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BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	)	Case No. 99-1729-EL-ETP
In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues	)	Case No. 99-1730-EL-ETP

DIRECT TESTIMONY OF

DR. JOHN W. WILSON

ON BEHALF OF

SHELL ENERGY SERVICES COMPANY, L.L.C.

MAY 5, 2000

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I. QUALIFICATIONS AND INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 2715 "M" Street, N.W., Washington, D.C. 20007.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a B.S. degree with senior honors and a Masters Degree in Economics from the University of Wisconsin. I have also received a Ph.D. in Economics from Cornell University. My major fields of study were industrial organization and public regulation of business, and my doctoral dissertation was a study of utility pricing and regulation.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE THAT TIME?

A. After completing my graduate education I was an assistant professor of economics at the United States Military Academy, West Point, New York. In that capacity, I taught courses in both economics and government. While at West Point, I also served as an economic consultant to the Antitrust Division of the United States Department of Justice.

After leaving West Point, I was employed by the Federal Power Commission, first as a staff economist and then as Chief of FPC's Division of Economic Studies. In that capacity, I was involved in regulatory matters involving most phases of FPC regulation of electric utilities and the natural gas industry. Since 1973 I have been employed as an economic consultant by various clients including federal, state and local governments, private enterprise and nonprofit organizations. This work has pertained to a wide range of issues concerning public utility regulation, insurance rate regulation, antitrust matters and economic and financial analysis.

Q. WOULD YOU PLEASE DESCRIBE SOME OF YOUR ADDITIONAL PROFESSIONAL ACTIVITIES?

A. I have authored a variety of articles and monographs, including a number of studies dealing with utility regulation and economic policy. I have consulted on regulatory, financial and competitive market matters with the Federal Communications Commission, the National Academy of Sciences, the Ford Foundation, the National Regulatory Research Institute, the Electric Power Research Institute, the U.S. Department of Justice Antitrust Division, the Federal Trade Commission Bureau of Competition, the Commerce Department, the Department of the Interior, the Department of Energy, the Small Business Administration, the Department of Defense, the Tennessee Valley Authority, the Federal Energy Administration, and numerous state and provincial agencies and legislative bodies in the United States and Canada.

Previously, I was a member of the Economics Committee of the U.S. Water Resources Council, the FPC Coordinating Representative for the Task Force on Future Financial Requirements for the National Power Survey, the Advisory Committee to the National Association of Insurance Commissioners (NAIC) Task Force on Profitability and Investment Income, and the NAIC's Advisory Committee on Nuclear Risks.

In addition, I have testified on numerous occasions as an expert on financial, competitive and regulatory issues, and I have participated as a speaker, panelist, or moderator in many professional conferences and programs dealing with business regulation, financial issues, economic policy and antitrust matters. I am a member of the American Economic Association and an associate member of the American Bar Association and the ABA's Antitrust, Insurance and Regulatory Law Sections.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. My testimony in this case is presented on behalf of Shell Energy Service Company, L.L.C.

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

A. The purpose of my testimony is to respond to American Electric Power Company, Inc. ("AEP") filings in this matter on behalf of its subsidiaries, Columbus Southern Power Company ("CSP") and Ohio Power Company ("OPCO"). The primary focus of this analysis is on the residential and small commercial markets. It is my understanding that these are the markets in which Shell Energy Service Company intends to focus its electricity marketing efforts if, as a result of this restructuring proceeding, conditions in these markets are conducive to competitive entry. Of course, if so-called stranded cost burdens are excessive and if competitive shopping incentives are inadequate or operational support and corporate separation rules allow FE to discriminate in favor of its own or affiliated generation enterprises, this intended competitive entry will not occur. The topics that I will discuss deal primarily with (1) Transition Charges Rules, (2) Shopping Incentive Rules, (3) Operational Support Rules, and (4) Corporate Separation Plan.

The remainder of my direct testimony is organized under these respective topics. Because of time and resource limitations I have not had the opportunity to fully review and consider all aspects of the CSP and OPCO filings in this case. During the course of reviewing the objections of other intervenors and the Commission Staff Report, I did note numerous additional issues, that I do not address here, but where I believe I would be in agreement with the Staff and the objecting parties. My failure to address these issues should therefore be viewed as a time and resource limitation, and it should not be interpreted as acquiescence in, or concurrence with, those unaddressed aspects of the CSP and OPCO Transition Plan filings.

Q. **PLEASE SUMMARIZE YOUR KEY FINDINGS AND RECOMMENDATIONS.**

A. CSP and OPCO have very substantially overstated their so-called "stranded" or "above market" generation costs and, therefore, the appropriate level of transition charges. Hand-in-hand with this, the

Companies have also understated prospective competitive market prices as well as the shopping incentive that is necessary in order to cause a minimum of 20 percent of their loads in each class to switch to a competitive electric generation provider other than CSP and OPCO. My analysis shows that:

- CSP's and OPCO's total "stranded" or "above market" generation plant costs can be reasonably estimated to be negative by at least \$2.0 billion and possibly by as much as \$4.0 billion. In other words, rather than "stranded costs," CSP's and OPCO's generation assets embody very large "stranded benefits". This is in stark contrast to the \$500 - \$600 million of stranded costs as estimated by the Companies. The more likely negative stranded costs or "stranded benefits" should be used to eliminate other regulatory assets in the transition charge.

- As I will explain in detail below, my review and evaluation of the Companies' filings leads me to conclude that the \$500 - \$600 million stranded generation cost estimate is largely a diversion to distract attention from three related strategic corporate objectives. The first of these is to actually recover GTC amounts that are nearly double the Companies' own estimated stranded generation costs. The second is to attempt to preserve recovery of approximately $1 billion ($611 million for OPCO and $363 million for CSP) of so-called "regulatory assets and other transition costs" that are claimed in Part F of the filings. The third objective is to set the stage for a large corporate windfall by transferring OPCO's and CSP's generation assets to an unregulated environment at book value when, if fact, these assets are likely to be worth at least twice that amount.

- CSP and OPCO have proposed a shopping credit with a negative incentive – one which would inevitably result in higher total costs for switching customers and therefore act as a switching disincentive. In contrast to this disincentive, the Commission should establish a reasonable initial shopping credit of approximately $0.05 to $0.055/kwh (which includes a $0.007 incentive) for customers who choose to switch to competitive generation suppliers that are not affiliated with AEP. This shopping credit should include at least $0.035/kwh to cover the likely wholesale market rate (both demand and commodity costs) for firm electricity, plus $0.01/kwh to cover retailers' marketing, operating and customer service expenses, including profits and the various tariff items that competitive retailers will have to pay CSP and OPCO.

- An additional shopping incentive of at least $0.007 per kwh is required in order to reasonably expect that competition will cause a minimum of 20 percent of CSP's and OPCO's residential and small commercial class loads to switch to an alternative independent supplier by December 31, 2003.

- CSP's and OPCO's proposed Operational Support Rules should be significantly modified to remove provisions that would subject independent generation competitors to disadvantages and undermine the successful evolution of effective competition. These provisions include unreasonable restrictions on consumer switching, discriminatory customer service conditions and the imposition of unjustified burdens, charges and handicaps for competitive service providers.

- The Companies' proposed Corporate Separation Plans provide AEP and its corporate affiliates with undue advantages over competitive market rivals. Foremost among these is a proposal to effectively "transfer" generation assets to an unregulated entity at book value, which is well below the true economic or market value of these soon-to-be competitive assets. These separation plans also allow AEP to provide a number of competitive services through its regulated distribution utility business units and they provide for a variety of services and management to be shared by regulated and unregulated affiliates -- including accounting functions that are fundamental to potential cross subsidization issues.

II. TRANSITION CHARGES

Stranded Costs of Generating Plants [1]

Q. WHAT IS THE AMOUNT OF ABOVE-MARKET GENERATION COSTS THAT IS CLAIMED BY CSP AND OPCO IN THIS CASE?

[1] The discussion here reflects values that were claimed by the Companies in their original filing. More recently, the companies have filed certain supplemental testimony in which they increase their stranded cost claims. While I have not updated this analysis to reflect the Companies' revised claims, doing so would not change my conclusions and recommendations in any material way. The market value of CSP's and OPCO's generation assets exceed their book value by more than enough to eliminate the need for any type of transition charge.

A. CSP's and OPCO's claimed "above market" generation costs are summarized by Company witness Landon at page 44 of his direct testimony. In total, these amounts for AEP's Ohio operations range from $522 million to $656 million, depending on variations in gas price and environmental regulation assumptions. Broken down by Company, the Applicants' claimed above market or "stranded" generation plant costs are as follows:

	($millions)			
	CSP		**OPCO**	
	Base	Alternative	Base	Alternative
Net Gen. Plant Investment	974	974	1,309	1,309
Market Value of Gen. Plant	498	457	1,263	1,170
Stranded Costs	476	517	46	139

Q. **HOW DID CSP AND OPCO ARRIVE AT THESE ESTIMATED STRANDED GENERATION COST AMOUNTS?**

A. The Companies retained Analysis Group/Economics, an economic consulting firm, to perform discounted cash flow ("DCF") valuations of their generating plants. Although the Companies refer to these DCF valuations as "the lost revenue method", they are simply the calculation of the present value of projected free cash flows, which are the calculated annual differences between assumed costs of operating the Companies' steam generating plants and the projected revenues for electricity sales from those plants. Essentially, these DCF calculations project an estimated stream of expected revenues and costs for each Company's package of generating plants and then compute the present value of the difference between these projected revenues and costs. The present value of this projected revenue-cost difference is deemed to be the market value of each Companies' generation assets. Stranded costs are then defined as the difference between this estimated market value and the net investment value (or "book value") of the plants.

Q. DO YOU AGREE WITH THIS ESTIMATION APPROACH AND THE RESULTS THAT AEP OBTAINED FOR CSP AND OPCO?

A. While the DCF approach is an acceptable estimation method, it is inherently less accurate than divestiture. Any manipulation of the inputs used in the DCF calculations can suppress plant values and, thus, overstate the level of stranded costs.

Most market analysts would acknowledge that stranded costs can best be determined by comparing book value with the amount that the Company could obtain by selling its plants in a competitive market.[2] As David D. Marshall, the CEO of Duquesne Light Company, stated when his company recently auctioned off its generating plants:

> The results of the auction reinforce our belief that divesting generation was the fairest means by which to accomplish the transition to competition. The divestiture treats our company and its customers fairly by ensuring that we recover no less and no more than our actual stranded costs. It maximizes stranded cost mitigation by taking advantage of the currently favorable market conditions for plant sales. It realizes the benefits of our generation exchange with First Energy Corp., which has allowed us to auction an attractive portfolio of wholly-owned fossil plants. It increases competition by introducing a new generation company in the region and accelerating the onset of full retail competition in the Pittsburgh area (Duquesne Light Company, News Release, Pittsburgh, PA, September 27, 1999).

Many utilities around the country, including Duquesne, have done precisely that as a key part of their restructuring programs. Indeed, this is clearly the best way to restructure for competitive markets because it separates the ownership of potentially competitive generation from monopoly wire services. As such it removes the incentive for distribution/transmission

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2 Notably, AEP's expert witness, Dr. Landon, does not agree with this prevailing view. When asked:

> ...does Dr. Landon agree that asset divestiture is the most accurate method of determining the market value of generation costs?

He responded:

> Dr. Landon does not agree that divestiture is the most accurate method for determining the value of a generation asset that has been and continues to be used to serve customers. There may be positive and negative values for an asset that reflect alternative uses of the asset and that would affect its sale price. The value relevant for stranded cost analysis is the value of the electricity output based upon the current functioning of the generation asset and its projected functioning over the next few years. (See response to Shell-AEP-119, first set.)

monopolists to frustrate effective competition by favoring their affiliated generation businesses.

The second best competitive market alternative to generation divestiture, a system of behavioral rules designed to foster competition between utility affiliated generation enterprises and independent generators, is always a less certain road to competition because it retains all of the anticompetitive incentives of vertical integration and creates substantial policing and administrative burdens for regulators with all of the inherent imperfections and opportunities for anticompetitive gamesmanship that entails.

At any rate, while utilities in Ohio may elect to restructure by following the path of generation divestiture and true structural separation of monopoly and competitive services (and, in the process, accurately determining their stranded generation costs -- if any), Ohio law does not require them to do so. And if, like the AEP affiliates in this case, Ohio utilities elect to complicate (and, I would say, inhibit) the competitive restructuring process by retaining ownership of their generating plants, it is the Commission's obligation to find an alternative (and, unfortunately, less accurate) way of estimating stranded costs.

Q. HOW SHOULD THIS ESTIMATION PROCESS BE IMPLEMENTED?

A. In developing stranded cost estimates, the Commission should follow two principles. First, it should attempt to follow a procedure that estimates the best and highest price that the utility would obtain by selling its generating plants in a competitive market. Second, the Commission should resolve uncertainty in favor of the central objective of restructuring – that is, to foster the development of a competitive generation market to replace the current utility generation monopoly. In following this second principle, the Commission should be mindful that it is the utility's own choice to not divest which causes any ambiguity about the true level of stranded costs in the first place. By divesting generation, and thus laying the best possible foundation for the evolution of nondiscriminatory competition, the utility would accurately establish stranded costs. This, coupled with the fact that erring on the high side in making stranded cost estimates will cripple the ability of independent competitors (who have no opportunity to game a stranded cost subsidy), should lead the Commission to constrain stranded cost awards to the lowest level consistent with what may reasonably be expected to be the highest and best attainable price that the utility could obtain by competitive market divestiture.

In this regard, it is also highly likely that the strategic value of a utility's generation assets is greater when they are retained as part of a vertically integrated enterprise that combines the region's transmission/distribution monopolist together with the lion's share of all control area generation under coordinated ownership. In other words, actual stranded costs are likely to be less when the utility retains generation ownership (and the monopoly value that goes hand-in-hand with, say, an 80 percent generation market share within the same vertically integrated corporate family) than if these same assets are sold into a competitive market.

Given these circumstances, when there is uncertainty in estimating stranded costs, the benefit of the doubt should certainly not go to benefit the party that chose the second-best restructuring path and created such doubt in the first place – especially when doing so will cripple competition and imperil the whole point of restructuring.

<u>**Adjusted DCF Method**</u>

Q. HOW SHOULD THE COMMISSION ESTIMATE CSP'S AND OPCO'S GENERATION PLANT VALUES AND STRANDED COSTS?

A. One straightforward approach is to test the sensitivity of the Companies' own forecasts to reasonable changes in the underlying assumptions. I have done this and found that the valuation estimates exhibit substantial variability in response to changes in the underlying assumptions. Probably the most significant assumption in this regard is the expected market price of power. The Companies' valuation model assumes that there will be competitive generation markets in which prevailing prices simply reflect the optimal engineering marginal cost equilibrium. In the CSP and OPCO analysis the assumed firm power price, encompassing both energy and capacity charges, is only 2.35¢/kwh in 2000, rising to 2.43¢/kwh in 2003 and 3.55¢/kwh in 2015.[3] Not only is this price assumption very low, the annual rate of increase in the real price is negative over the first three years and less than one-third of one percent per year for 15 years, assuming a 2.5 percent annual rate of inflation. In my opinion, these competitive market price assumptions in the AEP control area, where AEP now owns and will not divest the majority of all generation resources, are exceedingly optimistic.

Q. **IS THERE NEW RECENT EVIDENCE INDICATING THAT COMPETITIVE PRICES ARE NOT LIKELY TO PREVAIL IN MARKET CONTROL AREAS WHERE, AS HERE, GENERATION RESOURCE OWNERSHIP IS HIGHLY CONCENTRATED?**

A. Yes, recent studies by the U.S. Department of Energy reach that conclusion. I have attached DOE's report on this matter as Exhibit JWW-1.

Q. **HAVE RECENT ECAR PRICE LEVELS BEEN SUBSTANTIALLY ABOVE THE ASSUMED PRICE LEVELS IN AEP'S ANALYSIS?**

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3 In the "high gas" scenario, the 2003 and 2015 values are 2.70¢/kwh and 3.86¢/kwh, respectively.

A. Yes. CSP's and OPCO's own purchased power costs in the wholesale market, as reflected in their FERC Form 1 reports, are much greater that these amounts. In 1998, CSP paid an average of 3.5¢/kwh and OPCO paid 3.3¢/kwh. Moreover, it does not appear that these much higher price conditions are likely to disappear nearly as soon as is assumed in the Companies' generation plant valuation model. According to McGraw-Hill Energy's March 20, 2000 edition of <u>Power Markets Week</u>, July-August, 2000 summer market contracts in ECAR's Into Cinergy market were at 16.2 cents/kwh, with the possibility of even higher price levels if AEP's Cook nuclear units are not returned to service as anticipated.

Q. **IS THIS UPWARD PRICE VOLATILITY A NEW PHENOMENON?**

A. No. As most industry observers are aware, the Midwest has been plagued by substantial price spikes for several summers. The most drastic of these occurred during 1998. During June of that year there were incidents where prices for wholesale power rose to levels that were *hundreds of times higher* than prices typically paid by buyers. The FERC studied and documented some of the price impacts and market conditions surrounding the price run-ups in its Staff Report. The FERC Staff Report found that a main cause of the price spikes was an imbalance between supply and demand. See Staff Report, p. vii and 2-1. According to the FERC Staff Report, while peak demand in the ECAR and MAIN regions increased by almost 6% from 1996 to 1998 (*Id.*), available generating capacity actually declined (*Id. at* 2-3):

> [d]ue to declining available resources in comparison to the rapidly growing demand, available capacity margins in ECAR and MAIN have dropped from 17 percent in 1996 to 11.9 percent in 1998. This decline places much greater reliance on resources from outside the region to meet regional loads (*Id.*, footnote omitted).

Q. ARE THERE SPECIAL PROBLEMS IN THE MIDWEST THAT INCREASE THIS REGION'S PRICE VULNERABILITY?

A. Yes. Nuclear generation problems in the Midwest have been a particular problem. This includes troubled nuclear units owned by Commonwealth Edison (Zion, LaSalle, Dresden and Quad Cities) and Illinois Power (Clinton), as well as AEP's Cook plant. While these utilities have recently made some significant efforts to improve the operation of their nuclear plants, it is reasonable to assume that a portion of this Midwest nuclear capacity is at risk.

According to the NERC's September 1998 Reliability Assessment for 1998-2007:

> Recent experience with nuclear unit availability in the Midwest and New England raises additional concern [regarding capacity adequacy]. Without evidence of improved or sustained reliable operation of nuclear units, it seems prudent to assume that operational capacity resource adequacy will continue to be impacted. Also, licensing or

> economic issues could possibly cause additional nuclear retirements in light of increasing competition in the generation sector. In the past two years, Connecticut and Maine Yankee nuclear units in New England (totaling 1,430 MW) and the Zion nuclear plant (two units totaling 2,080 MW) were retired before the end of their planned commercial life. Recently, plans to retire the Millstone 1 nuclear unit (641 MW) in Connecticut also was announced.

In addition to persistent generation capacity issues, together with AEP's dominant market share in its control area, there are also transmission constraints that contribute to the conclusion that optimal competitive market pricing results are unlikely in the near future. For example, there is the persistent shortage of transmission capability into eastern Wisconsin and Upper Michigan, a region known as the Wisconsin Upper Michigan System (WUMS). The inability to transfer power into WUMS eliminates WUMS as an effective source of supply into the Midwest at critical times because local loads must be served by WUMS capacity. Likewise, in another recent case, I examined the summer 1999 non-firm monthly ATC values for transfers from Central and Southwest ("CSW" – AEP's new affiliate) to AEP and found that CSW could transfer about 1850 MW into AEP through Ameren and through TVA. Such a CSW transfer could effectively foreclose other competitors in SPP and SERC from competing in the AEP market.[4] There has also been a voltage concern on the FirstEnergy system whereby up to 50% of the system load must be served by generation located in the FirstEnergy service territory. While these and other constraints change from year to year, such constraints are likely to impact potential regional power flows in this area for some years to come and thus undermine theoretical assumptions about the optimal prices that might prevail in smoothly functioning competitive markets.

Q. **DO CSP'S AND OPCO'S ESTIMATED PLANT VALUES DEPEND HEAVILY ON THE ASSUMPTION OF COMPETITIVE MARKET CONDITIONS?**

A. Yes. When asked to:

> Please explain how Mr. Kahn's estimation of wholesale energy prices, which is based on the short-run variable cost of the marginal unit dispatched in a hypothetical market, is affected by the fact that a highly competitive market structure does not yet exist in Ohio.

[4] CSW could use the Ameren-AEP corridor, which had an ATC of 1000 MW in the summer of 1999. It could also use the 800 MW ATC limit into the Associated Electric Cooperative (AEC) in two ways. About 300 MW could be scheduled from AEC to TVA and into AEP, with the 300 MW ATC on the AEC-TVA interface limiting the path. The other 500 MW could be scheduled along the AEC-Entergy-TVA-AEP path without reaching any ATC limits. There was also a 50 MW ATC from CSW to Entergy that could be scheduled with no ATC limit being reached. To mitigate certain market power concerns raised by their merger, AEP and CSW made several commitments, including (1) a limitation of their ability to contract for firm transmission capacity from AEP East to AEP West to 250 MW unless authorized to contract for more by the FERC; (2) waive their native load priority for transfers of energy from AEP West to AEP East for a four-year period following consummation of the merger; (3) schedule available capacity between ERCOT and SPP on the HVDC ties on a first-in-time basis; and (4) join a FERC-approved RTO transferring to the RTO functions related to transmission service, transmission security and reliability in control area responsibilities. (FERC Docket Nos. EC98-40-000, ER98-2786-000 and ER98-2770-000, Exhibit AEG-48)

the Companies responded merely that:

> Dr. Kahn has assumed a fully competitive market to assess the question of whether utilities can recover regulatory assets in the marketplace.

Q. TO WHAT EXTENT DO CSP'S AND OPCO'S ESTIMATED PLANT VALUES AND STRANDED COSTS CHANGE AS A RESULT OF CHANGING THE MARKET PRICE ASSUMPTIONS TO REFLECT ECAR MARKET PRICES IN THE 3.5¢ RANGE?

A. Making just this one change raises estimated plant values by more than $2 billion in the Companies' base environment scenario and produces an end result showing $1.5 billion of stranded benefits. These adjusted results are shown in Exhibit JWW-3, and they can be compared with the results in Exhibit JWW-2, which are replications of the Companies' base environment results as summarized in Exhibit JLH-2.

Q. ARE THERE OTHER CHANGES THAT SHOULD ALSO BE MADE TO THE COMPANIES' MODEL?

A. Yes. There are several errors that should be corrected and there are also several other assumption modifications that produce even larger "stranded benefits."

Q. WHAT ARE THE ERRORS THAT SHOULD BE CORRECTED?

A. I noticed at least two. First, there is a simple discounting error that improperly inflates stranded costs by about $50 million, and, second, cash flows are artificially reduced by $15 million to $25 million in each year by deducting office building and other non-production plant construction costs as an offset to generation plant revenues.

Q. WHAT IS THE DISCOUNTING ERROR IN THE COMPANY'S MODEL?

A. The Company discounts year 2001 revenues and costs by a full 12 months to obtain an estimated 1/01/01 present value. This procedure of discounting values that occur throughout the year by a full 12 months (as if they occurred at the end of the year) rather than by 6 months (so as to properly reflect the annual average discount) is repeated in every year, and it produces an excessively discounted end result. For example, if cash flow of $20 million that occurs over the course of a year is discounted at 10.78% (the discount rate used by the Company for CSP) for a full twelve months, the net present value at January 1 is $18.054 million. In contrast, if the $20 million is discounted correctly, using a half year convention (i.e., only dollars realized at the very end of the year should be discounted for a full twelve months, and dollars earned at the very beginning should not be discounted at all – to get to a beginning-of-year value), then the net present value is $19.002 million – a substantial difference.

Q. WHAT ARE THE OFFICE BUILDING AND OTHER NON-GENERATION PLANT CONSTRUCTION COSTS THAT CSP AND OPCO IMPROPERLY DEDUCTED FROM GENERATION REVENUES IN CALCULATING STRANDED GENERATION PLANT COSTS?

A. These were revealed on April 14 in the Companies' response to data request OCC, 9th Set, Q 112-RFPP, Attachment 1, page 1. They include the following by year:

($000)

CSP	2000	2001	2002	2003	2004
Chillicothe Bldg.	1861	1870	1675	1666	1905
Training Facility	3256	3273	3281	3268	3333
Delaware Bldg.	1437	1444	1448	1442	1471
Other Bldg. Repair	1100	1106	1108	1104	1126
	7654	7693	7712	7683	7836
OPCO					
Lima Bldg.	1930	1940	1945	1937	1976
Fostoria Bldg.	1000	1005	1008	1004	1024
Canton Office Bldg.	720	724	725	723	737
Coshocton Office Bldg.	575	578	579	577	589
McConnelsville Bldg.	415	417	418	417	425
Misc. Land Purchases	500	503	504	502	512
Other Bldg. Add. & Rep.	2942	2997	2954	2953	3012
Cook Coal Terminal	455	155	195	800	816
Windsor Coal Co.	2911	284	-----	------	------
Southern Ohio Coal Co.	6921	7711	-----	------	------
	18,369	15,273	8,338	8,013	9,090

Q. **IN ADDITION TO CORRECTING THESE ERRORS, ARE THERE OTHER VARIABLES IN THE COMPANIES' ANALYSIS WHICH, IF MODIFIED, PRODUCE EVEN LARGER STRANDED BENEFIT ESTIMATES?**

A. Yes. In addition to the low market price for electricity (and correcting for the erroneous discounting procedure and non-generation construction cost deductions), changes in other assumptions produce even larger stranded benefit estimates. For example, the Companies discount the projected earnings streams for CSP and OPCO generating plants using a 12.66 percent equity cost and a capital structure comprised of 60 percent equity and 40 percent debt. Adjusting these assumptions to reflect a 10.5% equity cost estimate and a capital structure that is 60 percent debt and 40 percent equity, increases stranded benefits by another $600 million.

Other possible DCF alterations that some analysts may make include (1) different expense assumptions, (2) a different generation plant capital improvement scenario, and (3) higher capacity factors for some plants (especially with higher electricity market price assumptions). As is acknowledged in the prepared direct testimony of the Companies' expert, Dr. Kahn:

> Historical data on fixed plant O&M costs have been unreliable predictors of future costs. They are likely to be

> even less reliable in the future since competitive markets will change how plants are utilized. Moreover, increases in efficiency and corresponding changes in fixed O&M will vary widely by plant and by operator (Prepared Direct Testimony of Edward P. Kahn, p. 20, ll. 15-19).

Q. **IS IT REASONABLE TO ASSUME A CAPITAL STRUCTURE COMPRISED OF 60 PERCENT DEBT AND 40 PERCENT EQUITY IN THIS MODEL?**

A. Yes. First, the ownership of these assets is going to be retained by AEP, either directly or by a subsidiary. At 12/31/98 AEP's consolidated capital structure was comprised of more than 60 percent debt and less than 40 percent equity. Second, the debt/equity ratio assumption for an unregulated generation company in AEP's own underlying documentation in this case is 60 percent debt and 40 percent equity (see response to OCC, 2nd Set, Q.48-RFPD Attachment, page 1 of 2).

Q. **PLEASE SUMMARIZE THE ASSUMPTIONS AND RESULTS THAT YOU SHOW IN EXHIBIT JWW-5.**

A. Exhibit JWW-5 shows that by making appropriate corrections and alternative assumptions in the DCF model, the valuation of AEP's Ohio generating plants (i.e., the CSP and OPCO plants) exceeds book value by more than $2.5 billion. This stranded benefit of more than $2.5 billion compares with more than $600 million in stranded costs that is suggested in the Companies' filing. The changes that I have made to the Companies' analysis in Exhibit JWW-5 include the following:

(1) Correct the discount procedure to reflect 1/1/01 rather than mid-year 2000 present values.

(2) Correct construction expenditures so as to remove the office building and other non-generating plant costs itemized above. I have removed the actual values reported for the period 2000-2004 and $8 million per year for CSP and $9 million per year for OPCO for the period 2005-2015.

(3) Assume a minimum 3.5¢ firm electricity wholesale market price. This price is adjusted in each year in accordance with (i.e., in proportion to) the Companies' own adjustment to prices presented on line 2 (but not used) in JLH-2.[5]

(4) Use a 10.5% equity cost rate and a 60/40 (debt/equity) ratio to develop an appropriate discount rate (8.51% for OPCO and 8.98% for CSP).

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[5] See prepared direct testimony of Laura J. Thomas at pages 17-18.

As shown in Exhibit JWW-5, these changes to the Companies' valuation analysis raise CSP's and OPCO's plant valuations to nearly $5 billion, in comparison with book value of less than $2.5 billion, thus producing estimated generation plant stranded benefits of more than $2.5 billion. This amount should be deducted from all other regulatory assets so as to properly eliminate any transition charge in this case.

Q. **BESIDES DENYING THE RECOVERY OF ANY ADDITIONAL GTC, IS IT APPROPRIATE TO CREDIT STRANDED GENERATION PLANT BENEFITS (I.E., THE EXTENT TO WHICH THE PLANTS' ECONOMIC VALUATION EXCEEDS THEIR BOOK VALUE) AGAINST ANY OTHER ACCUMULATED REGULATORY ASSETS?**

A. Yes. The failure to do so would mean that the risks and rewards for utility investors and customers were not symmetrically aligned. Even well known utility company advocates, who favor policies that require customers to assume the risk of decline in the value of prudently incurred investments are among the first to concede that this principle entitles customers to the gain when regulated assets rise in value. For example, Dr. Alfred E. Kahn, who testified in behalf of "the regulatory compact" back when that concept was first invented in the mid-1980s, has written more recently:

> ...to the extent the unregulated operations make use of facilities the costs of which have been recovered by depreciation charges to purchasers of the regulated services –

> or, more generally, that the companies realize capital gains by selling for more than net book value assets that have been included in rate base – there is a sense in which that differential really "belongs" to the purchasers of the regulated services, so long as their commissions have operated consistently on an original cost or prudent investment basis for determining allowable revenues. <u>This proposition is the corollary of the entitlement of the utility companies to recovery of their stranded costs.</u>[6] (Emphasis added.)

Q. PLEASE SUMMARIZE THE ASSUMPTION CHANGES AND STRANDED COST RESULTS THAT ARE SHOWN IN EXHIBITS JWW-2 THROUGH JWW-5.

A. The assumption changes and stranded cost (benefit) results modeled in Exhibits JWW-2 through JWW-5 are as follows:

Exhibit No.	Assumption Changes	Total Plant Value $ Bil		Stranded Cost (Benefit) $ Bil	
		CSP	OPCO	CSP	OPCO
JWW-2	None	$0.457	$1.170	$0.518	$0.139
JWW-3	• Raise Electricity Price to 3.5¢/kwh	$1.003	$2.838	$(0.029)	$(1.529)
JWW-4	• Correct Discount to Mid Year • Remove Non-Generation Construction • Raise Electricity Price to 3.5¢/kwh	$1.113	$3.055	$(0.139)	$(1.745)

6 Alfred E. Kahn, *Letting Go: Deregulating the Process of Deregulation or: Temptation of the Kleptocrats and the Political Economy of Regulatory Disingenuousness,* (MSU Public Utilities Papers, 1998), pp. 83-84.

Exhibit No.	Assumption Changes	Total Plant Value $ Bil		Stranded Cost (Benefit) $ Bil	
JWW-5	• Correct Discount to Mid Year • Remove Non-Generation Construction • Raise Electricity Price to 3.5¢/kwh • Reduce Eq. Cost to 10.5% • Use 60/40 Debt/Eq. Ratio	$1.289	$3.503	$(0.315)	$(2.193)

Q. DOES THIS ANALYSIS PROVE THAT THE COMPANIES' STRANDED COST ANALYSIS IS WRONG?

A. Only in part. It also shows that alternative views about the future will produce substantially different valuations. That is precisely why utilities that actually divest their generating plants sell them to the highest bidder. In that way, plant market value (and stranded costs) are determined by the most optimistic assumptions about the future rather than by what may be the modest assumptions of one analyst.

As to the Companies' assumptions, surely their electricity market price assumptions are lower than can reasonably be expected (especially in the early years of market development) in view of actual ECAR prices and AEP's dominant market share (and resulting competitive market limitations) that can be expected to prevail without divestiture. To the extent that AEP's electricity price assumptions are low, it follows that their plant utilization assumptions (i.e., capacity factors) and net revenue forecasts are also likely to be low.

Also, independent power producers who acquire existing generating plants from regulated utilities often recognize that there are ways to cut operating costs, raise efficiency levels and alter capital expenditure plans in ways that improve plant value. All of these and other considerations are likely to be relevant to some potential competitive bidders who would be likely to produce market valuations for CSP's and OPCO's generating plants that exceed those flowing from the Companies' operating and market assumptions.

Q. **HAS AEP ACKNOWLEDGED THAT IT MAY BE POSSIBLE FOR COMPETITIVE SERVICE PROVIDERS WHO ACQUIRE GENERATING PLANTS TO FIND WAYS THAT IMPROVE PLANT VALUE IN COMPETITIVE MARKETS?**

A. Yes. In response to the question:

> In what ways will competitive markets change how plants are utilized?

the Company responded:

> Owners' incentives will change in a competitive marketplace. Consequently this will change their behavior. Some plants

> are expected to be utilized more, some less (Response to Shell-AEP-84, first set).

Likewise, Dr. Kahn has testified:

> ...competitive markets will change how plants are utilized. Moreover, increases in efficiency and corresponding changes in fixed O&M will vary widely by plant and by operator (Direct Testimony of Edward P. Kahn, p. 20, ll. 17-19).

Q. **ARE THERE OTHER ASSUMPTION ADJUSTMENTS THAT MIGHT BE MADE?**

A. Yes. While I have not assembled a full list of assumption alternatives, in addition to variations in the assumptions discussed above, some bidders for divested generating plants may have tax considerations that permit them to value plants on a basis other than the full maximum statutory income tax rates used by AEP, and they may have longer plant life expectancies (or be able to alter plants or their own operations to achieve greater output over longer lives), or they may have inflation assumptions that exceed the relatively modest 2.5 percent annual rate used by CSP and OPCO. Analytical changes like these would produce even higher valuation estimates.

Q. **THE VALUATION ESTIMATES SUGGESTED BY YOUR DCF ALTERATIONS PRESENTED IN EXHIBIT JWW-5 IMPLY MARKET VALUES FOR CSP'S AND OPCO'S FOSSIL PLANTS**

AVERAGING UP TO $412 PER KW. IS THIS AMOUNT REALISTIC IN VIEW OF ACTUAL MARKET TRANSACTIONS?

A. Yes. Other utility companies in nearby regions, such as Duquesne (which like CSP and OPCO is in ECAR) and Commonwealth Edison, recently sold large packages of their fossil generating capacity at prices averaging $652/kw and $750/kw, respectively. If CSP and OPCO generating capacity were valued in the same range as these other comparable recent sales, the Company's estimated generation "stranded benefits" would exceed $5.0 billion.

<u>Regression Method</u>

Q. **IS THERE ADDITIONAL ACTUAL MARKET EVIDENCE INDICATING THAT THE TRUE VALUE OF CSP'S AND OPCO'S GENERATING PLANTS IS MUCH GREATER AND THAT THE STRANDED BENEFIT OFFSET TO TRANSITION COSTS IS ALSO CORRESPONDINGLY GREATER THAN IS SUGGESTED BY THE COMPANIES' FILING?**

A. Yes. RDI, the Commission Staff's valuation consultant in the FirstEnergy case, developed a regression model, based on recent utility generation asset sales, that can be used to estimate the likely market value of CSP's and OPCO's fossil generation capacity. I have reviewed and replicated RDI's regression results and have found that they support the conclusion that CSP's and OPCO's DCF analysis substantially understates plant value and greatly overstates stranded costs.

My regression results, based on RDI's data, are shown in Exhibit JWW-6. For comparative convenience, I have numbered these models as RDI did in its draft Report in the FirstEnergy case. While I have replicated RDI Model 1, I concur in their view that it exhibits too much colinearity to be reliable, and I have therefore not included it in Exhibit JWW-6.

Applying the models in Exhibit JWW-6 to CSP's and OPCO's generation resource packages, I obtain the following estimated market valuations for their fossil fuel plants:

Model No.	CSP Value	OPCO Value
2	$465/kw	$513 - 632/kw
3	$633/kw	$662 - 781/kw
4	$644/kw	$673 - 792/kw

The calculation of these results is shown in Exhibit JWW-7. Using an average estimated value of $600 per kw for AEP's steam generating plants, the resulting market value estimate for Ohio capacity (CSP plus OPCO) is $6.971 billion.[7]

[7] 11,619 MW x $600/kw = $6,971,400,000

This amount compares with CSP's and OPCO's combined book value of $2.283 billion, implying stranded benefits for generation capacity of more than $4.5 billion rather than the Applicant's claim of a $500 million to $600 million stranded cost.

Q. WHAT EXPLAINS THIS VERY LARGE DIFFERENCE IN ESTIMATED MARKET VALUE?

A. AEP has valued its steam generating plants at very low levels, ranging from $133 to $174 per kw of nameplate capacity as follows:

	Base Case	Alternative Case
CSP	159.70/kw	174.00/kw
OPCO	133.58/kw	144.25/kw

These estimated valuations are substantially below the amounts that other Midwest utilities have actually realized from the sale of their generation capacity. For example, Commonwealth Edison recently sold 8,757 MW of its bundled steam generation capacity for $750/kw and Duquesne Light (which, like CSP and OPCO, is in ECAR) sold its steam generation assets for an average price of $652 per kw.

In other words, even if the $600+/kw valuation suggested by these recent comparable asset sales and corroborated by the results of the regression analysis reported here were deemed to be on the high side of market expectations, a much lower generation asset valuation in the range of $400/kw would still produce a stranded benefit result of $2.4 billion instead of $500 million to $600 million of stranded costs.

Q. IN EXHIBIT JWW-6, WHY DO YOU SHOW A RANGE OF VALUES FOR OPCO'S STEAM GENERATING PLANTS INSTEAD OF A SINGLE AVERAGE VALUE?

A. The RDI regression model that I used to calculate these estimates properly recognizes that larger packages of generation assets in a region generally command a premium price. Thus, the estimated value of OPCO's steam generation resources varies depending on whether or not they are valued as a single package. In my opinion, the higher estimates presented in Exhibit JWW-6, which values OPCO's steam generation assets as a single package, is the proper one to use in this case. That is so because the Company intends to retain its unified ownership of this entire package. Even so, I recognize that if a sale were to take place, it would be in the public interest to break up this highly concentrated package, even though that would reduce the monopoly premium value that the assets could command as a single package. Because AEP intends to retain the entire CSP and OPCO generation packages, it is appropriate here to value them so as to reflect the market value (including the market premium) that they command as a package. In fact, by breaking AEP's steam generation into two packages

(OPCO and CSP), as I have done here, the market value tends to be understated in relation to the single package's true value to AEP, which would imply even higher generation plant stranded benefits.

Q. ARE THERE ADDITIONAL CONSIDERATIONS WHICH INDICATE THAT AEP HAS UNDERESTIMATED ITS GENERATION PLANT VALUES?

A. Yes. The Company's valuation model assumes that there is no residual economic value associated with these generating plants after the end of their economic life. The only excuses offered for this omission were that:

- It is impossible to determine, with any degree of accuracy, what the salvage value and/or the value of plant sites for each generating unit will be in year 2030.
- Whatever salvage value the plants do have in 2030, after discounting, will have a negligible impact on the present value of the total cash flows (See Response to Question #142, Shell Energy Services, Co., L.L.C. Interrogatories and Requests for Production of Documents, First Set).

In my opinion, this glosses over a significant omission that is likely to be worth at least $10 million or more, and it is logically inconsistent with the Companies' willingness to base other transition cost estimates on highly speculative assumptions. Salvage value and plant site values should be incorporated into the analysis. Without these values, the plant values are underestimated and transition costs are further overestimated.

Q. YOU STATED EARLIER THAT IN YOUR OPINION CSP'S AND OPCO'S STRANDED GENERATION PLANT COST STUDIES WERE LARGELY A DIVERSION FROM THE COMPANIES' REAL STRATEGIC OBJECTIVES IN THIS CASE WHICH ARE: (1) TO RECOVER EVEN LARGER AMOUNTS THAN THESE STUDIES INDICATE, (2) TO PRESERVE RECOVERY OF OTHER TRANSITION CHARGE AMOUNTS, AND (3) TO SET THE STAGE FOR A GENERATION ASSET TRANSFER AT BOOK VALUE TO AN UNREGULATED ENVIRONMENT. PLEASE EXPLAIN THOSE CONCLUSIONS.

A. The stated net book value (at 12/31/00) of AEP's generation assets at issue in this case is $2.148 billion,[8] or $185/kw. While there are likely to be reasonable differences in what various parties may believe AEP's generation assets are really worth (an issue that would be accurately resolved only through divestiture), it seems virtually certain that the

[8] See Exhibit No. ___ JHL-2, line 39.

valuations proposed in the Companies' stranded generation plant cost studies (CSP = $160 to $175/kw, and OPCO = $133 to $144/kw) are substantial understatements. That notwithstanding, the Companies are actually proposing to recover GTC amounts that are much larger than (nearly double) the stranded cost amounts implied in their own stranded cost studies.

The proposed Transition Charge Riders set forth in proposed tariff Sheets No. 68-1D for CSP and OPCO, which are purportedly to recover stranded generation plant costs, entirely bypass Dr. Landon's elaborate valuation modeling effort. Instead, they reflect the simple differences between the generation components of the Companies' proposed rates (excluding claimed regulatory assets) and Dr. Kahn's projected market price of generation (as adjusted by Ms. Thomas for loss factors, load factors and time-of-use characteristics in order to create an annual average market price for each customer class).[9] In other words, rather than being derived from Dr. Landon's modeling, the proposed transition charge for each Company was calculated as the simple difference between each Companies' weighted annual average projected market price and its unbundled generation revenue, excluding regulatory assets. These amounts, as set forth in

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[9] Dr. Kahn's projected market price of generation was a provided input to Dr. Landon's analysis (i.e., line 2 of Exhibit No. ___ JHL-2) as was Ms. Thomas' adjusted revenue amount (i.e., line 3 of Exhibit No. ___ JHL-2).

proposed tariff Sheets No. 68-1D, average $0.0124402 for CSP and $0.0021311 for OPCO.[10]

Applying these proposed tariff amounts to the Companies' average annual loss adjusted generation (i.e., metered energy) for the period 2001-2005 produces annual GTC revenues of $192.65 million for CSP and $98.78 million for OPCO:[11]

(16,462 GWH/1.063) x $0.01244 = $192.65 million

(49,345 GWH/1.064) x $0.00213 = $98.78 million.

Over the five-year period, 2001-2005, the present value (at 1/1/01) of this income stream (using AEP's proposed discount rates[12]) is $1.142 billion, which is nearly double the total stranded cost estimates developed by Dr. Landon. In short, other than "window dressing," Dr. Landon's elaborate valuation modeling effort is superfluous to this case, as the values that he derives are not fundamental to any aspect of the Companies' transition plans.

Q. **WHAT EXPLAINS THE FACT THAT THE PROPOSED GTC RECOVERY, AS REFLECTED ON PROPOSED TARIFF SHEETS**

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10 See David Roush, WP-Part A, page 1 of 45 for OPCO and page 1 of 31 for CSP.

11 Estimated loss adjustment factors were 6.3% for CSP and 6.4% for OPCO, as reflected at pages 3-9 of Roush WP-Part A for CSP and pages 3-11 of Roush WP-Part A for OPCO.

12 These discount rates are 10.78% and 10.47% for CSP and OPCO, respectively. Using the lower discount rates proposed in Exhibit JWW-5 would produce a higher present value.

NO. 68-1D, EXCEEDS EVEN THE EXCESSIVE STRANDED GENERATION PLANT VALUES COMPUTED BY DR. LANDON?

A. Quite simply, it is that the GTC estimation approach adopted by Mr. Forrester effectively builds into stranded costs substantial amounts that AEP projects to incur <u>after</u> 1/1/01. These projected costs do not yet exist and are entirely avoidable. If permitted, this strategy would serve to unduly cripple competition for the entire transition period (2001 – 2005) by continuing to subsidize AEP's retained generation business on a going-forward basis throughout those five years.

Q. PLEASE EXPLAIN.

A. Mr. Forrester's proposal is to institute a stranded cost recovery approach that establishes a GTC in each year equal to the difference between the Companies' unbundled generation cost levels (<u>as estimated in rate cases years ago</u>) and projected competitive market prices. These historic benchmark generation cost levels reflect no efficiency gains since the rate cases in which they were established. Very large claimed merger efficiency gains are excluded as well as any expected cost reductions resulting from new competitive pressures. Mr. Forrester's approach simply extrapolates old rate case generation costs into the transition period and those become the base for calculating a GTC equal to the difference between AEP's historic cost levels and projected competitive market prices. This effectively subsidizes excess costs that AEP might incur after 1/1/01 (if historic inefficiencies are retained), but which are now entirely avoidable.

Q. HOW CAN AEP AVOID THESE COSTS?

A. Either by operating more efficiently than they did during the historic period that was the rate case foundation for the generation cost of service underlying present rates, or by divesting their generation at its true market value. So long as AEP's generating plants have a market value equal to or greater than their net book value at 1/1/01 (about $185/kw) there should be no GTC. To, nevertheless, project a GTC into the future, as Mr. Forrester does, reflecting the difference between AEP's historic generating costs and projected competitive market prices, allows CSP and OPCO compensation for creating new (and avoidable) stranded costs after 1/1/01. Perpetuating this subsidization for costs to be incurred after 1/1/01 would, of course, be a catastrophic blow to the emergence of competition throughout the entire transition period.

Q. DOES AEP BELIEVE THAT IT IS ENTITLED TO A GTC THAT RECOVERS FUTURE COSTS THAT ARE NOW AVOIDABLE BUT MIGHT BE INCURRED AND BECOME STRANDED IN THE FUTURE?

A. Apparently so. That is certainly what Mr. Forrester's proposed GTC mechanism will do. Moreover, as the Company has stated:

> For purposes of estimating and recovering stranded costs, AEP-Ohio should seek only those costs that will, or are likely to, become unrecoverable in a competitive market-place. This does not mean, however, that AEP-Ohio is obligated to restructure its operations or transform its way of conducting business without regard for other changes solely to lower its expected stranded investments and, thus, reduce stranded cost estimates. AEP-Ohio is entitled to recover all such costs that it would have recovered under regulation as a going concern. (See response to Shell-AEP-96, first set.)

I disagree. After 1/1/01, AEP is obliged to transform its way of conducting the generation business or suffer the consequences of additional stranded costs. CSP and OPCO are not entitled to recover costs incurred after that time that may have been recoverable by a regulated concern that did not face competition.

Q. **HAVE THE COMPANIES MADE IT CLEAR THAT THEY DO NOT INTEND TO RECOGNIZE EFFICIENCY GAINS SINCE THEIR LAST RATE CASES IN ASSESSING STRANDED COSTS FOR FUTURE OPERATIONS?**

A. Yes. First, on its face, Mr. Forrester's proposed approach makes no such accommodations. Second, in response to the question:

> What is the most recent estimate of savings associated with the merger of AEP and Central and South West Corporation

(CSW) on a total company basis and on a jurisdictional basis for CSP and OPCO individually?

the Companies responded:

The information requested is neither relevant nor reasonably calculated to lead to discovery of admissible evidence. (See response to OCC Question #350, ninth set.)

Contrary to this response, the information requested, quite obviously, goes directly to the core of how Mr. Forrester's proposed GTC approach (which assesses future stranded costs, calculated as the difference between future market prices and historic rate case costs – as measured prior to any merger or competition-induced savings) overstates actual stranded costs.

Q. IS DR. LANDON'S VALUATION ANALYSIS RELIED UPON IN ANY WAY IN THE COMPANIES' FILINGS?

A. Yes. In defending the Companies' proposed stranded generation-related regulatory asset amounts (which are summarized on page 3 of Part F, § (B)(1)(a) of each Company's filing and whose tariff amounts are set forth in proposed tariff Sheet No. 67-1D), Mr. Forrester concludes that "based upon Company witness Landon's testimony regarding stranded costs, it is clear that it is highly unlikely that either CSP or OPCO would be able to recover any of those regulatory assets in a competitive market" (prepared direct testimony of William R. Forrester, p. 8). Thus, to the extent that Dr. Landon's generation asset valuations are too low and (as is strongly indicated above) the correct plant values imply negative stranded costs or stranded benefits, the Companies' proposed generation-related regulatory assets (Part F, § (B)(1)(a), page 3) can be recovered in a deregulated generation market. In that case, the Commission should not approve either the proposed Transition Charge Rider (proposed tariff Sheet No. 68-1D) or the proposed Regulatory Asset Charge Rider (proposed tariff Sheet No. 67-1D).

Q. ASSUMING THAT A PROPER GENERATION ASSET VALUATION REVEALS THAT AEP'S PLANTS ARE WORTH MORE THAN THEIR NET BOOK VALUE AND THAT SUSTAINABLE MARKET PRICES WILL RECOVER MORE THAN UNBUNDLED GENERATION REVENUE, EXCLUDING REGULATORY ASSETS, DO THE COMPANIES' AGREE THAT CLAIMED REGULATORY ASSET AMOUNTS SHOULD BE OFFSET BY THIS EXCESS?

A. No. Perhaps anticipating this result, Dr. Landon was asked:

> Q. Do you believe that if a utility has stranded benefits they should be used as an offset to regulatory assets in the transition charge?

His answer was:

> A. No, I do not. If the state chooses to change its regulatory relationship with utilities, it should not have a claim on market values in excess of book values.... (See prepared direct testimony of John H. Landon, p. 22.)

This answer, of course, ignores the fundamental issue as to whether claimed transition charges reflect legitimate costs that are not recoverable under competition. If, as appears to be the case here, attainable market revenues will be more than sufficient to fully recover net plant costs, at least to that extent, transition costs and regulatory assets are recoverable without tariff riders or surcharges.

Dr. Landon's answer is also logically inconsistent with his later reasoning:

> To the extent that the utility will face market prices that will be lower than its production costs, its investments will diminish in value and shareholders must be compensated for it. However, if there are certain advantages that the utility enjoys which will enable its production costs to be below market, then any such gains should offset the compensation for stranded generation costs. The economic and equity justification for such netting or offsets are essentially the same. (See Dr. Landon's response to Question #48, OCC, First Set.)

Q. TO WHAT EXTENT SHOULD THE COMMISSION OFFSET THE COMPANIES PROPOSED REGULATORY ASSET CHARGE RIDER?

A. In my opinion it should be completely offset. As shown in Part F, § (B)(1)(a) of the CSP and OPCO filings, the Companies' combined projected regulatory assets and other transition costs total less than $1 billion ($610 million for OPCO and $363 million for CSP). Moreover, two-thirds of this total is for claimed transition costs that the Commission has not yet recognized or approved as a regulatory asset. Since the present value of reasonably expected cash flows from the Companies' generation assets (i.e., their market value) exceed their net book value by at least $2 billion, there is no need for any separate regulatory asset charge at all.

Q. ARE THERE ADDITIONAL REASONS WHY THE COMMISSION SHOULD BE CONCERNED ABOUT THE EXTENT TO WHICH AEP'S OHIO STRANDED BENEFITS EXCEED STRANDED COSTS?

A. Yes. This situation creates a strong economic incentive for AEP to attempt to capture the difference as a private windfall. One way in which this could occur would be for AEP to reorganize in a way that separates distribution and transmission into a regulated company and transfer generation at book value to an unregulated enterprise. This strategy could be undertaken in two separately staged steps. This scenario may be along the lines of what

Mr. Forrester had in mind in describing Exhibit No. ___ WRF-2, his schematic of AEP's Corporate Separation Plan:

> AEP may also create a competitive retail electric supply (CRS) affiliate shown on this exhibit as AEP Competitive Retail Energy Co. The black and white single-hatched line on this exhibit shows the separation between the electric utility (i.e., the wires companies) and the unregulated generation and competitive retail electric supply affiliate (prepared direct testimony of William R. Forrester, p. 21).

Q. **IS DR. LANDON CORRECT IN ARGUING THAT OVERSTATING STRANDED COSTS WOULD NOT PROVIDE AEP WITH A COMPETITIVE ADVANTAGE?**

A. No. Dr. Landon argues:

> ...overstating stranded costs does not provide a competitive advantage to an incumbent. Recovering estimated stranded costs that turn out to exceed actual costs would not make an incumbent a better competitor. (Response to Question #104, Shell Energy Services CO., L.L.C., Interrogatories and Requests for Production of Documents, First Set).

It may be true that allowing for the recovery of overstated stranded costs will not make CSP and OPCO more efficient, lower cost or better quality service providers (as would be likely to occur under the prodding of competition). But, allowing excessive stranded cost charges, which, in turn, reduce shopping credits and squeeze or eliminate competitive vendor margins, will surely impair competitive entry and survival, and serve to entrench AEP's already dominant market position.

III. SHOPPING INCENTIVE

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S SHOPPING INCENTIVE RULES?

A. Yes. The Commission's shopping incentive rules provide the requirements under which each electric utility must propose an adequate shopping incentive as part of its transition plan. In accordance with Chapter 4901:1-20-03, Ohio Administrative Code, the shopping incentive in each utility's Electric Transition Plan "must be sufficient to cause customers representing at least twenty percent of the load of each customer class to switch generation suppliers to someone other than the incumbent utility by the midpoint of the utility's market development period but no later than December 31, 2003."

The CSP and OPCO Proposal

Q. DO CSP AND OPCO PROPOSE SUCH SHOPPING INCENTIVES IN THIS CASE?

A. No. The Companies propose no shopping incentives. Instead, they argue that transition charges should be established at a level that permits them to profitably sell generated electricity to customers at a price equal to a projected short run marginal cost of production. They further argue that shopping credits should be established at the lower of this projected marginal cost level or the unbundled generation rate of the current tariff. As I have shown above, this level appears to be well below reasonably anticipated generation prices in this market, and it is certainly much too low to attract competitive entry. In effect, CSP and OPCO propose that any "shopping incentive" must be created by competitors as a result of their own marketing innovations rather than by rate making considerations in this case. In accordance with this view, in order for competition to succeed, competitor-developed innovations must be substantial enough to both beat AEP's projected marginal cost price and enough to cover all of the vendors' own costs of competitive operations, customer acquisition and the transaction costs of switching.

Q. WHAT IS WRONG WITH THIS PROPOSAL?

A. There are a number of things that are obviously wrong with this proposal. Most fundamentally, it completely fails to meet the clear regulatory requirement that each utility, as part of its transition plan, must implement an <u>incentive</u> sufficient to <u>cause</u> at least twenty percent of sales to <u>switch</u> to alternative suppliers. To argue, as AEP does, that any incentive must, instead, be created entirely by independent competitor innovations, stands the regulatory requirement on its head. That position is particularly absurd in view of the fact that AEP is, itself, seeking transition cost reimbursement because of anticipated competitive innovations that it presumably expects to bring down the market price of electric generation.

Second, the Company's proposal further illustrates an important way in which CSP and OPCO have understated projected competitive market prices and thus the value of their own generation assets. Surely, the customer acquisition and transaction costs that competitors must bear are a portion of the total costs that must be considered in establishing competitive market prices. Ironically, while AEP has made every conceivable effort to account for (and, arguably, overstate) all of its own anticipated costs in developing proposed transition charges (which will be a disincentive to customer switching), it ignores competitors' basic operating costs, customer acquisition costs and transaction costs (some of which will result from CSP's and OPCO's own proposed service charges to competitors) in computing estimated competitive market prices.

Given the formula:

$$G = RTC + GTC + g$$

where "G" is CSP's and OPCO's total cost of generation, "RTC" is regulatory transition costs, "GTC" is generation transition costs and "g" is the residual representing competitive market generation costs, the Companies' proposed shopping credit (i.e., the amount that a customer's total bill -- if it were to take service from CSP or OPCO – would be reduced if generation service were taken from a competitor) would never exceed "g". Under this approach (and assuming that "g" is an accurate representation of the price charged by competitors), customers who consider switching would have absolutely no price incentive to do so. This, coupled with the fact that "g" is depressed for the reasons discussed above, makes it virtually impossible (let alone likely) to conclude that there is any reasonable probability that at least twenty percent of the load of each customer class would be caused to switch to competitive generation suppliers by virtue of the zero shopping incentive in the Companies' transition plan.

Q. **IN DEVELOPING THEIR SHOPPING CREDIT PROPOSALS IN THIS CASE, DID CSP AND OPCO TAKE INTO ACCOUNT THAT A REASONABLE PROFIT TO A COMPETITIVE GENERATION SUPPLIER IS A NECESSARY COMPONENT IN PRICING SALES TO RETAIL CUSTOMERS?**

A. No.

Q. **IN DEVELOPING THEIR SHOPPING CREDIT PROPOSAL IN THIS CASE, DID CSP AND OPCO TAKE INTO ACCOUNT THE COSTS INCURRED BY A COMPETITIVE GENERATION**

SUPPLIER IN SELLING TO RETAIL CUSTOMERS, SUCH AS COLLECTION COSTS, RESERVES FOR BAD DEBTS, ACCOUNTS PAYABLE, CUSTOMER CALL CENTERS AND OFFICE OVERHEADS?

A. No.

Q. IN DEVELOPING THEIR SHOPPING CREDIT PROPOSAL IN THIS CASE, DID CSP AND OPCO TAKE INTO ACCOUNT PRICE PREMIUMS FOR HIGH USAGE PERIODS IF USAGE EXCEEDS AN ASSUMED CUSTOMER LOAD PROFILE AND PENALTY PROVISIONS ARE IMPOSED UPON GENERATION SUPPLIERS UNDER THE COMPANY'S OATT FOR DEVIATIONS IN SUPPLY AND LOAD?

A. No.

Q. IS IT PLAUSIBLE TO EXPECT AT LEAST A 20 PERCENT LOAD SWITCH EVEN WITHOUT A PRICE INCENTIVE SIMPLY BECAUSE SOME CUSTOMERS MAY BE FED UP WITH THEIR INCUMBENT UTILITY'S POOR SERVICE AND HIGH PRICES OR BECAUSE COMPETITORS MAY BE ABLE TO BUNDLE NEW INNOVATIVE SERVICES WITH GENERATION OR MAY BE ABLE TO WORK WITH LOAD AGGREGATORS, LIKE

MUNICIPALITIES, TO GAIN LOAD DIVERSITY BENEFITS THAT MIGHT SAVE SOME COSTS?

A. Apparently AEP thinks so. When CSP and OPCO were asked whether they believe that customers will switch to alternative suppliers under their proposal, Mr. Forrester said:

> Yes. The customer survey included in Part H indicates there are even customers who say they will switch to an alternative supplier even if they have to pay more than they are paying to CSP and OPCO (prepared direct testimony of William R. Forrester, p. 29).

He goes on to cite the potential for municipal aggregation and other factors as further contributing to the potential for switching.

Q. **DO YOU AGREE?**

A. No. All of these scenarios are unlikely. First, the CSP and OPCO restructuring plans do not provide much, if any, opportunity for customers to obtain service quality different from what they would receive by retaining these companies as their generation supplier. Since CSP and OPCO will continue to provide all transmission, distribution and customer billing as well as reliability services to all customers on a nondiscriminatory basis regardless of generation supplier, rational customers are not likely to perceive a likelihood of service improvements as a result of changing generation suppliers.

I would note in this regard that my reading of the shopping incentive requirement, as specified by the Commission in its Finding and Order of November 30, 1999 in Case No. 99-1141-EL-ORD, is that the shopping incentive, itself, which must be specific to the utility's tariffs and rate schedules, (not some other factor like customer dissatisfaction) must be sufficient to cause at least a twenty percent switch. Thus, if a switch were to occur that resulted from something that was not part of the utility's transition plan (e.g., such as pent-up customer animosity), that switch, as an economic matter, could not be deemed to have been caused by a shopping incentive specific to the utility's tariffs and rate schedules. In other words, to simply say that there may be a myriad of factors (external to its transition plan) that could cause some customer switching even without a price incentive in the residential shopping credit is not in compliance with the Commission's requirements. Those requirements are that a shopping incentive, specific to the utility's tariffs and rate schedules and sufficient to cause at least a 20 percent switch, must be part of the transition plan.

A second reason to doubt the likelihood of substantial load switching without a significant shopping incentive is that AEP's own affiliates will, no doubt, attempt to compete with and emulate any independent generation suppliers who offer successful innovations. Third, evidence that is available from other states that have attempted to encourage generation competition (e.g., California, Massachusetts, New York and Pennsylvania) indicates that, without significant price incentives, very little switching occurs in residential markets. Finally, regarding municipal aggregation as a vehicle for switching, (1) there is little real evidence of this occurring without similar price incentives, (2) CSP and OPCO have not developed any specific programs under which this could occur,[13] and (3) if such aggregation were to become feasible, there is little reason (without a price incentive) to expect that it would occur through a competitive generation supplier rather than through AEP or one of its own unregulated affiliates. Especially in view of the fact that virtually all recent municipalization efforts have been premised primarily on the expectation of substantial cost savings, it is highly unlikely that this type of aggregation will result in substantial switching of generation suppliers without a significant price inducement.

Alternative Recommendation

Q. WHAT SHOPPING CREDIT DO YOU RECOMMEND IN ORDER TO PROVIDE AN INCENTIVE WHICH CAN REASONABLY BE EXPECTED TO CAUSE CUSTOMERS REPRESENTING AT LEAST TWENTY PERCENT OF THE COMPANY'S

[13] Mr. Forrester merely states that, "...the logical assumption is that the General Assembly did not provide this opportunity in vain. The political leadership of the state must have expected some governmental aggregation to occur" (prepared direct testimony of William R. Forrester, p. 31).

RESIDENTIAL CLASS RETAIL LOAD TO SWITCH GENERATION SUPPLIERS TO SOMEONE OTHER THAN AN AEP AFFILIATE BY DECEMBER 31, 2003?

A. In my opinion, a shopping credit in the range of $0.05 to $0.055/kwh ($2000) is required. This amount represents a wholesale market price of $0.035/kwh, plus an allowance of about one cent for retail operating costs, and a 0.7 cent switching incentive. For a typical CSP or OPCO residential customer with an average monthly load of about 900 kwh,[14] this incentive amounts to total savings of $75.60 per year, or about 10% of the customer's total annual electric utility service costs.

Q. **HOW DOES A SHOPPING CREDIT IN THIS RANGE COMPARE WITH CSP'S AND OPCO'S GENERATION COSTS FOR RESIDENTIAL SERVICE?**

A. The Companies' residential generation costs, as developed in their most recent class cost of service studies, are in this same range. OPCO's generation costs for residential service, per the Company's class cost of service study for 12 months ended 3/31/95 (total revenue at settlement ROR) were $344.7 million.[15] These revenues relate to 6,784 Gwh,[16]

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[14] In 1998, OPCO's average monthly sales per residential customer were 904 kwh and CSP's were 836 kwh.

[15] See OPCO Part A. Schedule UNB-4, page 61 of 72.

[16] See OPCO Part A, Schedule UNB-4, page 29 of 72.

indicating average generation cost-of-service revenue of $0.0508/kwh. CSP's generation costs for residential service, per the Company's class cost of service study for 12 months ended 12/31/91 (total revenue at court ordered ROR) were 273.9 million.[17] These revenues relate to 5,121 Gwh,[18] indicating average generation cost-of-service revenue of $0.0535/kwh.

Q. WHAT IS YOUR BASIS FOR RECOMMENDING A 0.7 CENT PER KWH SWITCHING INCENTIVE?

A. In my opinion, this is the minimum amount that can reasonably be expected to cause at least twenty percent of the Company's residential class retail load to switch generation suppliers to someone other than AEP by December 31, 2003. This opinion is based on my understanding of extensive empirical work that has been done during the last three decades on the price elasticity of demand for electricity.

Until the 1960s, it was generally believed (in the electric utility industry and by academic researchers) that the demand for electricity had little relationship to its price.[19] Those views may be consistent with AEP's opinion in this case that price incentives are not required in order to prompt electricity customers to shift their consumption. In the 1950s and 1960s,

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17 See CSP Part A, Schedule UNB-4, page 69 of 76.

18 See CSP Part A, Schedule UNB-4, page 45 of 76.

19 See, for example, Franklin M. Fisher in association with Carl Kaysen, A Study in Econometrics: The Demand for Electricity in the United States, (Amsterdam: North Holland Publishing Co.), 1962.

most electric utilities in the United States, including AEP, did their load forecasting simply by extrapolating historical sales trend lines over time into the future without reference to projected variations in price. But academic research in the late 1960s and early 1970s, coupled with the actual demand experience that electric utilities encountered in the 1970s when prices rose substantially, proved that these old views were wrong. Electricity demand, we learned, is heavily influenced by price – especially when consumers have alternatives.

Alternatives in the future, we expect, will be substantially better than alternatives in the past. That is so because electricity provided by "Vendor A" is more perfectly substitutable for electricity provided by "Vendor B" than alternative fuels or capital expenditures (e.g., for more energy-efficient equipment or construction) were for electricity in the past. In other words, the price elasticity of demand for CSP's and OPCO's electricity sales is likely to be significantly higher with direct electric-on-electric competition than it was in the past when monopoly electric generation suppliers faced price competition only from other fuels, capital expenditures, alternative locations or self-generation.

While there are, as yet, no comprehensive empirical studies of price elasticity of demand in mature, competitive electric generation markets, there is some limited evidence from other states, and there is guidance that can be gained from all of the price elasticity of demand research on electric utility markets that was done in the 1970s and subsequently. These studies, which cover a wide range of electricity usage, generally indicate that residential demand for electricity exhibits a price elasticity in the range of -0.5 to -1.0.[20] This means that a 1 percent increase (decrease) in the residential price of electricity can be expected to prompt a ½ to 1 percent decrease (increase) in electricity demand. Price elasticity of demand values tend to be at the top of this range for residential usages with high levels of substitutability and lower for usages with low levels of substitutability.

As regards the issue of demand switching in this case, all residential electricity uses will have high levels of substitutability since electricity from one generation supplier should be viewed by most consumers to be highly substitutable for generation from another supplier for virtually all household electricity applications. In fact, I believe, price elasticity of demand in this context is likely to be well above the top end of the range suggested by the empirical studies noted above. This belief is corroborated by price elasticity of demand studies which show that for certain types of large industrial consumers (e.g., primary metal producers) price elasticities of demand sometimes exceeded unity, in part because these very large

[20] See, for example, L.D. Taylor, "The Demand for Electricity: A Survey" The Bell Journal of Economics, Volume 6, No. 1, pp. 74-110, and the studies cited therein; and Electric Power Research Institute, Electric Utility Rate Design Study, Topic 2, Elasticity of Demand, February 1977, and the studies cited therein.

industrial consumers had the economic ability to substitute self-generated electricity for purchased electricity.[21]

For these reasons, in order to make a reasonable estimate of the minimum price incentive required to cause at least 20 percent of CSP's and OPCO's residential loads to switch to alternative competitive generation suppliers, I believe that it is appropriate to assume that price elasticity of demand in this market may be as high as –2.0. This means that a 1 percent price differential may be expected to cause an inverse demand change of 2.0 percent. Or, in other words, a ten percent total price incentive may be expected to cause a 20 percent load shift.

Since all of the price elasticity of demand evidence noted above pertains to the total retail price for electricity (not just the unbundled cost of generation alone) and since AEP's retail residential rates average about \$0.072/kwh, this means that a shopping incentive of at least \$0.007/kwh will be required in order to cause at least 20 percent of AEP's residential loads to switch to alternative suppliers.

Q. CAN THE COMMISSION BE CERTAIN THAT A \$0.007/KWH INCENTIVE (AND A RESULTING 5.0¢ TO 5.5¢/KWH SHOPPING

[21] See, for example, the same sources referenced in the prior footnote. One possible reservation in transferring this observation to today's residential electric markets is the fact that large industrial end-users, who may spend millions of dollars per month on electric power, have greater incentives than residential consumers to seek out and switch to lower cost alternatives.

CREDIT) WILL CAUSE 20 PERCENT OF AEP'S RESIDENTIAL LOAD TO SWITCH TO ALTERNATIVE SUPPLIERS?

A. No. While I believe that the –2.0 price elasticity of demand assumption is reasonable in light of existing empirical evidence and the additional considerations discussed above, this price elasticity expectation is substantially higher than can be fully documented at this time. Also, this is a long-run elasticity estimate (i.e., the total or ultimate amount of switching that can be expected over time as a result of the price differential) and there is no guarantee that the full long-run impact of the price differential will occur as quickly as the end of 2003. Finally, this relatively high price elasticity estimate assumes that there will be a high level of motivation for consumers in residential markets to make the effort required to seek out and switch to lower cost competitive suppliers. Given the fact that this 0.7¢ incentive will save the average residential customer only about $6.30 per month, the implicitly expected level of switching still may not occur. For these reasons, there should be monitoring of the amount of load switching that actually occurs over time, together with interim increases in the incentive level if expected changes of this magnitude do not occur.

Q. **DOES AEP AGREE THAT SHOPPING INCENTIVES SHOULD BE INCREASED IF TARGET SWITCHING GOALS ARE NOT MET?**

A. No. According to AEP, there should be no provision for higher shopping incentives if initial incentives fail to work. Their stated reason for this position is that if there is any impression that shopping incentives may increase, some consumers will refrain from shopping now and hold out for larger incentives in the future. (See prepared direct testimony of William R. Forrester, p. 28.) In my opinion, this reasoning is invalid if customers who shop and switch now are assured that they are not locked-in, but will be treated equally if incentives change in the future.

Q. WHAT IF RESIDENTIAL PRICE ELASTICITY OF DEMAND PROVES TO BE EVEN GREATER THAN –2.0 IN THIS NEW AND DIFFERENT ENVIRONMENT THAT WILL BE CHARACTERIZED BY ELECTRICITY-ON-ELECTRICITY COMPETITION?

A. For the reasons discussed above, I do not believe that is likely. However, if that does happen, it will be observed through monitoring, and the Commission can then take whatever additional steps it deems to be appropriate. Also, I do not see this as a public policy risk, because the 20 percent switching benchmark is clearly a very minimum competitive goal – both under the Commission's regulations and as an economic matter. As is clear from all studies of market power, including the recent DOE study of emerging electricity markets presented in Exhibit JWW-1, if AEP retains an 80 percent market share (or even 70 percent or 60 percent), there will still be grossly excessive concentration and an end-result that falls far short of attaining a workably competitive market environment. Once again, it should be noted that the surest way to a successful competitive transition would be for AEP to divest its generation resources so as to break up the existing level of ownership concentration in the region. While AEP and its operating affiliates have not been required by law to do this, the Commission is certainly not at all compelled to establish ground rules designed to assist AEP in its efforts to maintain 80 percent (or greater) market dominance. Indeed, if an end result anywhere near that level were to occur, it would signify the defeat of competitive restructuring.

IV. OPERATIONAL SUPPORT ISSUES

Q. **PLEASE SUMMARIZE YOUR TESTIMONY CONCERNING OPERATIONAL SUPPORT ISSUES IN THIS CASE.**

A. CSP's and OPCO's proposed Operational Support Rules should be modified to remove provisions that would subject competitive service providers to disadvantages that would undermine the successful evolution of effective competition. These provisions include unreasonable restrictions on consumer switching, discriminatory customer service conditions and the imposition of unjustified burdens and handicaps for competitive service providers.

Q. WHAT ARE THE UNREASONABLE PROPOSED RESTRICTIONS ON CUSTOMER SWITCHING THAT SHOULD BE DENIED?

A. In its Filing, AEP proposes that when a customer selects an alternate generation supplier and then returns to standard service, "the customer is required to take the standard offer for the remainder of the Market Development Period, or for 12 months, whichever is longer."[22] Additionally, if a customer defaults to AEP's standard offer, it must choose an alternative supplier within 30 days or "service will be provided by the Company under the Company's standard schedules for the duration of the Market Development Period....[23] These limiting provisions are clearly anticompetitive as they would unreasonably lock customers into contracts for AEP's standard service offer for at least a full year and possibly much longer.[24] Such an unreasonable constraint could potentially eliminate large numbers of consumers from the competitive market for an extended period. Contract term requirements should be determined and regulated by the market, as part of the bargaining process. This is a critical concept. In a competitive market, one of the best forms of consumer protection is the

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22 AEP Transition Plan, Thomas Testimony at 5-6. *See also* AEP Transition Plan, OPCO Schedule UNB-1, PUCO No. 17, Original Sheet Nos. 3-2D, 3-18D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO No. 5, Original Sheet Nos. 3-2D, 3-14D.

23 AEP Transition Plan, Thomas Testimony at 5-6 (emphasis added). *See also* AEP Transition Plan, OPCO Schedule UNB-1, PUCO No. 17, Original Sheet Nos. 3-2D, 3-18D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO No. 5, Original Sheet Nos. 3-2D, 3-14D.

24 AEP's proposal is particularly anticompetitive given that its market development period could last until December 31, 2005. Ohio Rev. Code § 4928.40(A) ("The market development period shall end on December 31, 2005, unless otherwise authorized....").

consumer's ability to "vote with your feet." If a supplier is unsatisfactory – including the utility – then a consumer must be able to freely choose another supplier.

Q. WHY DOES AEP PROPOSE THIS RESTRICTION?

A. AEP claims that such minimum contract term requirements are necessary to prevent customer "gaming," *i.e.* selecting an alternative supplier in low-cost months and switching back to standard service in high-cost months to take advantage of averaged standard service offer rates.[25] To the extent that such potential gaming actually occurs, the Commission's market monitoring will detect it, and less draconian measures can be implemented to prevent it. For example, any supplier encouraging such behavior could have its license challenged by AEP. Also, if AEP's shopping credit/incentive is adequately set, competitive service providers will be able to provide service competitively on a compensatory basis and will have no incentive to drop their customers seasonally. The competitive reality is that suppliers have an incentive to retain their customer, not discard them for certain periods of the year, thus developing a reputation for unreliability.

Q. ARE THERE OTHER ASPECTS OF AEP'S PROPOSED SWITCHING RULES THAT ARE UNREASONABLE?

[25] AEP Transition Plan, Thomas Testimony, p. 6.

A. Yes. AEP's proposed switching fee is unreasonable. In its Filing, AEP proposes that "[t]he customer shall pay a charge of $5.00 to the Company whenever a customer-authorized change in CSP occurs."[26] This proposed "switching fee" for residential and small commercial customers is not cost-justified.

Q. **WHAT OTHER UNREASONABLE BURDENS DOES AEP INTEND TO IMPOSE ON COMPETITIVE SERVICE PROVIDERS?**

A. The Commission's rules require each utility's Operational Support Plan ("OSP") "to address how its current operational support system and any other technical implementation issues pertaining to competitive retail electric service will be used or changed to ensure a successful implementation of the customer's ability to choose its generation supplier."[27] These implementation issues include: (1) pre-ordering of the service; (2) ordering of the service (customer conversion); (3) provisioning of the service; (4) billing services; and (5) other services such as alternative

[26] AEP Transition Plan, OPCO Schedule UNB-1, PUCO No. 17, Original Sheet Nos. 3-3D, 3-18D. AEP also states, "this switching charge shall not apply in the following specific circumstances: (a) the customer's initial change to service under the Company's open access distribution schedules and service from an Electric Supplier, (b) the customer's Electric Supplier is changed involuntarily, (c) the customer returns to service from the customer's former Electric Supplier following an involuntary change in Electric Supplier, or (d) the customer's former Electric Supplier's services have been permanently terminated and the customer must choose another Electric Supplier." *Id.*

[27] Ohio Admin. Code § 4901-20-03, App. B(A).

supplier metering, alternative supplier meter reading, or other ancillary services for alternative suppliers.[28]

AEP has proposed Supplier Terms and Conditions of Service ("Supplier Tariff") to govern the relationship between it and "Energy Suppliers" or competitive service providers. As part of the Supplier Tariff, AEP seeks to impose registration requirements on Electric Suppliers which are independent of the Commission's own certification. As AEP states,

> Energy Suppliers desiring to provide competitive energy services to customers located within the Company's Service Territory must also register with the Company. The following information must be provided in order to register with the Company:
>
> (1) Proof of certification by the Commission, including any information provided to the Commission as part of the certification process.
>
> (2) A $100.00 annual registration fee payable to the Company.
>
> (3) An appropriate financial instrument to be held by the Company against Electric Supplier defaults and a description of the Electric Supplier's plan to procure sufficient electric energy and transmission services to meet the requirements of its firm service customers.
>
> (4) The name of the Electric Supplier, business and mailing addresses, and the names, telephone numbers and e-mail addresses of appropriate persons, including the 24-hour emergency contact telephone number and emergency contact person(s).
>
> (5) Details of the Electric Supplier's dispute resolution process for customer complaints.

[28] Ohio Admin. Code § 4901:1-20-03, App. B(C)(2)(a)-(e).

(6) A signed statement by the officer(s) of the Electric Supplier committing it to adhere to the Company's Open Access Distribution Schedules, Terms and Conditions of Open Access Distribution Service, Supplier Terms and Conditions of Service and any additional requirements stated in any agreement between the Electric Supplier and the Company regarding services provided by either party.[29]

These registration provisions place AEP in the role of ultimate gate keeper for market entry by competitive suppliers. They would require marketers to provide an additional "appropriate financial instrument" to protect AEP against default. The level and type of security required is unclear, as is the amount of flexibility a marketer would have in satisfying this requirement.

More troubling still is AEP's requirement that marketers describe to it how they plan to serve their customers. Requiring such disclosure to the incumbent service provider as a condition of market entry is an anticompetitive requirement. AEP must not be permitted to leverage its "registration" process into a means of obtaining forced disclosure of competitively sensitive information from third-party suppliers. Under SB3, it is solely within the Commission's province to administer certification for

[29] AEP Transition Plan, OPCO Schedule UNB-1, PUCO No. 17, Original Sheet Nos. 3-19D-3-20D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO No. 5, Original Sheet Nos. 3-15D - 3-16D.

competitive suppliers.[30] Additionally, on March 30, 2000, the Commission promulgated final certification rules for Competitive Retail Electric Service providers, in Docket No. 99-1609-EL-ORD.[31]

It is not AEP's role to decide who does and does not enter the competitive market. Once certificated by the Commission, a supplier should be free to enter and compete in any service territory without being burdened by barriers to market entry in the form of additional, utility-created certification requirements or anticompetitive disclosure obligations. Otherwise, competitive suppliers would be hamstrung in their efforts to enter Ohio's competitive electric markets efficiently, as they would be required to incur significant costs and invest substantial time responding to needlessly duplicative and intrusive utility "registration" requirements. In such case, the state's policy to "encourage innovation and market access for cost-effective supply and demand-side retail electric service,"[32] and to

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[30] SB3 declares, "[n]o electric utility, electric services company, electric cooperative, or governmental aggregator shall provide a competitive retail electric service to a consumer in this state on and after the starting date of competitive retail electric service without first being *certified by the Public Utilities Commission....*" Ohio Rev. Code § 4928.08(B) (emphasis added). It also states, "[t]he Commission may suspend, rescind, or conditionally rescind the certification of any electric utility, electric services company, electric cooperative, or governmental aggregator...." Ohio Rev. Code § 4928.08(D). SB3 gives no certification review power to electric distribution utilities.

[31] *See In the Matter of the Commission's Promulgation of Rues for Certification of Providers of Competitive Retail Electric Services Pursuant to Chapter 4928, Revised Code*, Case No. 99-1609-EL-ORD.

[32] Ohio Rev. Code §4928.02(E).

"ensure retail electric service consumers protection against...market deficiencies, and market power,"[33] would be frustrated.

The Commission should be clear that competitive suppliers need only satisfy the Commission's certification requirements to conduct business in the State of Ohio. Utilities like CSP and OPCO should not be allowed to force suppliers to satisfy a second set of certification-like requirements that duplicate the Commission's procedures or place additional financial or resource burdens on suppliers. Were each utility left to promulgate its own certification or registration regime, uneven requirements and inconsistent licensing results across the State would be the inevitable result, unfairly denying competitive choices to certain customers that are available to others under similar circumstances. The utility would become the *de facto* ultimate licensing body in its service territories (rather than the PUCO). This would create the evident opportunity for anticompetitive behavior through which the utility could thwart the entry of specific Electric Suppliers as competitive rivals. Given the clear potential for anticompetitive mischief, utilities like AEP, from whom suppliers initially must attract customers, should not be empowered to act as the watch-dogs of competitive market entry – this role is more appropriately left to the Commission.

33 Ohio Rev Code § 4928.02(H).

AEP also seeks to impose onerous credit requirements on competitive service providers. The registration requirements contained in AEP's proposed Supplier Tariff provide that Electric Suppliers must give AEP, "[a]n appropriate financial instrument to be held by the Company against Electric Supplier defaults...."[34] AEP also proposes to require Meter Service Providers ("MSP"), Meter Data Management Agents ("MDMA"), and Billing Agents ("BA") to submit "appropriate financial instruments" to AEP.[35]

Like the Company's proposed registration requirements, these provisions would give AEP unilateral discretion in dictating the form and amount of financial guarantees that competitive service providers must post, and in obtaining credit information from competitive service providers. Instead, competitive service providers should have reasonable options regarding the financial instrument they use to fulfill and Commission-determined deposit requirements. Furthermore, the amount of any deposit should be clearly stated in AEP's tariff and any credit requirements imposed on competitive service providers should be clearly defined in accord with Commission-

34 AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 3-19D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 3-15D.

35 AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 3-23D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet Nos. 3-16D-19D.

approved deposit levels so that AEP is not allowed to exercise discretion to impose unfair or discriminatory filing requirements on any competitive service providers.[36] To ensure that the Legislature's policy of bringing competition to Ohio is fulfilled,[37] the Commission should deny utilities unilateral discretion regarding the level of deposits and financial instruments necessary to satisfy those requirements.

Q. IN WHAT WAY WOULD AEP IMPOSE IMPROPER BARRIERS TO ELECTRIC SUPPLIER ACCESS TO BASIC CUSTOMER INFORMATION?

A. The Code of Conduct contained in AEP's proposed tariff states that it "shall make customer lists, which include name, address and telephone number, available on a nondiscriminatory basis to all nonaffiliated and affiliated certified retail electric competitors transacting business in its service territory, unless otherwise directed by the customer."[38] It states further,

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36 In terms of utility deposit requirements, the amount should be set subject to specific Commission parameters and should be "reasonable", *i.e.*, should reflect the actual risk – no more and no less – that utilities may shoulder if a default occurs (*e.g.*, equal to 30 days of peak period supply obligations). In turn, the supplier should be allowed to choose among various financial instruments to satisfy utilities' deposit level requirements (*i.e.*, letter of credit, corporate guarantees, cash deposit, etc.). This process would protect adequately the utilities' financial interests while providing a fair and efficient certification process for competitive suppliers.

37 *See* Ohio Rev. Code § 4928.02(B) ("It is the policy of this state to ...[e]nsure the availability of unbundled and comparable retail electric service...."). *See also* Ohio Rev. Code § 4928.02(E) ("It is the policy of this state to...encourage innovation and market access for cost-effective supply and demand-side retail electric service."). *See also* Ohio Rev. Code § 4928.02(I) ("It is the policy of this state to...ensure retail electric service consumers protection against...market deficiencies, and market power.").

38 AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 3-27D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 3-23D.

however, "[t]his provision does not apply to customer-specific information, obtained with proper authorization, necessary to fulfill the terms of a contract, or information related to the provision of general and administrative support services."[39] AEP also states, "[t]he Company shall not release any proprietary customer information (e.g., individual customer load profiles or billing histories) to an affiliate, or otherwise, without prior authorization of the customer, except as required by a regulatory agency or court of law."[40] By refusing to provide access to basic customer information,[41] including critically important customer-specific usage and load data, on a pre-enrollment basis to suppliers, AEP would be able to substantially hamper competitive marketing efforts. As expressed in the Commission's proposed Amendments to Rules for Electric Service and Safety Standards[42] and proposed Rules for Minimum Competitive Retail

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[39] AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 3-27D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 3-23D. This appears to contradict AEP's Operational Support Plan which indicates that "the information [12 months of customer specific consumption and load history] will be provided to a competitive retail supplier unless the customer does not want the information released." AEP Transition Plan, Part C, Operational Support Plan at 5.

[40] AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 3-27D (emphasis added). *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 3-223D.

[41] It is not clear whether AEP's promise to make available proprietary customer information "as required by a regulatory agency" means that it will provide customer-specific data in a pre-enrollment basis for all customers that do not affirmatively block such disclosure, as contemplated by the Commission's proposed rules.

[42] *In the Matter of the Commission's Promulgation of Amendments to Rules for Electric Service and Safety Standards Pursuant to Chapter 4928, Revised Code*, Case No. 99-1613-EL-ORD, Section 4901:1-20-22(D)(5) ("Draft ESSS Amendments") (emphasis added) ("An electric distribution company shall...provide customer-specific load pattern information to other electric light companies on a comparable and non-discriminatory basis ***unless the customer objects to the disclosure of such information....***").

Electric Service Standards,[43] customers should be able to prevent the disclosure of their "load pattern information" by affirmatively giving notice to AEP. However, there is no requirement either in SB3 or the Commission's rules that a customer affirmatively consent before its usage and load data can be released to a competitive supplier.[44] Accordingly, where a customer has chosen not to restrict the release of usage information, there is neither the authority nor necessity for AEP to require an Electric Supplier to obtain an additional authorization prior to providing access to usage and load data. Left unchanged, AEP's proposal would hinder the flow of information that is crucial to an Electric Supplier's ability to compete in the AEP service territories. The Commission should require AEP to modify its proposed tariff to provide unambiguously that Electric Suppliers may obtain such information at all times absent an affirmative customer request that AEP not disclose the information.

[43] *In the Matter of the Commission's Promulgation of Rules for Minimum Competitive Retail Electric Service Standards Pursuant to Chapter 4928, Revised Code*, Case No. 99-1611-EL-ORD, Section 4928:2-xx-10(D) ("Draft CRES Rules") ("A CRES provider shall provide customer-specific load pattern information to other electric light companies on a comparable and non-discriminatory basis unless the customer objects to the disclosure of such information.")

[44] AEP expands the Code of Conduct contained in the Commission's Transition Plan Rules to force ***non-affiliated*** suppliers to obtain affirmative customer authorization before it will release customer-specific information such as load pattern data. This conflicts with the Commission's intent, as expressed in the CRES rules and ESSS amendments promulgated on March 30, 2000, which allow release of the information ***unless*** the customer objects, i.e., no affirmative authorization is necessary before a competitive supplier may access the data.

In other states, the provision of customer information to competitive suppliers is required on a pre-enrollment basis without affirmative customer authorization. In Pennsylvania, for example, incumbent utilities must provide at least the following customer information to certificated electric generation suppliers ("EGS"): (1) name; (2) billing address; (3) service address; (4) account number; (5) rate class (or sub-class if available); and (6) load data, including 12-months of historical usage.[45] The Pennsylvania Utilities Commission ("PAPUC") found,

> Access to a customer's name, address, account number, rate class and ***load data is absolutely necessary for a supplier*** to have the ability to develop ***specific pricing offers*** and to have a ***meaningful opportunity to attract customers.***[46]

Similar information disclosure should be assured as part of AEP's Transition Plan. Specifically, for the purpose of providing retail electric services, a Commission-certificated Electric Supplier should have access to an "Eligible Customer List" containing the above-listed Customer Information for ***all*** customers who have not exercised their option to

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[45] Pennsylvania Public Utilities Commission, *Procedures Applicable to Electric Distribution Companies and Electric Generation Suppliers During the Transition to Full Retail Choice*, Docket No. M-00991230 at 14, entered May 18, 1999 ("PAPUC May 18 Order"). Customers are given the opportunity to prevent the disclosure of their load data or all of their information by sending a post-card notice to the utility. *Id.*

[46] *Id.* at 21.

prevent such disclosure.[47] Moreover, this access should be provided electronically and at no cost to competitive suppliers.[48]

Certain types of Customer Information must be available on a pre-enrollment basis without prior customer authorization in order for competitive providers to establish and provide the appropriate level of service to customers. Competitive suppliers need electronic access to customer information in order to analyze the market (especially mass residential and small commercial markets), formulate innovative and competitive offers, advise consumers regarding their energy needs, offer proposals , and provide service. A supplier cannot determine a customer's service and rate class eligibility, formulate a viable offer of service, advise a consumer of that offer, and then consummate the agreement without knowing who the customer is, how much electricity the specific customer uses, and the appropriate rate class and meter location. Access to Customer Information is critical to a competitive supplier's ability to determine

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47 In Pennsylvania, customers may restrict access to certain customer information. Specifically customers may either prevent the disclosure of (1) their load data; or (2) all of their information by checking a box on a return postcard. Otherwise, Customer Information is provided to certified EGSs via the Internet. PAPUC May 18 Order at 24-25.

48 Electronic Data Interexchange ("EDI") protocols have been developed in other jurisdictions to facilitate the Customer Information and enrollment process. However, states such as Pennsylvania will move such protocols to an Internet-based platform and, thereby, avoid unnecessary information transaction charges to both suppliers and utilities. The provision of this information is especially critical for competitive suppliers that focus on serving hundreds of thousands of residential customers. Charging for individual EDI transaction requests and responses for each customer's data would pose a significant barrier to competitive market entry.

customer eligibility and to provide service. CSP and OPCO should be required to provide access to that information electronically to Electric Suppliers as part of an Eligible Customer List on a pre-enrollment basis, without affirmative customer authorization for those customers who have not chosen to prevent the disclosure to such information.

Q. **WOULD AEP'S OPERATIONAL SUPPORT PLAN CREATE BARRIERS TO THE COMPETITIVE PROVISION OF ALTERNATIVE METERING AND BILLING SERVICES?**

A. Yes. AEP provides customers with the option to use an alternative Metering Service Provider ("MSP") and a qualified Billing Agent ("BA")[49] to provide consolidated billing and be "responsible for electronically transmitting funds received from the customer for charges from the Company for distribution service, together with associated customer account data, on the same day as receiving such funds."[50] However, the specific provisions for these options would almost certainly prevent customers from choosing an alternative metering or billing service.

[49] AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 3-17D and CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 3-13D.

[50] AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 3-24D and CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 3-20D.

First, AEP provides that it will credit only $0.12/month to OPCO residential customers and $0.11/month to CSP residential customers who choose an alternative MSP.[51] This credit will clearly not be sufficient to permit alternative metering because the new MSP would incur costs well in excess of 12 or 11 cents per month just to install and maintain a meter. These proposed meter credits – which equate to $1.44 and $1.32 per year – appear to reflect substantially less than the costs included in the Companies' own cost of service studies for metering service. An appropriate metering service credit should reflect at least the utility's own full costs of metering service.

Second, any new meter installed in the AEP service territories must meet unspecified criteria and be judged by AEP.[52] Either the MSP or the customer must pay an unspecified fee to have AEP's meter removed and returned to the Company.[53] These requirements represent further unspecified cost barriers (which likely exceed the Companies' proposed credits) for customers choosing alternative metering services which either

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[51] AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 10-1D and CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 10-1D.

[52] AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 10-1D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 10-1D.

[53] AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 10-1D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 10-1D.

must be clarified or curtailed so that customers may have a reasonable option for metering services.

In the case of billing services, even though AEP proposes that the BA would assume full consolidated billing responsibility for all charges, including responsibility for providing payment in full of all charges for distribution service from the Company by the due date, no consolidated billing credit to either the customer or the BA is provided for in the Companies' proposed tariffs. An appropriate consolidated billing service credit, reflecting the utility's own full cost of billing services (and not simply avoided costs), should be provided. Such a billing credit also enhances the potential overall "price to compare" and, therefore, the likelihood that consumers will receive the option of supplier consolidated billing and the attractiveness of the overall market to suppliers.

Q. WOULD AEP'S PROPOSED POLICY WITH RESPECT TO PARTIAL CUSTOMER PAYMENTS UNFAIRLY DISADVANTAGE COMPETITIVE SERVICE PROVIDERS?

A. Yes. AEP's Supplier Tariff states,

> Partial payment from a customer shall be applied to the various portions of the customer's total bill in the following order: (a) charges under the applicable open access distribution schedule, (b) charges under the American Electric Power Open Access Transmission Tariff, if separate from

charges for the customer's Electric Supplier, and (c) charges from the Electric Supplier and other CSPs.[54]

This proposed method of crediting partial payments would unfairly force competitive service providers to shoulder a disproportionate share of the risk related to customers not providing full payment for charges. Competitor-supplied services are no less important than the regulated services that will be provided by CSP and OPCO. Unlike these utilities, competitive service providers do not collect for "bad debt" through regulated rates with the regulated return on the bad debt account. If a competitive supplier is not paid or is paid late, it shoulders the full burden of that interrupted revenue, without compensation through regulated rates. Moreover, AEP's Filing puts *all* AEP charges ahead of competitive service provider charges – including arrearages owed to the Electric Supplier.

V. CORPORATE SEPARATION PLAN

Q. WHAT IS OBJECTIONABLE ABOUT AEP'S PROPOSED CORPORATE SEPARATION PLAN?

A. The objectionable parts of AEP's proposed Corporate Separation Plan are those that would provide the Company and its affiliates with undue advantages over competitive market rivals.

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54 AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 3-25D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 3-21D.

SB3 requires Transition Plans to contain a corporate separation plan which "provides, at a minimum, for the provision of...competitive retail electric service or the nonelectric product or service through a fully separate affiliate of the utility, [including] separate accounting requirements, [and] the code of conduct as ordered by the Commission......"[55] Such plans must also, "*satisf[y] the public interest in preventing unfair competitive advantages and preventing the abuse of market power.*"[56] Corporate separation plans must be:

> sufficient to ensure that the utility will not extend any undue preference or advantage to any affiliate, division, or part of its own business engaged in the business of supplying the competitive retail electric service or nonelectric product or service, including, but not limited to, utility resources...and to ensure that any such affiliate, division, or part will not receive undue preference or advantage from an affiliate, division, or part of the business engaged in business of supplying the noncompetitive retail electric service.[57]

The purpose of these rules, which "provide that all the state's electric utility companies must meet the same standards so a competitive advantage is not gained solely because of corporate affiliation,"[58] is to "create competitive equality, preventing unfair competitive advantage and prohibiting the abuse of market power."[59]

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[55] Ohio Rev. Code § 4928.17(A)(1).
[56] Ohio Rev. Code § 4928.17(A)(2).
[57] Ohio Rev. Code § 4928.17(A)(3).
[58] Ohio Admin. Code § 4901:1-20-16(A).
[59] Ohio Admin. Code § 4901:1-20-16(A).

Q. HOW WILL THIS PLAN PROVIDE THE COMPANY WITH UNDUE ADVANTAGES OVER COMPETITIVE MARKET RIVALS?

A. As part of its Corporate Separation Plan, AEP proposes to "establish new transmission subsidiaries and distribution subsidiaries," which, "will own and operate all of the transmission and distribution assets currently owned by OPCO and CSP."[60] In essence, AEP plans to transfer its transmission and distribution businesses to regulated subsidiaries, which would leave the original companies as unregulated generation services providers.[61] AEP states, "[t]he plan would be to leave all generating assets in the existing legal structure of OPCO and CSP…[t]he distribution and transmission assets would be transferred to new corporate entities."[62] This approach is apparently an attempt to "transfer" generation assets to an unregulated entity at book value, which is (as discussed in detail above) well below the true economic or market value of these soon-to-be competitive assets.

SB3 requires Corporate Separation Plans to provide, "at a minimum, for the provision of the competitive retail electric service or the nonelectric product or service through a fully separated affiliate of the utility…."[63] A critical part of separating AEP from its competitive service affiliate is the valuation

60 AEP Transition Plan, Forrester Testimony at 19.
61 AEP Transition Plan, Forrester Testimony at 19-21.
62 AEP Transition Plan, Pena Testimony at 3.

of the assets that are transferred in the process. An undervaluation of AEP's generation assets (*e.g.*, retention by the new generation affiliate at book value), would deprive ratepayers of benefits derived from the higher market value that the affiliates should pay for those assets. The proceeds from a transfer of generation assets at their true market value, which greatly exceeds book value, could then be used to offset transition costs, thus permitting the establishment of a more effective shopping incentive.[64]

Q. DOES AEP'S CORPORATE SEPARATION PLAN ALSO ALLOW FOR THE SHARING OF SERVICES AND MANAGEMENT WITH AFFILIATES?

A. Yes. AEP's Corporate Separation Plan allows a variety of services and management to be shared by AEP and its affiliates. AEP states, "AEPSC, a wholly-owned shared-services subsidiary of AEP, will perform the accounting for all companies, including the Separate AEP Companies."[65] Further, AEP plans to use AEPSC as a provider of accounting services and to use shared software systems, equipment, managers, and employees.[66]

Shared accounting services are especially suspect not only because they fail to establish complete separation, but also because they explicitly raise the

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63 Ohio Rev. Code § 4928.17(A)(1).

64 SB3 provides, "in no case shall the Commission establish a shopping incentive in an amount exceeding the unbundled component for retail electric generation service in the utility's approved transition plan" (Ohio Rev. Code § 4928.40(A)).

65 AEP Transition Plan, Knorr Testimony at 3.

potential for cross-subsidization among AEP's regulated and unregulated affiliates. SB3 requires Transition Plans to be "sufficient to ensure that the utility will not extend any undue preference or advantage to any affiliate, division or part of its electric service or nonelectric product or service, including...personnel...without compensation based upon fully loaded embedded costs charges to the affiliate...."[67] Further, it must "satisf[y] the public interest in preventing unfair competitive advantage...."[68] The Commission's rules provide, "[a]n electric utility may not share employees with any affiliate, if the sharing, in any way, violates [the Code of Conduct] of this rule."[69] The services that AEP will share with its affiliates could provide significant anticompetitive benefits of AEP against which competitive electric service providers will compete and shared accounting services could be employed to cover up the cross-subsidy. The sharing of these critical resources should be eliminated or severely curtailed. Otherwise, AEP's Corporate Separation Plan will fail to prevent unfair competitive advantages from being obtained by AEP's affiliates, in violation of SB3.

Q. DOES AEP PROPOSE TO OFFER COMPETITIVE SERVICES THROUGH ITS REGULATED AFFILIATES?

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66 AEP Transition Plan, Knorr Testimony at 3-5.
67 Ohio Rev. Code § 4928.17(A)(3).
68 Ohio Rev. Code § 4928.17(A)(2).
69 Ohio Admin. Code § 4901:1-20-16(1)(b).

A. Yes. AEP plans to provide a number of competitive services through its regulated transmission and distribution business units. It states, "the new transmission and new distribution subsidiaries will continue to provide transmission and distribution services to industrial and commercial customers...."[70] Further, "[t]he transmission and distribution services offered to customers include engineering analysis, emergency repairs, rebuilds and upgrades to customer-owned electric equipment, meter and laboratory services, power quality improvements and safety training."[71]

These services are closely associated with the kinds of services that competitors can offer. They are, therefore, more appropriately placed in AEP's competitive business units. If these services remain under the regulated business units as proposed, it will be easy for AEP to shift its costs from these services to regulated services contained in the same business unit. Such cross-subsidization is a potential problem when these services are contained in separate business units, let alone the same business unit.

Q. DOES AEP ACKNOWLEDGE THAT THESE ARE SERVICES WHICH ARE LIKELY TO BE OFFERED BY COMPETITIVE SERVICE PROVIDERS?

70 AEP Transition Plan, Forrester Testimony at 19.
71 AEP Transition Plan, Forrester Testimony at 19-20.

A. Yes. In response to the question:

> Please explain whether each of the services listed are services that will be offered by the distribution company or whether competing companies will be able to offer such services.

AEP responded:

> These services may be offered by other companies... (Response to Shell-AEP-37, First Set).

Q. ARE THERE PARTICULAR PROBLEMS WITH AEP'S PROPOSED IMPLEMENTATION OF ITS AFFILIATE CODE OF CONDUCT UNDER THE CORPORATE SEPARATION PLAN?

A. Yes. AEP reserves the right to violate the affiliate code of conduct during a "declared emergency."[72] It fails, however, to define what may constitute a "declared emergency." This could result in substantial anticompetitive impacts if, for example, a declared emergency included severe price spikes like those in the Spring and Summer of 1998.[73] If AEP generation personnel were allowed in the transmission control room during such events, a range of anticompetitive actions would be feasible, including the preferential misallocation of scarce transmission to transactions involving

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[72] AEP Transition Plan, OPCO Schedule UNB-1, PUCO Sheet No. 17, Original Sheet No. 3-24D. *See also* AEP Transition Plan, CSP Schedule UNB-1, PUCO Sheet No. 5, Original Sheet No. 3-28D.

[73] The Commission's rules also do not define "declared emergency." They state, "in a declared emergency situation, an electric utility may take actions necessary to ensure public safety and system reliability. The electric utility shall maintain a log of all such actions that do not comply with paragraph (G)(4) of this rule, which log shall be subject to review by the commission." Ohio Admin. Code § 4901:1-20-16(G)(4)(j),

AEP generating units. In light of the severe price spikes that have occurred in recent years in the Midwest, AEP's manipulation of transmission in favor of its own generators could drastically raise the price of wholesale power to competing suppliers causing them to incur financial hardship. Precautions, therefore, should be incorporated into AEP's Filing to prevent these results, including a narrow definition of "declared emergency."

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY AT THIS TIME?

A. Yes; it does.

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Horizontal Market Power in Restructured Electricity Markets

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Office of Economic, Electricity and Natural Gas Analysis
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Washington, DC 20585

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Contents

Executive Summary

What is market power and why is it important to electric restructuring?

Market power is defined as the ability of a supplier to profitably raise prices above competitive levels and maintain those prices for a significant time period. Concerns regarding market power have been widely examined in the economics literature and in antitrust practice across a broad range of industries.

The market power issue is of particular interest to policymakers and legislators as they consider electric power industry restructuring, because the exploitation of market power can significantly erode the consumer benefits that would be expected to result from the transition from regulated to competitive markets for electricity generation.

The economics and antitrust literature identify two types of market power, horizontal and vertical. Horizontal market power is exercised when a firm profitably drives up prices through its control of a single activity, such as electricity generation, where it controls a significant share of the total capacity available to the market. Vertical market power is exercised when a firm involved in two related activities, such as electricity generation and transmission, uses its dominance in one area to raise prices and increase profits for the overall enterprise. **This paper focuses on the issue of horizontal market power, providing evidence regarding its potential impact on restructured electricity markets.**

Antitrust remedies are not well-suited to address problems of market power in the electric power industry that result from existing high levels of concentration in generation. As noted in recent testimony from the Department of Justice, the antitrust laws do not outlaw the mere possession of monopoly power that is the result of skill, accident, or a previous regulatory regime.

What information is available regarding market power in competitive electricity markets?

Many electricity markets are highly concentrated, raising market power concerns. Schmalensee and Golub (1984) calculated values of the Herfindahl-Hirschmann Index (HHI), a standard measure of market concentration developed by the U.S. Department of Justice (DOJ) and the Federal Trade Commission (FTC), for electricity markets throughout the United States for 170 generation markets serving nearly three-quarters of the U.S. population. They found that, depending on the cost and demand assumptions used, 35 percent to 60 percent of all generation markets had HHI values above 1800 (the threshold for "high concentration" under the DOJ/FTC guidelines). A more recent study by Cardell, Hitt and Hogan (1997) suggests that electricity markets are still highly concentrated. Using 1994 data and a narrower definition of the geographic scope of electricity markets, they calculate HHI values for 112 regions based on State boundaries and North American Electric Reliability Council (NERC) subregions. Approximately 90 percent of the markets examined in this study had HHI values above 2500.

There is strong evidence that market power has been exercised in the electricity context. In both the United Kingdom (U.K.) and California, where data from competitive electricity generation markets are now available, researchers have found that wholesale power prices have been as much as 75 percent above competitive levels at times. Other studies examining electricity markets in Australia, New Jersey, and Colorado identify potential market power issues in those areas as well.

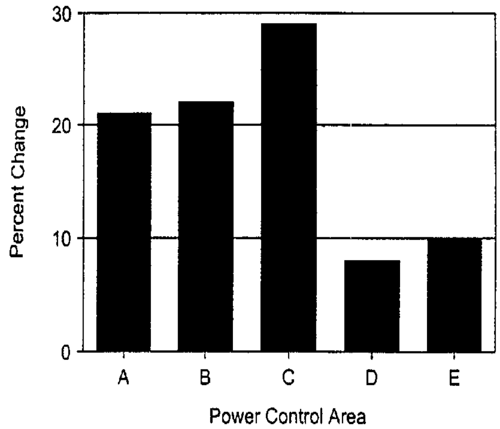
Entry or the threat of entry alone is unlikely to alleviate market power concerns. While the threat of entry undoubtedly helps to encourage competitive behavior, and actual entry reduces market concentration, both economic reasoning and experience suggest that the possibility of entry alone cannot alleviate all market power concerns in the electricity context. Because new plants must recover their capital costs as well as their operating costs to be attractive investments, there will be situations in which owners of existing plants who have market power can profitably raise prices above the competitive level without triggering entry.

The concern that entry alone will not be sufficient to deter the exercise of market power is borne out by the U.K. experience. Market power problems persisted in the U.K. despite substantial capacity additions by independent power producers and previously committed nuclear capacity between 1991 and 1997 that together represented additions equivalent to 25 percent of total capacity in the England-Wales Pool. Given that conditions within the U.K. market were more favorable to new entry than those in many U.S. regional power markets, potential entry should not be viewed as a "cure all" for market power in the near to medium term.

Opposition from existing competitors is also unlikely to alleviate or prevent the exercise of market power. Because surrounding generators would be able to profit from higher prices without having to idle their own capacity, they will generally welcome rather than oppose the exercise of market power by a dominant supplier.

New simulations of U.S. regional power markets using the Department of Energy's Policy Office Electricity Modeling System (POEMS) are reported in Section 4 of this paper. These analyses confirm that market power can be profitably exploited in some parts of the United States. In markets where concentration is high and transmission constraints impede imports of power from distant generators, firms can employ a simple market power bidding strategy to cut output and increase net revenues from generation by driving up the market price of electricity. The exploitation of market power can have a significant impact on wholesale power prices (Figure ES1), which is in most regions the largest component of the total delivered electricity prices paid by consumers in competitive markets.

Figure ES1. Changes in Wholesale Electricity Prices When Firms Exploit Market Power



Firms considered to have a high potential to exert market power were identified based on their market share and transmission capacity into the local market. The POEMS analysis indicated that these firms would be able to increase profits by 10 percent to 50 percent by reducing output and driving up prices. Wholesale power prices rose in corresponding power control areas (PCAs) by 8 percent to 30 percent as a result of the exercise of market power.

The simulations also show that the totality of restructuring legislation, not just provisions that directly address market power authority, are relevant to the market power issue. For example, the continuation of pancaked transmission rates in the absence of effective Regional Transmission Organizations (RTOs) with adequate size and scope generally increases the opportunity to profit from market power. However, RTOs themselves are not a panacea for market power, as evidenced by the significant opportunities to profitably exploit market power even in simulations that assume the operation of effective RTOs.

In sum, both the record of restructured markets to date and simulation analyses conducted by the Department of Energy suggest that the exercise of market power could, under some circumstances, significantly offset the projected benefits of competition in electricity generation markets.

What remedies can be used to address market power concerns in the electric sector?

Although many antitrust authorities express a preference for structural remedies to address market power concerns, a variety of options that fall along the spectrum between direct regulation of prices and divestiture could be applied as part of a market power mitigation strategy. Such options include creating bidding trusts for certain assets, requiring generators to offer real-time curtailment prices to end-use customers, or placing limits on the variance of bid prices for individual generating units. This paper briefly reviews these and other options that have been discussed, but does not attempt to evaluate them. Provided there is clear authority to address market power concerns and clear empowerment to exercise that authority, it may be appropriate to tailor the application of remedies to the facts of specific situations as they arise.

Introduction: The Issue of Horizontal Market Power

The shift to reliance on competitive market prices instead of regulated rates for electric generation raises the possibility that some firms could drive up prices by exercising market power. Market power is defined as the ability of a supplier to profitably raise prices above competitive levels and maintain those prices for a significant time period.

The economics and antitrust literature identify two types of market power, horizontal and vertical. Horizontal market power is exercised when a firm profitably drives up prices through its control of a single activity, such as electricity generation, where it owns a significant share of the total capacity available to the market, or a significant share of capacity "at the margin" (i.e., higher-cost capacity that tends to set the market price). Vertical market power is exercised when a firm involved in two related activities, such as electricity generation and transmission, uses its dominance in one area to raise prices and increase profits for the overall enterprise. Concerns related to vertical market power in the electricity sector are commonly understood. The mechanisms for addressing them, such as requirements for independent operation of the transmission system and non-discriminatory access to it are widely accepted.

This paper focuses on the issue of horizontal market power,[1] providing evidence regarding its likely importance in restructured electricity markets.

1. What Is Market Power and Why Does It Matter?

In a truly competitive market, market power is not a problem, because no single firm, or small group of firms, can determine market prices. Instead, all sellers (and buyers) are "price-takers," who assume that their own production and purchase decisions do not affect the market price. The most profitable strategy for a price-taking producer in a competitive market is to "bid" the output of each generating plant into the market at its variable cost of operation.[2] If the market price is equal to or greater than the bid for a particular plant, that plant runs, and any surplus of the market price over variable cost is available for contributing toward fixed costs or profits. If the market price is below the bid level for a particular plant, the owner has no regrets about having bid at variable cost, because running that plant would reduce rather than increase profit.[3]

Prices will, at times, rise above the variable cost of production of the most expensive plant serving a market even if no producer exercises market power. This occurs when demand exceeds maximum available supply at the bid price of the most expensive plant, and transmission constraints make it impossible to bring in more power from other regions. Buyers who are willing to pay prices that exceed the highest competitive bid will offer to do so, and prices will rise until they become high enough to balance supply and demand. The increase in price above the short-run variable cost reflects the value

[1]From this point forward in this paper, the term "market power" refers to horizontal market power.

[2]For electricity generators, the variable cost of production is the cost of fuel plus any operating and maintenance costs that vary with the amount of power produced.

[3]Exit from and entry into competitive markets is driven by the difference between a plant's revenue stream and its variable cost. For example, unless the revenue stream from an existing plant provides enough surplus over variable production costs to cover non-variable costs, such as annual and periodic maintenance costs, the owner will choose to retire it, reducing capacity available to serve the market. In addition, an investor contemplating construction of a new plant will not proceed unless he contemplates that its revenue stream will provide enough surplus over variable costs to provide a return of and on invested capital as well as future non-variable costs.

to consumers of consuming additional electricity in times of limited supply. These price increases allow peaking plants that operate only a few hours a year to recover their fixed costs. Such occurrences, or more generally the need to frequently run high-cost plants, can also signal investors that new capacity may be an attractive investment opportunity.

A firm is said to have market power when it acts in a manner that is intended to change market prices and can maintain prices at a non-competitive level for a significant time period. A firm with market power can profitably influence prices by raising its bid above its variable cost or otherwise reducing its output, in order to drive up prices and earn a higher level of total profit notwithstanding the loss of profit on the potential output it withholds.[4]

Any attempt to measure or understand the potential for market power must begin with a clear definition of the market that identifies both the geographic area and the products included. In markets where consumers can easily substitute other products or buy the same product at other locations, a firm's market power potential will generally be low. While defining the relevant market for the purpose of market power evaluation can be difficult even in the best of circumstances, it is especially problematic in the electricity industry.

Electricity markets are dynamic and can change dramatically over the course of just a few hours, creating opportunities to exercise market power even though the market may be very competitive under most circumstances. For example, the geographic scope of an electricity market is determined by the transmission system. Any change in available transmission capacity can quickly alter the geographic boundaries of the market. To cite another example, certain plants may be required to run at certain times in order to meet reliability needs, effectively giving them market power during those periods, because no other plants can act as substitutes. In other words, the "relevant market" for the purpose of gauging market power may be very different at 5 a.m. than at 5 p.m.

Other characteristics of electricity markets also increase opportunities to exploit market power compared with other industries. Because electricity markets have historically been structured as vertical monopolies with franchise territories, companies often own many plants in a region that cannot receive large flows of power from other areas, potentially allowing them to restrict output at one plant and receive higher prices for power produced at all of their other units. Second, there is very little opportunity for real-time demand response in electricity markets. As prices rise for any given product, the quantity demanded will fall, making it more difficult for producers to exercise market power. In current retail electricity markets, very few end-use consumers face real-time prices, or have the opportunity to be compensated at the market-clearing price for reducing their demand below the usual level by cutting load or switching to backup generation (or both).[5]

Conversely, several factors mitigate against the exercise of market power in well-functioning electric markets. First, to the extent that transmission capacity is available and is efficiently organized and priced, competition from distant producers within each of the three major electrical interconnections that serve the United States and Canada can help to deter the exercise of market power. Second, because a potential entrant has the ability to compete in distant as well as local markets for power, threats of retaliation against a new generator who adds capacity in a market where the incumbent exercises market power may not be credible.

[4]The transmission system offers further opportunities to exert market power in competitive electricity markets. Even if a firm does not own a particular transmission line, it could increase generation at particular plants in order to create congestion on the transmission system, thereby restricting imports and limiting competition. See Cardell, Hitt and Hogan (1997).

[5]While these options will not generally be attractive to small residential consumers, the commercial and industrial customers who account for approximately two-thirds of total electricity demand could make overall demand more price responsive and reduce price volatility while benefiting themselves by pursuing such options.

Do antitrust statutes provide sufficient authority to address market power problems that could arise in a restructured electricity sector?

As noted in recent testimony from the Department of Justice,[6] the antitrust laws do not outlaw the mere possession of monopoly power that is the result of skill, accident, or a previous regulatory regime. Antitrust remedies are thus not well-suited to address problems of market power in the electric power industry that result from existing high levels of concentration in generation. If market power in a restructured electricity sector is a matter of concern, it would be appropriate to address it in the context of comprehensive electricity restructuring legislation.

2. Concentration in Electric Generation Markets: An Indicator of Potential Market Power

The Herfindahl-Hirschmann Index (HHI), a widely used measure of market concentration, determines market concentration by computing the sum of the squared market share of each competitor. In a "perfect monopoly," in which one firm supplies 100 percent of the market, the maximum value of the HHI is at the maximum level of 10,000 (100 times 100). In extremely competitive markets, in which hundreds of firms each hold a fraction of 1 percent of the market, the HHI value approaches zero. The Horizontal Merger Guidelines issued jointly by the U.S. Department of Justice and the Federal Trade Commission use the HHI as a primary screening tool to identify whether markets are likely to have enough competitors to be workably competitive following a proposed merger. Markets with an HHI value below 1000 (e.g., 10 firms, each with a 10-percent market share) are presumed to be unconcentrated, while markets with an HHI of 1800 or more are considered to be highly concentrated. For markets with an HHI of 1800 or above, the antitrust agencies consider that a merger increasing the HHI by as little as 50 points has the potential to raise significant competitive concerns. Mergers that raise the HHI by 100 points or more in markets that are already highly concentrated (HHI of 1800 or above) are presumed to be likely to create or enhance market power or facilitate its exercise.[7]

Schmalensee and Golub (1984) calculate HHI values for electricity markets throughout the United States for 170 generation markets serving nearly three-quarters of the U.S. population, using alternative assumptions about the geographic scope of generation markets. They find a significant number of instances where market concentration as measured by the HHI is in the danger zone defined by the Horizontal Merger Guidelines. For example, under the assumption of low transmission capacity, between 35 percent and 60 percent of all generation markets have HHI values above 1800 across a range of alternative marginal cost and demand elasticity cases. The load-weighted mean HHI value ranges from 1590 to 2650, indicating substantial concentration. For the more favorable case of high transmission capacity, concentration is less severe, but up to 33 percent of markets still had HHI values above the threshold value of 1800 used in the merger guidelines to identify markets that are highly concentrated.

While the data used by Schmalensee and Golub do not reflect the increased market role of independent power since 1980,[8] there is little doubt that updated HHI calculations would identify some highly concentrated markets. A recent study by Cardell, Hitt and Hogan (1997) suggests that electricity markets

[6] U.S. Department of Justice (1999).

[7] See U.S. Department of Justice and the Federal Trade Commission (1997), Section 1.5.

[8] Beginning in 1978, Congress has acted to remove impediments to independent power through the Public Utility Regulatory Policies Act (PURPA), which required utilities to purchase power generated by qualified facilities, and the 1992 National Energy Policy Act (EPACT), which allowed for exempt wholesale generators.

are still highly concentrated today. Using 1994 data and a narrower definition of the geographic scope of electricity markets, they calculate HHI values for 112 regions based on State boundaries and North American Electric Reliability Council (NERC) subregions. Although the analysis does not reflect the recent spate of mergers and divestitures, approximately 90 percent of these regions have HHI values above 2500.

HHI indices only identify situations where some firms may possess enough market power to interfere with workable competition. They cannot indicate whether firms will actually exercise that market power, or the possible implications for prices and profits. Insights into those issues drawn from studies of competitive markets in California and the United Kingdom and modeling analyses of U.S. electricity markets are discussed below.

3. Evidence of Market Power in the United Kingdom, California, and Other Markets

Several studies have found evidence of market power in deregulated electricity markets or have analyzed the potential for market power. In both the United Kingdom (U.K.) and California, where data from competitive electric generation markets are now available, researchers have found that prices have been above competitive levels at times. Other studies examining electricity markets in Australia, New Jersey, and Colorado identify potential market power issues in those areas.

The Impact of Market Power on Wholesale Electricity Prices in the United Kingdom and California

Analysts have been able to assess the impacts of market power based on actual data from the U.K. and California. These studies suggest that generators in these two markets may have earned substantial excess revenues due to market power.

The U.K. experience has been the subject of many reviews, in part because that country was one of the first to implement competition in wholesale power markets. Since the creation of the U.K. power pool in 1990, the Office of Electricity Regulation (OFFER)[9] has investigated market power abuses on a number of occasions in response to unusually high pool prices. The U.K. market design provided generators with two types of compensation: capacity payments based on a day-ahead comparison of anticipated capacity requirements with available capacity, and energy payments based on system marginal prices. In early 1992, both system marginal prices and capacity payments rose dramatically. After investigating, OFFER determined that National Power and PowerGen, the two largest generating companies, which together accounted for 70 percent of total capacity in the pool, were bidding prices in excess of their marginal costs. In addition, PowerGen had declared a number of plants unavailable in order to raise the capacity payment. Once the capacity payment had been determined, PowerGen then declared the units available, making them eligible to receive the higher capacity payments. Although OFFER instituted a number of reforms after the episode, they seemed to have somewhat limited success in restraining market power.[10]

Wolfram (1998 and 1999) examined strategic bidding behavior by National Power and PowerGen. Using data on fuel costs and heat rates, she estimated the marginal cost of electricity for the system and compared this cost with the pool's "system

[9] In 1999, OFFER and the Office of Gas Supply were combined to create the Office of Gas and Electricity Markets, OFGEM.
[10] OFFER eventually instituted price caps on system marginal prices, required National Power and PowerGen to divest a portion of their generation assets, and required generators to file annual plans regarding scheduled plant outages.

marginal price"[11] in order to determine the price-cost markup (the difference between a generator's marginal cost and its bid price). Wolfram estimates that from 1992 to 1994, system marginal prices ranged from 19 percent to 25 percent above estimated marginal costs.

Wolak and Patrick (1997) examine the issue of capacity withholding in the U.K. power pool. Because of the structure of the U.K. power pool, firms can benefit significantly by withholding generation. Prices paid to generators include a capacity payment determined each half-hour by the pool operator, based on the level of reserves available and the value of lost load.[12] As reserve capacity falls, the capacity payment increases. By withholding capacity, firms receive both higher capacity payments and higher system marginal prices for their output, making this a very profitable strategy.

After analyzing the half-hourly market-clearing prices and quantities, and half-hourly bids and availability declarations from 1991 to 1995, the authors cite several pieces of evidence to demonstrate that National Power and PowerGen are strategically withholding capacity. First, they find that the percent of total capacity declared unavailable by National Power and PowerGen in 1995 during off-peak months is more than twice the average amount of capacity declared unavailable by all generators in off-peak months. In addition, they calculate average availability factors by fuel type for National Power and PowerGen and compare them to industry benchmarks based on NERC data for comparable units. For every fuel type, the availability factors for both National Power and PowerGen are below the industry benchmark. For example, average availability factors for combined-cycle gas turbines (CCGTs) are 53 percent and 64 percent for National Power and PowerGen, respectively, compared with an industry benchmark of 80 percent. By contrast, availability factors for independent power producers selling to the U.K. pool are all above the industry benchmark, ranging from 81 to 93 percent for CCGTs.

The California wholesale market is much newer than the U.K. market, having opened to competition in 1998. This market has an institutional structure different from that used in the U.K. — for example, there are no payments for capacity outside of those directly related to the provision of ancillary services. Despite the opportunity of California market designers to learn from the U.K. experience, early analyses provide some evidence that market power is being exercised. Borenstein, Bushnell and Wolak (1999) examine the California wholesale market for June-November 1998. They compute the aggregate marginal supply curve based on fuel costs, heat rates, and variable operating and maintenance (O&M) costs, using data from the California Energy Commission and other sources. Using the hourly generation levels from the Independent System Operator, they determine the competitive price for each hour. The competitive price is then compared to the hourly (unconstrained) price in the California Power Exchange (PX) to estimate the price-cost markup. For the entire 6-month period, total payments to generators were 29 percent, or $494 million, above competitive levels. At certain times, prices were as much as 75 percent above competitive levels. The highest markups were found during July and August from noon to 6 p.m., when demand is high. Wolak (2000) recently extended the analysis to include the summer of 1999, resulting in a revised estimate of more than $800 million in payments above competitive levels to generators during the summers of 1998 and 1999 taken together.

The studies discussed in this section generally report the price premium as a percentage of the wholesale market price of power. The wholesale price of power is only one component of the overall

[11]Pool prices in the U.K. include three distinct elements: the system marginal price, which equals the bid of the last generator scheduled for dispatch; a capacity payment designed to compensate generators for supplying capacity; and an uplift charge to adjust for differences in forecasted and actual demand and to cover the costs of additional services provided by generators (e.g., voltage support). Increased costs due to higher capacity payments are not reflected in this analysis, because only the system marginal price is examined.

[12]The value of lost load is the estimated amount that end-use customers receiving electricity with firm contracts would be willing to pay to avoid a disruption in their electricity service.

price paid by consumers for electricity service, which also includes the costs of transmission and distribution and other expenses. The same price impacts measured as a percentage of the total delivered price of electricity to end users would be significantly smaller, in many markets ranging from one-half to two-thirds of the generation-only percentage impact.

Other Evidence of Market Power in the United Kingdom and California

Empirical studies such as those by Wolfram (1998a, 1998b) and by Borenstein, Bushnell and Wolak (1999) measure the extent of market power by first estimating the marginal cost of and then comparing the estimates to prices. There are, however, a number of difficulties in attempting to estimate generation costs. Wolfram, for example, does not include variable O&M costs in her estimates, and thus may be understating actual generation costs. In California, generators do not explicitly submit bids for startup costs (as in other power pools) and must instead include these costs in their bid prices for energy (although the inclusion of startup costs would not fully account for the higher payments to California generators noted above). As such, a generator's bid may appear to be above marginal costs even though the bid price accurately reflects the generator's variable cost of production.

Other evidence, however, suggests that firms are exercising market power — bidding behavior in the U.K., for example. While firms will have an incentive to bid higher prices into the pool in order to receive higher revenues, these incentives are countered by a need to ensure that the plant is dispatched. Economic theory predicts that, if generators are behaving strategically, price-cost markups will be higher for plants that are more likely to set the pool price, and when more of a generator's inframarginal capacity is available. Wolfram finds evidence of both of these outcomes in the U.K. power pool. In addition, she finds that the variation in bid prices for a given generating unit is greater than the variation in bid prices across generating units.

Other analysts have compared actual California PX prices to a 1997 Borenstein and Bushnell study examining the potential for market power in the California wholesale market. In two of the four months examined, the model overestimates prices assuming either competition or market power. In the other two months, however, the model accurately predicts competitive prices for about 80 percent of the hours, generally when loads are low. For approximately 10 percent of the hours during these two months, actual PX prices fall within the range of predicted prices assuming market power.

Effect of Entry on Market Power

The entry of new competitors into the market is one important factor that can limit the ability to sustain prices above the competitive level for a significant time period, which defines market power. The possibility of rapid entry by new competitors can deter the exercise of market power by an incumbent firm that dominates its market, because the entry attracted by the above-normal profits associated with high prices can lead to overcapacity and subpar profits following entry.

While the threat of entry undoubtedly helps to encourage competitive behavior, and actual entry reduces market concentration, both economic reasoning and experience suggest that the possibility of entry alone cannot alleviate all market power concerns in the electricity context. Because new plants must recover their capital costs as well as their operating costs to be attractive investments, there will be situations in which owners of existing plants who have market power can profitably raise prices above the competitive level without triggering entry. For example, if the competitive price based on marginal costs is 2 cents per kilowatthour in a particular market during a particular time period, but a new entrant would not be attracted into the market for a price below 3 cents per kilowatthour, market power could be exercised to raise prices considerably above competitive levels without attracting new entry. There are also considerable lags in the siting and permitting processes that can both slow and limit entry that would otherwise result from the exercise of market power.

Although there has been considerable entry into the U.K. market since privatization, it has not completely eliminated market power. Pool prices during 1993 and 1994 were, on average, just below a potential entrant's long-run average costs. In addition, National Power and PowerGen retired significant amounts of generation as new firms entered the market in the early 1990s, thus limiting the net increase in capacity within the pool. The most recent price spikes in 1999 suggest that National Power and PowerGen can still exercise market power despite new entry and their subsequent decreases in market share.[13]

Market power problems have persisted in the U.K. despite substantial capacity additions by independent power producers (12,300 megawatts) and previously committed nuclear capacity (3,200 megawatts) between 1991 and 1997 that together represented additions equivalent to 25 percent of total capacity in the England-Wales Pool. Since conditions within the U.K. market were probably more favorable to the early entry of significant independent power producer capacity than those in many U.S. regional power markets, entry should probably not be viewed as the "cure all" for market power in the short to intermediate run.

Studies of Potential Market Power in Other Regions

Borenstein, Bushnell and Knittel (1997) analyze the potential for market power in New Jersey. Because of transmission constraints both within and into the Pennsylvania-New Jersey-Maryland (PJM) power pool, New Jersey ("PJM-East") may at times be a small, geographically distinct market, providing opportunities for generators to exercise market power. The analysis investigates the potential for the five major New Jersey utilities to raise prices by reducing their output, assuming that the surrounding markets (New York and "PJM-West") are perfectly competitive and will sell into the New Jersey market when possible, given prices and transmission constraints. They find that market prices begin to exceed competitive levels when demand in New Jersey rises above 14,500 megawatts (peak demand for New Jersey is assumed to be 16,500 megawatts in 2000 for this analysis). At this level of demand, potential price increases due to market power range from just a few percentage points to a factor of 4.

Colorado is another region in which the potential for market power has been analyzed. Sweester (1998) notes that transmission constraints and the presence of a dominant firm may provide opportunities to exercise market power in eastern Colorado. He examines the mitigating effects of various policy options or market developments. For example, the participation of rural electric cooperatives and municipal power agencies in competitive markets reduces the projected price-cost markups by approximately 10 percent. If 1,000 megawatts of new, competitive generation is assumed to enter the market, price-cost markups fall dramatically. The greatest reduction in price-cost markups under a market power scenario results from requiring 50 percent divestiture by the dominant firm.

Several State public utility commissions have also undertaken market power studies as part of restructuring. In Michigan, for example, staff at the Public Service Commission calculated HHI values for the State and concluded that the Michigan market is "so highly concentrated and the advantages of incumbent utilities are so pervasive that proactive measures are imperative." The Public Service Commission of Utah used simulation studies similar to the New Jersey and Colorado studies and found that the dominant firm would be able to exercise market power 45 to 60 percent of the time.

[13]Pool prices in the U.K. in July 1999 were about 80 percent higher than in the same period in 1998 despite relatively little increase in demand or fuel prices compared to the previous year. OFGEM determined that these price increases were due primarily to higher bid prices for coal-fired units owned by National Power and PowerGen. For a more detailed discussion, see Office of Gas and Electricity Markets (1999).

Impacts of Market Power on Other Generators

Demand for electricity in a particular market is often dispersed among a great number of loads. Given the widespread use of cogeneration by energy-intensive operations in the chemicals, petroleum, and pulp and paper industries, in most cases the net demand for power of the largest user is only a small fraction of total demand in a regional market. The relatively atomistic allocation of net demand among loads limits the attention that individual loads will rationally devote to detecting market power abuse and pursuing redress.

Although there will typically be important secondary suppliers even in markets where ownership of generation is highly concentrated, the exercise of market power by the dominant supplier is likely to be welcomed rather than opposed by its existing competitors. Indeed, these competitors are able to profit from the higher prices resulting from the withholding of capacity by the firm that exercises market power without having to idle their own capacity to achieve those prices. In fact, they will often increase their output in response to capacity withholding by the dominant firm (although if their increase in output is large enough to offset the entire price increase, then by definition the dominant firm does not have market power). In this sense, perhaps it is even better to be the competitor of a firm exercising market power than to have market power oneself. Policymakers should certainly not expect to rely on competitors' opposition to confront market power.

4. Analysis of Market Power Using POEMS

Analysis Methods

To gain additional insights into the potential for electricity generators to exercise market power, the Department's Policy Office carried out an exploratory analysis of market power using the Policy Office Electricity Modeling System (POEMS).[14] To examine the profitability of exploiting market power, we used POEMS to simulate a bidding strategy that raises the bids of plants in the middle of the dispatch order — so-called "mid-merit" plants — above the competitive level. Under many types of load conditions, members of this group are the marginal (price-determining) plants, and a change in their bidding strategy has the potential to affect market prices. We simulated a relatively simple bidding strategy — raising the bid in each hour for mid-merit plants to 150 percent of the competitive level. In reality, a generator with market power would probably attempt to maximize profits by taking a more strategic approach to influencing prices, such as withholding generation or raising bid prices only on certain units or in certain time periods. Nonetheless, the analysis illustrates the conditions under which generators could exert market power and provides some insights into its effects on electricity markets.

Economic reasoning and the market power literature identify high concentration in the ownership of generation that serves or could potentially serve a particular market as a key factor creating the potential to exercise market power. For this reason, two key indicators of a situation where the potential for market power is high are high ownership concentration within the local power control area (PCA)[15] and limited available transmission capacity that would allow generators outside the PCA to wheel power into the area. Together, these two factors

[14] POEMS is a modeling system that integrates the Energy Information Administration's National Energy Modeling System (NEMS) with TRADELEC™, which provides a much more detailed representation of electricity markets than the NEMS electricity module. For a description, application, and documentation of POEMS see U.S. Department of Energy, Office of Policy (1999).

[15] A power control area is an electric power system or combination of systems in a designated geographic area. The control area operator is responsible for controlling the facilities within it to ensure that load and generation are balanced at all times.

allow us to identify highly concentrated electricity markets.

To examine the potential for the exercise of market power in competitive electricity markets, the database supporting POEMS was searched to identify groups of firms with "high" and "low to modest" potential to exercise market power, based on concentration and transmission capacity information. Four to five companies in each category were identified according to the criteria given in Table 1.[16,17]

In addition to physical transmission capability, the organization and pricing structure of transmission markets also affect the ability of outside generators to compete.[18] For a given physical configuration of the transmission system, outside generators are less effective competitors if the system is balkanized and rates are pancaked than if postage stamp transmission charges are applied within appropriately sized Regional Transmission Organizations (RTOs). An additional scenario using pancaked rates was run to assess the impact of transmission pricing on market power. The results of the analysis assuming postage stamp rates are presented first, followed by a comparison of the postage stamp and pancaked rate scenarios.

Results

Result #1: None of the firms in the low market power potential group were able to raise their profitability by bidding their mid-merit units at 150 percent of the competitive bids. They lost more in operating surplus (revenues minus variable costs) from not running these units during periods when the market price fell between 100 percent and 150 percent of the competitive bid than they gained from the impact of their bidding strategy on prices.

In the group of firms with low-to-modest market power potential, each company analyzed owns less than 50 percent of the total capacity within its PCA. Further, these PCAs have transmission interconnection transfer capability that is over 100 percent of each selected company's generating capacity, thus providing an opportunity for generators outside the region to compete somewhat unconstrained by transmission limits. In general, these companies should have less opportunity to exercise market power because other generators within and outside the PCA would likely increase their output as prices began to rise. Each of the four companies is in a different regional transmission group, so there is not likely to be any interaction among the companies.

Table 1. Company Criteria for Market Power Scenarios

Scenario	Concentration of Ownership	Transmission Capability
High Market Power Potential	A single company owns more than 75% of the capacity in the power control area (PCA).	Transmission import capability into the PCA is less than 40% of the company's capacity.
Low to Modest Market Power Potential	The company owns 20% to 50% of the capacity in the power control area (PCA).	Transmission import capability into the PCA is over 100% of the company's capacity.

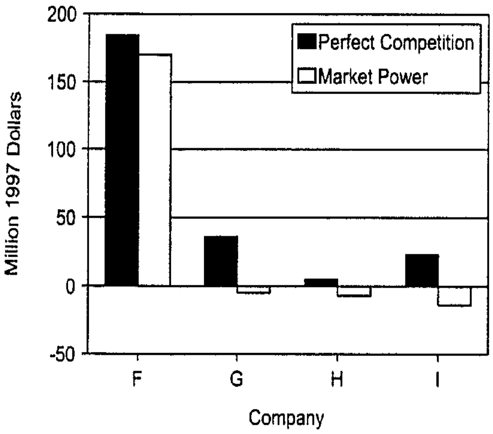
[16]Members of the high market power potential group were selected by applying the criteria in Table 1 to investor-owned utilities (IOUs) in the 20 regions into which the Nation's 140+ power control areas and 3,000+ utilities are assigned for purposes of reporting POEMS results. Then, all IOUs meeting these criteria were sorted by generation capacity and region. The four largest of these utilities (subject to a limitation of one per region) were included in the sample. One smaller firm with a dominant position in a region with smaller load was added to the group to avoid an exclusive focus on larger markets.

[17]Members of the "low to modest" market power potential group were randomly selected from among the many candidates meeting the relevant criteria in Table 1. Firms with "very low" market power potential were not considered in this analysis.

[18]Transmission constraints in POEMS will soon be revised using detailed analyses of bulk power flows. Changes in the representation of the transmission system would likely alter the POEMS results presented here.

In this scenario, none of these firms benefits from raising its bid prices. In fact, the operating surplus for three of the companies becomes negative (Figure 1). In other words, these firms can no longer cover their fixed costs. The higher bids increase generation prices in these PCAs by 2 to 9 percent, and the other companies in the PCA receive higher revenues. However, all the companies attempting to exercise market power lose a significant share of generation and are worse off.

Figure 1. Operating Surplus in 2000 for Firms with Low Market Power Potential Under Perfect Competition and Market Power Bidding Strategies



Result #2: Firms with high potential market power can generally increase their profits by exercising their power to raise prices. Operating surpluses for the six companies in the high market power potential group increase by 25 to 75 percent, and wholesale prices within the PCAs of each of the firms rise by 8 to 30 percent when the firms apply a strategy of bidding their mid-merit units at 150 percent of the competitive bid. Results for each company are given in Table 2.

Each of the firms in the group with high market power potential benefitted from raising its bid price. The increase in the market-clearing price more than offsets the loss of revenue due to decreases in output. For example, generation levels for Company A, which owns roughly 89 percent of the total capacity within its PCA, decline by more than 10 percent as a result of its higher bid price. Operating surpluses, on the other hand, rise by more than 60 percent, from \$4.70 per megawatthour to almost \$7.70 per megawatthour, leading to a \$106 million increase in total revenues — approximately 6 percent. At the same time, total costs fall by \$86 million, and Company A's operating surplus increases by nearly \$200 million (Figure 2). Altogether, the five generators earn an additional \$800 million in operating surplus, and wholesale prices within each of the PCAs rise by 8 to 30 percent as a result (Figure 3).

Table 2. Changes in Operating Margins and Prices for Firms with High Market Power Potential That Adopt a Bidding Strategy To Exploit Market Power

Company	Change in Generation (Gigawatthours)	Change in Revenues (Million 1997 Dollars)	Change in Costs (Million 1997 Dollars)	Change in Surplus (Million 1997 Dollars)	Change in Surplus per Megawatthour (1997 Dollars)
A	-10,185	106	-86	191	3.0
B	-22,468	-167	-493	326	6.7
C	-9,458	49	-182	231	5.7
D	-1,053	15	-22	38	2.4
E	-21,756	-271	-282	11	0.5

Figure 2. Revenues, Costs, and Operating Surplus in 2000 for Company A Under Perfect Competition and Market Power Bidding Strategies

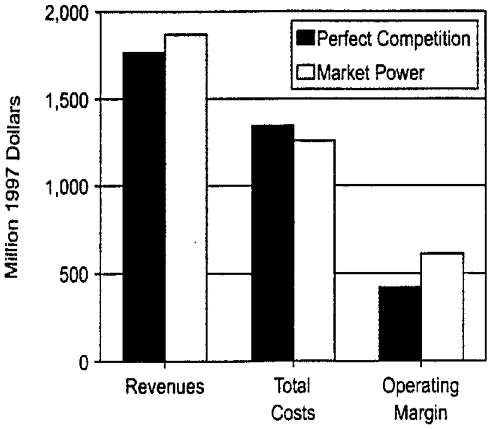
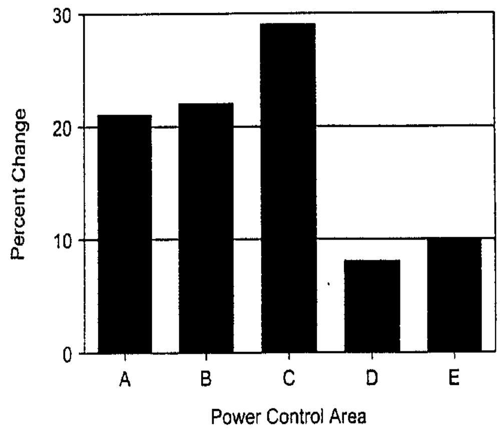
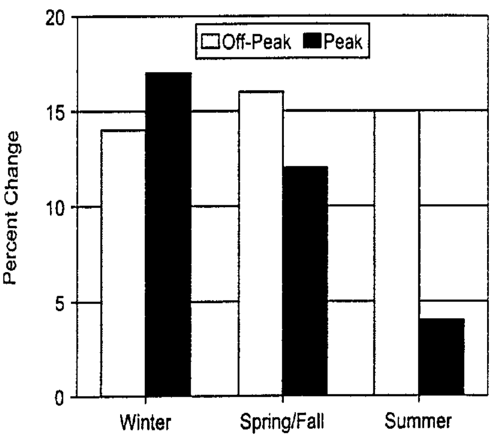


Figure 3. Changes in Wholesale Electricity Prices When Firms Exploit Market Power



For most of these firms, increasing the bid price of selected plants is profitable in virtually all time periods. In other words, at each level of load, the effect of the increase in price more than offsets any loss in generation. Figure 4 illustrates the percentage change in operating margins for Company A for six aggregate time periods: peak and off-peak for three seasons.[19] The largest increase in operating surplus for this firm occurs during the winter peak hours and the off-peak hours of summer, spring, and fall. The smallest increases occur during the summer peak hours. Most of the Company A plants for which prices are increased are relatively low-cost plants. In spite of the increase in bid prices, these plants are still less expensive than the high-cost plants used to satisfy the summer peak loads. Consequently, the market price remains relatively unchanged during the highest summer peak loads, and Company A's operating surplus increases less than during other time periods.

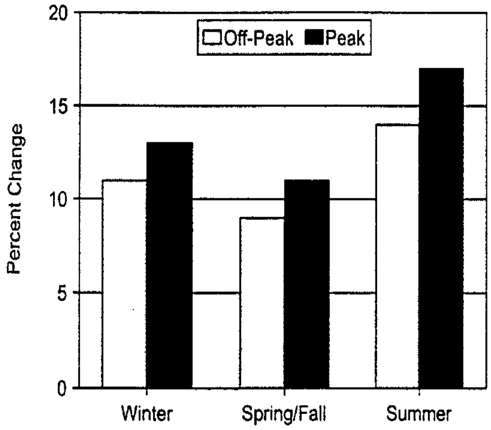
Figure 4. Changes in Operating Surplus in Different Time Periods for Company A



Seasonal variations in market power are quite different for Company B. In this case, the increase in bid prices causes these plants to become the marginal units during the highest demand periods, leading to substantial increases in prices and operating margins during the summer peak period. Operating surpluses increase less during the spring/fall off-peak periods, because the highest cost plants are not always needed. During those hours when demand is very low, raising the bid prices has no effect on market prices, because these plants are not utilized in either the base case or the market power scenarios (Figure 5).

[19]POEMS simulates 72 time periods per year. For the aggregation illustrated here, the off-peak period is defined as the 8 hours from 11 pm to 7 am, and on-peak is the 16 hours from 7 am to 11 pm. The winter months are defined as December through March, summer as June through September, and spring/fall as the remaining months.

Figure 5. Changes in Operating Surplus in Different Seasons for Company B



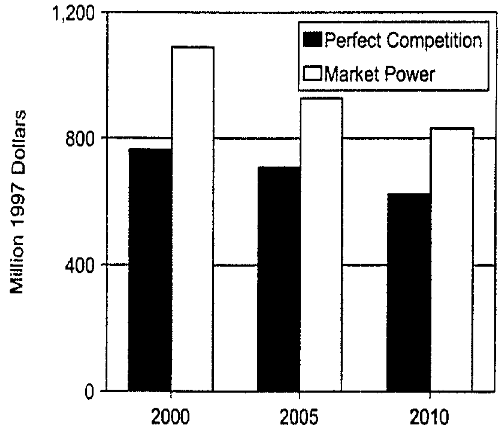
Result #3: The impacts of higher prices due to market power are felt across a wide region and benefit many firms. The increase in operating surplus flowing to all generators as a result of market power is more than twice the amount earned by only those plants exercising market power.

The effects of market power are experienced across a wide region, not just in the immediate PCA or RTG. Other generators both within and around the PCA benefit by receiving higher revenues for their output and by increasing output. For example, as Company A's generation decreases, other generators within the PCA increase their generation by roughly 430 gigawatthours. Generators in PCAs immediately surrounding Company A (those with direct transmission connections to Company A's PCA) increase output by roughly 8,120 gigawatthours. In this case, the PCA was a net exporter and becomes a net importer. Overall, other generators within the PCA earn higher operating surpluses amounting to an additional $41 million due to Company A's higher bid prices. Generators in the surrounding PCAs earn an additional $67 million, for a gain to all generators of $299 million (including Company A). For this particular example, generating capacity for the immediate surrounding competitors amounts to about 28 percent of the entire Eastern Interconnection.

Result #4: New entry by other firms eases market power over time.

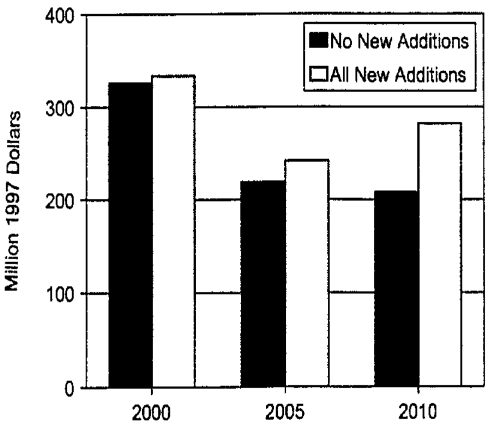
Because market power is driven in part by dominance in an area by one or a few players, a region could "grow" out of a potential market power problem through entry by other firms.[20] Figure 6 shows the operating surplus over time in the market power scenario as compared to the "perfect competition" scenario for Company B. By 2010, the firm's market power has not been eliminated altogether but is substantially diminished. Roughly 9,400 megawatts of new capacity is built in the PCA, and 4,000 megawatts of Company B's capacity is retired. As a result, total capacity owned by Company B within the PCA falls from 80 percent to 53 percent, assuming that other generators build all the new plants. If, however, Company B owns some of the new capacity, then its extra margin from exerting market power still decreases over time but to a lesser extent. Figure 7 illustrates the gain in operating surplus for the company if it builds no new plants and if it is assumed to build all the new plants in the PCA.

Figure 6. Changes in Operating Surplus Over Time for Company B



[20]In addition to the entry of new players, local regulators in some States have ordered current owners of capacity to divest their capacity, thereby immediately increasing the number of players in a given market.

Figure 7. Changes in Operating Surplus for Company B Under Different Ownership Assumptions for New Plants



Effects of Alternative Transmission Rate Structures

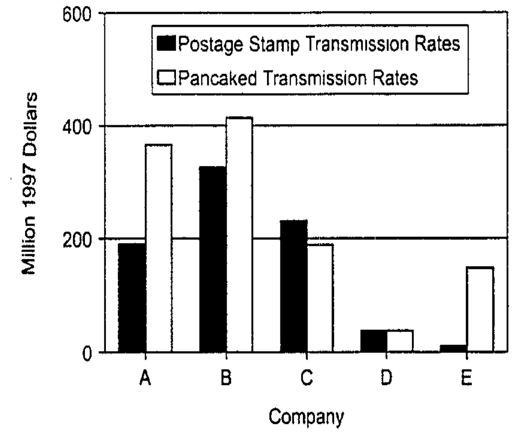
Result #5: The potential to exploit market power in restructured electricity markets increases if restructuring does not include provisions that increase the efficiency of transmission markets.

The results presented above were derived from model runs in which transmission prices were determined through "postage stamp" rates — the same assumption that is used in the underlying POEMS competition case. This assumption reflects the formation of effective regional transmission organizations (RTOs) under the Administration's proposal, which would clarify the authority of the Federal Energy Regulatory Commission (FERC) to mandate RTOs and remove tax law impediments that discourage the participation of public power and cooperative entities in RTOs. In contrast to the existing system of "pancaked" transmission rates, under which fees are paid to each transmission owner along the contract path, generators would pay a flat fee to wheel power anywhere within the RTO regardless of the distance traveled.

To assess the influence of transmission pricing on market power, the scenarios were re-run assuming pancaked rather than postage stamp rates. In both sets of scenarios, wheeling fees are assumed to be 50 percent of rates calculated using the *pro forma* tariffs identified in FERC Order 888. Although transmission rates are the same in both scenarios, the total amount of transmission fees paid by wholesale market participants is higher in this scenario because of the pancaked rate structure (assuming the volume of wholesale wheeling remains unchanged).[21] The additional fees raise the cost of wheeling power across more than one utility system and effectively reduce the geographic scope of several regional markets.

Three of the five firms in the high market power potential group are able to exploit their market power more effectively under pancaked rates (Figure 8). Although, as in the previous scenario, each firm bids 150 percent of its marginal cost, the pancaked transmission fees raise the cost of imported power, allowing generators to raise prices without losing significant market share. Company A, for example, sees a significantly smaller decline in generation output when pancaked rates are in

Figure 8. Change in Operating Surplus Under Different Transmission Rate Structures



[21]Because transmission owners are regulated monopolies, their revenue requirements are determined through rate-of-return regulation. As such, the total level of revenues collected by transmission owners from both wholesale and retail customers remains the same in the two scenarios. In POEMS, any revenue requirements not met through wholesale transmission fees are met through charges on native load customers.

place. Under postage stamp rates its output falls by more than 11 percent, while under pancaked rates its output falls by only 4 percent. Operating surplus per megawatthour increases by roughly 50 percent compared to the postage stamp scenario, because the lack of lower cost imports raises the price within the PCA. Overall, the firm earns an additional $175 million through its market power when pancaked rates are used.[22]

5. Remedies for Market Power

Although many antitrust authorities express a preference for structural remedies to address market power concerns, a variety of options that fall along the spectrum between direct regulation of prices and divestiture could be applied as part of a market power mitigation strategy. This section briefly outlines some of the possible options that have been discussed, but does not evaluate them.

➢ **Market Monitoring.** Absent the exercise of market power, competitors have an incentive to minimize outages during periods of peak demand and prices, in order to maximize profits. The outage experiences and bid strategies of generators with market power could be monitored, with appropriate penalties applied if evidence of market abuse is uncovered.

➢ **Creation of a Bidding Trust for Certain Assets.** Generators can agree to place some or all assets in a "bidding trust" to mitigate market power.

➢ **Contracts for Differences and Call Options.** Generators with market power could provide an RTO or other designated recipient with call options that are "in the money" if prices rise above preset threshold. This can reduce those generators' incentive to withhold capacity.

➢ **Requirements for Transmission Upgrades.** Generators could be required to upgrade transmission under their control to mitigate their market power in load pockets where they operate.

➢ **Interconnection Requirements.** Generators could be required to streamline access to transmission lines or plant sites under their control to reduce barriers to entry.

➢ **Requirements To Offer Real-Time Curtailment Prices to End-Use Customers.** A generation owner with market power could be required to offer its end-use customers real-time market prices for load curtailment. This would mitigate the price effect of any effort to withhold capacity.

➢ **Limitations on Variance of Bid Prices.** Under competition, bids for running individual units should not vary with market conditions (although market prices will). To mitigate market power, a generator with market power could agree to limited bands for bidding each unit.

➢ **Denial of Market-Based Rates.** Where allowed by law, regulators could revert to cost-based rates in instances where they have reason to believe that incumbent generators are exercising market power. However, denial of market-based pricing for electricity generation risks jeopardizing the benefits in terms of new products and services and greater incentives for efficiency that competition can bring to electricity consumers.

[22]Companies C and A, although not immediately adjacent to each other, are in nearby markets. In the postage stamp transmission scenario, Company C benefits slightly from the market power exerted by Company A, earning additional revenues over and above the surplus it receives due to its own market power. In the scenario with pancaked transmission rates, however, the two firms are separated into distinct markets as a result of the higher wheeling costs, and Company C earns slightly less revenue than in the postage stamp scenario.

6. Conclusion

The literature on recent experience with electricity sector competition and the new analysis using POEMS presented in this paper both suggest that the potential to exploit market power in restructured electric markets can significantly reduce the benefits to consumers that should result from the advent of competition in electricity markets.

Existing antitrust authority or the threat of new market entry does not appear to be adequate to alleviate concerns surrounding the potential exercise of market power in restructured electricity markets. In recent testimony, the Department of Justice noted that the antitrust laws do not outlaw the mere possession of monopoly power that is the result of skill, accident, or a previous regulatory regime. Antitrust remedies are thus not well-suited to address problems of market power in the electric power industry that result from existing high levels of concentration in generation. As for entry, a considerable exercise of market power is possible without inducing new entry. Moreover, even extensive entry by new competitors apparently did not prevent the exercise of market power in England and Wales over a long period of time.

While consideration of remedies to address market power is generally beyond the scope of this paper, we have briefly reviewed some of the options that have been discussed in the literature. Some options, such as the imposition of cost-based rates instead of market prices for electricity generation, risk jeopardizing the benefits in terms of new products and services and greater incentives for efficiency that competition can bring to electricity consumers. Others can be quite controversial. One attractive policy approach may be to assure adequate authority to address market power while applying a remedy best suited to the facts of each situation as it arises.

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Proje[illegible] Generation Related Net Stranded Costs
Columbus and Southern Power
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$377,543
NPV of Cash Flow 2016-2030	$79,210
Total NPV Cash Flow	$456,753
Base	$974,329
Net Stranded Costs	$517,576

Changes

No Change

Exhibit JWW-2
Page 1 of 2

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	PV @ 10.78%
Revenues																			
1) Total GWH Generation		Input	16,238	16,309	16,380	16,451	16,541	16,631	16,403	16,179	15,957	15,739	15,524	15,092	14,672	14,264	13,868	13,482	
2) AEP Price		Input	$23.52	$23.76	$24 01	$24 26	$25.53	$26 79	$27.58	$28.39	$29 22	$30 08	$30.96	$31.81	$32 69	$33 60	$34.53	$35.48	
3) Total Revenues		Input	$396,780	$404,538	$412,448	$420,512	$445,283	$470,053	$478,083	$486,251	$494,558	$503,006	$511,600	$511,972	$512,346	$512,719	$513,093	$513,467	
Expenses																			
4) Production Expenses excl. Fuel		Input	$59,059	$61,133	$63,279	$65,501	$68,766	$72,030	$74,846	$77,772	$80,812	$83,971	$87,254	$87,107	$86,961	$86,815	$86,669	$86,523	
5) Fuel Expense		Input	$179,910	$180,576	$181,249	$181,921	$186,411	$190,901	$194,245	$197,648	$201,110	$204,633	$208,218	$204,507	$200,863	$197,283	$193,767	$190,314	
6) Decommissioning/Dismantling		Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00	$0.00	$0 00	$0.00	$0.00	$0 00	$0 00	$17,953	$18,402	$0	$3,726	
7) SO2 Allowance Costs		Input	$11,627	$15,798	$16,967	$18,219	$19,643	$21,168	$18,248	$15,399	$12,612	$9,879	$8,206	$6,468	$4,689	$2,866	$996	$0	
8) A&G Expense		Input	$61,881	$66,843	$65,998	$69,905	$70,470	$73,034	$71,390	$75,668	$82,786	$75,590	$76,724	$77,874	$79,043	$80,228	$81,432	$82,653	
9) Depreciation - Steam	3.2%	Calculated	49,884	51,000	52,718	54,965	56,477	57,241	58,025	58,828	59,652	60,496	61,361	62,178	62,771	63,383	64,175	64,942	
10) - Hydro		Calculated	$0 00	$0 00	$0 00	$0 00	$0.00	$0.00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00	$0 00	$0 00	$0.00	$0.00	
11) Retirements			$0.00	$0.00	$0.00	$0 00	$0.00	$0.00	$0 00	$0 00	$0.00	$0.00	$0.00	$0.00	$10,999	$0.00	$0.00	$1,829	
12) Taxes - Nox and Scr	0.15%	Calculated	$0.00	$0.00	$0 00	$0.00	$0 00	$0.00	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
13) Taxes Other - Other		Input	$41,108	$42,707	$13,663	$14,163	$14,679	$15,216	$15,774	$16,351	$16,950	$17,573	$18,218	$18,885	$19,576	$20,293	$21,035	$21,805	
14) Total Expenses		Calculated	$403,469	$418,057	$393,874	$404,674	$416,446	$429,590	$432,528	$441,666	$453,922	$452,142	$459,981	$457,019	$482,855	$469,270	$448,074	$451,792	
15) Operating Income		Calculated	($6,689)	($13,519)	$18,574	$15,838	$28,837	$40,463	$45,555	$44,585	$40,636	$50,864	$51,619	$54,953	$29,491	$43,449	$65,019	$61,675	
16) Interest Expense	7 96%	Calculated	$31,504	$30,810	$30,863	$31,380	$31,105	$30,050	$28,989	$27,923	$26,851	$25,773	$24,688	$23,530	$22,084	$20,637	$19,390	$18,085	
17) Income Before Taxes		Calculated	($38,193)	($44,329)	($12,288)	($15,542)	($2,267)	$10,413	$16,566	$16,661	$13,785	$25,091	$26,931	$31,423	$7,407	$22,812	$45,630	$43,591	
18) Schedule M		Input	($2,886)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	
19) Taxable Income		Calculated	($41,079)	($44,792)	($12,751)	($16,005)	($2,730)	$9,950	$16,103	$16,198	$13,322	$24,628	$26,468	$30,960	$6,944	$22,349	$45,167	$43,128	
20) Current Fed/State T	40 56%	Calculated	($16,662)	($18,167)	($5,172)	($6,491)	($1,107)	$4,036	$6,531	$6,570	$5,403	$9,989	$10,735	$12,557	$2,817	$9,065	$18,320	$17,493	
21) Deferred FIT/ITC	35 00%	Calculated	$1,010	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	
22) Total Income Taxes		Calculated	($15,652)	($18,005)	($5,010)	($6,329)	($945)	$4,198	$6,693	$6,732	$5,566	$10,151	$10,897	$12,719	$2,979	$9,227	$18,482	$17,655	
23) Net Income Before Preferred		Calculated	($22,541)	($26,323)	($7,278)	($9,212)	($1,322)	$6,215	$9,872	$9,929	$8,220	$14,940	$16,033	$18,703	$4,429	$13,585	$27,148	$25,936	
Cash Flow																			
24) Net Income Before Preferred		From Above	($22,541)	($26,323)	($7,278)	($9,212)	($1,322)	$6,215	$9,872	$9,929	$8,220	$14,940	$16,033	$18,703	$4,429	$13,585	$27,148	$25,936	
25) Plus Interest Expense		From Above	$31,504	$30,810	$30,863	$31,380	$31,105	$30,050	$28,989	$27,923	$26,851	$25,773	$24,688	$23,530	$22,084	$20,637	$19,390	$18,085	
26) Plus Deferred Taxes		From Above	$1,010	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	$162	
27) Plus Depreciation		From Above	$49,884	$51,000	$52,718	$54,965	$56,477	$57,241	$58,025	$58,828	$59,652	$60,496	$61,361	$62,178	$62,771	$63,383	$64,175	$64,942	
28) Plus Retirements		From Above	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,999	$0	$0	$1,829	
29) Less Construction		External File	$31,943	$37,796	$25,332	$38,503	$23,598	$24,188	$24,793	$25,413	$26,048	$26,699	$27,367	$23,723	$24,316	$24,924	$24,579	$25,193	
30) Less Nox (SNCR)		External File	$0	$0	$44,239	$32,390	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
31) Less Nox (SCR) and Scrubber		External File	$0 00	$0.00	$0.00	$0.00	$0.00	$0 00	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
32) Total		Calculated	$27,914	$17,852	$6,893	$6,401	$62,823	$69,480	$72,256	$71,430	$68,837	$74,672	$74,878	$80,851	$76,128	$72,843	$86,295	$85,760	$80,043
															NPV	$ 377,543	$79,210
Capitalization																			
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																			
35) Gross Plant in Service - Steam G		Input	$1,574,841	$1,612,638	$1,682,209	$1,753,102	$1,776,700	$1,800,888	$1,825,681	$1,851,094	$1,877,142	$1,903,841	$1,931,208	$1,954,931	$1,968,248	$1,993,172	$2,017,750	$2,041,114	
36) - Hydro		Input	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00	$0 00	
37) Accum. Depreciation - Steam G		Calculated	*$629,812*	$680,812	$733,529	$788,494	$844,971	$902,212	$960,238	$1,019,066	$1,078,718	$1,139,213	$1,200,574	$1,262,752	$1,325,523	$1,388,906	$1,453,081	$1,518,023	
38) - Hydro		Input	$0 00	$0.00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00	$0 00	$0.00	$0 00	
39) Net Plant		Calculated	$945,029	$931,826	$948,680	$964,608	$931,729	$898,676	$865,443	$832,028	$798,424	$764,628	$730,634	$692,179	$642,725	$604,266	$564,669	$523,091	
40) Plus Fuel Inventory		Input	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$19,532	$19,532	$19,532	$19,057	
41) Plus M&S & Prepayments		Input	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	
42) Less Accum DFIT		Calculated	*$10,840*	$11,002	$11,164	$11,326	$11,488	$11,650	$11,812	$11,974	$12,136	$12,298	$12,461	$12,623	$12,785	$12,947	$13,109	$13,271	
43) Net Investment		Calculated	$974,329	$960,964	$977,656	$993,422	$960,381	$927,165	$893,771	$860,194	$826,428	$792,469	$758,313	$719,696	$667,472	$628,851	$589,093	$546,878	
44) Net Investment		Calculated	$974,329																
45) NPV of Cash Flow 2016-2030			$79,210																

Projected ation Related Net Stranded Costs
Ohio Power ompany
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$96[illegible]821
NPV of Cash Flow 2016-2030	$203,210
Total NPV Cash Flow	$1,170,031
Base	$1,309,382
Net Stranded Costs	$139,351

Change

No Change

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007
Revenues										
1) Total GWH Generation		Input	48,624	48,812	49,001	49,190	49,637	50,083	48,162	46,315
2) AEP Price		Input	$23 52	$23 76	$24 01	$24 26	$25.53	$26 79	$27 58	$28 39
3) Total Revenues		Input	$1,228,139	$1,246,894	$1,265,936	$1,285,269	$1,368,680	$1,452,091	$1,438,367	$1,424,772
Expenses										
4) Production Expenses excl. Fuel		Input	$245,453	$255,181	$265,294	$275,808	$289,321	$302,833	$306,582	$310,376
5) Fuel Expense		Input	$643,926	$615,424	$588,183	$562,149	$576,634	$591,119	$583,076	$575,142
6) Decommissioning/Dismantling		Input	$0 00	$0.00	$0 00	$0 00	$0.00	$0.00	$0 00	$0 00
7) SO2 Allowance Costs		Input	$0	$21,796	$29,084	$26,468	$25,964	$25,326	$18,675	$12,009
8) A&G Expense		Input	$93,279	$94,870	$101,464	$102,737	$103,708	$104,803	$105,907	$106,627
9) Depreciation - Steam Gas	3 40%	Calculated	90,998	97,166	105,150	109,772	112,666	116,097	119,423	122,459
10) - Hydro	2 70%	Calculated	$2,959	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955
11) Retirements		Input	$0.00	$0 00	$0.00	$0.00	$0 00	$0 00	$0 00	$0.00
12) Taxes - Nox and Scrubbe	0 15%	*Calculated*	$0	$41	$71	$80	$96	$103	$103	$103
13) Taxes Other - Other		Input	$78,147	$78,629	$42,536	$42,851	$43,172	$43,500	$43,835	$44,177
14) Total Expenses		Calculated	$1,154,761	$1,166,062	$1,134,737	$1,122,820	$1,154,516	$1,186,737	$1,180,556	$1,173,848
15) Operating Income		Calculated	$73,378	$80,832	$131,199	$162,449	$214,164	$265,354	$257,811	$250,924
16) Interest Expense	7 18%	Calculated	$38,150	$39,992	$43,780	$44,549	$43,749	$43,312	$42,689	$41,730
17) Income Before Taxes		Calculated	$35,228	$40,840	$87,419	$117,900	$170,415	$222,042	$215,121	$209,194
18) Schedule M		Input	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466
19) Taxable Income		Calculated	$38,694	$44,306	$90,885	$121,366	$173,881	$225,508	$218,587	$212,660
20) Current Fed/State Tax	40.56%	Calculated	$15,694	$17,971	$36,863	$49,226	$70,526	$91,466	$88,659	$86,255
21) Deferred FIT/ITC	35.00%	Input	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)
22) Total Income Taxes		Calculated	$14,481	$16,758	$35,650	$48,013	$69,313	$90,253	$87,446	$85,042
23) Net Income Before Preferred		Calculated	$20,746	$24,083	$51,769	$69,887	$101,102	$131,789	$127,675	$124,152
Cash Flow										
24) Net Income Before Preferred		From Above	$20,746	$24,083	$51,769	$69,887	$101,102	$131,789	$127,675	$124,152
25) Plus Interest Expense		From Above	$38,150	$39,992	$43,780	$44,549	$43,749	$43,312	$42,689	$41,730
26) Plus Deferred Taxes		From Above	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)
27) Plus Depreciation		From Above	$93,956	$100,121	$108,105	$112,727	$115,621	$119,053	$122,378	$125,414
28) Plus Retirements		From Above	$0	$0	$0	$0	$0	$0	$0	$0
29) Less Construction		Input	$97,735	$102,566	$80,117	$57,183	$92,019	$94,319	$96,677	$81,891
30) Less Nox (SNCR)		External File	$0	$162,512	$124,435	$10,173	$10,862	$4,639	$0	$0
31) Less Nox (SCR) and Scrubber		Input	$0 00	$0 00	$0 00	$0.00	$0.00	$0 00	$0 00	$0 00
32) Total		Calculated	$53,905	($102,096)	($2,111)	$158,594	$156,378	$193,983	$194,853	$208,192
Capitalization										
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%
Investment										
35) Gross Plant in Service - Steam Gen.		Input	$2,725,286	$2,990,364	$3,194,915	$3,262,272	$3,365,152	$3,464,110	$3,560,788	$3,642,679
36) - Hydro		Input	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453
37) Accum. Depreciation - Steam Gen.		Calculated	*$1,587,274*	$1,684,440	$1,789,590	$1,899,362	$2,012,028	$2,128,126	$2,247,549	$2,370,008
38) - Hydro		Input	$44,176	$47,131 00	$50,086 00	$53,042 00	$55,997.00	$58,952 00	$61,907 00	$64,863 00
39) Net Plant		Calculated	$1,203,289	$1,368,246	$1,464,693	$1,419,321	$1,406,579	$1,386,485	$1,360,785	$1,317,261
40) Plus Fuel Inventory		Input	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929
41) Plus M&S & Prepayments		Input	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000
42) Less Accum DFIT		Calculated	*$24,836*	$23,623	$22,410	$21,197	$19,984	$18,771	$17,558	$16,345
43) Net Investment		Calculated	$1,309,382	$1,475,552	$1,573,212	$1,529,053	$1,517,524	$1,498,643	$1,474,156	$1,431,845
44) Net Investment		Calculated	$1,309,382							
45) NPV of Cash Flow 2016-2030			$203,210							

Income Statement	2008	2009	2010	2011	2012	2013	2014	2015	PV @ 10.47%
Revenues									
1) Total GWH Generation	44,538	42,830	41,187	40,919	40,651	40,386	40,122	39,860	
2) AEP Price	$29.22	$30 08	$30 96	$31 81	$32.69	$33 60	$34.53	$35.48	
3) Total Revenues	$1,411,307	$1,397,968	$1,384,756	$1,409,979	$1,435,662	$1,461,812	$1,488,439	$1,515,550	
Expenses									
4) Production Expenses excl. Fuel	$314,218	$318,107	$322,045	$334,498	$347,432	$360,867	$374,821	$389,315	
5) Fuel Expense	$567,317	$559,598	$551,984	$555,312	$558,661	$562,029	$565,418	$568,827	
6) Decommissioning/Dismantling	$34,860	$35,731	$24,401	$25,011	$0	$0	$0	$0	
7) SO2 Allowance Costs	$5,309	$0	$0	$0	$0	$0	$0	$0	
8) A&G Expense	$108,064	$109,114	$110,205	$111,307	$112,420	$113,544	$114,680	$115,826	
9) Depreciation - Steam Gas	124,279	126,107	128,629	131,222	134,201	137,254	140,383	143,590	
10) - Hydro	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	
11) Retirements	$58,750 00	$0.00	$18,413 00	$0 00	$0	$0.00	$0 00	$0	
12) Taxes - Nox and Scrubbe	$103	$103	$103	$103	$103	$103	$103	$103	
13) Taxes Other - Other	$44,527	$44,884	$45,248	$45,620	$46,000	$46,387	$46,783	$47,186	
14) Total Expenses	$1,260,383	$1,196,600	$1,203,984	$1,206,028	$1,201,772	$1,223,139	$1,245,143	$1,267,803	
15) Operating Income	.$150,924	$201,368	$180,772	$203,951	$233,890	$238,673	$243,296	$247,747	
16) Interest Expense	$39,493	$37,211	$35,601	$33,977	$32,631	$31,262	$29,868	$28,450	
17) Income Before Taxes	$111,431	$164,157	$145,172	$169,974	$201,259	$207,411	$213,428	$219,298	
18) Schedule M	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	
19) Taxable Income	$114,897	$167,623	$148,638	$173,440	$204,725	$210,877	$216,894	$222,764	
20) Current Fed/State Tax	$46,602	$67,988	$60,287	$70,347	$83,036	$85,532	$87,972	$90,353	
21) Deferred FIT/ITC	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
22) Total Income Taxes	$45,389	$66,775	$59,074	$69,134	$81,823	$84,319	$86,759	$89,140	
23) Net Income Before Preferred	$66,042	$97,382	$86,097	$100,840	$119,436	$123,092	$126,669	$130,158	
Cash Flow									
24) Net Income Before Preferred	$66,042	$97,382	$86,097	$100,840	$119,436	$123,092	$126,669	$130,158	
25) Plus Interest Expense	$39,493	$37,211	$35,601	$33,977	$32,631	$31,262	$29,868	$28,450	
26) Plus Deferred Taxes	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
27) Plus Depreciation	$127,235	$129,063	$131,585	$134,177	$137,156	$140,209	$143,338	$146,546	
28) Plus Retirements	$58,750	$0	$18,413	$0	$0	$0	$0	$0	
29) Less Construction	$83,939	$82,352	$84,411	$86,521	$88,684	$90,901	$93,174	$95,503	
30) Less Nox (SNCR)	$0	$0	$0	$0	$0	$0	$0	$0	
31) Less Nox (SCR) and Scrubber	$0 00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
32) Total	$206,368	$180,091	$186,072	$181,260	$199,326	$202,449	$205,488	$208,437	$194,541
							NPV	$ 966,821	$203,210
Capitalization									
33) Debt	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity	60%	60%	60%	60%	60%	60%	60%	60%	
Investment									
35) Gross Plant in Service - Steam Gen.	$3,667,868	$3,750,219	$3,816,217	$3,902,738	$3,991,422	$4,082,323	$4,175,496	$4,270,999	
36) - Hydro	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	
37) Accum. Depreciation - Steam Gen.	$2,494,287	$2,620,395	$2,749,024	$2,880,246	$3,014,447	$3,151,700	$3,292,083	$3,435,674	
38) - Hydro	$67,818 00	$70,773 00	$73,728 00	$76,684.00	$79,639.00	$82,594.00	$85,549.00	$88,504.00	
39) Net Plant	$1,215,215	$1,168,504	$1,102,918	$1,055,260	$1,006,789	$957,481	$907,316	$856,274	
40) Plus Fuel Inventory	$80,308	$80,308	$78,043	$78,043	$78,043	$78,043	$78,043	$78,043	
41) Plus M&S & Prepayments	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	
42) Less Accum DFIT	$15,132	$13,919	$12,706	$11,493	$10,280	$9,067	$7,854	$6,641	
43) Net Investment	$1,318,391	$1,272,893	$1,206,255	$1,159,810	$1,112,552	$1,064,457	$1,015,505	$965,676	

Projec[illegible]eneration Related Net Stranded Costs
Columbus and Southern Power
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$923,691
NPV of Cash Flow 2016-2030	$79,210
Total NPV Cash Flow	$1,002,901
Base	$974,329
Net Stranded Costs	($28,572)

Change
Raise AEP Price to $35.00 and adjust accordingly

Exhibit JWW-
Page 1 of 2

Income Statement	Source	2000	2001	2002	2003	2004	2005	2006	2007
Revenues									
1) Total GWH Generation	Input	16,238	16,309	16,380	16,451	16,541	16,631	16,403	16,179
2) AEP Price	Input	$23.52	$36.54	$36.71	$36.88	$36.91	$36.93	$36.99	$37.05
3) Total Revenues	Calculated	$381,918	$595,910	$601,236	$606,674	$610,455	$614,104	$606,704	$599,464
Expenses									
4) Production Expenses excl. Fuel	Input	$59,059	$61,133	$63,279	$65,501	$68,766	$72,030	$74,846	$77,772
5) Fuel Expense	Input	$179,910	$180,576	$181,249	$181,921	$186,411	$190,901	$194,245	$197,648
6) Decommissioning/Dismantling	Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
7) SO2 Allowance Costs	Input	$11,627	$15,798	$16,967	$18,219	$19,643	$21,168	$18,248	$15,399
8) A&G Expense	Input	$61,881	$66,843	$65,998	$69,905	$70,470	$73,034	$71,390	$75,668
9) Depreciation - Steam 3.2%	Calculated	49,884	51,000	52,718	54,965	56,477	57,241	58,025	58,828
10) - Hydro	Calculated	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11) Retirements		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
12) Taxes - Nox and Scr 0.15%	Calculated	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
13) Taxes Other - Other	Input	$41,108	$42,707	$13,663	$14,163	$14,679	$15,216	$15,774	$16,351
14) Total Expenses	Calculated	$403,469	$418,057	$393,874	$404,674	$416,446	$429,590	$432,528	$441,666
15) Operating Income	Calculated	($21,552)	$177,854	$207,363	$202,000	$194,009	$184,514	$174,176	$157,798
16) Interest Expense 7.96%	Calculated	$31,504	$30,810	$30,863	$31,380	$31,105	$30,050	$28,989	$27,923
17) Income Before Taxes	Calculated	($53,055)	$147,044	$176,500	$170,621	$162,904	$154,464	$145,187	$129,875
18) Schedule M	Input	($2,886)	($463)	($463)	($463)	($463)	($463)	($463)	($463)
19) Taxable Income	Calculated	($55,941)	$146,581	$176,037	$170,158	$162,441	$154,001	$144,724	$129,412
20) Current Fed/State T 40.56%	Calculated	($22,690)	$59,453	$71,401	$69,016	$65,886	$62,463	$58,700	$52,489
21) Deferred FIT/ITC 35.00%	Calculated	$1,010	$162	$162	$162	$162	$162	$162	$162
22) Total Income Taxes	Calculated	($21,680)	$59,615	$71,563	$69,178	$66,048	$62,625	$58,862	$52,651
23) Net Income Before Preferred	Calculated	($31,376)	$87,429	$104,937	$101,443	$96,856	$91,839	$86,325	$77,223
Cash Flow									
24) Net Income Before Preferred	From Above	($31,376)	$87,429	$104,937	$101,443	$96,856	$91,839	$86,325	$77,223
25) Plus Interest Expense	From Above	$31,504	$30,810	$30,863	$31,380	$31,105	$30,050	$28,989	$27,923
26) Plus Deferred Taxes	From Above	$1,010	$162	$162	$162	$162	$162	$162	$162
27) Plus Depreciation	From Above	$49,884	$51,000	$52,718	$54,965	$56,477	$57,241	$58,025	$58,828
28) Plus Retirements	From Above	$0	$0	$0	$0	$0	$0	$0	$0
29) Less Construction	External File	$31,943	$37,796	$25,332	$38,503	$23,598	$24,188	$24,793	$25,413
30) Less Nox (SNCR)	External File	$0	$0	$44,239	$32,390	$0	$0	$0	$0
31) Less Nox (SCR) and Scrubber	External File	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
32) Total	Calculated	$19,080	$131,604	$119,109	$117,056	$161,001	$155,104	$148,708	$138,724
Capitalization									
33) Debt	Input	40%	40%	40%	40%	40%	40%	40%	40%
34) Equity	Input	60%	60%	60%	60%	60%	60%	60%	60%
Investment									
35) Gross Plant in Service - Steam G	Input	$1,574,841	$1,612,638	$1,682,209	$1,753,102	$1,776,700	$1,800,888	$1,825,681	$1,851,094
36) - Hydro	Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
37) Accum. Depreciation - Steam G	Calculated	*$629,812*	$680,812	$733,529	$788,494	$844,971	$902,212	$960,238	$1,019,066
38) - Hydro	Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
39) Net Plant	Calculated	$945,029	$931,826	$948,680	$964,608	$931,729	$898,676	$865,443	$832,028
40) Plus Fuel Inventory	Input	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140
41) Plus M&S & Prepayments	Input	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000
42) Less Accum DFIT	Calculated	*$10,840*	$11,002	$11,164	$11,326	$11,488	$11,650	$11,812	$11,974
43) Net Investment	Calculated	$974,329	$960,964	$977,656	$993,422	$960,381	$927,165	$893,771	$860,194
44) Net Investment	Calculated	$974,329							
45) NPV of Cash Flow 2016-2030		$79,210							

Income Statement	Source	2008	2009	2010	2011	2012	2013	2014	2015	PV @ 10.78%
Revenues										
1) Total GWH Generation	Input	15,957	15,739	15,524	15,092	14,672	14,264	13,868	13,482	
2) AEP Price	Input	$37.12	$37.19	$37.26	$37.33	$37.39	$37.44	$37.50	$38.09	
3) Total Revenues	Calculated	$592,386	$585,280	$578,359	$563,314	$548,550	$534,082	$520,077	$513,467	
Expenses										
4) Production Expenses excl. Fuel	Input	$80,812	$83,971	$87,254	$87,107	$86,961	$86,815	$86,669	$86,523	
5) Fuel Expense	Input	$201,110	$204,633	$208,218	$204,507	$200,863	$197,283	$193,767	$190,314	
6) Decommissioning/Dismantling	Input	$0.00	$0.00	$0.00	$0.00	$17,953	$18,402	$0	$3,726	
7) SO2 Allowance Costs	Input	$12,612	$9,879	$8,206	$6,468	$4,689	$2,866	$996	$0	
8) A&G Expense	Input	$82,786	$75,590	$76,724	$77,874	$79,043	$80,228	$81,432	$82,653	
9) Depreciation - Steam 3.2%	Calculated	59,652	60,496	61,361	62,178	62,771	63,383	64,175	64,942	
10) - Hydro	Calculated	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
11) Retirements		$0.00	$0.00	$0.00	$0.00	$10,999	$0.00	$0.00	$1,829	
12) Taxes - Nox and Scr 0.15%	Calculated	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
13) Taxes Other - Other	Input	$16,950	$17,573	$18,218	$18,885	$19,576	$20,293	$21,035	$21,805	
14) Total Expenses	Calculated	$453,922	$452,142	$459,981	$457,019	$482,855	$469,270	$448,074	$451,792	
15) Operating Income	Calculated	$138,465	$133,138	$118,378	$106,295	$65,695	$64,813	$72,003	$61,675	
16) Interest Expense 7.96%	Calculated	$26,851	$25,773	$24,688	$23,530	$22,084	$20,637	$19,390	$18,085	
17) Income Before Taxes	Calculated	$111,614	$107,365	$93,690	$82,765	$43,612	$44,175	$52,613	$43,591	
18) Schedule M	Input	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	
19) Taxable Income	Calculated	$111,151	$106,902	$93,227	$82,302	$43,149	$43,712	$52,150	$43,128	
20) Current Fed/State T 40.56%	Calculated	$45,083	$43,359	$37,813	$33,382	$17,501	$17,730	$21,152	$17,493	
21) Deferred FIT/ITC 35.00%	Calculated	$162	$162	$162	$162	$162	$162	$162	$162	
22) Total Income Taxes	Calculated	$45,245	$43,522	$37,975	$33,544	$17,663	$17,892	$21,314	$17,655	
23) Net Income Before Preferred	Calculated	$66,369	$63,844	$55,715	$49,221	$25,949	$26,283	$31,299	$25,936	
Cash Flow										
24) Net Income Before Preferred	From Above	$66,369	$63,844	$55,715	$49,221	$25,949	$26,283	$31,299	$25,936	
25) Plus Interest Expense	From Above	$26,851	$25,773	$24,688	$23,530	$22,084	$20,637	$19,390	$18,085	
26) Plus Deferred Taxes	From Above	$162	$162	$162	$162	$162	$162	$162	$162	
27) Plus Depreciation	From Above	$59,652	$60,496	$61,361	$62,178	$62,771	$63,383	$64,175	$64,942	
28) Plus Retirements	From Above	$0	$0	$0	$0	$10,999	$0	$0	$1,829	
29) Less Construction	External File	$26,048	$26,699	$27,367	$23,723	$24,316	$24,924	$24,579	$25,193	
30) Less Nox (SNCR)	External File	$0	$0	$0	$0	$0	$0	$0	$0	
31) Less Nox (SCR) and Scrubber	External File	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
32) Total	Calculated	$126,986	$123,575	$114,559	$111,368	$97,648	$85,542	$90,447	$85,760	$80,043
								NPV	$ 923,691	$79,210
Capitalization										
33) Debt	Input	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity	Input	60%	60%	60%	60%	60%	60%	60%	60%	
Investment										
35) Gross Plant in Service - Steam G	Input	$1,877,142	$1,903,841	$1,931,208	$1,954,931	$1,968,248	$1,993,172	$2,017,750	$2,041,114	
36) - Hydro	Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
37) Accum. Depreciation - Steam G	Calculated	$1,078,718	$1,139,213	$1,200,574	$1,262,752	$1,325,523	$1,388,906	$1,453,081	$1,518,023	
38) - Hydro	Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
39) Net Plant	Calculated	$798,424	$764,628	$730,634	$692,179	$642,725	$604,266	$564,669	$523,091	
40) Plus Fuel Inventory	Input	$22,140	$22,140	$22,140	$22,140	$19,532	$19,532	$19,532	$19,057	
41) Plus M&S & Prepayments	Input	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	
42) Less Accum DFIT	Calculated	$12,136	$12,298	$12,461	$12,623	$12,785	$12,947	$13,109	$13,271	
43) Net Investment	Calculated	$826,428	$792,469	$758,313	$719,696	$667,472	$628,851	$589,093	$546,878	

Projected Generation Related Net Stranded Costs
Ohio Power Company
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$2,634,723
NPV of Cash Flow 2016-2030	$203,210
Total NPV Cash Flow	$2,837,933
Base	$1,309,382
Net Stranded Costs	($1,528,551)

Change
Raise AEP Price to $35.00 and adjust accordingly

Exhibit JWW-3
Page 2 of 2

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	PV @ 10.47%
Revenues																			
1) Total GWH Generation		Input	48,624	48,812	49,001	49,190	49,637	50,083	48,162	46,315	44,538	42,830	41,187	40,919	40,651	40,386	40,122	39,860	
2) AEP Price		Input	$23.52	$37.63	$37.66	$37.70	$37 80	$37 88	$37 90	$37.93	$37 96	$37.98	$38.01	$37.91	$37 81	$37.70	$37.60	$38.02	
3) Total Revenues		Calculated	$1,143,636	$1,836,755	$1,845,388	$1,854,263	$1,876,373	$1,897,095	$1,825,339	$1,756,499	$1,690,477	$1,626,625	$1,565,454	$1,551,376	$1,537,111	$1,522,721	$1,508,699	$1,515,550	
Expenses																			
4) Production Expenses excl. Fuel		Input	$245,453	$255,181	$265,294	$275,808	$289,321	$302,833	$306,582	$310,376	$314,218	$318,107	$322,045	$334,498	$347,432	$360,867	$374,821	$389,315	
5) Fuel Expense		Input	$643,926	$615,424	$588,183	$562,149	$576,634	$591,119	$583,076	$575,142	$567,317	$559,598	$551,984	$555,312	$558,661	$562,029	$565,418	$568,827	
6) Decommissioning/Dismantling		Input	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00	$34,860	$35,731	$24,401	$25,011	$0	$0	$0	$0	
7) SO2 Allowance Costs		Input	$0	$21,796	$29,084	$26,468	$25,964	$25,326	$18,675	$12,009	$5,309	$0	$0	$0	$0	$0	$0	$0	
8) A&G Expense		Input	$93,279	$94,870	$101,464	$102,737	$103,708	$104,803	$105,907	$106,627	$108,064	$109,114	$110,205	$111,307	$112,420	$113,544	$114,680	$115,826	
9) Depreciation - Steam Gas	3 40%	Calculated	90,998	97,166	105,150	109,772	112,666	116,097	119,423	122,459	124,279	126,107	128,629	131,222	134,201	137,254	140,383	143,590	
10) - Hydro	2.70%	Calculated	$2,959	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	
11) Retirements		Input	$0 00	$0 00	$0 00	$0 00	$0.00	$0.00	$0.00	$0 00	$58,750.00	$0 00	$18,413 00	$0.00	$0	$0.00	$0.00	$0	
12) Taxes - Nox and Scrubbe	0 15%	*Calculated*	$0	$41	$71	$80	$96	$103	$103	$103	$103	$103	$103	$103	$103	$103	$103	$103	
13) Taxes Other - Other		Input	$78,147	$78,629	$42,536	$42,851	$43,172	$43,500	$43,835	$44,177	$44,527	$44,884	$45,248	$45,620	$46,000	$46,387	$46,783	$47,186	
14) Total Expenses		Calculated	$1,154,761	$1,166,062	$1,134,737	$1,122,820	$1,154,516	$1,186,737	$1,180,556	$1,173,848	$1,260,383	$1,196,600	$1,203,984	$1,206,028	$1,201,772	$1,223,139	$1,245,143	$1,267,803	
15) Operating Income		Calculated	($11,125)	$670,692	$710,651	$731,442	$721,856	$710,359	$644,782	$582,651	$430,095	$430,025	$361,471	$345,347	$335,339	$299,582	$263,556	$247,747	
16) Interest Expense	7 18%	Calculated	$38,150	$39,992	$43,780	$44,549	$43,749	$43,312	$42,689	$41,730	$39,493	$37,211	$35,601	$33,977	$32,631	$31,262	$29,868	$28,450	
17) Income Before Taxes		Calculated	($49,275)	$630,701	$666,871	$686,894	$678,108	$667,047	$602,093	$540,921	$390,601	$392,814	$325,870	$311,371	$302,708	$268,320	$233,687	$219,298	
18) Schedule M		Input	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	
19) Taxable Income		Calculated	($45,809)	$634,167	$670,337	$690,360	$681,574	$670,513	$605,559	$544,387	$394,067	$396,280	$329,336	$314,837	$306,174	$271,786	$237,153	$222,764	
20) Current Fed/State Tax	40 56%	Calculated	($18,580)	$257,218	$271,888	$280,010	$276,446	$271,960	$245,615	$220,803	$159,834	$160,731	$133,579	$127,698	$124,184	$110,236	$96,189	$90,353	
21) Deferred FIT/ITC	35 00%	Input	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
22) Total Income Taxes		Calculated	($19,793)	$256,005	$270,675	$278,797	$275,233	$270,747	$244,402	$219,590	$158,621	$159,518	$132,366	$126,485	$122,971	$109,023	$94,976	$89,140	
23) Net Income Before Preferred		Calculated	($29,482)	$374,696	$396,195	$408,097	$402,874	$396,300	$357,691	$321,331	$231,981	$233,296	$193,504	$184,886	$179,737	$159,297	$138,711	$130,158	
Cash Flow																			
24) Net Income Before Preferred		From Above	($29,482)	$374,696	$396,195	$408,097	$402,874	$396,300	$357,691	$321,331	$231,981	$233,296	$193,504	$184,886	$179,737	$159,297	$138,711	$130,158	
25) Plus Interest Expense		From Above	$38,150	$39,992	$43,780	$44,549	$43,749	$43,312	$42,689	$41,730	$39,493	$37,211	$35,601	$33,977	$32,631	$31,262	$29,868	$28,450	
26) Plus Deferred Taxes		From Above	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
27) Plus Depreciation		From Above	$93,956	$100,121	$108,105	$112,727	$115,621	$119,053	$122,378	$125,414	$127,235	$129,063	$131,585	$134,177	$137,156	$140,209	$143,338	$146,546	
28) Plus Retirements		From Above	$0	$0	$0	$0	$0	$0	$0	$0	$58,750	$0	$18,413	$0	$0	$0	$0	$0	
29) Less Construction		Input	$97,735	$102,566	$80,117	$57,183	$92,019	$94,319	$96,677	$81,891	$83,939	$82,352	$84,411	$86,521	$88,684	$90,901	$93,174	$95,503	
30) Less Nox (SNCR)		External File	$0	$162,512	$124,435	$10,173	$10,862	$4,639	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
31) Less Nox (SCR) and Scrubber		Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00	$0 00	$0.00	$0 00	$0.00	$0 00	
32) Total		Calculated	$3,677	$248,518	$342,315	$496,804	$458,151	$458,493	$424,869	$405,371	$372,307	$316,005	$293,478	$265,306	$259,627	$238,653	$217,530	$208,437	$194,541
															NPV	$2,634,723	$203,210
Capitalization																			
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																			
35) Gross Plant in Service - Steam Gen.		Input	$2,725,286	$2,990,364	$3,194,915	$3,262,272	$3,365,152	$3,464,110	$3,560,788	$3,642,679	$3,667,868	$3,750,219	$3,816,217	$3,902,738	$3,991,422	$4,082,323	$4,175,496	$4,270,999	
36) - Hydro		Input	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	
37) Accum. Depreciation - Steam Gen.		Calculated	*$1,587,274*	$1,684,440	$1,789,590	$1,899,362	$2,012,028	$2,128,126	$2,247,549	$2,370,008	$2,494,287	$2,620,395	$2,749,024	$2,880,246	$3,014,447	$3,151,700	$3,292,083	$3,435,674	
38) - Hydro		Input	$44,176	$47,131.00	$50,086 00	$53,042.00	$55,997 00	$58,952 00	$61,907 00	$64,863.00	$67,818.00	$70,773.00	$73,728 00	$76,684.00	$79,639.00	$82,594.00	$85,549.00	$88,504.00	
39) Net Plant		Calculated	$1,203,289	$1,368,246	$1,464,693	$1,419,321	$1,406,579	$1,386,485	$1,360,785	$1,317,261	$1,215,215	$1,168,504	$1,102,918	$1,055,260	$1,006,789	$957,481	$907,316	$856,274	
40) Plus Fuel Inventory		Input	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$80,308	$80,308	$78,043	$78,043	$78,043	$78,043	$78,043	$78,043	
41) Plus M&S & Prepayments		Input	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	
42) Less Accum DFIT		Calculated	*$24,836*	$23,623	$22,410	$21,197	$19,984	$18,771	$17,558	$16,345	$15,132	$13,919	$12,706	$11,493	$10,280	$9,067	$7,854	$6,641	
43) Net Investment		Calculated	$1,309,382	$1,475,552	$1,573,212	$1,529,053	$1,517,524	$1,498,643	$1,474,156	$1,431,845	$1,318,391	$1,272,893	$1,206,255	$1,159,810	$1,112,552	$1,064,457	$1,015,505	$965,676	
44) Net Investment		Calculated	$1,309,382																
45) NPV of Cash Flow 2016-2030			$203,210																

Projected Generation Related Net Stranded Costs
Columbus and Southern Power
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$1,024,387
NPV of Cash Flow 2016-2030	$88,588
Total NPV Cash Flow	$1,112,975
Base	$974,329
Net Stranded Costs	($138,646)

Changes

Raise AEP Price to $35.00 and adjust accordingly
Discount using 1-2 year
Construction Reduced

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007
Revenues										
1) Total GWH Generation		Input	16,238	16,309	16,380	16,451	16,541	16,631	16,403	16,179
2) AEP Price		Input	$23.52	$36 54	$36.71	$36 88	$36 91	$36 93	$36.99	$37 05
3) Total Revenues		Calculated	$381,918	$595,910	$601,236	$606,674	$610,455	$614,104	$606,704	$599,464
Expenses										
4) Production Expenses excl. Fuel		Input	$59,059	$61,133	$63,279	$65,501	$68,766	$72,030	$74,846	$77,772
5) Fuel Expense		Input	$179,910	$180,576	$181,249	$181,921	$186,411	$190,901	$194,245	$197,648
6) Decommissioning/Dismantling		Input	$0 00	$0.00	$0.00	$0 00	$0 00	$0 00	$0 00	$0 00
7) SO2 Allowance Costs		Input	$11,627	$15,798	$16,967	$18,219	$19,643	$21,168	$18,248	$15,399
8) A&G Expense		Input	$61,881	$66,843	$65,998	$69,905	$70,470	$73,034	$71,390	$75,668
9) Depreciation - Steam	3 2%	Calculated	49,884	50,877	52,348	54,349	55,613	56,124	56,652	57,199
10) - Hydro		Calculated	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
11) Retirements			$0 00	$0.00	$0.00	$0 00	$0 00	$0 00	$0 00	$0 00
12) Taxes - Nox and Scr	0 15%	Calculated	$0 00	$0.00	$0 00	$0 00	$0.00	$0 00	$0 00	$0.00
13) Taxes Other - Other		Input	$41,108	$42,707	$13,663	$14,163	$14,679	$15,216	$15,774	$16,351
14) Total Expenses		Calculated	$403,469	$417,934	$393,504	$404,058	$415,582	$428,473	$431,155	$440,037
15) Operating Income		Calculated	($21,552)	$177,977	$207,732	$202,616	$194,873	$185,631	$175,550	$159,427
16) Interest Expense	7 96%	Calculated	$31,504	$30,689	$30,505	$30,792	$30,294	$29,018	$27,743	$26,470
17) Income Before Taxes		Calculated	($53,055)	$147,287	$177,227	$171,824	$164,579	$156,613	$147,807	$132,957
18) Schedule M		Input	($2,886)	($463)	($463)	($463)	($463)	($463)	($463)	($463)
19) Taxable Income		Calculated	($55,941)	$146,824	$176,764	$171,361	$164,116	$156,150	$147,344	$132,494
20) Current Fed/State T	40 56%	Calculated	($22,690)	$59,552	$71,696	$69,504	$66,566	$63,334	$59,763	$53,740
21) Deferred FIT/ITC	35 00%	Calculated	$1,010	$162	$162	$162	$162	$162	$162	$162
22) Total Income Taxes		Calculated	($21,680)	$59,714	$71,858	$69,666	$66,728	$63,497	$59,925	$53,902
23) Net Income Before Preferred		Calculated	($31,376)	$87,573	$105,370	$102,158	$97,852	$93,117	$87,882	$79,056
Cash Flow										
24) Net Income Before Preferred		From Above	($31,376)	$87,573	$105,370	$102,158	$97,852	$93,117	$87,882	$79,056
25) Plus Interest Expense		From Above	$31,504	$30,689	$30,505	$30,792	$30,294	$29,018	$27,743	$26,470
26) Plus Deferred Taxes		From Above	$1,010	$162	$162	$162	$162	$162	$162	$162
27) Plus Depreciation		From Above	$49,884	$50,877	$52,348	$54,349	$55,613	$56,124	$56,652	$57,199
28) Plus Retirements		From Above	$0	$0	$0	$0	$0	$0	$0	$0
29) Less Construction		External File	$24,289	$30,103	$17,620	$30,820	$15,762	$16,188	$16,793	$17,413
30) Less Nox (SNCR)		External File	$0	$0	$44,239	$32,390	$0	$0	$0	$0
31) Less Nox (SCR) and Scrubber		External File	$0 00	$0 00	$0.00	$0 00	$0 00	$0.00	$0.00	$0.00
32) Total		Calculated	$26,734	$139,198	$126,526	$124,251	$168,158	$162,233	$155,646	$145,473
Capitalization										
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%
Investment										
35) Gross Plant in Service - Steam G		Input	$1,574,841	$1,604,945	$1,666,804	$1,730,014	$1,745,776	$1,761,964	$1,778,757	$1,796,170
36) - Hydro		Input	$0.00	$0.00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00
37) Accum. Depreciation - Steam G		Calculated	*$629,812*	$680,689	$733,037	$787,386	$842,998	$899,122	$955,774	$1,012,972
38) - Hydro		Input	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
39) Net Plant		Calculated	$945,029	$924,256	$933,767	$942,628	$902,778	$862,842	$822,983	$783,198
40) Plus Fuel Inventory		Input	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140
41) Plus M&S & Prepayments		Input	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000
42) Less Accum DFIT		Calculated	*$10,840*	$11,002	$11,164	$11,326	$11,488	$11,650	$11,812	$11,974
43) Net Investment		Calculated	$974,329	$953,394	$962,743	$971,442	$931,430	$891,332	$851,311	$811,363
44) Net Investment		Calculated	$974,329							
45) NPV of Cash Flow 2016-2030			$88,588							

Income Statement	2008	2009	2010	2011	2012	2013	2014	2015	PV @ 10.78%
Revenues									
1) Total GWH Generation	15,957	15,739	15,524	15,092	14,672	14,264	13,868	13,482	
2) AEP Price	$37 12	$37.19	$37 26	$37 33	$37 39	$37.44	$37.50	$38 09	
3) Total Revenues	$592,386	$585,280	$578,359	$563,314	$548,550	$534,082	$520,077	$513,467	
Expenses									
4) Production Expenses excl. Fuel	$80,812	$83,971	$87,254	$87,107	$86,961	$86,815	$86,669	$86,523	
5) Fuel Expense	$201,110	$204,633	$208,218	$204,507	$200,863	$197,283	$193,767	$190,314	
6) Decommissioning/Dismantling	$0.00	$0 00	$0.00	$0.00	$17,953	$18,402	$0	$3,726	
7) SO2 Allowance Costs	$12,612	$9,879	$8,206	$6,468	$4,689	$2,866	$996	$0	
8) A&G Expense	$82,786	$75,590	$76,724	$77,874	$79,043	$80,228	$81,432	$82,653	
9) Depreciation - Steam	57,766	58,354	58,963	59,525	59,861	60,217	60,753	61,264	
10) - Hydro	$0 00	$0 00	$0 00	$0 00	$0.00	$0 00	$0 00	$0.00	
11) Retirements	$0.00	$0 00	$0 00	$0.00	$10,999	$0 00	$0 00	$1,829	
12) Taxes - Nox and Scr	$0.00	$0 00	$0 00	$0.00	$0.00	$0 00	$0 00	$0.00	
13) Taxes Other - Other	$16,950	$17,573	$18,218	$18,885	$19,576	$20,293	$21,035	$21,805	
14) Total Expenses	$452,036	$450,000	$457,583	$454,366	$479,945	$466,104	$444,652	$448,114	
15) Operating Income	$140,350	$135,279	$120,776	$108,948	$68,605	$67,978	$75,425	$65,353	
16) Interest Expense	$25,199	$23,930	$22,663	$21,330	$19,718	$18,114	$16,716	$15,269	
17) Income Before Taxes	$115,151	$111,349	$98,113	$87,618	$48,887	$49,864	$58,709	$50,083	
18) Schedule M	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	
19) Taxable Income	$114,688	$110,886	$97,650	$87,155	$48,424	$49,401	$58,246	$49,620	
20) Current Fed/State T	$46,518	$44,975	$39,607	$35,350	$19,641	$20,037	$23,624	$20,126	
21) Deferred FIT/ITC	$162	$162	$162	$162	$162	$162	$162	$162	
22) Total Income Taxes	$46,680	$45,138	$39,769	$35,512	$19,803	$20,199	$23,786	$20,288	
23) Net Income Before Preferred	$68,472	$66,212	$58,344	$52,106	$29,084	$29,665	$34,922	$29,795	
Cash Flow									
24) Net Income Before Preferred	$68,472	$66,212	$58,344	$52,106	$29,084	$29,665	$34,922	$29,795	
25) Plus Interest Expense	$25,199	$23,930	$22,663	$21,330	$19,718	$18,114	$16,716	$15,269	
26) Plus Deferred Taxes	$162	$162	$162	$162	$162	$162	$162	$162	
27) Plus Depreciation	$57,766	$58,354	$58,963	$59,525	$59,861	$60,217	$60,753	$61,264	
28) Plus Retirements	$0	$0	$0	$0	$10,999	$0	$0	$1,829	
29) Less Construction	$18,048	$18,699	$19,367	$15,723	$16,316	$16,924	$16,579	$17,193	
30) Less Nox (SNCR)	$0	$0	$0	$0	$0	$0	$0	$0	
31) Less Nox (SCR) and Scrubber	$0.00	$0.00	$0.00	$0 00	$0 00	$0:00	$0.00	$0.00	
32) Total	$133,551	$129,959	$120,765	$117,400	$103,509	$91,234	$95,975	$91,127	$85,052
							NPV	$1,024,387	$88,588
Capitalization									
33) Debt	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity	60%	60%	60%	60%	60%	60%	60%	60%	
Investment									
35) Gross Plant in Service - Steam G	$1,814,218	$1,832,917	$1,852,284	$1,868,007	$1,873,324	$1,890,248	$1,906,826	$1,922,190	
36) - Hydro	$0 00	$0 00	$0 00	$0.00	$0.00	$0.00	$0 00	$0.00	
37) Accum. Depreciation - Steam G	$1,070,739	$1,129,093	$1,188,056	$1,247,581	$1,307,442	$1,367,659	$1,428,412	$1,489,677	
38) - Hydro	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00	$0.00	
39) Net Plant	$743,479	$703,824	$664,228	$620,426	$565,882	$522,589	$478,414	$432,513	
40) Plus Fuel Inventory	$22,140	$22,140	$22,140	$22,140	$19,532	$19,532	$19,532	$19,057	
41) Plus M&S & Prepayments	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	
42) Less Accum DFIT	$12,136	$12,298	$12,461	$12,623	$12,785	$12,947	$13,109	$13,271	
43) Net Investment	$771,483	$731,666	$691,907	$647,944	$590,629	$547,174	$502,837	$456,300	

Projected Generation Related Net Stranded Costs
Ohio Power Company
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$2,835,004
NPV of Cash Flow 2016-2030	$219,654
Total NPV Cash Flow	$3,054,658
Base	$1,309,382
Net Stranded Costs	($1,745,276)

Exhibit JWW-4
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Changes.

Raise AEP Price to $35.00 and adjust accordingly
Discount using 1/2 year
Construction Reduced

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	PV @ 10.47%
Revenues																			
1) Total GWH Generation		Input	48,624	48,812	49,001	49,190	49,637	50,083	48,162	46,315	44,538	42,830	41,187	40,919	40,651	40,386	40,122	39,860	
2) AEP Price		Input	$23.52	$37 63	$37.66	$37.70	$37 80	$37 88	$37.90	$37.93	$37.96	$37.98	$38.01	$37.91	$37.81	$37.70	$37.60	$38.02	
3) Total Revenues		Calculated	$1,143,636	$1,836,755	$1,845,388	$1,854,263	$1,876,373	$1,897,095	$1,825,339	$1,756,499	$1,690,477	$1,626,625	$1,565,454	$1,551,376	$1,537,111	$1,522,721	$1,508,699	$1,515,550	
Expenses																			
4) Production Expenses excl. Fuel		Input	$245,453	$255,181	$265,294	$275,808	$289,321	$302,833	$306,582	$310,376	$314,218	$318,107	$322,045	$334,498	$347,432	$360,867	$374,821	$389,315	
5) Fuel Expense		Input	$643,926	$615,424	$588,183	$562,149	$576,634	$591,119	$583,076	$575,142	$567,317	$559,598	$551,984	$555,312	$558,661	$562,029	$565,418	$568,827	
6) Decommissioning/Dismantling		Input	$0.00	$0.00	$0.00	$0 00	$0 00	$0 00	$0 00	$0.00	$34,860	$35,731	$24,401	$25,011	$0	$0	$0	$0	
7) SO2 Allowance Costs		Input	$0	$21,796	$29,084	$26,468	$25,964	$25,326	$18,675	$12,009	$5,309	$0	$0	$0	$0	$0	$0	$0	
8) A&G Expense		Input	$93,279	$94,870	$101,464	$102,737	$103,708	$104,803	$105,907	$106,627	$108,064	$109,114	$110,205	$111,307	$112,420	$113,544	$114,680	$115,826	
9) Depreciation - Steam Gas	3.40%	Calculated	90,998	96,889	104,455	108,784	111,372	114,496	117,515	120,245	121,759	123,282	125,498	127,784	130,457	133,204	136,027	138,929	
10) - Hydro	2.70%	Calculated	$2,959	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	
11) Retirements		Input	$0.00	$0.00	$0 00	$0 00	$0.00	$0 00	$0 00	$0 00	$58,750 00	$0.00	$18,413.00	$0 00	$0	$0.00	$0.00	$0	
12) Taxes - Nox and Scrubbe	0 15%	*Calculated*	$0	$41	$71	$80	$96	$103	$103	$103	$103	$103	$103	$103	$103	$103	$103	$103	
13) Taxes Other - Other		Input	$78,147	$78,629	$42,536	$42,851	$43,172	$43,500	$43,835	$44,177	$44,527	$44,884	$45,248	$45,620	$46,000	$46,387	$46,783	$47,186	
14) Total Expenses		Calculated	$1,154,761	$1,165,786	$1,134,042	$1,121,832	$1,153,222	$1,185,135	$1,178,649	$1,171,634	$1,257,863	$1,193,774	$1,200,852	$1,202,591	$1,198,028	$1,219,089	$1,240,787	$1,263,141	
15) Operating Income		Calculated	($11,125)	$670,969	$711,346	$732,431	$723,151	$711,961	$646,690	$584,865	$432,615	$432,851	$364,602	$348,785	$339,083	$303,632	$267,911	$252,409	
16) Interest Expense	7 18%	Calculated	$38,150	$39,762	$43,211	$43,756	$42,730	$42,076	$41,245	$40,086	$37,659	$35,195	$33,411	$31,623	$30,122	$28,607	$27,075	$25,528	
17) Income Before Taxes		Calculated	($49,275)	$631,207	$668,135	$688,675	$680,420	$669,885	$605,446	$544,779	$394,956	$397,657	$331,191	$317,162	$308,961	$275,025	$240,836	$226,881	
18) Schedule M		Input	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	
19) Taxable Income		Calculated	($45,809)	$634,673	$671,601	$692,141	$683,886	$673,351	$608,912	$548,245	$398,422	$401,123	$334,657	$320,628	$312,427	$278,491	$244,302	$230,347	
20) Current Fed/State Tax	40.56%	Calculated	($18,580)	$257,423	$272,401	$280,732	$277,384	$273,111	$246,975	$222,368	$161,600	$162,695	$135,737	$130,047	$126,720	$112,956	$99,089	$93,429	
21) Deferred FIT/ITC	35.00%	Input	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
22) Total Income Taxes		Calculated	($19,793)	$256,210	$271,188	$279,519	$276,171	$271,898	$245,762	$221,155	$160,387	$161,482	$134,524	$128,834	$125,507	$111,743	$97,876	$92,216	
23) Net Income Before Preferred		Calculated	($29,482)	$374,997	$396,946	$409,156	$404,249	$397,987	$359,684	$323,624	$234,569	$236,174	$196,667	$188,328	$183,454	$163,282	$142,960	$134,666	
Cash Flow																			
24) Net Income Before Preferred		From Above	($29,482)	$374,997	$396,946	$409,156	$404,249	$397,987	$359,684	$323,624	$234,569	$236,174	$196,667	$188,328	$183,454	$163,282	$142,960	$134,666	
25) Plus Interest Expense		From Above	$38,150	$39,762	$43,211	$43,756	$42,730	$42,076	$41,245	$40,086	$37,659	$35,195	$33,411	$31,623	$30,122	$28,607	$27,075	$25,528	
26) Plus Deferred Taxes		From Above	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
27) Plus Depreciation		From Above	$93,956	$99,845	$107,410	$111,739	$114,327	$117,451	$120,471	$123,200	$124,715	$126,237	$128,453	$130,740	$133,412	$136,159	$138,982	$141,884	
28) Plus Retirements		From Above	$0	$0	$0	$0	$0	$0	$0	$0	$58,750	$0	$18,413	$0	$0	$0	$0	$0	
29) Less Construction		Input	$79,366	$86,293	$71,779	$48,270	$82,929	$85,319	$87,677	$72,891	$74,939	$73,352	$75,411	$77,521	$79,684	$81,901	$84,174	$86,503	
30) Less Nox (SNCR)		External File	$0	$162,512	$124,435	$10,173	$10,862	$4,639	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
31) Less Nox (SCR) and Scrubber		Input	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00	$0 00	$0.00	$0 00	$0 00	$0.00	$0.00	$0.00	$0 00	$0 00	$0.00	
32) Total		Calculated	$22,046	$264,585	$350,141	$504,994	$466,303	$466,342	$432,509	$412,806	$379,540	$323,041	$300,320	$271,957	$266,091	$244,934	$223,631	$214,361	$200,070
																NPV	$2,835,004	$219,654
Capitalization																			
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																			
35) Gross Plant in Service - Steam Gen.		Input	$2,725,286	$2,974,091	$3,170,304	$3,228,748	$3,322,538	$3,412,496	$3,500,174	$3,573,065	$3,589,254	$3,662,605	$3,719,603	$3,797,124	$3,876,808	$3,958,709	$4,042,882	$4,129,385	
36) - Hydro		Input	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	
37) Accum. Depreciation - Steam Gen.		Calculated	*$1,587,274*	$1,684,163	$1,788,618	$1,897,402	$2,008,774	$2,123,269	$2,240,785	$2,361,030	$2,482,789	$2,606,071	$2,731,568	$2,859,353	$2,989,810	$3,123,013	$3,259,040	$3,397,969	
38) - Hydro		Input	$44,176	$47,131 00	$50,086 00	$53,042.00	$55,997 00	$58,952 00	$61,907 00	$64,863.00	$67,818 00	$70,773 00	$73,728 00	$76,684 00	$79,639 00	$82,594.00	$85,549 00	$88,504.00	
39) Net Plant		Calculated	$1,203,289	$1,352,250	$1,441,053	$1,387,756	$1,367,220	$1,339,727	$1,306,935	$1,256,625	$1,148,099	$1,095,214	$1,023,759	$970,540	$916,812	$862,554	$807,745	$752,365	
40) Plus Fuel Inventory		Input	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$80,308	$80,308	$78,043	$78,043	$78,043	$78,043	$78,043	$78,043	
41) Plus M&S & Prepayments		Input	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	
42) Less Accum DFIT		Calculated	*$24,836*	$23,623	$22,410	$21,197	$19,984	$18,771	$17,558	$16,345	$15,132	$13,919	$12,706	$11,493	$10,280	$9,067	$7,854	$6,641	
43) Net Investment		Calculated	$1,309,382	$1,459,556	$1,549,572	$1,497,488	$1,478,165	$1,451,885	$1,420,306	$1,371,209	$1,251,275	$1,199,603	$1,127,096	$1,075,090	$1,022,575	$969,530	$915,934	$861,767	
44) Net Investment		Calculated	$1,309,382																
45) NPV of Cash Flow 2016-2030			$219,654																

Projected Generation Related Net Stranded Costs
Columbus and Southern Power
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$1,164,328
NPV of Cash Flow 2016-2030	$121,828
Total NPV Cash Flow	$1,289,156
Base	$974,329
Net Stranded Costs	($314,827)

Changes:
Raise AEP Price to $35.00 and adjust accordingly
Discount using 1/2 year
Construction Reduced
Debt/Equity: 60/40, Cost of equity capital 10.5%

Exhibit JWW-5
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Income Statement	Source	2000	2001	2002	2003	2004	2005	2006	2007
Revenues									
1) Total GWH Generation	Input	16,238	16,309	16,380	16,451	16,541	16,631	16,403	16,179
2) AEP Price	Input	$23 52	$36.54	$36.71	$36 88	$36 91	$36 93	$36 99	$37 05
3) Total Revenues	Calculated	$381,918	$595,910	$601,236	$606,674	$610,455	$614,104	$606,704	$599,464
Expenses									
4) Production Expenses excl. Fuel	Input	$59,059	$61,133	$63,279	$65,501	$68,766	$72,030	$74,846	$77,772
5) Fuel Expense	Input	$179,910	$180,576	$181,249	$181,921	$186,411	$190,901	$194,245	$197,648
6) Decommissioning/Dismantling	Input	$0 00	$0 00	$0.00	$0 00	$0 00	$0 00	$0 00	$0.00
7) SO2 Allowance Costs	Input	$11,627	$15,798	$16,967	$18,219	$19,643	$21,168	$18,248	$15,399
8) A&G Expense	Input	$61,881	$66,843	$65,998	$69,905	$70,470	$73,034	$71,390	$75,668
9) Depreciation - Steam 3.2%	Calculated	49,884	50,877	52,348	54,349	55,613	56,124	56,652	57,199
10) - Hydro	Calculated	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
11) Retirements		$0.00	$0.00	$0 00	$0 00	$0 00	$0.00	$0 00	$0.00
12) Taxes - Nox and Scr 0.15%	Calculated	$0 00	$0 00	$0.00	$0 00	$0.00	$0.00	$0.00	$0 00
13) Taxes Other - Other	Input	$41,108	$42,707	$13,663	$14,163	$14,679	$15,216	$15,774	$16,351
14) Total Expenses	Calculated	$403,469	$417,934	$393,504	$404,058	$415,582	$428,473	$431,155	$440,037
15) Operating Income	Calculated	($21,552)	$177,977	$207,732	$202,616	$194,873	$185,631	$175,550	$159,427
16) Interest Expense 7 96%	Calculated	$47,255	$46,034	$45,757	$46,188	$45,441	$43,528	$41,614	$39,705
17) Income Before Taxes	Calculated	($68,807)	$131,943	$161,975	$156,428	$149,432	$142,104	$133,935	$119,723
18) Schedule M	Input	($2,886)	($463)	($463)	($463)	($463)	($463)	($463)	($463)
19) Taxable Income	Calculated	($71,693)	$131,480	$161,512	$155,965	$148,969	$141,641	$133,472	$119,260
20) Current Fed/State T 40.56%	Calculated	($29,079)	$53,328	$65,509	$63,259	$60,422	$57,450	$54,136	$48,372
21) Deferred FIT/ITC 35.00%	Calculated	$1,010	$162	$162	$162	$162	$162	$162	$162
22) Total Income Taxes	Calculated	($28,069)	$53,490	$65,671	$63,421	$60,584	$57,612	$54,298	$48,534
23) Net Income Before Preferred	Calculated	($40,738)	$78,453	$96,304	$93,006	$88,848	$84,492	$79,637	$71,189
Cash Flow									
24) Net Income Before Preferred	From Above	($40,738)	$78,453	$96,304	$93,006	$88,848	$84,492	$79,637	$71,189
25) Plus Interest Expense	From Above	$47,255	$46,034	$45,757	$46,188	$45,441	$43,528	$41,614	$39,705
26) Plus Deferred Taxes	From Above	$1,010	$162	$162	$162	$162	$162	$162	$162
27) Plus Depreciation	From Above	$49,884	$50,877	$52,348	$54,349	$55,613	$56,124	$56,652	$57,199
28) Plus Retirements	From Above	$0	$0	$0	$0	$0	$0	$0	$0
29) Less Construction	External File	$24,289	$30,103	$17,620	$30,820	$15,762	$16,188	$16,793	$17,413
30) Less Nox (SNCR)	External File	$0	$0	$44,239	$32,390	$0	$0	$0	$0
31) Less Nox (SCR) and Scrubber	External File	$0 00	$0.00	$0 00	$0.00	$0 00	$0 00	$0.00	$0.00
32) Total	Calculated	$33,122	$145,422	$132,712	$130,496	$174,302	$168,118	$161,272	$150,841
Capitalization									
33) Debt	Input	60%	60%	60%	60%	60%	60%	60%	60%
34) Equity	Input	40%	40%	40%	40%	40%	40%	40%	40%
Investment									
35) Gross Plant in Service - Steam G	Input	$1,574,841	$1,604,945	$1,666,804	$1,730,014	$1,745,776	$1,761,964	$1,778,757	$1,796,170
36) - Hydro	Input	$0 00	$0.00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
37) Accum. Depreciation - Steam G	Calculated	*$629,812*	$680,689	$733,037	$787,386	$842,998	$899,122	$955,774	$1,012,972
38) - Hydro	Input	$0 00	$0 00	$0 00	$0.00	$0 00	$0 00	$0 00	$0.00
39) Net Plant	Calculated	$945,029	$924,256	$933,767	$942,628	$902,778	$862,842	$822,983	$783,198
40) Plus Fuel Inventory	Input	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140
41) Plus M&S & Prepayments	Input	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000
42) Less Accum DFIT	Calculated	*$10,840*	$11,002	$11,164	$11,326	$11,488	$11,650	$11,812	$11,974
43) Net Investment	Calculated	$974,329	$953,394	$962,743	$971,442	$931,430	$891,332	$851,311	$811,363
44) Net Investment	Calculated	$974,329							
45) NPV of Cash Flow 2016-2030		$124,828							

Income Statement	2008	2009	2010	2011	2012	2013	2014	2015	PV @ 8.98%
Revenues									
1) Total GWH Generation	15,957	15,739	15,524	15,092	14,672	14,264	13,868	13,482	
2) AEP Price	$37.12	$37.19	$37 26	$37.33	$37.39	$37.44	$37.50	$38 09	
3) Total Revenues	$592,386	$585,280	$578,359	$563,314	$548,550	$534,082	$520,077	$513,467	
Expenses									
4) Production Expenses excl. Fuel	$80,812	$83,971	$87,254	$87,107	$86,961	$86,815	$86,669	$86,523	
5) Fuel Expense	$201,110	$204,633	$208,218	$204,507	$200,863	$197,283	$193,767	$190,314	
6) Decommissioning/Dismantling	$0.00	$0 00	$0.00	$0.00	$17,953	$18,402	$0	$3,726	
7) SO2 Allowance Costs	$12,612	$9,879	$8,206	$6,468	$4,689	$2,866	$996	$0	
8) A&G Expense	$82,786	$75,590	$76,724	$77,874	$79,043	$80,228	$81,432	$82,653	
9) Depreciation - Steam 3.2%	57,766	58,354	58,963	59,525	59,861	60,217	60,753	61,264	
10) - Hydro	$0 00	$0 00	$0 00	$0.00	$0 00	$0 00	$0 00	$0 00	
11) Retirements	$0.00	$0.00	$0 00	$0.00	$10,999	$0.00	$0.00	$1,829	
12) Taxes - Nox and Scr 0.15%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
13) Taxes Other - Other	$16,950	$17,573	$18,218	$18,885	$19,576	$20,293	$21,035	$21,805	
14) Total Expenses	$452,036	$450,000	$457,583	$454,366	$479,945	$466,104	$444,652	$448,114	
15) Operating Income	$140,350	$135,279	$120,776	$108,948	$68,605	$67,978	$75,425	$65,353	
16) Interest Expense 7 96%	$37,798	$35,895	$33,995	$31,996	$29,577	$27,171	$25,074	$22,904	
17) Income Before Taxes	$102,552	$99,384	$86,781	$76,953	$39,028	$40,807	$50,350	$42,449	
18) Schedule M	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	
19) Taxable Income	$102,089	$98,921	$86,318	$76,490	$38,565	$40,344	$49,887	$41,986	
20) Current Fed/State T 40.56%	$41,407	$40,122	$35,011	$31,024	$15,642	$16,364	$20,234	$17,029	
21) Deferred FIT/ITC 35.00%	$162	$162	$162	$162	$162	$162	$162	$162	
22) Total Income Taxes	$41,569	$40,285	$35,173	$31,186	$15,804	$16,526	$20,396	$17,191	
23) Net Income Before Preferred	$60,983	$59,100	$51,608	$45,766	$23,224	$24,282	$29,954	$25,257	
Cash Flow									
24) Net Income Before Preferred	$60,983	$59,100	$51,608	$45,766	$23,224	$24,282	$29,954	$25,257	
25) Plus Interest Expense	$37,798	$35,895	$33,995	$31,996	$29,577	$27,171	$25,074	$22,904	
26) Plus Deferred Taxes	$162	$162	$162	$162	$162	$162	$162	$162	
27) Plus Depreciation	$57,766	$58,354	$58,963	$59,525	$59,861	$60,217	$60,753	$61,264	
28) Plus Retirements	$0	$0	$0	$0	$10,999	$0	$0	$1,829	
29) Less Construction	$18,048	$18,699	$19,367	$15,723	$16,316	$16,924	$16,579	$17,193	
30) Less Nox (SNCR)	$0	$0	$0	$0	$0	$0	$0	$0	
31) Less Nox (SCR) and Scrubber	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00	$0.00	$0 00	
32) Total	$138,661	$134,812	$125,362	$121,726	$107,507	$94,908	$99,365	$94,224	$87,942
							NPV	$1,164,328	$124,828
Capitalization									
33) Debt	60%	60%	60%	60%	60%	60%	60%	60%	
34) Equity	40%	40%	40%	40%	40%	40%	40%	40%	
Investment									
35) Gross Plant in Service - Steam G	$1,814,218	$1,832,917	$1,852,284	$1,868,007	$1,873,324	$1,890,248	$1,906,826	$1,922,190	
36) - Hydro	$0 00	$0 00	$0.00	$0 00	$0 00	$0.00	$0.00	$0.00	
37) Accum. Depreciation - Steam G	$1,070,739	$1,129,093	$1,188,056	$1,247,581	$1,307,442	$1,367,659	$1,428,412	$1,489,677	
38) - Hydro	$0 00	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00	$0.00	
39) Net Plant	$743,479	$703,824	$664,228	$620,426	$565,882	$522,589	$478,414	$432,513	
40) Plus Fuel Inventory	$22,140	$22,140	$22,140	$22,140	$19,532	$19,532	$19,532	$19,057	
41) Plus M&S & Prepayments	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	
42) Less Accum DFIT	$12,136	$12,298	$12,461	$12,623	$12,785	$12,947	$13,109	$13,271	
43) Net Investment	$771,483	$731,666	$691,907	$647,944	$590,629	$547,174	$502,837	$456,300	

Projected Generation Related Net Stranded Costs
Ohio Power Company
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$3,187,320
NPV of Cash Flow 2016-2030	$315,559
Total NPV Cash Flow	$3,502,880
Base	$1,309,382
Net Stranded Costs	($2,193,498)

Changes
Raise AEP Price to $35.00 and adjust accordingly
Discount using 1/2 year
Construction Reduced
Debt/Equity: 60/40, Cost of equity capital 10.5%

Exhibit JWW-5
Page 2 of 2

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	PV @ 8.51%
Revenues																			
1) Total GWH Generation		Input	48,624	48,812	49,001	49,190	49,637	50,083	48,162	46,315	44,538	42,830	41,187	40,919	40,651	40,386	40,122	39,860	
2) AEP Price		Input	$23.52	$37.63	$37.66	$37.70	$37.80	$37.88	$37.90	$37.93	$37.96	$37.98	$38.01	$37.91	$37.81	$37.70	$37.60	$38.02	
3) Total Revenues		Calculated	$1,143,636	$1,836,755	$1,845,388	$1,854,263	$1,876,373	$1,897,095	$1,825,339	$1,756,499	$1,690,477	$1,626,625	$1,565,454	$1,551,376	$1,537,111	$1,522,721	$1,508,699	$1,515,550	
Expenses																			
4) Production Expenses excl. Fuel		Input	$245,453	$255,181	$265,294	$275,808	$289,321	$302,833	$306,582	$310,376	$314,218	$318,107	$322,045	$334,498	$347,432	$360,867	$374,821	$389,315	
5) Fuel Expense		Input	$643,926	$615,424	$588,183	$562,149	$576,634	$591,119	$583,076	$575,142	$567,317	$559,598	$551,984	$555,312	$558,661	$562,029	$565,418	$568,827	
6) Decommissioning/Dismantling		Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$34,860	$35,731	$24,401	$25,011	$0	$0	$0	$0	
7) SO2 Allowance Costs		Input	$0	$21,796	$29,084	$26,468	$25,964	$25,326	$18,675	$12,009	$5,309	$0	$0	$0	$0	$0	$0	$0	
8) A&G Expense		Input	$93,279	$94,870	$101,464	$102,737	$103,708	$104,803	$105,907	$106,627	$108,064	$109,114	$110,205	$111,307	$112,420	$113,544	$114,680	$115,826	
9) Depreciation - Steam Gas	3.40%	Calculated	90,998	96,889	104,455	108,784	111,372	114,496	117,515	120,245	121,759	123,282	125,498	127,784	130,457	133,204	136,027	138,929	
10) - Hydro	2.70%	Calculated	$2,959	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	
11) Retirements		Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$58,750.00	$0.00	$18,413.00	$0.00	$0	$0.00	$0.00	$0	
12) Taxes - Nox and Scrubbe	0.15%	*Calculated*	$0	$41	$71	$80	$96	$103	$103	$103	$103	$103	$103	$103	$103	$103	$103	$103	
13) Taxes Other - Other		Input	$78,147	$78,629	$42,536	$42,851	$43,172	$43,500	$43,835	$44,177	$44,527	$44,884	$45,248	$45,620	$46,000	$46,387	$46,783	$47,186	
14) Total Expenses		Calculated	$1,154,761	$1,165,786	$1,134,042	$1,121,832	$1,153,222	$1,185,135	$1,178,649	$1,171,634	$1,257,863	$1,193,774	$1,200,852	$1,202,591	$1,198,028	$1,219,089	$1,240,787	$1,263,141	
15) Operating Income		Calculated	($11,125)	$670,969	$711,346	$732,431	$723,151	$711,961	$646,690	$584,865	$432,615	$432,851	$364,602	$348,785	$339,083	$303,632	$267,911	$252,409	
16) Interest Expense	7.18%	Calculated	$57,225	$59,643	$64,817	$65,634	$64,096	$63,113	$61,867	$60,129	$56,488	$52,792	$50,117	$47,435	$45,184	$42,910	$40,613	$38,292	
17) Income Before Taxes		Calculated	($68,350)	$611,326	$646,529	$666,797	$659,055	$648,847	$584,823	$524,736	$376,126	$380,059	$314,485	$301,350	$293,900	$260,722	$227,299	$214,118	
18) Schedule M		Input	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	
19) Taxable Income		Calculated	($64,884)	$614,792	$649,995	$670,263	$662,521	$652,313	$588,289	$528,202	$379,592	$383,525	$317,951	$304,816	$297,366	$264,188	$230,765	$217,584	
20) Current Fed/State Tax	40.56%	Calculated	($26,317)	$249,360	$263,638	$271,859	$268,719	$264,578	$238,610	$214,239	$153,963	$155,558	$128,961	$123,633	$120,611	$107,155	$93,598	$88,252	
21) Deferred FIT/ITC	35.00%	Input	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
22) Total Income Taxes		Calculated	($27,530)	$248,147	$262,425	$270,646	$267,506	$263,365	$237,397	$213,026	$152,750	$154,345	$127,748	$122,420	$119,398	$105,942	$92,385	$87,039	
23) Net Income Before Preferred		Calculated	($40,820)	$363,179	$384,104	$396,151	$391,550	$385,482	$347,426	$311,710	$223,377	$225,714	$186,737	$178,930	$174,501	$154,780	$134,913	$127,079	
Cash Flow																			
24) Net Income Before Preferred		From Above	($40,820)	$363,179	$384,104	$396,151	$391,550	$385,482	$347,426	$311,710	$223,377	$225,714	$186,737	$178,930	$174,501	$154,780	$134,913	$127,079	
25) Plus Interest Expense		From Above	$57,225	$59,643	$64,817	$65,634	$64,096	$63,113	$61,867	$60,129	$56,488	$52,792	$50,117	$47,435	$45,184	$42,910	$40,613	$38,292	
26) Plus Deferred Taxes		From Above	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
27) Plus Depreciation		From Above	$93,956	$99,845	$107,410	$111,739	$114,327	$117,451	$120,471	$123,200	$124,715	$126,237	$128,453	$130,740	$133,412	$136,159	$138,982	$141,884	
28) Plus Retirements		From Above	$0	$0	$0	$0	$0	$0	$0	$0	$58,750	$0	$18,413	$0	$0	$0	$0	$0	
29) Less Construction		Input	$79,366	$86,293	$71,779	$48,270	$82,929	$85,319	$87,677	$72,891	$74,939	$73,352	$75,411	$77,521	$79,684	$81,901	$84,174	$86,503	
30) Less Nox (SNCR)		External File	$0	$162,512	$124,435	$10,173	$10,862	$4,639	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
31) Less Nox (SCR) and Scrubber		Input	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
32) Total		Calculated	$29,782	$272,649	$358,904	$513,868	$474,968	$474,875	$440,874	$420,936	$387,178	$330,178	$307,096	$278,370	$272,200	$250,735	$229,122	$219,538	$204,902
																	NPV	$3,187,320	$315,559
Capitalization																			
33) Debt		Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
34) Equity		Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
Investment																			
35) Gross Plant In Service - Steam Gen.		Input	$2,725,286	$2,974,091	$3,170,304	$3,228,748	$3,322,538	$3,412,496	$3,500,174	$3,573,065	$3,589,254	$3,662,605	$3,719,603	$3,797,124	$3,876,808	$3,958,709	$4,042,882	$4,129,385	
36) - Hydro		Input	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	
37) Accum. Depreciation - Steam Gen.		Calculated	*$1,587,274*	$1,684,163	$1,788,618	$1,897,402	$2,008,774	$2,123,269	$2,240,785	$2,361,030	$2,482,789	$2,606,071	$2,731,568	$2,859,353	$2,989,810	$3,123,013	$3,259,040	$3,397,969	
38) - Hydro		Input	$44,176	$47,131.00	$50,086.00	$53,042.00	$55,997.00	$58,952.00	$61,907.00	$64,863.00	$67,818.00	$70,773.00	$73,728.00	$76,684.00	$79,639.00	$82,594.00	$85,549.00	$88,504.00	
39) Net Plant		Calculated	$1,203,289	$1,352,250	$1,441,053	$1,387,756	$1,367,220	$1,339,727	$1,306,935	$1,256,625	$1,148,099	$1,095,214	$1,023,759	$970,540	$916,812	$862,554	$807,745	$752,365	
40) Plus Fuel Inventory		Input	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$80,308	$80,308	$78,043	$78,043	$78,043	$78,043	$78,043	$78,043	
41) Plus M&S & Prepayments		Input	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	
42) Less Accum DFIT		Calculated	*$24,536*	$23,623	$22,410	$21,197	$19,984	$18,771	$17,558	$16,345	$15,132	$13,919	$12,706	$11,493	$10,280	$9,067	$7,854	$6,641	
43) Net Investment		Calculated	$1,309,382	$1,459,556	$1,549,572	$1,497,488	$1,478,165	$1,451,885	$1,420,306	$1,371,209	$1,251,275	$1,199,603	$1,127,096	$1,075,090	$1,022,575	$969,530	$915,934	$861,767	
44) Net Investment		Calculated	$1,309,382																
45) NPV of Cash Flow 2016-2030			$315,559																

Ordinary Least Squares Linear Regression
RDI Data

Descriptive Statistics - Regression Analysis						
	$/KW	MW	CF	FC	MP	SS
MEAN	342.00	1840.93	38.95	22.09	24.47	2.38
STD. DEVIATION	222.90	1726.70	25.35	8.62	3.86	10.38
N	30	30	30	30	30	30

RDI Model 2 - Linear Regression
$/KW = ß0 + ß1MW + ß2CF + ß3MP + ß4SS

Linear Regression Model Results					
Adjusted R-SQR = .62885 (MSE = 135.7959)	Constant Beta 0	MW Beta 1	CF Beta 2	MP Beta 3	SS Beta 4
COEFFICIENTS	174.5158	0.0271	2.3355	-0.0332	3.4496
STD. ERROR	285.2932	0.0191	2.0692	9.7269	3.6099
T-STAT	0.6120	1.4150	1.1290	-0.0030	0.9560

RDI Model 3 - Linear Regression
$/KW = ß0 + ß1MW + ß2CF + ß3FC + ß4MP

Linear Regression Model Results					
Adjusted R-SQR = .6288 (MSE = 135.8067)	Constant Beta 0	MW Beta 1	CF Beta 2	FC Beta 3	MP Beta 4
COEFFICIENTS	174.3870	0.0271	2.3368	-11.5234	11.2076
STD. ERROR	285.3671	0.0191	2.0697	6.2299	7.6695
T-STAT	0.6110	1.4150	1.1290	-1.8500	1.4610

Model 4 - Linear Regression
$\$/KW = ß_0 + ß_1MW + ß_2CF + ß_3SS$

Linear Regression Model Results				
Adjusted R-SQR = .6431 (MSE = 133.15896)	Constant Beta 0	MW Beta 1	CF Beta 2	SS Beta 3
COEFFICIENTS	173.5901	0.0271	2.3390	11.5132
STD. ERROR	87.2567	0.0187	1.7649	4.5779
T-STAT (Bold values are sign. @ 95% CI)	1.989	1.449	1.325	**2.515**

RDI Data

	N	$/KW	MW	CF	FC	MP	SS
Morro Bay	1	189	2645	30	26.32	23.36	-2.96
Contra Costa	2	396	3065	30	29	23.36	-5.65
Encina, CT's	3	295	967	34	31.52	23.36	-8.16
Alamitos	4	203	4396	5	29.29	23.36	-5.93
Cool Water	5	99	2276	18	29.08	23.36	-5.72
Ormond Beach	6	29	1500	1	34.71	23.36	-11.35
El Segundo	7	86	1020	16	32.27	23.36	-8.91
Long Beach	8	56	543	0	37	23.36	-13.64
High Grove	9	33	280	0	36.42	23.36	-13.06
Bridgeport Harbor	10	258	1063	47	20.11	23.65	3.54
Com Ed Assets	11	750	8757	37	11.36	36.43	25.07
Somerset	12	344	151	58	16.81	23.65	6.84
Brayton Point	13	397	3867	33	17.31	23.65	6.34
Canal, Kendell, Wyman	14	470	993	55	16.81	23.65	6.84
Beco Assets	15	268	818	44	34.47	23.65	-10.82
Canal	16	267	289	60	16.41	23.65	7.24
West Springfield	17	162	170	19	26.42	23.65	-2.77
Colstrip	18	606	2632	84	6.26	23.14	16.86
Huntley	19	261	1344	68	14.23	20.67	6.44
Kintigh, Milliken, etc.	20	667	1430	35	15.34	20.67	5.33
Bowline, Lovett, etc.	21	270	1754	37	21.77	23.61	1.85
Arthur Kill	22	347	1456	11	25.02	23.61	-1.4
Ravenswood	23	275	2170	20	25.25	23.61	-1.64
Astoria, Gowanus, Narrows	24	269	1865	27	25.64	23.61	-2.03
Fort Martin	25	616	276	70	12.81	35.23	22.42
Conemaugh, Keystone, etc.	26	408	3667	37	13.56	22.88	9.32
Homer City	27	947	1884	85	10.72	22.88	12.17
Sunbury	28	227	398	72.08	15.61	22.88	7.27
Duquesne Assets	29	652	2212	56.11	16.01	35.23	19.22
Centralia	30	413	1340	79.16	15.13	23.9	8.77
	MEAN	**342.00**	**1840.93**	**38.95**	**22.09**	**24.47**	**2.38**
	S.Deviation	**222.90**	**1726.70**	**25.35**	**8.62**	**3.86**	**10.38**
	N	**30**	**30**	**30**	**30**	**30**	**30**

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* * * * M U L T I P L E   R E G R E S S I O N * * * *
RDI Data - Model 2
$/KW = ß0 + ß1MW + ß2CF + ß3MP + ß4SS

Listwise Deletion of Missing Data

Equation Number 1   Dependent Variable..   KW

Block Number 1. Methcd: Enter   MW   CF   MP   SS

Variable(s) Entered on Step Number
1.. SS
2.. MW
3.. MP
4.. CF

Multiple R	.82465
R Square	.68004
Adjusted R Square	.62885
Standard Error	135.79599

Analysis of Variance

	DF	Sum of Squares	Mean Square
Regression	4	979838.22299	244959.55575
Residual	25	461013.77701	18440.55108

F =   13.28374   Signif F = .0000

------------------ Variables in the Equation ------------------

Variable	B	SE B	Beta	T	Sig T
MW	.027089	.019139	.209844	1.415	.1693
CF	2.335476	2.069215	.265650	1.129	.2697
MP	-.033217	9.726855	-5.751E-04	-.003	.9973
SS	11.527249	6.227985	.536865	1.851	.0760
(Constant)	174.515763	285.293181		.612	.5463

End Block Number 1 All requested variables entered.

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* * * * MULTIPLE REGRESSION * * * *
RDI Data - Model 3
$/KW = ß0 + ß1MW + ß2CF + ß3FC + ß4MP

Listwise Deletion of Missing Data

Equation Number 1   Dependent Variable..   KW

Block Number 1. Method: Enter   MW   CF   MP   FC

Variable(s) Entered on Step Number
1.. FC
2.. MW
3.. MP
4.. CF

Multiple R	.82462
R Square	.67999
Adjusted R Square	.62879
Standard Error	135.80667

Analysis of Variance

	DF	Sum of Squares	Mean Square
Regression	4	979765.69613	244941.42403
Residual	25	461086.30387	18443.45215

F = 13.28067   Signif F = .0000

------------------ Variables in the Equation ------------------

Variable	B	SE B	Beta	T	Sig T
MW	.027094	.019143	.209882	1.415	.1693
CF	2.336756	2.069673	.265795	1.129	.2696
MP	11.493685	7.294925	.198997	1.576	.1277
FC	-11.523352	6.229947	-.445392	-1.850	.0762
(Constant)	174.387037	285.367108		.611	.5467

End Block Number 1 All requested variables entered.

.31 Mar 00 SPSS for MS WINDOWS Release 6.0

* * * * M U L T I P L E   R E G R E S S I O N * * * *
RDI Data - Model 4
$/KW = ß0 + ß1MW + ß2CF + ß3SS

Listwise Deletion of Missing Data

Equation Number 1   Dependent Variable..   KW

Block Number 1. Method: Enter   MW   CF   SS

Variable(s) Entered on Step Number
1.. SS
2.. MW
3.. CF

Multiple R	.82465
R Square	.68004
Adjusted R Square	.64312
Standard Error	133.15896

Analysis of Variance

	DF	Sum of Squares	Mean Square
Regression	3	979838.00793	326612.66931
Residual	26	461013.99207	17731.30739

F =   18.42011   Signif F = .0000

------------------ Variables in the Equation ------------------

Variable	B	SE B	Beta	T	Sig T
MW	.027095	.018695	.209889	1.449	.1592
CF	2.338963	1.764852	.266046	1.325	.1966
SS	11.513172	4.577882	.536209	2.515	.0184
(Constant)	173.590092	87.256678		1.989	.0573

End Block Number 1 All requested variables entered.

Calculation of AEP's Fossil Plant Values (RDI Regression Model)

Model 2

$/kw = 174.52 + 0.0271 MW + 2.3355 CF – 0.0332 MP + 3.4496SS

CSP		OPCO	
	174.52		174.52
+ 0.0271 (2,860) =	77.51	+ 0.0271 (8,759) =	237.37
+ 2.3355 (59.34) =	138.59	+ 2.3355 (65.70) =	153.44
- 0.0332 (35.53) =	(1.18)	- 0.0332 (35.53) =	(1.18)
+ 3.4496 (22.04) =	76.03	+ 3.4496 (19.71) =	67.99
	465/kw		513 - 632/kw[1]

Model 3

$/kw = 174.39 + 0.0271 MW + 2.3368 CF – 11.5234 FC + 11.2076 MP

CSP		OPCO	
	174.39		174.39
+ 0.0271 (2,860) =	77.51	+ 0.0271 (8,759) =	237.37
+ 2.3368 (59.34) =	138.67	+ 2.3368 (65.70) =	153.53
- 11.5234 (13.49) =	(155.45)	- 11.5234 (15.82) =	(182.30)
+ 11.2076 (35.53) =	398.21	+ 11.2076 (35.53) =	398.21
	633/kw		662 - 781/kw[1]

Model 4

$/kw = 173.59 + 0.0271 MW + 2.3390 CF + 11.5132SS

CSP		OPCO	
173.59		173.59	
+ 0.0271 (2,860) =	77.51	+ 0.0271 (8,759) =	237.37
+ 2.3390 (59.34) =	138.80	+ 2.3390 (65.70) =	153.67
+ 11.5132 (22.04) =	253.75	+ 11.5132 (19.71) =	226.93
	644/kw		673 - 792/kw[1]

[1] Lower end of indicated range assumes that generation is valued as two equal but separate (competing) packages.

COLUMBUS SOUTHERN POWER COMPANY: CASE NO. 99-1729-EL-ETP
AND OHIO POWER COMPANY : CASE NO. 99-1730-EL-ETP

SHELL ENERGY SERVICES CO., L.L.C. INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, FIRST SET
MARCH 10, 2000

Question #119:

Shell-AEP-119 - (P. 32, L. 3-4): Whether mandatory or voluntary, does Dr. Landon agree that asset divestiture is the most accurate method of determining the market value of generation assets? Please explain your answer in full.

Response:

Dr. Landon does not agree that divestiture is the most accurate method for determining the value of a generation asset that has been and continues to be used to serve customers. There may be positive and negative values for an asset that reflect alternative uses of the asset and that would affect its sale price. The value relevant for stranded cost analysis is the value of the electricity output based upon the current functioning of the generation asset and its projected functioning over the next few years.

Preparer of Response: John H. Landon

COLUMBUS SOUTHERN POWER COMPANY: CASE NO. 99-1729-EL-ETP
AND OHIO POWER COMPANY : CASE NO. 99-1730-EL-ETP

SHELL ENERGY SERVICES CO., L.L.C. INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, FIRST SET
MARCH 10, 2000

Question #84:

Shell-AEP-84 - (P. 20, L. 16-17): In what ways will competitive markets change how plants are utilized?

Response:

Owners' incentives will change in a competitive marketplace. Consequently, this will change their behavior. Some plants are expected to be utilized more, some less.

Preparer of Response: Edward P. Kahn

COLUMBUS SOUTHERN POWER COMPANY: CASE NO. 99-1729-EL-ETP
AND OHIO POWER COMPANY : CASE NO. 99-1730-EL-ETP

SHELL ENERGY SERVICES CO., L.L.C. INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, FIRST SET
MARCH 10, 2000

Question #142:

Shell-AEP-142 - (Exhibit JHL-2): Has Dr. Landon included the salvage value and/or the value of the plant sites for each generating unit at the end of its economic life?

a. If the answer to Shell-AEP-142 is affirmative, please provide all analysis conducted by or for Dr. Landon which estimates these values.

b. If the answer to Shell-AEP-142 is negative, please explain why these values were not included.

c. Does Dr. Landon believe the plants have salvage value? Please explain this answer.

d. Does Dr. Landon believe the plant sites have value? Please explain this answer.

Response:

No

a. Not Applicable.

b. It is impossible to determine, with any degree of accuracy, what the salvage value and/or the value of the plant sites for each generating unit will be in year 2030.

c. Whatever salvage value the plants do have in 2030, after discounting, will have a negligible impact on the present value of the total cash flows.

d. Whatever value the plant sites do have in 2030, after discounting, will have a negligible impact on the present value of the total cash flows.

Preparer of Response: John H. Landon

COLUMBUS SOUTHERN POWER COMPANY: CASE NO. 99-1729-EL-ETP
AND OHIO POWER COMPANY : CASE NO. 99-1730-EL-ETP

SHELL ENERGY SERVICES CO., L.L.C. INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, FIRST SET
MARCH 10, 2000

Question #96:

Shell-AEP-96 - (P. 9, 14-19): Given that fairness is a priority, what is Dr. Landon's view regarding the nature and extent of AEP's obligation to mitigate its stranded costs?

Response:

AEP-Ohio should, in the context of stranded cost recovery, ensure that ratepayers are required to pay only their legitimate share. This obligation is no different from AEP-Ohio's obligation under regulation to pass on only prudently incurred costs to ratepayers. For purposes of estimating and recovering stranded costs, AEP-Ohio should seek only those costs that will, or are likely to, become unrecoverable in a competitive market-place. This does not mean, however, that AEP-Ohio is obligated to restructure its operations or transform its way of conducting business without regard for other changes solely to lower its expected stranded investments and, thus, reduce stranded cost estimates. AEP-Ohio is entitled to recover all such costs that it would have recovered under regulation as a going concern.

Preparer of Response: John H. Landon

COLUMBUS SOUTHERN POWER COMPANY: CASE NO. 99-1729-EL-ETP
AND OHIO POWER COMPANY : CASE NO. 99-1730-EL-ETP

SHELL ENERGY SERVICES CO., L.L.C. INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS, FIRST SET
MARCH 10, 2000

Question #104:

Shell-AEP-104 - (P. 17, L. 18 through P. 18, L. 3): In Dr. Landon's view, would an incumbent have an unfair competitive advantage if its recoverable stranded costs are over-stated? Please explain your answer in full.

Response:

The question is ambiguous so as to render a coherent response impracticable. For instance what is the term "over-stated" intended to convey. Over-stated with respect to what? Over-stated with respect to what an incumbent's stranded costs are believed to be or what its stranded costs actually turn out to be? Stating stranded costs, above someone else's best present estimates, does not make these costs recoverable. In this sense, over-stating stranded costs does not provide a competitive advantage to an incumbent. Recovering estimated costs that turn out to exceed actual costs would not make an incumbent a better competitor. Competitive success in a market for any good or service is determined by the ability to offer better quality at lower prices. More money in the bank would not, by itself, lower an incumbent's marginal cost of generation or improve the quality of its products or services.

Preparer of Response: John H. Landon

COLUMBUS SOUTHERN POWER COMPANY: CASE NO. 99-1729-EL-ETP
AND OHIO POWER COMPANY : CASE NO. 99-1730-EL-ETP

OHIO CONSUMERS' COUNSEL'S INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS, NINTH SET
MARCH 31, 2000

Question #112-RFPD:

Please provide all data and calculations used to determine the non-environmental capital additions for CSP and OPC, as included in Exhibit JHL-2.

Response:

Details supporting capital expenditures for CSP & OPC, as provided in Exhibit JHL-2, are provided in OCC, 9th Set, Q. 112-RFPD, Attachment 1. For the period 2004 through 2015 in Exhibit JHL-2, expenditures were escalated at 2.5 % per year.

Preparer of Response: Oliver J. Sever, Jr.

OCC, 9th Set, Q 112- RFPD
Attachment 1
Page 1 of 1

CSP & OP
Capital Expenditures Budget
($000)

	2000	2001	2002	2003	2004
CSP					
Other Production					
Conesville	12,241	8,890	10,328	15,396	5,439
Picway	705	679	2,314	635	612
Beckjord	49	57	1,146	8	1,785
Stuart	1,711	3,038	3,293	2,775	3,220
Zimmer	332	1,061	147	10,241	3,837
Total Other Production	15,038	13,724	17,228	29,054	14,892
Environmental	9,251	16,380	392	1,766	870
General					
Chillicothe Building Addition	1,861	1,870	1,875	1,868	1,905
Training Facility	3,256	3,273	3,281	3,268	3,333
Delaware Building	1,437	1,444	1,448	1,442	1,471
Other building repair	1,100	1,106	1,108	1,104	1,126
Total General	7,654	7,693	7,712	7,683	7,836
Total CSP Capital Expenditures	31,943	37,797	25,332	38,503	23,598
OP					
Other Production					
Amos	2,637	15,390	1,591	1,061	1,322
Cardinal	1,306	6,334	22,612	3,781	114
Gavin	8,070	4,451	27,148	10,121	6,081
Kammer	24,550	12,221	4,771	13,283	10,155
Mitchell	26,141	19,515	2,255	3,731	38,213
Muskingum	5,553	22,157	10,462	6,031	11,373
Racine	907	76	78	76	-
Sporn	4,420	1,909	2,623	2,066	11,669
OP Total Other Production	73,584	82,052	71,540	40,150	78,928
Environmental	5,782	4,241	238	8,120	4,000
General					
Lima Building	1,930	1,940	1,945	1,937	1,976
Fostoria Building	1,000	1,005	1,008	1,004	1,024
Canton Office Building Improvement	720	724	725	723	737
Coshocton Office Building	575	578	579	577	589
McConnelsville Building Addition	415	417	418	417	425
Misc. Land purchases	500	503	504	502	512
Other Building additions and repair	2,942	2,957	2,964	2,953	3,012
Cook Coal Terminal	455	155	195	800	816
Windsor Coal Co.	2,911	284	-	-	-
Southern Ohio Coal Co.	6,921	7,711	-	-	-
Total General	18,369	16,273	8,338	8,913	9,090
Total OP Capital Expenditures	97,735	102,566	80,116	57,183	92,018

COLUMBUS SOUTHERN POWER COMPANY: CASE NO. 99-1729-EL-ETP
AND OHIO POWER COMPANY : CASE NO. 99-1730-EL-ETP

OHIO CONSUMERS' COUNSEL'S INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS, SECOND SET
JANUARY 21, 2000

Question #48-RFPD:

Please provide all workpapers used to develop the fixed carrying charge rates for new CT and CC units into their component parts (e.g., return on equity, depreciation, etc.) in Dr. Kahn's analysis.

Response:

See OCC, 2nd Set, Q. 48-RFPD Attachment.

Preparer of Response: Edward P. Kahn

Return Requirements for New Entrants

1. Basic Assumptions

We assume that the capital structure of an unregulated generation company building gas-fired merchant plants is 60% debt and 40% equity. This is a conservative degree of leverage corresponding to the financial structure of many individual projects. Firms in this business (as will be seen below) are often more leveraged.

The cost of equity capital is estimated to be 13.5% and the cost of debt is assumed to be 8.5%. The rationale for these assumptions is given below.

2. The Resulting Fixed Charge Rate

Using these assumptions on capital structure and the cost of debt and equity, the fixed charge rate is then calculated in Table 1 assuming a marginal tax rate of 40% as follows:

Table 1. Fixed Charge Rate

Component	Cost (%)	Weight	Weighted Cost (%)	Tax Effect	Tax Weighted Cost (%)
Equity	13.5	0.4	5.4	3.60	9.00
Debt	8.5	0.6	5.1	(2.04)	3.06
Total					12.06

3. Cost of Equity Capital

To estimate the cost of equity we look at firms in the merchant generation business, who stock is publicly traded. There are not many such firms. Table 2 lists four well-known firms of this kind. In this table, I list both the observed beta of the stock and the debt/equity ratio. The table also computes the "pure equity" or unlevered beta, using a standard textbook relationship for these quantities.[1] This calculation also assumes a 40% tax rate.

Table 2. Levered and Unlevered Betas of Merchant Generation Firms

	Beta	D/E	Unlevered Beta
Calpine	0.77	2.99	0.275
AES	1.81	5.20	0.438
Dynegy	0.8	1.13	0.477
Enron	0.85	0.92	0.547
Average			0.434

[1] The market data comes from http://www.marketguide.com. The formula relating the levered to the unlevered beta is Levered beta = (1 + (1- tax rate) (D/E)) Unlevered beta. This formula is derived in T. Copeland and J. Weston. *Financial Theory and Corporate Policy*. 3rd edition. Addison Wesley Publishing Company, 1988, pp. 456-457.

Of the four firms listed in Table 2, Calpine is the closest to a pure merchant generation company. The other firms, in addition to merchant generation, have significant assets in electricity distribution and natural gas.

Using the average unlevered beta from Table 2, i.e. 0.434, and the Capital Asset Pricing Model (CAPM), we can derive a cost of equity for a firm with a 60/40 debt/equity capital structure. First, we compute the levered beta for such a firm, using the standard formula. Using a 40% tax rate, this is 0.8246. Next we use the CAPM formula to estimate the cost of equity capital. This formula is:

Cost of equity = Risk-free rate + Market risk premium * levered beta.[2]

We use 5.69% for the risk-free rate and 8.4% for the long-term risk premium.[3] This results in a cost of equity capital of 12.6%. We have used 13.5%, which takes into account other factors not explicitly estimated, such as depreciation and overheads.

4. Cost of Debt

To estimate the cost of debt, the risk and maturity of loans must be taken into account. For merchant plants that have sold rated bonds, we have a measure of both the risk and maturity. Table 3 lists three recent transactions of this kind that have been rated by Standard and Poor's.[4]

Table 3. Rated Debt for Merchant Plants

Transaction	Finance $ million	Rating	Maturity
Homer City	830	BBB-	20-27
NYSEG AES	601	BBB-	30
Commonwealth Edison EME	1800	BBB	5-20

The yield spread between debt of this kind and the corresponding maturities in T-bonds is about 180 basis points.[5] The current yield on long term Treasury bonds is about 6.7%, so the cost of debt for these firms would be 8.5%.

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[2] For a discussion of CAPM, see, for example, Copeland and Weston, *op. cit.*, Chapter 7.

[3] The risk-free rate is the return on one-year Treasury bonds as of December, 1999. The market risk premium is the long term realized return on stocks in excess of the return on intermediate term government bonds (see Ibbotson Associates *Stocks, Bonds, Bills, and Inflation 1999 Yearbook)*

[4] See Standard and Poor's (S&P), AES Eastern Energy L.P., *Infrastructure Finance*, (April) 1999a; Standard and Poor's (S&P), Edison Mission Holdings, *Infrastructure Finance*, (June) 1999b; and Standard and Poor's (S&P), Edison Mission Midwest Holdings, *Infrastructure Finance*, (November) 1999c.

[5] See http://bondchannel.bridge.com/publicspreads.cgi?Industrial

COLUMBUS SOUTHERN POWER COMPANY: CASE NO. 99-1729-EL-ETP
AND OHIO POWER COMPANY : CASE NO. 99-1730-EL-ETP

OHIO CONSUMERS' COUNSEL'S INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS, NINTH SET
MARCH 31, 2000

Question #350:

What is the most recent estimate of savings associated with the merger of AEP and Central and South West Corporation (CSW) on a total company basis and on a jurisdictional basis for CSP and OPCO individually?

Response:

The information requested is neither relevant nor reasonably calculated to lead to discovery of admissible evidence.

Preparer of Response: Counsel

COLUMBUS SOUTHERN POWER COMPANY: CASE NO. 99-1729-EL-ETP
AND OHIO POWER COMPANY : CASE NO. 99-1730-EL-ETP

OHIO CONSUMERS' COUNSEL'S INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS, FIRST SET
JANUARY 17, 2000

Question #48:

Mr. Landon concludes at page 21 that above- and below-market production costs should be netted when determining a utility's stranded costs. What are the economic and/or equity considerations that justify such a conclusion?

Response:

The purpose of an exercise to calculate stranded costs is to determine the effect that introducing retail choice will have on a utility's investments that have been previously authorized or mandated by regulators. The rationale for reimbursing stranded costs to a utility is that its shareholders should not be burdened with a loss in value of the company's previously authorized or mandated investments caused by the state's decision to repeal regulation. To the extent that the utility will face market prices that will be lower than its production costs, its investments will diminish in value and shareholders must be compensated for it. However, if there are certain advantages that the utility enjoys which will enable its production costs to be below market, then any such gains should offset the compensation for stranded generation costs. The economic and equity justifications for such netting or offsets are essentially the same. The entity subject to regulation has been the utility. Regulators have historically considered the impact of all of their decisions on the entire utility, not on individual generation plants or assets. Ohio's PUC, for example, has based its rate making for each of OPCO and CSP on the effects that such rates would have on the two respective companies and their ratepayers. Therefore, net stranded generation costs should be computed for each of the companies, after accounting for both above market and below market production costs for each of them. Since OPCO and CSP have historically been separately regulated, Dr. Landon separately calculated their stranded generation costs.

Preparer of Response: John H. Landon