant (*i.e.*, plant that is utilized by the Company in providing generation service, transmission service, and distribution service) and Common Plant (*i.e.*, plant that is utilized by the Company in providing all aspects of electric service and all aspects of gas service). Because General and Common Plant are only partially used for providing generation service, it is necessary to allocate only a portion of total General and Common Plant to the Rate Base being used for setting the cost-based rate for capacity. As discussed earlier, some of the General and Common Plant allocated to electric production is further allocated between demand (*i.e.*, fixed cost) and energy (*i.e.*, variable cost).

IV. CALCULATION OF COST-BASED CAPACITY RATE – O&M

Q. PLEASE DESCRIBE HOW O&M EXPENSES WERE DETERMINED IN THE FORMULA.

A. The 2011 FERC Form 1 includes O&M Expenses segregated into the specific accounts established by the FERC in its Uniform System of Accounts. Accounts 501 through 557 are designated as accounts to track costs related to the production of electricity. Other accounts are specifically related to transmission and distribution. Finally, there is a series of accounts, Accounts 920 through 935, that are related to Administrative and General (A&G) expenses and the costs of which, in many cases, are incurred for the benefit of all utility functions. As such, it is necessary to allocate these costs to production, transmission, and distribution functions using reasonable and commonly accepted allocation factors. The bases for allocating A&G expenses are included in the schedules in Attachment WDW-1.

Q. ARE ALL O&M COSTS ALLOCATED TO THE PRODUCTION FUNCTION ASSOCIATED WITH THE COST OF PROVIDING CAPACITY UNDER THE FRR?

A. No. There are production O&M costs that are associated with providing the energy. An obvious example of such a cost is fuel. The Company's O&M expenses for 2011 included almost $500 million in fuel costs; however, fuel costs are variable in nature and such costs are not incurred if there is no generation. Because the Application filed in these proceedings is seeking to recover only the "fixed" cost of providing capacity service, the Company is not seeking any recovery in this filing for costs that can be avoided, such as fuel, emission allowances, reagent costs, etc. The schedules included in Attachment WDW-1 demonstrate the basis for allocating production-related costs between demand-related (*i.e.*, fixed) costs and energy-related (*i.e.*, variable) costs.

Q. WAS IT NECESSARY TO MAKE ANY ADJUSTMENTS TO THE 2011 O&M EXPENSES, AS SET FORTH IN THE FERC FORM 1?

A. Yes. There were two significant adjustments necessary to reflect the appropriate O&M levels associated with providing capacity for the Duke Energy Ohio Load Zone. The first such adjustment is related to the fact that the Company transferred its investment in several non-regulated gas generating assets to subsidiary companies. These assets are gas-fired generating units (commonly known as the Midwest Gas Assets) that were acquired by Duke Energy Ohio as a result of the merger between Duke Energy and

Cinergy Corp. Because the transfer occurred in April 2011, O&M expenses reported in the FERC Form 1 for that year reflect costs incurred by Duke Energy Ohio in 2011 for the period during which it had direct ownership of these assets. The Midwest Gas Assets have never been used to provide capacity or energy service to retail customers in Duke Energy Ohio's service territory and the Company is not seeking recovery of any of the fixed costs associated with these assets. Consequently, it was necessary to eliminate the O&M expenses associated with these assets from the O&M expenses shown in the 2011 FERC Form 1. For the accounts deemed "Production O&M Accounts," the designation of whether these accounts reflected capacity cost or energy costs followed the designations that were approved in Case No. 10-2929.

The second adjustment to O&M required for the revenue requirement calculation was to ensure that only costs allocable to the generation function were included in the calculation.

V. CALCULATION OF COST-BASED CAPACITY RATE – DEPRECIATION

Q. WHAT WAS YOUR SOURCE FOR THE DEPRECIATION EXPENSES USED IN THE REVENUE REQUIREMENT FORMULA?

A. Depreciation expenses are per books and are reported on pages 336 and 337 of the FERC Form 1 Annual Report for 2011. Depreciation expense for production plant is exclusively a capacity-related cost for generation. An adjustment was required to the 2011 depreciation expense for "Other Production," in order to remove the depreciation expense attributable to the Midwest Gas assets which, as described above, were transferred during that year. Depreciation expenses for General and Common Plant were allocated to generation and then were further allocated between capacity-related and energy-related categories.

VI. CALCULATION OF COST-BASED CAPACITY RATE – TAXES OTHER THAN INCOME

Q. WHAT WAS YOUR SOURCE FOR TAXES OTHER THAN INCOME TAXES USED IN THE REVENUE REQUIREMENT FORMULA?

A. Pages 262 and 263 of the FERC Form 1 Annual Report for 2011 provide the per books tax expenses for Duke Energy Ohio during 2011. The major categories of these non-income taxes are: (1) labor-related taxes such as FICA, (2) property taxes, and (3) miscellaneous items such as sales and use taxes and franchise taxes. The Ohio Excise Tax is not included in the revenue requirement calculation here, as it is recovered via a pass-through rider as part of the Company's distribution rates.

The labor-related property taxes are allocated to generation based on the relative proportion of labor for production as compared with labor in the other functions. This information is provided on pages 354 and 355 of the FERC Form 1. Property Taxes are allocated to generation based on the relative proportion of Plant for generation relative to transmission and distribution Plant. Finally, the amount of "Other" non-income taxes allocated to generation was based on the relative proportion of production Plant.

One final step requires that the labor-related taxes allocated to generation be further allocated between capacity-related and energy-related costs. This was done using allocations of labor costs, also developed in the revenue requirements model.

VII. CALCULATION OF COST-BASED CAPACITY RATE – RETURN

Q. HOW DID YOU CALCULATE THE RETURN COMPONENT OF THE COMPANY'S REVENUE REQUIREMENT?

A. Duke Energy Ohio witness James H. Vander Weide, Ph.D., supports the Company's return on equity recommendation of 11.15 percent. The Company's average cost of long-term debt for 2011 was 4.11 percent and 53 percent of its capitalization was comprised of equity. Knowing the rates of return for equity and debt, and knowing the relative proportion of equity to debt, I calculate the overall cost of capital, on an after-tax return on rate base, to be 7.85 percent. The calculation of return on rate base is shown on page 10 of Attachment WDW-1.

This after-tax return on rate base, multiplied by the rate base, results in the amount of return, after income taxes, required for the Company to meet all of its cost obligations and earn a fair and reasonable return for shareholders' investment in Duke Energy Ohio's generating facilities providing its noncompetitive FRR capacity service.

VIII. CALCULATION OF COST-BASED CAPACITY RATE – INCOME TAXES

Q. HOW DID YOU COMPUTE THE INCOME TAX COMPONENT OF THE COMPANY'S REVENUE REQUIREMENT?

A. The income tax component of the revenue requirement calculation is determined by applying the calculated income tax rate times the pre-tax return on equity. On page 16 of Attachment WDW-1, there is a summary of the calculated income tax rate.

Q. IS THERE ANYTHING NOTEWORTHY ABOUT HOW THE INCOME TAX RATE WAS CALCULATED?

A. The calculation includes allowances for amortization of accumulated deferred income tax credits. In addition to this adjustment, the Company made another adjustment to reflect a provision advocated by Staff and approved by the Commission regarding the gross domestic production tax credit (sometimes referred to as the Section 199 deduction).

This deduction is based on a provision of the Internal Revenue Code that allows companies performing certain domestic activities to take a special deduction against taxable income. The generation of electricity is an activity that qualifies for this deduction. Generally, a company must have taxable income before this credit can be used and any unused credit does not carry forward to future years. Nevertheless, the Company reduced the amount of tax expense by incorporating this special deduction into its calculation of the income tax rate to be used in the revenue requirement calculation. Here again, the Company's revenue requirement calculation mirrors the methodology already approved by the Commission.

IX. TOTAL FIXED COST OF CAPACITY

Q. WHEN ALL OF THE COMPONENTS OF THE COMPANY'S FIXED COST OF CAPACITY ARE ADDED UP, WHAT IS THE TOTAL REVENUE REQUIREMENT FOR DUKE ENERGY OHIO'S COST OF PROVIDING NON-COMPETITIVE CAPACITY SERVICE AS AN FRR ENTITY?

A. Page 3 of Attachment WDW-1 summarizes the revenue requirement calculation. The total revenue requirement, before recognizing any revenue derived from the legacy generation, is $[redacted] on an average annualized basis for the period between August 1, 2012, and May 31, 2015. Dividing this figure by the Company's retail demand and then by 365 days, results in a rate of $323.26 per MW-day as the fixed cost of Duke Energy Ohio's FRR capacity obligation.

X. CREDIT FOR REVENUE

Q. IS THE COMPANY EXPECTED TO EARN ANY REVENUE FROM ITS LEGACY GENERATION WHILE IT IS PROVIDING NON-COMPETITIVE CAPACITY SERVICE AS AN FRR ENTITY?

A. Yes. These assets will be available to sell energy and ancillary services into the PJM market. As Duke Energy Ohio witness Ben Zhang, Ph.D., describes in his testimony, the Company's proprietary in-house production cost model was used to estimate the value of the energy and ancillary sales expected for the period August 1, 2012, through May 31, 2015. Based on assumptions about the operating characteristics of the Company's generating units, projected fuel prices, projected prices for energy and ancillary services, and various other inputs, Dr. Zhang projects that the Company's legacy generation will earn $[redacted] on an average annualized basis from the sales of energy and ancillary services during that period.

XI. NET FIXED COST OF CAPACITY TO BE DEFERRED

Q. AFTER REFLECTING THE ENERGY AND ANCILLARY SERVICE MARGINS IN THE REVENUE REQUIREMENT CALCULATION, WHAT IS THE COMPANY'S NET COST OF PROVIDING NONCOMPETITIVE CAPACITY SERVICE AS AN FRR ENTITY?

A. On an average annualized basis, after accounting for energy and ancillary service margins, it costs Duke Energy Ohio $364,876,433 per year to meet its obligation of providing noncompetitive capacity service. On a per MW-day basis, the average rate is $224.15.

Q. WHAT FIGURE IS THE COMPANY USING TO CALCULATE THE AMOUNT OF COST RECOVERY IT IS SEEKING IN ITS CAPACITY OBLIGATION RIDER (RIDER DR-CO)?

A. In any given period, the Company will compare its net fixed cost of providing noncompetitive capacity service against the below-cost market price being recovered from PJM. For example, PJM's final zonal clearing price for the 2012/2013 planning year is $16.74 per MW-day. Comparing Duke Energy Ohio's cost of capacity of $224.15 per MW-day to the $16.73 per MW-day revenue received from PJM would mean that the Company would be seeking recovery through Rider DR-CO of the difference between those amounts ($224.15 minus $16.73) multiplied by the Duke Energy Ohio's retail load obligation. The difference in the rates will change as the PJM market price changes in planning years 2013/2014 and 2014/2015. On average, the PJM market price over the period August 1, 2012, through May 31, 2015, is $66.06 per MW-day. As such, on average, the Company will be deferring for recovery via Rider DR-CO the difference between $224.15 per MW-day and $66.06 per MW-day, or $158.08 per MW-day.

Q. HOW DOES DUKE ENERGY OHIO'S REQUESTED COST-BASED RATE COMPARE TO THE CHARGE THE COMMISSSION ADOPTED UNDER THE STATE COMPENSATION MECHANISM IT APPROVED ON JULY 2, 2012?

A. As of the time of this testimony, in Ohio, only AEP Ohio has been authorized to recover its embedded costs for providing noncompetitive capacity service as an FRR entity. And, of note, AEP Ohio's FRR obligations are the same as those imposed upon Duke Energy Ohio through the relevant PJM tariffs and agreements. That is, both FRR entities are providing the same noncompetitive capacity service in Ohio. AEP Ohio and Duke Energy Ohio share many characteristics; so, an apples-to-apples comparison may be appropriate with sufficient caveats for the differences such as resource mix and capacity/load ratio. As shown on page 1 of Attachment B to the Application, Duke Energy Ohio's revenue requirement, when converted to $/MW-day rate, is $224.15 per MW-day. This figure was arrived at applying a formula for computing the revenue requirement that is nearly identical to that approved for AEP Ohio. By contrast, AEP Ohio's average rate is approximately $189 per MW-day.

These figures are fairly comparable; however, there are some differences between AEP Ohio and Duke Energy Ohio that cause AEP Ohio's number to be lower. The greatest factor driving the AEP Ohio rate down is the fact that Ohio Power (one of the two former AEP entities that make up what is now AEP Ohio) has significant revenue sources in the wholesale market. Importantly therefore, the $189 per MW-day figure is a combination of a much higher net number for Columbus Southern Power and a lower net number for Ohio Power.

A more appropriate comparison of fixed costs between AEP Ohio and Duke Energy Ohio would be based on a consideration of the fixed cost of providing noncompetitive capacity service before any credits for energy or ancillary service margins. Such an approach would avoid the substantial difference in revenues from sales in the wholesale market. Based on the evidence in Case No. 10-2929 and as illustrated in Attachment WDW-3, it can be shown that the capacity rate approved by the Commission for AEP Ohio is $322.85 per MW-day, without accounting for credits for energy and ancillary services. The rate proposed by Duke Energy Ohio for essentially the same noncompetitive capacity service, excluding any credits for energy and ancillary services, is $323.26 per MW-day. So, Duke Energy Ohio's fixed cost of production is within 41 cents per MW-day of the rate the Commission approved for AEP Ohio.

The similarity in the prices is not surprising considering that the AEP Ohio and Duke Energy Ohio jointly own four generating stations. And the proposals requested in these proceedings, if approved, would result in similarly situated utilities with like capacity obligations receiving commensurate just and reasonable compensation.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS IT EXPECTS TO DEFER?

A. In the Application, the Company proposed to make a filing on March 1, 2013, to implement Rider DR-CO. As an evidentiary hearing will proceed subsequent to that identified date, Duke Energy Ohio now proposes to make a filing for the initial rider rates within sixty days after the Commission's order approving the Company's Application in these proceedings. At that time, the Company will file an Application providing details about its proposed allocation of costs to the various customer classes and its proposed rate design for recovery.

Q. WHY IS THE COMPANY PROPOSING TO DEFER COSTS INCURRED AS OF AUGUST 1, 2012?

A. Duke Energy Ohio has been incurring costs relative to its binding capacity obligations as an FRR entity since January 1, 2012. However, it is seeking here to recover such costs for the period between August 1, 2012, and May 31, 2015. The former date reflects the first month after the Commission authorized the recovery of costs for noncompetitive, wholesale capacity service. And the latter month reflects the date on which the Company's FRR obligations will terminate.

Q. IS THE COMPANY ASKING FOR RECOVERY OF ANY COSTS FOR MONTHS PRIOR TO THE DATE OF ITS APPLICATION?

A. No. Similar to other cases where the Commission granted authority to defer a cost for recovery in a future period, the Company is only asking to defer costs incurred beginning with the month of its Application. The Company is making no request for deferral for costs incurred prior to August 2012. The Company's request is no different than any other deferral request where a company seeks to recover a deferred cost in a future period, and the Commission has approved such requests on a number of occasions.[3]

XII. 2012 EARNINGS AND PREVIEW OF SEET FILING

Q. DO THE COMPANY'S ACTUAL 2012 OPERATING RESULTS SUPPORT THE COMPANY'S ASSERTION THAT IT IS NOT EARNING A REASONABLE RATE OF RETURN?

A. Yes. The table below is a summary of Duke Energy Ohio's electric operating income for 2012. This data is based on audited financial data and will be published in the FERC Form 1 Annual Report for 2012.

Operating Revenues	$1,689,223,992
Operation Expenses	1,219,362,957
Maintenance Expenses	141,133,823
Depreciation Expense	138,702,981
Depreciation Expense for Asset Retirement Costs	4,855
Amortization. & Depletion of Utility Plant	20,192,099
Amortization of Utility Plant Acquisition Adj.	19,006,130
Regulatory Debits	24,962,734
Less: Regulatory Credits	(6,466,534)
Taxes Other Than Income Taxes	154,035,122
Earnings Before Interest and Taxes	($21,710,175)

The implication of the Company operating results for 2012 is very clear. Even including the Company's distribution and transmission businesses, the Company's earnings for 2012 are not even enough to pay for interest expense on the Company's debt, much less provide any return to shareholders.

[3] See generally, *In the Matter of the Application of Columbia Gas of Ohio, Inc., for Authority to Defer Environmental Investigation and Remediation Costs,* Case No. 08-606-GA-AAM, Opinion and Order, at pp. 2-3 (approval to defer remediation costs incurred after January 1, 2008) and *In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Defer Environmental and Remediation Costs,* Case No. 09-712-GA-AAM, Opinion and Order, at pg. 3 (approval to defer remediation costs incurred after January 1, 2008).

The Company's annual filing for its SEET is more detailed than the summary above and the Company's SEET filing for 2012 will not be made until May 2013; however, the Company has processed enough data to provide a preview of the results for 2012. Following the formula for the SEET prescribed in Case No. 11-3549-EL-SSO, *et al.*, the Company's preliminary estimate of actual earnings for 2012 is negative 3.4 percent on its total electric business (*i.e.*, distribution, transmission, and generation). The result of the preliminary SEET analysis is consistent with the data in the table above. For 2012, not only did the Company's shareholders not get any return from their invested capital (*i.e.*, common equity), they actually lost part of their investment. As detailed in the testimony of Duke Energy Ohio witness Brian D. Savoy, the Company's loss on its legacy generation business exceeded thirteen percent, dragging down the overall earnings of Duke Energy Ohio's total electric business.

In Case No. 10-2929, the Commission found that an earnings level of a positive 7.6 percent would be "insufficient to yield reasonable compensation for AEP-Ohio's provision of capacity to CRES providers in fulfillment of its FRR capacity obligations."[4] It is difficult to conceive of how a return on equity at 7.6 percent can be deemed too low by the Commission for one company, AEP Ohio, providing the exact same service (noncompetitive, wholesale FRR capacity) for which another company subject to its jurisdiction is earning less than 0.00 percent. Pursuant to the testimony of Dr. Vander Weide, a reasonable rate of return equity is 11.15 percent.

[4] *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 102929-EL-UNC, Opinion and Order, at pg. 23 (July 2, 2012).

XIII. <u>CONCLUSION</u>

Q. WERE ATTACHMENTS WDW-1 THROUGH WDW-3 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION CONTAINED ON ATTACHMENTS WDW-1 THROUGH WDW-3 TRUE AND ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

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

A. Yes.

DUKE ENERGY OHIO DAILY CAPACITY RATES | Rate Schedule 101
Twelve Months Ending December 31, 2011 | Page 1

1 **Capacity Daily Rates (before credits for margins from sales of capacity, energy, and ancillary services)**

2 $/MW = Annual Production Fixed Cost (A)
3 (5 CP Demand/365)(B)

4 **$323.26** = $526,225,032
5 4459.85 / 365

6 **Capacity Daily Rates (After credits for margins from sales of energy and ancillary services)**

7 $/MW = Annual Production Fixed Cost Net of Margins from Energy and Ancillary Services (c)
8 (5 CP Demand/365)(B)

9 **$224.15** = $364,876,433
10 4459.85 / 365

11 **Capacity Daily Rates (Net of Existing Sales at FZCP)**

12 $/MW = Annual Production Fixed Cost Net of Existing Sales at FZCP and Margins from Energy and Ancillary Services (c)
13 (5 CP Demand/365)(B)

14 **$158.08** = $257,337,205
15 4459.85 / 365

16 Average of demand at time of five highest daily peaks (MW) 4,460

Note: (A) From page 3, line 6 + line 7.
(B) Average of 5 highest monthly peaks (MW)
Form 1, page 400, column (b) less DEK and wholesale demand. (See workpaper)

Generator Step Up Transformer Workpaper
Twelve Months Ending December 31, 2011

Line	Description	Reference	Amount
1	GSU & Associated Investment	(A)	$23,208,297
2	Total Transmission Investment	FF1, P.207, L.58, Col.g	$608,828,977
3	Percent (GSU to Total Trans. Investment)	L.1 / L.2	3.81%
4	Transmission Depreciation Expense	FF1, P.336, L.7, Col.b	$11,199,710
5	GSU Related Depreciation Expense	L.3 x L.4	$426,928
6	Station Equipment Acct. 353 Investment	FF1, P.207, L.50, Col.g	$338,926,542
7	Percent (GSU to Acct. 353)	L.1 / L.6	6.85%
8	Transmission O&M (Accts 562 & 570)	FF1,P.321, L. 93, Col.b, and L.107, Col.b	$2,931,899
9	GSU & Associated Investment O&M	L.7 x L.8	$200,764

Note: (A) Same as amount shown in Attachment H-22 Formula rate filed with PJM.

ANNUAL PRODUCTION FIXED COST
Twelve Months Ending December 31, 2011

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Line	Description	Reference	Req thru 5/15 (C)	Annualized
1	Return on Rate Base	P.4, L.18	$372,542,287	$131,485,513
2	Operation & Maintenance Expense	P.11, L.12	479,587,228	169,266,081
3	Depreciation Expense	P.13, L.10	223,343,099	78,826,976
4	Taxes Other Than Income Taxes	P.14, L.6	177,971,898	62,813,611
5	Income Tax	P.15, L.7	97,352,081	$34,359,558
6	Total Revenue Requirement	Sum (L.1 thru L.5)	**$1,350,796,592**	**$476,751,738**
7	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]
9	Total Fixed Costs to Collect Over Remainder of FRR	Sum (L. 6 thru L.8)	**$1,186,276,446**	**$418,685,804**
10	[redacted]	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]	[redacted]
12	Total Revenue to Recover Through End of FRR	Sum (L.9 thru L.11)	725,235,452	255,965,454
13	Plus: Commercial Activities Tax	(B)	3,886,630	1,371,752
14	Net Revenue to Collect		**$729,122,082**	**$257,337,205**

Note: (A) Internally calculated based on projected market prices, FRR obligations, and projections of market prices.
(B) Commercial Activities Tax at 0.26% of total revenue.
(C) Reflects the total for the period August 1, 2012, through May 31, 2015, which is the duration of the Company's FRR obligation.

RETURN ON PRODUCTION -RELATED INVESTMENT
Twelve Months Ending December 31, 2011

Line	Description	Reference	Amount (1)	Demand (2)	Energy (3)
1	**ELECTRIC PLANT**				
2	Gross Plant in Service	P.5, L.5	$3,608,188,601	$3,574,328,638	$33,859,963
3	Less: Accumulated Depreciation	P.5, L.10	1,306,015,709	1,301,540,820	4,474,889
4	Net Plant in Service	L.2 - L.3	$2,302,172,892	$2,272,787,818	$29,385,074
5	Less: Accumulated Deferred Taxes	P.5, L.11	(636,466,948)	(638,956,932)	2,489,984
6	Plant Held for Future Use	Note (A)	-	-	-
7	Construction Work in Progress	Note (A)	-	-	-
8	Subtotal - Electric Plant	L.4 + L.5 + L.6 + L.7	$1,665,705,944	$1,633,830,886	$31,875,058
9	**WORKING CAPITAL**				
10	Materials & Supplies				
11	Fuel	P.8, L.2	$83,305,297	$0	$83,305,297
12	Nonfuel	P.8, L.7	40,681,661	40,681,661	-
13	Total M & S	L.11 + L.12	$123,986,958	$40,681,661	$83,305,297
14	Prepayments	Note (B)	-	-	-
15	Cash Working Capital	Note (A)	-	-	-
16	Total Rate Base	L.8 + L.13 + L.14 + L.15	$1,789,692,902	$1,674,512,547	$115,180,355
17	Weighted Cost of Capital	P.10, L.4	7.852%	7.852%	7.852%
18	Return on Rate Base	L.16 x L.17	$140,529,667	$131,485,513	$9,044,153

Note (A) None requested.
(B) None requested. Commission approved formula excluded prepayments except for pre-paid pension asset.

PRODUCTION-RELATED
ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
Twelve Months Ending December 31, 2011

		System		Production			
Line	Description	Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1	**Gross Plant in Service (Note A)**						
2	Plant in Service (Excl. Gen & Intangible) (Note C)	FF1, P.204-207, L.100	$5,913,165,008	FF1, P.205, L.46(g)	$3,379,461,653	$3,379,461,653	$0
3	Allocated General & Intangible Plant	P.6, L.16	168,803,540		86,793,890	54,265,855	32,528,035
4	Common Plant	P.7, L.17	$298,250,155		141,933,058	140,601,130	1,331,928
5	Total	L.2 + L.3 + L.4	$6,380,218,703		$3,608,188,601	$3,574,328,638	$33,859,963
						99%	1%
6	Percent of Total Gross Plant in Service	L.5 ÷ Line 2, Col.(1)			56.55%	56.02%	0.53%
7	Accum Provision for Depreciation (Notes A & D)	FF1, P.219	$2,091,025,475	FF1, P.219, L.20+L.24	$1,226,882,363	$1,226,882,363	$0
8	General Plant	FF1, p. 219, L.28	21,340,622	Note (B)	10,972,730	6,860,443	4,112,286
9	Allocated Common Plant	P.7, L.18	143,816,541		68,160,616	67,798,014	362,602
10	Total	L.7 + L.8 + L.9	$2,256,182,638		$1,306,015,709	$1,301,540,820	$4,474,889
11	Accum Deferred Income Taxes (Note A)	FF1, P.234 (Acct. 190, L.8) P. 272-273 (Acct 281, L.8) P.274-275 (Acct 282, L.5) P.276-277 (Acct. 283, L.9)	($1,435,857,338)	P.5a, P.5b	($636,466,948)	($638,956,932)	$2,489,984

Note: (A) Excludes ARO amounts.
(B) Allocated using factors on P.6, line 15, for General Plant. See P.7 for Common.
(C) Includes Generator Step-Up Transformers and Other Generation related investments previously included in the transmission accounts.
(D) Includes Accumulated Depreciation associated with the Generator Step-Up Transformers and Other Generation investments.

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
Twelve Months Ending December 31, 2011

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Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
	Account 190 (Detailed Accounts)				
1	Accrual NQ Pension ST	211,667	68,326	90,255	53,086
2	Accrual OPEB ST	754,644	243,599	321,780	189,265
3	Accrual Post Retirement ST	263,011	84,900	112,148	65,963
4	Accrued Pension Admin Fees	1,297,854	1,298,479	(625)	-
5	Accrued Vacation	4,101,676	1,468,226	1,492,710	1,140,740
6	Annual Incentive Plan Comp	1,221,256	696,439	133,437	391,380
7	Asset Retirement Obligation	7,429,180	1,821,556	241,057	5,366,567
8	Bad Debts - Tax over Book	538,955	-	481,408	57,547
9	Cash Flow Hedge - Reg Asset/Liab	(660,340)	-	(660,340)	-
10	Demand Side Management (DSM) Defer	-	-	-	-
11	Emission Allowance Expense	36,398,482	36,398,482	-	-
12	Employee Benefits	-	-	-	-
13	Environmental Reserve	(16)	-	-	(16)
14	FAS 106 OPEB OCI	3,612,740	3,612,730	6	4
15	FAS 112 Medical Expenses Accrual	2,389,124	906,861	919,277	562,986
16	FAS 112 Medical Funding Payment	(372,956)	(122,886)	(157,457)	(92,613)
17	FAS 87 Non Qual Plan OCI	42,247	42,247	-	-
18	FAS 87 Qual Plan OCI	(18,880,817)	(18,880,817)	-	-
19	Federal Benefit of State for 190 CY	54,489	-	54,489	-
20	Federal Benefit of State for 190 PY	839,222	-	839,222	-
21	Federal Benefit of State on 190 Gain Contingency PY	390,179	-	390,179	-
22	FERC - FIT Adj Offset to Regulatory Asset (254100)	($2,634,885)	$0	($2,197,337)	($437,548)
23	Gas Supplier Refunds	147,962	-	-	147,962
24	Joint Owner Pension Receivable	(5,034,832)	(5,031,751)	(3,081)	-
25	Joint Owner Pension Receivable-NC	6,482,672	6,482,672	-	-
26	KY 190002 Adjustment to Deferreds	(34,714)	-	(34,714)	-
27	Lease Meters-Current	(4,351,201)	-	1,695,129	(6,046,330)
28	Leased Meters - Elec & Gas	15,607,854	-	12,834,583	2,773,271
29	Mark to Market - LT	(1,365,344)	(1,365,344)	-	-
30	Mark to Market - ST	(783,126)	(783,126)	-	-
31	Meters & Transformers	-	-	-	-
32	MGP Sites	9,776,179	-	(218,438)	9,994,617
33	Miscellaneous	(1,283,890)		(1,283,890)	-
34	Natural Gas in Transit	96,538	-	-	96,538
35	Non-qualifed Pension - Payment	(303,570)	(124,585)	(178,985)	-
36	Non-qualified Pension - Accrual	1,419,357	478,194	647,039	294,124
37	OCI - Actuarial GL NQ	(42,247)	(42,247)	-	-
38	OCI - Actuarial GL Qual	18,880,817	18,880,817	-	-
39	OCI - FAS 106 Actuarial Gain/Loss	(3,612,588)	(3,612,588)	-	-
40	Offsite Gas Storage Costs	3,437,449	-	-	3,437,449
41	OPEB Admin Fees	(3,310,616)	(3,309,476)	(1,140)	-
42	OPEB Expense Accrual	16,139,592	5,103,746	7,069,135	3,966,711
43	OPEB Funding Payment	(1,889,025)	(680,698)	(698,433)	(509,894)
44	Other Noncurrent After-tax DTA for EPRI Credit	220,341	172,607	23,867	23,867
45	Payable 401 (K) Match	61,544	20,173	26,049	15,322
46	Property Tax - Propane Inventory	536,061	-	-	536,061
47	Property Tax Reserves	17,258,304	14,450,964	(5,447,194)	8,254,534
48	Retirement Plan Expense - Underfunded	(6,012,992)	(7,977,650)	5,481,004	(3,516,346)
49	Retirement Plan Funding - Underfunded	-	-	-	-

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
Twelve Months Ending December 31, 2011

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Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
50	Save-A-Watt Regulated Deferred Liability	3,824,541	-	3,824,541	-
51	Severance Accrual ST	(19,494)	(487)	(11,847)	(7,160)
52	SIT - Known Reserves - Cur Asset	61,541	76,502	(14,961)	-
53	Surplus Materials Write-Off Asset	862,907	862,907	-	-
54	Surplus Materials Write-off Liab	4,084	4,084	-	-
55	Tax Int Accrual - Non-cur Liab	1,356,403	(376,601)	1,733,004	-
56	Tax Interest Accrual - Cur Liab	-	-	-	-
57	Unamortized Debt Discount	(2,159,580)	(2,330,151)	1,539,206	(1,368,635)
58	Unamortized Debt Premium	579,251	1,276,384	(418,204)	(278,929)
59	Unbilled Revenue - Ruel	4,144,444	-	-	4,144,444
60	Uncollectible Provision PIP ADJ	(1,535,805)	-	-	(1,535,805)
61	**Total Account 190**	$106,154,529	$49,812,488	$28,622,879	$27,719,162
	Account 281 (Detailed Accounts)				
62	Pollution Control	($41,315,543)	($41,315,543)	$0	$0
	Account 282 (Detailed Accounts)				
63	263A ADJUSTMENT	(6,613,243)	(1,555,714)	(5,057,529)	-
64	481(a) Fixed Asset Retirement	353,687	353,687	-	-
65	AFUDC Interest	(854,247)	182	(652,935)	(201,494)
66	Asset Retirement Costs - ARO	(198,911)	192,413	2,698	(394,022)
67	Book Capital Lease Meters	(19,755,547)	-	(15,225,028)	(4,530,519)
68	Book Depr On Trans Equip to ADR	310,651	(305)	265,454	45,502
69	Book Depreciation/Amortization	291,610,629	149,441,734	92,829,604	49,339,291
70	Book Gain/Loss on Property	(88,395)	1,434	(89,829)	-
71	Casualty Loss	($3,525,213)	(3,525,213)	-	-
72	Contributions in Aid (CIACs)	4,298,337	486,708	812,158	2,999,471
73	Cost of Removal	(2,685,591)	87,979	(1,644,622)	(1,128,948)
74	Equipment Repairs - Annual Adj	(73,214,162)	(73,214,162)	-	-
75	Excess Salvage	864,620	-	125,782	738,838
76	FAS 34	(5,484,853)	(5,472,458)	(15,757)	3,362
77	FERC - FIT Adj Offset to Regulatory Liability (182320)	22,467,884	-	16,976,628	5,491,256
78	FERC - FIT Plant Adj (Util - 410)	(1,018,036,656)	(389,773,184)	(494,485,251)	(133,778,221)
79	FERC - FIT Plant Adj (Util - 411)	9,420,173	-	9,420,173	-
80	FERC - FIT Plant Adj (Util - 411)	(2,737,895)	(3,424,067)	490,898	195,274
81	FERC - SIT Adj Offset to Regulatory Liability (182320)	(8,792,929)	-	(7,733,802)	(1,059,127)
82	FERC - SIT Plant Adj (Util - 410)	(9,176,360)	(17,062,585)	13,276,898	(5,390,673)
83	FERC - SIT Plant Adj (Util 411)	4,433,793	(1,181,782)	4,951,445	664,130
84	FERC - SIT Plant Adj (Util 411)	287,127	-	287,127	-
85	FIN 48 After Tax NC 282 CY Dec Payable	(1,131,353)	-	(1,131,353)	-
86	FIN 48 After Tax NC 282 CY Dec Payable	(126,065)	-	(126,065)	-
87	FIN 48 After Tax NC 282 CY Inc Payable	4,239,389	-	4,239,389	-
88	FIN 48 After Tax NC 282 CY Inc Payable	472,389	-	472,389	-
89	FIN 48 After Tax NC 282 Gain Contingency PY Dec Payable	(21,204,671)	-	(21,204,671)	-
90	FIN 48 After Tax NC 282 Gain Contingency PY Dec Payable	(437,159)	-	(437,159)	-
91	FIN 48 After Tax NC 282 Gain Contingency PY Inc Payable	21,204,668	-	21,204,668	-
92	FIN 48 After Tax NC 282 Gain Contingency PY Inc Payable	437,160	-	437,160	-
93	FIN 48 After Tax NC 282 PY Dec Payable	(15,878,859)	-	(15,878,859)	-

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
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Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
94	FIN 48 After Tax NC 282 PY Dec Payable	(1,785,521)	-	(1,785,521)	-
95	FIN 48 After Tax NC 282 PY Inc Payable	33,767,646	-	33,767,646	-
96	FIN 48 After Tax NC 282 PY Inc Payable	3,778,844	-	3,778,844	-
97	Impairment of Plant Assets	57,601,570	57,601,570	-	-
98	KY - Bonus Depreciation Adj	475,392	172,964	140,399	162,029
99	KY 282101 Adjustment to Deferreds	(1,683,642)	-	(1,683,642)	-
100	Loss on ACRS	(13,121,594)	(216,010)	(8,305,308)	(4,600,276)
101	Miscellaneous	(23,336,468)	-	(23,336,468)	-
102	Non-Cash Overhead Basis Adj	38,713,770	3,989,717	34,832,192	(108,139)
103	OH - Bonus Depreciation Adj	158,159	19,737	123,438	14,984
104	OH - Franchise Tax Adj	(64,166)	(14,864)	(33,013)	(16,289)
105	Other Non-Current After-Tax DTL for PP&E	$7,880,939	($63,481,303)	$107,988,105	($36,625,863)
106	Other Non-Current AT ST DTL for PP&E	(3,812,312)	(9,649,738)	7,663,300	(1,825,874)
107	Purchase Accounting Adjustment	-	-	-	-
108	Repairs 481(a) (Pursuant to 3115)	(27,352,656)	(27,352,656)	-	-
109	Repairs Allowed on Post ADR Prop	(746,844)	(270,620)	(252,561)	(223,663)
110	Section 174 R&E Deduction	(956,942)	(590,008)	(366,934)	-
111	Self Developed Software	(7,667,618)	(2,609,750)	(3,405,012)	(1,652,856)
112	T & D Repairs - Annual Adj.	-	-	-	-
113	T & D Repairs 481(a) (pursuant to 3115)	-	-	-	-
114	Tax Depreciation/Amortization	(526,275,801)	(173,344,265)	(221,558,996)	(131,372,540)
115	Tax Gains/Losses	(11,078,329)	89,378	(11,174,271)	6,564
116	Tax Interest Capitalized	9,224,545	6,400,248	1,933,285	891,012
117	**Total Account 282**	($1,295,822,630)	($553,900,933)	($479,564,906)	($262,356,791)
	Account 283 (Detailed Accounts)				
118	ARO Regulatory Asset	(5,141,980)	(4,828)	(162,998)	(4,974,154)
119	Deferred Fuel Cost Purch Gas Adjustment.	2,098,533	-	-	2,098,533
120	Deferred Ohio Smart Grid Costs	1,857,810	-	1,273,283	584,527
121	Deferred Pipeline Installation Costs	-	-	-	-
122	Emission Allowance Trading	(43,641,559)	(43,641,559)	-	-
123	Inventory & Contract Write-up	(1,623,109)	(1,623,109)	-	-
124	KY 283101 Adjustment to Deferreds	(17,357)	-	(17,357)	-
125	Loss on Reacquired Debt-Amort	(1,988,719)	-	(1,276,482)	(712,237)
126	Merger Costs	634,496	334,802	196,942	102,752
127	Miscellaneous Current Taxable Inc. Adj - DTL	-	-	-	-
128	Miscellaneous NC Taxable Income Adj - DTL	(26,118,288)	(26,118,288)	-	-
129	Noncurrent Bad Debt Provision	2,190,454	-	308,348	1,882,106
130	Other Deferred State Taxes - After-Tax	(2,338,440)	-	(2,338,440)	-
131	Other Non-Current After-Tax DTL	(13,210,667)	$0	($13,210,667)	$0
132	Partnership Income K-1	73,930	-	73,930	-
133	POST IN SERVICE - CARRYING COSTS	(5,723,324)	-	-	(5,723,324)
134	Rate Case - Deferred Costs	-	-	-	-
135	Reg Asset - Accr Pension FAS158 - FAS87Qual	5,545,067	-	3,896,713	1,648,354
136	Reg Asset - Accr Pension FAS158 - FAS87NQ	(89,861)	-	(119,045)	29,184
137	Reg Asset - Accr Pension FAS158 - FAS87Qual	(35,692,092)	-	(24,763,664)	(10,928,428)
138	Reg Asset - DEO Econ Dev				
139	Reg Asset - Elec Rate Case Expense	(422,108)	-	(373,403)	(48,705)
140	Reg Asset - MGP Costs	(24,490,345)	-	(834,746)	(23,655,599)
141	Reg Asset Hurricane Ike Storm Damage	(4,495,822)	-	(4,495,822)	-
142	Reg Asset Smart Grid Deferred Depr.	(2,818,417)	-	(2,226,548)	(591,869)
143	Reg Asset Smart Grid Dfd Other O&M	(5,578,268)	-	(3,571,389)	(2,006,879)
144	Reg Asset Smart Grid Gas Furnace	(2,448,113)	-	(2,448,113)	-
145	Reg Asset Smart Grid PISCC	(3,543,660)	-	(2,838,737)	(704,923)
146	Reg Asset/Liab Def Revenue	(3,007,946)	(3,007,946)	-	-
147	Reg Asset/Liab Def Revenue NC	78,634	78,634	-	-
148	Reg Asset-Pension Post Retirement PAA-FAS 106 and Oth	(8,981,533)	-	(5,669,590)	(3,311,943)
149	Reg Asset-Pension Post Retirement PAA-FAS87NQ and Oth	(135,944)	-	(84,876)	(51,068)
150	Reg Asset-Pension Post Retirement PAA-FAS87Qual and Oth	(18,118,251)	-	(11,424,050)	(6,694,201)
151	Reg Liab RSLI & Other Misc Dfd Costs	57,906	-	57,906	-
152	Retirement Plan Expense - Overfunded	62,281,262	22,063,458	31,682,075	8,535,729
153	Retirement Plan Funding - Overfunded	(28,566,515)	-	(28,566,515)	-
154	Reverse Book Partnership Earnings	-	-	-	-
155	RSP Costs Capitalization	(39,143,238)	(39,143,238)	-	-
156	RTC Amortization	-	-	-	-
157	Sec 481 Adj - State Inc Tax	(886)	(886)	-	-
158	Tax Int Accrual - Non-cur Asset	(502,819)	-	(502,819)	-

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT
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Line No.	Account Title	Total Company	Legacy Generation	Other Electric	Gas
159	Tax Interest Accrual - Cur Asset	-	-	-	-
160	Vacation Carryover - Reg Asset	(1,852,525)	-	(1,166,445)	(686,080)
161	Total Account 283	($204,873,694)	($91,062,960)	($68,602,509)	($45,208,225)
	Total Account 190	$106,154,529	$49,812,488	$28,622,879	$27,719,162
	Total Account 281	($41,315,543)	($41,315,543)	$0	$0
	Total Account 282	($1,295,822,630)	($553,900,933)	($479,564,906)	($262,356,791)
	Total Account 283	(204,873,694)	(91,062,960)	(68,602,509)	(45,208,225)
		(1,435,857,338)	(636,466,948)	(519,544,536)	(279,845,854)

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT (PRODUCTION)
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Line No.	Account Title	Legacy Generation	Percent Allocated To Demand	Amount Demand	Amount Energy	Allocation Basis
	Account 190 (Detailed Accounts)					
1	Accrual NQ Pension ST	68,326	63%	$42,719	$25,607	S&W
2	Accrual OPEB ST	243,599	63%	152,305	91,294	S&W
3	Accrual Post Retirement ST	84,900	63%	53,082	31,818	S&W
4	Accrued Pension Admin Fees	1,298,479	63%	811,844	486,635	S&W
5	Accrued Vacation	1,468,226	63%	917,974	550,252	S&W
6	Annual Incentive Plan Comp	696,439	63%	435,432	261,007	S&W
7	Asset Retirement Obligation	1,821,556	0%	-	1,821,556	Excluded AROs from Rate Base
8	Bad Debts - Tax over Book	-	100%	-	-	
9	Cash Flow Hedge - Reg Asset/Liab	-	100%	-	-	
10	Demand Side Management (DSM) Defer	-	100%	-	-	
11	Emission Allowance Expense	36,398,482	0%	-	36,398,482	100% energy
12	Employee Benefits	-	100%	-	-	
13	Environmental Reserve	-	100%	-	-	
14	FAS 106 OPEB OCI	3,612,730	63%	2,258,775	1,353,955	S&W
15	FAS 112 Medical Expenses Accrual	906,861	63%	566,994	339,867	S&W
16	FAS 112 Medical Funding Payment	(122,886)	63%	(76,832)	(46,054)	S&W
17	FAS 87 Non Qual Plan OCI	42,247	63%	26,414	15,833	S&W
18	FAS 87 Qual Plan OCI	(18,880,817)	63%	(11,804,790)	(7,076,027)	S&W
19	Federal Benefit of State for 190 CY	-	100%	-	-	
20	Federal Benefit of State for 190 PY	-	100%	-	-	
21	Federal Benefit of State on 190 Gain Contingency PY	-	100%	-	-	
22	FERC - FIT Adj Offset to Regulatory Asset (254100)	-	100%	-	-	
23	Gas Supplier Refunds	-	100%	-	-	
24	Joint Owner Pension Receivable	(5,031,751)	100%	(5,031,751)	-	100% demand
25	Joint Owner Pension Receivable-NC	6,482,672	100%	6,482,672	-	100% demand
26	KY 190002 Adjustment to Deferreds	-	100%	-	-	
27	Lease Meters-Current	-	100%	-	-	
28	Leased Meters - Elec & Gas	-	100%	-	-	
29	Mark to Market - LT	(1,365,344)	100%	(1,365,344)	-	100% energy
30	Mark to Market - ST	(783,126)	100%	(783,126)	-	100% energy
31	Meters & Transformers	-	100%	-	-	
32	MGP Sites	-	100%	-	-	
33	Miscellaneous	-	100%	-	-	
34	Natural Gas in Transit	-	100%	-	-	
35	Non-qualifed Pension - Payment	(124,585)	63%	(77,894)	(46,691)	S&W
36	Non-qualified Pension - Accrual	478,194	63%	298,980	179,214	S&W
37	OCI - Actuarial GL NQ	(42,247)	63%	(26,414)	(15,833)	S&W
38	OCI - Actuarial GL Qual	18,880,817	63%	11,804,790	7,076,027	S&W
39	OCI - FAS 106 Actuarial Gain/Loss	(3,612,588)	63%	(2,258,686)	(1,353,902)	S&W
40	Offsite Gas Storage Costs	-	100%	-	-	
41	OPEB Admin Fees	(3,309,476)	63%	(2,069,173)	(1,240,303)	S&W
42	OPEB Expense Accrual	5,103,746	63%	3,190,998	1,912,748	S&W
43	OPEB Funding Payment	(680,698)	63%	(425,591)	(255,107)	S&W
44	Other Noncurrent After-tax DTA for EPRI Credit	172,607	100%	172,607	-	100% Demand
45	Payable 401 (K) Match	20,173	63%	12,613	7,560	S&W
46	Property Tax - Propane Inventory	-	100%	-	-	
47	Property Tax Reserves	14,450,964	100%	14,450,964	-	100% Demand
48	Retirement Plan Expense - Underfunded	(7,977,650)	63%	(4,987,840)	(2,989,810)	S&W
49	Retirement Plan Funding - Underfunded	-	100%	-	-	
50	Save-A-Watt Regulated Deferred Liability	-	100%	-	-	
51	Severance Accrual ST	(487)	63%	(304)	(183)	S&W
52	SIT - Known Reserves - Cur Asset	76,502	100%	76,502	-	
53	Surplus Materials Write-Off Asset	862,907	100%	862,907	-	100% demand
54	Surplus Materials Write-off Liab	4,084	100%	4,084	-	100% demand
55	Tax Int Accrual - Non-cur Liab	(376,601)	100%	(376,601)	-	100% demand
56	Tax Interest Accrual - Cur Liab	-	100%	-	-	
57	Unamortized Debt Discount	(2,330,151)	100%	(2,330,151)	-	100% demand
58	Unamortized Debt Premium	1,276,384	100%	1,276,384	-	100% demand
59	Unbilled Revenue - Ruel	-	100%	-	-	
60	Uncollectible Provision PIP ADJ	-	100%	-	-	

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT (PRODUCTION)
Twelve Months Ending December 31, 2011

Rate Schedule 101
Page 5b WP

Line No.	Account Title	Legacy Generation	Percent Allocated To Demand	Amount Demand	Amount Energy	Allocation Basis
61	**Total Account 190**	$49,812,488		$12,284,543	$37,527,945	
	Account 281 (Detailed Accounts)					
62	Pollution Control	($41,315,543)	100%	($41,315,543)	$0	100% demand
	Account 282 (Detailed Accounts)					
63	263A ADJUSTMENT	($1,555,714)	100%	($1,555,714)	$0	100% demand
64	481(a) Fixed Asset Retirement	353,687	100%	353,687	-	100% demand
65	AFUDC Interest	182	100%	182	-	100% demand
66	Asset Retirement Costs - ARO	192,413	100%	192,413	-	100% demand
67	Book Capital Lease Meters	-	0%	-	-	
68	Book Depr On Trans Equip to ADR	(305)	100%	(305)	-	100% demand
69	Book Depreciation/Amortization	149,441,734	100%	149,441,734	-	100% demand
70	Book Gain/Loss on Property	1,434	100%	1,434	-	100% demand
71	Casualty Loss	(3,525,213)	100%	(3,525,213)	-	100% demand
72	Contributions in Aid (CIACs)	486,708	100%	486,708	-	100% demand
73	Cost of Removal	87,979	100%	87,979	-	100% demand
74	Equipment Repairs - Annual Adj	(73,214,162)	100%	(73,214,162)	-	100% demand
75	Excess Salvage	-	0%	-	-	
76	FAS 34	(5,472,458)	100%	(5,472,458)	-	100% demand
77	FERC - FIT Adj Offset to Regulatory Liability (182320)	-	0%	-	-	
78	FERC - FIT Plant Adj (Util - 410)	(389,773,184)	100%	(389,773,184)	-	100% demand
79	FERC - FIT Plant Adj (Util - 411)	-	0%	-	-	
80	FERC - FIT Plant Adj (Util - 411)	(3,424,067)	100%	(3,424,067)	-	100% demand
81	FERC - SIT Adj Offset to Regulatory Liability (182320)	-	0%	-	-	
82	FERC - SIT Plant Adj (Util - 410)	(17,062,585)	100%	(17,062,585)	-	100% demand
83	FERC - SIT Plant Adj (Util 411)	(1,181,782)	100%	(1,181,782)	-	100% demand
84	FERC - SIT Plant Adj (Util 411)	-	0%	-	-	
85	FIN 48 After Tax NC 282 CY Dec Payable	-	0%	-	-	
86	FIN 48 After Tax NC 282 CY Dec Payable	-	0%	-	-	
87	FIN 48 After Tax NC 282 CY Inc Payable	-	0%	-	-	
88	FIN 48 After Tax NC 282 CY Inc Payable	-	0%	-	-	
89	FIN 48 After Tax NC 282 Gain Contingency PY Dec Payable	-	0%	-	-	
90	FIN 48 After Tax NC 282 Gain Contingency PY Dec Payable	-	0%	-	-	
91	FIN 48 After Tax NC 282 Gain Contingency PY Inc Payable	-	0%	-	-	
92	FIN 48 After Tax NC 282 Gain Contingency PY Inc Payable	-	0%	-	-	
93	FIN 48 After Tax NC 282 PY Dec Payable	-	0%	-	-	
94	FIN 48 After Tax NC 282 PY Dec Payable	-	0%	-	-	
95	FIN 48 After Tax NC 282 PY Inc Payable	-	0%	-	-	
96	FIN 48 After Tax NC 282 PY Inc Payable	-	0%	-	-	
97	Impairment of Plant Assets	57,601,570	100%	57,601,570	-	100% demand
98	KY - Bonus Depreciation Adj	172,964	100%	172,964	-	100% demand
99	KY 282101 Adjustment to Deferreds	-	0%	-	-	
100	Loss on ACRS	(216,010)	100%	(216,010)	-	100% demand
101	Miscellaneous	-	0%	-	-	
102	Non-Cash Overhead Basis Adj	3,989,717	100%	3,989,717	-	100% demand
103	OH - Bonus Depreciation Adj	19,737	100%	19,737	-	100% demand
104	OH - Franchise Tax Adj	(14,864)	100%	(14,864)	-	100% demand
105	Other Non-Current After-Tax DTL for PP&E	(63,481,303)	100%	(63,481,303)	-	100% demand
106	Other Non-Current AT ST DTL for PP&E	(9,649,738)	100%	(9,649,738)	-	100% demand
107	Purchase Accounting Adjustment	-	0%	-	-	
108	Repairs 481(a) (Pursuant to 3115)	(27,352,656)	100%	(27,352,656)	-	100% demand
109	Repairs Allowed on Post ADR Prop	(270,620)	100%	(270,620)	-	100% demand
110	Section 174 R&E Deduction	(590,008)	100%	(590,008)	-	100% demand
111	Self Developed Software	(2,609,750)	100%	(2,609,750)	-	100% demand
112	T & D Repairs - Annual Adj.	-	0%	-	-	
113	T & D Repairs 481(a) (pursuant to 3115)	-	0%	-	-	
114	Tax Depreciation/Amortization	(173,344,265)	100%	(173,344,265)	-	100% demand
115	Tax Gains/Losses	89,378	100%	89,378	-	100% demand
116	Tax Interest Capitalized	6,400,248	100%	6,400,248	-	100% demand

ELECTRIC PLANT IN SERVICE, ACCUMULATED DEPRECIATION AND ADIT (PRODUCTION)
Twelve Months Ending December 31, 2011

Rate Schedule 101
Page 5b WP

Line No.	Account Title	Legacy Generation	Percent Allocated To Demand	Amount Demand	Amount Energy	Allocation Basis
117	**Total Account 282**	($553,900,933)		($553,900,933)	$0	
	Account 283 (Detailed Accounts)					
118	ARO Regulatory Asset	(4,828)	100%	($4,828)	$0	100% demand
119	Deferred Fuel Cost Purch Gas Adjustment.	-	100%	-	-	
120	Deferred Ohio Smart Grid Costs	-	100%	-	-	
121	Deferred Pipeline Installation Costs	-	100%	-	-	
122	Emission Allowance Trading	(43,641,559)	0%	-	(43,641,559)	100% energy
123	Inventory & Contract Write-up	(1,623,109)	100%	(1,623,109)	-	100% demand
124	KY 283101 Adjustment to Deferreds	-	100%	-	-	
125	Loss on Reacquired Debt-Amort	-	100%	-	-	
126	Merger Costs	334,802	0%	-	334,802	Omit
127	Miscellaneous Current Taxable Inc. Adj - DTL	-	100%	-	-	
128	Miscellaneous NC Taxable Income Adj - DTL	(26,118,288)	100%	(26,118,288)	-	To be conservative, allocate all to Demand
129	Noncurrent Bad Debt Provision	-	100%	-	-	
130	Other Deferred State Taxes - After-Tax	-	100%	-	-	
131	Other Non-Current After-Tax DTL	-	100%	-	-	
132	Partnership Income K-1	-	100%	-	-	
133	POST IN SERVICE - CARRYING COSTS	-	100%	-	-	
134	Rate Case - Deferred Costs	-	100%	-	-	
135	Reg Asset - Accr Pension FAS158 - FAS87Qual	-	100%	-	-	
136	Reg Asset - Accr Pension FAS158 - FAS87NQ	-	100%	-	-	
137	Reg Asset - Accr Pension FAS158 - FAS87Qual	-	100%	-	-	
138	Reg Asset - DEO Econ Dev	-	100%	-	-	
139	Reg Asset - Elec Rate Case Expense	-	100%	-	-	
140	Reg Asset - MGP Costs	-	100%	-	-	
141	Reg Asset Hurricane Ike Storm Damage	-	100%	-	-	
142	Reg Asset Smart Grid Deferred Depr.	-	100%	-	-	
143	Reg Asset Smart Grid Dfd Other O&M	-	100%	-	-	
144	Reg Asset Smart Grid Gas Furnace	-	100%	-	-	
145	Reg Asset Smart Grid PISCC	-	100%	-	-	
146	Reg Asset/Liab Def Revenue	(3,007,946)	100%	(3,007,946)	-	To be conservative, allocate all to Demand
147	Reg Asset/Liab Def Revenue NC	78,634	100%	78,634	-	
148	Reg Asset-Pension Post Retirement PAA-FAS 106 and Oth	-	100%	-	-	
149	Reg Asset-Pension Post Retirement PAA-FAS87NQ and Oth	-	100%	-	-	
150	Reg Asset-Pension Post Retirement PAA-FAS87Qual and Oth	-	100%	-	-	
151	Reg Liab RSLI & Other Misc Dfd Costs	-	100%	-	-	
152	Retirement Plan Expense - Overfunded	22,063,458	63%	13,794,662	8,268,796	S&W
153	Retirement Plan Funding - Overfunded	-	100%	-	-	
154	Reverse Book Partnership Earnings	-	100%	-	-	
155	RSP Costs Capitalization	(39,143,238)	100%	(39,143,238)	-	To be conservative, allocate all to Demand
156	RTC Amortization	-	100%	-	-	
157	Sec 481 Adj - State Inc Tax	(886)	100%	(886)	-	100% demand
158	Tax Int Accrual - Non-cur Asset	-	100%	-	-	
159	Tax Interest Accrual - Cur Asset	-	100%	-	-	
160	Vacation Carryover - Reg Asset	-	100%	-	-	
161	Total Account 283	($91,062,960)		($56,024,999)	($35,037,961)	
	Total Account 190	$49,812,488		$12,284,543	$37,527,945	
	Total Account 281	(41,315,543)		(41,315,543)	-	
	Total Account 282	(553,900,933)		(553,900,933)	-	
	Total Account 283	(91,062,960)		(56,024,999)	(35,037,961)	
		($636,466,948)		($638,956,932)	$2,489,984	

PRODUCTION-RELATED GENERAL PLANT ALLOCATION (Gross Plant)
Twelve Months Ending December 31, 2011

Line	Acct	Description	Total System (A)	Allocation Factor	Related to Production	Demand	Energy
			(1)	(2)	(3)=(1)*(2)	(4)	(5)
1		GENERAL PLANT (A)					
2	389	Land	$951,856	(B)	$489,417	$305,997	$183,420
3	390	Structures	24,870,920	(B)	12,787,907	7,995,340	4,792,567
4	391	Office Furniture & Equipment	3,012,092	(B)	1,548,730	968,307	580,423
5	392	Transportation Equipment	4,249,299	(B)	2,184,866	1,366,036	818,830
6	393	Stores Equipment	-	(B)	0	0	0
7	394	Tools, Shop & Garage Equipment	13,977,270	(B)	7,186,707	4,493,321	2,693,386
8	395	Lab Equipment	125,110	(B)	64,328	40,220	24,108
9	396	Power Operated Equipment	1,088,311	(B)	559,578	349,863	209,715
10	397	Communications Equipment	41,923,534	(B)	21,555,867	13,477,303	8,078,564
11	398	Miscellaneous Equipment	71,746	(B)	36,890	23,065	13,825
12	Sum	Subtotal	$90,270,138		$46,414,290	$29,019,452	$17,394,838
13	Calc	Percent			51.417%	32.147%	19.270%
14	303	INTANGIBLE PLANT	$78,533,402	(B)	$40,379,600	$25,246,403	$15,133,197
15	Calc	Percent			51.417%	32.147%	19.270%
16	Sum	TOTAL GENERAL AND INTANGIBLE	$168,803,540		$86,793,890	$54,265,855	$32,528,035

Note: (A) Data from Form 1, pages 204-207.
(B) Allocation factors based on wages and salaries in electric operation and maintenance expenses excluding A&G.

a. Total wages and salaries in electric operation and maintenance expenses excluding administrative and general expense, FF1, P.354, Col.(b), Ln.28 - L.27.	$104,144,423
b. Production wages and salaries in electric operation and maintenance expense, FF1, P.354, Col.(b), L.20.	$53,548,045
c. Production Labor as Percent of All Labor (excl. A&G)	51.42%
d. Percent production labor allocated to demand (Page 12 wp)	62.52%

PRODUCTION-RELATED COMMON PLANT ALLOCATION (Gross Plant)
Twelve Months Ending December 31, 2011

Line	Acct	COMMON PLANT	Total System (A)	Electric (B)	Production Demand	Production Energy
			(1)	(2)	(3)	(4)
		Organization	$60,936	$50,882		
1	1030	Miscellaneous Intangible Plant	121,525,222	101,473,560		
2	1890	Land and Land Rights	2,159,616	1,803,279		
3	1900	Structures & Improvements	114,812,886	95,868,760		
4	1910	Office Furniture & Equipment	3,937,989	3,288,221		
5	1911	Electronic Data Processing - Non SmartGrid	777,724	649,400		
6	1920	Transportation Equipment	85,311	71,235		
7	1921	Trailers	474,273	396,018		
8	1930	Stores Equipment	170,074	142,012		
9	1940	Tools, Shop & Garage Equipment	1,583,528	1,322,246		
10	1950	Laboratory Equipment	23,250	19,414		
11	1960	Power Operated Equipment	153,899	128,506		
12	1970	Communication Equipment - Non SmartGrid	51,956,109	43,383,351		
13	1980	Miscellaneous Equipment	429,603	358,719		
14	1990, 1991	Retirement Work in Process - ARO	99,735	83,279		
15		Total Common Plant (FF1, Pg. 201, L.8, Col.(h))	$298,250,155			
16		Common Plant Allocated to Electric		$249,038,879		
17		Allocated to Production (C)			$140,601,130	$1,331,928
18		Accumulated Depreciation (FF1, Pg. 201, L.14,Col.(h))	$143,816,541	$120,086,812	$67,798,014	$362,602

Note: (A) Form 1, page 356.
(B) 83.5% Common Plant Allocation factor (Form 1, Page 356.2).
(C) Electric share of common plant times allocation plant allocation factors on P.5.

PRODUCTION-RELATED MATERIALS & SUPPLIES
Twelve Months Ending December 31, 2011

		SYSTEM		PRODUCTION			
		Reference	Amount	Reference	Amount	Demand	Energy
			(1)		(2)	(3)	(4)
1	**Materials & Supplies (A)**						
2	Fuel	FF1, P.227, L.1, Col.(c)	$83,305,297		$83,305,297	$0	$83,305,297
3	Non-Fuel						
4	Production	FF1, P.227, L.7	$40,712,928	(B)	$40,681,661	$40,681,661	$0
5	Transmission	FF1, P.227, L.8	15,567,661		0	0	0
6	Distribution	FF1, P.227, L.9	53,246,189		0	0	0
7	Total Non-Fuel	L.4 + L.5 + L.6	$109,526,778		$40,681,661	$40,681,661	$0

Note: (A) Form 1 includes Gas & Electric.
(B) Allocation to Electric from Internal Accounting Records.

PRODUCTION-RELATED GENERAL PLANT ALLOCATION
ADMINISTRATIVE & GENERAL EXPENSE ALLOCATION
Twelve Months Ending December 31, 2011

			SYSTEM		PRODUCTION			
		Account	Reference	Amount	Reference	Amount	Demand	Energy
				(1)	(2)	(3)	(4)	(5)
1	Administrative & General Expense							
2	Related to Salaries & Wages							
3	A&G Salaries	920	FF1, P.323	$39,458,630				
4	Outside Services	923	FF1, P.323	23,949,569				
5	Employee Pension & Benefits	926	FF1, P.323	39,270,593				
6	Office Supplies	921	FF1, P.323	26,537,635				
7	Injuries & Damages	925	FF1, P.323	5,550,657				
8	Franchise Requirements	927	FF1, P.323	0				
9	Duplicate Charges - Vr.	929	FF1, P.323	(2,177,122)				
10	Total		L. 3 thru L.9	$132,589,962	(A)	$68,173,918	$42,624,151	$25,549,766
11	Miscellaneous General Expenses	930.2	FF1, P.323	421,972	(A)	216,966	135,653	81,313
12	Admin Expense Transfer - Credit	922	FF1, P.323	2,489	(A)	1,280	800	480
13	Property Insurance	924	FF1, P.323	5,635,613	(C)	3,187,094	3,157,185	29,908
14	Regulatory Commission Expenses	928	FF1, P.323	0	(B)	0	0	0
15	Rents	931	FF1, P.323	12,240,223	(A)	6,293,568	3,934,907	2,358,661
16	Maintenance of General Plant	935	FF1, P.323	3,338,824	(A)	1,716,727	1,073,343	643,383
17	Total A&G Expense		L.10 thru 16	$154,229,083		$79,589,553	$50,926,039	$28,663,511

Note: All costs associated with plants transferred to DECAM have been removed from Column (1).
(A) Allocation % based on Salaries and Wages from Note B, P.6.
(B) Excludes all regulatory assessments.
(C) Allocation % based on Plant from P.5, L.5.

Duke Energy Ohio (Consolidated) Cost of Capital
Twelve Months Ending December 31, 2011

Line	Description	Reference	Total Company Capitalization	Weighted Cost Ratios	Cost of Capital	Weighted Cost of Capital %
			(1)	(2)	(3)	(4) = (2 x 3)
1	Long Term Debt	(A)	$2,542,087,279	46.84%	4.11%	1.925%
2	Preferred Stock	(B)	0	0.00%	0.00%	0.000%
3	Common Stock	(C)	2,885,228,457	53.16%	11.15%	5.927%
4	Total		$5,427,315,736	100.00%		7.85%

Note: (A) Page 10 WP.
(B) Duke Energy Ohio has no preferred equity.
(C) Page 10 WP.
ROE based on approved rate in Case 10-2929-EL-UNC.

Duke Energy Ohio Consolidated
Capital Structure
December 31, 2011
(In Dollars)

	Actual 12/31/11		Purchase Accounting	Goodwill Impairments Sep09 and Jun10	Other Asset Impairment Charges	Adjusted 12/31/11	Midwest DENA Equity BU 75032	Midwest DENA Equity BU 75012 (3)	Capital Structure excluding Purchase accounting and Midwest DENA	
Current Maturities of Long-Term Debt	$ 507,186,062		$ -			$ 507,186,062			$ 507,186,062	
Non-Current Liabilities										
Long-Term Debt	$ 2,047,916,406		$ 5,979,144			$ 2,053,895,550			$ 2,053,895,550	
Deferred Debt Expense	$ (15,878,296)		$ (3,603,474)			$ (19,481,770)			$ (19,481,770)	
0257010 Unamortized Gain-Debt	$ 487,437					$ 487,437			$ 487,437	
Total Long-Term Debt Excl. Current Maturities	**$ 2,032,525,547**	**28%**	**$ 2,375,670**	**$ -**	**$ -**	**$ 2,034,901,217**	**$ -**	**$ -**	**$ 2,034,901,217**	**41%**
Total Long Term Debt	**$ 2,539,711,609**	**33%**	**$ 2,375,670**	**$ -**	**$ -**	**$ 2,542,087,279**	**$ -**	**$ -**	**$ 2,542,087,279**	**47%**
Common Stock Equity										
0201000 Common Stock Issued	$ 762,136,231		$ -			$ 762,136,231	$ -	$ -	$ 762,136,231	
0207001 Premium on capital stock	$ -		$ 362,457,437			$ 362,457,437			$ 362,457,437	
0208000 Donations From Stockholder	$ 28,950,000		$ 197,206,819			$ 226,156,819			$ 226,156,819	
0208001 Donations From Stockholder-DENA	$ 1,462,336,840		$ -			$ 1,462,336,840	$ (1,462,336,840)		$ -	
0208010 Donat Recvd From Stkhld Tax	$ 15,641,578		$ 68,538,328			$ 84,179,906			$ 84,179,906	
0210020 Gain on Redemption of Capital	$ -		$ 147,685			$ 147,685			$ 147,685	
0211003 Misc Paid In Capital	$ -		$ -			$ -		$ (1,171,126,922)	$ (1,171,126,922)	
0211004 Misc Paid In Capital Purch Acctg	$ 1,123,780,148		$ (2,879,949,148)			$ (1,756,169,000)			$ (1,756,169,000)	
0211008 Misc PIC Pushdown Adj RE	$ 1,756,169,000		$ -			$ 1,756,169,000			$ 1,756,169,000	
0211005 Misc Paid in Capital Premerger Equity	$ 557,581,098		$ (603,514,486)			$ (45,933,388)			$ (45,933,388)	
0211007 Misc PIC Premerg RE for Div	$ 140,474,493		$ (625,474,493)			$ (485,000,000)			$ (485,000,000)	
0211110 PIC - Sharesaver (BDMS account)	$ -		$ (3,350,836)			$ (3,350,836)			$ (3,350,836)	
0214010 Common stock equity inter-company	$ -		$ (21,750,868)			$ (21,750,868)			$ (21,750,868)	
0216000/0216100 Unappropriated RE/Undistr Subsid Earnings	$ (846,467,235)		$ 897,879,035	(1) 1,403,452,846	66,703,441 (1)	$ 1,521,568,087	$ (118,321,307)		$ 1,403,246,780	
0216100 Unappropriated RE/Undistr Subsid Earnings-Equitization	$ -		$ -			$ -	$ 1,698,890,655	$ -	$ 1,698,890,655	
0438000 Dividends Declared on Common Stock	$ -					$ -			$ -	
Current Year Net Income	$ 194,332,094		$ 23,012,765	(2) -	51,585,816 (2)	$ 268,930,675	$ (27,930,761)	$ (92,609,786)	$ 148,390,128	
Accum other comprehensive income (loss)	$ (27,759,807)		$ (45,455,363)			$ (73,215,170)	$ -		$ (73,215,170)	
Total Common Stock Equity	**$ 5,167,174,440**	**72%**	**$ (2,630,253,125)**	**$ 1,403,452,846**	**$ 118,289,257**	**$ 4,058,663,418**	**$ 90,301,747**	**$ (1,263,736,708)**	**$ 2,885,228,457**	**59%**
% Including Total LTD		**67%**								**53%**
TOTAL CAPITALIZATION (excluding current maturities)	**$ 7,199,699,987**		**$ (2,627,877,455)**	**$ 1,403,452,846**	**$ 118,289,257**	**$ 6,093,564,635**	**$ 90,301,747**	**$ (1,263,736,708)**	**$ 4,920,129,674**	
TOTAL CAPITALIZATION	**$ 7,706,886,049**		**$ (2,627,877,455)**	**$ 1,403,452,846**	**$ 118,289,257**	**$ 6,600,750,697**	**$ 90,301,747**	**$ (1,263,736,708)**	**$ 5,427,315,736**	

Notes:
(1) Purchase Accounting & Other Asset Impairment Charges income statement impacts are adjusted in prior year retained earnings balances net of tax at an assumed tax rate of 38% - 2006, 33.5% - 2007, 37.4% - 2008, 35.4% - 2009 and 35.4% - 2010.
(2) Purchase Accounting & Other Asset Impairment Charges income statement impacts are adjusted in current year retained earnings balances net of tax at an assumed tax rate of 35.4%.
(3) Midwest DENA Assets were reclassed from B.U. 75032 to B.U. 75012 in June 2011.

ANNUAL FIXED COSTS
PRODUCTION O & M EXPENSE
EXCLUDING FUEL USED IN ELECTRIC GENERATION
Twelve Months Ending December 31, 2011

Line No.	Description	Account Number	Total Company (1)	(Demand) Fixed (2)	(Energy) Variable (3)
1	Fuel and Fuel Related Expenses	501	$493,120,673		$493,120,673
2	Rents	507	509,240	509,240	0
3	Other Production Expenses (C)	557	25,319,519	25,319,519	0
4	System Control of Load Dispatching	556	0	0	0
5	Other Steam Expenses (C)	(A)	199,881,780	92,310,519	105,580,002
6	Combustion Turbine	(A)	0		
7	Purchased Power (D)	555	173,973,216	0	0
8	Total Production Expense Excluding				
9	Fuel Used In Electric Generation above		$892,804,428	$118,139,278	$598,700,675
10	A & G Expense P.10, L.17		79,589,553	50,926,039	28,663,511
11	Generator Step Up related O&M	(B)	2,931,899	200,764	2,731,135
12	Total O & M		$975,325,880	$169,266,081	$630,095,321

NOTE: (A) Amounts recorded in Accounts 500, 502-509, 510-514, 546, 548-550 and 551-554 classified into Fixed and Variable Components in accordance with P.13 and P.13 WP.

(B) FF1, P.321, L.93 & L.107 (ACCTS. 562 & 570) times GSU Investment to Account 353 ratio (See P.2)

(C) Excludes costs attributable to the Midwest Gas Assets transferred to DECAM in April 2011.

(D) For purposes of calculating the revenue requirement on page 3, all purchased power expense is forecasted through remainder of FRR. 2011 actual expense is ignored.

CLASSIFICATION OF FIXED AND VARIABLE
PRODUCTION EXPENSES
Twelve Months Ending December 31, 2011

Line No.	Description	FERC Account Number	Demand Related	Energy Related
1	**POWER PRODUCTION EXPENSES**			
2	**Steam Power Generation**			
3	Operation supervision and engineering	500	xx	-
4	Fuel	501	-	xx
5	Steam expenses	502	xx	-
6	Steam from other sources	503	-	xx
7	Steam transferred-Cr.	504	-	xx
8	Electric expenses	505	xx	-
9	Miscellaneous steam power expenses	506	xx	-
10	Rents	507	xx	-
11	Allowances	509	-	xx
12	Maintenance supervision and engineering	510	-	xx
13	Maintenance of structures	511	xx	-
14	Maintenance of boiler plant	512	-	xx
15	Maintenance of electric plant	513	-	xx
16	Maintenance of miscellaneous steam plant	514	xx	-
17	Total steam power generation expenses			
18	**Hydraulic Power Generation**			
19	Operation supervision and engineering	535	xx	-
20	Water for power	536	xx	-
21	Hydraulic expenses	537	xx	-
22	Electric expenses	538	xx	-
23	Misc. hydraulic power generation expenses	539	xx	-
24	Rents	540	xx	-
25	Maintenance supervision and engineering	541	xx	-
26	Maintenance of structures	542	xx	-
27	Maintenance of reservoirs, dams and waterways	543	xx	-
28	Maintenance of electric plant	544	-	xx
29	Maintenance of miscellaneous hydraulic plant	545	xx	-
30	Total hydraulic power generation expenses			
31	**Other Power Generation**			
32	Operation supervision and engineering	546	xx	-
33	Fuel	547	-	xx
34	Generation expenses	548	xx	-
35	Miscellaneous other power generation expenses	549	xx	-
36	Rents	550	xx	-
37	Maintenance supervision and engineering	551	xx	-
38	Maintenance of structures	552	xx	-
39	Maintenance of generation and electric plant	553	xx	-
40	Maintenance of misc. other power generation plant	554	xx	-
41	Total other power generation expenses			
42	**Other Power Supply Expenses**			
43	Purchased power	555	-	xx
44	System control and load dispatching	556	xx	-
45	Scheduling, System Control & Dispatch Services	561.4	xx	-
46	Reliability, Planning and Standards Development	561.8	xx	-
47	Other expenses	557	xx	-
48	Station equipment operation expense (A)	562	xx	-
49	Station equipment maintenance expense (A)	570	xx	-
50	Market Facilitation, Monitoring and Compliance Services	575.7	xx	-

Note: (A) Allocable share of Generator Step-Up Charges from page 2.

PRODUCTION-RELATED DEPRECIATION EXPENSE
Twelve Months Ending December 31, 2011

Line	Production Plant	Depreciation Expense	(Demand) Fixed	(Energy) Variable
		(1)	(2)	(3)
1	Steam (A)	$70,962,135	$70,962,135	$0
2	Nuclear	0	0	0
3	Hydro	0	0	0
4	Conventional	0	0	0
5	Pump Storage	0	0	0
6	Other Production (B)	191,607	191,607	0
7	Int. Comb	0	0	0
8	Production Related General, Common & Intangible Plant (C)	14,993,358	4,819,966	2,889,184
9	Common Plant (D)	5,146,873	2,426,340	12,977
10	Generator Step Up Related Depreciation (E)	426,928	426,928	0
11	Total Production	$91,720,901	$78,826,976	$2,902,161

Note: (A) P.336 of the Form 1, L.2(b). Excludes expenses for AROs.
(B) Excludes depreciation associated with assets transferred to DECAM during 2011.
(C) Total General & Intangible Plant (from P.336 of the FF1 adjusted for amortization adjustments) times ratio of Production Related General Plant to Total General Plant, computed on P. 6.
(D) P.336 of Form 1, L.11(b). Allocations based on ratio of plant from P.7.

PRODUCTION-RELATED
TAXES OTHER THAN INCOME TAXES
Twelve Months Ended December 31, 2011

		System		Production Amount	
	Description	Reference	Amount	Allocator	Demand
			(1)		(2)
1	Labor Related	(A)	9,506,466	(B)	$4,887,949
2	Property Related	(A)	100,481,972	(C)	56,292,050
3	Other	(A)	2,916,016	(C)	1,633,612
4	Ohio Excise (kWh) Tax	(A)	71,919,288	(D)	0
5	Commercial Activities Tax	(A)	3,220,328	(E)	0
6	Total Taxes Other Than Income Taxes	Sum	$188,044,070		$62,813,611

Note: (A) Taxes other than Income Taxes will be those reported in FF1, P. 262 & 263. Excludes taxes associated with assets transferred to DECAM.

(B) Total (Col. (1), L.1) allocated on the basis of wages & salaries in Electric O & M Expenses (excl. A & G), P.354, Col.(b) and Services

	Amount	%	
(1) Total W & S (excl. A & G)	104,144,423	100.00%	
(2) Production W & S	53,548,045	51.42%	
(3) Production W&S (Percent Demand)		62.52%	------> (See P.12 workpaper)

(C) Allocated based on gross plant (Page 6). (Excludes taxes on assets transferred to DECAM).

(D) Recovered via separate rider in distribution charges.

(E) Actual amount for 2011 is ignored. Instead, the CAT is Incorporated in revenue requirement calculation on P.3.

PRODUCTION-RELATED INCOME TAX
Twelve Months Ended December 31, 2011

Line	Description	Reference	Amount	(Demand) Fixed	(Energy) Variable
			(1)	(2)	(3)
1	Return on Rate Base	P.4, L.18	$140,529,667	$131,485,513	$9,044,153
2	Interest Expense	P.10,L.1*P.4,L.16	34,446,005	32,229,142	2,216,862
3	Taxable Income	L.1 - L.2	106,083,662	99,256,371	6,827,291
4	Effective Income Tax Rate	P.16, L.2	35.2796%	35.2796%	35.2796%
5	Income Tax Calculated	L.1 x L.2	37,425,927	35,017,284	2,408,643
6	ITC Adjustment	P.16, L.13	(663,957)	(657,726)	(6,231)
7	Income Tax	L.3 + L.4	$36,761,970	$34,359,558	$2,402,412
8	Commercial Activities Tax	ORC 5751	0.26%	0.26%	0.26%

COMPUTATION OF EFFECTIVE INCOME TAX RATE
Twelve Months Ended December 31, 2011

Line	Description	Reference	Amount
1	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} * {1 - DPAD} =	(A)	31.8500%
2	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		35.2796%
3	where WCLTD and WACC from Exhibit B-11 and FIT, SIT & p as shown below.		
4	GRCF=1 / (1 - T)		1.467351431
5	Federal Income Tax Rate	FIT	35.0000%
6	State Income Tax Rate	SIT	0.0000%
7	Percent of FIT deductible for state purposes	p	0.0000%
8	Weighted Cost of Long Term Debt	WCLTD	1.9247%
9	Weighted Average Cost of Capital	WACC	7.8522%
10	Amortized Investment Tax Credit (enter negative)	FF1, P.114, L.19, Col.g	($800,115)
11	Gross Plant Allocation Factor	L.19	56.55%
12	Production Plant Related ITC Amortization	L.10 x L.11	(452,487)
13	ITC Adjustment	L.12 x L.4	(663,957)
	Gross Plant Allocator Total		
14	Gross Plant	P.6, L.6, Col.2	$6,380,218,703
15	Production Plant Gross	P.6, L.5, Col.2	3,608,188,601
16	Demand Related Production Plant	P.6, L.5, Col.3	3,574,328,638
17	Energy Related Production Plant	P.6, L.5, Col.4	$33,859,963
18	Production Plant Gross Plant Allocator	L.16 / L.15	56.55%
19	Production Plant - Demand Related	L.17 / L. 16	99.06%
20	Production Plant - Energy Related	L.18 / L.16	0.94%

Note: (A) Gross Domestic Production Tax Credit, Section 199, Internal Revenue Code.
Assume 9% of Taxable Income for credit.

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Ohio
Revenue Requirement for Capacity Cost Calculation

	Description	Total For Period (a)	Avg Annual	Comment
1	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	
4	[redacted]	[redacted]	[redacted]	[redacted]
5	Total Revenue (Current Projection)	$625,561	$220,786	Sum Lines 1 thru 4
6	Fixed Costs (excluding return)	880,902	310,907	O&M, Depreciation, Other Taxes Based on 2011 Form 1
7	Earnings Before Interest & Taxes	(255,341)	(90,120)	Line 5 - Line 6
8	Interest Expense	91,316	32,229	Wtd avg cost of debt at 12/31/11 from SEET times Rate Base
9	Taxable Income	(346,656)	(122,349)	Revenue required for 0% ROE (*i.e.* , Break even)
10	Return on Equity at 11.15% ROE	281,225	99,256	Incremental Revenue to go from of 0% ROE to 11.15% ROE
11	Income Taxes on Incremental Return + CAT	97,353	34,360	Reflects adjustment for Gross Domestic Production Tax Credit
12	Commercial Activities Tax	3,887	1,372	0.26% of Total Revenue
13	Total Incremental Revenue Required	**$729,122**	**$257,337**	
14	[redacted]	[redacted]	[redacted]	[redacted]
15	Average Annualized Net Amount	$729,122	$257,337	L.14-L.1
16	Average Capacity Rate ($/MW-Day)			
17	Total Cost of Capacity (Before FZCP Sales)		$224.15	L.14 ÷ 5 CP (4459.85 MW) ÷ 365 days
18	Net Cost of Capacity (After FZCP Sales)		**$158.08**	L.15 ÷ 5 CP (4459.85 MW) ÷ 365 days
19	Rate Base		$1,674,513	P.4 (Attachment B)
20	Equity Ratio		53.2%	P.10 (Attachment B)
21	Earnings Before Interest & Taxes		($90,120)	Line 7
22	Tax Expense		(43,164)	Line 21 * Tax Rate
23	Earnings After Taxes		($46,956)	Line 21 - Line 22
24	Return on Rate Base		-5.27%	Line 23 ÷ (Line 19 * Line 20)
25	Interest Expense		$32,229	Line 8
26	Net Income		($79,185)	Line 23 - Line 25
27	Return on Equity		**-8.90%**	Line 26 ÷ (Line 19 * Line 20)

Duke Energy Ohio
Comparison of AEP Capacity Rates to Duke Energy Ohio

	Capacity Rate Before Deductions					
	As Filed		Staff [b]		Order	
Columbus Souther Power	348.05	(a)	289.59	(c)	n/a	
Ohio Power	634.37	(a)	318.76	(c)	n/a	
Total AEP Ohio	509.05	(a)	305.48	(c)	322.85	(d)
Duke Energy Ohio	323.26	(b)	n/a		n/a	

	Deductions for Margins					
	As Filed		Staff [b]		Order	
Columbus Souther Power	20.46	(a)	74.73	(c)	n/a	
Ohio Power	255.14	(a)	211.98	(c)	n/a	
Total AEP Ohio	153.33	(a)	159.07	(c)	133.96	(d)
Duke Energy Ohio	99.21	(b)	n/a		n/a	

	Net Capacity Charge					
	AEP Ohio [a]		Staff [b]		Order	
Columbus Souther Power	327.59	(a)	214.86	(c)	n/a	
Ohio Power	379.23	(a)	106.78	(c)	n/a	
Total AEP Ohio	355.72	(a)	146.41	(c)	188.89	(e)
Duke Energy Ohio	224.05	(b)	n/a		n/a	

[a] Per Kelly Pearce Testimony & Exhibits in Case No. 10-2929-EL-UNC, filed March 23, 2012.

[b] Per Company's Application Attachment B.

[c] Per Testimony and Exhibits of Emily S. Medine, in Case No. 10-2929-EL-UNC, filed May 7, 2012.

[d] Commission's July 2, 2012, Order in Case No. 10-2929-EL-UNC. See page 2 for details of Commission's adjustment to Staff's proposed figure. Commission only specified adjustments for combined AEP Ohio in its order.

Duke Energy Ohio
Comparison of AEP Capacity Rates to Duke Energy Ohio

Commission's July 2, 2012, Order in Case No. 10-2929-EL-UNC

Adjustments Made to Staff's May 7, 2012, Position

Affecting the Fixed Cost	
Prepaid Pension asset	$3.20
Amortization of Severance	4.70
ROE to 11.15%	10.09
Rounding (unexplained)	(0.62)
Affecting the Credits for Energy Margins	
Trapped Energy Credits	$20.11
Energy Diverted to Wheeling Power	5.00