37

FILE

EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets	)	Case No. 08- 917-EL-~~UNC~~ SSO
and	)	
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan	)	Case No. 08- 918-EL-~~UNC~~ SSO

DIRECT TESTIMONY OF
PHILIP J. NELSON
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: July 31, 2008

INDEX TO DIRECT TESTIMONY OF
PHILIP J. NELSON
PUCO CASE NO. 08-917-EL-UNC
PUCO CASE NO. 08-918-EL-UNC

<u>SUBJECT</u> <u>PAGE</u>

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DIRECT TESTIMONY OF
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CASE NO. 08-917-EL-UNC
CASE NO. 08-918-EL-UNC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Philip J. Nelson. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE INDICATE BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY.

A. I am employed as Director of Strategic Initiatives in the Corporate Budgeting and Planning Department for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO), referred to collectively as AEP Ohio.

PERSONAL DATA

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from West Liberty State College in 1979 receiving a Bachelor of Science Degree in Business Administration, majoring in accounting. In 1979, I was employed by Wheeling Power Company, an affiliate of AEP, in the Managerial Department. At

Wheeling Power, I was responsible for rate filings with the Public Service Commission of West Virginia (PSC), for resolving customer complaints made to the PSC, as well as for preparation of the Company's operating budgets and capital forecasts. In 1996 I transferred to the AEP-West Virginia State Office in Charleston, West Virginia as a senior rate analyst. In 1997 I transferred to AEPSC as a senior rate consultant in the Energy Pricing and Regulatory Services Department, with my primary responsibility being the oversight of OPCO's and CSP's Electric Fuel Component (EFC) filings. In 1999 I transferred to the Financial Planning Department as a Staff Financial Analyst. I was promoted to my current position in April 2007.

PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to explain the Companies' proposal for the implementation of a cost recovery mechanism for fuel, purchased power and environmental variable costs consistent with provisions of Am. Sub. S.B. 221 (S.B. 221). I provide a calculation of the fuel adjustment clause (FAC) component presently reflected in each Company's most current standard service offer (SSO). I also calculate capital carrying costs on environmental capital additions. Finally, I support the capital carrying cost rates used by me and other AEP Ohio witnesses.

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring EXHIBITS PJN 1 through 13.

Q. DID YOU SPONSOR TESTIMONY IN VARIOUS CASES BEFORE THIS COMMISSION SINCE THE ENACTMENT OF AM. SUB. S.B. 3 (S.B. 3) IN 1999 AND BEFORE?

A. Yes. I have sponsored testimony in several cases before this Commission since the passage of S.B. 3 including Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP (Electric Transition Plan or ETP), Case No. 04-169-EL-UNC (Rate Stabilization Plan or RSP) and Case Nos. 07-1191-EL-UNC, et al, (RSP 4% cases). I also provided testimony in Case No. 98-101-EL-EFC and 98-102-EL-EFC, pre-S.B. 3 fuel adjustment clause cases involving OPCO and CSP respectively. I mention these particular cases since they are the foundation of the Companies' current generation related rates or SSO. The EFC cases, while filed prior to the passage of S.B. 3, determined the fuel rates that were in place on October 5, 1999 and thus included in the unbundled frozen rates during the market development period. Since the Companies are proposing increases to the SSO in this case, I have reviewed these cases and used data as appropriate to establish a basing point for development of the FAC and environmental capital carrying cost components.

PRIOR EFC FUEL METHODOLOGY AND DEFINITION OF FAC

Q. WOULD YOU PLEASE DESCRIBE IN GENERAL TERMS THE ELECTRIC FUEL COMPONENT (EFC) METHODOLOGY USED IN OHIO PRIOR TO THE ENACTMENT OF S.B. 3?

A. Yes. The EFC was a semi-annual rate adjustment to recover costs of fuel, purchased power and certain environmental items. The fuel component was limited to the "151" component of Account 501 fuel. Purchased power was limited to the fuel component of "economic" purchased power. This definition is used to calculate the cost to the internal customer (Net Energy Cost or NEC). Without going into great detail, the EFC followed the FERC fuel clause definition and limited the items in the fuel clause to the narrow NEC definition of fuel. For instance fuel handling, (Account 152) which clears to Account 501 (fuel) was not includible. Likewise purchased power demand charges or capacity payments were not includible. The EFC did, however, include certain environmental items such as emission allowance consumption expense, and gains on the sale of allowances and research and development expenditures for new clean coal technology.

Q. ARE THE COMPANIES PROPOSING TO REESTABLISH THAT EFC METHODOLOGY?

A. No. S.B. 221 provides for a broader cost-based adjustment that includes all prudently incurred fuel, purchased power, and environmental components in an ESP. The Companies believe that it is reasonable and efficient to include all these components in a single cost recovery mechanism rather than have separate clauses for each. The costs the Companies are proposing to include are variable costs directly related to energy produced or purchased to serve the internal load customer. The Companies are not proposing to include the capital carrying costs on environmental capital in the FAC. Company witness Mr. Baker addresses the recovery of those capital carrying costs in his testimony.

Q. WHAT ACCOUNTS ARE INCLUDED IN THE PROPOSED FAC?

A. The following is a list of accounts that are proposed for inclusion in the FAC along with a brief description of each account. For efficiency in discussing this clause I have given it an acronym that may be read to suggest only fuel and I and other witnesses may refer to it as a "fuel" clause; however, that term encompasses the broader definition that I just mentioned and discuss below.

- **501 Fuel** – This account includes the cost of fuel and transportation costs used in the production of steam for generation of electricity. For the Companies, this is the vast majority of variable costs associated with energy production. This account was also charged with audit fees in connection with the EFC audit requirements. The Companies will incur audit fees in connection with requirements pertaining to the new Commission FAC rules and will charge this account as well.
- **502 Steam Expenses (Environmental subaccounts)** – This account includes the cost of material and expenses used in the production of steam for generation of electricity. In recent years the majority of the expenses recorded in this account have been chemicals used in environmental equipment such as selective catalytic reduction equipment (SCRs) and flue gas desulfurization (FGDs) equipment. These chemicals are referred to as environmental consumables and include lime, limestone, trona, and urea. Lime and limestone are used in FGDs to remove sulfur from the post combustion process. Urea is the primary chemical agent used in the removal of NOX. Trona is necessary to hinder the formation of SO3, where an FGD and SCR

are used in tandem. The Companies are including the subaccounts used to record environmental costs. The Companies will also include in the FAC any new environmental related chemicals that may be required in the future.

- **509 Allowances** – This account records the cost of emission allowances to cover the emission of effluents such as SO2 and NOX.
- **518 Nuclear Fuel Expense** – This account includes the net amortization of the cost of nuclear fuel assemblies. The Companies do not own or operate a nuclear generating plant and are not currently incurring this cost and are not expecting to incur this expense in the foreseeable future.
- **547 Fuel** – This account includes the cost of fuel used in other than steam electric generation, such as a simple cycle gas peaking unit. Combined Cycle gas plants record their fuel cost in Account 501.
- **555 Purchased Power** – This account records the cost of electricity purchased including transactions under the AEP Power Pool. It includes both energy and demand or capacity charges. PJM ancillary services that are recorded in Account 555 will not be included in the FAC but will be included in the Transmission Cost Recovery Rider (TCRR) as they are today.
- **507 Rents (Applicable subaccounts only)** – If a purchase contract or unit power sale is required to be recorded as a lease per accounting rules, then the demand charge associated with a power contract may be recorded in this account. Currently, the demand charge for a CSP purchase under a FERC unit power sale contract is recorded in Account 507. As part of the FAC the

Companies are requesting authority to move these types of demand charges to Account 555.

- **557 Other Expenses (Power Supply – applicable subaccounts only)** – This account is or will be used to record the cost of renewable energy credits (RECs) to meet a portion of the renewable requirements of S.B. 221, particularly in the near term.
- **411.8 Gains from Disposition of Allowances and 411.9 Losses from Disposition of Allowances** – If gains or losses are experienced on the sale or other disposition of emission allowances, they are recorded in these accounts. Regular sales of allowances occur at the annual EPA auction resulting in gains each year. Sales to third parties are periodically made and settlements under the FERC-approved AEP Interim Allowance Agreement (IAA) can result in gains and losses.
- **Other Accounts and subaccounts** – If environmental, fuel, purchased power and renewable costs or taxes are recorded in accounts or subaccounts not specifically mentioned in my testimony or listed on my exhibits, the Companies may include them in the FAC. For example a carbon tax could be implemented and recorded in a tax account. Clearly, this would be federally mandated carbon or energy tax recoverable though the FAC.

IDENTIFICATION OF THE FAC COMPONENT OF THE CURRENT SSO

Q. IS IT NECESSARY TO IDENTIFY THE FAC COMPONENT OF THE COMPANIES' MOST RECENT SSO RATES?

A. Yes. Since the Companies are proposing to re-implement a fuel clause in accordance with S.B. 221, it is necessary to properly identify the FAC costs in their most recent SSO, so the remaining base rate component of the SSO can be established. In my testimony I develop the components of the most recent SSO which, under the Electric Security Plan (ESP), will be included in the proposed FAC.

Q. HOW DID THE COMPANIES IDENTIFY THE FAC COMPONENT OF THEIR MOST RECENT SSO?

A. It was a three-step process. First, I identified the frozen EFC rate for each Company from my exhibits and testimony in the Electric Transition Plan cases. Then, I added calendar year 1999 amounts for the additional fuel, purchased power and environmental accounts that are included in the requested FAC for this proceeding. This second step places the base FAC in the most recent SSO on a comparable basis to the 2009 FAC. I have used calendar year 1999 data from the FERC Form 1 and other financial records as the base period for the additional components that were not in the frozen EFC. Finally, to the frozen EFC rate and the rate developed for the other components, I made an adjustment for subsequent rate changes to arrive at a base FAC component that is equal to the fuel related costs presently reflected in the most recent SSO.

Q. PLEASE DESCRIBE THE RATE CHANGES THAT OCCURRED DURING THE RSP PERIOD THAT ARE RELEVANT TO THE FROZEN EFC AND THE OTHER COMPONENTS OF THE FAC.

A. For the market development period which ran from January 1, 2001 through December 31, 2005, the EFC rates in effect on October 5, 1999 were frozen. However, beginning with the January 2006 billing cycle, generation rates, which included the EFC, were increased by 7% and 3% per year for three years for OPCO and CSP, respectively. CSP also increased its generation rates in 2007 by approximately 4.43% through the Power Acquisition Rider (PAR). The PAR is a cost recovery mechanism to recover the costs associated with the purchase of power by CSP to serve the former Monongahela Power Company's service territory in the Marietta area and, therefore, I have treated it as a component of the base period FAC in the most recent SSO. The other major change that occurred was the end of the Regulatory Asset Charge (RAC) for OPCO on December 31, 2007. The October 5, 1999 OPCO EFC was unbundled in the ETP case to identify the component for the Gavin Cap and the mine investment/shutdown costs and assign those costs to the RAC. I have attached Exhibit No. PJN-2 from the ETP case as an exhibit in this proceeding (EXHIBIT PJN-7) to show the EFC rate absent the components included in the RAC.

Q. PLEASE SUMMARIZE THE ADJUSTMENTS YOU MADE TO ARRIVE AT THE FAC COMPONENT OF THE MOST RECENT SSO?

A. I have made adjustments for the three rate changes discussed above. I make an adjustment to increase the FAC for the base period for the 3% and 7% generation increases granted to CSP and OPCO respectively in the RSP. I compounded the 3% and 7% increases for 3 years and applied that to the frozen EFC and the other base year components to arrive at an adjustment per kWh . The compound rate for CSP is 9.3% and for OPCO is 22.5%. Companies witness Mr. Roush converted the PAR revenue to a cents-per-kWh rate which I added to base period FAC for CSP. For OPCO, I use the EFC rate net of the component for the RAC as identified in the ETP.

Q. HOW DO THESE ADJUSTMENTS IMPACT THE REVENUE REQUIREMENT FOR CSP AND OPCO?

A. By adding the escalation factors of 7% and 3% both OPCO and CSP's customer impact is reduced. The PAR adjustment to the FAC base period rate further reduces the impact on CSP's customers. Conversely, the loss of the RAC for OPCO increases its revenue requirement. The adjustments made above, coupled with the frozen EFC and 1999 data for the other FAC components, properly identify the FAC component of the most recent SSO for fuel, purchased power and environmental variable expenses.

Q. IS IT THE COMPANIES' POSITION THAT THE EXPENSES ON ITS BOOKS IN 1999 FOR THE ACCOUNTS OTHER THAN THE EFC WERE IN FACT THE LEVEL INCLUDED IN RATES?

A. No. Many of the costs would have been established in the Companies' general rate cases filed some time before and the EFC rate at October 1999 would not have been based on calendar year 1999 data. However, since the EFC rates in place during the market development period were those effective in October 1999, using 1999 cost data is a reasonable, albeit conservative, method of establishing the other FAC components for the base period.

FORECAST OF FAC COSTS

Q. ARE COSTS THAT THE COMPANIES ARE SEEKING TO RECOVER IN THE FAC EXPECTED TO BE HIGHER THAN THE ADJUSTED FUEL COMPONENT OF THE COMPANIES' MOST RECENT SSO RATES DEVELOPED AS DESCRIBED ABOVE?

A. Yes. The Companies expect fuel and environmental costs to be substantially higher than the fuel rates in our most recent SSO. Recent prices for fuel have increased dramatically. Since the Companies have much of their fuel supply under contracts they have some protection from the increases. Unfortunately, however, as they expire lower cost contracts are being replaced by much higher cost contracts. Also, environmental variable costs continue to increase. While allowance expense for the Companies has come down in recent years due to the addition of environmental controls, the operating expenses (consumables) of the environmental controls at the generating plants are climbing rapidly. Since the FAC will include emission allowance costs, as well as the gains from the sale of allowances, the benefits of the lower allowance requirements associated with environmental controls will be reflected in the customers' rates.

Q. HOW DID THE COMPANIES CALCULATE THE FAC CHARGE THEY ARE PROPOSING IN THIS PROCEEDING?

A. The Companies have projected 2009 costs for the NEC, those environmental items in the prior EFC, and the additional cost items to be included in the FAC. These costs were assigned to internal load and off-system uses, as explained below in more detail. The NEC off-system uses include off-system sales to non-AEP entities as well as to other AEP operating companies. For example OPCO's sales of energy to CSP though the FERC-approved AEP Interconnection Agreement (AEP Pool) is an off-system use for OPCO. The total FAC costs less those assigned off-system, results in the costs for the internal load. The internal load costs, determined for each Company, are divided by the internal load MWh to develop a 2009 rate. The same methodology was used to establish the FAC rate in the most recent SSO.

ALLOCATION FACTORS

Q. HOW ARE THE ALLOCATION FACTORS DEVELOPED TO ASSIGN THE COSTS TO INTERNAL LOAD?

A. Off-system Sales (OSS) of energy to non-AEP companies for the NEC component of fuel cost is determined by a stacking of the Companies' generation resources and an assignment of the highest cost resources to OSS on an hour-by-hour basis. An exception to this is purchases made specifically for internal load such as the renewable purchases required under S.B. 221. For those costs not assigned directly by the NEC, I have used a ratio developed from the NEC MWh data to assign energy related costs between internal load and off-system uses or I directly assign the cost to either internal load or OSS. I developed this MWh data for the base period using 1999 Net Energy Requirement (NER) reports and for 2009 using forecast NER data.

Q. WHAT ITEMS ARE DIRECTLY ASSIGNED TO INTERNAL LOAD OR OSS?

A. I assign purchased power capacity charges directly to internal load since capacity is purchased or acquired to meet internal load obligations. Also, AEP Pool primary energy purchased is assigned 100% to internal load including the portion that is not in the NEC. Renewable and dedicated purchases are likewise assigned directly to internal load. However pool energy recorded in Account 555 that is related to the Companies' Member Load Ratio (MLR) share of the cost of making an off-system sale is assigned 100% to OSS.

Q. PLEASE DESCRIBE IN MORE DETAIL THE MLR SHARE OF THE COST OF MAKING AN OFF-SYSTEM SALE?

A. The FERC issued Accounting Release No.14 (AR-14) in 1991. It requires that members of power pools such as the AEP companies, record system pool transactions on a gross basis rather than a net basis. Prior to this pronouncement the AEP companies would record only the net margin of making an OSS in Account 447- sales for resale. Since 1991 the Companies are required to record the full revenue from the sale in Account 447 and the offsetting cost in Account 555. In the NEC report the AEP Pool transactions are recorded on a net basis, i.e., there is no affiliate MWh purchase transaction for the company's MLR share of the cost of making an OSS. Since the FAC includes costs recorded in Account 555 in addition to that which is in the NEC, I identify and segregate the AR-14 component and assign it directly to OSS.

Q. WHAT INTERNAL LOAD ALLOCATION FACTOR IS APPLIED TO THE NON-NEC ACCOUNTS INCLUDED IN THE FAC?

A. I have developed two separate energy allocation factors for 1999 and 2009. They are the AEP Sources allocator and the Non-Affiliate Sources allocator. For the accounts or portions of accounts that are not assigned through the NEC algorithm and are associated with AEP generation, I use the energy allocation factor computed for AEP Sources. These include all costs in Account 501 that are not in the NEC, Account 502 costs, Account 509 costs, and Lawrenceburg non-capacity purchased power costs currently in Account 555. I also use the AEP Sources energy allocation factor for allocation of Accounts 411.8 and 411.9, allowance gains and losses. External purchased power is allocated based on the Non-Affiliate Sources energy allocation factor for 2009. For 1999, the external purchased power was assigned based on accounting records.

DEDICATED PURCHASED POWER

Q. WHAT ARE DEDICATED PURCHASED POWER PURCHASES AND DO THE COMPANIES ANTICIPATE ANY FOR THE ESP PERIOD?

A. Dedicated purchases are those where an RFP has been issued or is planned to solicit power to serve Ohio retail loads. The Companies are planning RFPs to enter into contracts to supply a portion of Ohio retail load during the ESP period as explained in Companies' witness Mr. Baker's testimony.

Q. ARE RENEWABLE PURCHASES INCLUDED IN THE FORECAST FAC RATES?

A. Yes. I have included the costs for Purchased Renewable Energy and/or Renewable Energy Credits (RECs) in my calculation of the 2009 FAC. The estimated costs for purchases were provided to me by Companies' witness Mr. Godfrey.

<u>DESCRIPTION OF EXHIBITS ASSOCIATED WITH THE FAC</u>

Q. WOULD YOU PLEASE DESCRIBE YOUR EXHIBITS SUPPORTING THE FAC?

A. Yes:

EXHIBIT PJN-1 provides the calculation of the FAC component of the current SSO rate for CSP.

EXHIBIT PJN-2 provides the calculation of the 2009 FAC rate for CSP.

EXHIBIT PJN-3 provides the calculation of the internal load sales allocation factors for 1999 and 2009 for CSP.

EXHIBIT PJN-4 provides the calculation of the FAC component of the current SSO rate for OPCO.

EXHIBIT PJN-5 provides the calculation of the 2009 FAC rate for OPCO.

EXHIBIT PJN-6 provides the calculation of the internal load allocation factors for 1999 and 2009 for OPCO.

EXHIBIT PJN-7 provides a copy of EXHIBIT NO. __PJN-2 from the ETP case.

<u>CAPITAL CARRYING COSTS ON ENVIRONMENTAL INVESTMENT</u>

Q. ARE THE COMPANIES REQUESTING AN INCREASE FOR ENVIRONMENTAL COSTS BEYOND THE VARIABLE COSTS INCLUDED IN THE FAC?

A. Yes. The Companies have made significant capital investment in environmental facilities and are requesting the capital carrying cost on those facilities that are not currently reflected in rates. The capital carrying cost is the annual cost associated with the investment of a dollar of capital asset investment. Capital expenditures are typically long lived assets that are recovered over the life of the asset. Investors require both a return on and of their capital expenditures. The capital carrying cost is determined by applying an annual carrying cost rate, expressed as a percent of the capital expenditure, to the total amount spent on a capital project or projects. The carrying cost rate includes the cost of money (weighted average cost of capital), a depreciation component, an income tax component, property and other taxes component and an administrative and general component. It does not include direct O&M expenses. Also, because of the depreciation component the rate varies based on the expected life of the project. The rate is higher the shorter the life of the project.

Q. PLEASE DESCRIBE THE CAPITAL STRUCTURE THAT WAS USED FOR THE CAPITAL CARRYING CHARGE CALCULATIONS?

A. A capital structure of 50% common equity and 50% debt was used in determination of the capital structure. This is consistent with the recent capital structures of the Companies and consistent with how the Companies intend to capitalized over the period that the ESP will be in effect.

Q. WHAT PROJECTS ARE THE COMPANIES INCLUDING IN THE CALCULATION OF THE CAPITAL CARRYING COST?

A. The Companies are including the dollars spent for all environmental projects from the beginning of the Market Development Period (MDP) through the ESP period, less offsets to give recognition to the RSP increases. More specifically, the 2008 capital carrying cost is based on the 2001 through 2008 net cumulative environmental capital expenditures for each company multiplied by its carrying cost rate. The 2009 carrying cost is the cumulative capital expenditures through 2009 times the carrying cost rate. The 2010 carrying cost is the cumulative capital expenditures through 2010 times the carrying cost rate. The 2011 carrying cost is the cumulative capital expenditures through 2011 times the carrying cost rate. I calculate the incremental capital carrying cost rate for 2009, 2010 and 2011 assuming the capital additions are spread evenly over each year which I refer to on my exhibit (EXHIBIT PJN-8) as "One-Half Year Convention".

Q. HAVE YOU REFLECTED THE RSP OFFSETS TO THE CAPITAL EXPENDITURES THE COMPANIES ARE INCLUDING IN THEIR REQUESTS?

A. Yes. The Companies are proposing to offset a large portion of the environmental capital expenditures made since the start of the MDP with their initial estimates of such expenditures made in the RSP case, as well as environmental expenditures that were a component of the Companies' RSP 4% cases. The offset for OPCO is about $1.5 billion in capital expenditures and for CSP the corresponding amount is about $400 million. These offsets are composed of the baseline estimates for environmental capital spending established in the RSP case as well as the additional capital expenditures in the RSP 4% cases. While the 4% cases included a specific component for recovery of environmental expenditures in rates, the original RSP case's 3% and 7% generation increases and the Commission's order did not. Also, S.B. 221 does not require such an offset. However, the Companies believe it is a conservative and reasonable approach to offset the environmental expenditures the

Companies have made or will make though 2008 with not only the RSP 4% investments but the RSP case original estimate of environmental capital. Therefore, the capital carrying costs the Companies are requesting in this case are based on capital expenditures that have not been included in any case before this Commission from 2001 to present.

Q. HOW DID YOU DETERMINE THE AMOUNT OF THE OFFSETS?

A. I reviewed the filings and my testimony in the RSP and RSP 4% cases. I believe the projects and the expenditures the Companies were expecting to make on environmental projects were well documented in those cases. The amounts I have used as an offset appear in my previous testimony in those proceedings.

Q. HAS OPCO'S RETAIL REVENUE REQUIREMENT BEEN REDUCED TO RECOGNIZE THAT ENVIRONMENTAL PLANT INVESTMENT CAN BE RECOVERED THROUGH THE AEP POOL CAPACITY CHARGE?

A. Yes, in the calendar year following the year generation plant, including environmental, is placed into electric plant-in-service (EPIS), the capacity charge for AEP Pool surplus companies is increased for such investment. OPCO is a surplus company under the capacity provision of the AEP Pool. CSP is a deficit company. Therefore, I have reduced OPCO's revenue requirement associated with environmental capital investment to recognize recovery by OPCO through the AEP Pool. I made a simplifying assumption that the AEP Pool credit applies regardless of the date the plant is actually recorded in EPIS. That is, a dollar spent on capital is assumed to flow through the AEP Pool capacity settlement, whether in fact the expenditure is still in construction work in progress (CWIP) or in EPIS. This is consistent with the capital carrying cost rate used by the Companies in their calculation of revenue requirement discussed above. That is, the carrying cost rate is a levelized rate over the life of the property and therefore is not dependent upon whether the environmental expenditure has been recorded in EPIS or is still in CWIP. The AEP Pool capacity allocation factor is 71% which is based on the ratio of OPCO's May 2008 Primary Capacity Reservation of 5,953,300 kW divided by OPCO's May 2008 Member Primary Capacity of 8,443,000 kW.

Q. WHAT INVESTMENT LIFE IS ASSUMED FOR THE ENVIRONMENTAL ADDITIONS?

A. I assumed a 25-year life which is an approximation that coincides with estimates of generation unit remaining plant lives for the Ohio generation fleet.

Q. WHAT EQUITY COMPONENT WAS USED IN THE CAPITAL CARRYING COST RATE?

A. I used a 10.5% return on equity (ROE). This rate was approved by the Commission in Case No. 05-765-EL-UNC. The use of this conservative rate is intended to limit debate in this case about the ROE component of the capital carrying cost rate.

DESCRIPTION OF EXHIBITS ASSOCIATED WITH ENVIRONMENTAL CARRYING CHARGES

Q. PLEASE BRIEFLY DESCRIBE YOUR EXHIBITS ASSOCIATED WITH THE COMPANIES' REQUEST FOR CARRYING COSTS ON ENVIRONMENTAL CAPITAL INVESTMENT.

A. EXHIBIT PJN-8 provides a calculation of the 2008, 2009, 2010 and 2011 revenue requirement for OPCO and CSP using the methodologies described. An incremental amount is shown over the prior year, using the half year convention.

EXHIBIT PJN-9 is a list of the major capital projects the Company have undertaken with the associated cost.

EXHIBIT PJN-10 provides the calculation and components of the carrying cost rate which is applied to the capital expenditures to calculate the revenue requirement.

EXHIBIT PJN-11 provides the calculation of the return component of the carrying cost rate. The return component is the Weighted Average Cost of Capital (WACC).

EXHIBIT PJN-12 provides the calculation of the environmental capital additions identified in the RSP and RSP 4% cases (Offsets).

SUMMARY OF FAC AND ENVIRONMENTAL OFFSETS TO REVENUE REQUIREMENT

Q. HOW DOES THE VALUE OF YOUR FAC CREDIT AND YOUR ENVIRONMENTAL CREDIT COMPARE TO THE ACTUAL REVENUE INCREASES GENERATED BY THE 3% AND 7% INCREASE AND THE RSP 4% CASE INCREASES?

A. EXHIBIT PJN-13 provides a comparison. For OPCO, it shows that the adjustments and credits I have provided exceed the revenue produced by the 3% and 7% generation rate increase and Case No. 07-1278-EL-UNC, et al, revenue increases. For CSP, the adjustments and credits I provide consume almost all the revenue increases granted. Therefore, nothing of the RSP and 4% generation increases are available to recover any other cost increases beyond fuel and environmental capital carrying cost.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

EXHIBIT PJN-1

COLUMBUS SOUTHERN POWER COMPANY
FAC BASE PERIOD

Line No.	A	B	C	D	E	F	G
1	**EFC Rate Per Transition Plan Case No. 99-1729-EL-ETP**		Notes				Cents/Kwh
2							
3		The Unbundled EFC Included:					
4		Account 151 Component of Account 501- Fuel	(3)				
5		Account 555 - Energy					
6		Account 509 - Allowance Consumption Costi					
7		Account 411.8 Gains on Sales of Allowances					
8		Account 411.9 Losses on Sales of Allowances					
9		An RA and SLA component					
10		**Frozen EFC Rate**					1.373
11							
12	**Additional S.B. 221 FAC Accounts at 1999 Level**						
13							
14				Additional Fuel and Environmental Accounts in FAC			
15						Internal Load	
16	Account	Description		1999 Amount	Allocation Factor	Allocated Amount	
17							
18	501	Fuel (Ash Handling)		$ 5,723,429	93%	$ 5,349,287	
19	501	Fuel - Procurement, Unloading & Handling		$ 4,859,523	93%	$ 4,541,855	
20	501	Fuel Handling - No Load (CV4)	(1)	$ 68,238	93%	$ 63,777	
21	501	Ash Sales Proceeds	(4)	$ -	93%	$ -	
22	501	Gypsum handling/disposal costs	(4)	$ -	93%	$ -	
23	507	Depr & Capacity portion-Affil (Lawrenceburg)	(1),(2)	$ -	93%	$ -	
24	555	Purch Pwr-NonTrading-Nonassoc (Non-Fuel)		$ 17,159,879	IPS*	$ 5,797,649	
25	555	Pool Capacity		$ 114,794,238	100%	$ 114,794,238	
26	555	Purchased Power - Pool Energy (152 and 1/2 Maintenance)	(3)	$ 5,047,340	100%	$ 5,047,340	
27	555	Purchased Power - Pool Energy (MLR for OSS AR-14)	(3)	$ 17,860,329	0%	$ -	
28	555	PJM Emer.Energy Purch.	(2)	$ -	93%	$ -	
29	555	PurchPwr-O&M & Tax portion-Affiliate (Lawrenceburg)	(1),(2)	$ -	93%	$ -	
30	557	Renewable Energy Credits	(2)	$ -	100%	$ -	
31	502	Emission Control Chemicals Sub-Accounts	(4)	$ 6,728,250	93%	$ 6,288,423	
32		Total		$ 172,241,226		$ 141,882,570	
33		Internal Load MWH				17,886,352	
34		**Additional FAC Components Rate**					0.793
35		Subtotal					2.166
36		RSP Rate Adjustment - 3% per year for 3 years					0.201
37		Power Acquisition Rider Adjustment					0.185
38		**FAC presently in rates**					2.552
39							
40							
41	(1) Applies to only CSP						
42	(2) Item did not exist in 1999						
43	(3) This account is divided into components to allocate separately				*Interchange Power Statement		
44	(4) Item existed but this sub-account did not exist in 1999						

EXHIBIT PJN-2

COLUMBUS SOUTHERN POWER COMPANY
FAC 2009 FORECAST

Line No.	A	B	C	D	E	F	G
1	**Fuel and Environmental Costs Included in Prior EFC & FAC**			Net Energy Cost (NEC)			
2					Assigned	Assigned	
3	Account	Description	Notes	Total	Off-System	To Internal Load	Cents/Kwh
4							
5	501	Fuel Consumed		$ 283,653,589	$ 79,915,170	$ 203,738,419	
6	501	Fuel Consumed - No Load (CV4)	(1)	$ 42,671,105	$ 5,494,603	$ 37,176,502	
7	501	Fuel Survey Activity				$ -	
8	501	Fuel Oil Consumed		$ 3,417,160	$ 1,228,489	$ 2,188,671	
9	501	Natural Gas Consumed (Waterford)	(1)	$ 67,549,303	$ 40,738,716	$ 26,810,587	
10	547	Fuel - Gas Turbine (Darby)	(1)	$ 13,610,775	$ 13,370,994	$ 239,781	
11	555	Purch Pwr-NonTrading-Nonassoc (Fuel)	(3)	$ 126,473,490	$ 20,156,110	$ 106,317,380	
12	555	Purchased Power - Pool Energy (Fuel)	(3)	$ 246,220,000	$ -	$ 246,220,000	
13	555	Purch Power-Fuel Portion-Affil (Lawrenceburg)	(1)	$ 102,597,788	$ 43,858,248	$ 58,739,540	
14		Total		$ 886,193,210	$ 204,762,330	$ 681,430,880	
15		Internal Load MWH				23,831,540	
16		**NEC Rate**					2.859
17				Environmental Accounts in EFC			
18						Internal Load	
19				2009 Amount	Allocation Factor	Allocated Amount	
20	509	Allowance Consumption Expense (All Sub Accounts)		$ 8,439,000	82%	$ 6,882,647	
21	411.8	Gain on Sale of Allowances		$ (376,000)	82%	$ (306,657)	
22	411.9	Losses on Sales of Allowances		$ -	82%	$ -	
23		Total		$ 8,063,000		$ 6,575,990	
24		Internal Load MWH				23,831,540	
25		**EFC Environmental Component**					0.028
26							
27	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC			
28						Internal Load	
29	Account	Description		2009 Amount	Allocation Factor	Allocated Amount	
30							
31	501	Fuel (Ash Handling)		$ 11,288,000	82%	$ 9,206,223	
32	501	Fuel - Procurement, Unloading & Handling		$ 13,981,000	82%	$ 11,402,589	
33	501	Fuel Handling - No Load (CV4)	(1)	$ -	82%	$ -	
34	501	Ash Sales Proceeds		$ (200,000)	82%	$ (163,115)	
35	501	Gypsum handling/disposal costs		$ -	82%	$ -	
36	507	Depr & Capacity portion-Affil (Lawrenceburg)	(1)	$ 33,401,000	100%	$ 33,401,000	
37	555	Purch Pwr-NonTrading-Nonassoc (Non-Fuel)	(3)	$ 18,304,820	33%	$ 6,027,447	
38	555	Pool Capacity	(1)	$ 33,831,000	100%	$ 33,831,000	
39	555	Purchased Power - Pool Energy (152 and 1/2 Maintenance)	(3)	$ 36,687,330	100%	$ 36,687,330	
40	555	Purchased Power - Pool Energy (MLR for OSS AR-14)	(3)	$ 166,523,670	0%	$ -	
41	555	PJM Emer.Energy Purch.		$ 18,000	82%	$ 14,680	
42	556	PurchPwr-O&M & Tax portion-Affiliate (Lawrenceburg)	(1)	$ 26,975,000	82%	$ 22,000,165	
43	557	Renewable Energy Credits		$ 919,600	100%	$ 919,600	
44	502	Emission Control Chemicals Sub-Accounts		$ 34,566,000	82%	$ 28,191,203	
45		Total		$ 376,295,420		$ 181,518,103	
46		Internal Load MWH				23,831,540	
47		**Additional FAC Components Rate**					0.762
48		**2009 FAC**					3.649
49							
50							
51	(1) Applies to only CSP						
52	(2) Not separately forecast						
53	(3) This account is divided into components to allocate separately						

COLUMBUS SOUTHER POWER COMPANY - NET ENERGY COST (NEC)
Allocators

Ln. No.	A	B	C	D	E
1	COLUMBUS SOUTHERN POWER COMPANY	1999			
2		NER	AEP	Ohio Dedic.	Non-Affil.
3	FUEL IDENTIFIED PORTION (A/C 151 FUEL BASIS)	All Sources	Sources	Sources	Sources
4		MWH	MWH	MWH	MWH
5	ACTUAL				
6					
7	1. OWN FOSSIL GENERATION	13,716,340	13,716,340		
8		-			
9	2. OTHER PURCHASES (CASH SETTLED):	-			
10	System Pool - Primary/Economy	4,402,666	4,402,666		
11	OVEC Surplus Purchase	249,409			249,409
12	AEP System - Cash Purchases	1,885,396			1,885,396
13	Interruptible Buy-Through/SDI	657			657
14	TOTAL	6,538,128	4,402,666		2,135,462
15					
16	3. IDENTIFIED SOURCES (1 + 2)	20,256,468	18,121,006		2,135,462
17					
18	4. OFF-SYSTEM ALLOCATION OF SOURCES:				
19	System Pool - Primary/Economy	28,170	28,170		
20	Allocated to AEP Deliveries (cash):	-			
21	OVEC Surplus Purchase	71,829			71,829
22	AEP System Cash Purchases	1,103,467			1,103,467
23	Own Generation	1,070,994	1,070,994		
24	Own Generation -- Coal Conversion	85,410	85,410		
25	Interruptible Buy-Through/SDI	5,620			5,620
26	TOTAL	2,365,490	1,184,574		1,180,916
27					
28	5. IDENTIFIED FOR NER (3 - 4) - Internal Load	17,890,978	16,936,432		954,546
29					
30	6. TOTAL (4 + 5)	20,256,468	18,121,006		2,135,462
31					
32	Percent Allocaters For Assigning non-NEC Costs (Line 28/30)		93%		45%
33					
34	A. FUEL IDENTIFIED FOR NER (LINE 5)	17,890,978			
35	B. NON-MONETARY INTER-COMPANY				
36	RECEIPTS/(DELIVERIES)	(4,626)			
37	C. FUEL IDENTIFIED FOR NER (A + B)	17,886,352			
38	D. OUT OF PERIOD ADJUSTMENT				
39	E. CONVENTIONAL HYDRO (P1, 1b)	-			
40	F. TOTAL SUPPLY FOR NER - Internal Load	17,886,352			
41					
42					
43					

44	A	B	C	D	E
45	COLUMBUS SOUTHERN POWER COMPANY	2009			
46		NER	AEP	Ohio Dedic.	Non-Affil.
47	FUEL IDENTIFIED PORTION (A/C 151 FUEL BASIS)	All Sources	Sources	Sources	Sources
48		MWH	MWH	MWH	MWH
49	ACTUAL				
50					
51	1. OWN FOSSIL GENERATION	16,076,590	16,076,590		
52					
53	2. OTHER PURCHASES (CASH SETTLED):				
54	System Pool - Primary/Economy	11,270,950	11,270,950		
55	OVEC Surplus Purchase	733,910			733,910
56	AEP System - Cash Purchases	1,448,560		1,206,009	242,551
57	TOTAL	13,453,420	11,270,950	1,206,009	976,461
58					
59	3. IDENTIFIED SOURCES (1 + 2)	29,530,010	27,347,540	1,206,009	976,461
60					
61	4. OFF-SYSTEM ALLOCATION OF SOURCES:				
62	System Pool - Primary/Economy				
63	Allocated to AEP Deliveries (cash):				
64	OVEC Surplus Purchase	483,660			483,660
65	AEP System Cash Purchases	171,270			171,270
66	Own Generation	5,043,540	5,043,540		
67	TOTAL	5,698,470	5,043,540	-	654,930
68					
69	5. IDENTIFIED FOR NER (3 - 4) - Internal Load	23,831,540	22,304,000	1,206,009	321,531
70					
71	6. TOTAL (4 + 5)	29,530,010	27,347,540	1,206,009	976,461
72					
73	Percent Allocaters For Assigning non-NEC Costs (Line 69/71)		82%	100%	33%
74					
75	A. FUEL IDENTIFIED FOR NER (LINE 5)	23,831,540			
76	B. NON-MONETARY INTER-COMPANY				
77	RECEIPTS/(DELIVERIES)	-			
78	C. FUEL IDENTIFIED FOR NER (A + B)	23,831,540			
79	D. OUT OF PERIOD ADJUSTMENT				
80	E. CONVENTIONAL HYDRO (P1, 1b)	-			
81	F. TOTAL SUPPLY FOR NER - Internal Load	23,831,540			

EXHIBIT PJN -4

OHIO POWER COMPANY
FAC BASE PERIOD

Line No.	A	B	C	D	E	F	G
1	**EFC Rate Per Transition Plan Case No. 99-1730-EL-ETP**		Notes				Cents/Kwh
2							
3		The Unbundled EFC Included:					
4		Account 151 Component of Account 501- Fuel	(3)				
5		Account 555 - Fuel					
6		Account 509 - Allowance Consumption Cost					
7		Account 411.8 Gains on Sales of Allowances					
8		Account 411.9 Losses on Sales of Allowances					
9		An RA component					
10		**Frozen EFC Rate**					1.343
11							
12	**Additional S.B. 221 FAC Accounts at 1999 Level**						
13							
14				Additional Fuel and Environmental Accounts in FAC			
15						Internal Load	
16	Account	Description		1999 Amount	Allocation Factor	Allocated Amount	
17							
18	501	Fuel (Ash Handling)		$ 3,909,802	75%	$ 2,943,671	
19	501	Fuel - Procurement, Unloading & Handling		$ 15,467,351	75%	$ 11,645,295	
20	501	Fuel Handling - No Load (CV4)	(1)	$ -	75%	$ -	
21	501	Ash Sales Proceeds	(4)	$ -	75%	$ -	
22	501	Gypsum handling/disposal costs	(4)	$ -	75%	$ -	
23	501	Gypsum Sales Proceeds	(4)	$ -	75%	$ -	
24	507	Depr & Capacity portion-Affil (Lawrenceburg)	(1),(2)	$ -	100%	$ -	
25	555	Purch Pwr-NonTrading-Nonassoc (Non-Fuel)		$ 25,918,236	IPS*	$ 8,928,721	
26	555	Pool Capacity		$ -	100%	$ -	
27	555	Purchased Power - Pool Energy (152 and 1/2 Maintenance)	(3)	$ 659,781	100%	$ 659,781	
28	555	Purchased Power - Pool Energy (MLR for OSS AR-14)	(3)	$ 14,908,626	0%	$ -	
29	555	PJM Emer.Energy Purch.	(2)	$ -	75%	$ -	
30	555	PurchPwr-O&M & Tax portion-Affiliate (Lawrenceburg)	(1),(2)	$ -	75%	$ -	
31	557	Renewable Energy Credits	(2)	$ -	100%	$ -	
32	502	Emission Control Chemicals Sub-Accounts	(4)	$ 23,341,016	75%	$ 17,573,341	
33		Total		$ 84,204,812		$ 41,750,810	
34		Internal Load MWH				37,149,684	
35		**Additional FAC Components Rate**					0.112
36		Subtotal					1.456
37		RSP Rate Adjustment - 7% per year for 3 years					0.327
38		**FAC presently in rates**					1.783
39							
40							
41	(1) Applies to only CSP						
42	(2) Item did not exist in 1999						
43	(3) This account is divided into components to allocate separately				*Interchange Power Statement		
44	(4) Item existed but this sub-account did not exist in 1999						

OHIO POWER COMPANY
FAC 2009 FORECAST

Line No.	A	B	C	D	E	F	G
1	**Fuel and Environmental Costs Included in Prior EFC & FAC**			Net Energy Cost (NEC) in EFC			
2					Assigned	Assigned	
3	Account	Description	Notes	Total	Off-System	To Firm Load	Cents/Kwh
4							
5	501	*Fuel Consumed*		$ 1,298,519,564	$ 599,872,071	$ 698,647,493	
6	501	Fuel Consumed - No Load (CV4)	(1)	$ -	$ -	$ -	
7	501	Fuel Survey Activity		$ -	$ -	$ -	
8	501	Fuel Oil Consumed		$ 32,078,216	$ 15,492,079	$ 16,586,137	
9	501	Natural Gas Consumed (Waterford)	(1)	$ -	$ -	$ -	
10	547	Fuel - Gas Turbine (Darby)	(1)	$ -	$ -	$ -	
11	555	Purch Pwr-NonTrading-Nonassoc (Fuel)	(3)	$ 202,950,010	$ 49,805,030	$ 153,144,980	
12	555	Purchased Power - Pool Energy (Fuel)	(3)	$ 3,380	$ -	$ 3,380	
13	555	Purch Power-Fuel Portion-Affil (Lawrenceburg)	(1)		$ -	$ -	
14		Total		$ 1,533,551,170	$ 665,169,180	$ 868,381,990	
15		Internal Load MWH				32,279,810	
16		**NEC Rate**					2.690
17				Environmental Accounts in EFC			
18						Firm Load	
19				2009 Amount	Allocation Factor	Allocated Amount	
20	509	*Allowance Consumption Expense (All Sub Accounts)*		$ 16,007,000	54%	$ 8,647,066	
21	411.8	Gain on Sale of Allowances		$ (25,821,000)	54%	$ (13,948,641)	
22	411.9	Losses on Sales of Allowances		$ 12,374,000	54%	$ 6,684,501	
23		Total		$ 2,560,000		$ 1,382,926	
24		Internal Load MWH				32,279,810	
25		**EFC Environmental Component**					0.004
26							
27	**Additional S.B. 221 FAC Accounts Forecast for 2009**			Additional Fuel and Environmental Accounts in FAC			
28						Firm Load	
29	Account	Description		2009 Amount	Allocation Factor	Allocated Amount	
30							
31	501	Fuel (Ash Handling)		$ 14,354,000	54%	$ 7,754,107	
32	501	Fuel - Procurement, Unloading & Handling		$ 32,013,000	54%	$ 17,293,593	
33	501	Fuel Handling - No Load (CV4)	(1)	$ -	54%	$ -	
34	501	Ash Sales Proceeds		$ (2,050,000)	54%	$ (1,107,421)	
35	501	Gypsum handling/disposal costs		$ 1,354,000	54%	$ 731,438	
36	507	Depr & Capacity portion-Affili (Lawrenceburg)	(1)	$ -	100%	$ -	
37	555	Purch Pwr-NonTrading-Nonassoc (Non-Fuel)	(3)	$ 57,303,250	33%	$ 19,051,979	
38	555	Pool Capacity	(1)	$ -	100%	$ -	
39	555	Purchased Power - Pool Energy (152 and 1/2 Maintenance)	(3)	$ 390	100%	$ 390	
40	555	Purchased Power - Pool Energy (MLR for OSS AR-14)	(3)	$ 163,998,230	0%	$ -	
41	555	PJM Emer.Energy Purch.		$ 21,000	54%	$ 11,344	
42	555	PurchPwr-O&M & Tax portion-Affiliate (Lawrenceburg)	(1)	$ -	54%	$ -	
43	557	Renewable Energy Credits		$ 1,170,400	100%	$ 1,170,400	
44	502	Emission Control Chemicals Sub-Accounts		$ 121,881,000	54%	$ 65,840,764	
45		Total		$ 390,045,270		$ 110,746,593	
46		Internal Load MWH				32,279,810	
47		**Additional FAC Components Rate**					0.343
48		**2009 FAC**					3.038
49							
50							
51	(1) Applies to only CSP						
52	(2) Not separately forecast						
53	(3) This account is divided into components to allocate separately						

EXHIBIT PJN -6

OHIO POWER COMPANY - NET ENERGY COST (NEC)
Allocators

Ln. No.	A	B	C	D	E
1	OHIO POWER COMPANY	1999			
2		NER	AEP	Ohio Dedic.	Non-Affil.
3	FUEL IDENTIFIED PORTION (A/C 151 FUEL BASIS)	All Sources	Sources	Sources	Sources
4		MWH	MWH	MWH	MWH
5	ACTUAL				
6					
7	1. OWN FOSSIL GENERATION	46,770,125	46,770,125		
8					
9	2. OTHER PURCHASES (CASH SETTLED):				
10	System Pool - Primary/Economy	431,093	431,093		
11	OVEC Surplus Purchase	925,101			925,101
12	AEP System - Cash Purchases	2,893,952			2,893,952
13	Interruptible Buy-Through/SDI	7,653			7,653
14	TOTAL	4,257,799	431,093		3,826,706
15					
16	3. IDENTIFIED SOURCES (1 + 2)	51,027,924	47,201,218		3,826,706
17					
18	4. OFF-SYSTEM ALLOCATION OF SOURCES:				
19	System Pool - Primary/Economy	7,922,627	7,922,627		
20	Allocated to AEP Deliveries (cash):	-			
21	OVEC Surplus Purchase	788,391			788,391
22	AEP System Cash Purchases	1,746,079			1,746,079
23	Own Generation	3,303,531	3,303,531		
24	Own Generation -- Coal Conversion	437,486	437,486		
25	Interruptible Buy-Through/SDI	19,601			19,601
26	TOTAL	14,217,715	11,663,644		2,554,071
27					
28	5. IDENTIFIED FOR NER (3 - 4) - Internal Load	36,810,209	35,537,574		1,272,635
29					
30	6. TOTAL (4 + 5)	51,027,924	47,201,218		3,826,706
31					
32	**Percent Allocaters For Assigning non-NEC Costs (Line 28/30)**		75%		33%
33					
34	A. FUEL IDENTIFIED FOR NER (LINE 5)	36,810,209			
35	B. NON-MONETARY INTER-COMPANY				
36	RECEIPTS/(DELIVERIES)	176,045			
37	C. FUEL IDENTIFIED FOR NER (A + B)	36,986,254			
38	D. OUT OF PERIOD ADJUSTMENT				
39	E. CONVENTIONAL HYDRO (P1, 1b)	163,430			
40	F. TOTAL SUPPLY FOR NER - Internal Load	37,149,684			
41					
42					

43	A	B	C	D	E
44	OHIO POWER COMPANY	2009			
45		NER	AEP	Ohio Dedic.	Non-Affil.
46	FUEL IDENTIFIED PORTION (A/C 151 FUEL BASIS)	All Sources	Sources	Sources	Sources
47		MWH	MWH		MWH
48	ACTUAL				
49					
50	1. OWN FOSSIL GENERATION	54,636,880	54,636,880		
51					
52	2. OTHER PURCHASES (CASH SETTLED):				
53	System Pool - Primary/Economy	180	180		
54	OVEC Surplus Purchase	2,566,920		-	2,566,920
55	AEP System - Cash Purchases	1,918,860		1,632,173	286,687
56	TOTAL	4,485,960	180	1,632,173	2,853,607
57					
58	3. IDENTIFIED SOURCES (1 + 2)	59,122,840	54,637,060	1,632,173	2,853,607
59					
60	4. OFF-SYSTEM ALLOCATION OF SOURCES:				
61	System Pool - Primary/Economy	19,366,290	19,366,290		
62	Allocated to AEP Deliveries (cash):				
63	OVEC Surplus Purchase	1,701,490			1,701,490
64	AEP System Cash Purchases	203,360			203,360
65	Own Generation	6,974,270	6,974,270		
66	Buckeye	(1,218,730)	(1,218,730)		
67	TOTAL	27,026,680	25,121,830	-	1,904,850
68					
69	5. IDENTIFIED FOR NER (3 - 4) - Internal Load	32,096,160	29,515,230	1,632,173	948,757
70					
71	6. TOTAL (4 + 5)	59,122,840	54,637,060	1,632,173	2,853,607
72					
73	**Percent Allocaters For Assigning non-NEC Costs (Line 69/71)**		54%	100%	33%
74					
75	A. FUEL IDENTIFIED FOR NER (LINE 5)	32,096,160			
76	B. NON-MONETARY INTER-COMPANY				
77	RECEIPTS/(DELIVERIES)	-			
78	C. FUEL IDENTIFIED FOR NER (A + B)	32,096,160			
79	D. OUT OF PERIOD ADJUSTMENT				
80	E. CONVENTIONAL HYDRO (P1, 1b)	183,650			
81	F. TOTAL SUPPLY FOR NER - Internal Load	32,279,810			

EXHIBIT PJN-7

OHIO POWER COMPANY
CALCULATION OF GAVIN CAP RECOVERY COMPONENT
OF OCTOBER 5, 1999 EFC RATE

OCTOBER 5, 1999 EFC RATE CENTS/KWH								1.45654
GAVIN CAP INCLUDED IN 1.45654 MILLS/KWH RATE								
	Dec-98	Jan-99	Feb-99	Mar-99	Apr-99	May-99	Total	
Capped Price (c/mBtu)	167.9	167.9	167.9	168.07	168.07	168.07		
Plant Consumption (tBtu)	16.8	16.9	15.2	16.9	16.3	15.9		
Capped Fuel Cost ($000)	$ 28,207	$ 28,375	$ 25,521	$ 28,404	$ 27,395	$ 26,723	$ 164,625	
GAVIN COST W/O CAP AND EXCLUDING I/S COSTS								
Gavin Price (From Pool Report)	27,814	27,067	23,932	26,269	25,118	24,421		
Investment/Shutdown Included	1,948	2,153	1,884	2,274	2,403	2,588		
Net Gavin to Compare w/Capped Price	$ 25,866	$ 24,914	$ 22,048	$ 23,995	$ 22,715	$ 21,833	$ 141,371	
Total Difference							$ 23,254	
Gavin Jurisdiction Factor							0.68	
EFC Jurisdictional Difference							$ 15,813	
EFC Jurisdictional Sales							13,888,500	
GAVIN CAP RECOVERY COMPONENT CENTS/KWH								$\boxed{0.11386}$
RESIDUAL EFC FUEL RATE CENTS/KWH								1.34268

EXHIBIT PJN-8

Environment Capital Carrying Cost

	$Millions			
	2001 Thru 2008	2009	2010	2011
OP				
Total Environmental Capital Additions - Cumulative	2,394	2,545	2,598	2,705
Capital Additions Identified in RSP and 4% Cases (Offset)	(1,494)	(1,494)	(1,494)	(1,494)
Incremental Environmental Capital Additions	900	1,051	1,104	1,211
Carrying Cost Rate 25 Year Property	13.98%	13.98%	13.98%	13.98%
Carrying Cost Before Pool Allocation	126	147	154	169
Pool Capacity Allocation Factor	71%	71%	71%	71%
Carrying Costs Internal Load	89	104	110	120
Jurisdictional Allocation Factor	94.2%	94.2%	94.2%	94.2%
Jurisdictional Revenue Requirement	84	98	103	113
Incremental YE		14	5	10
Incremental One-Half Year Convention		7	10	7

	$Millions			
	2001 Thru 2008	2009	2010	2011
CSP				
Total Environmental Capital Additions - Cumulative	563	631	673	732
Capital Additions Identified in RSP and 4% Cases (Offset)	(387)	(387)	(387)	(387)
Incremental Environmental Capital Additions	176	244	286	345
Carrying Cost Rate 25 Year Property	14.94%	14.94%	14.94%	14.94%
Carrying Cost Before Pool Allocation	26	36	43	52
Pool Capacity Allocation Factor	100%	100%	100%	100%
Carrying Costs Internal Load	26	36	43	52
Jurisdictional Allocation Factor	97.8%	97.8%	97.8%	97.8%
Jurisdictional Revenue Requirement	26	36	42	50
Incremental YE		10	6	9
Incremental One-Half Year Convention		5	8	7

EXHIBIT PJN-9

Environmental Expenditures Actual and Forecast
($000s)

	Major Project	Cumulative for 2008	Cumulative for 2009	Cumulative for 2010	Cumulative for 2011
CSP	Beckjord U6 FGD	-	3,035	14,088	26,142
	Conesville Unit 4 FGD	127,209	155,426	155,426	155,426
	Conesville Unit 4 SCR	40,216	47,548	47,548	47,548
	Conesville Unit 5 FGD	39,146	54,410	54,495	54,580
	Conesville Unit 5 SCR	0	0	1,613	14,068
	Conesville Unit 6 FGD	47,656	47,656	63,014	63,099
	Conesville Unit 6 SCR	0	0	1,613	14,068
	Stuart Units 1-4 FGD	183,369	183,369	183,369	183,369
	Stuart Units 1-4 SCR	38,278	38,278	38,278	38,278
	Zimmer Unit 1 SCR	33,168	33,168	33,168	33,168
	Associated SO2 Landfill	8,929	13,703	20,019	25,199
	Mercury	0	0	5,024	5,024
	NOx Assoc	11,629	11,629	11,629	11,697
	Other FGD	8,119	8,408	9,056	9,056
	Other Environmental	25,625	34,182	34,292	51,490
CSP Total		**$563,344**	**$630,812**	**$672,632**	**$732,212**
OPCo	Amos Unit 3 Precipitator and Ash Disposal	81,880	112,052	134,490	214,233
	Amos Unit 3 FGD	293,219	305,479	306,591	306,591
	Amos Unit 3 SCR	83,988	83,988	83,988	83,988
	Cardinal Unit 1 FGD	292,301	292,301	292,301	292,301
	Cardinal Unit 1 SCR	85,165	85,165	85,165	85,165
	Gavin Units 1 and 2 SCR	115,089	115,089	115,089	115,089
	Kammer Units 1-3 Fuel Switch	36,231	67,857	77,610	77,610
	Mitchell Unit 1 FGD	506,253	506,253	506,253	506,253
	Mitchell Unit 2 FGD	481,236	492,389	492,389	492,389
	Muskingum River Unit 5 SCR	86,963	86,963	86,963	86,963
	Associated SO2 Landfill	85,474	95,561	101,632	101,632
	Mercury	3,799	3,952	3,952	3,952
	NOx Assoc	33,236	36,571	37,299	37,687
	Other FGD	8,920	11,197	17,515	19,847
	Other SCR	30,516	33,303	34,417	39,898
	Other Environmental	169,660	217,343	222,737	241,687
OPCo Total		**$2,393,930**	**$2,545,463**	**$2,598,391**	**$2,705,285**
Grand Total		**$2,957,274**	**$3,176,275**	**$3,271,023**	**$3,437,497**

Columbus Southern Power
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2007

	Investment Life (Years)										
	5	7	8	10	15	20	25	30	33	40	50
Return (1)	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11
Depreciation (2)	17.96	12.12	10.31	7.81	4.59	3.07	2.23	1.71	1.48	1.12	0.81
FIT (3) (4)	1.56	2.67	2.59	1.49	1.79	1.86	1.64	1.50	1.44	1.34	1.24
Property Taxes, General & Admin Expenses	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95
	30.58	25.85	23.97	20.37	17.45	16.00	14.94	14.27	13.99	13.52	13.12

(1) See EXHIBIT PJN-11
(2) Sinking Fund annuity with R1 Dispersion of Retirements
(3) Assuming MACRS Tax Depreciation
(4) @ 35% Federal Income Tax Rate

Ohio Power
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2007

	Investment Life (Years)										
	5	7	8	10	15	20	25	30	33	40	50
Return (1)	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11
Depreciation (2)	17.96	12.12	10.31	7.81	4.59	3.08	2.23	1.71	1.48	1.12	0.81
FIT (3) (4)	1.56	2.67	2.59	1.49	1.79	1.86	1.64	1.50	1.44	1.34	1.24
Property Taxes, General & Admin Expenses	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
	29.63	24.89	23.01	19.41	16.49	15.04	13.98	13.31	13.03	12.56	12.16

(1) See EXHIBIT PJN-11

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 35% Federal Income Tax Rate

EXHIBIT PJN-11

Weighted Average Cost of Capital

Description	Capital Ratio	Cost of Capital	Weighted Average Cost of Capital
Columbus Southern			
Debt	50.0%	5.73%	2.86%
Equity	50.0%	10.50%	5.25%
Total	100.0%		8.11%
Ohio			
Debt	50.0%	5.71%	2.86%
Equity	50.0%	10.50%	5.25%
Total	100.0%		8.11%

EXHIBIT PJN-12

Capital Additions Identified in RSP and 4% Cases

2003 10-K Data As Provided in the RSP	2003 10-K 2004 - 2006	2007	2008	Total Thru RSP Period	2009	2010	2004 - 2010 Total
OPCO							
Section 1: Estimated Costs of NOx Compliance (NOX SIP CALL)	273	32	-	305	-	-	305
Section 2: Estimated Costs of SO2 Compliance (Title IV of CAA)	541	212	-	753	-	-	753
Section 3: Estimated Costs to Comply with Future Reduction Requirements	103	161	138	402	52	-	454
Total As Reported in 2003 10-K	917	405	138	1,460	52	-	1,512
CSP							
Section 1: Estimated Costs of NOx Compliance (NOX SIP CALL)	29	29	1	59	2	2	63
Section 2: Estimated Costs of SO2 Compliance (Title IV of CAA)	-	-	-	-	-	-	-
Section 3: Estimated Costs to Comply with Future Reduction Requirements	4	10	41	55	111	18	184
Total As Reported in 2003 10-K	33	39	42	114	113	20	247
TOTAL OHIO							
Section 1: Estimated Costs of NOx Compliance (NOX SIP CALL)	302	61	1	364	2	2	368
Section 2: Estimated Costs of SO2 Compliance (Title IV of CAA)	541	212	-	753	-	-	753
Section 3: Estimated Costs to Comply with Future Reduction Requirements	107	171	179	457	163	18	638
Total As Reported in 2003 10-K	950	444	180	1,574	165	20	1,759

BASELINE ENVIRONMENTAL	OPC	CSP	TOTAL
Total Original RSP 2004 - 2010 (See Test PJN Pg. 4, Case 07-63)	1,512	247	1,759
Less 2009 and 2010	(52)	(133)	(185)
Total Original RSP 2004 - 2008	1,460	114	1,574
Capital RSP 4% Case No, _____	34	273	307
Total Identified in RSP and 4% Cases at YE 2008	**1,494**	**387**	**1,881**

EXHIBIT PJN-13

FUEL AND ENVIRONMENTAL REDUCTIONS TO REQUESTED INCREASES
COMPARED TO REVENUE PRODUCED BY RSP 3% AND 7% INCREASES AND RSP 4 % CASES

	$millions		
	OPCO	CSP	Total
FUEL CREDIT FOR 3% & 7% VALUE			
Load	29,200	23,700	
3% and 7% RSP Adjustment to FAC Base Cents/kwh	0.323	0.201	
Revenue Requirement Value of RSP Adjustment to FAC	$ 94	$ 48	$ 142
ENVIRONMENTAL CAPITAL OFFSET CREDIT VALUE			
Environmental Carrying Cost Calculated w/o Any Offset	$ 224	$ 82	$ 306
Environmental Carrying Cost With Offset for RSP Estimates and 4% Case	$ 84	$ 26	$ 110
Revenue Requirement Value of Credit	$ 140	$ 56	$ 196
Total Value of RSP and RSP 4% Case Adjustment	$ 234	$ 104	$ 338
2008 REVENUE INCREASE FOR 3% AND 7% AND RSP 4% CASE			
RSP 3% & 7 % Increase Annual Revenue Produced in 2008	$ 190	$ 80	$ 270
Annual Revenue Produced by Settlement in 4% RSP Case No.07-1278	$ 5	$ 29	$ 34
Annual Revenue Produced by 3% and 7% and 4% Case	$ 195	$ 109	$ 304
Value of Company Credits in Excess of Revenue Produced	$ 39	$ (5)	$ 34