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Exhibit WHH-1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY, PURSUANT TO CHAPTERS 11, 19, 21, 22 AND 28 OF THE PUBLIC UTILITY CODE, FOR APPROVAL OF (1) A PLAN OF CORPORATE RESTRUCTURING, INCLUDING THE CREATION OF A HOLDING COMPANY AND (2) THE MERGER OF THE NEWLY FORMED HOLDING COMPANY AND UNICOM CORPORATION	:	APPLICATION DOCKET NO. A-_____

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MAY 11 2000

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EXHIBITS TO TESTIMONY OF WILLIAM H. HIERONYMUS

VOLUME IV

EXHIBIT NO. APP-300

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Commonwealth Edison Company on behalf of itself and its public utility affiliates	)))	Docket No. EC00-___-000
and	)	
PECO Energy Company on behalf of itself and its public utility affiliates	)))	

JOINT APPLICATION OF COMMONWEALTH EDISON COMPANY AND ITS PUBLIC UTILITY AFFILIATES AND PECO ENERGY COMPANY AND ITS PUBLIC UTILITY AFFILIATES FOR APPROVAL OF MERGER

PREPARED DIRECT TESTIMONY AND EXHIBITS OF WILLIAM H. HIERONYMUS ON BEHALF OF APPLICANTS

DIRECT TESTIMONY OF WILLIAM H. HIERONYMUS

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William H. Hieronymus. My business address is PHB Hagler Bailly, Inc. ("PHB Hagler Bailly"), One Memorial Drive, Cambridge, Massachusetts 02142.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am Senior Vice President of PHB Hagler Bailly, Inc., the commercial consulting subsidiary of Hagler Bailly. Hagler Bailly is a worldwide provider of consulting, research and other professional services to corporations and governments on energy, telecommunications, transportation and the environment.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE?

A. I received my Bachelor's degree from the University of Iowa in 1965, my Master's degree in economics in 1967 and a Doctoral degree in economics in 1969 from the University of Michigan, where I was a Woodrow Wilson Fellow and National Science Foundation Fellow. After serving in the U.S. Army, I began my consulting career. In 1973, I joined Charles River Associates Inc. as a specialist in antitrust economics. By the mid-1970s my focus was principally on the economics of energy and network industries. In 1978, I joined Putnam Hayes & Bartlett, Inc., where my consulting practice has focused almost exclusively on network industries, particularly electric utilities. Putnam, Hayes & Bartlett, Inc. merged with Hagler Bailly, Inc. in 1998.

During the past 25 years, I have completed numerous assignments for electric utilities; state and federal government agencies and regulatory bodies; energy and equipment companies; research organizations and trade associations; independent power producers and investors; international aid and lending agencies; and foreign governments. While I have worked on most economics-related aspects of the utility sector, a major theme has been public policies and their relation to the operation of utility companies.

Since about 1988, the main focus of my consulting has been on electric utility industry restructuring, regulatory innovation and privatization. In that year, I began work on the

restructuring and privatization of the electric utility industry of the United Kingdom, an assignment on which I worked nearly full time through the completion of the restructuring in 1990. I also led a major study of the reorganization of the New Zealand electricity sector, focusing mainly on competition issues in the generating sector. Following privatization of the U.K. industry, I continued to work in the United Kingdom for electricity clients based there and I was also involved in restructuring studies concerning the former Soviet Union, Eastern Europe, the European Union and specific European countries.

Late in 1993, I returned to the United States, where I have worked on restructuring, regulatory reform and, increasingly, the competitive future of the U.S. electricity industry. In this context, I have testified before FERC and state commissions on market power issues concerned with several electric utility mergers (including convergence mergers), power pool tariff filings, sales and purchases of jurisdictional assets and market rate applications. More generally, I have testified before state and federal regulatory commissions, federal and state courts and legislatures on numerous matters concerning the electric utility and other network industries. My resume is included as Exhibit No. APP-301.

II. PURPOSE, SUMMARY OF ANALYSIS AND CONCLUSIONS

Purpose

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by Commonwealth Edison Company ("ComEd") and PECO Energy Company ("PECO") (collectively, the "Applicants") to determine the potential competitive impact of their proposed merger on electricity markets. I performed the Competitive Analysis Screen described in Appendix A to the Commission's Merger Policy Statement ("Order No. 592"),[1] which in turn is intended to comport with the Department of Justice and Federal Trade Commission ("DOJ/FTC") Horizontal Merger

[1] Order No. 592, *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, FERC Stats. & Regs. (Regulations Preambles) ¶ 31,044 (1996), *on reconsideration*, Order No. 592-A, 79 FERC ¶ 61,321 (1997).

Guidelines ("Guidelines"). As appropriate, my testimony also takes into consideration the Commission's Notice of Proposed Rulemaking ("Merger NOPR").[2] The primary focus of my testimony is potential horizontal market power effects (i.e., those arising from the combination of electric generating assets) that potentially could result in creating or enhancing the ability to increase prices in the electricity market. I also address vertical effects concerning barriers to entry that might undercut the presumption that long-run generation markets are competitive. I have reviewed the testimony of the Applicants' witnesses, Steven T. Naumann and Robert N. Spencer, who explain why the Applicants do not have any realistic ability to exert vertical market power in the Midwest as a result of their control over transmission facilities during the period before such control is transferred to independent entities.

Summary of Analysis and Conclusions

Q. DOES YOUR ANALYSIS INDICATE THAT APPLICANTS WILL BE ABLE TO RAISE THE PRICES OF ELECTRICITY ABOVE THE LEVELS THEY COULD HAVE CHARGED ABSENT THE MERGER?

A. No, quite the contrary. The Applicants' merger, when combined with the generation-based mitigation measures to which they will agree as a condition of merger approval, if the Commission is persuaded that such mitigation is necessary, will not lead to material increases in concentration or in Applicants' market share in any relevant market. My analysis provides strong support for the conclusion that the merger will not adversely impact competition in any relevant market or enable Applicants to raise prices above the levels they would have been able to charge if there had been no merger. Thus, I recommend that the Commission find that the merger will not adversely affect competition and, insofar as market power is the critical issue, should approve the merger.

I have performed the Appendix A screen analysis to assess whether the merger should raise any competitive concerns. In accordance with Appendix A and the Commission's regulations, I performed screen analyses of two different measures: Economic Capacity

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[2] Revised Filing Requirements Under Part 33 of the Commission's Regulations ("Merger NOPR"), 83 FERC ¶61,027 (1998), 63 Fed. Reg. 20340 (April 24, 1998).

and Available Economic Capacity. As will be explained below, I rely, and encourage the Commission to rely, solely on the analysis of Economic Capacity. The Available Economic Capacity numbers are too unreliable to be useful and do not inform merger policy under the evolving competitive conditions relevant to this merger.

My analysis of Economic Capacity shows that screen failures occur only in the ComEd market and are largely traceable to the small amount of generation rights that PECO has in the ComEd market pre-merger, namely a 300 MW pre-merger long term power sale from ComEd to PECO. Additionally, PECO controls approximately 30 to 63 MW of energy from its uncommitted 233 MW share of the Clinton nuclear plant that is presumed to be imported into the ComEd market (based on the prorated expected share of ATC into ComEd). Little energy from PECO's other generation, located primarily in eastern and central Pennsylvania, reaches the ComEd market. In simple terms, the screen failure arises because PECO would have been a minor competitor of ComEd in the ComEd destination market pre-merger. Post-merger, that minor competitor will be consolidated with ComEd, so that (in the absence of mitigation) there will be a slight lessening of competition in the region.

The screen failure in the ComEd market is linked to the 300 MW sale. Once the 300 MW sale expires, there will no longer be a screen failure. While the lessening of competition in the intervening period would be minimal, Applicants are nonetheless prepared to mitigate it in a way that will eliminate the screen failure and ensure that competition is preserved at its pre-merger level if the Commission is not persuaded that such mitigation is unnecessary. As described in the Application, Applicants are willing to sell PECO's rights under the 300 MW contract to an unaffiliated entity. Because of the sale to an unaffiliated third party, the level of competition pre-merger will be preserved. My analysis demonstrates that this mitigation is fully effective. While the mitigation might be considered "interim", the period that it covers: a) extends to the termination of the PECO contract that is the principal cause of the screen failure; b) extends beyond the last date on which ComEd has option or contract rights to the capacity that it is divesting to Edison Mission; and c) extends far enough into the future to allow economic entry of substantial amounts of new capacity.

Apart from these pre-mitigation screen failures in the ComEd market, there are no significant adverse effects of the merger. As discussed below, the analysis demonstrates little overlap in markets between Applicants and little participation by ComEd in the PJM markets where the bulk of PECO's generation is located. This conclusion is supported by Applicants' historic sales patterns which show a quite similar lack of significant overlap.

Applicants are prepared, if required by the SEC, to contract for a 100 MW firm path from ComEd to PECO. This path will be used only when it is economic to transfer power from the ComEd to PECO areas, having taken alternative uses of the power into account. As is shown in the testimony of Mr. Naumann, the principal effect of this path on transmission, when it is used, is to reduce west-to-east ATCs from northern Illinois to eastern PJM by approximately 100 MW. Applicants' analysis of the power flow effects of the path, which is incorporated into my market power study, shows that loop flows are not very different from the contract path effects. Use of the 100 MW path reduces concentration in the ComEd market wherein the screen is failed. The path, and resulting changes in loop flows when the path is used, creates no screen failures in any other market.

In performing the Appendix A analysis, I resolved uncertainties about which assumptions to use by making conservative assumptions; that is, I made the assumptions that were most likely to detect an increase in market concentration in the relevant destination markets.[3] In fact, actual increases in market concentration will likely be much less than calculated using the Appendix A screen. Most importantly, the screen assumes that ComEd continues to control all of the 9,300 MW of generation that it is the process of divesting. A more forward-looking perspective would recognize that the restructuring of generation asset ownership undertaken by ComEd in the past several years will result in ultimately relinquishing control over this generation. This restructuring, coupled with the participation by both of the Applicants in regional transmission organizations, is

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[3] For example, as discussed *infra*, the only significant screen violations arise from PECO's long term purchase from ComEd. The power associated with that contract is deliverable in the American Electric Power ("AEP") or Ameren markets, not in ComEd. However, in my analysis I assumed that PECO could sell power from that contract in the ComEd market without having to acquire transmission into the ComEd market. The screen failures in my analysis are directly traceable to that assumption. Had I assumed that the PECO power was located at the point of contract delivery, these screen failures would not have occurred.

unquestionably pro-competitive and will broadly benefit electric markets in the affected regions.

The conclusions from my analysis are consistent with and supported by the basic facts surrounding the merger. ComEd is located in the Mid-America Interconnected Network, Inc. ("MAIN"), with its generation and distribution system located primarily in Chicago and Northern Illinois, and PECO is located in the Mid-Atlantic Area Council ("MAAC") (which consists of a single control area, PJM Interconnection, L.L.C. ("PJM")). PECO's generation and distribution system is located primarily in Philadelphia and Eastern Pennsylvania. The distance between Chicago and Philadelphia is almost 700 miles. Electrically, utilities in East Central Area Reliability Coordination Agreement ("ECAR") and Southeastern Electric Reliability Council ("SERC") are located between ComEd and PECO. There are at least two intervening utilities on all paths between ComEd and PJM.

As is shown in sales data contained in my workpapers, Applicants had overlapping sales to a number of utilities in 1997 and 1998. However, the amounts sold by at least one of the Applicants were small in virtually all cases. If overlap markets are defined as those in which each Applicant sold at least 100,000 MWhs (equivalent to only 11.4 MW on a year-round basis), there were only six such overlap markets in 1997 and 1998 (excluding ComEd's own market). In only one market, Michigan Electric Coordinating Council ("MECS"), did each Applicant sell more than 500,000 MWh.[4]

More generally, PECO sells only small amounts in Mid-Continent Area Power Pool ("MAPP") and MAIN. Its 1998, total sales to utilities in these reliability councils were about 2 million MWh, less than the amount purchased under its 300 MW contract with ComEd; about 60 percent of that total was sold back to ComEd, mostly out of its 300 MW contract. Conversely, other than the contract with PECO, ComEd sells only trace amounts (43,000 MWh in 1998) to utilities in PJM, NYPP and NEPOOL. Neither

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[4] Sales information is based on sales contracts reported in FERC Form 1s. The 1997 markets were AEP, Cinergy, Illinois Power (IP), Tennessee Valley Authority (TVA), Virginia Electric Power (VP) and Wisconsin Energy Company (WEP). The 1998 markets were Allegheny Energy (APS), AEP, Cinergy, IP, MECS and TVA. Because data for Applicants' power marketing operations are not segregated from utility sales from their owned and controlled resources, these data may overstate the amount of overlap. As discussed *infra*, PECO, in particular, is a highly active power marketer and its Form 1 reports sales all over the country, including sales to utilities located thousands of miles away from any PECO generation (e.g., in southern California and Washington state).

Applicant is among the most significant sellers in the remaining overlap areas, ECAR and VACAR. The fact that Applicants, in general, do not overlap is highly significant to the analysis. It means that the merger will not materially reduce the level of competition. That is, in areas where they do not overlap at all, the merger will have no effect on the structure of competition in the region, and would thus be expected to have no effect on prices in the region. In the areas where they do overlap, the market share of at least one Applicant is so small that there would be no appreciable effect on the level of competition, and the merger would not give the Applicants the ability to injure the overlapping markets or raise prices.

Other factors, not taken into account in the Appendix A analysis, support the conclusion that the merger does not create a market power issue. At its core, the market power issue is whether the merger creates or enhances the ability of Applicants to raise prices by profitably withholding capacity or offering it for sale only at anticompetitive prices. In this case, ComEd brings to the merger very little capacity that can be withheld from the market. At the very high load times when prices are most readily and profitably manipulated, ComEd is short of capacity. ComEd controls little capacity that realistically could be withheld at other times. The bulk of the non-nuclear capacity that is "controlled" by ComEd consists of options or contracts for the capacity that it has sold. ComEd is not the plant operator for any of this capacity. If it does not exercise an option, the capacity reverts wholly to the owner. In his testimony, Mr. Naumann explains the limits on ComEd's control of the capacity that is being sold to Edison Mission Energy. The only capacity actually operated by ComEd is its nuclear capacity. For physical, economic and regulatory reasons (i.e., NRC oversight), nuclear capacity is exceptionally hard to withhold, either strategically or tactically. Both ComEd and PECO have a high percentage of nuclear and other low incremental cost generation in their portfolios, which means that their winning strategy is to sell high volumes of electricity at prices lower than those of their competitors. Given the low levels of participation of each of the Applicants in the other's markets today, the merger does not provide a new strategy that would allow them to manipulate markets in order to raise prices.

The merger creates no material vertical market power issues related to transmission ownership and operation. This lack of ability to exercise vertical market power, and

evidence that ComEd has not done so in the past, is discussed at length by Mr. Naumann. PECO is a member of the PJM Interconnection, an ISO with an associated power exchange. ComEd is a member of the Midwest Independent System Operator ("MISO"), an ISO that has been approved by the FERC and is currently scheduled to begin operations on June 1, 2001. In the interim, ComEd provides open access service under Orders No. 888 and 889. Moreover, as discussed by Mr. Naumann, ComEd will be transferring all control area responsibility to an Independent Transmission Company ("ITC"). PECO has no control area responsibility, as its control area is operated by PJM. As also discussed by Mr. Naumann and Mr. Spencer, neither ComEd nor PECO is a security coordinator with the ability to direct transmission curtailment. Moreover, Mr. Naumann explains that ComEd's ability to withhold capacity from the market will be severely limited.

Neither utility controls significant fuels supplies or fuels delivery systems. PECO operates a gas distribution system in four counties that surround, but do not include, the city of Philadelphia. Its gas service area includes three gas-fired independent power stations, two of which have bypassed the distribution system. The third, which is only 28 MW, has a readily available bypass option and is currently negotiating for a discounted distribution rate. Even if PECO were in a position to exercise vertical market power over the gas-fired generation served by its LDC, that generation is very remote from ComEd and any vertical effects would not redound to ComEd and hence would have no nexus to this merger. Neither utility possesses a monopoly over potential generation sites.

Q. DID YOUR APPENDIX A ANALYSIS TAKE INTO ACCOUNT NEW GENERATION PLANNED OR BEING BUILT IN THE REGION, OR NEW PLANNED POWER TRANSACTIONS INVOLVING APPLICANTS OR OTHERS IN THE AFFECTED REGIONS?

A. Yes, but only to a limited extent. Numerous utilities, IPPs and others have responded to the capacity shortages that have affected the Midwest over the past several summers by planning the construction of significant new generation resources. Estimates of the planned generation exceed 20,000 MW, but I included far less than this in my analysis. Among the new generation that I did include in my analysis is a 250 MW affiliated

generation unit being considered in North Chicago (although I am informed that a firm decision to build the unit has not been made). As I discuss later, for all other new generation, I included only that planned generation which has passed sufficient project, regulatory and/or financing hurdles such that its construction is relatively certain. If even a material fraction of the planned additions are built, market concentration will be lower.

It is also my understanding that ComEd, like other utilities in the region, is shopping for new power supplies to complement its power supply portfolio in coming years. This would be accomplished with power purchase contracts of various durations. Such purchases would have been made even if there had been no merger, so they have little impact on the analysis. I am told that ComEd does not at present know the amount or duration of such purchases, but I conservatively assumed a 300 MW ComEd purchase from a planned generating facility in its control area that would not otherwise have been considered to be sufficiently certain to be included in my analysis.

Q. PLEASE PROVIDE AN OVERVIEW OF THE APPENDIX A ANALYSES YOU CONDUCTED USING THE DELIVERED PRICE TEST.

A. I conducted several different analyses of the Economic Capacity supply measure that provide the Commission with a full and comprehensive analysis of the potential impacts of the merger and proposed mitigation by the Applicants. These analyses were structured to illuminate the causes of any changes in destination market HHIs, and to assist the Commission in determining which were, and which were not, due to potentially adverse effects of the merger on competition.

The first analysis of the merger's impact on power markets that I undertook was the effect of combining Applicants' pre-merger market shares. This analysis is generally referred to as the "2AB method."[5] It is essentially an analysis of a merger where there are no economic changes resulting from a merger – no rate impact, no change in

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[5] "2AB" refers to the change in HHI resulting from the merger of company a (with market share A) and Company b (with market share B). This formula is derived from the HHI calculation as follows:

Applicants' pre-merger HHI = $A^2 + B^2$

Applicants' post-merger HHI = $(A+B)^2 = A^2 + B^2 + 2AB$

Thus, the change in HHI resulting from the merger equals 2AB.

transmission for integration purposes, etc. This analysis properly depicts the effects of the merger when the 100 MW path is not being used by Applicants.

In addition, I examined a scenario that assumes the 100 MW path is used. In this analysis, Applicants' use of the 100 MW transmission reservation reduces available transmission capacity (ATC) on some interfaces; the analysis takes into consideration the loop flow impact of this interconnection. Relying on data from Applicants (contained in Mr. Naumann's testimony), I adjusted ATCs to take into account the impacts of the planned interconnection and recalculated HHIs.

Next, I took into account Applicants' provisional mitigation plan in order to confirm that it eliminates the screen failures in these analyses of Economic Capacity. Finally, I performed sensitivities that a) assumed that full TTCs were available to interconnect markets and b) assumed zero transmission rates. These are intended as limiting cases to show how the evolution of RTOs might maximize economic power flows over the existing grid and the effects of this expanded market on the extent to which geographically distant utilities would compete in common markets.

These sensitivities support the robustness of my conclusions.

Q. PLEASE DESCRIBE YOUR DELIVERED PRICE TEST ANALYSIS OF AVAILABLE ECONOMIC CAPACITY.

A. I performed an analysis for the Available Economic Capacity measure similar to that described above for Economic Capacity. The key difference between these two measures is that Available Economic Capacity considers only that capacity that remains after the utility meets its native load and contractual obligations. In the pre-restructured market, this measure may have provided a useful measure of the capacity that can participate in wholesale power markets. However, for reasons described later in my testimony, this measure is losing its usefulness and, at least in the case of this merger, an analysis of it requires speculative and potentially contentious assumptions concerning, *inter alia,* the pace of elimination of retail native load obligations for ComEd, PECO, and other utilities throughout the affected regions. In order to satisfy the Commission's rules requiring that merger applicants perform an Available Economic Capacity analysis, I did such an analysis. I based my analysis on 1998 retail loads for Applicants and others, escalating

those loads based on projected growth in electric demands throughout the region. That is, I made no assumption about retail access. In general, although that analysis showed some scattered and non-systematic screen failures, I do not believe that they should be given any meaningful weight since predictions of the amount of Available Economic Capacity controlled by Applicants and other suppliers are neither reliable nor probative of future market conditions.

Organization of Testimony

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In Section III, I outline the Applicants' business operations and the status of deregulation in the states of Illinois and Pennsylvania. Section IV describes the economic framework used in the analysis as set out in the Commission's Order No. 592. A description of the methodology I used in conducting the analysis is included in Section V. My analysis of the merger's impact on competition is included in Section VI. Section VII contains my conclusions.

III. DESCRIPTION OF THE PARTIES

Commonwealth Edison Company

Q. PLEASE DESCRIBE COMED.

A ComEd, a regulated electric utility, is the principal subsidiary of Unicom Corporation. ComEd is engaged principally in the production, purchase, transmission, distribution and sale of electricity. Its service territory is in Northern Illinois, including the Chicago metropolitan area.

ComEd has sold all of its fossil generation;[6] ComEd's remaining generation assets consist of approximately 9,200 MW of nuclear generation.

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[6] As is described in the Application, the sale of the State Line and Kincaid stations has been completed. The planned sale of the balance of ComEd's non-nuclear plant to Edison Mission Energy has been approved by the Commission in a different docket, and is expected to close in the near future.

Its Kincaid and State Line generating stations were sold to affiliates of Dominion Resources ("DRI") and the Southern Company ("Southern") in February 1998 and December 1997, respectively. Under the terms of the sales, ComEd entered into exclusive 15-year purchase power agreements for the output of the plants (1,598 MW). In essence, these are tolling contracts. ComEd provides the fuel for them and has the right to the output produced in return for fixed payments and the payment of variable O&M costs.

In March 1999, ComEd entered into an agreement to sell the remainder of its fossil generation, totaling approximately 9300 MW, to Edison Mission Energy ("EME"). The sale is expected to be completed in December 1999. As part of the sale, ComEd will enter into three power purchase agreements with terms that will extend for five years or less. Mr. Naumann discusses these agreements in his testimony.

In addition to the 300 MW power sale contract with PECO, it has 1,150 MW of long term firm sales contracts that will be in effect in 2001. These are included in my analysis. It also has long term firm purchase contracts, beyond the repurchase contracts detailed above, of 941 MW.[7]

Q. TO WHICH UTILITIES DOES COMED INTERCONNECT?

A. ComEd is a member of the MAIN regional council. It is directly interconnected to other utilities in MAIN (Illinois Power Company ("IP"), Ameren, Central Illinois Light Company ("CILCO") and Wisconsin Energy (WEP)); utilities to its east in ECAR (AEP and Northern Indiana Public Service Company ("NIPS")); and utilities to its west in the MAPP (MidAmerican Energy Company ("MIDAM") and Alliant).

ComEd is an owner-member of the MISO. On September 16, 1998, the Commission granted approval to form MISO. As a member-owner, ComEd will turn over functional control of its transmission system when the MISO becomes operational (expected to be in June 2001).

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[7] This does not include a 600 MW contract with Enron, signed in November 1999. This contract is for peaking energy in summer months only. The contract must be nominated on a day-ahead basis and the contract price is the market price in the day-ahead market. Since ComEd can neither withhold the power from this contract, nor benefit with respect to it from higher prices, I do not count the contracted capacity as being under ComEd's control. The 941 MW of purchases used in my analysis includes 300 MW of purchases for which no contract exists as of mid-November, 1999.

Q. DOES COMED HAVE ANY TRANSMISSION DEPENDENT UTILITIES ("TDUS")?

A. ComEd has three full requirements TDUs in its control area: the Cities of Naperville, Batavia and St. Charles, Illinois. Each of these TDUs has requirements contracts with termination dates ending May 31, 2007.

ComEd has one partial requirements TDU, the City of Rochelle, Illinois. In addition, there are three other TDUs who obtain their requirements from alternative suppliers: the City of Geneva, Illinois (supplier is WEP); and the cities of Rock Falls and Winnetka, Illinois (supplier is the Illinois Municipal Electric Agency).

Q. DOES UNICOM HAVE ANY UNREGULATED SUBSIDIARIES IN THE ENERGY BUSINESS?

A. Yes. Unicom Enterprises, Inc. is the holding company for various unregulated Unicom subsidiaries. Unicom Active Energy Management Systems provides an integral line of energy monitoring solutions and related consulting services. Unicom Distributed Energy provides distributed generation systems (through Turbo Generator Power Systems, a joint venture with Allied Signal), complete engineering and feasibility studies, flexible financing and leasing packages. Unicom Energy Solutions provides single-source energy and operational solutions. Unicom Energy, Inc. provides a single source for natural gas, electricity and related services. Unicom Thermal Holdings, Inc. provides retail district energy systems and site specific thermal energy products. Unicom Power Holdings, Inc. provides creative energy solutions that yield significant cost savings and reduced risks associated with the overall energy supply through a customized portfolio. Finally, Midwest Mechanical is a mechanical service provider that designs, installs and services heating, ventilation and air conditioning (HVAC) systems for more than 1,600 commercial and industrial customers in the Chicago area.

PECO Energy Company

Q. PLEASE DESCRIBE PECO.

A. PECO is an electric and gas utility serving electric customers at retail in the six-county Philadelphia, Pennsylvania area and serving retail natural gas customers in five suburban counties. PECO owns approximately 9,500 MW of generation (not including generation purchased by AmerGen), including about 4,300 MW of nuclear generation.[8]

PECO is a member of the Pennsylvania-New Jersey-Maryland ("PJM") Interconnection, a power pool which integrates, through central dispatch, the generation and operations of its member companies. PJM consists of over 130 members located in all or part of Pennsylvania, New Jersey, Maryland, Delaware, Virginia and the District of Columbia. There is approximately 56,000 MW of pooled generating capacity within PJM. PJM is directly interconnected to SERC (VP); ECAR (APS and FirstEnergy); and the New York ISO (directly with Niagara Mohawk Company ("NIMO"), New York State Electric & Gas Corporation ("NYSEG") and Consolidated Edison Company ("ConEd")).

On March 31, 1997, the members of PJM converted its organization from an unincorporated association into a limited liability company. In November 1997, the Commission issued an order authorizing PJM to establish an independent system operator ("ISO") and an hourly energy market known as the PJM Power Exchange ("PJM PX"). PJM dispatches generation based on the economic merit order of the generating units. On March 10, 1999, the Commission issued an order granting PJM utilities the authority to charge market-based prices for sales of energy and certain ancillary services into the PJM PX.

Q. DOES PECO HAVE ANY FULL OR NEAR-FULL REQUIREMENTS WHOLESALE CUSTOMERS?

A. PECO has contracts to supply the following full or near-full requirements customers: Boroughs of Butler, Lavallette, Madison, Pemberton and Seaside Heights, New Jersey and Boroughs of Ephrata and Middletown, Pennsylvania.

Q. PLEASE DESCRIBE PECO'S GAS DISTRIBUTION OPERATIONS.

A. PECO provides retail gas sales and transportation in a five county area surrounding Philadelphia. PECO's retail natural gas sales and transportation activities are regulated by the Pennsylvania Public Utility Commission ("PaPUC"). PECO, through its subsidiary Horizon Energy Company, d/b/a Exelon Energy ("Exelon Energy"), is participating in pilot programs outside its gas service territory to market gas and other services to retail customers. PECO's natural gas supply is acquired under contracts with suppliers with terms up to five years. It has long-term firm transportation contracts to move its gas supply to the market area with Texas Eastern Transmission Corporation ("Texas Eastern") and Transcontinental Gas Pipe Line Corporation ("Transcontinental"). PECO also has acquired underground storage from Texas Eastern, Transcontinental, Equitrans, Inc. and CNG Transmission Corporation.

Q. WHAT OTHER BUSINESS VENTURES DOES PECO HAVE?

A. PECO is a competitive generation supplier offering a variety of unregulated energy and utility infrastructure services, including electric supply, to businesses and residential customers across Pennsylvania. PECO is a wholesale marketer of electricity nationally, and participates in joint ventures which provide telecommunication services in the Philadelphia metropolitan region.

In 1997, PECO and British Energy, plc (Scotland) formed a 50-50 joint venture, AmerGen Energy Company, LLC ("AmerGen"), to acquire and operate nuclear generating stations in the United States. British Energy owns and operates 15 nuclear plants in the United Kingdom. To date, AmerGen has acquired or entered into letters of intent to acquire five nuclear generating stations totaling approximately 4,200 MW. In PJM, AmerGen acquired Three Mile Island (786 MW) and Oyster Creek (619 MW) from GPU; in New York, AmerGen acquired Nine Mile Point No. 1 (618 MW) from NIMO and a portion of Nine Mile Point No. 2 (674 MW) from NIMO and NYSEG; in Illinois, AmerGen acquired Clinton (930 MW) from IP; and in New England, AmerGen acquired

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[8] PECO recently bought half of Conectiv's share of the Peach Bottom nuclear plant, which PECO operates.

Vermont Yankee (540 MW) from the owners of the Vermont Yankee Nuclear Corporation.

Each of AmerGen's asset acquisitions, with the exception of Clinton and Nine Mile Point, have purchase power agreements ("PPAs") with the sellers to buy back the full output from these units. The termination dates for these PPAs range from December 31, 2001 (Three Mile Island) to 12 years after the closing of the agreement (Vermont Yankee). PECO will market any capacity available from these units on behalf of AmerGen. With respect to Nine Mile Point, the PPA covers 95 percent of the output. With respect to Clinton, the PPA covers the re-purchase by IP of 75 percent of the plant's output through 2004. PECO will market the remaining 25 percent share.

Deregulation in Pennsylvania and Illinois

Q. PLEASE DESCRIBE THE STATUS OF ELECTRIC DEREGULATION IN PENNSYLVANIA.

A. The Pennsylvania legislature passed the Electricity Generation, Customer Choice and Competition Act in December 1996, which mandated that electric utilities unbundle electric service into separate generation, transmission and distribution services with open retail competition for the supply of electricity phased-in between January 1, 1999 and January 1, 2000. Pilot programs began in 1997.

Q. WHAT IS THE CURRENT STATUS OF DEREGULATION IN ILLINOIS?

A. At the end of 1997, the Illinois General Assembly passed the Customer Choice Law as part of electric restructuring in the state. Retail competition for large business customers (over 4 MW load) and for a percentage of non-residential customers began October 1, 1999. By December 31, 2000 retail choice will be available to all non-residential customers. Full retail competition (including residential customers) will be effective by May 1, 2002.

Q. ARE THERE ANY PRELIMINARY RESULTS IN ILLINOIS SINCE CUSTOMER CHOICE BECAME AVAILABLE TO BUSINESS CUSTOMERS?

A. Yes, there are some very preliminary numbers. ComEd reports that, as of October 15, 1999, out of 42,000 customers eligible for customer choice, 430 of ComEd's business customers have selected alternative electric providers. Another 2,400 customers have requested usage and billing information, presumably to inform themselves about potential savings from selecting alternative suppliers.

IV. FRAMEWORK FOR THE ANALYSIS

Q. WHAT ARE THE GENERAL MARKET POWER ISSUES RAISED BY MERGER PROPOSALS?

A. Market power analysis of a merger proposal examines whether the merger would cause a material increase in the merging firms' market power or a significant reduction in the competitiveness of relevant markets. Market power is defined as the ability of a firm or group of firms to sustain profitably a significant increase in the price of their products above a competitive level.

In merger analyses, the critical issue is the change in market competitiveness due to the merger. While the pre-merger competitiveness of markets may, as under the DOJ/FTC Guidelines, affect the amount of such change that is acceptable, the focus remains on the change in market competitiveness caused by the merger.

This focus on the effects of the merger means that the merger analysis examines those business areas where the merging firms are competitors. In most instances, the merger will not affect competition in markets in which the merging firms do not compete. Analysis of the effects of a merger on market power in businesses in which the merging firms both participate is sometimes referred to as horizontal market power assessment. In the proposed merger of ComEd and PECO, therefore, the focus is properly on those markets in which both firms are actual or potential competitors. The analysis is intended to measure the adverse impact, if any, of the elimination of a competitor as a result of the combination.

Vertical market effects of the merger relate to the merging firms' ability and incentives to use their market position over a product or service to affect competition in a related business or market. For example, vertical effects could result if the merger of two electric utilities created an opportunity and incentive to operate transmission in a manner that created market power for the generation activity of the merged company that did not exist previously. The Commission has identified market power as also arising from dominant control over potential generation sites or over fuels supplies and delivery systems. These are issues that could undercut the presumption that long-run generation markets are competitive.

Q. WHAT ARE THE MAIN ELEMENTS IN DEVELOPING AN ANALYSIS OF MARKET POWER?

A. Understanding the competitive impact of a merger requires defining the relevant market (or markets) in which the merging firms participate. Participants in a relevant market include all suppliers and, in some instances potential suppliers, who can compete to supply the products produced by the merging parties and whose ability to do so diminishes the ability of the merging parties to increase prices. Hence, determining the scope of a market is fundamentally an analysis of the potential for competitors to respond to an attempted price increase. Typically, markets are defined in two dimensions: geographic and product. Thus, the relevant market is composed of companies that can supply a given product (or its close substitute) to customers in a given geographic area.

Q. HOW HAS THE COMMISSION TYPICALLY EXAMINED PROPOSED MERGERS INVOLVING ELECTRIC UTILITIES?

A. Historically, the Commission examined mergers by focusing on specific product markets and by using a "hub-and-spoke" screening test to evaluate whether a further examination of potential market power was warranted. With the issuance of Order No. 592 in December 1996, the Commission changed its analytic approach and adopted a "delivered price test." Appendix A (the "Competitive Analysis Screen") of Order No. 592 outlines a detailed analytic method that applicants are required to follow in their applications and that the Commission will use in screening the competitive impact of mergers. If a proposed merger raises no market power concerns (i.e., passes the Appendix A screen),

the inquiry is generally complete. If a proposed merger raises potential market power concerns, applicants can propose mitigation measures at the time of application.

Q. WHAT PRODUCTS HAS THE COMMISSION GENERALLY CONSIDERED?

A. The Commission generally has defined the relevant product markets to be long-term capacity, short-term capacity ("Uncommitted Capacity") and non-firm energy ("Available Economic Capacity" and "Economic Capacity"). The Commission has determined that long-term capacity markets are presumed to be competitive, unless special factors exist that limit the ability of new generation to be sited or receive fuel.

The Commission has considered competition in transmission services and has examined whether the combination of ownership of transmission facilities creates the opportunity or incentive for the merging parties to restrict access to transmission.

Q. HOW HAS THE COMMISSION ANALYZED GEOGRAPHIC MARKETS?

A. To examine geographic markets, the Commission traditionally has focused on the utilities that are directly interconnected to the applicant companies. This "destination market" approach was continued in Order No. 592. Each utility that is directly interconnected to the applicants is considered a separate "destination market." Additionally, the Commission has suggested that utilities who historically have been customers of applicants are also potential "destination markets."

The supply alternatives to each destination market are defined using the "delivered price test," which identifies suppliers that can reach a destination market at a cost no more than 5 percent over the pre-merger market price. The supply is considered economic if a supplier's generation can be delivered to a destination market, including delivery costs (which include transmission rates, transmission losses and ancillary services), at a cost that is within 105 percent of the destination market price. Physical transmission constraints also are taken into consideration in determining the potential supply to the destination market. Thus, unlike the "hub-and-spoke" methodology, competing suppliers are no longer defined by bright lines. Competing suppliers are defined as those who have capacity (energy) that is physically and economically deliverable to the destination

market. Their importance in the market (i.e., their market share) is determined by the amount of such capacity.

This test is intended to be a conservative screen to determine whether further analysis of market power is necessary. If the Appendix A analysis shows that a company will not be able to exercise market power in its first-tier destination markets, it generally follows that the applicants will not have market power in more broadly defined and more geographically remote markets. The screen is the first step in determining whether there is a need for further investigation. If the screening test is not passed, leaving open the issue of whether the merger will create market power, the Commission invites applicants to propose mitigation remedies targeted to reduce potential anti-competitive effects to safe harbor levels. In the alternative, the Commission will undertake a proceeding to determine whether unmitigated market power concerns mean that the merger is contrary to the public interest.

Q. WHAT FRAMEWORK DOES THE COMMISSION USE TO DETERMINE WHETHER A MERGER POSES POTENTIAL MARKET POWER CONCERNS?

A. In Order No. 592, the Commission adopted the DOJ/FTC Guidelines for measuring market concentration levels by the HHI. To determine whether a proposed merger will have a significant anti-competitive impact, the DOJ and FTC consider the level of the HHI after the merger (the post-merger HHI) and the change in the HHI that results from the combination of the market shares of the merging entities. Markets with a post-merger HHI of less than 1000 are considered "unconcentrated." The DOJ and FTC generally consider mergers in such markets to have no anti-competitive impact. Markets with post-merger HHIs of 1000 to 1800 are considered "moderately concentrated." In those markets, mergers that result in an HHI change of 100 points or fewer are considered unlikely to have anti-competitive effects. Finally, post-merger HHIs of more than 1800 are considered to indicate "highly concentrated" markets. The Guidelines suggest that in these markets, mergers that increase the HHI by 50 points or fewer are unlikely to have a significant anti-competitive impact, while mergers that increase the HHI by more than 100 points are considered likely to reduce market competitiveness.

V. DESCRIPTION OF METHODOLOGY

Q. PLEASE SUMMARIZE THE METHODOLOGY THAT YOU USED TO ANALYZE THE COMPETITIVE EFFECTS OF THE MERGER.

A. I evaluated the competitive effects of the merger using the methodology described in Appendix A, as summarized above. I used PHB Hagler Bailly's Competitive Analysis Screening model ("CASm"), which implements the delivered price test and other calculations required in Appendix A, to do the required analyses. The source and methodology for the data required to conduct the delivered price test in CASm are described in Exhibit No. APP-302. A technical description of CASm is provided in Exhibit No. APP-303.

Q. WHAT DESTINATION MARKETS DID YOU ANALYZE?

A. I examined 42 destination markets that could potentially be impacted by the merger.[9]

I included ComEd and its first-tier utilities: AEP, NIPS, IP, Ameren, CILCO, MIDAM, Alliant-West, Alliant-East and WEP.

I also included PECO's first-tier utilities (specifically, utilities first-tier to PJM): FirstEnergy, APS, VP and the NYISO. In analyzing PJM, I took into consideration the predominant west-to-east energy flow and defined markets by the three high-voltage interfaces within PJM: West, Central and East.[10,11]

Finally, I included additional destination markets that represent historical customers of Applicants based on a review of 1997 and 1998 sales reported in the FERC Form 1:[12]

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9 Exhibit No. APP-304 includes a list of utilities (and corresponding abbreviations used in other exhibits), including destination markets.

10 The PJM regions and related transmission limits are discussed in the Commission's Order in Docket No. ER97-3729-000, issued March 10, 1999. 86 FERC ¶ 61,248.

11 Both the ECAR-to-PJM and SERC-to-PJM interconnections occur in Western PJM (APS's in the far West and VP's in the West). I examined four PJM destination markets: PJM West-Central-East (PJM_W+C+E), PJM Central-East (PJM_C+E), PJM East (PJM_East) and an overall PJM market (PJM_All).

12 I excluded certain categories of customers as destination markets. First, I excluded power marketers, for the obvious reason that they do not comprise control areas. Similarly, I excluded municipals, cooperatives and TDUs which do not comprise a control area; instead, utility control areas that are destination markets are proxies for the competitive alternatives faced by these customers. Additionally, I excluded utilities which,

Associated Electric Coop; Carolina Power & Light; Cinergy; City Water, Light and Power; Cleco; Dayton Power & Light; Hoosier Energy Rural Electric Coop; Duke; Duquesne; East Kentucky Power Coop; Entergy; LG&E Energy; Madison Gas & Electric; MECS; Missouri Public Service Co.; NEPOOL; Northern States Power; South Carolina Electric & Gas Co.; South Carolina Public Service Authority; Southern Company; Tennessee Valley Authority; Upper Peninsula Power; Western Resources; and Wisconsin Public Service Corp.

These destination markets include potentially impacted markets in accordance with the Commission's guidance in Appendix A, defined to include each first tier utility to the Applicants as well as their historical trading partners. Included in these destination markets are the full range of "intermediate" markets, i.e., those control areas between ComEd and PECO.

Q. DID YOU ANALYZE A DESTINATION MARKET FOR APPLICANTS' TDU CUSTOMERS?

A. Yes. The relevant PJM markets I analyzed are reasonable proxies for any of PECO's remaining TDU customers. Similarly, the ComEd destination market is a reasonable proxy for the competitive alternatives available to its TDU customers.

Q. WHAT TIME PERIODS DID YOU ANALYZE?

A. For each destination market, I examined eleven time periods for both the Economic Capacity and Available Economic Capacity measures, selected to reflect a broad range of system conditions. I describe this in more detail in Exhibit No. APP-302. Broadly, I evaluated hourly load data to aggregate similar hours. I defined periods within three seasons (Summer, Winter and Shoulder) to reflect the differences in unit availability and transmission capacity as well as base flows on the network. Previously, I generally have considered nine time periods: three seasons times three periods (Peak, Off-Peak and Shoulder). In view of interest in market conditions when prices have "spiked" during

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while customers, were not likely to be receiving physical delivery of Applicants' generation; this category primarily includes utilities in the Western States Coordinating Council and Florida Regional Coordinating

high load hours in the summer, I expanded this to eleven time periods by expanding the number of summer (high-priced) time periods evaluated to reflect different summer conditions and ensure that I covered the range of plausible market conditions in each of the destination markets.

The periods evaluated (and the designations used to refer to these periods in exhibits) are:

SUMMER (*June-July-August*)

Super Peak 1 (S_SP1):	Top 25 load hours
Super Peak 2 (S_SP2):	Next 125 load hours
Super Peak 3 (S_SP3):	Next 350 load hours
Peak (S_P):	Remaining peak hours
Off-peak (S_OP):	All off-peak hours

WINTER (December-January-February)

Super Peak (W_SP):	Top 150 load hours
Peak (W_P):	Remaining peak hours
Off-peak (W_OP):	All off-peak hours

SHOULDER (March-April-May-September-October-November).

Super Peak (SH_SP):	Top 150 load hours
Peak (SH_P):	Remaining peak hours
Off-peak (SH_OP):	All off-peak hours

Q. WHAT "COMPETITIVE" PRICE LEVELS DID YOU ANALYZE?

A. For each destination market, I evaluated conditions assuming destination market prices ranging from $15/MWh in the Winter and Shoulder Off-Peak periods (W_OP and SH_OP) to $100/MWh in the Summer Highest Peak period (S_SP1). This broad range of prices, in combination with the time periods, should be reflective of a sufficient range of system conditions such that a full picture of the merger's effects is captured.

Council. Finally, I excluded three customers whose purchases in 1997 and 1998 were de minimis (less than $100,000 for this purpose): Minnesota Power, Central and SouthWest and Oklahoma Gas & Electric.

Q. DID YOU TAKE SYSTEM LAMBDAS INTO CONSIDERATION IN CHOOSING THE PRICE LEVELS TO ANALYZE?

A. *Broadly yes. As I discuss in Exhibit No. APP-302, I reviewed system lambda data for* several markets and believe the data are (i) not necessarily reflective of competitive prices in those markets; and (ii) do not provide as comprehensive a range of system conditions as do my assumptions. For example, a number of utilities report a constant system lambda on a year-round basis, while other utilities in the region show significant differences depending on season. There are a number of well known limitations to using system lambdas as a basis for competitive prices: utilities do not necessarily apply the same methodology to calculate system lambdas, there are frequently reporting errors, and neighboring utilities can report varying system lambdas. However, I did take the system lambda data into account in selecting the prices to analyze, particularly to identify the lower range of price to be analyzed.

I also considered using market price data reported in industry trade publications such as *Power Markets Week*. There are limitations with these data as well: they represent a fairly limited number of trades in relevant regions; they are not necessarily consistent with all the underlying data used in the Appendix A analysis (e.g., in Appendix A transmission rates are assumed to be the maximum filed-rates, while the market prices would reflect actual transmission costs incurred); and there are far fewer pricing "hubs" for reported market data than there are destination markets.

Ultimately, I concluded that a range of prices from $15 per MWh in off-peak periods to $100 in the summer super peak was sufficient to fully explore possible differences in expected competitive conditions throughout the year. The $15 price is the lowest typical price that can be anticipated on a non-transitory basis. While transactions data (and some occasional system lambda data) demonstrate that prices can sometimes exceed $100 per MWh, modeling higher prices would not change my results. At $100 per MWh, essentially all of the capacity of all of the market participants in all of the relevant markets is economic (the incremental costs even of inefficient peaking units is less than $105/MWh), so the supply of economic energy would not be different at higher prices.

Q. PLEASE DESCRIBE THE BASIC MODEL ARCHITECTURE YOU USED IN ANALYZING THIS MERGER.

A. Briefly, CASm is a linear programming model developed specifically to perform the calculations required in undertaking the delivered price test. The model includes each potential supplier as a distinct "node" or area that is connected via a transportation (or "pipes") representation of the transmission network. Each link in the network has its own non-simultaneous limit and cost. Potential suppliers are allowed to use all economically and physically feasible links or paths to reach the destination market. In instances where more generation meets the economic facet of the delivered price test than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on the relative amount of economic generation that each party controls at a constrained interface.

I represented simultaneous imports into a destination market based on a "common limiting element" approach consistent with the Commission's approach outlined in *FirstEnergy*.[13]

Q. WHAT REPRESENTATIVE YEAR DID YOUR ANALYSIS COVER?

A. Order No. 592 requires that the analysis be forward looking. I intend my analysis to approximate conditions in 2001 as a representative near-term future year. I used control area to control area limits (ATCs and TTCs) from current (i.e., third quarter 1999) OASIS postings to represent the transfer capacity between each area in the model. These are the most recently available data. (The analysis is conducted in $1999.)

Where appropriate, I adjusted other relevant data to approximate 2001 conditions. As described in Exhibit No. APP-303, this includes load, generation costs and confirmed new construction.

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[13] Ohio Edison, et al., 80 FERC ¶ 61,039 at 61,107.

Q. DID YOU MAKE ANY CHANGES IN THE ATC DATA POSTED ON OASIS IN CONDUCTING THE DELIVERED PRICE TEST?

A. Yes, but only with respect to imports into the ComEd market. First, I adjusted ATCs between ComEd and its directly interconnected utilities to reflect the impact of the completion of pending transmission upgrades in the ComEd system, which are described in Mr. Naumann's testimony. These transmission upgrades include the construction of two new 345 kV lines between ComEd's Lockport and Lombard transmission substations. Second, I applied a simultaneous available import capability into the ComEd market of 4,500 MW, based on an analysis conducted by ComEd also described in Mr. Naumann's testimony.

Q. HOW DOES YOUR MODEL ACCOUNT FOR THE UNITS THAT COMED HAS DIVESTED TO SOUTHERN, DOMINION RESOURCES, AND EME?

A. As discussed above, ComEd sold the units, but arranged for a buyback of the capacity of the State Line and Kincaid units, in Power Purchase Agreements that last 15 years. My general methodology for dealing with long term power arrangements is to treat the capacity as belonging to the purchaser. I employed that methodology here, assuming that the entire output of the State Line and Kincaid units was available to ComEd when economic.

The divestitures to EME employed a more complicated buyback arrangement, in which ComEd contracted for the capacity in decreasing amounts over time and retained options to purchase the uncontracted capacity to give it flexibility in meeting uncertain load obligations under its retail access program. As described by Mr. Naumann, EME will have rights to market energy from the units if not used by ComEd.

For purposes of my market screen analysis, I assumed that ComEd contracts for the full capacity of the units. This is a worst-case scenario that tends to maximize the appearance of concentration in the markets and maximize any market power problem relating to the merger.

For purposes of my analysis, I treated ComEd's cost of each contract as the variable cost payment that ComEd must make when it nominates energy under the contract. Hence,

the EME capacity is treated as controlled by ComEd whenever the variable payment is below 105 percent of the market price. At some price levels and for some contracts, my projected dispatch cost of the units is below ComEd's cost under the contract. Under these circumstances (a market price that is lower than ComEd's contract cost but above the dispatch cost of the units), ComEd would not nominate the output under the contracts and EME would be able to sell the output to other purchasers. In these limited circumstances, I treated the output of the units as controlled by EME.

Q. ARE EXISTING TRANSACTIONS BETWEEN COMED AND PECO IMPORTANT IN YOUR ANALYSES OF THIS MERGER?

A. Yes. As discussed above, a prime concern in merger analysis is that the merger would reduce the number of competitors in a region, allowing the remaining competitors to raise prices above the level that would otherwise have existed. Because all of ComEd's generation is at least three wheels away from PJM, which is a very robust market, there is little basis for concern that elimination of ComEd as a separate competitor in the PJM market will allow Applicants to exercise market power. For similar reasons, PECO's Pennsylvania generation is competitively unimportant in Illinois. However, as I have described above, the pre-merger 300 MW power sale from ComEd to PECO made PECO a competitor in that region.[14]

Q. PLEASE DESCRIBE THE 300 MW SALE FROM COMED TO PECO.

A. PECO has a 10-year 300 MW power purchase contract with ComEd which began in 1997. The point of delivery for the power is the ComEd-AEP interconnect or the ComEd-CIPS (i.e., Ameren) interconnect.[15] ComEd has the right to curtail this transaction in the event it has a capacity emergency in accordance with its Emergency Load Conservation Procedure. In 1999, the transaction was curtailed for only 26 hours. At the option of PECO, ComEd can also re-purchase this energy from PECO, and has

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[14] Additionally, PECO's ownership interest in the Clinton facility, through its AmerGen affiliate, provides additional generation that PECO could have sold in the ComEd region as a separate competitor if there was no merger. PECO also participates, pre-and post-merger, in the midwestern markets to the extent that its other contracts and owned capacity provide it with deliverable economic capacity.

[15] PECO informs me that it almost always takes delivery at the AEP interconnect.

done so.[16] While there is no long-term firm transmission service reservation associated with this transaction, PECO has been using non-firm transmission to move energy from this contract. Year-to-date (through September 1999), 43 percent of the energy from this transaction was delivered to PECO load in PJM. Over the 1997-99 period, 40 percent of the energy was delivered to PECO.

Q. HOW DID YOU ANALYZE THIS CONTRACT?

A. My analysis treats the 300 MW power contract between Applicants in a manner consistent with other long-term contracts analyzed, namely a transfer of control over generation (in this case 300 MW) from the seller (ComEd) to the buyer (PECO).

This contract, however, is distinguishable from many typical utility long-term contracts in that the point of delivery is not in the purchasing party's control area. Both as a matter of practice and contract, PECO generally takes delivery of this energy in the AEP control area. Two other factors distinguish this contract, namely ComEd's recall rights and the fact that it has historically re-purchased a portion of the energy from PECO.

My general practice is to treat power for which control is transferred from the seller to the buyer as located at the contract point of delivery. I deviated from this practice in the case of this contract, and assumed PECO controlled this generation in ComEd's control area. This is conservative in that a larger overlap is assumed to exist between Applicants in the ComEd control area than would otherwise be determined if I treated the 300 MW in either the AEP or Ameren control area, as specified by the contract. Indeed, treating the contract as giving PECO 300 MW in the ComEd market area, rather than the AEP area, is the direct cause of the only screen failures produced by my analysis.[17] The 300 MW of energy is then subject to allocation by limited transmission from ComEd into surrounding

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[16] In January-September 1999, for example, ComEd accounted for only 1.6 percent of PECO's sales of the 300 MW. In 1998, in contrast, ComEd accounted for 28 percent. The difference is primarily attributable to the return to service of ComEd nuclear capacity that did not operate for much of 1998.

[17] Had I treated the contract as being located in the AEP service area, the 300 MW would have had to compete with AEP's capacity (and other capacity that reaches the AEP control area) for available transmission from AEP to ComEd. As a result, it would have been so severely "squeezed" in the proration of available transmission capacity that it would not have caused a screen failure in the ComEd market.

destination markets.[18] Because PECO takes the energy on an round the clock basis, I assume ComEd supplies the 300 MW from its lowest-cost energy sources.

As discussed above, Applicants are willing to sell contract rights to the 300 MW to an unaffiliated third party if necessary to obtain merger approval. If the contract rights are sold to a third party, control of the capacity is transferred to that party, and the capacity is no longer controlled by Applicants. I have performed further analyses assuming that the 300 MW have been sold to a third party. Those analyses show that the sale would eliminate any merger-related increases in the Appendix A screen for Economic Capacity.

Q. HOW DID YOU ANALYZE AMERGEN'S OWNERSHIP OF THE CLINTON PLANT?

A. As discussed above, PECO's subsidiary AmerGen has purchased the Clinton facility from IP, but has agreed to sell 75 percent of the output back to IP through 2004. Consistent with my treatment of other power sale arrangements, I treated the 75 percent as belonging to IP. I treated the remaining 25 percent of the plant (approximately 230 MW) as belonging to PECO in my analysis (even though PECO has only 50 percent ownership in AmerGen). The effect of this assumption is to increase the market concentrations (relative to an assumption that PECO owns only 50 percent of AmerGen), and the merger-related changes in concentrations, in IP and other markets to the south and west of ComEd. However, because the IP market is only moderately concentrated, the change in market concentration arising from the Clinton ownership is not problematic; in the other markets, the change in market concentration arising from the merger is not material. It is possible that some of the Clinton output could be sold into the ComEd market. However, the transmission capacity between IP and ComEd (and, more generally, into ComEd) is limited, and I have treated Clinton identically to all other capacity, pro-rating the amount of that capacity that could be transferred to ComEd, consistent with my general methodology for allocating limited transmission capacity, described in Exhibit No. APP-302. After the pro-rated allocation of capacity, some 30 to

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[18] One might speculate that this treatment is not conservative in the markets in-between Applicants (particularly the AEP destination market), but as I demonstrate later in my testimony and exhibits, Applicants' overlap in the AEP market is small. Hence, an additional 300 MW controlled by PECO in the AEP market would not be consequential to the HHI screen.

63 MW from AmerGen's share of the Clinton unit enters the ComEd destination market, depending on the time period and market conditions. This pro-rated allocation of capacity has been factored into the Appendix A study results that I present.

Q. WOULDN'T IT HAVE BEEN MORE CONSERVATIVE TO ASSUME THAT ALL OF AMERGEN'S SHARE OF CLINTON GETS INTO THE COMED MARKET?

A. Yes. However, while I have sought to make conservative assumptions, more likely to amplify than conceal the effects of the merger, "conservative" does not extend to "biased." Simply to assume that AmerGen's share of Clinton is in the ComEd market, as an exception to an otherwise consistent allocation of scarce transmission, would be improper. Any consistent means of transmission allocation that would have brought all of AmerGen's share of Clinton into the market would also have brought in all of Clinton that is not controlled by AmerGen. Such a methodology also would have substituted other nearby and/or low cost generation (depending on the method used) for the generation that my proration method allowed into the ComEd market. Among the losers for any method that brought in all of AmerGen's Clinton share almost certainly would be the share my method allocated to PECO's distant capacity in Pennsylvania.

Moreover, any paradigm that gets all of Clinton into the market, such as allocating all transmission to the lowest cost suppliers, would mean that if Applicants were to artificially withhold their share of Clinton from the ComEd market, the transmission made available for re-allocation would go to other very low cost generation (e.g., the Callaway station or MidAmerican's share of the Quad Cities plant). While such a substitution would change the HHI calculation, it would not actually change the supply curve of imports into the ComEd area.

Q. PLEASE DESCRIBE THE 100 MW PATH RESERVATION BETWEEN COMED AND PECO.

A. As discussed above and as described in the testimony of Mr. McDonald, Applicants are prepared to interconnect via a 100 MW firm transmission reservation from ComEd to the PJM border, if required to do so by the SEC.

Q. HOW DID YOU ANALYZE THIS INTERCONNECTION PLAN?

A. Applicants will use the path when it is economic to do so. When it is not used, it will be re-posted on OASIS by the party that controls the transmission and be made available to other parties. I have modeled both states. To model the effects of the merger when the path is being used, I assumed that, post-merger, Applicants would supply 100 MW of energy to PECO from resources in the ComEd area during all hours.[19] This 100 MW flow assumption has the greatest adverse affect on PJM markets, since it assumes that Applicants' share of such markets is increased by the full amount of the interconnection in all hours. This analysis also takes into account the loop flow effects of the power transfer. It was not necessary to explicitly and separately model the effects of the merger when the path is not being used. When the path is not used, there is no change from the pre-merger case in how Applicants' systems are used or in the flows on the transmission network. Hence, the effects of the merger are limited to combining Applicants' pre-merger shares of each destination market; I calculated these using the pre-merger model runs. By modeling both states, I made the most conservative assessment possible: within ComEd, the most conservative assessment arises when the transmission does not occur as that would increase Applicants' post-merger share of the market within ComEd; to the east of ComEd, the most conservative assessment assumes that the transaction does occur, as that would reduce ATC in the region, reducing the ability of other competitors to serve those areas. Since 100 MW of power is assumed to be transferred from the midwest to eastern PJM, it doubly impacts Applicants' share of PJM markets by increasing their controlled deliverable economic capacity and reducing the transmission available to others.

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[19] As discussed *infra*, when the path is not being used and is posted for reassignment, the post-merger case will look exactly like the pre-merger case, except that Applicants' shares are combined. Hence, the analysis allows the merger to be evaluated under both feasible conditions with respect to the integration path: that it is being used and that it is not.

VI. IMPACT OF THE MERGER ON COMPETITION

Q. WHAT SPECIFIC ANALYSES DID YOU CONDUCT TO EVALUATE THE POTENTIAL EFFECTS ARISING FROM THE COMBINATION OF GENERATION ASSETS?

A. Consistent with the guidance in the *Merger Policy Statement*, I analyzed Economic Capacity and Available Economic Capacity, focusing on the combination of Applicants' generation. Given the status of restructuring in Pennsylvania and Illinois, and more generally, the Economic Capacity analysis is the only analysis relevant to this merger. As discussed *infra,* the Available Economic Capacity analyses does not provide reliable and useful insight into future market conditions since the native load that distinguishes this analysis from the Economic Capacity analysis is changing at unpredictable rates and in the long run will be eliminated.

I have not analyzed Total Capacity and Uncommitted Capacity, for two reasons. First, these measures are not required explicitly by the *Merger Policy Statement* or the NOPR in Docket No. RM98-4-000. Second, in this instance, Applicants are three wheels from one another, which, under the normal application of the Commission's "hub-and-spoke" analysis of Total and Uncommitted Capacity, would result in them not being in the same market.

Economic Capacity

Q. WHAT DID YOUR ANALYSIS SHOW FOR ECONOMIC CAPACITY?

A. The Economic Capacity analysis confirms that the Applicants' overlap in virtually all destination markets is sufficiently small that the HHI screen is passed readily. The only exception to this conclusion is in the ComEd destination market. In this market, the screen is failed in all time periods except for the highest super-peak period. The screen is passed in this period because, during the highest load hours, ComEd has recalled the 300 MW of capacity that is under contract to PECO pursuant to the terms of that contract. In these highest load hours, PECO does not control the 300 MW pre-merger and, hence, the merger does not reconsolidate the 300 MW with other ComEd-controlled capacity. The only other market in which the HHI increases by more than 50 points is the Illinois Power

market, wherein AmerGen's 25 percent of the Clinton unit is located.[20] In this market, the HHI increase is between about 41 to 74 points, with the largest increase in the lower load periods. The Illinois Power market is at most moderately concentrated (HHI between 1,000 and 1,800). Hence, the screen value for the change in HHI is 100 and the screen is comfortably passed.

Exhibit No. APP-305 shows that Applicants' market shares, pre- and post-merger, in the destination markets around and between them are not large and the overlap is small. Outside of its home market, ComEd's largest share is in the Illinois Power market, with shares ranging from 9 to 14 percent. PECO's share of that market is about 2 percent in all time periods. PECO's largest share is in the PJM-East market, ranging from 16 to 19 percent; ComEd's share of that market is under one percent in all periods. In intervening markets between PJM and ComEd, most of which are only moderately concentrated in most periods, each Applicant's share is well under 10 percent. The typical changes in HHI levels are 20 points or less.[21]

Q. PLEASE DESCRIBE THE RESULTS FOR THE COMED DESTINATION MARKET.

A. Under the base case (i.e., when the 100 MW path is not used), PECO has a pre-merger share of 1.4 - 2 percent in most time periods. In off-peak periods, its share rises to a maximum of 2.3 percent. PECO's share is made up of four elements: (1) the 300 MW of power purchased from ComEd and assumed to reside in ComEd's control area; (2) 30 to 63 MW of power from AmerGen's Clinton plant in Illinois Power's control area that is prorated into ComEd; and (3) between 0 and 51 MW of power from PECO generation in PJM that is economic and deliverable (after proration) into the ComEd market.

ComEd has a 63 to 76 percent share of this destination market, consisting of currently owned generation and contract rights and about 500 MW of owned or contracted

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[20] There is one minor exception, for one time period in the CILCO market (winter off-peak), where the HHI change is 60 points in a moderately concentrated market (HHI of 1118).

[21] The exception is the NIPS destination market, where ComEd has a share of up to 13 percent but PECO has a share of 1.5 percent or less. The HHI changes are 34 points or less in a moderately to highly concentrated market.

generation expected to be on-line by 2001.[22] Other local generation within ComEd's control area includes small amounts owned by ComEd TDUs and about 1,700 MW of merchant generation.[23] Imports from ECAR, MAIN and MAPP are approximately 4,500 MW, the simultaneous limit imposed into ComEd.[24]

Q. PLEASE SUMMARIZE THE HHI RESULTS FOR THE COMED DESTINATION MARKET.

A. These are shown in the table below; as described above, these results reflect analyses assuming (1) no additional flows between PECO and ComEd and (2) the 100 MW firm transmission path.

ComEd Market		Pre-Merger			Pre-Mitigation Post-Merger			
					No Firm Transmission Path	100 MW Transmission ComEd to PECO		
Economic Capacity	Market Price ($/MWh)	ComEd Market Share	PECO Market Share	HHI	Delta HHI (2AB)	Merged Market Share	HHI	Delta HHI
Summer Super Peak	$100	75.7%	0.10%	5791	15	75.4%	5755	-37
Summer Super Peak	75	73.1%	1.40%	5419	205	74.1%	5562	142
Summer Super Peak	50	73.2%	1.40%	5429	205	74.2%	5572	143
Summer Peak	30	63.8%	1.40%	4238	179	64.8%	4368	130
Summer Off-Peak	20	71.0%	1.80%	5136	256	72.2%	5313	178
Winter Super Peak	25	65.9%	1.50%	4504	198	67.0%	4647	143
Winter Peak	20	73.2%	1.80%	5407	264	74.5%	5602	194
Winter Off-Peak	15	67.7%	2.00%	4657	271	69.2%	4861	204
Shoulder Super Peak	40	66.0%	1.40%	4453	185	67.1%	4587	134
Shoulder Peak	25	63.4%	1.70%	4179	216	64.5%	4329	149
Shoulder Off-Peak	15	64.6%	2.30%	4254	297	66.3%	4478	224

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22 As noted earlier, approximately 300 MW of these purchases are assumed to come from a planned unit for which no contract exists. This pre-supposes that between now and 2001, ComEd will contract for additional generation to meet potential load requirements.

23 I discuss the planned generation in ComEd's control area in Exhibit No. APP-302. As I describe there, all of these units are either under construction or have passed sufficient project, financing and regulatory hurdles such that an in-service date by 2001 is considered highly probable.

24 When the 100 MW transfer from ComEd to PECO is being modeled, ComEd's simultaneous import capability increases by 100 MW to 4,600 MW.

Q. DO THE HHI RESULTS FOR THE COMED MARKET ACCURATELY REFLECT THE POTENTIALLY ADVERSE IMPACT OF THE MERGER ON THE CURRENT WHOLESALE CUSTOMERS IN THE COMED AREA?

A. This result is highly conservative in the way in which the PECO contract is modeled. As discussed earlier in my testimony, the 300 MW contract is for delivery in AEP or Ameren. Had I treated it in a manner that mirrors the contract, PECO as the owner of the contract would have been allocated only a prorated share of the available transmission back into ComEd. The more conservative treatment that I used assumes that all of the 300 MW competes in the ComEd market without the cost or limits of the transmission system. This reflects the fact that, in selling the capacity back to ComEd, PECO can, and has, "booked out" the purchase against a sale back to ComEd. This could not be done in selling the power to any party other than ComEd.[25] Hence, my treatment of the contract materially overstates PECO's role as a seller to any wholesale purchaser in the ComEd control area other than ComEd itself.

ComEd's current wholesale customers include TDUs with aggregate demand that is small relative to the amount of potentially available supply. To the extent these TDUs are served under multi-year contracts (see Ms. Juracek's testimony), they are insulated from any potential increase in market price due to the hypothetically enhanced ability of Applicants to raise prices post-merger.[26] Also, to the extent such customers are under contract, their ability to access competing suppliers is only theoretical, not real. In any event, assuming that TDUs are free to shop for power, the competitive conditions that they face will be identical for the ComEd control area.

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[25] While PECO could, in effect, book out purchases against other parties, it still would be required to take delivery of the energy at the AEP or Ameren border. With ComEd, the energy never leaves the ComEd control area with a bookout.

[26] Three of ComEd's six TDUs can have some of their requirements supplied competitively in 2000-2001.

Q. DO YOUR ECONOMIC CAPACITY RESULTS CHANGE SIGNIFICANTLY WHEN YOU ASSUME ADDITIONAL INTERCONNECTION BY A FIRM 100 MW WEST TO EAST TRANSMISSION PATH?

A. No. These results are shown in Exhibit No. APP-306. There are two potential affects from the 100 MW path. First, when the path is being utilized, Applicants' amount of capacity controlled in the ComEd market is decreased by 100 MW and their controlled capacity in the PECO system is increased by 100 MW. Second, again during the times when the path is being utilized, there will be merger-related changes in power flows that can affect the transmission system in a way that either increases or decrease concentration in Applicants' markets or in other markets.

The first of these effects reduces merger-related increases in concentration within the ComEd, market, the only market in which there are screen failures. Since my overall analysis also considers the case where the path is not used, I do not rely on this path-related deconcentration in reaching my conclusions. Use of the path increases the effect of the merger on PJM-East relative to the base case; however, the increase is slight and the maximum merger effect on the PJM-East market remains at under 32 points of HHI increase, far below the 100 point threshold for a moderately concentrated market.

Loop flow effects arising from the use of the 100 MW path were analyzed by Applicants' engineering staff and are addressed in Mr. Naumann's testimony. I utilized his analytic results to determine the change in the non-firm ATCs that would result from the path utilization and the consequent affects on market concentration. Specifically, and as he recommended in his testimony, I adjusted the path ATCs by the amount of the change in FCITCs that his load flow studies produced as a consequence of assuming the flow of 100 MW from ComEd to PJM-East. As he describes, the loop flow effects moderately deconcentrate the ComEd market and have minor effects on transmission in between the ComEd and PJM-East markets. In some intervening markets, a reduction in ATCs arising from the 100 MW path has a slight concentrating effect. However, in no case does the integration path create a screen failure. Quite simply, since the merger, without the 100 MW transfer, has such a slight effect on intervening markets, the reduction in ATC available to others due to the assumed transfer of 100 MW does not cause any screen violations.

Q. IS THE MERGER LIKELY TO CAUSE ANY LARGER INCREASES IN POWER TRANSFERS THAN THE 100 MW THAT YOUR ANALYSIS EXAMINES?

A. No, not appreciably. Recall that PECO already has the right to take 300 MW of energy from ComEd in the AEP market area. PECO's use and disposition of this energy has varied depending on market conditions. For example, in 1998 only 17.5 percent of energy taken under the contract was actually delivered to PJM and PECO whereas in 1999 (through September), 43 percent of it was delivered to PJM and PECO. In the future, as in the past, the Applicants will dispatch energy from ComEd to PECO only when it is economic to do so. The fact that ComEd has not found PECO (or PJM) to be its highest value market, and hence has made only small sales on its own account to PJM, coupled with the fact that PECO itself has sold little more than 100 MW of its 300 MW of ComEd energy into PJM (on average) suggests that the degree to which the merged company can expect to transfer energy from west to east will typically be in the range of around 100 MW, plus or minus. In this context, it also is notable that the cost of transferring power will change only modestly on the basis of tariff changes arising from the new ISOs. PECO already is a member of PJM. ComEd is already directly connected to AEP and its sales to the east will not benefit from a reduction in pancaking once the MISO becomes operational. Assuming that the Alliance RTO is formed and has a non-pancaked rate, transfers from ComEd to PJM would face one less wheeling charge (at least for power sent via AEP and Virginia Power or FirstEnergy), but so will other MISO members as well as power from AEP and the Michigan utilities.

Q. PLEASE DESCRIBE HOW THE MITIGATION THAT APPLICANTS HAVE OFFERED AFFECTS THE HHI RESULTS FOR ECONOMIC CAPACITY IN THE COMED MARKET.

A. As described in the Application, Applicants have stated their willingness to sell the 300 MW PECO contract that is the principal cause of the screen failure to a third party should the Commission deem it necessary. This mitigation eliminates the screen violations in all time periods as shown below.

ComEd Market			No Firm Transmission Path		100 MW Transmission ComEd to PECO	
			Pre-Mitigation	Post-Mitigation	Pre-Mitigation	Post-Mitigation
Economic Capacity	Market Price ($/MWh)	Pre-Merger HHI	Delta HHI	Delta HHI	Delta HHI	Delta HHI
Summer Super Peak	$100	5791	15	20	-37	-37
Summer Super Peak	75	5419	205	19	142	-36
Summer Super Peak	50	5429	205	19	143	-36
Summer Peak	30	4238	179	18	130	-31
Summer Off-Peak	20	5136	256	29	178	-41
Winter Super Peak	25	4504	198	21	143	-32
Winter Peak	20	5407	264	38	194	-31
Winter Off-Peak	15	4657	271	57	204	-8
Shoulder Super Peak	40	4453	185	18	134	-37
Shoulder Peak	25	4179	216	22	149	-38
Shoulder Off-Peak	15	4254	297	66	224	-2

In the base case, the change in HHI falls to about 20 points in all but off-peak periods. In off-peak periods when the market price is assumed to be only $15 per MWh, the change in HHI is 57 and 66 points. This is above the level that is presumed to not create a market power issue in the *Merger Guidelines*, but below the level that is presumed to create a failure, a "gray area" in the Merger Policy Standards. Since this condition occurs only in the lowest priced period, during which there is substantial competing capacity,[27] the "gray area" result does not signal a market power problem.

The merger, with mitigation, slightly deconcentrates the ComEd destination market if the 100 MW transmission path is used. This result occurs because Applicants reduce controlled generation by 400 MW (sale of the contract plus the 100 MW transfer), and the market size increases slightly by 100 MW (the export of 100 MW from the ComEd control area allows an extra 100 MW of import capability). As noted previously, my conclusions concerning the effects of the merger on midwest markets do not rely on the

[27] Prices at the level that give rise to the "gray area" result typically occur only during overnight periods in off-peak seasons. During such hours, there is a great deal of inflexible plant, such as baseload coal, that is at or near minimum load. (Minimum load levels are typically 15 to 25 percent of full load capability for fossil steam plant.) This minimum load amount is producing energy and, hence is "in the market" even if the variable cost of the units is below the market price, since running, even at a loss, is necessary if the plant is to be available during higher priced daytime periods. Moreover, plant producing at minimum load can quickly increase output if prices rise. Hence, any attempt to raise prices would attract very rapid and substantial competition.

deconcentrating effects of the power transfer. The effect of mitigation on all other markets is shown in Exhibit APP-307. Since there are no pre-mitigation failures in markets other than ComEd, there also are no failures post-mitigation.

Sensitivities

Q. PLEASE DESCRIBE THE EFFECTS OF THE SENSITIVITY ANALYSES YOU UNDERTOOK.

A. As I described earlier, I performed two sensitivity studies. For purposes of these sensitivities, I analyzed only a subset of the destination markets, consisting of ComEd's control area and the PJM markets; historic overlapping markets in between ComEd and PECO; and control areas impacted by the 100 MW path. I analyzed 15 such destination markets.[28]

In the first sensitivity study, I assumed that full TTCs, rather than ATCs, were available to interconnect markets. See Exhibit No. APP-308.

In the second sensitivity study, I assumed zero transmission rates, as a limiting case showing the effects of market enlargement on the competitive effects of the merger. See Exhibit No. APP-309.

My conclusions are further supported by these sensitivity analyses. While the absolute numbers reflected in these sensitivities differ slightly from those of my base case and 100 MW flow case, my conclusions remain robust. Indeed, in most cases, the merger causes still smaller increases in HHIs than in my main cases. These cases were designed to investigate whether future changes in the tariff structure and reservation practices of RTOs that increase transmission capability and make distant suppliers, such as the Applicants, more closely competitive. The fact that these sensitivities show no adverse effect means that my conclusions are likely to remain robust as market institutions change.

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[28] These include ComEd, four PJM markets, IP, NIPS, AEP, VP, APS, FirstEnergy, MECS, CPL, TVA and DLCO.

Available Economic Capacity

Q. HAVE YOU ALSO ANALYZED THE EFFECTS OF THE MERGER ON AVAILABLE ECONOMIC CAPACITY?

A. Yes. However, I believe that this analysis is of at best limited value and should not be relied upon in assessing the future effects of the merger on competition.

Q. WHY SHOULD THE AVAILABLE ECONOMIC CAPACITY ANALYSIS NOT BE RELIED UPON HERE?

A. Order No. 592 indicates that the merger analysis is intended to be forward looking. Available Economic Capacity analysis differs from the Economic Capacity analysis solely in that native and requirements customer loads are deducted from the resources controlled by each supplier. Capacity required to meet native load is deducted from the resources available from each supplier on the assumption that only its higher cost remaining resources are available to sell into the market. As the Order recognizes, under conditions of full retail access, all capacity is in the market, in which case the Available Economic Capacity analysis becomes identical to the Economic Capacity.

From a market power perspective, any valid information that the Available Economic Capacity analysis provides incrementally to the Economic Capacity analysis depends on at least two assumptions. First, the capacity that serves native load is not available to make sales in the market-priced wholesale market and its control by a supplier cannot affect the wholesale market. Second, the capacity that is sold to native load customers is insulated from any increase in prices in the competitive part of the market. Neither assumption is wholly true. Most importantly, if (as is the case with the Available Economic Capacity analysis) the competitive supply is treated as a residual after individual suppliers' native loads are met, the withholding of any capacity, whether "dedicated" to native load or not, nevertheless affects prices in the competitive market. Second, depending on the precise nature of state regulation (for example, whether there are long term rate freezes or frequent rate cases, whether there is a fuel and purchased power adjustment clause, whether margins on wholesale sales offset retail revenue

requirements), the existence of native load may variously impede, contribute to or be neutral with respect to the possible exercise of market power in wholesale power markets.

If these were the only problems with Available Economic Capacity as a measure of participation in wholesale markets, then it still might have considerable value if native load requirements and the amount of capacity controlled by suppliers could be predicted with the level of confidence that was feasible only a few years ago. However, the transition to retail access that is occurring throughout the country means that a forward looking analysis of Available Economic Capacity is necessarily fraught with assumptions and transitory in relevance. Moreover, a merger policy that relies on it will give perverse signals to utilities from the point of view of public policy. A utility that builds new merchant capacity, thereby increasing market supply, may find itself with an Available Economic Capacity "problem" in a market where little such capacity exists and any new supplies clearly are pro-competitive. Similarly, a utility whose policies create a rapid success of competing retail access providers may find that it has created an Available Economic Capacity problem for itself as a result. A merger policy that penalizes suppliers for such pro-competitive activities would be counter-productive.

Q. WHY IS AN ANALYSIS OF AVAILABLE ECONOMIC CAPACITY SPECULATIVE?

A. I, and other practitioners, have interpreted Order No. 592's definition of Available Economic Capacity as being net of load served under state regulation. As retail access reduces the amount of load retained by the historic provider as a regulated utility,[29] the amount of that utility's Available Economic Capacity increases. Hence, any forward-looking analysis of Available Economic Capacity depends on a forecast of the pace of retail access for each supplier in the market, an inherently speculative undertaking.

The amount and ownership of Available Economic Capacity depends also on the divestiture plans of utilities and the nature of take-back contracts and other contracts

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[29] It is not clear whether load served by an unregulated subsidiary of the formerly-load serving utility should be deducted. On the one hand, the load such an affiliate serves requires purchases from the market. Hence, in deciding whether an action to increase market prices is profitable, a generation owner would take such contractual responsibilities into account in much the same manner as its remaining native load responsibility. However, load served by an affiliate is not subject to state regulatory pricing rules.

entered into by the buyer. Clearly, divestiture plans for the future are not knowable and, as recent experience shows, utilities can change their plans quickly. Even if the period being analyzed is relatively near into the future, so that the amount of divestiture can be projected with some confidence, the existence, control, and pricing provisions of associated contracts may not be known.

Of course, any forecast contains elements of uncertainty. But in the case of Available Economic Capacity, which is a residual market after native load requirements are taken into account, small changes in assumptions about loads and the control of capacity can have quite magnified impacts on market shares and market concentration. Yet, the underlying supply and demand for power in the region is wholly unaffected by either the pace of retail access or the transfer of generation and contracts among parties.

Q. WHY IS ANY ANALYSIS OF AVAILABLE ECONOMIC CAPACITY TRANSITORY IN ITS MEANING?

A. Because the results of the analysis are so dependent on the balance between the pace of retail access and asset dispositions, any result, even if correct for a particular year, will be incorrect for the following year. PECO's retail access is well advanced. Other PJM utilities also are undergoing retail access. Some have sold significant generation with very short term take-back contracts. Some divested generation that initially is not subject to take-back contracts will be committed to long term sales. PECO's share of the PJM Available Economic Capacity "market", and the market HHI, will change substantially from year to year. This is far less true for Economic Capacity.

ComEd has just begun its retail access. At this point in time, the amount of access that will occur is highly uncertain. Moreover, to preserve its ability to serve retained load, ComEd has retained various option rights to the plants it has divested to EME. The extent to which it will exercise those rights depends significantly on the pace of retail access. Both the amount of retained load and the amount of capacity that is deemed under ComEd's control will, therefore, change from year to year. Its Available Economic Capacity, being determined by the balance between the two, will change even more dramatically and unpredictably. Other utilities that are beginning, or will soon begin

retail access in the region, will also experience substantial changes in their Available Economic Capacity.

Q. THESE CAVEATS NOTWITHSTANDING, HAVE YOU PROVIDED AN AVAILABLE ECONOMIC CAPACITY ANALYSIS?

A. Yes. The results of the analysis are shown in Exhibit No. APP-310 for both the base case and the case that assumes a 100 MW west-to-east interconnection path.

Q. WHAT DID YOU ASSUME IS THE LEVEL OF RETAIL ACCESS IN YOUR ANALYSIS?

A. I assumed that each utility retains its full, historic load responsibility. In a slightly different context,[30] the Commission has indicated its distaste for hypothetical assumptions about the extent of retail access in markets where such access has begun. To avoid such hypothetical assumptions, I simply have assumed that retail access will not materially affect the amount that the various suppliers can make available to the wholesale market. In the midwestern markets that are most likely to be problematic based on the Economic Capacity analysis, retail access either has not yet begun or is just now beginning. Hence, the zero access assumption for suppliers to these markets likely is not far off the mark.

Q. WHAT DOES THIS ANALYSIS SHOW IN TERMS OF THE EFFECTS OF THE MERGER?

A. The base case analysis shows that, as was the case with Economic Capacity, the problem market is the ComEd market. For the 451 other markets-time periods analyzed, there are a total of 10 screen failures. No market has more than one failure. In the majority of cases, concentration in the market in which the failure occurs is at the low end of the moderately concentrated range (post-merger between 1,000 and 1,200) and the change in HHI barely exceeds 100 points.

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30 *EME Homer City Generation, L.P.*, 86 FERC ¶ 61,016 (1999).

In the analyses incorporating the 100 MW path there are a few more failures (a total of 20) and a somewhat different pattern in terms of geography and time periods. For example, there are a number of screen failures in SERC. In the 100 MW case, there also are a number of markets in which the HHI is reduced by significant amounts. In some SERC markets, remote from both Applicants, there are both screen failures and HHI reductions of comparable magnitudes in the same market in different time periods.[31]

Q. DOES THE SALE OF THE 300 MW CONTRACT TO A THIRD PARTY ELIMINATE THESE SCREEN FAILURES?

A. The majority are eliminated, including most of the failures in the ComEd market. These results are contained in my workpapers.

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS OF AVAILABLE ECONOMIC CAPACITY?

A. There are a few, mostly marginal screen failures scattered around various markets with no systematic pattern, except in the ComEd market that is the focus of the mitigation that Applicants have offered. In view of the nature of the screen failures and the significant concerns that I have identified about performing or relying on the Available Economic Capacity analysis, I do not believe that these screen failures demonstrate any competitive harm arising from the merger.[32]

Applicants' Lack of Control Over Withdrawable Capacity

Q. IN YOUR SUMMARY, YOU INDICATED THAT APPLICANTS CONTROL DISPROPORTIONATELY SMALL SHARES OF CAPACITY THAT CAN BE

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[31] Some of these results illustrate the extent to which the Available Economic Capacity test can produce misleading results. For example, in the Duke market, one of the most heavily nuclear markets in the United States, PECO is one of only two suppliers, and has a share of over 90 percent in the shoulder off-peak period. This is because there is so little low cost capacity not required to meet native load of its owners (such load being assumed to be served by the lowest cost resources) that PECO's "uncommitted" resources from the Clinton nuclear plant and the 300 MW purchase from ComEd that I model with a zero price are about the only *Available Economic Capacity that can economically reach the Duke market at a price near $15/MWh.* However, it is obvious that a few hundred MW of such capacity does not determine the market price in the Duke control area (several hundred miles away) during off-peak periods.

[32] Notably, all but three of the 20 screen failures in Available Economic Capacity are eliminated by the mitigation offered by Applicants, and, the other three failures occur in markets that are only moderately concentrated.

WITHHELD TO INCREASE PRICES AND THAT THE MERGER DOES NOT CONCENTRATE THE OWNERSHIP OF SUCH CAPACITY. WHY IS THIS RELEVANT TO THE ANALYSIS OF THIS MERGER?

A. The only way in which a generator, or group of generators, can increase prices is by reducing the supply that is available at a given price. This "withholding" of capacity can be achieved either by simply not making the capacity available or by offering the capacity at a price higher than it would be offered at under competition.

Capacity that is out of the market (has an incremental cost that is higher than the market price) cannot be effectively withheld, since such capacity is not relevant to price determination – it is not part of economic supply whether withheld or not. Capacity that has a cost that is well below the market price can, other things equal, be withheld. However, the lower the variable cost of producing energy from a given plant, the less likely it is that withholding capacity from that plant is profitable.

This can be demonstrated by example. Suppose that a generator has 2,000 MW of economic capacity with a variable cost of $20 per MWh and that the competitive price is $25 per MWh. The contribution to fixed costs and profit is thus $5 times 2,000 MWh, or $10,000 per hour. Suppose also that by withholding 500 MW of capacity (or bidding it at a price of $28 per MWh or higher) it can drive the price to $28 per MWh. The contribution is now $8 times 1,500 or $12,000 and the action is profitable.

Now suppose the same set of facts except that the variable cost of the plant is $10 per MWh. If bid competitively, the contribution is $15 times 2,000 MWh or $30,000. Removing sufficient economic capacity to raise the market price to $28 per MWh (again, 500 MW in this example) results in a contribution of $18 times 1,500 MWh, or $27,000 and the action is unprofitable.

As the example demonstrates, the profitability of withholding capacity depends on two factors: a) the profits lost on each MW withheld and b) the number (or proportion) of MW that must be withheld to achieve a given increase in price. Point a) means that deep baseload plant, which has higher contribution margins than plant with higher variable costs, is more difficult to withhold profitably. Point b) means that it is more difficult to withhold plant profitably when prices are such that the merit order is flat (as it is during

low and moderate load periods) compared to when the merit order is steep (high load periods when transmission may be constrained and when only high variable cost capacity competes to set market prices).

Q. DO APPLICANTS CONTROL SIGNIFICANT AMOUNTS OF PLANT THAT IT IS LIKELY TO BE PROFITABLE TO WITHHOLD?

A. Generally speaking, no. ComEd in particular controls little such plant as a result of the divestiture of its fossil units, The merger does not result in a problematic concentration of control over economically withdrawable plant.

Q. WHAT ARE THE RELEVANT CHARACTERISTICS OF PLANT CONTROLLED BY COMED?

A. ComEd controls its nuclear plants.[33] Since it has full dispatch rights for the Kincaid and State Line plants that it has divested, I assume that it also controls them. Mr. Naumann discusses ComEd's control, or lack thereof, over the balance of its previously owned fossil plant that is being sold to EME in his testimony. For purposes of my analysis, I concluded that since ComEd does not operate the divested plant, the amount that it can be said to control, in the sense of being able to withhold it from the market, is limited to, at most, the Kincaid and State Line stations and the portion of the capacity being sold to Edison Mission identified by Mr. Naumann in his testimony.

Exhibit No. APP-311 shows the plants controlled by ComEd and by PECO, together with regional amounts of plants controlled by others. ComEd controls about 9,000 MW of nuclear plants (and the low-cost Kincaid and State Line plants) with a dispatch cost below $15 per MWh.[34] It controls no generation between $15 and $25 per MWh, and less than 500 MW of plant with a dispatch price between $25 and $30 per MWh.[35]

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[33] I assume, for these purposes, that ComEd and PECO both control (and could withhold) their shares of jointly owned plant. In practice, the unilateral withholding of a share of a jointly owned plant, particularly a nuclear plant, may not be feasible.

[34] All plant ratings and dispatch costs in the table are from the Appendix A analysis database. Plant ratings are summer values and are derated for forced outages. Variable costs include fuel and variable O&M.

[35] The almost 500 MW of ComEd generation priced at $25 to $30/MWh in Exhibit No. APP-311 represents planned affiliated merchant generation and other purchases from planned units. This is a conservative estimate

Both system lambda data and reported market price data from *Power Markets Week* indicate that off-peak prices in MAIN typically are about $15 per MWh. (See Exhibit No. APP-312.) Prices commonly are below $30 in most other hours except in peak hours in the summer and super-peak hours in shoulder months. Indeed, in the ComEd control area in 1998, system lambdas were above $30 in less than 300 hours (3 percent of the time). Thus, ComEd controls only about 1,500 MW (the Kincaid and State Line units) that is near-marginal in off-peak hours, 500 MWh of potential future generation that is near-marginal when prices are closer to $30 per MWh, and only a portion of the capacity sold to EME as near-marginal capacity in the summer super-peak hours when prices can rise rapidly in response to relatively small changes in load or capacity.[36]

Q. CAN YOU RELATE COMED'S CAPACITY IN THESE PRICE BANDS TO THE CAPACITY CONTROLLED BY OTHERS IN ITS AREA?

A. Yes. If I define a market area composed of ComEd and its first tier interconnections, ComEd has a 17 percent share of the deep baseload capacity. This is the capacity that is least capable of being economically withheld. Its share of $20-30 capacity is 16 percent and its share of capacity above $30 is 13 percent.

Q. ARE THERE ANY OTHER CHARACTERISTICS OF COMED'S CAPACITY THAT MAKE IT DIFFICULT TO WITHHOLD?

A. Yes. Seventy percent of its controlled capacity is nuclear. As discussed by Mr. Naumann, nuclear plant has very long cycle times (i.e., slow rates for increasing and decreasing power levels), creating severe economic penalties for withholding generation. Moreover, nuclear plant is subject to close oversight by the NRC.

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of ComEd's future generation/purchase additions for 2001. I am informed that, as of this date, only 62 or 63 MW of this generation is committed for 2001.

[36] In reviewing the material in Mr. Naumann's testimony, the Commission should bear in mind that because of operational issues, such as the need to maintain a margin of quick reaction reserves, the stated capacity of peakers materially overstates their ability to produce energy in normal conditions.

Q. DOES PECO ALSO HAVE CAPACITY THAT IS DISPROPORTIONATELY DEEP BASELOAD?

A. Yes, albeit to a lesser degree. Almost half of PECO's capacity is nuclear. This, along with low-priced fossil and purchase contracts, constitutes 8 percent of the capacity with dispatch prices below $15 per MWh in the region consisting of itself and its first tier interconnections. It has 2 percent of the capacity in the $15-20 dispatch cost range, one percent of the capacity dispatched at between $20-25, and 5 percent of the capacity in excess of $30 per MWh.

Q. YOU INDICATED THAT COMED WILL NOT CONTROL SIGNIFICANT AMOUNTS OF PLANT THAT, AS A HYPOTHETICAL MATTER, MIGHT PROFITABLY BE WITHHELD IN ORDER TO INCREASE PRICES. MIGHT IT NOT BE THE CASE THAT COMBINING THE COMED DEEP BASELOAD PLANT WITH PECO'S LARGER AMOUNTS OF CYCLING PLANT INCREASES PECO'S INCENTIVE TO INCREASE PRICES?

A. That is a hypothetical possibility. However, because of the distance between PECO and ComEd, the withholding of PECO capacity could increase the value of ComEd generation only if the withholding affected prices over a very wide area. At a bare minimum, this area would have to encompass PJM, ECAR and MAIN. As can be computed from Exhibit No. APP-311, Applicants control only 9 percent of the capacity in this region and only 8 percent of the capacity with dispatch prices above $30 that is marginal or near-marginal at times conducive to price spikes. Applicants' market share is greatest in the $25-30 band, still only about 20 percent, and their share of economic capacity at such prices is in this market area is less than 10 percent. Moreover, PECO's mid-merit capacity is on the eastern edge of this large region, whereas ComEd's capacity is on the western edge. If PECO were hypothetically to drive up prices in eastern PJM by withholding capacity, any transmission constrain between ComEd and PECO would disconnect the prices in the PECO and ComEd regions.[37]

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[37] Nodal prices in the PJM power exchange demonstrate this effect. When there is a constraint between PJM-East and other parts of PJM, prices in the east and prices for power in other regions (and for power imported from

Q. WHAT DO YOU CONCLUDE FROM THIS ASSESSMENT OF THE TYPES OF GENERATION CONTROLLED BY APPLICANTS?

A. The merger does not materially increase concentration of control over the types of generation most likely to be withdrawn in order to increase prices. Hence, it does not increase Applicants' ability to increase prices. Because of the geographic distance between PECO's mid-merit generation and ComEd's generation, any hypothetical ability that PECO might have to increase prices in PJM-East would be unlikely to have a significant effect on prices received for output from the ComEd facilities in Illinois. Hence, the merger has little effect on the incentive to increase prices.

Other Potential Market Power Issues

Q. ARE THERE ANY OTHER ISSUES THAT WOULD AFFECT COMPETITION IN THE RELEVANT MARKETS?

A. As noted earlier, I have not formally analyzed competition in long-term markets which the Commission has found to be presumptively competitive (although I discuss entry in this section as well). The possible exceptions to this presumption arise from vertical issues -- control over transmission, sites or fuels supplies, that might block entry in the long term.

Q. WHAT IS THE ISSUE CONCERNING AN APPLICANT'S CONTROL OVER ESSENTIAL FUELS OR DELIVERY SYSTEMS?

A. In the context of long term capacity markets, the issue is whether the merging parties can foreclose or impede the entry of competing generators.

Q. DO THESE APPLICANTS HAVE THE ABILITY TO FRUSTRATE ENTRY DUE TO THEIR CONTROL OVER FUELS OR FUEL DELIVERY SYSTEMS?

A. No. PECO Energy Distribution is an LDC covering a limited area in Eastern Pennsylvania. Its larger customers of the type that would include even small electric

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the west of PJM) are disconnected. Any action taken to further increase prices in the east will have no effect on prices beyond the constraint.

generators are free to purchase their own gas supplies. PECO has offered transportation services to its larger commercial and industrial customers since 1985. Currently over 700 customers obtain their gas commodity from third party suppliers. Beginning in July 2000, PECO Energy will offer transportation services to all customers, including residential customers.

PECO's LDC activity is easily bypassed by large customers. While PECO Energy is permitted to discount its transportation rate to meet competitive pressures, there are a number of customers on PECO's system who have opted to bypass the utility completely and connect directly to an interstate gas pipeline (e.g., Sun Oil and Tosco). Existing larger customers often use the threat of bypass to achieve reduced rates (e.g., Lukens Steel, USX, PQ Corporation and PECO's own Eddystone and Cromby generating stations) and PECO is currently in active negotiations with several other customers (e.g., the Merck IPP and Smith Kline Beecham.) As noted earlier, PECO provides gas distribution service to only one electric generator, a 28 MW facility owned by Merck. Newly built facilities could readily avoid PECO's small service area or connect directly to an interstate pipeline.

Q. ARE THERE ANY OTHER VERTICAL ISSUES OF CONCERN IN THIS MERGER?

A. No. This merger should raise no other vertical market power concerns. PECO has already turned the operational control of its transmission system over to a the PJM ISO. ComEd has committed to join the MISO and to creating an independently owned and governed institution under MISO to which it will turn over its retained control area operator functions. Further, Commission Orders No. 888 and 889 ensure that transmission owners such as Applicants will not be able to foreclose access to any essential transmission facilities, including connecting new merchant plants to their grids. Normally and in the absence of special circumstances, the Commission has found that ISO commitments are sufficient to extinguish vertical market power issues arising from control of transmission. More specific reasons why Applicants cannot exercise vertical market power by control over transmission are discussed extensively by Mr. Naumann.

Q. DO APPLICANTS EXERCISE CONTROL OVER THE AVAILABLE GENERATION SITES?

A. No. I was unable to identify any special barriers to entry in this regard.

The geographic areas served by these Applicants are relatively small and the geographic area that must be included in any market definition that contains both Applicants encompasses quite a large region and includes many control areas. Entrants who could compete in areas potentially affected by this merger would not need to locate new facilities in Applicants' service areas or connect to Applicants' transmission systems. In any event, Applicants' open access transmission, overseen by the Commission, and their ISO membership and commitments should moot any concerns in this regard.

Q. EARLIER, YOU STATED THAT THE COMMISSION HAS FOUND LONG-TERM MARKETS TO BE PRESUMPTIVELY COMPETITIVE. PLEASE ELABORATE.

A. In Order No. 888, the Commission in referring to a decision in *Entergy Services, Inc.*, noted that "after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets."[38] In the Merger NOPR, the Commission stated that "[a]s restructuring in the wholesale and retail electricity markets progresses, short-term markets appear to be growing in importance. The role of long-term capacity markets appears to be *diminishing*."[39]

Q. IS THERE ANY EVIDENCE THAT THERE WILL BE ENTRY INTO THE MAIN, PJM AND IN-BETWEEN ECAR AND SERC MARKETS WITHIN THE NEXT FEW YEARS?

A. Yes. First, entry can be accomplished in far shorter periods of time than were required with the large coal and nuclear generation facilities that used to be the chosen technology. According to the Department of Energy, conventional and advanced combined cycle

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[38] Order No. 888 at 31,649 n.86 (citation omitted).

generating units have a lead time of three years, and combustion turbines (i.e., peaking capacity) have a lead time of only two years.[40] The Elwood and Rocky Road merchant plants were installed in less than two years on the ComEd system.

There is substantial evidence that additional entry will occur. I identified more than 50,000 MW of planned new generating capacity in the relevant portions of the Eastern Interconnection in the next few years.[41] (See Exhibit No. APP-314.) This includes about 3,500 MW in the ComEd control area. The fact that much of this planned capacity is not yet in the construction phase demonstrates that the near term prospect of opening up competition in generation, a recent phenomenon, is a major spur to the development of new merchant capacity.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend that the Commission determine that this merger will not have an adverse effect on competition in markets subject to its jurisdiction.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

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[39] Merger NOPR, *op. cit.*, at 20.

[40] *Assumptions to the Annual Energy Outlook 1999*, Energy Information Administration, U.S. Department of Energy, December 1998, p. 59.

[41] In my analyses, I included only about 20,000 MW of planned generating capacity, representing those units that are likely, given milestones reached to date.

EXHIBITS

Exhibit No. APP-301	Resume of William H. Hieronymus
Exhibit No. APP-302	Data and Methodology
Exhibit No. APP-303	Description of CASm Model
Exhibit No. APP-304	List of Utilities and Abbreviations
Exhibit No. APP-305	Economic Capacity (no additional interconnection)
Exhibit No. APP-306	Economic Capacity (100 MW West to East path)
Exhibit No. APP-307	Economic Capacity with Mitigation
Exhibit No. APP-308	Sensitivity: TTC
Exhibit No. APP-309	Sensitivity: No Transmission Costs
Exhibit No. APP-310	Available Economic Capacity
Exhibit No. APP-311	Regional Generating Plant Characteristics
Exhibit No. APP-312	Competitive Market Price Data
Exhibit No. APP-313	Planned Generating Capacity

AFFIDAVIT

COMMONWEALTH OF MASSACHUSETTS §
§
COUNTY OF MIDDLESEX §

William H. Hieronymus, being duly sworn, deposes and states: that he prepared the Direct Testimony and Exhibits of William H. Hieronymus and that the statements contained therein and the Exhibits attached hereto are true and correct to the best of his knowledge and belief.

William H. Hieronymus

SUBSCRIBED AND SWORN TO BEFORE ME, this the 18th day of November, 1999.

Notary Public, Commonwealth of Massachusetts

Printed Name: Elizabeth Dunning

My Commission Expires: 06/16/06

WILLIAM H. HIERONYMUS **Senior Vice President**

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators and policy makers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy and regulatory issues. He has spent the last several years working on restructuring and privatization of utility systems internationally and on changing regulatory systems and management strategies in mature electricity systems. In his twenty-plus years of consulting to this sector he also has performed a number of more specific functional tasks including the selection of investments, determining procedures for contracting with independent power producers, assistance in contract negotiation, tariff formation, demand forecasting and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of utility clients before regulatory bodies, federal courts and legislative bodies in the United States and United Kingdom. Since joining Putnam, Hayes & Bartlett, Inc. (PHB) (which merged with Hagler Bailly, Inc. in 1998) he has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Assignments

- Dr. Hieronymus served as an advisor to a western electric utility on restructuring and related regulatory issues and has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment he helped develop, and testified respecting, a settlement with the state regulatory commission staff that provides, among other things, for accelerated recovery of strandable assets. He also prepared numerous briefings for the senior management group on various topics related to restructuring.

- For several utilities seeking merger approval he has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The analyses he has sponsored cover the destination market-oriented traditional FERC tests, Justice Department-oriented market structure tests similar to the Order 592 required analyses, behavioral tests of the ability to raise prices and examination of vertical market power arising from ownership of transmission and generation and from ownership of distribution facilities in the context of retail access. The mergers on which he has testified include both electricity mergers and combination mergers involving electricity and gas companies.

- For utilities and power pools preparing structural reforms, he has assisted in examining various facets of proposed reforms. This analysis has included both features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also

has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.

- For the New England Power Pool he examined the issue of market power in connection with its movement to market-based pricing for energy, capacity and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC.

- As part of a large PHB team he assisted a midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

- Dr. Hieronymus has contributed substantially to PHB's activities in the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation.

- He has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of the utilities' assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which the utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs and assisted companies in internal stranded cost and asset valuation studies.

- He has contributed to the development of benchmarking analyses for U.S. utilities. These have been used in work with PHB's clients to develop regulatory proposals, set cost reduction targets, restructure internal operations and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package that PHB has tailored to region-specific applications. He and other PHB personnel have provided numerous multi-day training sessions using the package to help our utility clients in educating management personnel in the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- Dr. Hieronymus has made numerous presentations to U.S. utility managements on the U.K. electricity system and has arranged meetings with senior executives and regulators in the U.K. for the senior managements of U.S. utilities.

- For a task force of utilities, regulators, legislators and other interested parties created by the Governor's office of a northeastern state he prepared

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Senior Vice President

background and briefing papers as part of a PHB assignment to assist in developing a consensus proposal for electricity industry restructuring.

- For an East Coast electricity holding company, he prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand management programs.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico and before the Federal Energy Regulatory Commission in plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant cost for tariff setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that are currently under construction. His testimony has covered the likely cost of plant completion, forecasts of operating performance and extensive analyses of ratepayer and shareholder impacts of completion, deferral and cancellation.

- For utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning continuing the construction projects. Areas of inquiry included plant cost, financial feasibility, power marketing opportunities, the impact of potential regulatory treatments of plant cost on shareholders and customers and evaluation of offers to purchase partially completed facilities.

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major midwestern utility, he headed a team that assisted senior management in devising its strategic plans including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition and diversification opportunities.

- On behalf of two West Coast utilities, he testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of

the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

- For a large western combination utility, Dr. Hieronymus participated in a major 18-month effort to provide it with an integrated planning and rate case management system. His specific responsibilities included assisting the client in design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts and forecasts of the impacts of conservation and load management programs.

- For two midwestern utilities, he prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee..

- For a major combination electric and gas utility, he directed the adaptation of a PHB-developed financial simulation model for use in resource planning and evaluation of conservation programs.

U.K. Assignments

- Following promulgation of the White Paper setting out the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional electricity councils focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, he assisted several of the U.K. individual electricity companies in understanding the evolving system, in development of use of system tariffs, and in developing strategic plans and management and technical capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for an 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- He also has consulted on the separate reorganization and privatization of the Scottish electricity sector. PHB's role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation and company strategy. .

- He has assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment have been policy issues such as incentives for economic purchasing of power, the scope of the price control, and the use of comparisons among companies as a basis for price regulation. His model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted this same utility in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus has assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment includes advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development he performed analyses of least cost power options, evaluation of the return on a major plant investment that the Bank was considering and forecasts of electricity prices in support of assessment of a major investment in an electricity intensive industrial plant.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, he developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command and control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution

companies, its regulation and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which is to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization will be based on regional electricity companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, he continued to advise the Russian energy and power ministry and government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company he analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electric generating and electricity distribution industries in New Zealand, he undertook an analysis of industry structure and regulatory alternatives for achieving economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.
- For EPRI, he directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, Dr. Hieronymus developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, he filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines on fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guideline on cost-of-service standards.
- For private utility clients, he assisted in the preparation of comments on draft Federal Energy Regulatory Commission (FERC) regulations and in preparing their compliance plans for PURPA Section 133.
- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act of 1978. The report focused on the relationship between those purposes and cost-of-service and ratemaking positions under consideration in the generic hearings required by PURPA.
- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.
- For the DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.
- For the commissioners of a public utility commission, he assisted in preparation of briefing papers, lines of questioning and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES
FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force and formed an important basis for

the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, he developed a load forecasting model designed to interface with the utility's revenue forecasting system- planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.

- For the DOE, he directed the development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and constructed a forecasting model for their interim use.

- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area level forecasting models of electric utility companies.

- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.

- For a midwestern electric utility, he has provided consulting assistance in improving its load forecast and has testified in defense of the revised forecasting models.

- For an East Coast gas utility, he testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These include both Sherman Act Section One and Two cases, contract negotiations, generic rate hearings, ITC hearings and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor he has testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, he is assisting clients in responding to the Antitrust Division of the U.S. Department of Justice's Hart-Scott-Rodino requests.

WILLIAM H. HIERONYMUS
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- For a private client, he headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.
- For a industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, he developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), Dr. Hieronymus was the principal investigator in a series of studies for forecasting future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation and utility-related opportunities for investment bankers.

Before joining PHB, Dr. Hieronymus was program manager for Energy Market Analysis at Charles River Associates. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving in the U.S. Army. He is a present or past member of the American Economics Association and the International Association of Energy Economists, and a past member of the Task Force on Coal Supply of the New England Energy Policy Commission. He is the author of a number of reports in the field of energy economics and has been an invited speaker at numerous conferences.

Dr. Hieronymus received a B.A. from the University of Iowa and M.A. and Ph.D. degrees in economics from the University of Michigan.

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DATA AND METHODOLOGY

This appendix describes the data required to conduct the market power analyses as well as the source and methodology used to collect and input the necessary data. The delivered price test requires estimating the generating resources for each of the potential suppliers in the model, specifying the transmission network that these suppliers can use to reach the relevant destination market, load in each market and the destination market price. All of the relevant data used in the analyses is included in my workpapers.

PHB Hagler Bailly's Competitive Analysis Screening model ("CASm") was used to conduct the delivered price test. A complete description of CASm is provided in Exhibit No. APP-303. Briefly, CASm is a linear programming model developed specifically to perform the calculations required in undertaking the delivered price test. The model includes each potential

supplier as a distinct "node" or area that is connected via a transportation (or "pipes") representation of the transmission network. Each link in the network has its own non-simultaneous limit and cost. This limit is the control area to control area limit. Flow restrictions can also be applied across sets of links to capture any relevant simultaneous limits. Potential suppliers are allowed to use all economically and physically feasible links or paths to reach the destination market. In instances where more generation meets the economic criterion of the delivered price test than can actually be delivered on the transmission network, scarce transmission capacity is allocated based on a proration method described below.

Regions Modeled

The list of utilities (and corresponding abbreviations used in other exhibits) is included in Exhibit No. APP-304. Included in the analysis are utilities from each of the following NERC regions:

- Mid-Atlantic Area Council ("MAAC", which is PJM)
- East Central Area Reliability Coordination Agreement ("ECAR")
- Southeastern Electric Reliability Council ("SERC")
- Southwest Power Pool ("SPP")
- Mid-Continent Area Power Pool ("MAPP")
- Mid-America Interconnected Network ("MAIN")
- Northeast Power Coordinating Council ("NPCC", which includes NEPOOL and NYISO)

This list of candidate suppliers does not pre-judge the question of the geographic scope of the specific destination market, which is determined via the delivered price test.[1,2]

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[1] This list was selected in recognition of the Commission's guidance regarding the number of wheels a potential supplier can realistically travel and still be considered a player in the destination market. For example, in *FirstEnergy*, the Commission limited the number of wheels "a supplier could reasonably travel to reach the destination market," recognizing that "[m]ore distant suppliers would face considerable losses and transmission costs." 80 FERC ¶61,039 at 61,104. In *FirstEnergy*, the Commission limited the potential suppliers to those within four wheels. Ibid.

Also, the request for comments on the use of computer models in merger analysis suggests that "three wheels has been deemed adequate." Inquiry Concerning the Commission's Policy on the Use of Computer Models in Merger Analysis, Notice of Request for Written Comments and Intent to Convene a Technical Conference, Docket No. PL98-6-000, April 16, 1998, page 24. Including a broader geographic region implies adding

Estimating Supply Resources for Each Node

Supply curves, consisting of a price and quantity for each node, are developed and entered into CASm.

Supply Capacity

The main source for data on generating plant capability, including non-utility generators ("NUGs"), is the Form EIA-411. I used the publications dated April 1999 (the most up-to-date data available), supplemented by earlier editions as necessary. The EIA-411 provides data on summer and winter capacity, planned retirements and additions and jointly-owned units. For jointly-owned plants, shares were assigned to each of the respective owners. Summer ratings were used for the summer and shoulder periods and winter ratings for the winter period. The data were adjusted to reflect planned retirements and capacity additions through 2001, as detailed in the EIA-411 forms.

I included those utility and merchant plants that are scheduled to enter service by 2001. However, I limited these new plants to those that have passed project, regulatory or financial hurdles (e.g., interconnection agreements, financing, regulatory approvals or site permits), or which have started construction. The specific merchant plants included are shown in Exhibit No. APP-313.

Of particular relevance are the merchant plants expected to be on-line in ComEd's control area by 2001. Based on information provided by ComEd and other publicly available information, I included in my analysis new planned generation that is sufficiently well advanced to justify its inclusion in the 2001 time period, as shown in my workpapers.[3]

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additional potential suppliers not controlled by the Applicants; thus, defining the set of potential suppliers in this manner is conservative.

[2] I analyzed market participants as if the electric utility mergers pending before the Commission had been approved and mergers consummated.

[3] The new generation expected to be on-line in ComEd's control area by 2001 includes a 110 MW addition to Dynegy's Rocky Road facility, a 575 MW Enron plant and a 500 MW MidAmerican plant. Additionally, a ComEd affiliate is assumed, for purposes of my analysis, to add a 220 MW unit and ComEd is assumed to enter into a long-term contract for the output of a planned 300 MW unit.

Each supplier's generating resources also were adjusted to reflect long-term capacity purchase and sales.[4] Specifically, the following methodology was used to account for purchases and sales.

Data on long-term firm sales (one year or more) are included in FERC Form 1 and EIA Form 412 filings (or databases based on these forms), Form EIA-411, individual utility resource plans or NERC's Electricity Supply and Demand ("ES&D") database. These public data on purchases and sales, however, are not entirely complete or consistent across sources.

To the extent a utility has sold capacity under a long-term agreement, ownership over that resource is assumed to pass to the buyer.[5] Accordingly, as with jointly-owned units, generation ownership was adjusted to reflect the transfer of control by assuming that the sale resulted in a decrease in capacity for the seller and a corresponding increase in capacity for the buyer. Consistent with guidance provided in Appendix A, it was assumed that system power sales were comprised of the lowest-cost supply for the seller unless a more representative price could be identified.[6] To the extent that long-term sales could be identified specifically as unit sales (e.g., ComEd's repurchase of generation from the Kincaid and State Line units), the capacity of the specific generating unit was adjusted and the variable element of the purchase price attributed to the sale was the variable cost of the unit. The dispatch price for system purchases was based on the energy price reported for long-term purchases in the FERC Form 1 where such purchases could be identified and a variable cost price determined.[7]

The capacity representing firm purchases and sales and shares of jointly-owned units was "moved" in the model from its actual physical location to the geographic location of the buyer. This treatment is consistent with using the public source ATC transmission data that represent the incremental amount of capacity available for conducting trades after accounting for base flows on

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4 This treatment does not include requirements contracts.

5 Consistent with this assumption, NUGs were assumed to be under the control of the purchasing utility.

6 "[T]he lowest running cost units are used to serve native load and other firm contractual obligations" (Appendix A, p. 11). The lowest-cost supply that was available year-round (i.e., excluding hydro) was used.

7 In instances where the purchases could not be matched with FERC Form 1 data, the dispatch price was estimated based on the capacity factor of the purchase.

the system. Thus, the methodology is consistent with the transmission data that was used to reflect available transmission capacity.

Since the delivered price test is intended to evaluate energy products, the capacity (in MWs) reported in the Form EIA-411 was de-rated to approximate the actual availability of the units in each period. That is, it was assumed that generation capacity would be unavailable during some hours of the year for either (planned) maintenance or forced (unplanned) outages. Data reported in the most recent NERC Generating Availability Data System was used to calculate the "average equivalent availability factor" to estimate total outages, and the "average equivalent forced outage rate" to estimate forced outages for fossil and nuclear plants.[8] Scheduled maintenance was assumed to occur only during the non-peak (shoulder) seasons and forced outages were assumed to occur uniformly throughout the year.

This treatment of generating availability is designed to account for the fact that resource availability changes by season. It is consistent with how the time periods evaluated were defined (based on similar load hours in each season, rather than by similar load hours for the entire year), and with specifying transmission capacity by season, as discussed below.[9]

Applicants' Long-Term Power Contracts

PECO

PECO has a number of long-term purchase contracts, totaling about 3,600 MW, including purchase contracts from planned merchant generation.

PECO also has a number of sales contracts in varying amounts to a number of parties. PECO's long-term sales (excluding requirements contracts) total about 1,000 MW. The treatment of these contracts is consistent with the treatment of other long-term contracts described above. The contracts were generally priced at the actual contract price, which was provided to me by the

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[8] These data were supplemented, where necessary, by data from other public sources such as NERC and Electric Power Research Institute.

[9] A spreadsheet detailing the capacity and price of every unit in the model is included in a set of confidential workpapers filed with the application. These workpapers were filed confidentially since they contain proprietary information on the Applicants' purchase and sales contracts.

Applicants, or at a (conservative) proxy price intended to reflect dispatch provisions. The details for each contract are provided in a set of confidential workpapers filed with this testimony.

ComEd

ComEd also has a number of long-term sales contracts, totaling about 1,450 MW in 2001.

Its long-term purchase contracts include buyback agreements for the sale of its fossil units. ComEd's contracts with Dominion and Southern (Kincaid and State Line, respectively) cover the purchase of 100 percent of the output of these units for a fifteen-year period. ComEd's has three separate contracts with Edison Mission Energy, one for Collins (2,698 MW), one for peaking units (944 MW) and one for other coal-fired units (5,005 MW). Each are five year transition contracts, with options to reduce the amount of generation purchased. In years 3-5, ComEd has the option to drop units from the Collins and peaker contracts. For the other fossil units, over the five-year period the amount of contracted capacity is reduced annually, but replaced with options for an increasing amount of capacity. In addition, ComEd also has a 600 MW (summer) contract for purchases a merchant plant in its control area (Elwood) and a 41 MW contract for purchases from an IPP in its control area. The details of ComEd's contracts and how they were treated in my analysis is contained in a set of confidential workpapers filed with this testimony.

Applicants' Firm Transmission Contracts

Both Applicants have long-term firm transmission contracts that are not associated with long-term power contracts. Consistent with the April 1998 Notice of Proposed Rulemaking, I assumed that this transmission is not dedicated solely to use by Applicants, but is available to other suppliers.[10]

AmerGen Supply

AmerGen, the joint venture between PECO and British Energy has acquired or is in the process of acquiring a number of nuclear assets in the relevant geographic regions. These include:

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[10] Revised Filing Requirements Under Part 33 of the Commission's Regulations ("Merger NOPR"), 83 FERC ¶61,027 (1998), 63 Fed. Reg. 20340 (April 24, 1998). ("Transmission capacity along transmission paths between suppliers and destination markets that is reserved under a long-term firm transmission contract by suppliers should be presumed to be available to other suppliers unless the capacity is committed to a long-term power transaction." Slip op, page 34.)

- In PJM: Three Mile Island (786 MW) and Oyster Creek (619 MW), both from GPU;
- In NYPOOL: Nine Mile Point (1,292 MW) from Niagara Mohawk Corporation and NYSEG
- In NEPOOL: Vermont Yankee (540 MW) from the owners of the Vermont Yankee Nuclear Corporation.
- Other: Clinton (930 MW) from IP

As described in the main text of the testimony, all of these asset acquisitions have purchased power agreements with the sellers to buyback the full output from these units, with the exceptions of Clinton (only 75 percent of Clinton's output is being sold back to Illinois Power) and Nine Mile Point (95 percent of AmerGen's share of Nine Mile Point is being sold back). Termination dates of these PPAs range from December 31, 2001 (Three Mile Island) to 12 years after the closing of the agreement (Vermont Yankee). PECO will market any capacity available from these units on behalf of AmerGen through power purchase agreements consistent with FERC requirements.[11]

Supply Cost

In calculating the supply curves, supply from each unit was assumed to be available at any price above its incremental cost (the delivered price test assumes supply is economic if its cost is up to 105% of the competitive market price). The incremental cost is calculated by multiplying the fuel cost for the unit by the unit's efficiency (heat rate) and adding any additional variable costs that may apply, such as costs for variable operations and maintenance and costs for environmental controls.[12] Data were taken from the following sources:

- Heat rates – EIA Form 860, supplemented in a few instances by data from Form EIA-411. (Note that the most recently available data is from the 1995 Form 860.)

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[11] Given a marketing arrangement between PECO and British Energy, as well as to be conservative, I attribute the full 25 percent of AmerGen's Clinton share to PECO.

[12] For NUGs, the incremental costs were estimated based on the energy price reported in relevant regulatory filings, if available. Otherwise, NUGs were assumed to be must-run and the variable costs set to zero. New merchant capacity included in the analysis was priced assuming a heat rate of 10,000 Btu/kWh for combustion turbines and 7,000 Btu/kWh for combined cycle plants. Variable O&M was also applied to the new units consistent with the assumptions for existing units.

PROPRIETARY INFORMATION

Docket Number A-110550 F0147

Name of Document Home Address List

Date Document Received 5-10-2000

DOCUMENT CONTAINS

PROPRIETARY INFORMATION

- Fuel costs – Form 423. The estimated dispatch cost is based on spot or interruptible fuel prices for a twelve month period ending June 1999, the last complete year for which data were available. Seasonal estimates were derived from the monthly data and applied to derive dispatch costs by season. To the extent all fuel purchases in that period had been made under contract rather than at spot prices, an incremental price based on reported spot or interruptible prices in the relevant region was estimated. Fuel prices were escalated to 2001 based on the forecasts in the 1999 EIA Annual Energy Outlook.

- Variable O&M – $1/MWh for gas and oil steam units, $3/MWh for scrubbed coal-fired units and $2/MWh for other coal-fired units (generic estimates based on trade and industry sources).

- SO_2 adder – $200/ton. The adder was applied to all relevant units assuming that Phase 2 had been implemented as planned; all units are assumed to pay an adder based on the SO_2 content of the fuel burned.

The data set representing the supply cost was used for all pre- and post-merger analyses. In the post-merger analysis that assumes a firm 100 MW transmission path from ComEd to PECO, 100 MW of ComEd capacity is "moved" to PECO.[13]

Transmission Network

Appendix A specified that the transmission system be modeled on the basis of inter-control area ATCs or TTCs using transmission prices based on transmission providers' maximum non-firm OATT rates except where lower rates could be clearly documented. This dictated a transportation representation of the transmission network and the structure of CASm was designed to conform to Appendix A. This representation remains appropriate for portions of the United States, where transmission service is generally provided under each transmission provider's Open Access tariff. Basing tariffs on OATT rates is increasingly undercut by RTO transmission pricing arrangements, however, and the Commission has instructed applicants to account for them.[14] Also, proposed regional transmission organizations that are not yet operating, such as the Midwest ISO, will reduce pancaking of control area to control area transmission rates by charging only one rate to

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[13] In the model, this is represented by moving 100 MW of Braidwood and adding it to PECO's generating resources at the same capacity and price. This is a largely a modeling convenience, as no particular unit is committed to the energy transfer.

[14] Merger NOPR, page 29.

travel through or out of their systems. Finally, some pricing systems, such as MAPP's flow-based method for determining transmission rates, create a more complex matrix of transmission prices that is not wholly consistent with a transportation model. Nonetheless, with some simplification, each of these alternative arrangements can be modeled in CASm, as described below.

Transmission Capacity

Limits were placed on the amount of capacity that could be transferred over the transmission network by both non-simultaneous control area to control area limits and simultaneous interface limits. Control area-to-control area limits are still applicable in most of the regions modeled. In the SPP and MAPP regions, however, transmission reservations are no longer based solely on control area to control area limits, but consider the impact of any particular transfer on key elements of the network (termed "flowgates").

Control area to control area transmission capability was taken primarily from postings on the Open Access Same-Time Information System or "OASIS." OASIS reports Total Transmission Capability ("TTC"), firm Available Transmission Capability ("ATC") and non-firm ATC. Data generally are provided monthly for a twelve-month period starting with the next month. Monthly non-firm ATCs postings from the third quarter of 1999 were used in most instances.[15] In all instances, I used the most recent data available at the time the analysis was conducted. Seasonal differences in transmission capability were captured by using the average of June-August postings to represent a summer capability; the average of December-February postings to represent a winter capability; and the average of remaining months to represent a shoulder capability.[16]

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15 The exception is for some interfaces in MAPP, as discussed below.

16 In instances where two parties post different capability for the same path, the lower of the reported values was generally used. This assumption was made on the basis that if a party sought use of a particular path, the lower of the reported values would be applicable unless the utilities at both the receipt and delivery points could agree differently.

One exception to this treatment was for PJM interconnections. There, I used postings on PJM's OASIS and not postings for the interconnected utilities. PJM adjusts its ATCs to reflect some of the simultaneous effects of reservations; for example, if a reservation is made from VP to PJM, PJM adjusts the ATC from APS to PJM and FirstEnergy to PJM.

In addition, third-party postings, i.e., ATCs from one utility to another utility that it is not directly interconnected with, were not included in the analyses.

With respect to ATCs into and out of the ComEd control area, I started with ATC data posted on OASIS. However, given that ComEd is in the process of implementing planned transmission upgrades in its control area (Lockport-Lombard is the major upgrade), I adjusted ATC data to reflect these changes in transmission. Mr. Naumann provided me with the adjustments, based on the amount of the change in FCITCs that his analysis produced as a consequence of assuming the existence of the transmission upgrade. These data are found in my workpapers.

Using an ATC value, as opposed to a TTC value, is appropriate given the manner in which generating resources were moved to each node to reflect for jointly-owned units and long-term purchases and sales. Non-firm ATCs are the appropriate input assumption for transfer capability since Economic Capacity and Available Economic Capacity are intended to reflect competition in non-firm energy.[17] However, I did analyze results using TTCs as a sensitivity.

With respect to MAPP and SPP, the SPP continues to calculate control area to control area values and the most recent such data (June 1999) were used for the SPP region and its direct interconnections. For MAPP, some of the individual companies still list control area to control area limits and for these links, data from the third quarter of 1999 were available. For the remaining MAPP interconnections, data from the fourth quarter of 1998 was used.[18]

Transmission Rates

The Commission's Appendix A guidelines implicitly assume a depiction of the transmission system wherein control area to control area transactions occur using each of the relevant control area's Open Access (Order 888) tariffs. Appendix A also instructs applicants to model any applicable discounts that are systematically available, and to account for regional transmission organizations as they arise.

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[17] In reality, utilities frequently post the same value for both firm and non-firm ATCs.

[18] Given that data is generally reported for the next 12 months, this implies that the fourth quarter 1998 data covered through the winter of 2000. The data collected during the second quarter of 1999 would include additional information on just the spring of 2000.

In implementing transmission rates into the analysis, regardless of the transmission regime, it has been assumed that transmission charges would be incurred for the transmission system where the generator is located and for wheeling the power through intermediate systems, but not for the destination market. No transmission charge is included for the transmission system in which the load is located. This has no impact on the analysis, since including this charge (the transmission charge included in the bundled rate of the transmission provider in the area where the customer is located, or the "zonal" or postage stamp charges in the case of an RTO) would symmetrically raise the delivered cost for each supply to reach the destination market by the same amount. Thus, the relative economics would not be impacted.[19] Losses, which are assumed to be 2.8 percent based on a review of loss factors in Order 888 tariffs, are assessed for each wheel incurred along the path to deliver power to the destination market but are not added for the final wheel into the destination market.

In the regions potentially impacted by this merger, there are significant regional transmission arrangements that can alter the cost of transmission (indeed, lowering the costs in each instance), either by providing for lower rates or by eliminating pancaking of transmission rates. The MISO, which is assumed to exist in all of the scenarios that I analyzed, reduces the cost of transmission by eliminating pancaking. Additionally, SPP and MAPP both have distance sensitive rates available that allow users to transact under lower transmission costs than control area to control area pancaked 888 rates. These alternative transmission tariffs were incorporated into CASm, with some simplifying assumptions described below.[20]

Order 888 Tariffs.

Consistent with Order No. 592, the ceiling rates in Exhibit 8 (Non-Firm Point-to-Point Transmission Service) of each utility's Order No. 888 filings were used for utilities that are not part

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[19] Likewise, distinctions between "bundled and unbundled" transactions, which affect the price paid for the final delivery of power, do not affect the relative delivered prices of competing supplies.

[20] Another potentially relevant transmission arrangement is the proposed Alliance RTO. I did not include the Alliance in my analysis. It would not have a consequential impact on the results.

of RTO arrangements.[21] In many instances, utilities report both on-peak and off-peak ceiling rates in its Order No. 888 filing. If so, then the applicable transmission rate for the on- and off-peak periods were used. If not, then the filed ceiling rate was applied for all periods. Ancillary service charges from Exhibits 1 (Scheduling, System Control and Dispatch Service) and 2 (Reactive Supply and Voltage Control from Generation Sources Service) of Order No. 888 filings were added where applicable to determine the final rates.

Midwest ISO

Under the MISO's proposed rate structure, there are two applicable rates. First, a weighted average tariff rate is applicable for "through" and "out" transactions and is applied for all paths from a MISO member to a non-MISO member. It is calculated as the weighted average of all of the MISO members rates using load data from the MISO filing for weights and tariff data from the individual company's Order 888 tariffs.[22] The second rate, the "in" and "within" rate, is applicable for trades into and within the MISO. This rate is based on the zone where the load is located. As discussed earlier, the final import rate is not applied in CASm; thus the zonal MISO rates are not used in the analyses.

MAPP

Currently, MAPP has in place a regional tariff ("Schedule F") that allows parties to transact using rates based on the impact of each trade on various transmission facilities throughout the affected network, rather than the traditional contract path methodology. The basic MAPP schedule rates are determined by the facilities used when moving power between any two points within the region. The resulting rates are discounted by various amounts depending upon the type of service provided (firm vs. non-firm), the time of service (peak vs. off-peak), and the duration of service (monthly vs. hourly). The most recent hourly non-firm on and off-peak rates available for the summer 1999 were used. These hourly rates are derived from the basic MAPP $MW-mile

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[21] In some cases, individual utility rates also are relevant to the zonal rates and for computing "through and out" rates within RTOs. In instances where transmission data were not reported in dollars per MWh, the $/MW rates were converted to $/MWh rates using the "Appalachian" method. 39 FERC ¶ 61,296 at 61,965.

[22] The illustrative calculation shown in the MISO filing with FERC shows a unified tariff rather than a calculation based on weighted averages *per se*. This should differ from the methodology that I have used only in that the inter-system diversity (about 2 percent) would be taken into account using the methodology shown in the filing.

program, but are discounted during both the peak and off-peak periods.[23] The MAPP rate structure was implemented in CASm by assuming that the MAPP utilities scheduled and paid for transmission service along a contract path basis.[24]

The Schedule F rates were applied to paths within MAPP; for trades from a MAPP utility to a utility outside of MAPP, the Schedule F tariff was applied until the MAPP border company was reached, at which point the border company's Order 888 rate was applied. For trades into MAPP, the Order 888 rates were applied until the MAPP region was actually entered, whereafter the MAPP rate was applied.

SPP

SPP has a regional tariff that provides for distance sensitive rates.[25] The SPP tariff lists rates between any two eligible members and, like the MAPP rate, was implemented along a contract path. The eligibility requirements under the SPP tariff allow any SPP member or utilities first tier to the SPP to transact under the tariff. Also, the SPP posts discounts for non-firm service over specific paths, rather than for all lines as in MAPP. The discounts are currently posted on a monthly basis, although the tariff allows for such postings to be made more frequently. In CASm, discounts were applied by path, as in the SPP tariff, and by season based on the historical discount rates applied since the SPP tariff went into effect.

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23 Off-Peak rates are half of on-peak rates. Discounts do not vary by season for the MAPP rates.

24 In some instances, this implementation methodology means that utilities may pay a slightly different rate to trade within MAPP than is actually possible under MAPP's regional tariff. Still, this result is consistent with the Appendix A instructions to use maximum-filed transmission rates and the resulting rates are low enough that this does not impact the amount of capacity that is included in the market.

25 This tariff was filed with the Commission on June 1, 1998. I understand that the SPP has recently filed an updated tariff with the Commission that would revise the SPP's open access transmission tariff to price short-term firm and non-firm services on the basis of the open access rate of the transmission provider where the load is located. (Docket No. ER99-4327-000, 89 FERC ¶ 61,084 (October 27, 1999)). Modeling this alternative transmission arrangement in the SPP would have an inconsequential impact on the results of my analysis. This can be seen by comparing the results of my base cases with the sensitivity analysis that I performed that assumed no transmission rates.

Allocation of Limited Transmission

Appendix A notes that there are various methods for allocating transmission, and that Applicants should support the method used.[26] There are two basic approaches to allocating limited transmission capacity: economic and pro rata. Under an economic allocation, available transmission is assigned on the basis of the cost of the capacity (energy) competing to use limited transmission capability. The lowest cost capacity is assumed to have a priority in using the transmission. Higher cost generation is excluded, despite its having costs below 105 percent of the destination market price. In contrast, pro rata methods of allocation treat all generation that meets the delivered price test equally in allocating scarce transmission.

The paradigm lying behind the proration required by the Order No. 592 delivered price test (whether economic or pro rata methods are used) can be likened to a tree, for which the root is the destination market. At the furthest extremes are small branches, each one of which is connected to a single larger branch and so on until the trunk and root are reached. There is no ambiguity concerning the path. Hence, at every node (joining with a large branch), all of the capacity that can access the limited capacity of the branch can be calculated; each small branch's capacity is reduced proportionately to the capacity of the branch. This can be repeated successively, moving inward to the destination market.

Even taking into account the simplifications required by a "transportation" representation of transmission, real world transmission systems are more complex. The "small branch" distant utilities have multiple paths by which a destination market can be reached. In some cases, paths may first be in a direction away from the destination market, looping around onto another path to it. An analysis that takes this important complexity into account is computationally very difficult. Allocation methods differ partly in terms of how the problem is simplified in order to make computation tractable. This is described further in Exhibit No. APP-303.

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[26] Order No. 592, ¶ 31,044 at 30,133. ("In many cases, multiple suppliers could be subject to the same transmission path limitation to reach the same destination market and the sum of their economic generation capacity could exceed the transmission capability available to them. In these cases, the ATC must be allocated among the potential suppliers for analytic purposes. There are various methods for accomplishing this allocation. Applicants should support the method used.")

The major drawback of using an economic allocation is that it tends to continually reallocate the same low cost energy, principally hydro and nuclear energy (and non-dispatchable NUG capacity) over and over to each destination market in the Economic Capacity measure. This occurs partly because Appendix A does not take into consideration the opportunity cost of supplying alternative markets to the destination market being analyzed,[27] but primarily because each destination market is analyzed separately. This allows the same low cost supplies to be allocated to each of the destination markets. While this is not wholly inappropriate, since the purpose of Appendix A is to measure potentially competing supply to each destination market, it does mean that the very low cost supplies can travel far and wide and occupy a highly disproportionate share of available transmission. This repeated allocation of the same energy is particularly troublesome given the large area involved in the analysis in the instant case. This flaw is less severe in the Available Economic Capacity measure, where the native load obligations absorb each control area's lowest cost resources.

For purposes of this analysis, I allocated limited transmission capacity using a "squeeze-down" method, so-named because it seeks to prorate capacity at each node. I believe it to be the closest approximation to what the Commission applied in the FirstEnergy merger[28] that is computationally feasible. Under this method, shares of available transmission are allocated at each interface, diluting as they get closer to the destination market. When there is economic supply (i.e., having a delivered cost less than 105 percent of the destination market price) competing to get through a constrained transmission interface into a control area, the transmission capability is allocated to the suppliers in proportion to the amount of economic supply each supplier has outside the interface.

Shares on each transmission path are based on the shares of deliverable energy at the source node for the particular path being analyzed. The calculations start at the outside of a

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[27] Indeed, if opportunity costs were taken into account, and one was considering a regional dispatch, available transmission capacity appropriately would be allocated on the basis of economics.

[28] *Ohio Edison Company, et al.*, 80 FERC ¶ 61,039 at 61,107. ("When there was more economic capacity (or available economic capacity) outside of a transmission interface than the unreserved capability would allow to be delivered into the destination market, the transmission capability was allocated to the suppliers in proportion to the amount of economic capacity each supplier had outside the interface.")

network defined with the destination market as its center and end at the destination market itself. A series of decision rules are required to accomplished this proration. The purpose of these decision rules is limited to assigning a unique power flow direction to each link for any given destination market analysis. Once the links are given a direction, the complex network can be solved. CASm implements a series of rules to determine the direction of the path. The first rule (and the one expected to be applied most frequently) is based on the direction of the flow under an economic allocation of transmission capacity. Other options take into consideration the predominant flow on the line based on desired volume (the amount of economic capacity seeking to reach the destination market, the number of participants seeking to use a path in a particular direction and the path direction that points toward the destination market.

The model proceeds to assign each supplier at each node a share equal to their maximum supply capability. At each node, "new" suppliers (those located at the node outside of the next interface) are given a share equal to their supply capability and the shares of more distant suppliers (those who have had to pass through interfaces more remote from the destination market in order to reach the node) are scaled down to match the line capacity into the node. Ultimately, the shares at the destination market represent the prorated shares of economic capacity that is economically and physically feasible.

Simultaneous Import Capability

In order to determine simultaneous transmission limitations, I utilized data from various NERC transmission assessment reports. These reports indicate common limiting facilities for multiple transmission interconnections into a single market. For those instances where a common facility limits imports over multiple paths, I assumed that the maximum import capability was no greater than the maximum of the individual path limits. This is consistent with the Commission's approach outlined in the FirstEnergy decision.[29] All of the simultaneous limits applied in the model are included in my workpapers.

For the PJM destination markets, I applied the methodology detailed on the PJM OASIS site regarding how PJM adjusts available transmission capacity into and out of PJM from the West

and South. In brief, PJM considers the paths between PJM and APS, VP, and First Energy to be "associated" paths and adjusts the ATC value on all three paths when a reservation is made on any of the paths. I modeled this by applying a simultaneous limit into and out of PJM equal to the maximum rating of three paths.

For the ComEd destination market, I applied a simultaneous import capability of 4,500 MW based on information provided by Mr. Naumann.[30] The 4,500 MW simultaneous import capability into ComEd consists of 2,500 MW from the East, 1,000 MW from the South and 1,000 MW from Iowa and Wisconsin. With the 100 MW transaction from ComEd to PECO, the simultaneous import value increases by 100 MW from the East.

Treatment of Merger Interconnection Plans

As described in the testimony, two analyses were conducted of post-merger conditions: (1) the effect of combining Applicants' pre-merger generation assuming no additional flows from ComEd to PECO; and (2) assuming a 100 MW firm transmission path from ComEd to PECO (with 100 MW of the 300 MW purchase moving from ComEd to PECO).

In the first of these analyses, no special treatment of transmission was required.[31] In the second, I adjusted ATC based on load flow analyses that identified the change in First Contingency Incremental Transfer Capability (FCITC) resulting from a firm 100 MW power flow from ComEd to PECO, which were provided to me by Mr. Naumann. The changes in ATC are detailed in my workpapers.

Load Data and Time Periods Analyzed

The most up-to-date hourly load data filed with the Commission (generally covering 1998 calendar year) was used for two purposes: (1) as a measure of native load responsibility for the Available

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29 80 FERC ¶61,039 at 61,104.

30 I understand that this value was derived by estimating the First Contingency Total Transfer Capacity on a simultaneous basis into ComEd (roughly 5,150 MW) and adjusting for base flows into the market (about 650 MW).

31 It was not necessary to conduct a loop flow analysis of the base case (i.e., interconnection via the existing 300 MW ComEd-PECO contract), since there are not expected to be any changes in the use of this contract as a result of the merger.

Economic Capacity measure and (2) to determine the correct seasonal time periods to evaluate (i.e., to group similar hours).

Load Data for Available Economic Capacity

For the Available Economic Capacity measure, I generally used hourly load data from FERC Form 714 for the most recent period available at the time this analysis was undertaken. For the few utilities that do not file Form 714s (e.g., some cooperatives and municipal utilities) or whose data were otherwise unavailable, data from the EIA-411 along with a load shape based on those of similar utilities for which data were available were used.[32]

As noted in my testimony, this analysis did not assume any load loss due to retail access. Nor did it assume that the divestitures in PJM, NYPP or NEPOOL "created" available economic capacity; rather generation and historic (i.e., pre-divestiture) loads were matched up.

Period Definitions Based on Hourly Load Data

Appendix A requires applicants to evaluate the merger's impact on competition under different system conditions. For example, aggregating summer peak and shoulder peak conditions may mask important differences in unit availability and therefore a merger could potentially impact competition differently in these seasons. Thus, applicants are directed to evaluate enough sufficiently different conditions to show the merger's impact across a range of system conditions. On the other hand, the Merger Guidelines discuss the ability to "sustain" a price increase, and a finding that a structural test (HHI) that violates the safe harbor for some sub-set of hours during the year may not be indicative of any market power problems. Therefore, there is a trade-off between defining enough periods to capture the merger's impact under different system conditions and defining periods so narrowly as to make the resulting concentration statistics irrelevant to an evaluation of whether a price increase could be sustained.

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[32] The load data were escalated to 2001, based on the projected energy growth rate reported in the EIA-411 or FERC Form 714. If such data were not available, a regional growth rate reported for the relevant NERC region was used. In 1998, PJM provided an aggregate hourly load file that did not break out load between each of the PJM operating companies. To derive company specific load values, I used the percentages from the 1997 FERC 714 data, which were provided by operating company. The resulting load values were used to cover the lowest cost units of the PJM utilities in each period for the Available Economic Capacity measure.

In this analysis, eleven periods were used to evaluate the impact of the merger under different system conditions. An evaluation of the hourly load data, discussed above, was used to aggregate similar hours. Periods were defined within the three seasons of the year to reflect the differences in unit availability and transmission capacity. Generating resource availability is much lower during the shoulder due to scheduled outages; therefore, treating "peak" hours in the shoulder the same as those in the summer, for example, will not provide an accurate picture of the potential supply available in the markets. Additionally, baseflows on the network, and thus transmission capacity availability, can vary by a large amount between the summer and winter seasons; combining these two periods would again potentially mask important aspects. Finally, there are a number of reasons to pay special attention to the summer peak period, which one might expect to be the most likely time for market power to be exercised in the region, and this requires defining periods within each of the seasons.

The three seasons are defined as Summer (June through August), Winter (December through February), and Shoulder (March through May; September through November). In order to ensure that the time periods evaluated were consistent across suppliers and destination markets, it was necessary to pick a reference utility to identify top load hours. ComEd's load data was used to select the top load hours to be grouped into each period. Each hour appears in only one period (e.g., in the summer, the top 25 period contains the top 25 hours; the top 150 hours contains hours 26 to 150; the top 500 period contains hours 151 to 500, etc.).

The periods evaluated (and the designations used to refer to these periods on other exhibits) are described in my testimony.

Price Data

In order to select the appropriate price bands to analyze (see discussion in testimony), I prepared a comparison of system lambda and price data in *Power Markets Week*. These data are summarized in Exhibit APP-312.

COMPETITIVE ANALYSIS SCREENING MODEL (CASm)

PHB Hagler Bailly developed the Competitive Analysis Screening model ("CASm_v80") to perform the calculations required in order to conduct a market power analysis under Appendix A of the FERC Merger Policy Statement ("Order No. 592" or "Appendix A"). The delivered price test specified in Appendix A requires an analysis of market concentration for a large number of markets under a number of different conditions. CASm facilitates this process by performing the required calculations.

The primary requirement of Appendix A is to assess potential suppliers to a market using a "delivered price test". This test involves comparing variable generation costs plus delivery costs (transmission rates, transmission losses and ancillary services) to a "market price." If the delivered cost of generation is less than 105 percent of the market price, the generation is considered economic. Economic generation is further limited to the amount that can be delivered into the market, given transmission capability and constraints.

CASm implements the prescribed delivered price test by determining -- for each destination market, for each relevant time period, and for each relevant supply measure -- potential supply to the destination market both pre- and post-merger. In effect, CASm determines the relevant geographic market by applying the delivered price test, based on the economics of production and delivery (transmission rates, transmission losses and ancillary services), and also based on the physical transmission capacity available to the competing suppliers on an open access basis. This requires a delivery route for the energy on the established transmission paths, each of which has a capability, transmission rate and transmission losses associated with it. CASm finds the supply that can be delivered to the destination market consistent with cost minimization and the delivered price test.

As a formal matter, CASm minimizes the production and transmission costs of supplying demand in the destination market. Any shortfall in demand is filled by a hypothetical generator located in the destination market that can produce an unlimited amount of energy at 105 percent of the market price. On this basis, any supplier who can profitably supply energy to the destination market will do so, to the maximum extent that their cost structure and the transmission system allow. This formulation ensures that no supplied generation is uneconomic; the hypothetical generator will undercut all such suppliers.

CASm determines pre- and post-merger market shares and calculates concentration (as measured by the Herfindahl-Hirschman Index, or HHI) and the change in HHIs.

To undertake these analyses, CASm solves a series of scenarios involving a network of interconnected suppliers. By limiting suppliers based on the economics of generation and delivery, or by limiting the interconnections between those suppliers based on the transmission capability, each Appendix A analysis can be completed. CASm includes a simplified depiction of the transmission system, essentially a system of "pipes" with independent, fixed capacity between and among utilities.

The following sections describe:

- What data inputs are required to operate CASm
- How different analyses are undertaken in CASm
- What outputs CASm produces; and
- How CASm is implemented.

INPUT DATA

Market Participants

The largest element of the required data for CASm relates to individual market participants, which generally are utilities with both generating capacity and load obligations. In addition, some market participants may have load obligations but no generating capacity (e.g., transmission dependent utilities, or TDUs) or have generating capacity but no load obligations (e.g., merchant capacity). CASm regards all distinct market participants as having the ability to both supply and consume electricity. The particular circumstances of each analysis will determine the extent to which each activity is possible.

Nodes

In CASm, a node is a location where electricity is generated or consumed, or where it may "split" or change direction. All market participants are defined as having a unique node, and hence unique location in the transportation network. Total simultaneous import limits can be imposed at each node to mirror reliability restrictions.

Output Capability

Each market participant may have generating ability, which is defined generically in terms of any number of "tranches" of generation having both a quantity (MW) and dispatch cost ($/MWh). This output capability and cost may differ over time, for example because of planned and unplanned outage rates and fuel prices. CASm has a number of data inputs available for modifying the underlying physical availability of generating assets to get the relevant "supply curve" for any given model period. CASm can also cover generation tranches to account for load obligations at each node (used for the Available Economic Capacity measure, as discussed below).

Destination Market Prices

For each destination market, a prevailing market price is defined. The destination market price is used to calculate a threshold price that potential suppliers must meet to be included in the market for economic-based analyses (that is, the "delivered price test").

Interconnections

Interconnections represent the network that links market participants together. These interconnections are represented as a "transportation" network, where flows are specifically directed.

Lines

A line between two nodes in CASm may represent either a single line, or the combined effect of a number of lines. Each line has an upper limit on the flow, and losses may occur on the line. Since capacity on the line may represent physical limits less firm commitments, limits are allowed to be different, depending on the direction of the flow. Limits on the simultaneous flow on combinations of lines can be imposed to simulate the effect of loopflow or reliability constraints. As well as this, CASm can enforce "flowgate" limits based on combinations of injections at defined groups of nodes.

Scenarios

The final input area for CASm is related to scenario definition. Scenarios define which parties are considering merging, which load periods are relevant, and so on. In effect, the scenarios define a number of individual analyses to be performed, and how they should be compared to each other for reporting purposes.

Accounting for Ownership

It is sometimes necessary to merge the results for several nodes, or to split them, based on ownership changes between scenarios. CASm has a "report as" function that will merge the results of several nodes into a single to correctly account for ownership.

REQUIRED CALCULATIONS

Appendix A's delivered price test defines two different supply measures to evaluate:

- **Economic Capacity** is the amount of capacity that can reach a market at a cost (including transmission rates, transmission losses and ancillary services) no more than 105 percent of the destination market price.

- **Available Economic Capacity** is the amount of Economic Capacity that is available after serving native load and other net firm commitments with the lowest cost units.

For every analysis, the following process is undertaken:

First, a Linear Programming (LP) problem is solved. The LP construction is slightly different, depending on the underlying assumptions of each of the supply measures. CASm includes two options for allocating scarce transmission capacity. CASm has a "proration" option, which is

called "squeeze-down". This is discussed in detail below. Another option is an economic allocation of limited transfer capability. Under this option, where available supply exceeds the ability of the network to deliver that capacity to the destination market, the least-cost supply is allocated the available transmission capacity.[1]

The final step involves calculating what can be delivered to the destination market, after accounting for line losses. CASm allocates total system losses amongst suppliers on the basis on how much they injected, and how far away (how many wheels) they are from the destination market.

Economic Capacity

For the Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

supply < quantity[2], for each node and tranche

supply + flows in = flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

sum over lines (flow * simultaneous factor) <= simultaneous limit, for all limits

sum over nodes (net injection * flowgate factor) <= flowgate limit, for all limits

The objective is slightly different when transmission capacity is to be prorated. The objective then becomes:

minimize cost for supplies at the destination market; and

minimize divergence from calculated pro rata "share", for each supplier

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1 CASm can be modified to apply different proration methods when appropriate for some analyses.

2 Available quantity may be modified. See discussion in the Output Capacity section.

Available Economic Capacity

For the Available Economic Capacity analysis, CASm solves an LP with the following form:

minimize cost for supplies at the destination market

subject to:

supply cost at destination < system lambda + 5%, for all suppliers

supply < quantity (less native load), for each node and tranche

supply + flows in = flows out + "demand", for each node

line flows are adjusted for losses, for all interconnections

line flows < available limit, for all interconnections (constrained network only)

sum over lines (flow * simultaneous factor) <= simultaneous limit, for all limits

sum over nodes (net injection * flowgate factor) <= flowgate limit, for all limits

This is different from the economic capacity analysis only to the extent that potential suppliers are required to meet their load obligations.

When transmission capacity is to be prorated the objective becomes:

minimize cost for supplies at the destination market; and

minimize divergence from calculated pro rata "share", for each supplier

OUTPUTS

The primary output from CASm is a report that summarizes the results of different analyses. For each destination market, load period and FERC analysis type, CASm reports the following for both pre- and post-merger:

- Supplied MW
- Market Share
- HHIs

This report also shows the change in HHIs post-merger compared to pre-merger.

CASm also produces a transmission report that shows the detail of each node, and the injections and flows between them. Finally, a summary of the results for each market is also produced.

"SQUEEZE-DOWN" PRORATION

In the "squeeze-down" proration algorithm, prorated shares on each line are based on the weighted shares of deliverable energy at the source node for that line. As discussed below more fully below, weighted shares at the destination market node are calculated by a recursive algorithm that starts at the "outside" of the network, calculating shares on each line until it reaches the "middle". Specifically, where available supply exceeds the ability of the network to deliver that capacity to the destination market, suppliers are allocated shares at each node, and hence each outgoing line, based on the results of an algorithm that considers both supply and transfer capability at each node. Starting at the "outside" of the network, CASm calculates a share at each node that is based on a proportion of the incoming transfer capability (and the share of that capability allocated to each supplier), and the maximum economic supply available at that node. When the algorithm reaches the destination market, a total share of the incoming transfer capability has been determined.

This algorithm requires that all possible paths are simultaneously feasible, which, in turn, requires that each line be assigned a unique "direction". The steps of the proration algorithm include:

1. A C++ program enumerates all possible paths to the destination, the cost of transmission on each path and the maximum possible flow on the path. A "wheel limit", or maximum number of point-to-point links, may be imposed on paths.

2. The minimum "entry cost" for each supplier is calculated. This cost is the injection cost of the cheapest generator that has capacity for possible delivery to the destination.

3. Paths for which the entry cost plus the transmission cost are higher than 105% of the destination market price are rejected as being uneconomic.

4. To the extent remaining paths are not simultaneously feasible (because, for example, suppliers can seek to use the paths in both directions), a series of decision rules for determining the direction of the line are undertaken (in the following order):

    - Instructions can be manually input as to the chosen direction of a line.
    - Merger-case decisions should be consistent with base-case decisions.
    - The direction of the line as determined in an economic allocation of available transmission is applied.
    - The direction heading toward a destination market, if it is clear, is chosen.
    - The direction that retains the maximum potential volume-weighted flow on the line (calculated from the paths that depend on this line) is chosen.
    - The direction on which the maximum number of economic paths depend is chosen.

If these other options fail to reach a feasible solution, manual input will be required.

5. Proration begins at nodes furthest from the destination market (where only exports, and no imports are being attempted). Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability.

6. Proration continues at the next set of nodes, that should consist only of nodes with inflows from "resolved" nodes from step 5. Suppliers at these nodes are assigned a "share" equal to their maximum economic supply capability. Suppliers from the "resolved" nodes have their shares scaled down to match the transmission capacity into the node.

7. To the extent an iteration of the algorithm does not resolve any additional nodes and the destination market has not yet been reached (i.e., a loop is detected), flow is disallowed from any unresolved node to the furthest and smallest node affected by a loop.

8. The proration has been completed when the destination market node has been resolved. At that point, the "shares" at the destination market represent the prorated shares of deliverable energy.

9. Injections for each supplier are "capped" at the calculated shares, and these injections are then checked for economic feasibility. While suppliers need not deliver their energy to the destination in exactly the way that their share was calculated, the solution is still both economically and physically feasible. The final solution represents the least-cost method of delivering these supplies.

CASM IMPLEMENTATION

CASm_v80 has been implemented using GAMS (Generalized Algebraic Modeling System), release 2.5. GAMS is a programming language which supports both data manipulation and calls to many mainstream mathematical modeling systems. The linear programming problems generated by CASm are solved by BDMLP. The path enumeration program has been written in Microsoft Visual C++ version 5.

Suppliers Included in Analysis

(Destination Markets in Bold)

Node	Supplier	NERC	Control Area
AECI	**Associated Electric Coop Inc**	**SERC**	**Associated Electric Coop, Inc.**
AEP	**AEP Generating Co**	**ECAR**	**American Electric Power Co., Inc.**
AES_NY	AES Corp. (former NYSEG assets)	NPCC	New York Power Pool
AES_PJM_E	*AES's Accomack County Plant*	MAAC	*PJM Interconnect PA-NJ-MD*
ALEC	Alabama Electric Coop Inc	SERC	Alabama Electric Coop, Inc.
ALLIANT_E	**Wisconsin Power & Light Co**	**MAIN**	**Alliant East**
ALLIANT_W	**Alliant Energy - West**	**MAPP**	**Alliant West**
AMEREN	**Ameren Corp.**	**MAIN**	**Ameren Corp.**
AMPO	*American Municipal Power - Ohio*	ECAR	*American Electric Power Co., Inc.*
APS	**Allegheny Energy, Inc.**	**ECAR**	**Allegheny Energy, Inc.**
BEPC	Basin Electric Power Cooperative	MAPP	WAPA Billings East (UM-East)
BGE	Baltimore Gas & Electric Co	MAAC	PJM Interconnect PA-NJ-MD
BREC	Big Rivers Electric Corp.	ECAR	Big Rivers Electric Corp.
CAJN	*Cajun Electric Power Coop Inc*	SERC	*Cajun Electric Power Coop, Inc.*
CAL_NE	Calpine	NPCC	ISO New England
CAPO	**Carolina Power & Light Co**	**SERC**	**Carolina Power & Light Co.**
CE+PECO	**Merged Unicom/PECO entity**	**NA**	**NA**
CELE	**CLECO Corporation**	**SPP**	**Cleco Corp.**
CHGE	*Central Hudson Gas & Elec Corp*	*NPCC*	*New York Power Pool*
CILCO	**Central Illinois Light Co**	**MAIN**	**Central Illinois Light Co.**
CIMO	Independence City of	SPP	Independence Power & Light Dept.
CIN	**Cincinnati Gas & Electric**	**ECAR**	**Cinergy Services, Inc.**
COMED	**Commonwealth Edison Co.**	**MAIN**	**Commonwealth Edison Co.**
CON	Conectiv	MAAC	*PJM Interconnect PA-NJ-MD*
CONED	Consolidated Edison Co-NY Inc	NPCC	New York Power Pool
CP	Consumers Energy	ECAR	Michigan Electric Power Coordination Center
CSW_SPP	Central & South West SPP	SPP	Central & South West SPP
CWL	Columbia City Of	MAIN	Columbia Water & Light Dept.
CWLP	**Springfield City Of**	**MAIN**	**Springfield Water, Light & Power**
DECO	Detroit Edison	ECAR	Michigan Electric Power Coordination Center
DLCO	**Duquesne Light**	**ECAR**	**Duquesne Light Co.**
DOV_EAST	*Dover, City of*	MAAC	PJM Interconnect PA-NJ-MD
DPC	Dairyland Power Coop	MAPP	Dairyland Power Coop
DPL	**Dayton Power & Light**	**ECAR**	**Dayton Power & Light Co.**
DRI	Dominion Resources	NA	NA
DUKE	**Duke Power Co**	**SERC**	**Duke Energy Corp.**
DYN	*Dynegy (including IP)*	NA	NA
EDE	Empire District Electric Co	SPP	Empire District Electric Co.
EEI	Electric Energy, Inc.	MAIN	Electric Energy, Inc.
EKPC	**East Kentucky Power Coop.**	**ECAR**	**East Kentucky Power Coop, Inc.**
EME	Edison Mission Energy	NA	NA
EME_COMED	*EME (ComEd Fossil)*	MAIN	*Commonwealth Edison Co.*
ENRON	Enron Corp.	NA	NA
ENT	**Entergy**	**SERC**	**Entergy Corp.**
EPE	El Paso Energy	NA	NA
FENER	**First Energy**	**ECAR**	**First Energy**
FPL_NE	*FPL Group*	NPCC	*ISO New England*
GPU	General Public Utilities	MAAC	PJM Interconnect PA-NJ-MD
GRRD	Grand River Dam Authority	SPP	Grand River Dam Authority
GSEC	Golden Spread Electric Coop	SPP	Southwestern Public Service Co.
HEC	**Hoosier Energy Coop.**	**ECAR**	**Hoosier Energy Coop.**
IMEA	*Illinois Municipal Elec Agency*	MAIN	*Ameren Corp.*
IP	**Illinois Power Co**	**MAIN**	**Illinois Power Co.**
IPL	Indianapolis Power & Light	ECAR	Indianapolis Power & Light Co.
KACY	Kansas City City of	SPP	Kansas City Board of Public Utilities
KAMO	KAMO Electric Coop Inc	SPP	Grand River Dam Authority
KCPL	*Kansas City Power & Light Co*	SPP	*Kansas City Power & Light Co.*
KEY_NY	Keyspan	NPCC	New York Power Pool
LAFA	Lafayette City of	SPP	Lafayette Utilities System
LANS	*Lansing, City of*	ECAR	Michigan Electric Power Coordination Center
LEPA	Louisiana Energy & Power Auth	SPP	Louisiana Energy & Power Authority
LES	Lincoln Electric System	MAPP	Lincoln Electric System

Node	Supplier	NERC	Control Area
LGE	LG&E Energy Corp.	ECAR	LG&E Energy Corp.
LIPA	Long Island Power Authority	NPCC	New York Power Pool
LSP	LS Power	NA	NA
MARQ	Marquette City Of	MAIN	Upper Peninsula Power Co.
MDU	Montana-Dakota Utilities Co	MAPP	Otter Tail Power Co.
MEAG	Municipal Electric Authority of Georgia	SERC	Southern Company
MEAN	Municipal Energy Agency of NE	MAPP	Nebraska Public Power District
MECS	MECS	ECAR	Michigan Electric Power Coordination Center
MGE	Madison Gas & Electric Co	MAIN	Madison Gas & Electric Co.
MIDAM	MidAmerican Energy Co.	MAIN	MidAmerican Energy Co.
MIDW	Midwest Energy Inc	SPP	MidWest Energy, Inc.
MIT_COMED	New Supplier (mitigation)	MAIN	Commonwealth Edison Co.
MMWEC	Massachusetts Mun Whls Elec Co	NPCC	ISO New England
MP	Minnesota Power, Inc.	MAPP	Minnesota Power, Inc.
MPC	Minnkota Power Coop Inc	MAPP	Otter Tail Power Co.
MPS	UtiliCorp United Inc (MPS)	SPP	Missouri Public Service Co.
MPW	Muscatine Power & Water	MAPP	Muscatine Power & Water
MS	Morgan Stanley & Co.	NA	NA
NE_VAR	Various NEPOOL Suppliers	NPCC	ISO New England
NEES	New England Electric System	NPCC	ISO New England
NEPOOL	ISO New England	NPCC	ISO New England
NIMO	Niagara Mohawk Power Corp	NPCC	New York Power Pool
NIPS	Northern Indiana Public Service	ECAR	Northern Indiana Public Service Co.
NPPD	Nebraska Public Power District	MAPP	Nebraska Public Power District
NRG_NE	NRG Energy	NPCC	ISO New England
NRG_NY	NRG Energy	NPCC	New York Power Pool
NSP	Northern States Power Company	MAPP	Northern States Power Co.
NU	Northeast Utilities	NPCC	ISO New England
NWPS	Northwestern Public Service Co	MAPP	WAPA Billings East (UM-East)
NYPA	Power Authority Of State Of NY	NPCC	New York Power Pool
NYPP	New York Power Pool	NPCC	New York Power Pool
NYSEG	New York State Elec & Gas Corp	NPCC	New York Power Pool
ODEC	Old Dominion Electric Power Coop	SERC	Virginia Electric & Power Co.
OKGE	Oklahoma Gas & Electric Co	SPP	Oklahoma Gas & Electric Co.
OMPA	Oklahoma Municipal Power Auth	SPP	Central & South West SPP
OPC	Oglethorpe Power Corp	SERC	Southern Company
OPPD	Omaha Public Power District	MAPP	Omaha Public Power District
ORION_NY	Orion	NPCC	New York Power Pool
OTP	Otter Tail Power Company	MAPP	Otter Tail Power Co.
OVEC	Ohio Valley Electric Corp.	ECAR	Ohio Valley Electric Corp.
PECO	PECO Energy	MAAC	PJM Interconnect PA-NJ-MD
PEPCO	Potomac Electric Power Co	MAAC	PJM Interconnect PA-NJ-MD
PGE	PG&E Generating	NA	NA
PJM_ALL	PJM Interconnect PA-NJ-MD	MAAC	PJM Interconnect PA-NJ-MD
PJM_C+E	PJM - Central and East	MAAC	PJM Interconnect PA-NJ-MD
PJM_W+C+E	PJM - West, Central and East	MAAC	PJM Interconnect PA-NJ-MD
PJM_WEST	PJM - West	MAAC	PJM Interconnect PA-NJ-MD
PPL	PP&L Global	MAAC	PJM Interconnect PA-NJ-MD
PSEG	Public Service Electric & Gas	MAAC	PJM Interconnect PA-NJ-MD
ROGE	Rochester Gas & Electric Corp	NPCC	New York Power Pool
SCEG	South Carolina Electric & Gas Co.	SERC	South Carolina Electric & Gas Co.
SCPSA	South Carolina Public Service Authority	SERC	South Carolina Public Service Authority
SEC	Sunflower Electric Power Corp	SPP	Sunflower Electric Power Corp., Inc.
SEPA	Southeastern Power Administration	SERC	Southeastern Power Administration
SIGE	Southern Indiana Gas & Electric	ECAR	Southern Indiana Gas & Electric Co.
SIKE	Sikeston City of	SPP	Southwestern Power Administration
SIPC	Southern Illinois Power Coop	MAIN	Southern Illinois Power Coop
SITHE	Sithe Energies	NA	NA
SMEPA	South Mississippi El Pwr Assn	SERC	South Mississippi Electric Power Association
SMMP	Southern Minnesota Mun P Agny	MAPP	Southern Minnesota Municipal Power Agency
SOCO	Southern Company	SERC	Southern Company
SOY	Soyland Power Coop Inc	MAIN	Illinois Power Co.
SPRM	Springfield City of	SPP	Southwestern Power Administration
STJO	St. Joseph Light & Power	MAPP	St. Joseph Light & Power Co.
SWEPA	Southwestern Power Administration	SPP	Southwestern Power Administration

Node	Supplier	NERC	Control Area
SWPS	Southwestern Public Service Co	SPP	Southwestern Public Service Co.
TRACT	Tractebel	NA	NA
TVA	**Tennessee Valley Authority**	**SERC**	**Tennessee Valley Authority**
UGI	UGI Corp.	MAAC	PJM Interconnect PA-NJ-MD
UPA	*United Power Assn*	MAPP	*United Power Association*
UPA_TDU	UPA TDU	MAPP	United Power Association
UPP	**Upper Peninsula Power Co**	**MAIN**	**Upper Peninsula Power Co.**
UTILCOR	*Utilicorp*	SPP	NA
VINE_EAST	Vineland, City of	MAAC	PJM Interconnect PA-NJ-MD
VP	**Virginia Electric & Power Co**	**SERC**	**Virginia Electric & Power Co.**
WAPA	Western Area Power Administration	MAPP	WAPA Billings East (UM-East)
WEFA	Western Farmers Elec Coop Inc	SPP	Western Farmers Electric Coop
WEP	**Wisconsin Electric Power Co**	**MAIN**	**Wisconsin Electric Power Co.**
WEP_NE	Wisvest	NPCC	ISO New England
WEPL	UtiliCorp United (West Plains Energy)	SPP	West Plains Energy
WILL	Williams Energy	NA	NA
WPPI	Wisconsin Public Power Inc Sys	MAPP	Wisconsin Electric Power Co.
WPS	**Wisconsin Public Service Corp**	**MAIN**	**Wisconsin Public Service Corp.**
WR	***Western Resources***	**SPP**	***Western Resources***

Note: In addition to these nodes, there are additional nodes for merchant plants, TDUs and purchases and sales.

Competitive Analysis Screening Model (CASm)
HHI Report.
Unicom/PECO Market Power Analysis
Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
COMED	S_SP1	$100	75.7%	0.1%	5,791	75.8%	5,806	15
COMED	S_SP2	$75	73.1%	1.4%	5,419	74.5%	5,624	205
COMED	S_SP3	$50	73.2%	1.4%	5,429	74.6%	5,634	205
COMED	S_P	$30	63.8%	1.4%	4,238	65.2%	4,417	179
COMED	S_OP	$20	71.0%	1.8%	5,136	72.8%	5,392	256
COMED	W_SP	$25	65.9%	1.5%	4,504	67.4%	4,702	198
COMED	W_P	$20	73.2%	1.8%	5,407	75.0%	5,671	264
COMED	W_OP	$15	67.7%	2.0%	4,657	69.7%	4,928	271
COMED	SH_SP	$40	66.0%	1.4%	4,453	67.4%	4,638	185
COMED	SH_P	$25	63.4%	1.7%	4,179	65.1%	4,395	216
COMED	SH_OP	$15	64.6%	2.3%	4,254	66.9%	4,551	297
PJM_ALL	S_SP1	$100	0.0%	11.7%	933	11.7%	933	0
PJM_ALL	S_SP2	$75	0.0%	11.7%	929	11.7%	929	0
PJM_ALL	S_SP3	$50	0.0%	11.8%	932	11.8%	932	0
PJM_ALL	S_P	$30	0.0%	12.7%	864	12.7%	864	0
PJM_ALL	S_OP	$20	0.1%	10.5%	874	10.6%	876	2
PJM_ALL	W_SP	$25	0.0%	12.0%	841	12.0%	841	0
PJM_ALL	W_P	$20	0.0%	11.0%	872	11.0%	872	0
PJM_ALL	W_OP	$15	0.1%	11.9%	877	12.0%	879	2
PJM_ALL	SH_SP	$40	0.0%	12.1%	869	12.1%	869	0
PJM_ALL	SH_P	$25	0.0%	11.4%	806	11.4%	806	0
PJM_ALL	SH_OP	$15	0.1%	11.2%	842	11.3%	844	2
PJM_C+E	S_SP1	$100	0.0%	15.7%	1,280	15.7%	1,280	0
PJM_C+E	S_SP2	$75	0.0%	15.7%	1,271	15.7%	1,271	0
PJM_C+E	S_SP3	$50	0.0%	15.9%	1,281	15.9%	1,281	0
PJM_C+E	S_P	$30	0.0%	17.4%	1,173	17.4%	1,173	0
PJM_C+E	S_OP	$20	0.1%	14.6%	1,163	14.7%	1,166	3
PJM_C+E	W_SP	$25	0.1%	16.2%	1,116	16.3%	1,119	3
PJM_C+E	W_P	$20	0.1%	15.2%	1,196	15.3%	1,199	3
PJM_C+E	W_OP	$15	0.2%	15.6%	1,133	15.8%	1,139	6
PJM_C+E	SH_SP	$40	0.1%	16.3%	1,107	16.4%	1,110	3
PJM_C+E	SH_P	$25	0.1%	14.9%	1,032	15.0%	1,035	3
PJM_C+E	SH_OP	$15	0.2%	14.4%	1,009	14.6%	1,015	6
PJM_EAST	S_SP1	$100	0.0%	17.0%	1,396	17.0%	1,396	0
PJM_EAST	S_SP2	$75	0.0%	17.1%	1,383	17.1%	1,383	0
PJM_EAST	S_SP3	$50	0.0%	17.3%	1,392	17.3%	1,392	0
PJM_EAST	S_P	$30	0.0%	19.4%	1,270	19.4%	1,270	0
PJM_EAST	S_OP	$20	0.0%	16.2%	1,222	16.2%	1,222	0
PJM_EAST	W_SP	$25	0.0%	19.0%	1,237	19.0%	1,237	0
PJM_EAST	W_P	$20	0.2%	17.5%	1,297	17.7%	1,304	7
PJM_EAST	W_OP	$15	0.7%	18.7%	1,331	19.4%	1,357	26
PJM_EAST	SH_SP	$40	0.0%	18.2%	1,240	18.2%	1,240	0
PJM_EAST	SH_P	$25	0.0%	17.1%	1,088	17.1%	1,088	0
PJM_EAST	SH_OP	$15	0.7%	16.3%	1,124	17.0%	1,147	23
PJM_W+C+E	S_SP1	$100	0.0%	11.7%	921	11.7%	921	0
PJM_W+C+E	S_SP2	$75	0.0%	11.7%	917	11.7%	917	0
PJM_W+C+E	S_SP3	$50	0.0%	11.8%	920	11.8%	920	0
PJM_W+C+E	S_P	$30	0.0%	12.8%	851	12.8%	851	0
PJM_W+C+E	S_OP	$20	0.1%	10.5%	858	10.6%	860	2
PJM_W+C+E	W_SP	$25	0.1%	12.4%	846	12.5%	848	2
PJM_W+C+E	W_P	$20	0.1%	11.5%	863	11.6%	865	2
PJM_W+C+E	W_OP	$15	0.1%	12.0%	849	12.1%	851	2
PJM_W+C+E	SH_SP	$40	0.0%	12.0%	851	12.0%	851	0
PJM_W+C+E	SH_P	$25	0.0%	11.3%	794	11.3%	794	0
PJM_W+C+E	SH_OP	$15	0.1%	11.1%	823	11.2%	825	2

Economic Capacity
No Transmission Path

Market	Period	Price	BASE COMED Mkt Share	BASE PECO Mkt Share	BASE HHI Pre-Merger	MERGER CE + PECO Mkt Share	MERGER HHI Post-Merger	HHI Chg
AECI	S_SP1	$100	2.6%	0.6%	1,210	3.2%	1,213	3
AECI	S_SP2	$75	2.6%	0.7%	1,209	3.3%	1,213	4
AECI	S_SP3	$50	2.6%	0.7%	1,211	3.3%	1,215	4
AECI	S_P	$30	2.7%	0.7%	1,253	3.4%	1,257	4
AECI	S_OP	$20	3.9%	1.1%	1,194	5.0%	1,203	9
AECI	W_SP	$25	1.8%	0.8%	1,502	2.6%	1,505	3
AECI	W_P	$20	2.4%	1.1%	1,486	3.5%	1,491	5
AECI	W_OP	$15	5.1%	0.2%	602	5.3%	604	2
AECI	SH_SP	$40	1.9%	0.7%	1,291	2.6%	1,294	3
AECI	SH_P	$25	2.7%	1.1%	1,292	3.8%	1,298	6
AECI	SH_OP	$15	6.0%	0.3%	554	6.3%	558	4
AEP	S_SP1	$100	3.5%	0.3%	1,724	3.8%	1,726	2
AEP	S_SP2	$75	3.4%	0.4%	1,724	3.8%	1,727	3
AEP	S_SP3	$50	3.4%	0.4%	1,719	3.8%	1,722	3
AEP	S_P	$30	2.8%	0.7%	1,673	3.5%	1,677	4
AEP	S_OP	$20	3.3%	0.5%	1,958	3.8%	1,961	3
AEP	W_SP	$25	0.2%	0.5%	1,680	0.7%	1,680	0
AEP	W_P	$20	0.9%	0.5%	1,879	1.4%	1,880	1
AEP	W_OP	$15	1.2%	0.7%	2,451	1.9%	2,453	2
AEP	SH_SP	$40	1.1%	1.0%	1,323	2.1%	1,325	2
AEP	SH_P	$25	1.1%	0.9%	1,440	2.0%	1,442	2
AEP	SH_OP	$15	0.1%	0.9%	2,174	1.0%	2,174	0
ALLIANT_E	S_SP1	$100	10.8%	0.0%	2,763	10.8%	2,763	0
ALLIANT_E	S_SP2	$75	10.4%	0.2%	2,755	10.6%	2,759	4
ALLIANT_E	S_SP3	$50	10.8%	0.2%	2,614	11.0%	2,618	4
ALLIANT_E	S_P	$30	9.8%	0.2%	2,495	10.0%	2,499	4
ALLIANT_E	S_OP	$20	11.7%	0.3%	2,273	12.0%	2,280	7
ALLIANT_E	W_SP	$25	8.9%	0.2%	1,755	9.1%	1,759	4
ALLIANT_E	W_P	$20	10.5%	0.3%	1,642	10.8%	1,648	6
ALLIANT_E	W_OP	$15	8.7%	0.4%	1,615	9.1%	1,622	7
ALLIANT_E	SH_SP	$40	7.3%	0.2%	1,707	7.5%	1,710	3
ALLIANT_E	SH_P	$25	7.5%	0.2%	1,606	7.7%	1,609	3
ALLIANT_E	SH_OP	$15	7.6%	0.4%	1,539	8.0%	1,545	6
ALLIANT_W	S_SP1	$100	11.7%	0.2%	1,194	11.9%	1,199	5
ALLIANT_W	S_SP2	$75	11.3%	0.4%	1,185	11.7%	1,194	9
ALLIANT_W	S_SP3	$50	11.5%	0.4%	1,187	11.9%	1,196	9
ALLIANT_W	S_P	$30	11.2%	0.5%	1,072	11.7%	1,083	11
ALLIANT_W	S_OP	$20	14.1%	0.4%	1,267	14.5%	1,278	11
ALLIANT_W	W_SP	$25	10.7%	0.5%	962	11.2%	973	11
ALLIANT_W	W_P	$20	11.4%	0.5%	1,129	11.9%	1,140	11
ALLIANT_W	W_OP	$15	10.2%	0.6%	1,097	10.8%	1,109	12
ALLIANT_W	SH_SP	$40	9.7%	0.4%	1,007	10.1%	1,015	8
ALLIANT_W	SH_P	$25	10.6%	0.5%	981	11.1%	992	11
ALLIANT_W	SH_OP	$15	9.8%	0.6%	1,058	10.4%	1,070	12
AMEREN	S_SP1	$100	4.0%	0.5%	2,108	4.5%	2,112	4
AMEREN	S_SP2	$75	5.5%	0.6%	2,051	6.1%	2,058	7
AMEREN	S_SP3	$50	5.5%	0.6%	2,044	6.1%	2,051	7
AMEREN	S_P	$30	3.5%	0.7%	2,042	4.2%	2,047	5
AMEREN	S_OP	$20	4.2%	0.9%	2,247	5.1%	2,255	8
AMEREN	W_SP	$25	3.3%	0.7%	2,078	4.0%	2,083	5
AMEREN	W_P	$20	3.9%	0.9%	2,338	4.8%	2,345	7
AMEREN	W_OP	$15	3.2%	0.5%	2,543	3.7%	2,546	3
AMEREN	SH_SP	$40	3.9%	0.7%	1,798	4.6%	1,803	5
AMEREN	SH_P	$25	3.2%	0.9%	1,850	4.1%	1,856	6
AMEREN	SH_OP	$15	6.5%	0.7%	2,078	7.2%	2,087	9

Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
APS	S_SP1	$100	0.7%	0.1%	1,939	0.8%	1,939	0
APS	S_SP2	$75	0.7%	0.1%	1,939	0.8%	1,939	0
APS	S_SP3	$50	0.7%	0.2%	1,909	0.9%	1,909	0
APS	S_P	$30	0.9%	0.2%	1,764	1.1%	1,764	0
APS	S_OP	$20	1.4%	0.1%	1,777	1.5%	1,777	0
APS	W_SP	$25	1.5%	0.4%	1,733	1.9%	1,734	1
APS	W_P	$20	0.3%	0.4%	1,958	0.7%	1,958	0
APS	W_OP	$15	6.5%	0.8%	1,691	7.3%	1,701	10
APS	SH_SP	$40	1.0%	0.6%	1,559	1.6%	1,560	1
APS	SH_P	$25	1.6%	0.6%	1,520	2.2%	1,522	2
APS	SH_OP	$15	4.1%	1.3%	1,352	5.4%	1,363	11
CAPO	S_SP1	$100	0.7%	0.1%	4,217	0.8%	4,217	0
CAPO	S_SP2	$75	0.7%	0.1%	4,217	0.8%	4,217	0
CAPO	S_SP3	$50	0.7%	0.1%	4,154	0.8%	4,154	0
CAPO	S_P	$30	0.8%	0.1%	3,979	0.9%	3,979	0
CAPO	S_OP	$20	1.1%	0.1%	3,640	1.2%	3,640	0
CAPO	W_SP	$25	1.0%	0.1%	4,203	1.1%	4,203	0
CAPO	W_P	$20	1.6%	0.2%	3,844	1.8%	3,845	1
CAPO	W_OP	$15	3.7%	0.4%	3,320	4.1%	3,323	3
CAPO	SH_SP	$40	0.7%	0.3%	3,299	1.0%	3,299	0
CAPO	SH_P	$25	1.0%	0.2%	2,875	1.2%	2,875	0
CAPO	SH_OP	$15	4.1%	0.7%	2,598	4.8%	2,604	6
CELE	S_SP1	$100	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_SP2	$75	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_SP3	$50	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_P	$30	0.1%	0.8%	7,012	0.9%	7,012	0
CELE	S_OP	$20	0.6%	3.9%	3,187	4.5%	3,192	5
CELE	W_SP	$25	0.2%	1.1%	5,383	1.3%	5,383	0
CELE	W_P	$20	1.3%	4.2%	1,832	5.5%	1,843	11
CELE	W_OP	$15	2.7%	0.0%	1,836	2.7%	1,836	0
CELE	SH_SP	$40	0.1%	0.9%	5,982	1.0%	5,982	0
CELE	SH_P	$25	0.2%	1.1%	5,871	1.3%	5,871	0
CELE	SH_OP	$15	2.0%	0.0%	2,166	2.0%	2,166	0
CILCO	S_SP1	$100	12.8%	0.4%	2,002	13.2%	2,012	10
CILCO	S_SP2	$75	12.4%	0.7%	1,989	13.1%	2,006	17
CILCO	S_SP3	$50	12.4%	0.7%	1,990	13.1%	2,007	17
CILCO	S_P	$30	11.1%	0.7%	1,983	11.8%	1,999	16
CILCO	S_OP	$20	12.3%	0.7%	2,027	13.0%	2,044	17
CILCO	W_SP	$25	10.5%	0.8%	2,014	11.3%	2,031	17
CILCO	W_P	$20	12.0%	0.8%	2,087	12.8%	2,106	19
CILCO	W_OP	$15	17.5%	1.7%	1,058	19.2%	1,118	60
CILCO	SH_SP	$40	10.7%	0.7%	1,961	11.4%	1,976	15
CILCO	SH_P	$25	10.2%	0.8%	1,968	11.0%	1,984	16
CILCO	SH_OP	$15	15.4%	1.6%	832	17.0%	881	49
CIN	S_SP1	$100	2.1%	1.6%	1,978	3.7%	1,985	7
CIN	S_SP2	$75	2.3%	1.6%	1,978	3.9%	1,985	7
CIN	S_SP3	$50	2.3%	1.7%	1,971	4.0%	1,979	8
CIN	S_P	$30	2.6%	1.7%	1,877	4.3%	1,886	9
CIN	S_OP	$20	4.1%	1.9%	2,075	6.0%	2,091	16
CIN	W_SP	$25	2.5%	1.8%	1,707	4.3%	1,716	9
CIN	W_P	$20	4.0%	2.1%	1,969	6.1%	1,986	17
CIN	W_OP	$15	3.7%	2.8%	2,459	6.5%	2,480	21
CIN	SH_SP	$40	2.2%	1.8%	1,622	4.0%	1,630	8
CIN	SH_P	$25	2.7%	1.9%	1,595	4.6%	1,605	10
CIN	SH_OP	$15	4.8%	3.2%	2,256	8.0%	2,287	31

Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
CWLP	S_SP1	$100	5.8%	0.5%	2,516	6.3%	2,522	6
CWLP	S_SP2	$75	5.6%	0.6%	2,511	6.2%	2,518	7
CWLP	S_SP3	$50	5.6%	0.6%	2,513	6.2%	2,520	7
CWLP	S_P	$30	5.1%	0.6%	2,500	5.7%	2,506	6
CWLP	S_OP	$20	6.4%	0.6%	1,972	7.0%	1,980	8
CWLP	W_SP	$25	4.9%	0.6%	3,082	5.5%	3,088	6
CWLP	W_P	$20	5.8%	0.6%	2,503	6.4%	2,510	7
CWLP	W_OP	$15	12.9%	1.6%	916	14.5%	957	41
CWLP	SH_SP	$40	4.5%	0.5%	2,999	5.0%	3,004	5
CWLP	SH_P	$25	4.6%	0.6%	2,836	5.2%	2,842	6
CWLP	SH_OP	$15	11.2%	1.6%	839	12.8%	875	36
DLCO	S_SP1	$100	1.3%	1.5%	1,777	2.8%	1,781	4
DLCO	S_SP2	$75	1.2%	1.5%	1,777	2.7%	1,781	4
DLCO	S_SP3	$50	1.3%	1.6%	1,736	2.9%	1,740	4
DLCO	S_P	$30	1.4%	1.6%	1,654	3.0%	1,658	4
DLCO	S_OP	$20	1.8%	1.6%	1,752	3.4%	1,758	6
DLCO	W_SP	$25	1.7%	2.1%	2,081	3.8%	2,088	7
DLCO	W_P	$20	3.0%	2.2%	2,198	5.2%	2,211	13
DLCO	W_OP	$15	2.1%	2.8%	2,025	4.9%	2,037	12
DLCO	SH_SP	$40	1.4%	2.7%	1,882	4.1%	1,890	8
DLCO	SH_P	$25	1.9%	2.6%	1,880	4.5%	1,890	10
DLCO	SH_OP	$15	3.7%	3.9%	1,700	7.6%	1,729	29
DPL	S_SP1	$100	3.1%	0.6%	1,307	3.7%	1,311	4
DPL	S_SP2	$75	3.0%	0.7%	1,307	3.7%	1,311	4
DPL	S_SP3	$50	3.0%	0.7%	1,301	3.7%	1,305	4
DPL	S_P	$30	3.6%	0.8%	1,224	4.4%	1,230	6
DPL	S_OP	$20	4.9%	0.8%	1,316	5.7%	1,324	8
DPL	W_SP	$25	4.0%	0.8%	1,343	4.8%	1,349	6
DPL	W_P	$20	5.0%	0.9%	1,541	5.9%	1,550	9
DPL	W_OP	$15	8.6%	0.9%	1,211	9.5%	1,226	15
DPL	SH_SP	$40	2.6%	0.9%	1,306	3.5%	1,311	5
DPL	SH_P	$25	4.1%	1.0%	1,227	5.1%	1,235	8
DPL	SH_OP	$15	8.5%	1.4%	1,086	9.9%	1,110	24
DUKE	S_SP1	$100	0.3%	0.2%	5,609	0.5%	5,609	0
DUKE	S_SP2	$75	0.3%	0.2%	5,595	0.5%	5,595	0
DUKE	S_SP3	$50	0.3%	0.2%	5,529	0.5%	5,529	0
DUKE	S_P	$30	0.2%	0.0%	5,473	0.2%	5,473	0
DUKE	S_OP	$20	0.5%	0.0%	5,212	0.5%	5,212	0
DUKE	W_SP	$25	0.5%	0.1%	5,082	0.6%	5,082	0
DUKE	W_P	$20	0.2%	0.1%	4,983	0.3%	4,983	0
DUKE	W_OP	$15	0.3%	0.2%	4,470	0.5%	4,470	0
DUKE	SH_SP	$40	0.4%	0.3%	4,825	0.7%	4,825	0
DUKE	SH_P	$25	0.6%	0.1%	4,628	0.7%	4,628	0
DUKE	SH_OP	$15	2.4%	0.4%	4,353	2.8%	4,355	2
EKPC	S_SP1	$100	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_SP2	$75	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_SP3	$50	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_P	$30	0.5%	0.1%	7,613	0.6%	7,613	0
EKPC	S_OP	$20	0.7%	0.1%	7,644	0.8%	7,644	0
EKPC	W_SP	$25	0.6%	0.1%	7,617	0.7%	7,617	0
EKPC	W_P	$20	0.8%	0.1%	7,612	0.9%	7,612	0
EKPC	W_OP	$15	1.7%	0.1%	7,362	1.8%	7,362	0
EKPC	SH_SP	$40	0.4%	0.1%	7,387	0.5%	7,387	0
EKPC	SH_P	$25	0.6%	0.1%	7,397	0.7%	7,397	0
EKPC	SH_OP	$15	1.8%	0.2%	7,115	2.0%	7,116	1

Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
ENT	S_SP1	$100	0.1%	3.1%	3,561	3.2%	3,562	1
ENT	S_SP2	$75	0.1%	3.1%	3,561	3.2%	3,562	1
ENT	S_SP3	$50	0.1%	3.1%	3,561	3.2%	3,562	1
ENT	S_P	$30	0.2%	3.1%	3,488	3.3%	3,489	1
ENT	S_OP	$20	0.5%	6.5%	1,135	7.0%	1,142	7
ENT	W_SP	$25	0.3%	2.5%	3,406	2.8%	3,408	2
ENT	W_P	$20	0.3%	6.1%	1,144	6.4%	1,148	4
ENT	W_OP	$15	0.5%	0.2%	1,250	0.7%	1,250	0
ENT	SH_SP	$40	0.1%	3.0%	3,834	3.1%	3,835	1
ENT	SH_P	$25	0.3%	2.8%	3,467	3.1%	3,469	2
ENT	SH_OP	$15	2.9%	0.3%	1,343	3.2%	1,345	2
FENER	S_SP1	$100	1.0%	0.1%	1,929	1.1%	1,929	0
FENER	S_SP2	$75	0.9%	0.1%	1,929	1.0%	1,929	0
FENER	S_SP3	$50	0.9%	0.1%	1,901	1.0%	1,901	0
FENER	S_P	$30	1.1%	0.2%	1,767	1.3%	1,767	0
FENER	S_OP	$20	1.4%	0.1%	1,741	1.5%	1,741	0
FENER	W_SP	$25	1.9%	0.5%	1,723	2.4%	1,725	2
FENER	W_P	$20	3.1%	0.5%	1,911	3.6%	1,914	3
FENER	W_OP	$15	7.4%	0.7%	1,664	8.1%	1,674	10
FENER	SH_SP	$40	1.3%	0.6%	1,541	1.9%	1,543	2
FENER	SH_P	$25	2.0%	0.7%	1,503	2.7%	1,506	3
FENER	SH_OP	$15	7.0%	1.2%	1,420	8.2%	1,437	17
HEC	S_SP1	$100	1.9%	1.0%	1,865	2.9%	1,869	4
HEC	S_SP2	$75	1.9%	1.0%	1,865	2.9%	1,869	4
HEC	S_SP3	$50	1.9%	1.0%	1,862	2.9%	1,866	4
HEC	S_P	$30	2.2%	1.2%	1,824	3.4%	1,829	5
HEC	S_OP	$20	4.4%	1.2%	1,916	5.6%	1,927	11
HEC	W_SP	$25	2.0%	1.2%	1,763	3.2%	1,768	5
HEC	W_P	$20	2.9%	1.2%	1,840	4.1%	1,847	7
HEC	W_OP	$15	6.3%	1.6%	1,808	7.9%	1,828	20
HEC	SH_SP	$40	2.1%	1.1%	1,567	3.2%	1,572	5
HEC	SH_P	$25	2.3%	1.3%	1,645	3.6%	1,651	6
HEC	SH_OP	$15	7.5%	1.8%	1,695	9.3%	1,722	27
IP	S_SP1	$100	12.8%	1.7%	1,531	14.5%	1,575	44
IP	S_SP2	$75	12.3%	1.9%	1,520	14.2%	1,567	47
IP	S_SP3	$50	12.4%	1.9%	1,516	14.3%	1,563	47
IP	S_P	$30	11.3%	2.1%	1,467	13.4%	1,514	47
IP	S_OP	$20	12.7%	2.1%	1,497	14.8%	1,550	53
IP	W_SP	$25	11.7%	2.3%	1,480	14.0%	1,534	54
IP	W_P	$20	14.0%	2.3%	1,593	16.3%	1,657	64
IP	W_OP	$15	13.2%	2.8%	996	16.0%	1,070	74
IP	SH_SP	$40	9.4%	2.0%	1,480	11.4%	1,518	38
IP	SH_P	$25	9.4%	2.2%	1,432	11.6%	1,473	41
IP	SH_OP	$15	10.1%	2.7%	928	12.8%	983	55
LGE	S_SP1	$100	3.4%	0.5%	2,398	3.9%	2,401	3
LGE	S_SP2	$75	3.5%	0.6%	2,363	4.1%	2,367	4
LGE	S_SP3	$50	3.6%	0.6%	2,329	4.2%	2,333	4
LGE	S_P	$30	3.6%	0.6%	2,340	4.2%	2,344	4
LGE	S_OP	$20	4.8%	0.7%	2,404	5.5%	2,411	7
LGE	W_SP	$25	2.8%	0.6%	2,376	3.4%	2,379	3
LGE	W_P	$20	4.2%	0.6%	2,445	4.8%	2,450	5
LGE	W_OP	$15	6.3%	0.9%	2,406	7.2%	2,417	11
LGE	SH_SP	$40	2.6%	0.6%	2,128	3.2%	2,131	3
LGE	SH_P	$25	2.9%	0.7%	2,083	3.6%	2,087	4
LGE	SH_OP	$15	6.4%	1.1%	2,141	7.5%	2,155	14

Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
MECS	S_SP1	$100	0.5%	0.8%	3,368	1.3%	3,369	1
MECS	S_SP2	$75	0.5%	0.8%	3,368	1.3%	3,369	1
MECS	S_SP3	$50	0.5%	0.8%	3,359	1.3%	3,360	1
MECS	S_P	$30	0.5%	0.9%	3,366	1.4%	3,367	1
MECS	S_OP	$20	0.8%	0.1%	3,504	0.9%	3,504	0
MECS	W_SP	$25	1.2%	0.9%	2,295	2.1%	2,297	2
MECS	W_P	$20	2.7%	0.3%	2,259	3.0%	2,261	2
MECS	W_OP	$15	4.4%	0.5%	2,313	4.9%	2,317	4
MECS	SH_SP	$40	1.0%	1.0%	2,410	2.0%	2,412	2
MECS	SH_P	$25	1.3%	1.1%	2,384	2.4%	2,387	3
MECS	SH_OP	$15	4.7%	0.8%	2,384	5.5%	2,392	8
MGE	S_SP1	$100	2.2%	0.0%	4,751	2.2%	4,751	0
MGE	S_SP2	$75	2.2%	0.0%	4,751	2.2%	4,751	0
MGE	S_SP3	$50	2.2%	0.0%	4,750	2.2%	4,750	0
MGE	S_P	$30	2.3%	0.1%	4,370	2.4%	4,370	0
MGE	S_OP	$20	3.0%	0.1%	3,983	3.1%	3,984	1
MGE	W_SP	$25	4.3%	0.1%	3,009	4.4%	3,010	1
MGE	W_P	$20	6.2%	0.2%	2,614	6.4%	2,616	2
MGE	W_OP	$15	6.4%	0.3%	2,090	6.7%	2,094	4
MGE	SH_SP	$40	2.8%	0.1%	4,395	2.9%	4,396	1
MGE	SH_P	$25	3.5%	0.1%	3,913	3.6%	3,914	1
MGE	SH_OP	$15	5.1%	0.3%	2,711	5.4%	2,714	3
MIDAM	S_SP1	$100	10.4%	0.2%	1,666	10.6%	1,670	4
MIDAM	S_SP2	$75	10.0%	0.3%	1,658	10.3%	1,664	6
MIDAM	S_SP3	$50	10.1%	0.3%	1,666	10.4%	1,672	6
MIDAM	S_P	$30	9.6%	0.5%	1,469	10.1%	1,479	10
MIDAM	S_OP	$20	7.7%	0.3%	1,596	8.0%	1,601	5
MIDAM	W_SP	$25	9.1%	0.3%	1,351	9.4%	1,356	5
MIDAM	W_P	$20	9.4%	0.3%	1,384	9.7%	1,390	6
MIDAM	W_OP	$15	8.2%	0.5%	1,362	8.7%	1,370	8
MIDAM	SH_SP	$40	8.7%	0.3%	1,432	9.0%	1,437	5
MIDAM	SH_P	$25	9.2%	0.4%	1,260	9.6%	1,267	7
MIDAM	SH_OP	$15	8.4%	0.6%	1,287	9.0%	1,297	10
MPS	S_SP1	$100	2.0%	0.3%	1,879	2.3%	1,880	1
MPS	S_SP2	$75	2.3%	0.3%	1,873	2.6%	1,874	1
MPS	S_SP3	$50	2.3%	0.3%	1,874	2.6%	1,875	1
MPS	S_P	$30	2.0%	0.5%	1,806	2.5%	1,808	2
MPS	S_OP	$20	3.6%	0.2%	1,468	3.8%	1,469	1
MPS	W_SP	$25	2.8%	0.6%	1,572	3.4%	1,575	3
MPS	W_P	$20	4.7%	0.2%	1,459	4.9%	1,461	2
MPS	W_OP	$15	5.7%	0.3%	1,440	6.0%	1,443	3
MPS	SH_SP	$40	1.4%	0.3%	1,883	1.7%	1,884	1
MPS	SH_P	$25	2.6%	0.6%	1,586	3.2%	1,589	3
MPS	SH_OP	$15	4.3%	0.2%	1,456	4.5%	1,458	2
NEPOOL	S_SP1	$100	0.0%	0.0%	1,060	0.0%	1,060	0
NEPOOL	S_SP2	$75	0.0%	0.0%	1,060	0.0%	1,060	0
NEPOOL	S_SP3	$50	0.0%	0.0%	1,058	0.0%	1,058	0
NEPOOL	S_P	$30	0.0%	0.0%	1,077	0.0%	1,077	0
NEPOOL	S_OP	$20	0.0%	0.0%	1,097	0.0%	1,097	0
NEPOOL	W_SP	$25	0.0%	0.0%	1,066	0.0%	1,066	0
NEPOOL	W_P	$20	0.0%	0.0%	1,126	0.0%	1,126	0
NEPOOL	W_OP	$15	0.0%	0.0%	2,319	0.0%	2,319	0
NEPOOL	SH_SP	$40	0.0%	0.0%	1,073	0.0%	1,073	0
NEPOOL	SH_P	$25	0.0%	0.0%	1,059	0.0%	1,059	0
NEPOOL	SH_OP	$15	0.0%	0.0%	2,269	0.0%	2,269	0

Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
NIPS	S_SP1	$100	13.3%	0.3%	2,454	13.6%	2,462	8
NIPS	S_SP2	$75	12.8%	0.5%	2,443	13.3%	2,456	13
NIPS	S_SP3	$50	12.9%	0.5%	2,418	13.4%	2,431	13
NIPS	S_P	$30	11.6%	0.6%	2,231	12.2%	2,245	14
NIPS	S_OP	$20	12.1%	0.6%	2,187	12.7%	2,202	15
NIPS	W_SP	$25	9.4%	0.6%	1,522	10.0%	1,533	11
NIPS	W_P	$20	12.8%	0.9%	1,621	13.7%	1,644	23
NIPS	W_OP	$15	11.3%	1.1%	1,487	12.4%	1,512	25
NIPS	SH_SP	$40	12.1%	0.7%	1,479	12.8%	1,496	17
NIPS	SH_P	$25	9.6%	0.7%	1,410	10.3%	1,423	13
NIPS	SH_OP	$15	11.3%	1.5%	1,404	12.8%	1,438	34
NSP	S_SP1	$100	1.8%	0.1%	2,614	1.9%	2,614	0
NSP	S_SP2	$75	1.7%	0.1%	2,614	1.8%	2,614	0
NSP	S_SP3	$50	1.8%	0.1%	2,329	1.9%	2,329	0
NSP	S_P	$30	1.9%	0.1%	2,250	2.0%	2,250	0
NSP	S_OP	$20	3.1%	0.1%	2,468	3.2%	2,469	1
NSP	W_SP	$25	2.5%	0.1%	2,054	2.6%	2,055	1
NSP	W_P	$20	3.9%	0.2%	2,220	4.1%	2,222	2
NSP	W_OP	$15	5.2%	0.3%	2,762	5.5%	2,765	3
NSP	SH_SP	$40	2.6%	0.1%	1,877	2.7%	1,878	1
NSP	SH_P	$25	3.1%	0.2%	1,912	3.3%	1,913	1
NSP	SH_OP	$15	6.0%	0.3%	2,609	6.3%	2,613	4
NYPP	S_SP1	$100	0.0%	0.9%	947	0.9%	947	0
NYPP	S_SP2	$75	0.0%	0.9%	947	0.9%	947	0
NYPP	S_SP3	$50	0.0%	0.9%	961	0.9%	961	0
NYPP	S_P	$30	0.0%	1.0%	980	1.0%	980	0
NYPP	S_OP	$20	0.0%	0.9%	1,000	0.9%	1,000	0
NYPP	W_SP	$25	0.0%	0.5%	981	0.5%	981	0
NYPP	W_P	$20	0.0%	0.7%	1,079	0.7%	1,079	0
NYPP	W_OP	$15	0.0%	1.0%	1,478	1.0%	1,478	0
NYPP	SH_SP	$40	0.0%	1.7%	893	1.7%	893	0
NYPP	SH_P	$25	0.0%	1.7%	823	1.7%	823	0
NYPP	SH_OP	$15	0.0%	3.9%	1,105	3.9%	1,105	0
SCEG	S_SP1	$100	0.3%	0.3%	2,939	0.6%	2,939	0
SCEG	S_SP2	$75	0.3%	0.4%	2,939	0.7%	2,939	0
SCEG	S_SP3	$50	0.3%	0.4%	2,876	0.7%	2,876	0
SCEG	S_P	$30	0.4%	0.0%	2,776	0.4%	2,776	0
SCEG	S_OP	$20	0.7%	0.0%	2,706	0.7%	2,706	0
SCEG	W_SP	$25	0.5%	0.0%	2,984	0.5%	2,984	0
SCEG	W_P	$20	0.4%	0.2%	2,942	0.6%	2,942	0
SCEG	W_OP	$15	1.2%	0.1%	1,353	1.3%	1,353	0
SCEG	SH_SP	$40	0.3%	0.4%	2,290	0.7%	2,290	0
SCEG	SH_P	$25	0.6%	0.0%	2,208	0.6%	2,208	0
SCEG	SH_OP	$15	1.1%	0.3%	1,178	1.4%	1,179	1
SCPSA	S_SP1	$100	0.3%	0.3%	1,821	0.6%	1,821	0
SCPSA	S_SP2	$75	0.3%	0.3%	1,821	0.6%	1,821	0
SCPSA	S_SP3	$50	0.3%	0.3%	1,809	0.6%	1,809	0
SCPSA	S_P	$30	0.5%	0.0%	1,786	0.5%	1,786	0
SCPSA	S_OP	$20	0.7%	0.0%	1,723	0.7%	1,723	0
SCPSA	W_SP	$25	0.6%	0.0%	1,939	0.6%	1,939	0
SCPSA	W_P	$20	0.5%	0.2%	1,904	0.7%	1,904	0
SCPSA	W_OP	$15	0.6%	0.1%	1,868	0.7%	1,868	0
SCPSA	SH_SP	$40	0.4%	0.4%	1,567	0.8%	1,567	0
SCPSA	SH_P	$25	0.8%	0.0%	1,572	0.8%	1,572	0
SCPSA	SH_OP	$15	0.6%	0.3%	1,468	0.9%	1,468	0

Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
SOCO	S_SP1	$100	0.0%	2.4%	5,929	2.4%	5,929	0
SOCO	S_SP2	$75	0.0%	2.4%	5,929	2.4%	5,929	0
SOCO	S_SP3	$50	0.0%	2.4%	5,891	2.4%	5,891	0
SOCO	S_P	$30	0.1%	2.5%	5,752	2.6%	5,753	1
SOCO	S_OP	$20	0.1%	0.0%	6,162	0.1%	6,162	0
SOCO	W_SP	$25	0.2%	2.4%	5,257	2.6%	5,258	1
SOCO	W_P	$20	0.8%	0.0%	5,581	0.8%	5,581	0
SOCO	W_OP	$15	3.3%	0.1%	3,180	3.4%	3,181	1
SOCO	SH_SP	$40	0.1%	2.4%	5,086	2.5%	5,086	0
SOCO	SH_P	$25	0.1%	0.2%	5,283	0.3%	5,283	0
SOCO	SH_OP	$15	3.7%	0.1%	2,721	3.8%	2,722	1
TVA	S_SP1	$100	2.4%	0.2%	5,124	2.6%	5,125	1
TVA	S_SP2	$75	2.4%	0.3%	5,124	2.7%	5,125	1
TVA	S_SP3	$50	2.4%	0.3%	5,124	2.7%	5,125	1
TVA	S_P	$30	2.5%	0.3%	5,139	2.8%	5,141	2
TVA	S_OP	$20	2.5%	0.3%	5,661	2.8%	5,663	2
TVA	W_SP	$25	1.6%	0.2%	4,393	1.8%	4,394	1
TVA	W_P	$20	1.1%	0.1%	5,447	1.2%	5,447	0
TVA	W_OP	$15	3.3%	0.5%	5,068	3.8%	5,071	3
TVA	SH_SP	$40	1.7%	0.2%	4,245	1.9%	4,246	1
TVA	SH_P	$25	1.7%	0.2%	4,584	1.9%	4,585	1
TVA	SH_OP	$15	3.4%	0.7%	4,810	4.1%	4,815	5
UPP	S_SP1	$100	0.2%	0.0%	3,273	0.2%	3,273	0
UPP	S_SP2	$75	0.2%	0.0%	3,273	0.2%	3,273	0
UPP	S_SP3	$50	0.2%	0.0%	3,273	0.2%	3,273	0
UPP	S_P	$30	0.3%	0.0%	3,604	0.3%	3,604	0
UPP	S_OP	$20	0.6%	0.0%	4,757	0.6%	4,757	0
UPP	W_SP	$25	3.6%	0.1%	2,243	3.7%	2,244	1
UPP	W_P	$20	6.7%	0.2%	2,059	6.9%	2,062	3
UPP	W_OP	$15	8.5%	0.3%	2,276	8.8%	2,281	5
UPP	SH_SP	$40	0.0%	0.0%	5,018	0.0%	5,018	0
UPP	SH_P	$25	0.0%	0.0%	6,258	0.0%	6,258	0
UPP	SH_OP	$15	0.0%	0.0%	7,959	0.0%	7,959	0
VP	S_SP1	$100	0.8%	0.2%	1,984	1.0%	1,984	0
VP	S_SP2	$75	0.7%	0.2%	1,984	0.9%	1,984	0
VP	S_SP3	$50	0.7%	0.2%	1,951	0.9%	1,951	0
VP	S_P	$30	0.8%	0.1%	1,906	0.9%	1,906	0
VP	S_OP	$20	1.4%	0.1%	1,821	1.5%	1,821	0
VP	W_SP	$25	1.4%	0.4%	1,821	1.8%	1,822	1
VP	W_P	$20	3.0%	0.4%	2,002	3.4%	2,004	2
VP	W_OP	$15	7.9%	0.7%	1,743	8.6%	1,754	11
VP	SH_SP	$40	0.9%	0.6%	1,596	1.5%	1,597	1
VP	SH_P	$25	1.7%	0.7%	1,536	2.4%	1,538	2
VP	SH_OP	$15	8.0%	1.2%	1,373	9.2%	1,392	19
WEP	S_SP1	$100	1.0%	0.0%	8,506	1.0%	8,506	0
WEP	S_SP2	$75	0.9%	0.0%	8,506	0.9%	8,506	0
WEP	S_SP3	$50	0.9%	0.0%	8,506	0.9%	8,506	0
WEP	S_P	$30	0.8%	0.0%	8,601	0.8%	8,601	0
WEP	S_OP	$20	1.2%	0.0%	8,470	1.2%	8,470	0
WEP	W_SP	$25	5.9%	0.1%	3,787	6.0%	3,788	1
WEP	W_P	$20	7.2%	0.2%	3,550	7.4%	3,553	3
WEP	W_OP	$15	6.7%	0.3%	2,992	7.0%	2,996	4
WEP	SH_SP	$40	7.7%	0.2%	3,422	7.9%	3,425	3
WEP	SH_P	$25	7.6%	0.2%	3,356	7.8%	3,359	3
WEP	SH_OP	$15	7.8%	0.4%	2,516	8.2%	2,522	6

Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
WPS	S_SP1	$100	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_SP2	$75	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_SP3	$50	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_P	$30	0.6%	0.0%	5,994	0.6%	5,994	0
WPS	S_OP	$20	0.8%	0.0%	6,427	0.8%	6,427	0
WPS	W_SP	$25	2.2%	0.1%	3,648	2.3%	3,648	0
WPS	W_P	$20	2.7%	0.1%	3,753	2.8%	3,754	1
WPS	W_OP	$15	3.2%	0.2%	4,218	3.4%	4,219	1
WPS	SH_SP	$40	1.3%	0.0%	3,808	1.3%	3,808	0
WPS	SH_P	$25	2.0%	0.0%	3,611	2.0%	3,611	0
WPS	SH_OP	$15	4.1%	0.2%	4,238	4.3%	4,240	2
WR	S_SP1	$100	0.4%	0.4%	6,016	0.8%	6,016	0
WR	S_SP2	$75	0.5%	0.4%	6,014	0.9%	6,014	0
WR	S_SP3	$50	0.5%	0.4%	6,014	0.9%	6,014	0
WR	S_P	$30	0.8%	0.4%	5,128	1.2%	5,129	1
WR	S_OP	$20	1.5%	0.8%	4,557	2.3%	4,559	2
WR	W_SP	$25	1.4%	0.4%	5,027	1.8%	5,028	1
WR	W_P	$20	2.4%	0.1%	4,473	2.5%	4,473	0
WR	W_OP	$15	3.1%	0.1%	4,500	3.2%	4,501	1
WR	SH_SP	$40	0.6%	0.3%	5,037	0.9%	5,037	0
WR	SH_P	$25	1.2%	0.5%	4,805	1.7%	4,806	1
WR	SH_OP	$15	2.4%	0.1%	4,243	2.5%	4,243	0

Competitive Analysis Screening Model (CASm)
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			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
COMED	S_SP1	$100	75.7%	0.1%	5,791	75.4%	5,755	-37
COMED	S_SP2	$75	73.1%	1.4%	5,419	74.1%	5,562	142
COMED	S_SP3	$50	73.2%	1.4%	5,429	74.2%	5,572	143
COMED	S_P	$30	63.8%	1.4%	4,238	64.8%	4,368	130
COMED	S_OP	$20	71.0%	1.8%	5,136	72.2%	5,313	178
COMED	W_SP	$25	65.9%	1.5%	4,504	67.0%	4,647	143
COMED	W_P	$20	73.2%	1.8%	5,407	74.5%	5,602	194
COMED	W_OP	$15	67.7%	2.0%	4,657	69.2%	4,861	204
COMED	SH_SP	$40	66.0%	1.4%	4,453	67.1%	4,587	134
COMED	SH_P	$25	63.4%	1.7%	4,179	64.5%	4,329	149
COMED	SH_OP	$15	64.6%	2.3%	4,254	66.3%	4,478	224
PJM_ALL	S_SP1	$100	0.0%	11.7%	933	11.8%	936	2
PJM_ALL	S_SP2	$75	0.0%	11.7%	929	11.9%	931	2
PJM_ALL	S_SP3	$50	0.0%	11.8%	932	12.0%	934	2
PJM_ALL	S_P	$30	0.0%	12.7%	864	12.9%	868	4
PJM_ALL	S_OP	$20	0.1%	10.5%	874	10.8%	880	6
PJM_ALL	W_SP	$25	0.0%	12.0%	841	12.1%	843	2
PJM_ALL	W_P	$20	0.0%	11.0%	872	11.2%	874	1
PJM_ALL	W_OP	$15	0.1%	11.9%	877	12.3%	881	4
PJM_ALL	SH_SP	$40	0.0%	12.1%	869	12.2%	872	3
PJM_ALL	SH_P	$25	0.0%	11.4%	806	11.6%	809	3
PJM_ALL	SH_OP	$15	0.1%	11.2%	842	11.5%	847	5
PJM_C+E	S_SP1	$100	0.0%	15.7%	1,280	15.9%	1,282	3
PJM_C+E	S_SP2	$75	0.0%	15.7%	1,271	16.0%	1,274	3
PJM_C+E	S_SP3	$50	0.0%	15.9%	1,281	16.2%	1,284	3
PJM_C+E	S_P	$30	0.0%	17.4%	1,173	17.7%	1,179	5
PJM_C+E	S_OP	$20	0.1%	14.6%	1,163	15.0%	1,169	5
PJM_C+E	W_SP	$25	0.1%	16.2%	1,116	16.5%	1,122	6
PJM_C+E	W_P	$20	0.1%	15.2%	1,196	15.6%	1,202	6
PJM_C+E	W_OP	$15	0.2%	15.6%	1,133	16.0%	1,141	8
PJM_C+E	SH_SP	$40	0.1%	16.3%	1,107	16.6%	1,112	5
PJM_C+E	SH_P	$25	0.1%	14.9%	1,032	15.3%	1,039	7
PJM_C+E	SH_OP	$15	0.2%	14.4%	1,009	14.9%	1,018	9
PJM_EAST	S_SP1	$100	0.0%	17.0%	1,396	17.3%	1,398	2
PJM_EAST	S_SP2	$75	0.0%	17.1%	1,383	17.3%	1,386	2
PJM_EAST	S_SP3	$50	0.0%	17.3%	1,392	17.6%	1,395	3
PJM_EAST	S_P	$30	0.0%	19.4%	1,270	19.7%	1,275	6
PJM_EAST	S_OP	$20	0.0%	16.2%	1,222	16.6%	1,228	6
PJM_EAST	W_SP	$25	0.0%	19.0%	1,237	19.3%	1,244	7
PJM_EAST	W_P	$20	0.2%	17.5%	1,297	18.1%	1,308	10
PJM_EAST	W_OP	$15	0.7%	18.7%	1,331	19.8%	1,364	32
PJM_EAST	SH_SP	$40	0.0%	18.2%	1,240	18.5%	1,245	5
PJM_EAST	SH_P	$25	0.0%	17.1%	1,088	17.5%	1,096	7
PJM_EAST	SH_OP	$15	0.7%	16.3%	1,124	17.5%	1,154	30
PJM_W+C+E	S_SP1	$100	0.0%	11.7%	921	11.8%	925	3
PJM_W+C+E	S_SP2	$75	0.0%	11.7%	917	11.9%	920	3
PJM_W+C+E	S_SP3	$50	0.0%	11.8%	920	12.0%	923	3
PJM_W+C+E	S_P	$30	0.0%	12.8%	851	12.9%	856	4
PJM_W+C+E	S_OP	$20	0.1%	10.5%	858	10.8%	863	6
PJM_W+C+E	W_SP	$25	0.1%	12.4%	846	12.7%	850	4
PJM_W+C+E	W_P	$20	0.1%	11.5%	863	11.8%	867	3
PJM_W+C+E	W_OP	$15	0.1%	12.0%	849	12.3%	854	5
PJM_W+C+E	SH_SP	$40	0.0%	12.0%	851	12.2%	854	3
PJM_W+C+E	SH_P	$25	0.0%	11.3%	794	11.5%	797	3
PJM_W+C+E	SH_OP	$15	0.1%	11.1%	823	11.4%	829	6

Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
AECI	S_SP1	$100	2.6%	0.6%	1,210	3.2%	1,215	4
AECI	S_SP2	$75	2.6%	0.7%	1,209	3.2%	1,214	4
AECI	S_SP3	$50	2.6%	0.7%	1,211	3.3%	1,216	5
AECI	S_P	$30	2.7%	0.7%	1,253	3.4%	1,258	5
AECI	S_OP	$20	3.9%	1.1%	1,194	4.9%	1,203	9
AECI	W_SP	$25	1.8%	0.8%	1,502	2.6%	1,506	4
AECI	W_P	$20	2.4%	1.1%	1,486	3.4%	1,493	6
AECI	W_OP	$15	5.1%	0.2%	602	5.2%	603	2
AECI	SH_SP	$40	1.9%	0.7%	1,291	2.5%	1,293	2
AECI	SH_P	$25	2.7%	1.1%	1,292	3.7%	1,295	3
AECI	SH_OP	$15	6.0%	0.3%	554	6.2%	557	3
AEP	S_SP1	$100	3.5%	0.3%	1,724	3.8%	1,736	12
AEP	S_SP2	$75	3.4%	0.4%	1,724	3.7%	1,736	12
AEP	S_SP3	$50	3.4%	0.4%	1,719	3.7%	1,731	12
AEP	S_P	$30	2.8%	0.7%	1,673	3.5%	1,686	12
AEP	S_OP	$20	3.3%	0.5%	1,958	3.7%	1,970	13
AEP	W_SP	$25	0.2%	0.5%	1,680	0.7%	1,678	-2
AEP	W_P	$20	0.9%	0.5%	1,879	1.5%	1,877	-2
AEP	W_OP	$15	1.2%	0.7%	2,451	1.9%	2,453	2
AEP	SH_SP	$40	1.1%	1.0%	1,323	2.1%	1,320	-3
AEP	SH_P	$25	1.1%	0.9%	1,440	1.9%	1,435	-5
AEP	SH_OP	$15	0.1%	0.9%	2,174	1.0%	2,167	-7
ALLIANT_E	S_SP1	$100	10.8%	0.0%	2,763	10.6%	2,765	2
ALLIANT_E	S_SP2	$75	10.4%	0.2%	2,755	10.4%	2,761	6
ALLIANT_E	S_SP3	$50	10.8%	0.2%	2,614	10.8%	2,621	6
ALLIANT_E	S_P	$30	9.8%	0.2%	2,495	9.9%	2,501	6
ALLIANT_E	S_OP	$20	11.7%	0.3%	2,273	11.8%	2,280	7
ALLIANT_E	W_SP	$25	8.9%	0.2%	1,755	9.0%	1,757	2
ALLIANT_E	W_P	$20	10.5%	0.3%	1,642	10.6%	1,645	2
ALLIANT_E	W_OP	$15	8.7%	0.4%	1,615	8.9%	1,620	5
ALLIANT_E	SH_SP	$40	7.3%	0.2%	1,707	7.3%	1,710	3
ALLIANT_E	SH_P	$25	7.5%	0.2%	1,606	7.6%	1,610	4
ALLIANT_E	SH_OP	$15	7.6%	0.4%	1,539	7.7%	1,545	6
ALLIANT_W	S_SP1	$100	11.7%	0.2%	1,194	11.7%	1,195	1
ALLIANT_W	S_SP2	$75	11.3%	0.4%	1,185	11.5%	1,190	5
ALLIANT_W	S_SP3	$50	11.5%	0.4%	1,187	11.7%	1,192	5
ALLIANT_W	S_P	$30	11.2%	0.5%	1,072	11.5%	1,080	8
ALLIANT_W	S_OP	$20	14.1%	0.4%	1,267	14.3%	1,275	8
ALLIANT_W	W_SP	$25	10.7%	0.5%	962	11.1%	970	8
ALLIANT_W	W_P	$20	11.4%	0.5%	1,129	11.7%	1,135	7
ALLIANT_W	W_OP	$15	10.2%	0.6%	1,097	10.6%	1,107	10
ALLIANT_W	SH_SP	$40	9.7%	0.4%	1,007	10.0%	1,011	5
ALLIANT_W	SH_P	$25	10.6%	0.5%	981	11.0%	989	7
ALLIANT_W	SH_OP	$15	9.8%	0.6%	1,058	10.2%	1,068	10
AMEREN	S_SP1	$100	4.0%	0.5%	2,108	4.5%	2,113	5
AMEREN	S_SP2	$75	5.5%	0.6%	2,051	6.0%	2,059	8
AMEREN	S_SP3	$50	5.5%	0.6%	2,044	6.1%	2,052	8
AMEREN	S_P	$30	3.5%	0.7%	2,042	4.1%	2,048	5
AMEREN	S_OP	$20	4.2%	0.9%	2,247	5.0%	2,256	9
AMEREN	W_SP	$25	3.3%	0.7%	2,078	4.0%	2,083	5
AMEREN	W_P	$20	3.9%	0.9%	2,338	4.8%	2,344	7
AMEREN	W_OP	$15	3.2%	0.5%	2,543	3.7%	2,546	2
AMEREN	SH_SP	$40	3.9%	0.7%	1,798	4.5%	1,804	6
AMEREN	SH_P	$25	3.2%	0.9%	1,850	4.1%	1,856	6
AMEREN	SH_OP	$15	6.5%	0.7%	2,078	7.2%	2,089	10

Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
APS	S_SP1	$100	0.7%	0.1%	1,939	0.9%	1,940	1
APS	S_SP2	$75	0.7%	0.1%	1,939	0.9%	1,941	1
APS	S_SP3	$50	0.7%	0.2%	1,909	0.9%	1,910	1
APS	S_P	$30	0.9%	0.2%	1,764	1.1%	1,764	1
APS	S_OP	$20	1.4%	0.1%	1,777	1.5%	1,777	0
APS	W_SP	$25	1.5%	0.4%	1,733	1.9%	1,733	-1
APS	W_P	$20	0.3%	0.4%	1,958	0.6%	1,955	-2
APS	W_OP	$15	6.5%	0.8%	1,691	7.1%	1,697	6
APS	SH_SP	$40	1.0%	0.6%	1,559	1.6%	1,568	9
APS	SH_P	$25	1.6%	0.6%	1,520	2.3%	1,522	2
APS	SH_OP	$15	4.1%	1.3%	1,352	5.2%	1,364	12
CAPO	S_SP1	$100	0.7%	0.1%	4,217	0.8%	4,230	13
CAPO	S_SP2	$75	0.7%	0.1%	4,217	0.8%	4,230	13
CAPO	S_SP3	$50	0.7%	0.1%	4,154	0.8%	4,167	13
CAPO	S_P	$30	0.8%	0.1%	3,979	0.9%	3,992	13
CAPO	S_OP	$20	1.1%	0.1%	3,640	1.2%	3,652	12
CAPO	W_SP	$25	1.0%	0.1%	4,203	1.1%	4,225	22
CAPO	W_P	$20	1.6%	0.2%	3,844	1.8%	3,867	23
CAPO	W_OP	$15	3.7%	0.4%	3,320	4.1%	3,345	24
CAPO	SH_SP	$40	0.7%	0.3%	3,299	1.0%	3,311	12
CAPO	SH_P	$25	1.0%	0.2%	2,875	1.3%	2,886	11
CAPO	SH_OP	$15	4.1%	0.7%	2,598	4.7%	2,612	13
CELE	S_SP1	$100	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_SP2	$75	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_SP3	$50	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_P	$30	0.1%	0.8%	7,012	0.9%	7,013	0
CELE	S_OP	$20	0.6%	3.9%	3,187	4.5%	3,192	5
CELE	W_SP	$25	0.2%	1.1%	5,383	1.3%	5,383	1
CELE	W_P	$20	1.3%	4.2%	1,832	5.5%	1,843	11
CELE	W_OP	$15	2.7%	0.0%	1,836	2.8%	1,836	0
CELE	SH_SP	$40	0.1%	0.9%	5,982	1.0%	5,982	0
CELE	SH_P	$25	0.2%	1.1%	5,871	1.3%	5,872	0
CELE	SH_OP	$15	2.0%	0.0%	2,166	2.0%	2,165	-1
CILCO	S_SP1	$100	12.8%	0.4%	2,002	13.1%	2,011	9
CILCO	S_SP2	$75	12.4%	0.7%	1,989	12.9%	2,002	14
CILCO	S_SP3	$50	12.4%	0.7%	1,990	12.9%	2,003	14
CILCO	S_P	$30	11.1%	0.7%	1,983	11.7%	1,996	14
CILCO	S_OP	$20	12.3%	0.7%	2,027	12.7%	2,042	15
CILCO	W_SP	$25	10.5%	0.8%	2,014	11.1%	2,028	14
CILCO	W_P	$20	12.0%	0.8%	2,087	12.6%	2,107	19
CILCO	W_OP	$15	17.5%	1.7%	1,058	18.9%	1,109	52
CILCO	SH_SP	$40	10.7%	0.7%	1,961	11.3%	1,968	6
CILCO	SH_P	$25	10.2%	0.8%	1,968	10.9%	1,975	7
CILCO	SH_OP	$15	15.4%	1.6%	832	16.6%	872	40
CIN	S_SP1	$100	2.1%	1.6%	1,978	3.7%	1,984	6
CIN	S_SP2	$75	2.3%	1.6%	1,978	3.9%	1,985	6
CIN	S_SP3	$50	2.3%	1.7%	1,971	3.9%	1,978	7
CIN	S_P	$30	2.6%	1.7%	1,877	4.2%	1,886	8
CIN	S_OP	$20	4.1%	1.9%	2,075	6.0%	2,092	17
CIN	W_SP	$25	2.5%	1.8%	1,707	4.3%	1,722	15
CIN	W_P	$20	4.0%	2.1%	1,969	6.0%	1,991	22
CIN	W_OP	$15	3.7%	2.8%	2,459	6.5%	2,487	28
CIN	SH_SP	$40	2.2%	1.8%	1,622	4.0%	1,637	15
CIN	SH_P	$25	2.7%	1.9%	1,595	4.6%	1,612	17
CIN	SH_OP	$15	4.8%	3.2%	2,256	8.1%	2,296	39

Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
CWLP	S_SP1	$100	5.8%	0.5%	2,516	6.2%	2,521	5
CWLP	S_SP2	$75	5.6%	0.6%	2,511	6.1%	2,517	6
CWLP	S_SP3	$50	5.6%	0.6%	2,513	6.1%	2,519	6
CWLP	S_P	$30	5.1%	0.6%	2,500	5.7%	2,507	6
CWLP	S_OP	$20	6.4%	0.6%	1,972	6.9%	1,979	7
CWLP	W_SP	$25	4.9%	0.6%	3,082	5.5%	3,088	6
CWLP	W_P	$20	5.8%	0.6%	2,503	6.3%	2,510	7
CWLP	W_OP	$15	12.9%	1.6%	916	14.4%	954	39
CWLP	SH_SP	$40	4.5%	0.5%	2,999	5.1%	3,003	5
CWLP	SH_P	$25	4.6%	0.6%	2,836	5.2%	2,841	5
CWLP	SH_OP	$15	11.2%	1.6%	839	12.7%	871	33
DLCO	S_SP1	$100	1.3%	1.5%	1,777	2.8%	1,780	2
DLCO	S_SP2	$75	1.2%	1.5%	1,777	2.8%	1,780	2
DLCO	S_SP3	$50	1.3%	1.6%	1,736	2.8%	1,738	2
DLCO	S_P	$30	1.4%	1.6%	1,654	3.0%	1,657	3
DLCO	S_OP	$20	1.8%	1.6%	1,752	3.4%	1,755	4
DLCO	W_SP	$25	1.7%	2.1%	2,081	3.8%	2,086	5
DLCO	W_P	$20	3.0%	2.2%	2,198	5.2%	2,209	11
DLCO	W_OP	$15	2.1%	2.8%	2,025	4.9%	2,030	5
DLCO	SH_SP	$40	1.4%	2.7%	1,882	4.1%	1,890	8
DLCO	SH_P	$25	1.9%	2.6%	1,880	4.6%	1,890	10
DLCO	SH_OP	$15	3.7%	3.9%	1,700	7.8%	1,724	25
DPL	S_SP1	$100	3.1%	0.6%	1,307	3.7%	1,313	6
DPL	S_SP2	$75	3.0%	0.7%	1,307	3.7%	1,313	6
DPL	S_SP3	$50	3.0%	0.7%	1,301	3.7%	1,307	6
DPL	S_P	$30	3.6%	0.8%	1,224	4.3%	1,232	8
DPL	S_OP	$20	4.9%	0.8%	1,316	5.7%	1,327	11
DPL	W_SP	$25	4.0%	0.8%	1,343	4.7%	1,351	8
DPL	W_P	$20	5.0%	0.9%	1,541	5.8%	1,553	11
DPL	W_OP	$15	8.6%	0.9%	1,211	9.5%	1,227	16
DPL	SH_SP	$40	2.6%	0.9%	1,306	3.5%	1,312	6
DPL	SH_P	$25	4.1%	1.0%	1,227	5.1%	1,236	9
DPL	SH_OP	$15	8.5%	1.4%	1,086	9.9%	1,108	22
DUKE	S_SP1	$100	0.3%	0.2%	5,609	0.5%	5,637	27
DUKE	S_SP2	$75	0.3%	0.2%	5,595	0.5%	5,622	27
DUKE	S_SP3	$50	0.3%	0.2%	5,529	0.5%	5,556	27
DUKE	S_P	$30	0.2%	0.0%	5,473	0.3%	5,501	29
DUKE	S_OP	$20	0.5%	0.0%	5,212	0.5%	5,243	31
DUKE	W_SP	$25	0.5%	0.1%	5,082	0.6%	5,106	25
DUKE	W_P	$20	0.2%	0.1%	4,983	0.3%	5,006	23
DUKE	W_OP	$15	0.3%	0.2%	4,470	0.5%	4,499	29
DUKE	SH_SP	$40	0.4%	0.3%	4,825	0.6%	4,857	31
DUKE	SH_P	$25	0.6%	0.1%	4,628	0.7%	4,662	35
DUKE	SH_OP	$15	2.4%	0.4%	4,353	2.8%	4,400	46
EKPC	S_SP1	$100	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_SP2	$75	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_SP3	$50	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_P	$30	0.5%	0.1%	7,613	0.6%	7,613	0
EKPC	S_OP	$20	0.7%	0.1%	7,644	0.8%	7,644	-1
EKPC	W_SP	$25	0.6%	0.1%	7,617	0.7%	7,618	0
EKPC	W_P	$20	0.8%	0.1%	7,612	0.9%	7,612	0
EKPC	W_OP	$15	1.7%	0.1%	7,362	1.8%	7,362	0
EKPC	SH_SP	$40	0.4%	0.1%	7,387	0.6%	7,387	0
EKPC	SH_P	$25	0.6%	0.1%	7,397	0.8%	7,397	0
EKPC	SH_OP	$15	1.8%	0.2%	7,115	1.9%	7,116	1

Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
ENT	S_SP1	$100	0.1%	3.1%	3,561	3.2%	3,562	1
ENT	S_SP2	$75	0.1%	3.1%	3,561	3.3%	3,562	1
ENT	S_SP3	$50	0.1%	3.1%	3,561	3.3%	3,562	1
ENT	S_P	$30	0.2%	3.1%	3,488	3.2%	3,489	1
ENT	S_OP	$20	0.5%	6.5%	1,135	7.0%	1,142	7
ENT	W_SP	$25	0.3%	2.5%	3,406	2.8%	3,408	2
ENT	W_P	$20	0.3%	6.1%	1,144	6.3%	1,147	3
ENT	W_OP	$15	0.5%	0.2%	1,250	0.7%	1,250	0
ENT	SH_SP	$40	0.1%	3.0%	3,834	3.1%	3,833	-2
ENT	SH_P	$25	0.3%	2.8%	3,467	3.1%	3,466	-1
ENT	SH_OP	$15	2.9%	0.3%	1,343	3.2%	1,342	-1
FENER	S_SP1	$100	1.0%	0.1%	1,929	1.1%	1,929	0
FENER	S_SP2	$75	0.9%	0.1%	1,929	1.0%	1,929	0
FENER	S_SP3	$50	0.9%	0.1%	1,901	1.1%	1,901	0
FENER	S_P	$30	1.1%	0.2%	1,767	1.3%	1,766	0
FENER	S_OP	$20	1.4%	0.1%	1,741	1.5%	1,741	0
FENER	W_SP	$25	1.9%	0.5%	1,723	2.3%	1,722	-1
FENER	W_P	$20	3.1%	0.5%	1,911	3.6%	1,906	-4
FENER	W_OP	$15	7.4%	0.7%	1,664	8.2%	1,665	2
FENER	SH_SP	$40	1.3%	0.6%	1,541	1.9%	1,549	8
FENER	SH_P	$25	2.0%	0.7%	1,503	2.7%	1,511	8
FENER	SH_OP	$15	7.0%	1.2%	1,420	8.2%	1,440	20
HEC	S_SP1	$100	1.9%	1.0%	1,865	2.9%	1,872	7
HEC	S_SP2	$75	1.9%	1.0%	1,865	2.9%	1,872	7
HEC	S_SP3	$50	1.9%	1.0%	1,862	2.9%	1,868	7
HEC	S_P	$30	2.2%	1.2%	1,824	3.3%	1,832	8
HEC	S_OP	$20	4.4%	1.2%	1,916	5.6%	1,930	14
HEC	W_SP	$25	2.0%	1.2%	1,763	3.2%	1,773	11
HEC	W_P	$20	2.9%	1.2%	1,840	4.1%	1,853	14
HEC	W_OP	$15	6.3%	1.6%	1,808	7.8%	1,835	27
HEC	SH_SP	$40	2.1%	1.1%	1,567	3.2%	1,581	13
HEC	SH_P	$25	2.3%	1.3%	1,645	3.6%	1,656	11
HEC	SH_OP	$15	7.5%	1.8%	1,695	9.3%	1,737	42
IP	S_SP1	$100	12.8%	1.7%	1,531	14.3%	1,571	40
IP	S_SP2	$75	12.3%	1.9%	1,520	14.1%	1,564	44
IP	S_SP3	$50	12.4%	1.9%	1,516	14.1%	1,561	44
IP	S_P	$30	11.3%	2.1%	1,467	13.2%	1,511	43
IP	S_OP	$20	12.7%	2.1%	1,497	14.7%	1,548	51
IP	W_SP	$25	11.7%	2.3%	1,480	13.8%	1,529	50
IP	W_P	$20	14.0%	2.3%	1,593	16.2%	1,656	63
IP	W_OP	$15	13.2%	2.8%	996	15.7%	1,065	68
IP	SH_SP	$40	9.4%	2.0%	1,480	11.3%	1,516	36
IP	SH_P	$25	9.4%	2.2%	1,432	11.6%	1,473	41
IP	SH_OP	$15	10.1%	2.7%	928	12.7%	980	52
LGE	S_SP1	$100	3.4%	0.5%	2,398	3.9%	2,401	3
LGE	S_SP2	$75	3.5%	0.6%	2,363	4.1%	2,367	4
LGE	S_SP3	$50	3.6%	0.6%	2,329	4.1%	2,333	4
LGE	S_P	$30	3.6%	0.6%	2,340	4.2%	2,344	4
LGE	S_OP	$20	4.8%	0.7%	2,404	5.5%	2,409	6
LGE	W_SP	$25	2.8%	0.6%	2,376	3.4%	2,384	8
LGE	W_P	$20	4.2%	0.6%	2,445	4.8%	2,448	3
LGE	W_OP	$15	6.3%	0.9%	2,406	7.1%	2,408	1
LGE	SH_SP	$40	2.6%	0.6%	2,128	3.2%	2,130	2
LGE	SH_P	$25	2.9%	0.7%	2,083	3.6%	2,086	3
LGE	SH_OP	$15	6.4%	1.1%	2,141	7.4%	2,147	6

Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
MECS	S_SP1	$100	0.5%	0.8%	3,368	1.3%	3,371	3
MECS	S_SP2	$75	0.5%	0.8%	3,368	1.3%	3,371	3
MECS	S_SP3	$50	0.5%	0.8%	3,359	1.3%	3,362	3
MECS	S_P	$30	0.5%	0.9%	3,366	1.4%	3,369	3
MECS	S_OP	$20	0.8%	0.1%	3,504	0.8%	3,508	4
MECS	W_SP	$25	1.2%	0.9%	2,295	2.1%	2,287	-8
MECS	W_P	$20	2.7%	0.3%	2,259	2.9%	2,243	-17
MECS	W_OP	$15	4.4%	0.5%	2,313	4.9%	2,300	-13
MECS	SH_SP	$40	1.0%	1.0%	2,410	2.2%	2,354	-56
MECS	SH_P	$25	1.3%	1.1%	2,384	2.6%	2,302	-82
MECS	SH_OP	$15	4.7%	0.8%	2,384	6.0%	2,324	-60
MGE	S_SP1	$100	2.2%	0.0%	4,751	2.2%	4,751	0
MGE	S_SP2	$75	2.2%	0.0%	4,751	2.2%	4,751	0
MGE	S_SP3	$50	2.2%	0.0%	4,750	2.2%	4,750	0
MGE	S_P	$30	2.3%	0.1%	4,370	2.4%	4,370	0
MGE	S_OP	$20	3.0%	0.1%	3,983	3.0%	3,983	0
MGE	W_SP	$25	4.3%	0.1%	3,009	4.4%	3,009	1
MGE	W_P	$20	6.2%	0.2%	2,614	6.3%	2,616	2
MGE	W_OP	$15	6.4%	0.3%	2,090	6.7%	2,094	4
MGE	SH_SP	$40	2.8%	0.1%	4,395	2.8%	4,395	0
MGE	SH_P	$25	3.5%	0.1%	3,913	3.5%	3,914	1
MGE	SH_OP	$15	5.1%	0.3%	2,711	5.3%	2,714	3
MIDAM	S_SP1	$100	10.4%	0.2%	1,666	10.4%	1,668	2
MIDAM	S_SP2	$75	10.0%	0.3%	1,658	10.2%	1,664	5
MIDAM	S_SP3	$50	10.1%	0.3%	1,666	10.3%	1,672	5
MIDAM	S_P	$30	9.6%	0.5%	1,469	9.9%	1,475	6
MIDAM	S_OP	$20	7.7%	0.3%	1,596	7.8%	1,600	3
MIDAM	W_SP	$25	9.1%	0.3%	1,351	9.2%	1,357	6
MIDAM	W_P	$20	9.4%	0.3%	1,384	9.5%	1,391	7
MIDAM	W_OP	$15	8.2%	0.5%	1,362	8.5%	1,371	10
MIDAM	SH_SP	$40	8.7%	0.3%	1,432	8.8%	1,438	6
MIDAM	SH_P	$25	9.2%	0.4%	1,260	9.4%	1,267	6
MIDAM	SH_OP	$15	8.4%	0.6%	1,287	8.8%	1,296	9
MPS	S_SP1	$100	2.0%	0.3%	1,879	2.3%	1,880	1
MPS	S_SP2	$75	2.3%	0.3%	1,873	2.6%	1,875	2
MPS	S_SP3	$50	2.3%	0.3%	1,874	2.6%	1,876	2
MPS	S_P	$30	2.0%	0.5%	1,806	2.5%	1,808	2
MPS	S_OP	$20	3.6%	0.2%	1,468	3.7%	1,469	1
MPS	W_SP	$25	2.8%	0.6%	1,572	3.4%	1,576	3
MPS	W_P	$20	4.7%	0.2%	1,459	4.8%	1,460	2
MPS	W_OP	$15	5.7%	0.3%	1,440	5.9%	1,442	2
MPS	SH_SP	$40	1.4%	0.3%	1,883	1.7%	1,884	1
MPS	SH_P	$25	2.6%	0.6%	1,586	3.2%	1,589	3
MPS	SH_OP	$15	4.3%	0.2%	1,456	4.4%	1,457	2
NEPOOL	S_SP1	$100	0.0%	0.0%	1,060	0.0%	1,060	0
NEPOOL	S_SP2	$75	0.0%	0.0%	1,060	0.0%	1,060	0
NEPOOL	S_SP3	$50	0.0%	0.0%	1,058	0.0%	1,058	0
NEPOOL	S_P	$30	0.0%	0.0%	1,077	0.0%	1,077	0
NEPOOL	S_OP	$20	0.0%	0.0%	1,097	0.0%	1,097	0
NEPOOL	W_SP	$25	0.0%	0.0%	1,066	0.0%	1,066	0
NEPOOL	W_P	$20	0.0%	0.0%	1,126	0.0%	1,126	0
NEPOOL	W_OP	$15	0.0%	0.0%	2,319	0.0%	2,319	0
NEPOOL	SH_SP	$40	0.0%	0.0%	1,073	0.0%	1,073	0
NEPOOL	SH_P	$25	0.0%	0.0%	1,059	0.0%	1,059	0
NEPOOL	SH_OP	$15	0.0%	0.0%	2,269	0.0%	2,269	0

Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
NIPS	S_SP1	$100	13.3%	0.3%	2,454	13.4%	2,491	37
NIPS	S_SP2	$75	12.8%	0.5%	2,443	13.1%	2,485	42
NIPS	S_SP3	$50	12.9%	0.5%	2,418	13.2%	2,460	42
NIPS	S_P	$30	11.6%	0.6%	2,231	12.0%	2,272	41
NIPS	S_OP	$20	12.1%	0.6%	2,187	12.5%	2,228	42
NIPS	W_SP	$25	9.4%	0.6%	1,522	9.9%	1,533	11
NIPS	W_P	$20	12.8%	0.9%	1,621	13.5%	1,640	19
NIPS	W_OP	$15	11.3%	1.1%	1,487	12.2%	1,507	20
NIPS	SH_SP	$40	12.1%	0.7%	1,479	12.6%	1,492	13
NIPS	SH_P	$25	9.6%	0.7%	1,410	10.1%	1,421	11
NIPS	SH_OP	$15	11.3%	1.5%	1,404	12.6%	1,434	29
NSP	S_SP1	$100	1.8%	0.1%	2,614	1.8%	2,614	0
NSP	S_SP2	$75	1.7%	0.1%	2,614	1.8%	2,614	0
NSP	S_SP3	$50	1.8%	0.1%	2,329	1.9%	2,329	0
NSP	S_P	$30	1.9%	0.1%	2,250	2.0%	2,251	0
NSP	S_OP	$20	3.1%	0.1%	2,468	3.2%	2,469	1
NSP	W_SP	$25	2.5%	0.1%	2,054	2.6%	2,054	1
NSP	W_P	$20	3.9%	0.2%	2,220	4.0%	2,221	1
NSP	W_OP	$15	5.2%	0.3%	2,762	5.3%	2,765	3
NSP	SH_SP	$40	2.6%	0.1%	1,877	2.7%	1,878	0
NSP	SH_P	$25	3.1%	0.2%	1,912	3.2%	1,913	1
NSP	SH_OP	$15	6.0%	0.3%	2,609	6.2%	2,612	3
NYPP	S_SP1	$100	0.0%	0.9%	947	0.9%	947	0
NYPP	S_SP2	$75	0.0%	0.9%	947	0.9%	947	0
NYPP	S_SP3	$50	0.0%	0.9%	961	0.9%	961	0
NYPP	S_P	$30	0.0%	1.0%	980	1.0%	980	0
NYPP	S_OP	$20	0.0%	0.9%	1,000	0.9%	1,000	0
NYPP	W_SP	$25	0.0%	0.5%	981	0.5%	981	0
NYPP	W_P	$20	0.0%	0.7%	1,079	0.7%	1,079	0
NYPP	W_OP	$15	0.0%	1.0%	1,478	1.0%	1,478	0
NYPP	SH_SP	$40	0.0%	1.7%	893	1.7%	893	0
NYPP	SH_P	$25	0.0%	1.7%	823	1.8%	823	0
NYPP	SH_OP	$15	0.0%	3.9%	1,105	4.0%	1,105	0
SCEG	S_SP1	$100	0.3%	0.3%	2,939	0.6%	2,940	1
SCEG	S_SP2	$75	0.3%	0.4%	2,939	0.6%	2,940	1
SCEG	S_SP3	$50	0.3%	0.4%	2,876	0.6%	2,877	1
SCEG	S_P	$30	0.4%	0.0%	2,776	0.4%	2,777	1
SCEG	S_OP	$20	0.7%	0.0%	2,706	0.7%	2,708	1
SCEG	W_SP	$25	0.5%	0.0%	2,984	0.5%	2,985	1
SCEG	W_P	$20	0.4%	0.2%	2,942	0.6%	2,942	0
SCEG	W_OP	$15	1.2%	0.1%	1,353	1.3%	1,356	3
SCEG	SH_SP	$40	0.3%	0.4%	2,290	0.7%	2,291	2
SCEG	SH_P	$25	0.6%	0.0%	2,208	0.7%	2,210	1
SCEG	SH_OP	$15	1.1%	0.3%	1,178	1.4%	1,184	6
SCPSA	S_SP1	$100	0.3%	0.3%	1,821	0.6%	1,823	2
SCPSA	S_SP2	$75	0.3%	0.3%	1,821	0.6%	1,823	2
SCPSA	S_SP3	$50	0.3%	0.3%	1,809	0.7%	1,811	2
SCPSA	S_P	$30	0.5%	0.0%	1,786	0.5%	1,788	2
SCPSA	S_OP	$20	0.7%	0.0%	1,723	0.7%	1,725	2
SCPSA	W_SP	$25	0.6%	0.0%	1,939	0.6%	1,940	1
SCPSA	W_P	$20	0.5%	0.2%	1,904	0.6%	1,909	5
SCPSA	W_OP	$15	0.6%	0.1%	1,868	0.7%	1,870	2
SCPSA	SH_SP	$40	0.4%	0.4%	1,567	0.8%	1,569	2
SCPSA	SH_P	$25	0.8%	0.0%	1,572	0.8%	1,574	2
SCPSA	SH_OP	$15	0.6%	0.3%	1,468	0.9%	1,471	3

Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
SOCO	S_SP1	$100	0.0%	2.4%	5,929	2.4%	5,938	9
SOCO	S_SP2	$75	0.0%	2.4%	5,929	2.4%	5,938	9
SOCO	S_SP3	$50	0.0%	2.4%	5,891	2.4%	5,900	9
SOCO	S_P	$30	0.1%	2.5%	5,752	2.6%	5,761	9
SOCO	S_OP	$20	0.1%	0.0%	6,162	0.1%	6,172	11
SOCO	W_SP	$25	0.2%	2.4%	5,257	2.6%	5,265	8
SOCO	W_P	$20	0.8%	0.0%	5,581	0.8%	5,591	9
SOCO	W_OP	$15	3.3%	0.1%	3,180	3.5%	3,184	5
SOCO	SH_SP	$40	0.1%	2.4%	5,086	2.5%	5,098	12
SOCO	SH_P	$25	0.1%	0.2%	5,283	0.3%	5,297	13
SOCO	SH_OP	$15	3.7%	0.1%	2,721	3.7%	2,738	17
TVA	S_SP1	$100	2.4%	0.2%	5,124	2.7%	5,126	2
TVA	S_SP2	$75	2.4%	0.3%	5,124	2.6%	5,126	2
TVA	S_SP3	$50	2.4%	0.3%	5,124	2.6%	5,126	2
TVA	S_P	$30	2.5%	0.3%	5,139	2.8%	5,152	14
TVA	S_OP	$20	2.5%	0.3%	5,661	2.7%	5,678	17
TVA	W_SP	$25	1.6%	0.2%	4,393	1.8%	4,405	11
TVA	W_P	$20	1.1%	0.1%	5,447	1.1%	5,463	15
TVA	W_OP	$15	3.3%	0.5%	5,068	3.8%	5,088	20
TVA	SH_SP	$40	1.7%	0.2%	4,245	1.9%	4,250	6
TVA	SH_P	$25	1.7%	0.2%	4,584	1.9%	4,591	7
TVA	SH_OP	$15	3.4%	0.7%	4,810	4.1%	4,823	13
UPP	S_SP1	$100	0.2%	0.0%	3,273	0.2%	3,272	-1
UPP	S_SP2	$75	0.2%	0.0%	3,273	0.2%	3,272	-1
UPP	S_SP3	$50	0.2%	0.0%	3,273	0.2%	3,272	-1
UPP	S_P	$30	0.3%	0.0%	3,604	0.3%	3,603	-2
UPP	S_OP	$20	0.6%	0.0%	4,757	0.6%	4,753	-4
UPP	W_SP	$25	3.6%	0.1%	2,243	3.7%	2,243	0
UPP	W_P	$20	6.7%	0.2%	2,059	6.8%	2,061	2
UPP	W_OP	$15	8.5%	0.3%	2,276	8.8%	2,280	5
UPP	SH_SP	$40	0.0%	0.0%	5,018	0.0%	5,018	0
UPP	SH_P	$25	0.0%	0.0%	6,258	0.0%	6,258	0
UPP	SH_OP	$15	0.0%	0.0%	7,959	0.0%	7,959	0
VP	S_SP1	$100	0.8%	0.2%	1,984	0.9%	1,984	0
VP	S_SP2	$75	0.7%	0.2%	1,984	0.9%	1,985	0
VP	S_SP3	$50	0.7%	0.2%	1,951	0.9%	1,952	0
VP	S_P	$30	0.8%	0.1%	1,906	1.0%	1,907	0
VP	S_OP	$20	1.4%	0.1%	1,821	1.5%	1,821	0
VP	W_SP	$25	1.4%	0.4%	1,821	1.8%	1,819	-2
VP	W_P	$20	3.0%	0.4%	2,002	3.4%	1,996	-5
VP	W_OP	$15	7.9%	0.7%	1,743	8.4%	1,748	5
VP	SH_SP	$40	0.9%	0.6%	1,596	1.6%	1,604	8
VP	SH_P	$25	1.7%	0.7%	1,536	2.4%	1,544	8
VP	SH_OP	$15	8.0%	1.2%	1,373	8.9%	1,392	19
WEP	S_SP1	$100	1.0%	0.0%	8,506	1.0%	8,497	-9
WEP	S_SP2	$75	0.9%	0.0%	8,506	1.0%	8,497	-9
WEP	S_SP3	$50	0.9%	0.0%	8,506	1.0%	8,497	-9
WEP	S_P	$30	0.8%	0.0%	8,601	0.9%	8,593	-8
WEP	S_OP	$20	1.2%	0.0%	8,470	1.2%	8,460	-10
WEP	W_SP	$25	5.9%	0.1%	3,787	6.0%	3,787	0
WEP	W_P	$20	7.2%	0.2%	3,550	7.2%	3,550	0
WEP	W_OP	$15	6.7%	0.3%	2,992	6.9%	2,994	2
WEP	SH_SP	$40	7.7%	0.2%	3,422	7.8%	3,427	5
WEP	SH_P	$25	7.6%	0.2%	3,356	7.7%	3,361	5
WEP	SH_OP	$15	7.8%	0.4%	2,516	8.0%	2,523	7

Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
WPS	S_SP1	$100	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_SP2	$75	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_SP3	$50	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_P	$30	0.6%	0.0%	5,994	0.6%	5,994	0
WPS	S_OP	$20	0.8%	0.0%	6,427	0.8%	6,427	0
WPS	W_SP	$25	2.2%	0.1%	3,648	2.2%	3,648	0
WPS	W_P	$20	2.7%	0.1%	3,753	2.8%	3,753	0
WPS	W_OP	$15	3.2%	0.2%	4,218	3.3%	4,219	1
WPS	SH_SP	$40	1.3%	0.0%	3,808	1.3%	3,808	0
WPS	SH_P	$25	2.0%	0.0%	3,611	2.0%	3,611	0
WPS	SH_OP	$15	4.1%	0.2%	4,238	4.2%	4,239	1
WR	S_SP1	$100	0.4%	0.4%	6,016	0.8%	6,016	0
WR	S_SP2	$75	0.5%	0.4%	6,014	0.8%	6,015	0
WR	S_SP3	$50	0.5%	0.4%	6,014	0.9%	6,015	0
WR	S_P	$30	0.8%	0.4%	5,128	1.2%	5,129	1
WR	S_OP	$20	1.5%	0.8%	4,557	2.2%	4,559	2
WR	W_SP	$25	1.4%	0.4%	5,027	1.8%	5,028	1
WR	W_P	$20	2.4%	0.1%	4,473	2.4%	4,474	1
WR	W_OP	$15	3.1%	0.1%	4,500	3.2%	4,501	1
WR	SH_SP	$40	0.6%	0.3%	5,037	0.9%	5,037	0
WR	SH_P	$25	1.2%	0.5%	4,805	1.7%	4,806	1
WR	SH_OP	$15	2.4%	0.1%	4,243	2.5%	4,243	0

Competitive Analysis Screening Model (CASm)
HHI Report
Unicom/PECO Market Power Analysis
Economic Capacity
No Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
COMED	S_SP1	$100	75.7%	0.1%	5,791	75.8%	5,811	20
COMED	S_SP2	$75	73.1%	1.4%	5,419	73.3%	5,438	19
COMED	S_SP3	$50	73.2%	1.4%	5,429	73.3%	5,448	19
COMED	S_P	$30	63.8%	1.4%	4,238	63.9%	4,255	18
COMED	S_OP	$20	71.0%	1.8%	5,136	71.2%	5,165	29
COMED	W_SP	$25	65.9%	1.5%	4,504	66.1%	4,526	21
COMED	W_P	$20	73.2%	1.8%	5,407	73.4%	5,445	38
COMED	W_OP	$15	67.7%	2.0%	4,657	68.1%	4,714	57
COMED	SH_SP	$40	66.0%	1.4%	4,453	66.2%	4,471	18
COMED	SH_P	$25	63.4%	1.7%	4,179	63.5%	4,201	22
COMED	SH_OP	$15	64.6%	2.3%	4,254	65.1%	4,320	66
PJM_ALL	S_SP1	$100	0.0%	11.7%	933	11.7%	933	0
PJM_ALL	S_SP2	$75	0.0%	11.7%	929	11.7%	929	0
PJM_ALL	S_SP3	$50	0.0%	11.8%	932	11.8%	932	0
PJM_ALL	S_P	$30	0.0%	12.7%	864	12.7%	864	0
PJM_ALL	S_OP	$20	0.1%	10.5%	874	10.6%	876	2
PJM_ALL	W_SP	$25	0.0%	12.0%	841	12.0%	841	0
PJM_ALL	W_P	$20	0.0%	11.0%	872	11.0%	871	-1
PJM_ALL	W_OP	$15	0.1%	11.9%	877	11.9%	877	0
PJM_ALL	SH_SP	$40	0.0%	12.1%	869	12.1%	869	0
PJM_ALL	SH_P	$25	0.0%	11.4%	806	11.4%	806	0
PJM_ALL	SH_OP	$15	0.1%	11.2%	842	11.1%	842	0
PJM_C+E	S_SP1	$100	0.0%	15.7%	1,280	15.7%	1,280	1
PJM_C+E	S_SP2	$75	0.0%	15.7%	1,271	15.8%	1,272	1
PJM_C+E	S_SP3	$50	0.0%	15.9%	1,281	16.0%	1,281	1
PJM_C+E	S_P	$30	0.0%	17.4%	1,173	17.5%	1,175	1
PJM_C+E	S_OP	$20	0.1%	14.6%	1,163	14.7%	1,166	3
PJM_C+E	W_SP	$25	0.1%	16.2%	1,116	16.3%	1,119	3
PJM_C+E	W_P	$20	0.1%	15.2%	1,196	15.3%	1,199	4
PJM_C+E	W_OP	$15	0.2%	15.6%	1,133	15.7%	1,137	4
PJM_C+E	SH_SP	$40	0.1%	16.3%	1,107	16.3%	1,109	2
PJM_C+E	SH_P	$25	0.1%	14.9%	1,032	15.0%	1,035	3
PJM_C+E	SH_OP	$15	0.2%	14.4%	1,009	14.5%	1,012	3
PJM_EAST	S_SP1	$100	0.0%	17.0%	1,396	17.0%	1,396	0
PJM_EAST	S_SP2	$75	0.0%	17.1%	1,383	17.1%	1,383	0
PJM_EAST	S_SP3	$50	0.0%	17.3%	1,392	17.3%	1,392	0
PJM_EAST	S_P	$30	0.0%	19.4%	1,270	19.5%	1,270	1
PJM_EAST	S_OP	$20	0.0%	16.2%	1,222	16.2%	1,224	2
PJM_EAST	W_SP	$25	0.0%	19.0%	1,237	19.0%	1,239	2
PJM_EAST	W_P	$20	0.2%	17.5%	1,297	17.7%	1,303	6
PJM_EAST	W_OP	$15	0.7%	18.7%	1,331	19.4%	1,357	25
PJM_EAST	SH_SP	$40	0.0%	18.2%	1,240	18.2%	1,240	1
PJM_EAST	SH_P	$25	0.0%	17.1%	1,088	17.2%	1,090	2
PJM_EAST	SH_OP	$15	0.7%	16.3%	1,124	17.0%	1,146	22
PJM_W+C+E	S_SP1	$100	0.0%	11.7%	921	11.7%	921	0
PJM_W+C+E	S_SP2	$75	0.0%	11.7%	917	11.7%	917	0
PJM_W+C+E	S_SP3	$50	0.0%	11.8%	920	11.8%	920	0
PJM_W+C+E	S_P	$30	0.0%	12.8%	851	12.8%	851	0
PJM_W+C+E	S_OP	$20	0.1%	10.5%	858	10.6%	860	2
PJM_W+C+E	W_SP	$25	0.1%	12.4%	846	12.5%	848	2
PJM_W+C+E	W_P	$20	0.1%	11.5%	863	11.6%	865	2
PJM_W+C+E	W_OP	$15	0.1%	12.0%	849	12.0%	850	1
PJM_W+C+E	SH_SP	$40	0.0%	12.0%	851	12.0%	851	0
PJM_W+C+E	SH_P	$25	0.0%	11.3%	794	11.3%	794	0
PJM_W+C+E	SH_OP	$15	0.1%	11.1%	823	11.1%	824	1

Economic Capacity
No Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
AECI	S_SP1	$100	2.6%	0.6%	1,210	3.3%	1,214	3
AECI	S_SP2	$75	2.6%	0.7%	1,209	3.2%	1,212	3
AECI	S_SP3	$50	2.6%	0.7%	1,211	3.2%	1,215	3
AECI	S_P	$30	2.7%	0.7%	1,253	3.4%	1,257	4
AECI	S_OP	$20	3.9%	1.1%	1,194	4.9%	1,201	8
AECI	W_SP	$25	1.8%	0.8%	1,502	2.6%	1,505	3
AECI	W_P	$20	2.4%	1.1%	1,486	3.4%	1,491	5
AECI	W_OP	$15	5.1%	0.2%	602	5.2%	602	1
AECI	SH_SP	$40	1.9%	0.7%	1,291	2.5%	1,293	2
AECI	SH_P	$25	2.7%	1.1%	1,292	3.7%	1,298	5
AECI	SH_OP	$15	6.0%	0.3%	554	6.1%	555	1
ALLIANT_E	S_SP1	$100	10.8%	0.0%	2,763	10.8%	2,763	1
ALLIANT_E	S_SP2	$75	10.4%	0.2%	2,755	10.5%	2,755	1
ALLIANT_E	S_SP3	$50	10.8%	0.2%	2,614	10.9%	2,615	1
ALLIANT_E	S_P	$30	9.8%	0.2%	2,495	9.9%	2,496	1
ALLIANT_E	S_OP	$20	11.7%	0.3%	2,273	11.8%	2,274	1
ALLIANT_E	W_SP	$25	8.9%	0.2%	1,755	9.0%	1,755	1
ALLIANT_E	W_P	$20	10.5%	0.3%	1,642	10.5%	1,643	1
ALLIANT_E	W_OP	$15	8.7%	0.4%	1,615	8.8%	1,616	1
ALLIANT_E	SH_SP	$40	7.3%	0.2%	1,707	7.3%	1,708	0
ALLIANT_E	SH_P	$25	7.5%	0.2%	1,606	7.5%	1,607	0
ALLIANT_E	SH_OP	$15	7.6%	0.4%	1,539	7.7%	1,540	1
ALLIANT_W	S_SP1	$100	11.7%	0.2%	1,194	11.9%	1,198	4
ALLIANT_W	S_SP2	$75	11.3%	0.4%	1,185	11.5%	1,188	4
ALLIANT_W	S_SP3	$50	11.5%	0.4%	1,187	11.6%	1,190	4
ALLIANT_W	S_P	$30	11.2%	0.5%	1,072	11.5%	1,077	5
ALLIANT_W	S_OP	$20	14.1%	0.4%	1,267	14.2%	1,271	4
ALLIANT_W	W_SP	$25	10.7%	0.5%	962	11.0%	968	6
ALLIANT_W	W_P	$20	11.4%	0.5%	1,129	11.6%	1,133	5
ALLIANT_W	W_OP	$15	10.2%	0.6%	1,097	10.5%	1,102	5
ALLIANT_W	SH_SP	$40	9.7%	0.4%	1,007	9.9%	1,010	4
ALLIANT_W	SH_P	$25	10.6%	0.5%	981	10.9%	987	5
ALLIANT_W	SH_OP	$15	9.8%	0.6%	1,058	10.0%	1,062	4
AMEREN	S_SP1	$100	4.0%	0.5%	2,108	4.5%	2,112	4
AMEREN	S_SP2	$75	5.5%	0.6%	2,051	6.0%	2,057	6
AMEREN	S_SP3	$50	5.5%	0.6%	2,044	6.1%	2,050	6
AMEREN	S_P	$30	3.5%	0.7%	2,042	4.1%	2,046	4
AMEREN	S_OP	$20	4.2%	0.9%	2,247	5.0%	2,254	7
AMEREN	W_SP	$25	3.3%	0.7%	2,078	3.9%	2,082	4
AMEREN	W_P	$20	3.9%	0.9%	2,338	4.7%	2,344	6
AMEREN	W_OP	$15	3.2%	0.5%	2,543	3.6%	2,546	3
AMEREN	SH_SP	$40	3.9%	0.7%	1,798	4.5%	1,803	5
AMEREN	SH_P	$25	3.2%	0.9%	1,850	4.1%	1,856	5
AMEREN	SH_OP	$15	6.5%	0.7%	2,078	7.0%	2,084	6
AEP	S_SP1	$100	3.5%	0.3%	1,724	3.9%	1,727	2
AEP	S_SP2	$75	3.4%	0.4%	1,724	3.7%	1,726	2
AEP	S_SP3	$50	3.4%	0.4%	1,719	3.8%	1,721	3
AEP	S_P	$30	2.8%	0.7%	1,673	3.5%	1,677	4
AEP	S_OP	$20	3.3%	0.5%	1,958	3.7%	1,960	3
AEP	W_SP	$25	0.2%	0.5%	1,680	0.7%	1,680	0
AEP	W_P	$20	0.9%	0.5%	1,879	1.4%	1,880	1
AEP	W_OP	$15	1.2%	0.7%	2,451	1.6%	2,452	1
AEP	SH_SP	$40	1.1%	1.0%	1,323	2.1%	1,325	2
AEP	SH_P	$25	1.1%	0.9%	1,440	1.9%	1,442	2
AEP	SH_OP	$15	0.1%	0.9%	2,174	0.8%	2,174	0

Economic Capacity
No Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
APS	S_SP1	$100	0.7%	0.1%	1,939	0.9%	1,939	0
APS	S_SP2	$75	0.7%	0.1%	1,939	0.9%	1,940	0
APS	S_SP3	$50	0.7%	0.2%	1,909	0.9%	1,909	0
APS	S_P	$30	0.9%	0.2%	1,764	1.1%	1,764	0
APS	S_OP	$20	1.4%	0.1%	1,777	1.5%	1,777	0
APS	W_SP	$25	1.5%	0.4%	1,733	1.9%	1,734	1
APS	W_P	$20	0.3%	0.4%	1,958	0.7%	1,958	0
APS	W_OP	$15	6.5%	0.8%	1,691	7.2%	1,700	9
APS	SH_SP	$40	1.0%	0.6%	1,559	1.5%	1,561	1
APS	SH_P	$25	1.6%	0.6%	1,520	2.2%	1,522	2
APS	SH_OP	$15	4.1%	1.3%	1,352	5.3%	1,361	10
CAPO	S_SP1	$100	0.7%	0.1%	4,217	0.8%	4,217	0
CAPO	S_SP2	$75	0.7%	0.1%	4,217	0.8%	4,217	0
CAPO	S_SP3	$50	0.7%	0.1%	4,154	0.8%	4,155	0
CAPO	S_P	$30	0.8%	0.1%	3,979	0.9%	3,979	0
CAPO	S_OP	$20	1.1%	0.1%	3,640	1.2%	3,640	0
CAPO	W_SP	$25	1.0%	0.1%	4,203	1.1%	4,203	0
CAPO	W_P	$20	1.6%	0.2%	3,844	1.8%	3,845	0
CAPO	W_OP	$15	3.7%	0.4%	3,320	4.0%	3,323	2
CAPO	SH_SP	$40	0.7%	0.3%	3,299	1.0%	3,299	0
CAPO	SH_P	$25	1.0%	0.2%	2,875	1.2%	2,876	0
CAPO	SH_OP	$15	4.1%	0.7%	2,598	4.7%	2,603	5
CELE	S_SP1	$100	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_SP2	$75	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_SP3	$50	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_P	$30	0.1%	0.8%	7,012	0.9%	7,013	0
CELE	S_OP	$20	0.6%	3.9%	3,187	4.5%	3,192	5
CELE	W_SP	$25	0.2%	1.1%	5,383	1.3%	5,383	0
CELE	W_P	$20	1.3%	4.2%	1,832	5.5%	1,843	11
CELE	W_OP	$15	2.7%	0.0%	1,836	2.8%	1,836	0
CELE	SH_SP	$40	0.1%	0.9%	5,982	1.0%	5,982	0
CELE	SH_P	$25	0.2%	1.1%	5,871	1.3%	5,872	0
CELE	SH_OP	$15	2.0%	0.0%	2,166	2.0%	2,166	0
CILCO	S_SP1	$100	12.8%	0.4%	2,002	13.3%	2,014	12
CILCO	S_SP2	$75	12.4%	0.7%	1,989	12.9%	2,000	11
CILCO	S_SP3	$50	12.4%	0.7%	1,990	12.9%	2,001	11
CILCO	S_P	$30	11.1%	0.7%	1,983	11.6%	1,994	11
CILCO	S_OP	$20	12.3%	0.7%	2,027	12.7%	2,037	10
CILCO	W_SP	$25	10.5%	0.8%	2,014	11.1%	2,025	11
CILCO	W_P	$20	12.0%	0.8%	2,087	12.6%	2,101	14
CILCO	W_OP	$15	17.5%	1.7%	1,058	18.6%	1,094	36
CILCO	SH_SP	$40	10.7%	0.7%	1,961	11.2%	1,971	9
CILCO	SH_P	$25	10.2%	0.8%	1,968	10.7%	1,978	11
CILCO	SH_OP	$15	15.4%	1.6%	832	16.3%	860	28
CIN	S_SP1	$100	2.1%	1.6%	1,978	3.8%	1,985	7
CIN	S_SP2	$75	2.3%	1.6%	1,978	3.9%	1,985	7
CIN	S_SP3	$50	2.3%	1.7%	1,971	3.9%	1,978	7
CIN	S_P	$30	2.6%	1.7%	1,877	4.2%	1,886	8
CIN	S_OP	$20	4.1%	1.9%	2,075	5.9%	2,090	15
CIN	W_SP	$25	2.5%	1.8%	1,707	4.3%	1,715	9
CIN	W_P	$20	4.0%	2.1%	1,969	6.0%	1,985	15
CIN	W_OP	$15	3.7%	2.8%	2,459	6.3%	2,477	18
CIN	SH_SP	$40	2.2%	1.8%	1,622	4.0%	1,629	8
CIN	SH_P	$25	2.7%	1.9%	1,595	4.6%	1,605	10
CIN	SH_OP	$15	4.8%	3.2%	2,256	7.8%	2,283	27

Economic Capacity
No Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
CWLP	S_SP1	$100	5.8%	0.5%	2,516	6.3%	2,521	5
CWLP	S_SP2	$75	5.6%	0.6%	2,511	6.1%	2,516	5
CWLP	S_SP3	$50	5.6%	0.6%	2,513	6.1%	2,518	5
CWLP	S_P	$30	5.1%	0.6%	2,500	5.7%	2,506	5
CWLP	S_OP	$20	6.4%	0.6%	1,972	6.9%	1,978	6
CWLP	W_SP	$25	4.9%	0.6%	3,082	5.4%	3,087	5
CWLP	W_P	$20	5.8%	0.6%	2,503	6.3%	2,508	5
CWLP	W_OP	$15	12.9%	1.6%	916	14.1%	945	29
CWLP	SH_SP	$40	4.5%	0.5%	2,999	5.0%	3,003	4
CWLP	SH_P	$25	4.6%	0.6%	2,836	5.1%	2,840	5
CWLP	SH_OP	$15	11.2%	1.6%	839	12.3%	863	24
DLCO	S_SP1	$100	1.3%	1.5%	1,777	2.8%	1,781	4
DLCO	S_SP2	$75	1.2%	1.5%	1,777	2.8%	1,781	4
DLCO	S_SP3	$50	1.3%	1.6%	1,736	2.8%	1,740	4
DLCO	S_P	$30	1.4%	1.6%	1,654	3.0%	1,659	4
DLCO	S_OP	$20	1.8%	1.6%	1,752	3.4%	1,757	6
DLCO	W_SP	$25	1.7%	2.1%	2,081	3.8%	2,088	7
DLCO	W_P	$20	3.0%	2.2%	2,198	5.1%	2,210	12
DLCO	W_OP	$15	2.1%	2.8%	2,025	4.7%	2,034	10
DLCO	SH_SP	$40	1.4%	2.7%	1,882	4.0%	1,889	7
DLCO	SH_P	$25	1.9%	2.6%	1,880	4.4%	1,889	9
DLCO	SH_OP	$15	3.7%	3.9%	1,700	7.4%	1,725	26
DPL	S_SP1	$100	3.1%	0.6%	1,307	3.8%	1,311	4
DPL	S_SP2	$75	3.0%	0.7%	1,307	3.7%	1,311	4
DPL	S_SP3	$50	3.0%	0.7%	1,301	3.7%	1,305	4
DPL	S_P	$30	3.6%	0.8%	1,224	4.3%	1,229	5
DPL	S_OP	$20	4.9%	0.8%	1,316	5.7%	1,324	7
DPL	W_SP	$25	4.0%	0.8%	1,343	4.7%	1,349	6
DPL	W_P	$20	5.0%	0.9%	1,541	5.8%	1,549	8
DPL	W_OP	$15	8.6%	0.9%	1,211	9.3%	1,222	12
DPL	SH_SP	$40	2.6%	0.9%	1,306	3.4%	1,311	4
DPL	SH_P	$25	4.1%	1.0%	1,227	5.0%	1,235	7
DPL	SH_OP	$15	8.5%	1.4%	1,086	9.6%	1,104	18
DUKE	S_SP1	$100	0.3%	0.2%	5,609	0.5%	5,609	0
DUKE	S_SP2	$75	0.3%	0.2%	5,595	0.5%	5,595	0
DUKE	S_SP3	$50	0.3%	0.2%	5,529	0.5%	5,529	0
DUKE	S_P	$30	0.2%	0.0%	5,473	0.3%	5,473	0
DUKE	S_OP	$20	0.5%	0.0%	5,212	0.5%	5,212	0
DUKE	W_SP	$25	0.5%	0.1%	5,082	0.6%	5,082	0
DUKE	W_P	$20	0.2%	0.1%	4,983	0.3%	4,983	0
DUKE	W_OP	$15	0.3%	0.2%	4,470	0.4%	4,470	0
DUKE	SH_SP	$40	0.4%	0.3%	4,825	0.6%	4,826	0
DUKE	SH_P	$25	0.6%	0.1%	4,628	0.7%	4,628	0
DUKE	SH_OP	$15	2.4%	0.4%	4,353	2.7%	4,355	1
EKPC	S_SP1	$100	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_SP2	$75	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_SP3	$50	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_P	$30	0.5%	0.1%	7,613	0.6%	7,613	0
EKPC	S_OP	$20	0.7%	0.1%	7,644	0.8%	7,644	0
EKPC	W_SP	$25	0.6%	0.1%	7,617	0.7%	7,617	0
EKPC	W_P	$20	0.8%	0.1%	7,612	0.9%	7,612	0
EKPC	W_OP	$15	1.7%	0.1%	7,362	1.8%	7,362	0
EKPC	SH_SP	$40	0.4%	0.1%	7,387	0.5%	7,387	0
EKPC	SH_P	$25	0.6%	0.1%	7,397	0.8%	7,397	0
EKPC	SH_OP	$15	1.8%	0.2%	7,115	1.9%	7,116	0

Economic Capacity
No Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
ENT	S_SP1	$100	0.1%	3.1%	3,561	3.2%	3,562	1
ENT	S_SP2	$75	0.1%	3.1%	3,561	3.3%	3,562	1
ENT	S_SP3	$50	0.1%	3.1%	3,561	3.3%	3,562	1
ENT	S_P	$30	0.2%	3.1%	3,488	3.2%	3,488	1
ENT	S_OP	$20	0.5%	6.5%	1,135	7.0%	1,142	7
ENT	W_SP	$25	0.3%	2.5%	3,406	2.8%	3,408	1
ENT	W_P	$20	0.3%	6.1%	1,144	6.3%	1,147	3
ENT	W_OP	$15	0.5%	0.2%	1,250	0.7%	1,250	0
ENT	SH_SP	$40	0.1%	3.0%	3,834	3.1%	3,835	1
ENT	SH_P	$25	0.3%	2.8%	3,467	3.1%	3,469	2
ENT	SH_OP	$15	2.9%	0.3%	1,343	3.1%	1,344	1
FENER	S_SP1	$100	1.0%	0.1%	1,929	1.1%	1,929	0
FENER	S_SP2	$75	0.9%	0.1%	1,929	1.0%	1,929	0
FENER	S_SP3	$50	0.9%	0.1%	1,901	1.1%	1,902	0
FENER	S_P	$30	1.1%	0.2%	1,767	1.3%	1,767	0
FENER	S_OP	$20	1.4%	0.1%	1,741	1.5%	1,742	0
FENER	W_SP	$25	1.9%	0.5%	1,723	2.3%	1,725	2
FENER	W_P	$20	3.1%	0.5%	1,911	3.6%	1,913	3
FENER	W_OP	$15	7.4%	0.7%	1,664	8.0%	1,672	8
FENER	SH_SP	$40	1.3%	0.6%	1,541	1.9%	1,543	1
FENER	SH_P	$25	2.0%	0.7%	1,503	2.6%	1,505	2
FENER	SH_OP	$15	7.0%	1.2%	1,420	8.0%	1,434	14
HEC	S_SP1	$100	1.9%	1.0%	1,865	3.0%	1,869	4
HEC	S_SP2	$75	1.9%	1.0%	1,865	2.9%	1,869	4
HEC	S_SP3	$50	1.9%	1.0%	1,862	2.9%	1,865	4
HEC	S_P	$30	2.2%	1.2%	1,824	3.3%	1,829	5
HEC	S_OP	$20	4.4%	1.2%	1,916	5.6%	1,927	10
HEC	W_SP	$25	2.0%	1.2%	1,763	3.2%	1,767	5
HEC	W_P	$20	2.9%	1.2%	1,840	4.1%	1,846	7
HEC	W_OP	$15	6.3%	1.6%	1,808	7.8%	1,826	19
HEC	SH_SP	$40	2.1%	1.1%	1,567	3.2%	1,572	4
HEC	SH_P	$25	2.3%	1.3%	1,645	3.5%	1,650	6
HEC	SH_OP	$15	7.5%	1.8%	1,695	9.2%	1,720	25
IP	S_SP1	$100	12.8%	1.7%	1,531	14.5%	1,575	44
IP	S_SP2	$75	12.3%	1.9%	1,520	14.1%	1,562	42
IP	S_SP3	$50	12.4%	1.9%	1,516	14.1%	1,559	42
IP	S_P	$30	11.3%	2.1%	1,467	13.1%	1,508	40
IP	S_OP	$20	12.7%	2.1%	1,497	14.6%	1,543	47
IP	W_SP	$25	11.7%	2.3%	1,480	13.7%	1,525	46
IP	W_P	$20	14.0%	2.3%	1,593	16.1%	1,648	56
IP	W_OP	$15	13.2%	2.8%	996	15.5%	1,055	59
IP	SH_SP	$40	9.4%	2.0%	1,480	11.2%	1,513	33
IP	SH_P	$25	9.4%	2.2%	1,432	11.4%	1,469	37
IP	SH_OP	$15	10.1%	2.7%	928	12.4%	973	45
LGE	S_SP1	$100	3.4%	0.5%	2,398	3.9%	2,402	3
LGE	S_SP2	$75	3.5%	0.6%	2,363	4.0%	2,366	3
LGE	S_SP3	$50	3.6%	0.6%	2,329	4.1%	2,333	4
LGE	S_P	$30	3.6%	0.6%	2,340	4.1%	2,344	4
LGE	S_OP	$20	4.8%	0.7%	2,404	5.4%	2,409	6
LGE	W_SP	$25	2.8%	0.6%	2,376	3.4%	2,379	3
LGE	W_P	$20	4.2%	0.6%	2,445	4.8%	2,449	4
LGE	W_OP	$15	6.3%	0.9%	2,406	7.0%	2,416	9
LGE	SH_SP	$40	2.6%	0.6%	2,128	3.1%	2,131	3
LGE	SH_P	$25	2.9%	0.7%	2,083	3.5%	2,086	3
LGE	SH_OP	$15	6.4%	1.1%	2,141	7.3%	2,153	11

Economic Capacity
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			BASE			MERGER		
Market	*Period*	*Price*	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
MECS	S_SP1	$100	0.5%	0.8%	3,368	1.3%	3,369	1
MECS	S_SP2	$75	0.5%	0.8%	3,368	1.3%	3,369	1
MECS	S_SP3	$50	0.5%	0.8%	3,359	1.3%	3,360	1
MECS	S_P	$30	0.5%	0.9%	3,366	1.4%	3,367	1
MECS	S_OP	$20	0.8%	0.1%	3,504	0.8%	3,505	0
MECS	W_SP	$25	1.2%	0.9%	2,295	2.0%	2,297	2
MECS	W_P	$20	2.7%	0.3%	2,259	2.8%	2,260	1
MECS	W_OP	$15	4.4%	0.5%	2,313	4.8%	2,316	3
MECS	SH_SP	$40	1.0%	1.0%	2,410	2.0%	2,412	2
MECS	SH_P	$25	1.3%	1.1%	2,384	2.4%	2,386	3
MECS	SH_OP	$15	4.7%	0.8%	2,384	5.3%	2,389	6
MGE	S_SP1	$100	2.2%	0.0%	4,751	2.2%	4,751	0
MGE	S_SP2	$75	2.2%	0.0%	4,751	2.2%	4,751	0
MGE	S_SP3	$50	2.2%	0.0%	4,750	2.2%	4,750	0
MGE	S_P	$30	2.3%	0.1%	4,370	2.3%	4,370	0
MGE	S_OP	$20	3.0%	0.1%	3,983	3.0%	3,983	0
MGE	W_SP	$25	4.3%	0.1%	3,009	4.3%	3,009	0
MGE	W_P	$20	6.2%	0.2%	2,614	6.2%	2,614	0
MGE	W_OP	$15	6.4%	0.3%	2,090	6.5%	2,091	1
MGE	SH_SP	$40	2.8%	0.1%	4,395	2.8%	4,395	0
MGE	SH_P	$25	3.5%	0.1%	3,913	3.5%	3,913	0
MGE	SH_OP	$15	5.1%	0.3%	2,711	5.2%	2,712	1
MIDAM	S_SP1	$100	10.4%	0.2%	1,666	10.5%	1,669	3
MIDAM	S_SP2	$75	10.0%	0.3%	1,658	10.2%	1,662	3
MIDAM	S_SP3	$50	10.1%	0.3%	1,666	10.3%	1,670	3
MIDAM	S_P	$30	9.6%	0.5%	1,469	9.9%	1,473	5
MIDAM	S_OP	$20	7.7%	0.3%	1,596	7.8%	1,598	1
MIDAM	W_SP	$25	9.1%	0.3%	1,351	9.2%	1,353	2
MIDAM	W_P	$20	9.4%	0.3%	1,384	9.5%	1,386	2
MIDAM	W_OP	$15	8.2%	0.5%	1,362	8.5%	1,365	4
MIDAM	SH_SP	$40	8.7%	0.3%	1,432	8.8%	1,435	3
MIDAM	SH_P	$25	9.2%	0.4%	1,260	9.3%	1,264	3
MIDAM	SH_OP	$15	8.4%	0.6%	1,287	8.7%	1,291	4
MPS	S_SP1	$100	2.0%	0.3%	1,879	2.4%	1,880	1
MPS	S_SP2	$75	2.3%	0.3%	1,873	2.6%	1,875	1
MPS	S_SP3	$50	2.3%	0.3%	1,874	2.6%	1,875	1
MPS	S_P	$30	2.0%	0.5%	1,806	2.5%	1,808	2
MPS	S_OP	$20	3.6%	0.2%	1,468	3.7%	1,468	1
MPS	W_SP	$25	2.8%	0.6%	1,572	3.4%	1,576	3
MPS	W_P	$20	4.7%	0.2%	1,459	4.8%	1,460	1
MPS	W_OP	$15	5.7%	0.3%	1,440	5.8%	1,441	1
MPS	SH_SP	$40	1.4%	0.3%	1,883	1.7%	1,884	1
MPS	SH_P	$25	2.6%	0.6%	1,586	3.1%	1,588	3
MPS	SH_OP	$15	4.3%	0.2%	1,456	4.4%	1,456	1
NEPOOL	S_SP1	$100	0.0%	0.0%	1,060	0.0%	1,060	0
NEPOOL	S_SP2	$75	0.0%	0.0%	1,060	0.0%	1,060	0
NEPOOL	S_SP3	$50	0.0%	0.0%	1,058	0.0%	1,058	0
NEPOOL	S_P	$30	0.0%	0.0%	1,077	0.0%	1,077	0
NEPOOL	S_OP	$20	0.0%	0.0%	1,097	0.0%	1,097	0
NEPOOL	W_SP	$25	0.0%	0.0%	1,066	0.0%	1,066	0
NEPOOL	W_P	$20	0.0%	0.0%	1,126	0.0%	1,126	0
NEPOOL	W_OP	$15	0.0%	0.0%	2,319	0.0%	2,319	0
NEPOOL	SH_SP	$40	0.0%	0.0%	1,073	0.0%	1,073	0
NEPOOL	SH_P	$25	0.0%	0.0%	1,059	0.0%	1,059	0
NEPOOL	SH_OP	$15	0.0%	0.0%	2,269	0.0%	2,269	0

Economic Capacity
No Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
NIPS	S_SP1	$100	13.3%	0.3%	2,454	13.5%	2,461	7
NIPS	S_SP2	$75	12.8%	0.5%	2,443	13.1%	2,450	7
NIPS	S_SP3	$50	12.9%	0.5%	2,418	13.2%	2,425	7
NIPS	S_P	$30	11.6%	0.6%	2,231	11.9%	2,239	7
NIPS	S_OP	$20	12.1%	0.6%	2,187	12.4%	2,195	8
NIPS	W_SP	$25	9.4%	0.6%	1,522	9.9%	1,530	8
NIPS	W_P	$20	12.8%	0.9%	1,621	13.4%	1,636	15
NIPS	W_OP	$15	11.3%	1.1%	1,487	12.0%	1,503	16
NIPS	SH_SP	$40	12.1%	0.7%	1,479	12.5%	1,490	11
NIPS	SH_P	$25	9.6%	0.7%	1,410	10.1%	1,420	9
NIPS	SH_OP	$15	11.3%	1.5%	1,404	12.4%	1,428	23
NSP	S_SP1	$100	1.8%	0.1%	2,614	1.8%	2,614	0
NSP	S_SP2	$75	1.7%	0.1%	2,614	1.8%	2,614	0
NSP	S_SP3	$50	1.8%	0.1%	2,329	1.9%	2,329	0
NSP	S_P	$30	1.9%	0.1%	2,250	2.0%	2,251	0
NSP	S_OP	$20	3.1%	0.1%	2,468	3.2%	2,468	0
NSP	W_SP	$25	2.5%	0.1%	2,054	2.6%	2,054	0
NSP	W_P	$20	3.9%	0.2%	2,220	4.0%	2,220	1
NSP	W_OP	$15	5.2%	0.3%	2,762	5.2%	2,763	1
NSP	SH_SP	$40	2.6%	0.1%	1,877	2.7%	1,877	0
NSP	SH_P	$25	3.1%	0.2%	1,912	3.2%	1,912	1
NSP	SH_OP	$15	6.0%	0.3%	2,609	6.1%	2,610	1
NYPP	S_SP1	$100	0.0%	0.9%	947	0.9%	947	0
NYPP	S_SP2	$75	0.0%	0.9%	947	0.9%	947	0
NYPP	S_SP3	$50	0.0%	0.9%	961	0.9%	961	0
NYPP	S_P	$30	0.0%	1.0%	980	1.0%	980	0
NYPP	S_OP	$20	0.0%	0.9%	1,000	0.9%	1,000	0
NYPP	W_SP	$25	0.0%	0.5%	981	0.5%	981	0
NYPP	W_P	$20	0.0%	0.7%	1,079	0.7%	1,079	0
NYPP	W_OP	$15	0.0%	1.0%	1,478	1.0%	1,478	0
NYPP	SH_SP	$40	0.0%	1.7%	893	1.7%	893	0
NYPP	SH_P	$25	0.0%	1.7%	823	1.7%	823	0
NYPP	SH_OP	$15	0.0%	3.9%	1,105	3.9%	1,105	0
SCEG	S_SP1	$100	0.3%	0.3%	2,939	0.6%	2,939	0
SCEG	S_SP2	$75	0.3%	0.4%	2,939	0.6%	2,939	0
SCEG	S_SP3	$50	0.3%	0.4%	2,876	0.6%	2,876	0
SCEG	S_P	$30	0.4%	0.0%	2,776	0.4%	2,776	0
SCEG	S_OP	$20	0.7%	0.0%	2,706	0.7%	2,706	0
SCEG	W_SP	$25	0.5%	0.0%	2,984	0.5%	2,984	0
SCEG	W_P	$20	0.4%	0.2%	2,942	0.5%	2,942	0
SCEG	W_OP	$15	1.2%	0.1%	1,353	1.2%	1,353	0
SCEG	SH_SP	$40	0.3%	0.4%	2,290	0.7%	2,290	0
SCEG	SH_P	$25	0.6%	0.0%	2,208	0.7%	2,208	0
SCEG	SH_OP	$15	1.1%	0.3%	1,178	1.3%	1,179	0
SCPSA	S_SP1	$100	0.3%	0.3%	1,821	0.6%	1,822	0
SCPSA	S_SP2	$75	0.3%	0.3%	1,821	0.6%	1,821	0
SCPSA	S_SP3	$50	0.3%	0.3%	1,809	0.7%	1,809	0
SCPSA	S_P	$30	0.5%	0.0%	1,786	0.5%	1,786	0
SCPSA	S_OP	$20	0.7%	0.0%	1,723	0.7%	1,723	0
SCPSA	W_SP	$25	0.6%	0.0%	1,939	0.6%	1,939	0
SCPSA	W_P	$20	0.5%	0.2%	1,904	0.5%	1,904	0
SCPSA	W_OP	$15	0.6%	0.1%	1,868	0.7%	1,868	0
SCPSA	SH_SP	$40	0.4%	0.4%	1,567	0.8%	1,567	0
SCPSA	SH_P	$25	0.8%	0.0%	1,572	0.8%	1,572	0
SCPSA	SH_OP	$15	0.6%	0.3%	1,468	0.8%	1,468	0

Economic Capacity
No Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
SOCO	S_SP1	$100	0.0%	2.4%	5,929	2.4%	5,929	0
SOCO	S_SP2	$75	0.0%	2.4%	5,929	2.4%	5,929	0
SOCO	S_SP3	$50	0.0%	2.4%	5,891	2.4%	5,891	0
SOCO	S_P	$30	0.1%	2.5%	5,752	2.6%	5,752	0
SOCO	S_OP	$20	0.1%	0.0%	6,162	0.1%	6,162	0
SOCO	W_SP	$25	0.2%	2.4%	5,257	2.6%	5,258	1
SOCO	W_P	$20	0.8%	0.0%	5,581	0.8%	5,582	0
SOCO	W_OP	$15	3.3%	0.1%	3,180	3.4%	3,180	0
SOCO	SH_SP	$40	0.1%	2.4%	5,086	2.5%	5,087	0
SOCO	SH_P	$25	0.1%	0.2%	5,283	0.3%	5,283	0
SOCO	SH_OP	$15	3.7%	0.1%	2,721	3.7%	2,721	0
TVA	S_SP1	$100	2.4%	0.2%	5,124	2.7%	5,125	1
TVA	S_SP2	$75	2.4%	0.3%	5,124	2.6%	5,125	1
TVA	S_SP3	$50	2.4%	0.3%	5,124	2.6%	5,125	1
TVA	S_P	$30	2.5%	0.3%	5,139	2.8%	5,140	1
TVA	S_OP	$20	2.5%	0.3%	5,661	2.7%	5,662	1
TVA	W_SP	$25	1.6%	0.2%	4,393	1.7%	4,394	0
TVA	W_P	$20	1.1%	0.1%	5,447	1.1%	5,448	0
TVA	W_OP	$15	3.3%	0.5%	5,068	3.7%	5,070	2
TVA	SH_SP	$40	1.7%	0.2%	4,245	1.9%	4,245	0
TVA	SH_P	$25	1.7%	0.2%	4,584	1.8%	4,585	1
TVA	SH_OP	$15	3.4%	0.7%	4,810	3.9%	4,814	3
VP	S_SP1	$100	0.8%	0.2%	1,984	0.9%	1,984	0
VP	S_SP2	$75	0.7%	0.2%	1,984	0.9%	1,985	0
VP	S_SP3	$50	0.7%	0.2%	1,951	0.9%	1,952	0
VP	S_P	$30	0.8%	0.1%	1,906	1.0%	1,907	0
VP	S_OP	$20	1.4%	0.1%	1,821	1.5%	1,821	0
VP	W_SP	$25	1.4%	0.4%	1,821	1.8%	1,822	1
VP	W_P	$20	3.0%	0.4%	2,002	3.3%	2,004	2
VP	W_OP	$15	7.9%	0.7%	1,743	8.6%	1,753	10
VP	SH_SP	$40	0.9%	0.6%	1,596	1.6%	1,597	1
VP	SH_P	$25	1.7%	0.7%	1,536	2.3%	1,538	2
VP	SH_OP	$15	8.0%	1.2%	1,373	9.2%	1,391	18
UPP	S_SP1	$100	0.2%	0.0%	3,273	0.2%	3,273	0
UPP	S_SP2	$75	0.2%	0.0%	3,273	0.2%	3,273	0
UPP	S_SP3	$50	0.2%	0.0%	3,273	0.2%	3,273	0
UPP	S_P	$30	0.3%	0.0%	3,604	0.3%	3,604	0
UPP	S_OP	$20	0.6%	0.0%	4,757	0.6%	4,757	0
UPP	W_SP	$25	3.6%	0.1%	2,243	3.6%	2,243	0
UPP	W_P	$20	6.7%	0.2%	2,059	6.7%	2,060	0
UPP	W_OP	$15	8.5%	0.3%	2,276	8.6%	2,277	1
UPP	SH_SP	$40	0.0%	0.0%	5,018	0.0%	5,018	0
UPP	SH_P	$25	0.0%	0.0%	6,258	0.0%	6,258	0
UPP	SH_OP	$15	0.0%	0.0%	7,959	0.0%	7,959	0
WEP	S_SP1	$100	1.0%	0.0%	8,506	1.0%	8,506	0
WEP	S_SP2	$75	0.9%	0.0%	8,506	0.9%	8,506	0
WEP	S_SP3	$50	0.9%	0.0%	8,506	0.9%	8,506	0
WEP	S_P	$30	0.8%	0.0%	8,601	0.8%	8,601	0
WEP	S_OP	$20	1.2%	0.0%	8,470	1.2%	8,470	0
WEP	W_SP	$25	5.9%	0.1%	3,787	6.0%	3,787	0
WEP	W_P	$20	7.2%	0.2%	3,550	7.2%	3,550	0
WEP	W_OP	$15	6.7%	0.3%	2,992	6.8%	2,992	1
WEP	SH_SP	$40	7.7%	0.2%	3,422	7.7%	3,423	0
WEP	SH_P	$25	7.6%	0.2%	3,356	7.7%	3,357	0
WEP	SH_OP	$15	7.8%	0.4%	2,516	7.9%	2,517	1

Economic Capacity
No Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
WPS	S_SP1	$100	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_SP2	$75	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_SP3	$50	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_P	$30	0.6%	0.0%	5,994	0.6%	5,994	0
WPS	S_OP	$20	0.8%	0.0%	6,427	0.8%	6,427	0
WPS	W_SP	$25	2.2%	0.1%	3,648	2.2%	3,648	0
WPS	W_P	$20	2.7%	0.1%	3,753	2.8%	3,753	0
WPS	W_OP	$15	3.2%	0.2%	4,218	3.2%	4,219	0
WPS	SH_SP	$40	1.3%	0.0%	3,808	1.3%	3,808	0
WPS	SH_P	$25	2.0%	0.0%	3,611	2.0%	3,611	0
WPS	SH_OP	$15	4.1%	0.2%	4,238	4.1%	4,238	0
WR	S_SP1	$100	0.4%	0.4%	6,016	0.8%	6,016	0
WR	S_SP2	$75	0.5%	0.4%	6,014	0.8%	6,015	0
WR	S_SP3	$50	0.5%	0.4%	6,014	0.8%	6,015	0
WR	S_P	$30	0.8%	0.4%	5,128	1.2%	5,129	1
WR	S_OP	$20	1.5%	0.8%	4,557	2.2%	4,559	2
WR	W_SP	$25	1.4%	0.4%	5,027	1.8%	5,028	1
WR	W_P	$20	2.4%	0.1%	4,473	2.4%	4,473	0
WR	W_OP	$15	3.1%	0.1%	4,500	3.1%	4,500	0
WR	SH_SP	$40	0.6%	0.3%	5,037	0.9%	5,037	0
WR	SH_P	$25	1.2%	0.5%	4,805	1.7%	4,806	1
WR	SH_OP	$15	2.4%	0.1%	4,243	2.5%	4,243	0

Competitive Analysis Screening Model (CASm)
HHI Report
Unicom/PECO Market Power Analysis
Economic Capacity
100 MW Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
COMED	S_SP1	$100	75.7%	0.1%	5,791	75.4%	5,755	-37
COMED	S_SP2	$75	73.1%	1.4%	5,419	72.9%	5,384	-36
COMED	S_SP3	$50	73.2%	1.4%	5,429	72.9%	5,393	-36
COMED	S_P	$30	63.8%	1.4%	4,238	63.5%	4,206	-31
COMED	S_OP	$20	71.0%	1.8%	5,136	70.7%	5,095	-41
COMED	W_SP	$25	65.9%	1.5%	4,504	65.7%	4,473	-32
COMED	W_P	$20	73.2%	1.8%	5,407	72.9%	5,377	-31
COMED	W_OP	$15	67.7%	2.0%	4,657	67.6%	4,649	-8
COMED	SH_SP	$40	66.0%	1.4%	4,453	65.8%	4,416	-37
COMED	SH_P	$25	63.4%	1.7%	4,179	63.1%	4,141	-38
COMED	SH_OP	$15	64.6%	2.3%	4,254	64.6%	4,252	-2
PJM_ALL	S_SP1	$100	0.0%	11.7%	933	11.8%	936	2
PJM_ALL	S_SP2	$75	0.0%	11.7%	929	11.9%	931	2
PJM_ALL	S_SP3	$50	0.0%	11.8%	932	12.0%	934	2
PJM_ALL	S_P	$30	0.0%	12.7%	864	12.9%	868	4
PJM_ALL	S_OP	$20	0.1%	10.5%	874	10.8%	880	6
PJM_ALL	W_SP	$25	0.0%	12.0%	841	12.1%	843	2
PJM_ALL	W_P	$20	0.0%	11.0%	872	11.2%	873	0
PJM_ALL	W_OP	$15	0.1%	11.9%	877	12.2%	879	2
PJM_ALL	SH_SP	$40	0.0%	12.1%	869	12.2%	872	3
PJM_ALL	SH_P	$25	0.0%	11.4%	806	11.6%	809	3
PJM_ALL	SH_OP	$15	0.1%	11.2%	842	11.4%	845	3
PJM_C+E	S_SP1	$100	0.0%	15.7%	1,280	15.9%	1,282	3
PJM_C+E	S_SP2	$75	0.0%	15.7%	1,271	16.0%	1,274	3
PJM_C+E	S_SP3	$50	0.0%	15.9%	1,281	16.2%	1,284	3
PJM_C+E	S_P	$30	0.0%	17.4%	1,173	17.7%	1,179	5
PJM_C+E	S_OP	$20	0.1%	14.6%	1,163	15.0%	1,168	5
PJM_C+E	W_SP	$25	0.1%	16.2%	1,116	16.5%	1,122	6
PJM_C+E	W_P	$20	0.1%	15.2%	1,196	15.6%	1,202	6
PJM_C+E	W_OP	$15	0.2%	15.6%	1,133	16.0%	1,140	7
PJM_C+E	SH_SP	$40	0.1%	16.3%	1,107	16.6%	1,112	5
PJM_C+E	SH_P	$25	0.1%	14.9%	1,032	15.3%	1,039	6
PJM_C+E	SH_OP	$15	0.2%	14.4%	1,009	14.9%	1,016	8
PJM_EAST	S_SP1	$100	0.0%	17.0%	1,396	17.3%	1,398	2
PJM_EAST	S_SP2	$75	0.0%	17.1%	1,383	17.3%	1,386	2
PJM_EAST	S_SP3	$50	0.0%	17.3%	1,392	17.6%	1,395	3
PJM_EAST	S_P	$30	0.0%	19.4%	1,270	19.7%	1,275	6
PJM_EAST	S_OP	$20	0.0%	16.2%	1,222	16.6%	1,228	6
PJM_EAST	W_SP	$25	0.0%	19.0%	1,237	19.3%	1,244	7
PJM_EAST	W_P	$20	0.2%	17.5%	1,297	18.1%	1,307	10
PJM_EAST	W_OP	$15	0.7%	18.7%	1,331	19.8%	1,363	31
PJM_EAST	SH_SP	$40	0.0%	18.2%	1,240	18.5%	1,245	5
PJM_EAST	SH_P	$25	0.0%	17.1%	1,088	17.5%	1,096	7
PJM_EAST	SH_OP	$15	0.7%	16.3%	1,124	17.4%	1,153	29
PJM_W+C+E	S_SP1	$100	0.0%	11.7%	921	11.8%	925	3
PJM_W+C+E	S_SP2	$75	0.0%	11.7%	917	11.9%	920	3
PJM_W+C+E	S_SP3	$50	0.0%	11.8%	920	12.0%	923	3
PJM_W+C+E	S_P	$30	0.0%	12.8%	851	12.9%	856	4
PJM_W+C+E	S_OP	$20	0.1%	10.5%	858	10.8%	863	6
PJM_W+C+E	W_SP	$25	0.1%	12.4%	846	12.7%	849	4
PJM_W+C+E	W_P	$20	0.1%	11.5%	863	11.8%	866	3
PJM_W+C+E	W_OP	$15	0.1%	12.0%	849	12.3%	853	3
PJM_W+C+E	SH_SP	$40	0.0%	12.0%	851	12.2%	854	3
PJM_W+C+E	SH_P	$25	0.0%	11.3%	794	11.5%	797	3
PJM_W+C+E	SH_OP	$15	0.1%	11.1%	823	11.4%	828	5

Economic Capacity
100 MW Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
AECI	S_SP1	$100	2.6%	0.6%	1,210	3.2%	1,215	4
AECI	S_SP2	$75	2.6%	0.7%	1,209	3.2%	1,213	4
AECI	S_SP3	$50	2.6%	0.7%	1,211	3.2%	1,215	4
AECI	S_P	$30	2.7%	0.7%	1,253	3.3%	1,258	5
AECI	S_OP	$20	3.9%	1.1%	1,194	4.8%	1,202	8
AECI	W_SP	$25	1.8%	0.8%	1,502	2.5%	1,506	4
AECI	W_P	$20	2.4%	1.1%	1,486	3.4%	1,492	6
AECI	W_OP	$15	5.1%	0.2%	602	5.1%	602	1
AECI	SH_SP	$40	1.9%	0.7%	1,291	2.5%	1,293	2
AECI	SH_P	$25	2.7%	1.1%	1,292	3.6%	1,295	2
AECI	SH_OP	$15	6.0%	0.3%	554	6.0%	555	1
ALLIANT_E	S_SP1	$100	10.8%	0.0%	2,763	10.6%	2,765	2
ALLIANT_E	S_SP2	$75	10.4%	0.2%	2,755	10.3%	2,757	3
ALLIANT_E	S_SP3	$50	10.8%	0.2%	2,614	10.7%	2,617	2
ALLIANT_E	S_P	$30	9.8%	0.2%	2,495	9.7%	2,498	3
ALLIANT_E	S_OP	$20	11.7%	0.3%	2,273	11.5%	2,274	1
ALLIANT_E	W_SP	$25	8.9%	0.2%	1,755	8.9%	1,754	-1
ALLIANT_E	W_P	$20	10.5%	0.3%	1,642	10.3%	1,640	-2
ALLIANT_E	W_OP	$15	8.7%	0.4%	1,615	8.6%	1,615	0
ALLIANT_E	SH_SP	$40	7.3%	0.2%	1,707	7.2%	1,708	1
ALLIANT_E	SH_P	$25	7.5%	0.2%	1,606	7.4%	1,607	1
ALLIANT_E	SH_OP	$15	7.6%	0.4%	1,539	7.4%	1,540	1
ALLIANT_W	S_SP1	$100	11.7%	0.2%	1,194	11.7%	1,195	1
ALLIANT_W	S_SP2	$75	11.3%	0.4%	1,185	11.3%	1,186	1
ALLIANT_W	S_SP3	$50	11.5%	0.4%	1,187	11.5%	1,187	1
ALLIANT_W	S_P	$30	11.2%	0.5%	1,072	11.3%	1,075	3
ALLIANT_W	S_OP	$20	14.1%	0.4%	1,267	14.0%	1,267	-1
ALLIANT_W	W_SP	$25	10.7%	0.5%	962	10.9%	965	3
ALLIANT_W	W_P	$20	11.4%	0.5%	1,129	11.4%	1,130	1
ALLIANT_W	W_OP	$15	10.2%	0.6%	1,097	10.3%	1,100	2
ALLIANT_W	SH_SP	$40	9.7%	0.4%	1,007	9.8%	1,008	1
ALLIANT_W	SH_P	$25	10.6%	0.5%	981	10.7%	983	2
ALLIANT_W	SH_OP	$15	9.8%	0.6%	1,058	9.8%	1,060	2
AMEREN	S_SP1	$100	4.0%	0.5%	2,108	4.5%	2,113	5
AMEREN	S_SP2	$75	5.5%	0.6%	2,051	5.9%	2,058	7
AMEREN	S_SP3	$50	5.5%	0.6%	2,044	6.0%	2,051	7
AMEREN	S_P	$30	3.5%	0.7%	2,042	4.0%	2,047	5
AMEREN	S_OP	$20	4.2%	0.9%	2,247	5.0%	2,256	9
AMEREN	W_SP	$25	3.3%	0.7%	2,078	3.9%	2,082	4
AMEREN	W_P	$20	3.9%	0.9%	2,338	4.7%	2,344	6
AMEREN	W_OP	$15	3.2%	0.5%	2,543	3.6%	2,545	2
AMEREN	SH_SP	$40	3.9%	0.7%	1,798	4.5%	1,803	5
AMEREN	SH_P	$25	3.2%	0.9%	1,850	4.0%	1,856	5
AMEREN	SH_OP	$15	6.5%	0.7%	2,078	6.9%	2,085	7
AEP	S_SP1	$100	3.5%	0.3%	1,724	3.8%	1,736	12
AEP	S_SP2	$75	3.4%	0.4%	1,724	3.6%	1,735	11
AEP	S_SP3	$50	3.4%	0.4%	1,719	3.7%	1,731	12
AEP	S_P	$30	2.6%	0.7%	1,673	3.4%	1,685	12
AEP	S_OP	$20	3.3%	0.5%	1,958	3.6%	1,970	12
AEP	W_SP	$25	0.2%	0.5%	1,680	0.7%	1,678	-2
AEP	W_P	$20	0.9%	0.5%	1,879	1.4%	1,877	-2
AEP	W_OP	$15	1.2%	0.7%	2,451	1.7%	2,452	1
AEP	SH_SP	$40	1.1%	1.0%	1,323	2.1%	1,320	-3
AEP	SH_P	$25	1.1%	0.9%	1,440	1.9%	1,435	-5
AEP	SH_OP	$15	0.1%	0.9%	2,174	0.8%	2,167	-7

Economic Capacity
100 MW Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
APS	S_SP1	$100	0.7%	0.1%	1,939	0.9%	1,940	1
APS	S_SP2	$75	0.7%	0.1%	1,939	0.9%	1,941	1
APS	S_SP3	$50	0.7%	0.2%	1,909	0.9%	1,910	1
APS	S_P	$30	0.9%	0.2%	1,764	1.0%	1,764	1
APS	S_OP	$20	1.4%	0.1%	1,777	1.4%	1,776	0
APS	W_SP	$25	1.5%	0.4%	1,733	1.9%	1,733	0
APS	W_P	$20	0.3%	0.4%	1,958	0.6%	1,955	-2
APS	W_OP	$15	6.5%	0.8%	1,691	7.0%	1,695	4
APS	SH_SP	$40	1.0%	0.6%	1,559	1.5%	1,568	9
APS	SH_P	$25	1.6%	0.6%	1,520	2.3%	1,522	2
APS	SH_OP	$15	4.1%	1.3%	1,352	5.1%	1,363	11
CAPO	S_SP1	$100	0.7%	0.1%	4,217	0.8%	4,230	13
CAPO	S_SP2	$75	0.7%	0.1%	4,217	0.8%	4,230	13
CAPO	S_SP3	$50	0.7%	0.1%	4,154	0.8%	4,167	13
CAPO	S_P	$30	0.8%	0.1%	3,979	0.9%	3,992	13
CAPO	S_OP	$20	1.1%	0.1%	3,640	1.2%	3,652	12
CAPO	W_SP	$25	1.0%	0.1%	4,203	1.0%	4,225	22
CAPO	W_P	$20	1.6%	0.2%	3,844	1.7%	3,867	22
CAPO	W_OP	$15	3.7%	0.4%	3,320	4.0%	3,344	24
CAPO	SH_SP	$40	0.7%	0.3%	3,299	1.0%	3,311	12
CAPO	SH_P	$25	1.0%	0.2%	2,875	1.2%	2,886	11
CAPO	SH_OP	$15	4.1%	0.7%	2,598	4.6%	2,611	12
CELE	S_SP1	$100	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_SP2	$75	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_SP3	$50	0.1%	0.8%	7,023	0.9%	7,023	0
CELE	S_P	$30	0.1%	0.8%	7,012	0.9%	7,013	0
CELE	S_OP	$20	0.6%	3.9%	3,187	4.5%	3,192	5
CELE	W_SP	$25	0.2%	1.1%	5,383	1.3%	5,383	1
CELE	W_P	$20	1.3%	4.2%	1,832	5.5%	1,843	11
CELE	W_OP	$15	2.7%	0.0%	1,836	2.8%	1,836	0
CELE	SH_SP	$40	0.1%	0.9%	5,982	1.0%	5,982	0
CELE	SH_P	$25	0.2%	1.1%	5,871	1.3%	5,872	0
CELE	SH_OP	$15	2.0%	0.0%	2,166	2.0%	2,165	-1
CILCO	S_SP1	$100	12.8%	0.4%	2,002	13.1%	2,011	9
CILCO	S_SP2	$75	12.4%	0.7%	1,989	12.7%	1,997	9
CILCO	S_SP3	$50	12.4%	0.7%	1,990	12.7%	1,998	9
CILCO	S_P	$30	11.1%	0.7%	1,983	11.5%	1,991	9
CILCO	S_OP	$20	12.3%	0.7%	2,027	12.5%	2,035	8
CILCO	W_SP	$25	10.5%	0.8%	2,014	10.9%	2,023	9
CILCO	W_P	$20	12.0%	0.8%	2,087	12.4%	2,100	13
CILCO	W_OP	$15	17.5%	1.7%	1,058	18.3%	1,087	30
CILCO	SH_SP	$40	10.7%	0.7%	1,961	11.1%	1,963	2
CILCO	SH_P	$25	10.2%	0.8%	1,968	10.6%	1,970	2
CILCO	SH_OP	$15	15.4%	1.6%	832	16.0%	852	20
CIN	S_SP1	$100	2.1%	1.6%	1,978	3.7%	1,984	6
CIN	S_SP2	$75	2.3%	1.6%	1,978	3.8%	1,984	6
CIN	S_SP3	$50	2.3%	1.7%	1,971	3.9%	1,977	6
CIN	S_P	$30	2.6%	1.7%	1,877	4.2%	1,885	8
CIN	S_OP	$20	4.1%	1.9%	2,075	5.9%	2,091	16
CIN	W_SP	$25	2.5%	1.8%	1,707	4.2%	1,721	15
CIN	W_P	$20	4.0%	2.1%	1,969	5.9%	1,990	21
CIN	W_OP	$15	3.7%	2.8%	2,459	6.3%	2,485	25
CIN	SH_SP	$40	2.2%	1.8%	1,622	4.0%	1,636	15
CIN	SH_P	$25	2.7%	1.9%	1,595	4.5%	1,611	16
CIN	SH_OP	$15	4.8%	3.2%	2,256	7.8%	2,292	35

Economic Capacity
100 MW Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
CWLP	S_SP1	$100	5.8%	0.5%	2,516	6.2%	2,521	5
CWLP	S_SP2	$75	5.6%	0.6%	2,511	6.0%	2,516	5
CWLP	S_SP3	$50	5.6%	0.6%	2,513	6.0%	2,518	5
CWLP	S_P	$30	5.1%	0.6%	2,500	5.6%	2,505	5
CWLP	S_OP	$20	6.4%	0.6%	1,972	6.8%	1,977	5
CWLP	W_SP	$25	4.9%	0.6%	3,082	5.4%	3,087	5
CWLP	W_P	$20	5.8%	0.6%	2,503	6.2%	2,508	5
CWLP	W_OP	$15	12.9%	1.6%	916	13.9%	941	26
CWLP	SH_SP	$40	4.5%	0.5%	2,999	5.0%	3,002	4
CWLP	SH_P	$25	4.6%	0.6%	2,836	5.1%	2,840	4
CWLP	SH_OP	$15	11.2%	1.6%	839	12.2%	859	21
DLCO	S_SP1	$100	1.3%	1.5%	1,777	2.8%	1,780	2
DLCO	S_SP2	$75	1.2%	1.5%	1,777	2.7%	1,780	2
DLCO	S_SP3	$50	1.3%	1.6%	1,736	2.8%	1,738	2
DLCO	S_P	$30	1.4%	1.6%	1,654	3.0%	1,657	2
DLCO	S_OP	$20	1.8%	1.6%	1,752	3.4%	1,755	3
DLCO	W_SP	$25	1.7%	2.1%	2,081	3.8%	2,086	5
DLCO	W_P	$20	3.0%	2.2%	2,198	5.1%	2,208	10
DLCO	W_OP	$15	2.1%	2.8%	2,025	4.7%	2,028	3
DLCO	SH_SP	$40	1.4%	2.7%	1,882	4.0%	1,890	7
DLCO	SH_P	$25	1.9%	2.6%	1,880	4.5%	1,890	10
DLCO	SH_OP	$15	3.7%	3.9%	1,700	7.5%	1,720	21
DPL	S_SP1	$100	3.1%	0.6%	1,307	3.7%	1,313	6
DPL	S_SP2	$75	3.0%	0.7%	1,307	3.6%	1,312	6
DPL	S_SP3	$50	3.0%	0.7%	1,301	3.6%	1,307	6
DPL	S_P	$30	3.6%	0.8%	1,224	4.2%	1,231	7
DPL	S_OP	$20	4.9%	0.8%	1,316	5.6%	1,326	10
DPL	W_SP	$25	4.0%	0.8%	1,343	4.7%	1,350	7
DPL	W_P	$20	5.0%	0.9%	1,541	5.7%	1,552	10
DPL	W_OP	$15	8.6%	0.9%	1,211	9.2%	1,222	11
DPL	SH_SP	$40	2.6%	0.9%	1,306	3.4%	1,312	6
DPL	SH_P	$25	4.1%	1.0%	1,227	5.0%	1,236	8
DPL	SH_OP	$15	8.5%	1.4%	1,086	9.5%	1,102	16
DUKE	S_SP1	$100	0.3%	0.2%	5,609	0.5%	5,637	27
DUKE	S_SP2	$75	0.3%	0.2%	5,595	0.5%	5,622	27
DUKE	S_SP3	$50	0.3%	0.2%	5,529	0.5%	5,556	27
DUKE	S_P	$30	0.2%	0.0%	5,473	0.3%	5,501	29
DUKE	S_OP	$20	0.5%	0.0%	5,212	0.5%	5,243	31
DUKE	W_SP	$25	0.5%	0.1%	5,082	0.6%	5,106	25
DUKE	W_P	$20	0.2%	0.1%	4,983	0.3%	5,005	21
DUKE	W_OP	$15	0.3%	0.2%	4,470	0.4%	4,496	27
DUKE	SH_SP	$40	0.4%	0.3%	4,825	0.6%	4,857	31
DUKE	SH_P	$25	0.6%	0.1%	4,628	0.7%	4,662	35
DUKE	SH_OP	$15	2.4%	0.4%	4,353	2.7%	4,399	46
EKPC	S_SP1	$100	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_SP2	$75	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_SP3	$50	0.4%	0.1%	7,609	0.5%	7,609	0
EKPC	S_P	$30	0.5%	0.1%	7,613	0.5%	7,613	0
EKPC	S_OP	$20	0.7%	0.1%	7,644	0.8%	7,644	-1
EKPC	W_SP	$25	0.6%	0.1%	7,617	0.7%	7,617	0
EKPC	W_P	$20	0.8%	0.1%	7,612	0.9%	7,612	0
EKPC	W_OP	$15	1.7%	0.1%	7,362	1.7%	7,362	0
EKPC	SH_SP	$40	0.4%	0.1%	7,387	0.5%	7,387	0
EKPC	SH_P	$25	0.6%	0.1%	7,397	0.8%	7,397	0
EKPC	SH_OP	$15	1.8%	0.2%	7,115	1.9%	7,116	0

Economic Capacity
100 MW Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
ENT	S_SP1	$100	0.1%	3.1%	3,561	3.2%	3,562	1
ENT	S_SP2	$75	0.1%	3.1%	3,561	3.3%	3,562	1
ENT	S_SP3	$50	0.1%	3.1%	3,561	3.3%	3,562	1
ENT	S_P	$30	0.2%	3.1%	3,488	3.2%	3,489	1
ENT	S_OP	$20	0.5%	6.5%	1,135	7.0%	1,142	7
ENT	W_SP	$25	0.3%	2.5%	3,406	2.8%	3,408	2
ENT	W_P	$20	0.3%	6.1%	1,144	6.3%	1,147	3
ENT	W_OP	$15	0.5%	0.2%	1,250	0.7%	1,250	0
ENT	SH_SP	$40	0.1%	3.0%	3,834	3.1%	3,833	-2
ENT	SH_P	$25	0.3%	2.8%	3,467	3.1%	3,466	-1
ENT	SH_OP	$15	2.9%	0.3%	1,343	3.1%	1,341	-2
FENER	S_SP1	$100	1.0%	0.1%	1,929	1.1%	1,929	0
FENER	S_SP2	$75	0.9%	0.1%	1,929	1.0%	1,929	0
FENER	S_SP3	$50	0.9%	0.1%	1,901	1.1%	1,901	0
FENER	S_P	$30	1.1%	0.2%	1,767	1.2%	1,767	0
FENER	S_OP	$20	1.4%	0.1%	1,741	1.5%	1,741	0
FENER	W_SP	$25	1.9%	0.5%	1,723	2.3%	1,722	-1
FENER	W_P	$20	3.1%	0.5%	1,911	3.5%	1,906	-5
FENER	W_OP	$15	7.4%	0.7%	1,664	8.0%	1,663	-1
FENER	SH_SP	$40	1.3%	0.6%	1,541	1.9%	1,549	8
FENER	SH_P	$25	2.0%	0.7%	1,503	2.6%	1,511	8
FENER	SH_OP	$15	7.0%	1.2%	1,420	8.0%	1,436	16
HEC	S_SP1	$100	1.9%	1.0%	1,865	2.9%	1,872	7
HEC	S_SP2	$75	1.9%	1.0%	1,865	2.9%	1,872	7
HEC	S_SP3	$50	1.9%	1.0%	1,862	2.9%	1,868	7
HEC	S_P	$30	2.2%	1.2%	1,824	3.3%	1,832	8
HEC	S_OP	$20	4.4%	1.2%	1,916	5.5%	1,929	13
HEC	W_SP	$25	2.0%	1.2%	1,763	3.2%	1,773	11
HEC	W_P	$20	2.9%	1.2%	1,840	4.0%	1,853	13
HEC	W_OP	$15	6.3%	1.6%	1,808	7.7%	1,834	26
HEC	SH_SP	$40	2.1%	1.1%	1,567	3.1%	1,581	13
HEC	SH_P	$25	2.3%	1.3%	1,645	3.5%	1,656	11
HEC	SH_OP	$15	7.5%	1.8%	1,695	9.2%	1,735	40
IP	S_SP1	$100	12.8%	1.7%	1,531	14.3%	1,571	40
IP	S_SP2	$75	12.3%	1.9%	1,520	13.9%	1,559	39
IP	S_SP3	$50	12.4%	1.9%	1,516	13.9%	1,555	39
IP	S_P	$30	11.3%	2.1%	1,467	12.9%	1,505	38
IP	S_OP	$20	12.7%	2.1%	1,497	14.4%	1,540	43
IP	W_SP	$25	11.7%	2.3%	1,480	13.6%	1,523	43
IP	W_P	$20	14.0%	2.3%	1,593	15.9%	1,646	54
IP	W_OP	$15	13.2%	2.8%	996	15.3%	1,051	54
IP	SH_SP	$40	9.4%	2.0%	1,480	11.1%	1,512	32
IP	SH_P	$25	9.4%	2.2%	1,432	11.3%	1,468	35
IP	SH_OP	$15	10.1%	2.7%	928	12.3%	970	42
LGE	S_SP1	$100	3.4%	0.5%	2,398	3.9%	2,401	3
LGE	S_SP2	$75	3.5%	0.6%	2,363	4.0%	2,366	3
LGE	S_SP3	$50	3.6%	0.6%	2,329	4.1%	2,333	3
LGE	S_P	$30	3.6%	0.6%	2,340	4.1%	2,344	4
LGE	S_OP	$20	4.8%	0.7%	2,404	5.4%	2,408	5
LGE	W_SP	$25	2.8%	0.6%	2,376	3.3%	2,384	8
LGE	W_P	$20	4.2%	0.6%	2,445	4.7%	2,447	2
LGE	W_OP	$15	6.3%	0.9%	2,406	6.9%	2,405	-2
LGE	SH_SP	$40	2.6%	0.6%	2,128	3.1%	2,130	2
LGE	SH_P	$25	2.9%	0.7%	2,083	3.5%	2,086	3
LGE	SH_OP	$15	6.4%	1.1%	2,141	7.2%	2,144	3

Economic Capacity
100 MW Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
MECS	S_SP1	$100	0.5%	0.8%	3,368	1.3%	3,371	3
MECS	S_SP2	$75	0.5%	0.8%	3,368	1.3%	3,371	3
MECS	S_SP3	$50	0.5%	0.8%	3,359	1.3%	3,362	3
MECS	S_P	$30	0.5%	0.9%	3,366	1.4%	3,369	3
MECS	S_OP	$20	0.8%	0.1%	3,504	0.8%	3,508	4
MECS	W_SP	$25	1.2%	0.9%	2,295	2.0%	2,287	-8
MECS	W_P	$20	2.7%	0.3%	2,259	2.8%	2,242	-17
MECS	W_OP	$15	4.4%	0.5%	2,313	4.8%	2,298	-14
MECS	SH_SP	$40	1.0%	1.0%	2,410	2.2%	2,354	-56
MECS	SH_P	$25	1.3%	1.1%	2,384	2.5%	2,301	-82
MECS	SH_OP	$15	4.7%	0.8%	2,384	5.8%	2,322	-62
MGE	S_SP1	$100	2.2%	0.0%	4,751	2.2%	4,751	0
MGE	S_SP2	$75	2.2%	0.0%	4,751	2.1%	4,750	0
MGE	S_SP3	$50	2.2%	0.0%	4,750	2.2%	4,750	0
MGE	S_P	$30	2.3%	0.1%	4,370	2.3%	4,370	0
MGE	S_OP	$20	3.0%	0.1%	3,983	2.9%	3,983	0
MGE	W_SP	$25	4.3%	0.1%	3,009	4.3%	3,008	0
MGE	W_P	$20	6.2%	0.2%	2,614	6.2%	2,614	0
MGE	W_OP	$15	6.4%	0.3%	2,090	6.4%	2,091	1
MGE	SH_SP	$40	2.8%	0.1%	4,395	2.7%	4,395	0
MGE	SH_P	$25	3.5%	0.1%	3,913	3.5%	3,913	0
MGE	SH_OP	$15	5.1%	0.3%	2,711	5.1%	2,712	1
MIDAM	S_SP1	$100	10.4%	0.2%	1,666	10.4%	1,668	2
MIDAM	S_SP2	$75	10.0%	0.3%	1,658	10.0%	1,660	2
MIDAM	S_SP3	$50	10.1%	0.3%	1,666	10.1%	1,668	2
MIDAM	S_P	$30	9.6%	0.5%	1,469	9.7%	1,471	2
MIDAM	S_OP	$20	7.7%	0.3%	1,596	7.6%	1,597	1
MIDAM	W_SP	$25	9.1%	0.3%	1,351	9.0%	1,354	2
MIDAM	W_P	$20	9.4%	0.3%	1,384	9.3%	1,387	3
MIDAM	W_OP	$15	8.2%	0.5%	1,362	8.2%	1,367	5
MIDAM	SH_SP	$40	8.7%	0.3%	1,432	8.7%	1,435	3
MIDAM	SH_P	$25	9.2%	0.4%	1,260	9.2%	1,263	2
MIDAM	SH_OP	$15	8.4%	0.6%	1,287	8.4%	1,290	3
MPS	S_SP1	$100	2.0%	0.3%	1,879	2.3%	1,880	1
MPS	S_SP2	$75	2.3%	0.3%	1,873	2.6%	1,875	1
MPS	S_SP3	$50	2.3%	0.3%	1,874	2.6%	1,875	1
MPS	S_P	$30	2.0%	0.5%	1,806	2.4%	1,808	2
MPS	S_OP	$20	3.6%	0.2%	1,468	3.6%	1,469	1
MPS	W_SP	$25	2.8%	0.6%	1,572	3.4%	1,575	3
MPS	W_P	$20	4.7%	0.2%	1,459	4.8%	1,460	1
MPS	W_OP	$15	5.7%	0.3%	1,440	5.7%	1,441	1
MPS	SH_SP	$40	1.4%	0.3%	1,883	1.7%	1,884	1
MPS	SH_P	$25	2.6%	0.6%	1,586	3.1%	1,588	3
MPS	SH_OP	$15	4.3%	0.2%	1,456	4.3%	1,456	1
NEPOOL	S_SP1	$100	0.0%	0.0%	1,060	0.0%	1,060	0
NEPOOL	S_SP2	$75	0.0%	0.0%	1,060	0.0%	1,060	0
NEPOOL	S_SP3	$50	0.0%	0.0%	1,058	0.0%	1,058	0
NEPOOL	S_P	$30	0.0%	0.0%	1,077	0.0%	1,077	0
NEPOOL	S_OP	$20	0.0%	0.0%	1,097	0.0%	1,097	0
NEPOOL	W_SP	$25	0.0%	0.0%	1,066	0.0%	1,066	0
NEPOOL	W_P	$20	0.0%	0.0%	1,126	0.0%	1,126	0
NEPOOL	W_OP	$15	0.0%	0.0%	2,319	0.0%	2,319	0
NEPOOL	SH_SP	$40	0.0%	0.0%	1,073	0.0%	1,073	0
NEPOOL	SH_P	$25	0.0%	0.0%	1,059	0.0%	1,059	0
NEPOOL	SH_OP	$15	0.0%	0.0%	2,269	0.0%	2,269	0

Economic Capacity
100 MW Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
NIPS	S_SP1	$100	13.3%	0.3%	2,454	13.4%	2,491	37
NIPS	S_SP2	$75	12.8%	0.5%	2,443	12.9%	2,480	37
NIPS	S_SP3	$50	12.9%	0.5%	2,418	13.0%	2,454	37
NIPS	S_P	$30	11.6%	0.6%	2,231	11.7%	2,267	36
NIPS	S_OP	$20	12.1%	0.6%	2,187	12.2%	2,221	35
NIPS	W_SP	$25	9.4%	0.6%	1,522	9.7%	1,529	7
NIPS	W_P	$20	12.8%	0.9%	1,621	13.2%	1,632	11
NIPS	W_OP	$15	11.3%	1.1%	1,487	11.8%	1,498	11
NIPS	SH_SP	$40	12.1%	0.7%	1,479	12.3%	1,486	7
NIPS	SH_P	$25	9.6%	0.7%	1,410	9.8%	1,416	6
NIPS	SH_OP	$15	11.3%	1.5%	1,404	12.2%	1,423	18
NSP	S_SP1	$100	1.8%	0.1%	2,614	1.8%	2,614	0
NSP	S_SP2	$75	1.7%	0.1%	2,614	1.7%	2,614	0
NSP	S_SP3	$50	1.8%	0.1%	2,329	1.9%	2,329	0
NSP	S_P	$30	1.9%	0.1%	2,250	1.9%	2,251	0
NSP	S_OP	$20	3.1%	0.1%	2,468	3.1%	2,469	1
NSP	W_SP	$25	2.5%	0.1%	2,054	2.5%	2,054	0
NSP	W_P	$20	3.9%	0.2%	2,220	4.0%	2,220	0
NSP	W_OP	$15	5.2%	0.3%	2,762	5.2%	2,764	2
NSP	SH_SP	$40	2.6%	0.1%	1,877	2.6%	1,877	0
NSP	SH_P	$25	3.1%	0.2%	1,912	3.1%	1,912	0
NSP	SH_OP	$15	6.0%	0.3%	2,609	6.0%	2,609	0
NYPP	S_SP1	$100	0.0%	0.9%	947	0.9%	947	0
NYPP	S_SP2	$75	0.0%	0.9%	947	0.9%	947	0
NYPP	S_SP3	$50	0.0%	0.9%	961	0.9%	961	0
NYPP	S_P	$30	0.0%	1.0%	980	1.0%	980	0
NYPP	S_OP	$20	0.0%	0.9%	1,000	0.9%	1,000	0
NYPP	W_SP	$25	0.0%	0.5%	981	0.5%	981	0
NYPP	W_P	$20	0.0%	0.7%	1,079	0.7%	1,079	0
NYPP	W_OP	$15	0.0%	1.0%	1,478	1.0%	1,478	0
NYPP	SH_SP	$40	0.0%	1.7%	893	1.7%	893	0
NYPP	SH_P	$25	0.0%	1.7%	823	1.8%	823	0
NYPP	SH_OP	$15	0.0%	3.9%	1,105	4.0%	1,105	0
SCEG	S_SP1	$100	0.3%	0.3%	2,939	0.6%	2,940	1
SCEG	S_SP2	$75	0.3%	0.4%	2,939	0.6%	2,940	1
SCEG	S_SP3	$50	0.3%	0.4%	2,876	0.6%	2,877	1
SCEG	S_P	$30	0.4%	0.0%	2,776	0.4%	2,777	1
SCEG	S_OP	$20	0.7%	0.0%	2,706	0.7%	2,708	1
SCEG	W_SP	$25	0.5%	0.0%	2,984	0.5%	2,985	1
SCEG	W_P	$20	0.4%	0.2%	2,942	0.6%	2,942	0
SCEG	W_OP	$15	1.2%	0.1%	1,353	1.2%	1,355	2
SCEG	SH_SP	$40	0.3%	0.4%	2,290	0.7%	2,291	2
SCEG	SH_P	$25	0.6%	0.0%	2,208	0.7%	2,209	1
SCEG	SH_OP	$15	1.1%	0.3%	1,178	1.3%	1,183	4
SCPSA	S_SP1	$100	0.3%	0.3%	1,821	0.6%	1,823	2
SCPSA	S_SP2	$75	0.3%	0.3%	1,821	0.6%	1,823	2
SCPSA	S_SP3	$50	0.3%	0.3%	1,809	0.7%	1,811	2
SCPSA	S_P	$30	0.5%	0.0%	1,786	0.5%	1,788	2
SCPSA	S_OP	$20	0.7%	0.0%	1,723	0.7%	1,725	2
SCPSA	W_SP	$25	0.6%	0.0%	1,939	0.6%	1,940	1
SCPSA	W_P	$20	0.5%	0.2%	1,904	0.5%	1,909	5
SCPSA	W_OP	$15	0.6%	0.1%	1,868	0.7%	1,869	1
SCPSA	SH_SP	$40	0.4%	0.4%	1,567	0.8%	1,569	2
SCPSA	SH_P	$25	0.8%	0.0%	1,572	0.8%	1,574	2
SCPSA	SH_OP	$15	0.6%	0.3%	1,468	0.8%	1,469	2

Economic Capacity
100 MW Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
SOCO	S_SP1	$100	0.0%	2.4%	5,929	2.4%	5,938	9
SOCO	S_SP2	$75	0.0%	2.4%	5,929	2.4%	5,938	9
SOCO	S_SP3	$50	0.0%	2.4%	5,891	2.4%	5,900	9
SOCO	S_P	$30	0.1%	2.5%	5,752	2.6%	5,761	9
SOCO	S_OP	$20	0.1%	0.0%	6,162	0.1%	6,172	11
SOCO	W_SP	$25	0.2%	2.4%	5,257	2.6%	5,265	8
SOCO	W_P	$20	0.8%	0.0%	5,581	0.8%	5,590	9
SOCO	W_OP	$15	3.3%	0.1%	3,180	3.4%	3,184	4
SOCO	SH_SP	$40	0.1%	2.4%	5,086	2.5%	5,098	12
SOCO	SH_P	$25	0.1%	0.2%	5,283	0.3%	5,297	13
SOCO	SH_OP	$15	3.7%	0.1%	2,721	3.6%	2,738	17
TVA	S_SP1	$100	2.4%	0.2%	5,124	2.7%	5,126	2
TVA	S_SP2	$75	2.4%	0.3%	5,124	2.6%	5,126	2
TVA	S_SP3	$50	2.4%	0.3%	5,124	2.6%	5,126	2
TVA	S_P	$30	2.5%	0.3%	5,139	2.7%	5,152	13
TVA	S_OP	$20	2.5%	0.3%	5,661	2.7%	5,678	17
TVA	W_SP	$25	1.6%	0.2%	4,393	1.7%	4,404	11
TVA	W_P	$20	1.1%	0.1%	5,447	1.1%	5,463	15
TVA	W_OP	$15	3.3%	0.5%	5,068	3.7%	5,087	19
TVA	SH_SP	$40	1.7%	0.2%	4,245	1.9%	4,250	5
TVA	SH_P	$25	1.7%	0.2%	4,584	1.8%	4,591	7
TVA	SH_OP	$15	3.4%	0.7%	4,810	3.9%	4,822	12
UPP	S_SP1	$100	0.2%	0.0%	3,273	0.2%	3,272	-1
UPP	S_SP2	$75	0.2%	0.0%	3,273	0.2%	3,272	-1
UPP	S_SP3	$50	0.2%	0.0%	3,273	0.2%	3,272	-1
UPP	S_P	$30	0.3%	0.0%	3,604	0.3%	3,603	-2
UPP	S_OP	$20	0.6%	0.0%	4,757	0.6%	4,753	-4
UPP	W_SP	$25	3.6%	0.1%	2,243	3.6%	2,242	0
UPP	W_P	$20	6.7%	0.2%	2,059	6.7%	2,059	0
UPP	W_OP	$15	8.5%	0.3%	2,276	8.5%	2,276	0
UPP	SH_SP	$40	0.0%	0.0%	5,018	0.0%	5,018	0
UPP	SH_P	$25	0.0%	0.0%	6,258	0.0%	6,258	0
UPP	SH_OP	$15	0.0%	0.0%	7,959	0.0%	7,959	0
VP	S_SP1	$100	0.8%	0.2%	1,984	0.9%	1,984	0
VP	S_SP2	$75	0.7%	0.2%	1,984	0.9%	1,985	0
VP	S_SP3	$50	0.7%	0.2%	1,951	0.9%	1,952	0
VP	S_P	$30	0.8%	0.1%	1,906	1.0%	1,907	0
VP	S_OP	$20	1.4%	0.1%	1,821	1.4%	1,821	0
VP	W_SP	$25	1.4%	0.4%	1,821	1.8%	1,819	-2
VP	W_P	$20	3.0%	0.4%	2,002	3.3%	1,997	-5
VP	W_OP	$15	7.9%	0.7%	1,743	8.3%	1,747	4
VP	SH_SP	$40	0.9%	0.6%	1,596	1.6%	1,604	8
VP	SH_P	$25	1.7%	0.7%	1,536	2.4%	1,544	8
VP	SH_OP	$15	8.0%	1.2%	1,373	8.9%	1,390	17
WEP	S_SP1	$100	1.0%	0.0%	8,506	1.0%	8,497	-9
WEP	S_SP2	$75	0.9%	0.0%	8,506	0.9%	8,497	-9
WEP	S_SP3	$50	0.9%	0.0%	8,506	0.9%	8,497	-9
WEP	S_P	$30	0.8%	0.0%	8,601	0.8%	8,593	-8
WEP	S_OP	$20	1.2%	0.0%	8,470	1.2%	8,460	-10
WEP	W_SP	$25	5.9%	0.1%	3,787	5.9%	3,785	-1
WEP	W_P	$20	7.2%	0.2%	3,550	7.1%	3,548	-2
WEP	W_OP	$15	6.7%	0.3%	2,992	6.7%	2,991	-1
WEP	SH_SP	$40	7.7%	0.2%	3,422	7.6%	3,425	2
WEP	SH_P	$25	7.6%	0.2%	3,356	7.5%	3,359	2
WEP	SH_OP	$15	7.8%	0.4%	2,516	7.6%	2,518	2

Economic Capacity
100 MW Transmission Path, WITH MITIGATION

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
WPS	S_SP1	$100	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_SP2	$75	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_SP3	$50	0.6%	0.0%	6,200	0.6%	6,200	0
WPS	S_P	$30	0.6%	0.0%	5,994	0.6%	5,994	0
WPS	S_OP	$20	0.8%	0.0%	6,427	0.8%	6,427	0
WPS	W_SP	$25	2.2%	0.1%	3,648	2.2%	3,648	0
WPS	W_P	$20	2.7%	0.1%	3,753	2.7%	3,753	0
WPS	W_OP	$15	3.2%	0.2%	4,218	3.2%	4,218	0
WPS	SH_SP	$40	1.3%	0.0%	3,808	1.3%	3,808	0
WPS	SH_P	$25	2.0%	0.0%	3,611	1.9%	3,611	0
WPS	SH_OP	$15	4.1%	0.2%	4,238	4.1%	4,238	0
WR	S_SP1	$100	0.4%	0.4%	6,016	0.8%	6,016	0
WR	S_SP2	$75	0.5%	0.4%	6,014	0.8%	6,015	0
WR	S_SP3	$50	0.5%	0.4%	6,014	0.8%	6,015	0
WR	S_P	$30	0.8%	0.4%	5,128	1.2%	5,129	1
WR	S_OP	$20	1.5%	0.8%	4,557	2.2%	4,559	2
WR	W_SP	$25	1.4%	0.4%	5,027	1.8%	5,028	1
WR	W_P	$20	2.4%	0.1%	4,473	2.4%	4,474	1
WR	W_OP	$15	3.1%	0.1%	4,500	3.1%	4,500	0
WR	SH_SP	$40	0.6%	0.3%	5,037	0.9%	5,037	0
WR	SH_P	$25	1.2%	0.5%	4,805	1.7%	4,806	1
WR	SH_OP	$15	2.4%	0.1%	4,243	2.5%	4,243	0

Competitive Analysis Screening Model (CASm)
HHI Report.
Unicom/PECO Market Power Analysis
Economic Capacity
Sensitivity: TTCs (pre-mitigation, 100 MW path)

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
COMED	S_SP1	$100	75.7%	0.2%	5,784	75.4%	5,751	-33
COMED	S_SP2	$75	73.1%	1.4%	5,412	74.1%	5,558	145
COMED	S_SP3	$50	73.2%	1.4%	5,422	74.2%	5,568	146
COMED	S_P	$30	63.8%	1.4%	4,228	64.8%	4,361	133
COMED	S_OP	$20	71.0%	1.8%	5,119	72.3%	5,304	185
COMED	W_SP	$25	65.9%	1.5%	4,506	67.0%	4,649	143
COMED	W_P	$20	73.2%	1.8%	5,413	74.4%	5,598	185
COMED	W_OP	$15	67.7%	1.9%	4,661	69.0%	4,845	184
COMED	SH_SP	$40	66.0%	1.4%	4,454	67.0%	4,584	130
COMED	SH_P	$25	63.4%	1.6%	4,181	64.5%	4,325	144
COMED	SH_OP	$15	64.6%	2.0%	4,263	66.0%	4,450	188
PJM_ALL	S_SP1	$100	0.0%	11.6%	927	11.8%	930	3
PJM_ALL	S_SP2	$75	0.0%	11.7%	923	11.8%	926	3
PJM_ALL	S_SP3	$50	0.0%	11.8%	925	11.9%	928	3
PJM_ALL	S_P	$30	0.0%	12.7%	853	12.9%	857	4
PJM_ALL	S_OP	$20	0.1%	10.4%	862	10.7%	868	6
PJM_ALL	W_SP	$25	0.0%	11.9%	825	12.0%	827	2
PJM_ALL	W_P	$20	0.0%	10.9%	858	11.1%	859	1
PJM_ALL	W_OP	$15	0.1%	11.9%	856	12.2%	860	4
PJM_ALL	SH_SP	$40	0.0%	11.8%	833	11.9%	836	3
PJM_ALL	SH_P	$25	0.0%	11.0%	774	11.2%	777	3
PJM_ALL	SH_OP	$15	0.1%	10.8%	797	11.1%	802	5
PJM_C+E	S_SP1	$100	0.0%	15.7%	1,278	15.9%	1,281	3
PJM_C+E	S_SP2	$75	0.0%	15.7%	1,270	15.9%	1,273	3
PJM_C+E	S_SP3	$50	0.0%	15.9%	1,279	16.2%	1,282	3
PJM_C+E	S_P	$30	0.1%	17.4%	1,171	17.7%	1,177	6
PJM_C+E	S_OP	$20	0.1%	14.6%	1,162	15.0%	1,168	6
PJM_C+E	W_SP	$25	0.1%	16.1%	1,126	16.5%	1,133	6
PJM_C+E	W_P	$20	0.1%	15.2%	1,191	15.6%	1,197	6
PJM_C+E	W_OP	$15	0.2%	15.0%	1,117	15.5%	1,125	8
PJM_C+E	SH_SP	$40	0.1%	16.2%	1,098	16.5%	1,103	5
PJM_C+E	SH_P	$25	0.1%	14.8%	1,019	15.2%	1,026	7
PJM_C+E	SH_OP	$15	0.2%	13.9%	993	14.4%	1,001	9
PJM_EAST	S_SP1	$100	0.0%	17.0%	1,395	17.3%	1,398	3
PJM_EAST	S_SP2	$75	0.0%	17.1%	1,382	17.3%	1,385	3
PJM_EAST	S_SP3	$50	0.0%	17.3%	1,391	17.6%	1,394	3
PJM_EAST	S_P	$30	0.0%	19.4%	1,268	19.7%	1,275	6
PJM_EAST	S_OP	$20	0.1%	16.2%	1,221	16.6%	1,227	6
PJM_EAST	W_SP	$25	0.0%	19.0%	1,235	19.3%	1,242	7
PJM_EAST	W_P	$20	0.2%	17.5%	1,295	18.1%	1,306	10
PJM_EAST	W_OP	$15	0.7%	18.7%	1,328	19.8%	1,361	33
PJM_EAST	SH_SP	$40	0.0%	18.2%	1,235	18.5%	1,240	5
PJM_EAST	SH_P	$25	0.1%	17.1%	1,082	17.5%	1,090	7
PJM_EAST	SH_OP	$15	0.8%	16.2%	1,112	17.5%	1,145	34
PJM_W+C+E	S_SP1	$100	0.1%	11.7%	913	11.9%	918	5
PJM_W+C+E	S_SP2	$75	0.1%	11.7%	908	11.9%	914	5
PJM_W+C+E	S_SP3	$50	0.1%	11.8%	911	12.0%	916	5
PJM_W+C+E	S_P	$30	0.1%	12.8%	840	13.0%	847	7
PJM_W+C+E	S_OP	$20	0.1%	10.5%	850	10.8%	855	5
PJM_W+C+E	W_SP	$25	0.1%	12.4%	842	12.7%	846	4
PJM_W+C+E	W_P	$20	0.1%	11.0%	851	11.3%	854	3
PJM_W+C+E	W_OP	$15	0.1%	12.0%	836	12.4%	841	4
PJM_W+C+E	SH_SP	$40	0.1%	12.1%	827	12.3%	831	4
PJM_W+C+E	SH_P	$25	0.1%	11.3%	766	11.6%	770	4
PJM_W+C+E	SH_OP	$15	0.1%	10.6%	764	11.0%	769	5

Economic Capacity
Sensitivity: TTCs (pre-mitigation, 100 MW path)

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
AEP	S_SP1	$100	3.9%	0.5%	1,524	4.3%	1,535	10
AEP	S_SP2	$75	3.5%	0.6%	1,522	4.0%	1,533	11
AEP	S_SP3	$50	3.5%	0.6%	1,524	4.0%	1,535	11
AEP	S_P	$30	3.5%	0.6%	1,577	4.0%	1,588	10
AEP	S_OP	$20	3.3%	0.4%	1,813	3.6%	1,824	11
AEP	W_SP	$25	0.6%	0.5%	1,551	1.1%	1,551	0
AEP	W_P	$20	0.2%	0.4%	1,796	0.7%	1,794	-1
AEP	W_OP	$15	0.1%	0.4%	2,433	0.4%	2,431	-2
AEP	SH_SP	$40	2.5%	0.7%	1,336	3.2%	1,336	0
AEP	SH_P	$25	0.8%	0.6%	1,405	1.4%	1,400	-5
AEP	SH_OP	$15	0.1%	0.5%	2,254	0.5%	2,244	-9
APS	S_SP1	$100	1.7%	0.2%	2,469	1.8%	2,491	22
APS	S_SP2	$75	1.6%	0.2%	2,469	1.8%	2,491	22
APS	S_SP3	$50	1.6%	0.2%	2,467	1.8%	2,489	22
APS	S_P	$30	1.8%	0.2%	2,474	1.9%	2,496	22
APS	S_OP	$20	2.7%	0.3%	2,446	2.9%	2,466	20
APS	W_SP	$25	2.2%	0.2%	2,113	2.4%	2,135	22
APS	W_P	$20	3.9%	0.3%	2,285	4.1%	2,307	22
APS	W_OP	$15	9.1%	0.4%	2,085	9.3%	2,109	24
APS	SH_SP	$40	1.8%	0.4%	1,936	2.1%	1,955	20
APS	SH_P	$25	2.4%	0.2%	1,895	2.7%	1,914	19
APS	SH_OP	$15	10.3%	0.5%	1,897	10.6%	1,920	22
CAPO	S_SP1	$100	0.8%	0.1%	3,410	0.8%	3,420	10
CAPO	S_SP2	$75	0.7%	0.1%	3,409	0.8%	3,420	10
CAPO	S_SP3	$50	0.7%	0.1%	3,351	0.8%	3,361	10
CAPO	S_P	$30	0.9%	0.1%	3,204	0.9%	3,216	12
CAPO	S_OP	$20	1.3%	0.1%	2,874	1.3%	2,883	9
CAPO	W_SP	$25	1.0%	0.1%	2,498	1.1%	2,508	10
CAPO	W_P	$20	1.9%	0.1%	2,216	1.9%	2,225	9
CAPO	W_OP	$15	4.9%	0.2%	1,865	5.0%	1,876	11
CAPO	SH_SP	$40	0.7%	0.2%	2,776	0.9%	2,786	10
CAPO	SH_P	$25	1.1%	0.1%	2,398	1.2%	2,406	9
CAPO	SH_OP	$15	5.1%	0.3%	2,223	5.2%	2,233	10
DLCO	S_SP1	$100	1.6%	1.6%	1,796	3.1%	1,801	5
DLCO	S_SP2	$75	1.6%	1.6%	1,795	3.1%	1,801	5
DLCO	S_SP3	$50	1.6%	1.6%	1,761	3.2%	1,766	5
DLCO	S_P	$30	1.7%	1.7%	1,751	3.4%	1,757	6
DLCO	S_OP	$20	2.9%	1.7%	1,993	4.5%	2,003	11
DLCO	W_SP	$25	1.9%	1.8%	2,040	3.7%	2,048	8
DLCO	W_P	$20	0.7%	1.9%	2,199	2.5%	2,202	3
DLCO	W_OP	$15	0.7%	2.2%	1,842	2.9%	1,847	5
DLCO	SH_SP	$40	1.5%	2.0%	1,728	3.4%	1,739	11
DLCO	SH_P	$25	2.1%	1.9%	1,874	4.0%	1,888	14
DLCO	SH_OP	$15	0.8%	2.4%	1,645	3.1%	1,649	4
FENER	S_SP1	$100	1.4%	0.4%	3,208	1.7%	3,209	2
FENER	S_SP2	$75	1.3%	0.4%	3,208	1.7%	3,209	2
FENER	S_SP3	$50	1.4%	0.4%	3,185	1.7%	3,187	2
FENER	S_P	$30	1.5%	0.5%	3,214	1.9%	3,215	1
FENER	S_OP	$20	2.0%	0.3%	3,197	2.2%	3,199	2
FENER	W_SP	$25	1.8%	0.5%	3,216	2.3%	3,224	8
FENER	W_P	$20	4.1%	0.4%	3,274	4.4%	3,281	7
FENER	W_OP	$15	5.1%	0.3%	3,043	5.4%	3,050	7
FENER	SH_SP	$40	1.3%	0.5%	3,168	1.8%	3,198	30
FENER	SH_P	$25	2.1%	0.5%	3,319	2.7%	3,350	31
FENER	SH_OP	$15	7.5%	0.4%	3,047	8.2%	3,069	23

Economic Capacity
Sensitivity: TTCs (pre-mitigation, 100 MW path)

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
IP	S_SP1	$100	11.7%	1.7%	1,540	13.2%	1,577	37
IP	S_SP2	$75	11.3%	1.9%	1,531	13.0%	1,572	40
IP	S_SP3	$50	11.3%	1.9%	1,531	13.1%	1,572	41
IP	S_P	$30	10.5%	2.1%	1,539	12.4%	1,580	41
IP	S_OP	$20	13.0%	2.1%	1,537	14.9%	1,586	50
IP	W_SP	$25	11.6%	2.3%	1,511	13.7%	1,561	50
IP	W_P	$20	14.6%	2.3%	1,600	16.7%	1,664	64
IP	W_OP	$15	13.9%	2.8%	1,012	16.5%	1,084	71
IP	SH_SP	$40	9.2%	1.9%	1,403	11.1%	1,438	34
IP	SH_P	$25	9.3%	2.2%	1,386	11.4%	1,425	39
IP	SH_OP	$15	11.2%	2.6%	949	13.6%	1,002	54
MECS	S_SP1	$100	0.5%	0.8%	3,193	1.3%	3,195	3
MECS	S_SP2	$75	0.5%	0.8%	3,193	1.3%	3,195	3
MECS	S_SP3	$50	0.5%	0.8%	3,183	1.3%	3,186	3
MECS	S_P	$30	0.5%	0.9%	3,186	1.4%	3,189	3
MECS	S_OP	$20	1.0%	0.1%	3,380	1.0%	3,383	3
MECS	W_SP	$25	1.2%	0.9%	2,066	2.1%	2,060	-6
MECS	W_P	$20	2.6%	0.1%	2,034	2.7%	2,020	-13
MECS	W_OP	$15	1.9%	0.3%	2,245	2.6%	2,216	-29
MECS	SH_SP	$40	1.0%	0.9%	2,191	2.1%	2,143	-48
MECS	SH_P	$25	1.2%	1.0%	2,142	2.3%	2,079	-63
MECS	SH_OP	$15	2.2%	0.3%	2,328	2.3%	2,308	-19
NIPS	S_SP1	$100	12.7%	0.3%	2,108	12.9%	2,138	30
NIPS	S_SP2	$75	12.3%	0.5%	2,098	12.7%	2,133	35
NIPS	S_SP3	$50	12.4%	0.5%	2,075	12.8%	2,110	35
NIPS	S_P	$30	11.1%	0.6%	1,900	11.6%	1,934	34
NIPS	S_OP	$20	11.7%	0.6%	1,878	12.2%	1,912	34
NIPS	W_SP	$25	9.1%	0.6%	1,360	9.6%	1,371	11
NIPS	W_P	$20	9.2%	0.7%	1,417	9.6%	1,430	14
NIPS	W_OP	$15	7.2%	0.5%	1,324	7.6%	1,333	10
NIPS	SH_SP	$40	9.3%	0.6%	1,289	9.7%	1,299	9
NIPS	SH_P	$25	9.4%	0.7%	1,250	9.8%	1,259	9
NIPS	SH_OP	$15	7.1%	0.6%	1,243	7.5%	1,251	8
TVA	S_SP1	$100	1.7%	0.1%	4,600	1.8%	4,601	1
TVA	S_SP2	$75	1.7%	0.2%	4,600	1.8%	4,601	1
TVA	S_SP3	$50	1.7%	0.2%	4,600	1.8%	4,601	1
TVA	S_P	$30	1.9%	0.2%	4,667	2.1%	4,669	2
TVA	S_OP	$20	2.5%	0.3%	5,148	2.7%	5,163	15
TVA	W_SP	$25	1.7%	0.2%	4,060	1.9%	4,070	10
TVA	W_P	$20	2.1%	0.2%	4,784	2.3%	4,792	8
TVA	W_OP	$15	4.0%	0.5%	4,532	4.4%	4,550	18
TVA	SH_SP	$40	1.7%	0.1%	3,971	1.8%	3,975	5
TVA	SH_P	$25	2.4%	0.2%	4,254	2.6%	4,260	6
TVA	SH_OP	$15	6.9%	0.5%	4,386	7.4%	4,399	14
VP	S_SP1	$100	0.7%	0.1%	4,892	0.8%	4,908	16
VP	S_SP2	$75	0.7%	0.1%	4,892	0.8%	4,908	16
VP	S_SP3	$50	0.7%	0.1%	4,792	0.8%	4,808	16
VP	S_P	$30	0.9%	0.1%	4,630	1.0%	4,646	16
VP	S_OP	$20	1.4%	0.1%	3,923	1.5%	3,939	16
VP	W_SP	$25	1.0%	0.1%	4,655	1.0%	4,660	6
VP	W_P	$20	1.9%	0.1%	4,171	1.9%	4,176	6
VP	W_OP	$15	5.1%	0.2%	3,284	5.3%	3,291	8
VP	SH_SP	$40	0.7%	0.2%	4,782	0.8%	4,803	20
VP	SH_P	$25	1.1%	0.1%	4,108	1.2%	4,125	17
VP	SH_OP	$15	6.0%	0.3%	2,968	6.2%	2,987	19

Competitive Analysis Screening Model (CASm)
HHI Report.
Unicom/PECO Market Power Analysis
Economic Capacity
Sensitivity: No Transmission Cost (pre-mitigation, 100 MW path)

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
COMED	S_SP1	$100	75.7%	0.1%	5,787	75.4%	5,751	-37
COMED	S_SP2	$75	73.1%	1.4%	5,415	74.1%	5,558	142
COMED	S_SP3	$50	73.2%	1.4%	5,425	74.2%	5,568	143
COMED	S_P	$30	63.8%	1.4%	4,232	64.8%	4,362	130
COMED	S_OP	$20	71.0%	1.7%	5,126	72.2%	5,302	177
COMED	W_SP	$25	65.9%	1.5%	4,482	67.0%	4,623	141
COMED	W_P	$20	73.2%	1.7%	5,399	74.4%	5,581	182
COMED	W_OP	$15	67.7%	1.9%	4,647	69.0%	4,834	187
COMED	SH_SP	$40	66.0%	1.4%	4,435	67.0%	4,570	134
COMED	SH_P	$25	63.4%	1.7%	4,154	64.5%	4,303	149
COMED	SH_OP	$15	64.6%	2.1%	4,248	66.1%	4,442	195
PJM_ALL	S_SP1	$100	0.1%	11.7%	929	11.9%	933	4
PJM_ALL	S_SP2	$75	0.1%	11.7%	925	11.9%	929	4
PJM_ALL	S_SP3	$50	0.1%	11.8%	928	12.0%	932	4
PJM_ALL	S_P	$30	0.1%	12.7%	863	13.0%	868	5
PJM_ALL	S_OP	$20	0.1%	10.5%	865	10.8%	870	6
PJM_ALL	W_SP	$25	0.1%	12.0%	845	12.2%	849	4
PJM_ALL	W_P	$20	0.1%	11.0%	876	11.3%	879	3
PJM_ALL	W_OP	$15	0.1%	11.8%	882	12.1%	887	5
PJM_ALL	SH_SP	$40	0.1%	12.1%	861	12.3%	865	4
PJM_ALL	SH_P	$25	0.1%	11.4%	805	11.7%	810	5
PJM_ALL	SH_OP	$15	0.1%	10.9%	835	11.4%	842	7
PJM_C+E	S_SP1	$100	0.0%	15.7%	1,279	15.9%	1,282	3
PJM_C+E	S_SP2	$75	0.0%	15.7%	1,271	16.0%	1,273	3
PJM_C+E	S_SP3	$50	0.0%	15.9%	1,280	16.2%	1,283	3
PJM_C+E	S_P	$30	0.0%	17.5%	1,158	17.7%	1,163	5
PJM_C+E	S_OP	$20	0.1%	14.6%	1,170	14.9%	1,174	4
PJM_C+E	W_SP	$25	0.1%	16.2%	1,115	16.5%	1,121	5
PJM_C+E	W_P	$20	0.1%	15.2%	1,183	15.5%	1,188	5
PJM_C+E	W_OP	$15	0.2%	14.8%	1,119	15.3%	1,128	8
PJM_C+E	SH_SP	$40	0.1%	16.3%	1,104	16.6%	1,109	5
PJM_C+E	SH_P	$25	0.1%	14.9%	1,015	15.3%	1,022	7
PJM_C+E	SH_OP	$15	0.2%	14.4%	1,010	14.9%	1,021	12
PJM_EAST	S_SP1	$100	0.0%	17.0%	1,396	17.3%	1,398	2
PJM_EAST	S_SP2	$75	0.0%	17.1%	1,383	17.3%	1,386	2
PJM_EAST	S_SP3	$50	0.0%	17.3%	1,392	17.6%	1,395	3
PJM_EAST	S_P	$30	0.0%	19.4%	1,268	19.7%	1,274	6
PJM_EAST	S_OP	$20	0.0%	16.2%	1,223	16.6%	1,228	5
PJM_EAST	W_SP	$25	0.0%	19.0%	1,235	19.3%	1,242	6
PJM_EAST	W_P	$20	0.0%	17.5%	1,296	17.9%	1,302	5
PJM_EAST	W_OP	$15	0.1%	18.3%	1,327	18.8%	1,336	9
PJM_EAST	SH_SP	$40	0.0%	18.2%	1,239	18.5%	1,244	5
PJM_EAST	SH_P	$25	0.0%	17.1%	1,082	17.5%	1,089	7
PJM_EAST	SH_OP	$15	0.1%	15.9%	1,123	16.5%	1,132	9
PJM_W+C+E	S_SP1	$100	0.1%	11.7%	920	11.9%	925	5
PJM_W+C+E	S_SP2	$75	0.1%	11.7%	916	11.9%	920	5
PJM_W+C+E	S_SP3	$50	0.1%	11.8%	918	12.0%	923	5
PJM_W+C+E	S_P	$30	0.1%	12.8%	849	13.0%	855	6
PJM_W+C+E	S_OP	$20	0.1%	10.5%	848	10.8%	854	6
PJM_W+C+E	W_SP	$25	0.1%	12.0%	806	12.3%	812	6
PJM_W+C+E	W_P	$20	0.1%	11.0%	843	11.3%	848	5
PJM_W+C+E	W_OP	$15	0.3%	11.9%	857	12.4%	867	9
PJM_W+C+E	SH_SP	$40	0.1%	12.0%	847	12.3%	852	5
PJM_W+C+E	SH_P	$25	0.1%	11.3%	786	11.6%	791	5
PJM_W+C+E	SH_OP	$15	0.1%	10.9%	831	11.3%	838	7

Economic Capacity
Sensitivity: No Transmission Cost (pre-mitigation, 100 MW path)

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
AEP	S_SP1	$100	3.4%	0.6%	1,655	3.9%	1,667	12
AEP	S_SP2	$75	3.3%	0.6%	1,655	3.8%	1,667	12
AEP	S_SP3	$50	3.3%	0.6%	1,656	3.8%	1,669	12
AEP	S_P	$30	2.9%	0.7%	1,667	3.5%	1,680	12
AEP	S_OP	$20	3.1%	0.7%	1,671	3.7%	1,684	12
AEP	W_SP	$25	0.5%	0.8%	1,491	1.4%	1,491	0
AEP	W_P	$20	0.5%	0.7%	1,493	1.3%	1,493	0
AEP	W_OP	$15	0.6%	0.9%	1,462	1.6%	1,461	0
AEP	SH_SP	$40	2.1%	0.9%	1,308	3.0%	1,307	-1
AEP	SH_P	$25	2.3%	1.0%	1,316	3.3%	1,315	-1
AEP	SH_OP	$15	1.9%	1.2%	1,301	3.1%	1,300	-2
APS	S_SP1	$100	0.8%	0.1%	1,933	1.0%	1,933	1
APS	S_SP2	$75	0.8%	0.1%	1,933	0.9%	1,933	1
APS	S_SP3	$50	0.8%	0.1%	1,903	1.0%	1,904	1
APS	S_P	$30	0.8%	0.2%	1,833	0.9%	1,834	0
APS	S_OP	$20	0.9%	0.1%	1,702	1.0%	1,703	0
APS	W_SP	$25	1.1%	0.4%	1,622	1.6%	1,623	0
APS	W_P	$20	1.2%	0.4%	1,570	1.6%	1,570	0
APS	W_OP	$15	1.5%	0.5%	1,424	2.1%	1,423	0
APS	SH_SP	$40	0.9%	0.6%	1,569	1.5%	1,578	9
APS	SH_P	$25	1.0%	0.6%	1,400	1.7%	1,408	8
APS	SH_OP	$15	1.3%	0.9%	1,200	2.2%	1,205	5
CAPO	S_SP1	$100	0.7%	0.1%	4,218	0.8%	4,231	13
CAPO	S_SP2	$75	0.7%	0.1%	4,218	0.8%	4,231	13
CAPO	S_SP3	$50	0.7%	0.1%	4,155	0.8%	4,168	13
CAPO	S_P	$30	0.7%	0.2%	3,980	0.8%	3,993	13
CAPO	S_OP	$20	0.8%	0.1%	3,588	0.9%	3,601	13
CAPO	W_SP	$25	0.7%	0.2%	4,195	0.9%	4,217	22
CAPO	W_P	$20	0.8%	0.2%	3,800	1.0%	3,821	21
CAPO	W_OP	$15	1.0%	0.2%	3,275	1.1%	3,295	21
CAPO	SH_SP	$40	0.7%	0.3%	3,299	0.9%	3,311	12
CAPO	SH_P	$25	0.8%	0.3%	2,870	1.0%	2,881	11
CAPO	SH_OP	$15	0.9%	0.3%	2,387	1.2%	2,396	10
DLCO	S_SP1	$100	1.5%	1.5%	1,800	3.0%	1,803	3
DLCO	S_SP2	$75	1.4%	1.5%	1,800	3.0%	1,803	3
DLCO	S_SP3	$50	1.5%	1.6%	1,758	3.0%	1,761	3
DLCO	S_P	$30	1.3%	1.6%	1,676	2.9%	1,679	2
DLCO	S_OP	$20	1.4%	1.6%	1,630	2.9%	1,632	2
DLCO	W_SP	$25	1.2%	2.2%	2,067	3.4%	2,071	4
DLCO	W_P	$20	1.3%	2.1%	2,056	3.4%	2,060	4
DLCO	W_OP	$15	1.4%	2.3%	1,787	3.7%	1,791	4
DLCO	SH_SP	$40	1.4%	2.6%	1,880	4.0%	1,887	8
DLCO	SH_P	$25	1.4%	2.7%	1,857	4.1%	1,865	8
DLCO	SH_OP	$15	1.5%	2.9%	1,611	4.5%	1,619	9
FENER	S_SP1	$100	1.0%	0.1%	1,928	1.1%	1,928	0
FENER	S_SP2	$75	0.9%	0.1%	1,929	1.0%	1,929	0
FENER	S_SP3	$50	0.9%	0.1%	1,901	1.1%	1,901	0
FENER	S_P	$30	0.9%	0.1%	1,838	1.0%	1,838	0
FENER	S_OP	$20	1.1%	0.1%	1,710	1.1%	1,710	0
FENER	W_SP	$25	1.4%	0.4%	1,613	1.8%	1,612	-1
FENER	W_P	$20	1.5%	0.4%	1,569	1.9%	1,569	-1
FENER	W_OP	$15	1.7%	0.5%	1,422	2.3%	1,422	0
FENER	SH_SP	$40	1.1%	0.6%	1,543	1.7%	1,550	7
FENER	SH_P	$25	1.3%	0.6%	1,396	2.0%	1,403	7
FENER	SH_OP	$15	1.5%	0.9%	1,194	2.4%	1,200	6

Economic Capacity
Sensitivity: No Transmission Cost (pre-mitigation, 100 MW path)

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
IP	S_SP1	$100	12.8%	1.7%	1,542	14.3%	1,582	40
IP	S_SP2	$75	11.8%	2.0%	1,502	13.6%	1,545	42
IP	S_SP3	$50	12.4%	1.9%	1,529	14.1%	1,573	44
IP	S_P	$30	11.0%	2.0%	1,399	12.8%	1,440	41
IP	S_OP	$20	11.9%	2.1%	1,400	13.9%	1,446	46
IP	W_SP	$25	11.1%	2.2%	1,338	13.1%	1,384	45
IP	W_P	$20	11.4%	2.2%	1,340	13.4%	1,387	47
IP	W_OP	$15	10.7%	2.5%	851	13.0%	901	50
IP	SH_SP	$40	9.1%	2.0%	1,461	11.0%	1,496	35
IP	SH_P	$25	8.6%	2.2%	1,283	10.7%	1,319	35
IP	SH_OP	$15	8.1%	2.3%	800	10.3%	837	36
MECS	S_SP1	$100	0.5%	0.8%	3,368	1.3%	3,371	3
MECS	S_SP2	$75	0.5%	0.8%	3,368	1.3%	3,371	3
MECS	S_SP3	$50	0.5%	0.8%	3,359	1.3%	3,362	3
MECS	S_P	$30	0.4%	0.9%	3,365	1.3%	3,368	3
MECS	S_OP	$20	0.6%	0.1%	3,479	0.7%	3,481	3
MECS	W_SP	$25	1.2%	1.0%	2,277	2.2%	2,266	-11
MECS	W_P	$20	1.3%	0.3%	2,206	1.6%	2,193	-13
MECS	W_OP	$15	1.4%	0.2%	2,252	1.6%	2,237	-15
MECS	SH_SP	$40	1.1%	1.0%	2,410	2.2%	2,353	-56
MECS	SH_P	$25	1.2%	1.2%	2,362	2.5%	2,300	-61
MECS	SH_OP	$15	1.4%	0.3%	2,348	1.8%	2,273	-75
NIPS	S_SP1	$100	13.3%	0.3%	2,453	13.4%	2,490	37
NIPS	S_SP2	$75	12.8%	0.5%	2,442	13.1%	2,484	42
NIPS	S_SP3	$50	12.9%	0.5%	2,416	13.2%	2,458	42
NIPS	S_P	$30	11.6%	0.6%	2,221	12.0%	2,263	41
NIPS	S_OP	$20	12.6%	0.6%	2,177	13.0%	2,219	42
NIPS	W_SP	$25	10.9%	0.7%	1,473	11.4%	1,486	13
NIPS	W_P	$20	9.4%	0.6%	1,500	9.8%	1,511	11
NIPS	W_OP	$15	7.2%	0.7%	1,467	7.6%	1,476	10
NIPS	SH_SP	$40	9.4%	0.6%	1,460	9.9%	1,469	9
NIPS	SH_P	$25	8.7%	0.8%	1,373	9.3%	1,384	10
NIPS	SH_OP	$15	6.9%	0.8%	1,361	7.5%	1,371	10
TVA	S_SP1	$100	2.4%	0.3%	5,123	2.6%	5,125	2
TVA	S_SP2	$75	2.3%	0.3%	5,122	2.6%	5,124	2
TVA	S_SP3	$50	2.3%	0.3%	5,122	2.6%	5,124	2
TVA	S_P	$30	2.3%	0.3%	4,994	2.6%	4,996	2
TVA	S_OP	$20	2.8%	0.3%	5,492	3.0%	5,494	2
TVA	W_SP	$25	1.3%	0.1%	4,385	1.5%	4,396	11
TVA	W_P	$20	1.6%	0.2%	4,831	1.7%	4,844	13
TVA	W_OP	$15	2.0%	0.3%	4,394	2.2%	4,409	15
TVA	SH_SP	$40	1.6%	0.2%	4,239	1.8%	4,244	6
TVA	SH_P	$25	1.9%	0.2%	4,576	2.1%	4,583	7
TVA	SH_OP	$15	2.2%	0.4%	4,112	2.6%	4,120	8
VP	S_SP1	$100	0.8%	0.1%	1,979	0.9%	1,979	0
VP	S_SP2	$75	0.8%	0.1%	1,979	0.9%	1,980	0
VP	S_SP3	$50	0.8%	0.1%	1,947	0.9%	1,947	0
VP	S_P	$30	0.7%	0.2%	1,885	0.9%	1,885	0
VP	S_OP	$20	0.9%	0.1%	1,715	0.9%	1,715	0
VP	W_SP	$25	1.1%	0.4%	1,693	1.5%	1,692	-1
VP	W_P	$20	1.1%	0.4%	1,595	1.5%	1,594	-1
VP	W_OP	$15	1.3%	0.3%	1,415	1.7%	1,414	0
VP	SH_SP	$40	1.0%	0.6%	1,606	1.5%	1,614	8
VP	SH_P	$25	1.1%	0.6%	1,423	1.7%	1,430	7
VP	SH_OP	$15	1.3%	0.6%	1,183	1.9%	1,191	7

Competitive Analysis Screening Model (CASm)
HHI Report.
Unicom/PECO Market Power Analysis
Available Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
COMED	S_SP1	$100	7.2%	11.0%	950	18.2%	1,108	158
COMED	S_SP2	$75	8.8%	11.3%	841	20.1%	1,040	199
COMED	S_SP3	$50	33.4%	5.6%	1,544	39.0%	1,918	374
COMED	S_P	$30	26.0%	3.3%	1,403	29.3%	1,575	172
COMED	S_OP	$20	35.8%	4.3%	2,066	40.1%	2,374	308
COMED	W_SP	$25	19.4%	3.8%	1,743	23.2%	1,890	147
COMED	W_P	$20	33.3%	4.8%	2,396	38.1%	2,716	320
COMED	W_OP	$15	49.6%	6.8%	2,915	56.4%	3,590	675
COMED	SH_SP	$40	12.5%	8.3%	1,228	20.8%	1,436	208
COMED	SH_P	$25	16.0%	4.1%	1,718	20.1%	1,849	131
COMED	SH_OP	$15	37.4%	8.3%	2,023	45.7%	2,644	621
PJM_ALL	S_SP1	$100	0.0%	5.2%	1,021	5.2%	1,021	0
PJM_ALL	S_SP2	$75	0.0%	5.6%	1,018	5.6%	1,018	0
PJM_ALL	S_SP3	$50	0.0%	8.0%	888	8.0%	888	0
PJM_ALL	S_P	$30	0.0%	10.6%	884	10.6%	884	0
PJM_ALL	S_OP	$20	0.0%	4.6%	1,076	4.6%	1,076	0
PJM_ALL	W_SP	$25	0.0%	5.7%	1,831	5.7%	1,831	0
PJM_ALL	W_P	$20	0.0%	10.7%	1,603	10.7%	1,603	0
PJM_ALL	W_OP	$15	0.0%	14.9%	3,288	14.9%	3,288	0
PJM_ALL	SH_SP	$40	0.0%	10.8%	933	10.8%	933	0
PJM_ALL	SH_P	$25	0.0%	6.0%	1,441	6.0%	1,441	0
PJM_ALL	SH_OP	$15	0.0%	13.4%	2,763	13.4%	2,763	0
PJM_C+E	S_SP1	$100	0.0%	5.8%	1,241	5.8%	1,241	0
PJM_C+E	S_SP2	$75	0.0%	6.4%	1,047	6.4%	1,047	0
PJM_C+E	S_SP3	$50	0.0%	9.5%	859	9.5%	859	0
PJM_C+E	S_P	$30	0.0%	12.2%	942	12.2%	942	0
PJM_C+E	S_OP	$20	0.0%	2.7%	1,172	2.7%	1,172	0
PJM_C+E	W_SP	$25	0.0%	6.2%	1,640	6.2%	1,640	0
PJM_C+E	W_P	$20	0.0%	10.7%	1,603	10.7%	1,603	0
PJM_C+E	W_OP	$15	0.0%	14.9%	3,288	14.9%	3,288	0
PJM_C+E	SH_SP	$40	0.0%	12.6%	1,141	12.6%	1,141	0
PJM_C+E	SH_P	$25	0.0%	6.0%	1,441	6.0%	1,441	0
PJM_C+E	SH_OP	$15	0.0%	13.4%	2,763	13.4%	2,763	0
PJM_EAST	S_SP1	$100	0.0%	3.4%	945	3.4%	945	0
PJM_EAST	S_SP2	$75	0.3%	5.0%	830	5.3%	833	3
PJM_EAST	S_SP3	$50	1.1%	8.7%	777	9.8%	796	19
PJM_EAST	S_P	$30	0.6%	11.2%	801	11.8%	814	13
PJM_EAST	S_OP	$20	0.0%	2.0%	1,389	2.0%	1,389	0
PJM_EAST	W_SP	$25	0.0%	4.3%	1,938	4.3%	1,938	0
PJM_EAST	W_P	$20	0.0%	10.7%	1,603	10.7%	1,603	0
PJM_EAST	W_OP	$15	0.0%	14.9%	3,288	14.9%	3,288	0
PJM_EAST	SH_SP	$40	0.0%	9.4%	760	9.4%	760	0
PJM_EAST	SH_P	$25	0.0%	4.3%	1,559	4.3%	1,559	0
PJM_EAST	SH_OP	$15	0.0%	13.4%	2,763	13.4%	2,763	0
PJM_W+C+E	S_SP1	$100	0.0%	5.2%	1,021	5.2%	1,021	0
PJM_W+C+E	S_SP2	$75	0.0%	5.1%	1,030	5.1%	1,030	0
PJM_W+C+E	S_SP3	$50	0.0%	8.7%	817	8.7%	817	0
PJM_W+C+E	S_P	$30	0.0%	11.4%	883	11.4%	883	0
PJM_W+C+E	S_OP	$20	0.0%	3.6%	1,103	3.6%	1,103	0
PJM_W+C+E	W_SP	$25	0.0%	5.7%	1,831	5.7%	1,831	0
PJM_W+C+E	W_P	$20	0.0%	10.7%	1,603	10.7%	1,603	0
PJM_W+C+E	W_OP	$15	0.0%	14.9%	3,288	14.9%	3,288	0
PJM_W+C+E	SH_SP	$40	0.0%	10.8%	933	10.8%	933	0
PJM_W+C+E	SH_P	$25	0.0%	6.0%	1,441	6.0%	1,441	0
PJM_W+C+E	SH_OP	$15	0.0%	13.4%	2,763	13.4%	2,763	0

Available Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
AECI	S_SP1	$100	4.2%	11.4%	665	15.6%	761	96
AECI	S_SP2	$75	2.2%	13.9%	633	16.1%	694	61
AECI	S_SP3	$50	6.6%	12.3%	559	18.9%	721	162
AECI	S_P	$30	6.2%	7.9%	739	14.1%	837	98
AECI	S_OP	$20	3.5%	14.5%	1,042	18.0%	1,144	102
AECI	W_SP	$25	2.8%	11.2%	973	14.0%	1,036	63
AECI	W_P	$20	0.0%	22.2%	1,399	22.2%	1,399	0
AECI	W_OP	$15	0.0%	13.7%	1,705	13.7%	1,705	0
AECI	SH_SP	$40	1.1%	16.1%	838	17.2%	873	35
AECI	SH_P	$25	2.1%	14.8%	946	16.9%	1,008	62
AECI	SH_OP	$15	0.0%	13.0%	1,131	13.0%	1,131	0
ALLIANT_E	S_SP1	$100	5.0%	6.7%	1,524	11.7%	1,591	67
ALLIANT_E	S_SP2	$75	3.6%	5.0%	891	8.6%	927	36
ALLIANT_E	S_SP3	$50	12.5%	2.1%	1,181	14.6%	1,234	53
ALLIANT_E	S_P	$30	8.3%	1.3%	1,614	9.6%	1,636	22
ALLIANT_E	S_OP	$20	15.7%	2.3%	1,301	18.0%	1,373	72
ALLIANT_E	W_SP	$25	5.8%	2.4%	1,065	8.2%	1,093	28
ALLIANT_E	W_P	$20	5.4%	3.8%	1,438	9.2%	1,479	41
ALLIANT_E	W_OP	$15	0.0%	4.3%	1,095	4.3%	1,095	0
ALLIANT_E	SH_SP	$40	4.4%	3.1%	832	7.5%	859	27
ALLIANT_E	SH_P	$25	0.0%	1.9%	1,183	1.9%	1,183	0
ALLIANT_E	SH_OP	$15	0.0%	4.0%	1,275	4.0%	1,275	0
AEP	S_SP1	$100	2.8%	12.7%	870	15.5%	941	71
AEP	S_SP2	$75	3.2%	9.3%	917	12.5%	977	60
AEP	S_SP3	$50	5.7%	7.7%	887	13.4%	975	88
AEP	S_P	$30	4.1%	4.6%	1,376	8.7%	1,414	38
AEP	S_OP	$20	0.0%	4.1%	2,011	4.1%	2,011	0
AEP	W_SP	$25	0.9%	5.7%	1,509	6.6%	1,519	10
AEP	W_P	$20	0.0%	5.7%	2,046	5.7%	2,046	0
AEP	W_OP	$15	0.0%	4.2%	5,148	4.2%	5,148	0
AEP	SH_SP	$40	3.3%	14.0%	940	17.3%	1,032	92
AEP	SH_P	$25	0.0%	7.1%	1,379	7.1%	1,379	0
AEP	SH_OP	$15	0.0%	4.6%	4,656	4.6%	4,656	0
APS	S_SP1	$100	2.0%	5.8%	1,739	7.8%	1,762	23
APS	S_SP2	$75	2.4%	4.1%	1,603	6.5%	1,623	20
APS	S_SP3	$50	0.6%	3.5%	1,468	4.1%	1,472	4
APS	S_P	$30	0.0%	1.8%	3,583	1.8%	3,583	0
APS	S_OP	$20	0.0%	4.4%	2,033	4.4%	2,033	0
APS	W_SP	$25	0.0%	5.0%	4,036	5.0%	4,036	0
APS	W_P	$20	0.0%	11.7%	3,318	11.7%	3,318	0
APS	W_OP	$15	0.0%	22.4%	2,576	22.4%	2,576	0
APS	SH_SP	$40	0.0%	7.4%	1,681	7.4%	1,681	0
APS	SH_P	$25	0.0%	5.7%	3,237	5.7%	3,237	0
APS	SH_OP	$15	0.0%	18.6%	2,789	18.6%	2,789	0
ALLIANT_W	S_SP1	$100	2.6%	8.7%	627	11.3%	672	45
ALLIANT_W	S_SP2	$75	2.9%	7.0%	620	9.9%	661	41
ALLIANT_W	S_SP3	$50	8.3%	4.8%	589	13.1%	669	80
ALLIANT_W	S_P	$30	7.5%	5.3%	604	12.8%	684	80
ALLIANT_W	S_OP	$20	13.2%	3.9%	978	17.1%	1,081	103
ALLIANT_W	W_SP	$25	5.4%	7.8%	708	13.2%	792	84
ALLIANT_W	W_P	$20	7.3%	2.5%	1,271	9.8%	1,308	37
ALLIANT_W	W_OP	$15	0.0%	5.9%	1,431	5.9%	1,431	0
ALLIANT_W	SH_SP	$40	4.5%	7.0%	677	11.5%	740	63
ALLIANT_W	SH_P	$25	3.7%	6.0%	749	9.7%	793	44
ALLIANT_W	SH_OP	$15	0.0%	6.1%	1,272	6.1%	1,272	0

Available Economic Capacity
No Transmission Path

Market	Period	Price	BASE COMED Mkt Share	BASE PECO Mkt Share	BASE HHI Pre-Merger	MERGER CE + PECO Mkt Share	MERGER HHI Post-Merger	HHI Chg
AMEREN	S_SP1	$100	3.0%	11.4%	576	14.4%	644	68
AMEREN	S_SP2	$75	2.9%	9.8%	531	12.7%	588	57
AMEREN	S_SP3	$50	8.2%	8.4%	549	16.6%	687	138
AMEREN	S_P	$30	5.2%	5.2%	733	10.4%	787	54
AMEREN	S_OP	$20	5.6%	8.6%	1,012	14.2%	1,108	96
AMEREN	W_SP	$25	1.4%	6.8%	794	8.2%	813	19
AMEREN	W_P	$20	4.8%	7.4%	1,261	12.2%	1,332	71
AMEREN	W_OP	$15	0.0%	6.5%	1,413	6.5%	1,413	0
AMEREN	SH_SP	$40	3.3%	11.4%	549	14.7%	624	75
AMEREN	SH_P	$25	1.1%	9.6%	768	10.7%	789	21
AMEREN	SH_OP	$15	0.0%	6.8%	1,126	6.8%	1,126	0
CAPO	S_SP1	$100	2.3%	16.5%	924	18.8%	1,000	76
CAPO	S_SP2	$75	2.4%	14.8%	766	17.2%	837	71
CAPO	S_SP3	$50	7.1%	12.5%	770	19.6%	948	178
CAPO	S_P	$30	1.3%	3.5%	1,175	4.8%	1,184	9
CAPO	S_OP	$20	0.0%	5.2%	3,102	5.2%	3,102	0
CAPO	W_SP	$25	0.0%	4.3%	2,372	4.3%	2,372	0
CAPO	W_P	$20	0.0%	11.9%	3,367	11.9%	3,367	0
CAPO	W_OP	$15	0.0%	43.5%	3,235	43.5%	3,235	0
CAPO	SH_SP	$40	2.0%	18.8%	926	20.8%	1,001	75
CAPO	SH_P	$25	0.0%	6.4%	1,740	6.4%	1,740	0
CAPO	SH_OP	$15	0.0%	53.9%	4,158	53.9%	4,158	0
CELE	S_SP1	$100	0.0%	7.9%	4,261	7.9%	4,261	0
CELE	S_SP2	$75	0.2%	8.1%	4,249	8.3%	4,252	3
CELE	S_SP3	$50	1.9%	8.6%	4,261	10.5%	4,294	33
CELE	S_P	$30	1.0%	6.9%	4,390	7.9%	4,404	14
CELE	S_OP	$20	0.0%	29.7%	1,772	29.7%	1,772	0
CELE	W_SP	$25	1.1%	6.1%	3,664	7.2%	3,677	13
CELE	W_P	$20	0.0%	28.8%	1,643	28.8%	1,643	0
CELE	W_OP	$15	0.0%	6.8%	2,264	6.8%	2,264	0
CELE	SH_SP	$40	1.8%	8.2%	3,189	10.0%	3,219	30
CELE	SH_P	$25	1.4%	7.6%	3,692	9.0%	3,713	21
CELE	SH_OP	$15	0.0%	5.9%	2,855	5.9%	2,855	0
CILCO	S_SP1	$100	2.3%	7.4%	663	9.7%	697	34
CILCO	S_SP2	$75	2.4%	6.4%	612	8.8%	643	31
CILCO	S_SP3	$50	9.2%	5.2%	505	14.4%	601	96
CILCO	S_P	$30	7.2%	4.8%	627	12.0%	696	69
CILCO	S_OP	$20	10.8%	3.4%	947	14.2%	1,020	73
CILCO	W_SP	$25	3.9%	4.6%	732	8.5%	768	36
CILCO	W_P	$20	9.8%	8.0%	990	17.8%	1,147	157
CILCO	W_OP	$15	0.0%	11.4%	1,415	11.4%	1,415	0
CILCO	SH_SP	$40	4.2%	7.5%	780	11.7%	843	63
CILCO	SH_P	$25	2.9%	4.6%	680	7.5%	707	27
CILCO	SH_OP	$15	0.0%	12.4%	1,098	12.4%	1,098	0
CIN	S_SP1	$100	3.3%	7.1%	992	10.4%	1,039	47
CIN	S_SP2	$75	3.7%	7.8%	881	11.5%	939	58
CIN	S_SP3	$50	3.8%	5.4%	895	9.2%	936	41
CIN	S_P	$30	4.5%	5.5%	1,408	10.0%	1,458	50
CIN	S_OP	$20	0.0%	8.0%	1,406	8.0%	1,406	0
CIN	W_SP	$25	0.0%	8.3%	1,004	8.3%	1,004	0
CIN	W_P	$20	2.9%	8.9%	1,698	11.8%	1,750	52
CIN	W_OP	$15	0.0%	13.6%	2,347	13.6%	2,347	0
CIN	SH_SP	$40	2.8%	11.0%	1,243	13.8%	1,305	62
CIN	SH_P	$25	0.0%	8.9%	1,405	8.9%	1,405	0
CIN	SH_OP	$15	0.0%	14.9%	1,854	14.9%	1,854	0

Available Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
CWLP	S_SP1	$100	1.8%	5.8%	994	7.6%	1,015	21
CWLP	S_SP2	$75	2.4%	5.3%	770	7.7%	795	25
CWLP	S_SP3	$50	7.7%	4.1%	798	11.8%	861	63
CWLP	S_P	$30	4.8%	3.9%	1,099	8.7%	1,136	37
CWLP	S_OP	$20	7.8%	2.9%	897	10.7%	942	45
CWLP	W_SP	$25	3.5%	4.7%	2,014	8.2%	2,047	33
CWLP	W_P	$20	12.2%	5.4%	1,245	17.6%	1,377	132
CWLP	W_OP	$15	0.0%	12.7%	1,760	12.7%	1,760	0
CWLP	SH_SP	$40	4.4%	5.4%	1,468	9.8%	1,516	48
CWLP	SH_P	$25	2.8%	4.0%	1,805	6.8%	1,827	22
CWLP	SH_OP	$15	0.0%	19.6%	1,720	19.6%	1,720	0
DLCO	S_SP1	$100	1.8%	10.0%	1,317	11.8%	1,353	36
DLCO	S_SP2	$75	1.8%	9.5%	715	11.3%	749	34
DLCO	S_SP3	$50	4.9%	5.9%	805	10.8%	863	58
DLCO	S_P	$30	1.4%	6.9%	1,367	8.3%	1,386	19
DLCO	S_OP	$20	0.0%	5.8%	2,699	5.8%	2,699	0
DLCO	W_SP	$25	0.0%	8.4%	2,417	8.4%	2,417	0
DLCO	W_P	$20	0.0%	17.2%	2,104	17.2%	2,104	0
DLCO	W_OP	$15	0.0%	46.4%	3,709	46.4%	3,709	0
DLCO	SH_SP	$40	2.3%	12.2%	645	14.5%	701	56
DLCO	SH_P	$25	0.0%	9.4%	2,406	9.4%	2,406	0
DLCO	SH_OP	$15	0.0%	47.8%	3,459	47.8%	3,459	0
DPL	S_SP1	$100	3.4%	6.6%	912	10.0%	957	45
DPL	S_SP2	$75	3.3%	6.1%	693	9.4%	733	40
DPL	S_SP3	$50	9.6%	4.2%	681	13.8%	762	81
DPL	S_P	$30	8.8%	4.1%	938	12.9%	1,010	72
DPL	S_OP	$20	0.0%	6.0%	1,470	6.0%	1,470	0
DPL	W_SP	$25	2.3%	7.6%	1,271	9.9%	1,306	35
DPL	W_P	$20	0.0%	10.8%	1,890	10.8%	1,890	0
DPL	W_OP	$15	0.0%	17.4%	1,739	17.4%	1,739	0
DPL	SH_SP	$40	2.4%	7.7%	599	10.1%	636	37
DPL	SH_P	$25	0.0%	8.7%	1,212	8.7%	1,212	0
DPL	SH_OP	$15	0.0%	18.3%	1,570	18.3%	1,570	0
DUKE	S_SP1	$100	0.9%	19.7%	1,359	20.6%	1,394	35
DUKE	S_SP2	$75	1.3%	20.5%	1,000	21.8%	1,053	53
DUKE	S_SP3	$50	0.4%	21.4%	1,010	21.8%	1,027	17
DUKE	S_P	$30	0.0%	6.6%	1,814	6.6%	1,814	0
DUKE	S_OP	$20	0.0%	19.2%	6,408	19.2%	6,408	0
DUKE	W_SP	$25	0.0%	4.1%	1,325	4.1%	1,325	0
DUKE	W_P	$20	0.0%	23.0%	6,166	23.0%	6,166	0
DUKE	W_OP	$15	0.0%	82.7%	6,993	82.7%	6,993	0
DUKE	SH_SP	$40	1.1%	16.8%	1,667	17.9%	1,704	37
DUKE	SH_P	$25	0.0%	9.5%	1,670	9.5%	1,670	0
DUKE	SH_OP	$15	0.0%	90.5%	8,278	90.5%	8,278	0
EKPC	S_SP1	$100	4.5%	6.7%	860	11.2%	920	60
EKPC	S_SP2	$75	4.1%	6.2%	666	10.3%	717	51
EKPC	S_SP3	$50	9.9%	4.5%	628	14.4%	717	89
EKPC	S_P	$30	5.1%	2.4%	2,439	7.5%	2,463	24
EKPC	S_OP	$20	0.0%	4.4%	4,436	4.4%	4,436	0
EKPC	W_SP	$25	4.0%	10.6%	1,147	14.6%	1,232	85
EKPC	W_P	$20	0.0%	33.9%	2,222	33.9%	2,222	0
EKPC	W_OP	$15	0.0%	77.1%	6,229	77.1%	6,229	0
EKPC	SH_SP	$40	2.7%	10.2%	763	12.9%	818	55
EKPC	SH_P	$25	0.0%	7.4%	1,833	7.4%	1,833	0
EKPC	SH_OP	$15	0.0%	53.9%	3,756	53.9%	3,756	0

Available Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
ENT	S_SP1	$100	1.0%	24.0%	912	25.0%	960	48
ENT	S_SP2	$75	1.3%	20.8%	773	22.1%	827	54
ENT	S_SP3	$50	4.1%	19.7%	704	23.8%	866	162
ENT	S_P	$30	4.2%	17.1%	772	21.3%	916	144
ENT	S_OP	$20	0.0%	35.7%	1,903	35.7%	1,903	0
ENT	W_SP	$25	1.2%	12.1%	984	13.3%	1,013	29
ENT	W_P	$20	0.0%	32.9%	1,685	32.9%	1,685	0
ENT	W_OP	$15	0.0%	23.7%	1,900	23.7%	1,900	0
ENT	SH_SP	$40	0.9%	20.2%	988	21.1%	1,024	36
ENT	SH_P	$25	0.0%	20.7%	1,037	20.7%	1,037	0
ENT	SH_OP	$15	0.0%	22.4%	2,141	22.4%	2,141	0
FENER	S_SP1	$100	1.0%	5.8%	2,352	6.8%	2,364	12
FENER	S_SP2	$75	2.0%	3.7%	2,079	5.7%	2,094	15
FENER	S_SP3	$50	0.4%	2.6%	2,181	3.0%	2,183	2
FENER	S_P	$30	0.0%	2.9%	1,922	2.9%	1,922	0
FENER	S_OP	$20	0.0%	2.3%	3,454	2.3%	3,454	0
FENER	W_SP	$25	0.0%	7.2%	4,114	7.2%	4,114	0
FENER	W_P	$20	0.0%	7.9%	2,000	7.9%	2,000	0
FENER	W_OP	$15	0.0%	19.2%	2,939	19.2%	2,939	0
FENER	SH_SP	$40	3.2%	8.3%	858	11.5%	911	53
FENER	SH_P	$25	0.0%	8.3%	3,274	8.3%	3,274	0
FENER	SH_OP	$15	0.0%	17.3%	2,839	17.3%	2,839	0
HEC	S_SP1	$100	0.0%	6.8%	1,405	6.8%	1,405	0
HEC	S_SP2	$75	1.2%	5.2%	1,382	6.4%	1,394	12
HEC	S_SP3	$50	14.3%	3.1%	1,043	17.4%	1,132	89
HEC	S_P	$30	13.5%	3.1%	1,566	16.6%	1,650	84
HEC	S_OP	$20	4.9%	4.3%	1,627	9.2%	1,669	42
HEC	W_SP	$25	5.6%	6.2%	1,417	11.8%	1,486	69
HEC	W_P	$20	3.1%	9.3%	1,337	12.4%	1,395	58
HEC	W_OP	$15	0.0%	11.0%	1,651	11.0%	1,651	0
HEC	SH_SP	$40	5.6%	8.1%	1,276	13.7%	1,367	91
HEC	SH_P	$25	2.4%	6.9%	1,528	9.3%	1,561	33
HEC	SH_OP	$15	0.0%	10.9%	1,515	10.9%	1,515	0
IP	S_SP1	$100	2.1%	10.8%	783	12.9%	828	45
IP	S_SP2	$75	2.5%	8.4%	633	10.9%	675	42
IP	S_SP3	$50	8.4%	6.3%	590	14.7%	696	106
IP	S_P	$30	6.7%	6.0%	728	12.7%	808	80
IP	S_OP	$20	9.3%	4.5%	976	13.8%	1,060	84
IP	W_SP	$25	3.1%	7.3%	992	10.4%	1,037	45
IP	W_P	$20	8.1%	5.3%	1,296	13.4%	1,382	86
IP	W_OP	$15	0.0%	8.7%	1,089	8.7%	1,089	0
IP	SH_SP	$40	3.7%	11.3%	767	15.0%	851	84
IP	SH_P	$25	2.2%	6.8%	1,006	9.0%	1,036	30
IP	SH_OP	$15	0.0%	10.0%	1,155	10.0%	1,155	0
LGE	S_SP1	$100	5.4%	5.4%	840	10.8%	898	58
LGE	S_SP2	$75	4.7%	6.0%	598	10.7%	654	56
LGE	S_SP3	$50	12.6%	4.2%	633	16.8%	739	106
LGE	S_P	$30	9.6%	3.7%	998	13.3%	1,069	71
LGE	S_OP	$20	0.0%	9.2%	1,594	9.2%	1,594	0
LGE	W_SP	$25	2.4%	6.3%	1,436	8.7%	1,466	30
LGE	W_P	$20	4.4%	9.9%	1,620	14.3%	1,707	87
LGE	W_OP	$15	0.0%	12.9%	2,347	12.9%	2,347	0
LGE	SH_SP	$40	3.0%	10.2%	780	13.2%	841	61
LGE	SH_P	$25	0.0%	7.4%	1,367	7.4%	1,367	0
LGE	SH_OP	$15	0.0%	13.7%	1,809	13.7%	1,809	0

Available Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
MECS	S_SP1	$100	2.0%	10.5%	1,041	12.5%	1,083	42
MECS	S_SP2	$75	1.9%	10.2%	731	12.1%	770	39
MECS	S_SP3	$50	4.8%	7.1%	827	11.9%	895	68
MECS	S_P	$30	3.4%	5.8%	1,476	9.2%	1,515	39
MECS	S_OP	$20	0.0%	3.6%	2,126	3.6%	2,126	0
MECS	W_SP	$25	0.0%	9.0%	2,380	9.0%	2,380	0
MECS	W_P	$20	0.0%	7.3%	4,441	7.3%	4,441	0
MECS	W_OP	$15	0.0%	24.9%	4,841	24.9%	4,841	0
MECS	SH_SP	$40	2.9%	10.4%	749	13.3%	809	60
MECS	SH_P	$25	0.0%	9.8%	2,026	9.8%	2,026	0
MECS	SH_OP	$15	0.0%	34.1%	3,292	34.1%	3,292	0
MGE	S_SP1	$100	5.2%	2.1%	1,802	7.3%	1,824	22
MGE	S_SP2	$75	4.3%	3.3%	1,781	7.6%	1,809	28
MGE	S_SP3	$50	6.3%	0.9%	2,570	7.2%	2,581	11
MGE	S_P	$30	4.4%	0.8%	2,710	5.2%	2,717	7
MGE	S_OP	$20	7.3%	1.5%	2,249	8.8%	2,271	22
MGE	W_SP	$25	4.1%	1.4%	1,928	5.5%	1,939	11
MGE	W_P	$20	18.9%	5.6%	2,286	24.5%	2,498	212
MGE	W_OP	$15	0.0%	12.6%	2,448	12.6%	2,448	0
MGE	SH_SP	$40	4.1%	1.6%	1,357	5.7%	1,370	13
MGE	SH_P	$25	3.3%	1.5%	2,066	4.8%	2,076	10
MGE	SH_OP	$15	0.0%	27.5%	2,680	27.5%	2,680	0
MIDAM	S_SP1	$100	2.4%	8.7%	623	11.1%	665	42
MIDAM	S_SP2	$75	2.1%	8.1%	637	10.2%	671	34
MIDAM	S_SP3	$50	6.5%	4.9%	939	11.4%	1,003	64
MIDAM	S_P	$30	5.6%	3.7%	942	9.3%	983	41
MIDAM	S_OP	$20	6.1%	1.5%	1,286	7.6%	1,304	18
MIDAM	W_SP	$25	4.6%	4.1%	1,099	8.7%	1,137	38
MIDAM	W_P	$20	11.9%	4.8%	1,122	16.7%	1,236	114
MIDAM	W_OP	$15	0.0%	9.4%	1,521	9.4%	1,521	0
MIDAM	SH_SP	$40	3.7%	8.5%	832	12.2%	895	63
MIDAM	SH_P	$25	4.6%	5.4%	1,240	10.0%	1,290	50
MIDAM	SH_OP	$15	0.0%	11.3%	1,515	11.3%	1,515	0
MPS	S_SP1	$100	0.6%	15.8%	884	16.4%	903	19
MPS	S_SP2	$75	1.8%	12.7%	705	14.5%	751	46
MPS	S_SP3	$50	9.3%	10.4%	733	19.7%	926	193
MPS	S_P	$30	2.3%	12.2%	760	14.5%	816	56
MPS	S_OP	$20	8.1%	3.4%	983	11.5%	1,038	55
MPS	W_SP	$25	3.5%	12.6%	885	16.1%	973	88
MPS	W_P	$20	4.2%	4.8%	1,103	9.0%	1,143	40
MPS	W_OP	$15	0.0%	9.3%	1,612	9.3%	1,612	0
MPS	SH_SP	$40	3.4%	9.7%	818	13.1%	884	66
MPS	SH_P	$25	1.9%	15.2%	992	17.1%	1,050	58
MPS	SH_OP	$15	0.0%	10.1%	1,380	10.1%	1,380	0
NEPOOL	S_SP1	$100	0.0%	0.0%	3,272	0.0%	3,272	0
NEPOOL	S_SP2	$75	0.0%	0.0%	2,452	0.0%	2,452	0
NEPOOL	S_SP3	$50	0.0%	0.0%	2,427	0.0%	2,427	0
NEPOOL	S_P	$30	0.0%	0.0%	2,607	0.0%	2,607	0
NEPOOL	S_OP	$20	0.0%	0.0%	3,091	0.0%	3,091	0
NEPOOL	W_SP	$25	0.0%	0.0%	2,553	0.0%	2,553	0
NEPOOL	W_P	$20	0.0%	0.0%	3,029	0.0%	3,029	0
NEPOOL	W_OP	$15	0.0%	0.0%	0	0.0%	0	0
NEPOOL	SH_SP	$40	0.0%	0.0%	2,483	0.0%	2,483	0
NEPOOL	SH_P	$25	0.0%	0.0%	2,548	0.0%	2,548	0
NEPOOL	SH_OP	$15	0.0%	0.0%	0	0.0%	0	0

Available Economic Capacity
No Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
NIPS	S_SP1	$100	1.8%	5.2%	927	7.0%	946	19
NIPS	S_SP2	$75	3.2%	4.1%	704	7.3%	730	26
NIPS	S_SP3	$50	8.5%	3.2%	773	11.7%	827	54
NIPS	S_P	$30	6.7%	4.0%	776	10.7%	830	54
NIPS	S_OP	$20	10.5%	4.7%	1,148	15.2%	1,247	99
NIPS	W_SP	$25	3.2%	7.5%	1,114	10.7%	1,162	48
NIPS	W_P	$20	5.7%	8.4%	2,195	14.1%	2,291	96
NIPS	W_OP	$15	0.0%	13.4%	1,596	13.4%	1,596	0
NIPS	SH_SP	$40	3.7%	7.4%	592	11.1%	647	55
NIPS	SH_P	$25	0.0%	9.3%	1,095	9.3%	1,095	0
NIPS	SH_OP	$15	0.0%	14.7%	1,381	14.7%	1,381	0
NSP	S_SP1	$100	6.8%	2.8%	796	9.6%	834	38
NSP	S_SP2	$75	2.9%	3.7%	704	6.6%	725	21
NSP	S_SP3	$50	7.2%	3.6%	524	10.8%	576	52
NSP	S_P	$30	5.5%	3.2%	708	8.7%	743	35
NSP	S_OP	$20	5.0%	2.8%	1,190	7.8%	1,218	28
NSP	W_SP	$25	4.6%	5.7%	876	10.3%	928	52
NSP	W_P	$20	9.2%	6.4%	1,001	15.6%	1,119	118
NSP	W_OP	$15	0.0%	7.3%	1,274	7.3%	1,274	0
NSP	SH_SP	$40	2.7%	5.3%	1,005	8.0%	1,034	29
NSP	SH_P	$25	2.2%	3.5%	891	5.7%	906	15
NSP	SH_OP	$15	0.0%	7.6%	1,162	7.6%	1,162	0
NYPP	S_SP1	$100	0.0%	2.5%	1,955	2.5%	1,955	0
NYPP	S_SP2	$75	0.0%	2.9%	1,850	2.9%	1,850	0
NYPP	S_SP3	$50	0.0%	3.6%	1,645	3.6%	1,645	0
NYPP	S_P	$30	0.0%	3.8%	1,650	3.8%	1,650	0
NYPP	S_OP	$20	0.0%	1.7%	2,758	1.7%	2,758	0
NYPP	W_SP	$25	0.0%	1.1%	2,379	1.1%	2,379	0
NYPP	W_P	$20	0.0%	1.9%	4,345	1.9%	4,345	0
NYPP	W_OP	$15	0.0%	2.2%	5,360	2.2%	5,360	0
NYPP	SH_SP	$40	0.0%	2.0%	1,283	2.0%	1,283	0
NYPP	SH_P	$25	0.0%	0.8%	1,224	0.8%	1,224	0
NYPP	SH_OP	$15	0.0%	1.9%	5,454	1.9%	5,454	0
SCEG	S_SP1	$100	0.0%	22.0%	1,550	22.0%	1,550	0
SCEG	S_SP2	$75	1.2%	13.6%	1,633	14.8%	1,666	33
SCEG	S_SP3	$50	0.0%	14.1%	1,529	14.1%	1,529	0
SCEG	S_P	$30	0.0%	5.3%	3,741	5.3%	3,741	0
SCEG	S_OP	$20	0.0%	17.1%	4,979	17.1%	4,979	0
SCEG	W_SP	$25	0.0%	6.1%	2,859	6.1%	2,859	0
SCEG	W_P	$20	0.0%	52.7%	4,338	52.7%	4,338	0
SCEG	W_OP	$15	0.0%	91.0%	8,361	91.0%	8,361	0
SCEG	SH_SP	$40	0.0%	19.0%	2,669	19.0%	2,669	0
SCEG	SH_P	$25	0.0%	9.2%	2,887	9.2%	2,887	0
SCEG	SH_OP	$15	0.0%	90.5%	8,278	90.5%	8,278	0
SCPSA	S_SP1	$100	0.0%	20.1%	1,481	20.1%	1,481	0
SCPSA	S_SP2	$75	0.9%	18.9%	1,015	19.8%	1,049	34
SCPSA	S_SP3	$50	0.0%	19.9%	1,253	19.9%	1,253	0
SCPSA	S_P	$30	0.0%	4.5%	5,171	4.5%	5,171	0
SCPSA	S_OP	$20	0.0%	8.8%	3,783	8.8%	3,783	0
SCPSA	W_SP	$25	0.0%	5.6%	2,180	5.6%	2,180	0
SCPSA	W_P	$20	0.0%	24.5%	5,713	24.5%	5,713	0
SCPSA	W_OP	$15	0.0%	58.9%	4,745	58.9%	4,745	0
SCPSA	SH_SP	$40	0.0%	20.0%	2,593	20.0%	2,593	0
SCPSA	SH_P	$25	0.0%	8.8%	3,239	8.8%	3,239	0
SCPSA	SH_OP	$15	0.0%	68.7%	5,348	68.7%	5,348	0

Available Economic Capacity
No Transmission Path

Market	Period	Price	BASE COMED Mkt Share	BASE PECO Mkt Share	BASE HHI Pre-Merger	MERGER CE + PECO Mkt Share	MERGER HHI Post-Merger	HHI Chg
SOCO	S_SP1	$100	0.0%	22.7%	2,171	22.7%	2,171	0
SOCO	S_SP2	$75	0.8%	23.4%	1,262	24.2%	1,299	37
SOCO	S_SP3	$50	1.1%	23.6%	1,154	24.7%	1,206	52
SOCO	S_P	$30	4.5%	25.7%	1,520	30.2%	1,751	231
SOCO	S_OP	$20	0.0%	4.7%	4,365	4.7%	4,365	0
SOCO	W_SP	$25	0.0%	11.8%	2,848	11.8%	2,848	0
SOCO	W_P	$20	0.0%	9.9%	7,954	9.9%	7,954	0
SOCO	W_OP	$15	0.0%	91.1%	8,379	91.1%	8,379	0
SOCO	SH_SP	$40	0.0%	20.5%	1,961	20.5%	1,961	0
SOCO	SH_P	$25	0.0%	10.9%	1,379	10.9%	1,379	0
SOCO	SH_OP	$15	0.0%	80.5%	6,613	80.5%	6,613	0
TVA	S_SP1	$100	4.2%	10.9%	1,099	15.1%	1,191	92
TVA	S_SP2	$75	3.4%	8.3%	984	11.7%	1,040	56
TVA	S_SP3	$50	1.9%	6.3%	872	8.2%	896	24
TVA	S_P	$30	6.8%	4.3%	1,089	11.1%	1,147	58
TVA	S_OP	$20	0.0%	6.2%	1,223	6.2%	1,223	0
TVA	W_SP	$25	0.0%	4.1%	1,033	4.1%	1,033	0
TVA	W_P	$20	0.0%	7.8%	1,427	7.8%	1,427	0
TVA	W_OP	$15	0.0%	19.0%	1,672	19.0%	1,672	0
TVA	SH_SP	$40	1.3%	15.2%	777	16.5%	817	40
TVA	SH_P	$25	0.0%	6.8%	1,012	6.8%	1,012	0
TVA	SH_OP	$15	0.0%	22.7%	1,789	22.7%	1,789	0
VP	S_SP1	$100	2.0%	5.5%	1,762	7.5%	1,784	22
VP	S_SP2	$75	1.8%	4.2%	1,893	6.0%	1,908	15
VP	S_SP3	$50	2.0%	3.5%	1,675	5.5%	1,689	14
VP	S_P	$30	0.0%	2.4%	1,261	2.4%	1,261	0
VP	S_OP	$20	0.0%	4.0%	4,026	4.0%	4,026	0
VP	W_SP	$25	0.0%	3.5%	2,848	3.5%	2,848	0
VP	W_P	$20	0.0%	17.3%	2,244	17.3%	2,244	0
VP	W_OP	$15	0.0%	33.6%	3,368	33.6%	3,368	0
VP	SH_SP	$40	0.0%	9.4%	965	9.4%	965	0
VP	SH_P	$25	0.0%	5.8%	2,999	5.8%	2,999	0
VP	SH_OP	$15	0.0%	21.2%	3,762	21.2%	3,762	0
UPP	S_SP1	$100	2.4%	1.1%	2,465	3.5%	2,470	5
UPP	S_SP2	$75	1.7%	1.4%	2,541	3.1%	2,546	5
UPP	S_SP3	$50	1.5%	0.2%	3,362	1.7%	3,363	1
UPP	S_P	$30	1.2%	0.2%	3,616	1.4%	3,616	0
UPP	S_OP	$20	3.6%	0.8%	4,716	4.4%	4,722	6
UPP	W_SP	$25	7.4%	1.5%	1,816	8.9%	1,838	22
UPP	W_P	$20	19.7%	5.2%	2,705	24.9%	2,910	205
UPP	W_OP	$15	0.0%	15.8%	2,739	15.8%	2,739	0
UPP	SH_SP	$40	0.0%	0.0%	10,000	0.0%	10,000	0
UPP	SH_P	$25	0.0%	0.0%	10,000	0.0%	10,000	0
UPP	SH_OP	$15	0.0%	0.0%	0	0.0%	0	0
WEP	S_SP1	$100	4.8%	2.5%	1,579	7.3%	1,603	24
WEP	S_SP2	$75	5.1%	3.5%	1,219	8.6%	1,255	36
WEP	S_SP3	$50	6.3%	0.8%	4,128	7.1%	4,138	10
WEP	S_P	$30	3.0%	0.4%	6,528	3.4%	6,530	2
WEP	S_OP	$20	0.0%	1.3%	7,441	1.3%	7,441	0
WEP	W_SP	$25	6.7%	2.5%	806	9.2%	840	34
WEP	W_P	$20	9.8%	3.7%	1,243	13.5%	1,316	73
WEP	W_OP	$15	0.0%	4.1%	1,119	4.1%	1,119	0
WEP	SH_SP	$40	4.3%	3.6%	742	7.9%	773	31
WEP	SH_P	$25	3.6%	2.2%	788	5.8%	804	16
WEP	SH_OP	$15	0.0%	5.4%	1,241	5.4%	1,241	0

Available Economic Capacity
No Transmission Path

Market	Period	Price	BASE: COMED Mkt Share	BASE: PECO Mkt Share	BASE: HHI Pre-Merger	MERGER: CE + PECO Mkt Share	MERGER: HHI Post-Merger	HHI Chg
WPS	S_SP1	$100	2.8%	1.2%	2,136	4.0%	2,143	7
WPS	S_SP2	$75	2.4%	1.9%	2,101	4.3%	2,110	9
WPS	S_SP3	$50	6.9%	1.0%	2,159	7.9%	2,173	14
WPS	S_P	$30	5.1%	0.9%	2,205	6.0%	2,214	9
WPS	S_OP	$20	4.9%	1.1%	1,872	6.0%	1,883	11
WPS	W_SP	$25	4.4%	1.6%	1,144	6.0%	1,158	14
WPS	W_P	$20	13.4%	4.3%	1,097	17.7%	1,212	115
WPS	W_OP	$15	0.0%	6.6%	1,495	6.6%	1,495	0
WPS	SH_SP	$40	6.1%	1.8%	965	7.9%	987	22
WPS	SH_P	$25	4.7%	2.0%	1,232	6.7%	1,251	19
WPS	SH_OP	$15	0.0%	14.7%	1,317	14.7%	1,317	0
WR	S_SP1	$100	0.6%	8.8%	1,011	9.4%	1,022	11
WR	S_SP2	$75	1.6%	7.7%	1,134	9.3%	1,159	25
WR	S_SP3	$50	6.8%	4.9%	1,708	11.7%	1,775	67
WR	S_P	$30	2.9%	3.8%	2,105	6.7%	2,127	22
WR	S_OP	$20	4.2%	5.5%	1,459	9.7%	1,505	46
WR	W_SP	$25	4.0%	6.6%	2,229	10.6%	2,282	53
WR	W_P	$20	0.0%	1.2%	2,087	1.2%	2,087	0
WR	W_OP	$15	0.0%	3.8%	3,044	3.8%	3,044	0
WR	SH_SP	$40	2.6%	4.5%	1,130	7.1%	1,153	23
WR	SH_P	$25	1.7%	4.2%	2,083	5.9%	2,097	14
WR	SH_OP	$15	0.0%	4.3%	2,737	4.3%	2,737	0

Competitive Analysis Screening Model (CASm)
HHI Report.
Unicom/PECO Market Power Analysis
Available Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
COMED	S_SP1	$100	7.2%	11.0%	950	18.3%	1,123	173
COMED	S_SP2	$75	8.8%	11.3%	841	19.0%	1,024	183
COMED	S_SP3	$50	33.4%	5.6%	1,544	38.1%	1,865	321
COMED	S_P	$30	26.0%	3.3%	1,403	28.5%	1,545	142
COMED	S_OP	$20	35.8%	4.3%	2,066	38.9%	2,330	264
COMED	W_SP	$25	19.4%	3.8%	1,743	22.2%	1,896	153
COMED	W_P	$20	33.3%	4.8%	2,396	36.9%	2,704	308
COMED	W_OP	$15	49.6%	6.8%	2,915	56.1%	3,564	649
COMED	SH_SP	$40	12.5%	8.3%	1,228	19.7%	1,441	214
COMED	SH_P	$25	16.0%	4.1%	1,718	18.9%	1,861	144
COMED	SH_OP	$15	37.4%	8.3%	2,023	44.7%	2,572	550
PJM_ALL	S_SP1	$100	0.0%	5.2%	1,021	5.3%	1,031	10
PJM_ALL	S_SP2	$75	0.0%	5.6%	1,018	5.7%	1,015	-3
PJM_ALL	S_SP3	$50	0.0%	8.0%	888	8.2%	884	-4
PJM_ALL	S_P	$30	0.0%	10.6%	884	11.0%	883	-1
PJM_ALL	S_OP	$20	0.0%	4.6%	1,076	4.6%	1,075	0
PJM_ALL	W_SP	$25	0.0%	5.7%	1,831	5.5%	1,865	33
PJM_ALL	W_P	$20	0.0%	10.7%	1,603	9.2%	1,622	20
PJM_ALL	W_OP	$15	0.0%	14.9%	3,288	14.0%	3,326	39
PJM_ALL	SH_SP	$40	0.0%	10.8%	933	10.7%	928	-5
PJM_ALL	SH_P	$25	0.0%	6.0%	1,441	5.5%	1,462	21
PJM_ALL	SH_OP	$15	0.0%	13.4%	2,763	11.1%	2,844	81
PJM_C+E	S_SP1	$100	0.0%	5.8%	1,241	5.8%	1,241	0
PJM_C+E	S_SP2	$75	0.0%	6.4%	1,047	6.8%	1,040	-7
PJM_C+E	S_SP3	$50	0.0%	9.5%	859	9.9%	859	0
PJM_C+E	S_P	$30	0.0%	12.2%	942	12.7%	939	-2
PJM_C+E	S_OP	$20	0.0%	2.7%	1,172	3.2%	1,169	-3
PJM_C+E	W_SP	$25	0.0%	6.2%	1,640	6.0%	1,673	33
PJM_C+E	W_P	$20	0.0%	10.7%	1,603	9.2%	1,622	20
PJM_C+E	W_OP	$15	0.0%	14.9%	3,288	14.0%	3,326	39
PJM_C+E	SH_SP	$40	0.0%	12.6%	1,141	12.5%	1,131	-11
PJM_C+E	SH_P	$25	0.0%	6.0%	1,441	5.5%	1,462	21
PJM_C+E	SH_OP	$15	0.0%	13.4%	2,763	11.1%	2,844	81
PJM_EAST	S_SP1	$100	0.0%	3.4%	946	3.3%	945	0
PJM_EAST	S_SP2	$75	0.3%	5.0%	830	5.7%	829	0
PJM_EAST	S_SP3	$50	1.1%	8.7%	777	10.1%	798	20
PJM_EAST	S_P	$30	0.6%	11.2%	801	12.3%	821	20
PJM_EAST	S_OP	$20	0.0%	2.0%	1,389	2.7%	1,369	-21
PJM_EAST	W_SP	$25	0.0%	4.3%	1,938	4.4%	1,947	9
PJM_EAST	W_P	$20	0.0%	10.7%	1,603	9.2%	1,623	20
PJM_EAST	W_OP	$15	0.0%	14.9%	3,288	14.0%	3,326	39
PJM_EAST	SH_SP	$40	0.0%	9.4%	760	9.7%	761	1
PJM_EAST	SH_P	$25	0.0%	4.3%	1,559	4.2%	1,544	-15
PJM_EAST	SH_OP	$15	0.0%	13.4%	2,763	11.1%	2,844	81
PJM_W+C+E	S_SP1	$100	0.0%	5.2%	1,021	5.3%	1,031	10
PJM_W+C+E	S_SP2	$75	0.0%	5.1%	1,030	5.3%	1,024	-6
PJM_W+C+E	S_SP3	$50	0.0%	8.7%	817	9.0%	818	1
PJM_W+C+E	S_P	$30	0.0%	11.4%	883	11.8%	883	1
PJM_W+C+E	S_OP	$20	0.0%	3.6%	1,103	3.9%	1,096	-6
PJM_W+C+E	W_SP	$25	0.0%	5.7%	1,831	5.5%	1,865	33
PJM_W+C+E	W_P	$20	0.0%	10.7%	1,603	9.2%	1,622	20
PJM_W+C+E	W_OP	$15	0.0%	14.9%	3,288	14.0%	3,326	39
PJM_W+C+E	SH_SP	$40	0.0%	10.8%	933	10.7%	928	-5
PJM_W+C+E	SH_P	$25	0.0%	6.0%	1,441	5.5%	1,462	21
PJM_W+C+E	SH_OP	$15	0.0%	13.4%	2,763	11.1%	2,844	81

Available Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
AECI	S_SP1	$100	4.2%	11.4%	665	15.6%	760	95
AECI	S_SP2	$75	2.2%	13.9%	633	15.9%	691	58
AECI	S_SP3	$50	6.6%	12.3%	559	18.7%	717	158
AECI	S_P	$30	6.2%	7.9%	739	13.9%	835	96
AECI	S_OP	$20	3.5%	14.5%	1,042	17.6%	1,136	94
AECI	W_SP	$25	2.8%	11.2%	973	13.7%	1,033	61
AECI	W_P	$20	0.0%	22.2%	1,399	21.0%	1,354	-44
AECI	W_OP	$15	0.0%	13.7%	1,705	11.0%	1,694	-11
AECI	SH_SP	$40	1.1%	16.1%	838	17.0%	871	33
AECI	SH_P	$25	2.1%	14.8%	946	16.6%	1,004	58
AECI	SH_OP	$15	0.0%	13.0%	1,131	10.4%	1,132	1
ALLIANT_E	S_SP1	$100	5.0%	6.7%	1,524	11.6%	1,643	119
ALLIANT_E	S_SP2	$75	3.6%	5.0%	891	7.8%	941	50
ALLIANT_E	S_SP3	$50	12.5%	2.1%	1,181	14.1%	1,226	46
ALLIANT_E	S_P	$30	8.3%	1.3%	1,614	9.2%	1,629	14
ALLIANT_E	S_OP	$20	15.7%	2.3%	1,301	17.3%	1,359	58
ALLIANT_E	W_SP	$25	5.8%	2.4%	1,065	7.7%	1,094	29
ALLIANT_E	W_P	$20	5.4%	3.8%	1,438	8.7%	1,489	50
ALLIANT_E	W_OP	$15	0.0%	4.3%	1,095	3.5%	1,109	13
ALLIANT_E	SH_SP	$40	4.4%	3.1%	832	7.1%	858	26
ALLIANT_E	SH_P	$25	0.0%	1.9%	1,183	1.5%	1,190	8
ALLIANT_E	SH_OP	$15	0.0%	4.0%	1,275	3.2%	1,288	13
AEP	S_SP1	$100	2.8%	12.7%	870	15.6%	950	80
AEP	S_SP2	$75	3.2%	9.3%	917	12.0%	970	53
AEP	S_SP3	$50	5.7%	7.7%	887	13.2%	971	83
AEP	S_P	$30	4.1%	4.6%	1,376	8.3%	1,411	35
AEP	S_OP	$20	0.0%	4.1%	2,011	3.7%	2,019	8
AEP	W_SP	$25	0.9%	5.7%	1,509	6.0%	1,504	-4
AEP	W_P	$20	0.0%	5.7%	2,046	5.1%	2,029	-18
AEP	W_OP	$15	0.0%	4.2%	5,148	3.8%	5,104	-45
AEP	SH_SP	$40	3.3%	14.0%	940	16.2%	1,006	66
AEP	SH_P	$25	0.0%	7.1%	1,379	6.5%	1,365	-14
AEP	SH_OP	$15	0.0%	4.6%	4,656	3.7%	4,736	79
APS	S_SP1	$100	2.0%	5.8%	1,739	7.7%	1,748	9
APS	S_SP2	$75	2.4%	4.1%	1,603	6.4%	1,602	-1
APS	S_SP3	$50	0.6%	3.5%	1,468	4.1%	1,450	-18
APS	S_P	$30	0.0%	1.8%	3,583	1.6%	3,560	-23
APS	S_OP	$20	0.0%	4.4%	2,033	4.0%	1,988	-44
APS	W_SP	$25	0.0%	5.0%	4,036	4.3%	4,008	-28
APS	W_P	$20	0.0%	11.7%	3,318	9.4%	3,347	28
APS	W_OP	$15	0.0%	22.4%	2,576	20.5%	2,612	36
APS	SH_SP	$40	0.0%	7.4%	1,681	6.8%	1,682	0
APS	SH_P	$25	0.0%	5.7%	3,237	4.9%	3,240	3
APS	SH_OP	$15	0.0%	18.6%	2,789	15.2%	2,922	133
ALLIANT_W	S_SP1	$100	2.6%	8.7%	627	11.3%	673	45
ALLIANT_W	S_SP2	$75	2.9%	7.0%	620	9.4%	660	40
ALLIANT_W	S_SP3	$50	8.3%	4.8%	589	12.7%	662	73
ALLIANT_W	S_P	$30	7.5%	5.3%	604	12.5%	679	75
ALLIANT_W	S_OP	$20	13.2%	3.9%	978	16.6%	1,072	94
ALLIANT_W	W_SP	$25	5.4%	7.8%	708	12.7%	786	78
ALLIANT_W	W_P	$20	7.3%	2.5%	1,271	9.6%	1,307	36
ALLIANT_W	W_OP	$15	0.0%	5.9%	1,431	5.3%	1,438	7
ALLIANT_W	SH_SP	$40	4.5%	7.0%	677	11.1%	743	66
ALLIANT_W	SH_P	$25	3.7%	6.0%	749	9.3%	793	45
ALLIANT_W	SH_OP	$15	0.0%	6.1%	1,272	5.4%	1,278	7

Available Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
AMEREN	S_SP1	$100	3.0%	11.4%	576	14.4%	642	66
AMEREN	S_SP2	$75	2.9%	9.8%	531	12.3%	582	51
AMEREN	S_SP3	$50	8.2%	8.4%	549	16.4%	681	132
AMEREN	S_P	$30	5.2%	5.2%	733	10.2%	785	53
AMEREN	S_OP	$20	5.6%	8.6%	1,012	13.7%	1,101	89
AMEREN	W_SP	$25	1.4%	6.8%	794	8.1%	813	18
AMEREN	W_P	$20	4.8%	7.4%	1,261	11.8%	1,332	71
AMEREN	W_OP	$15	0.0%	6.5%	1,413	6.0%	1,416	3
AMEREN	SH_SP	$40	3.3%	11.4%	549	14.5%	622	73
AMEREN	SH_P	$25	1.1%	9.6%	768	10.5%	789	21
AMEREN	SH_OP	$15	0.0%	6.8%	1,126	5.6%	1,134	9
CAPO	S_SP1	$100	2.3%	16.5%	924	18.8%	984	60
CAPO	S_SP2	$75	2.4%	14.8%	766	16.9%	823	58
CAPO	S_SP3	$50	7.1%	12.5%	770	19.5%	943	173
CAPO	S_P	$30	1.3%	3.5%	1,175	4.5%	1,186	11
CAPO	S_OP	$20	0.0%	5.2%	3,102	4.6%	3,105	3
CAPO	W_SP	$25	0.0%	4.3%	2,372	3.9%	2,372	0
CAPO	W_P	$20	0.0%	11.9%	3,367	9.6%	3,456	90
CAPO	W_OP	$15	0.0%	43.5%	3,235	41.2%	3,154	-81
CAPO	SH_SP	$40	2.0%	18.8%	926	21.2%	1,014	88
CAPO	SH_P	$25	0.0%	6.4%	1,740	5.7%	1,730	-10
CAPO	SH_OP	$15	0.0%	53.9%	4,158	48.0%	3,898	-260
CELE	S_SP1	$100	0.0%	7.9%	4,261	7.9%	4,261	0
CELE	S_SP2	$75	0.2%	8.1%	4,249	8.3%	4,252	3
CELE	S_SP3	$50	1.9%	8.6%	4,261	10.5%	4,293	32
CELE	S_P	$30	1.0%	6.9%	4,390	7.8%	4,402	12
CELE	S_OP	$20	0.0%	29.7%	1,772	29.7%	1,772	0
CELE	W_SP	$25	1.1%	6.1%	3,664	7.2%	3,679	15
CELE	W_P	$20	0.0%	28.8%	1,643	28.6%	1,634	-8
CELE	W_OP	$15	0.0%	6.8%	2,264	6.6%	2,273	9
CELE	SH_SP	$40	1.8%	8.2%	3,189	10.0%	3,219	29
CELE	SH_P	$25	1.4%	7.6%	3,692	9.0%	3,713	21
CELE	SH_OP	$15	0.0%	5.9%	2,855	5.7%	2,857	3
CILCO	S_SP1	$100	2.3%	7.4%	663	9.7%	698	35
CILCO	S_SP2	$75	2.4%	6.4%	612	8.4%	643	31
CILCO	S_SP3	$50	9.2%	5.2%	505	14.0%	595	90
CILCO	S_P	$30	7.2%	4.8%	627	11.7%	694	67
CILCO	S_OP	$20	10.8%	3.4%	947	13.7%	1,012	65
CILCO	W_SP	$25	3.9%	4.6%	732	8.1%	770	38
CILCO	W_P	$20	9.8%	8.0%	990	17.3%	1,139	149
CILCO	W_OP	$15	0.0%	11.4%	1,415	10.1%	1,414	0
CILCO	SH_SP	$40	4.2%	7.5%	780	11.4%	847	67
CILCO	SH_P	$25	2.9%	4.6%	680	7.1%	709	29
CILCO	SH_OP	$15	0.0%	12.4%	1,098	10.7%	1,095	-2
CIN	S_SP1	$100	3.3%	7.1%	992	10.4%	1,032	39
CIN	S_SP2	$75	3.7%	7.8%	881	10.9%	930	49
CIN	S_SP3	$50	3.8%	5.4%	895	8.6%	934	39
CIN	S_P	$30	4.5%	5.5%	1,408	10.0%	1,459	51
CIN	S_OP	$20	0.0%	8.0%	1,406	7.1%	1,405	-1
CIN	W_SP	$25	0.0%	8.3%	1,004	7.3%	993	-12
CIN	W_P	$20	2.9%	8.9%	1,698	11.0%	1,768	70
CIN	W_OP	$15	0.0%	13.6%	2,347	12.9%	2,319	-28
CIN	SH_SP	$40	2.8%	11.0%	1,243	13.7%	1,305	62
CIN	SH_P	$25	0.0%	8.9%	1,405	8.1%	1,405	-1
CIN	SH_OP	$15	0.0%	14.9%	1,854	13.3%	1,840	-14

Available Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
CWLP	S_SP1	$100	1.8%	5.8%	994	7.6%	1,023	29
CWLP	S_SP2	$75	2.4%	5.3%	770	7.3%	798	28
CWLP	S_SP3	$50	7.7%	4.1%	798	11.5%	858	59
CWLP	S_P	$30	4.8%	3.9%	1,099	8.5%	1,138	39
CWLP	S_OP	$20	7.8%	2.9%	897	10.3%	945	47
CWLP	W_SP	$25	3.5%	4.7%	2,014	7.9%	2,057	43
CWLP	W_P	$20	12.2%	5.4%	1,245	17.0%	1,363	118
CWLP	W_OP	$15	0.0%	12.7%	1,760	9.9%	1,798	39
CWLP	SH_SP	$40	4.4%	5.4%	1,468	9.4%	1,517	49
CWLP	SH_P	$25	2.8%	4.0%	1,805	6.5%	1,836	31
CWLP	SH_OP	$15	0.0%	19.6%	1,720	15.4%	1,725	5
DLCO	S_SP1	$100	1.8%	10.0%	1,317	11.7%	1,313	-4
DLCO	S_SP2	$75	1.8%	9.5%	715	11.0%	730	15
DLCO	S_SP3	$50	4.9%	5.9%	805	10.7%	849	44
DLCO	S_P	$30	1.4%	6.9%	1,367	7.5%	1,361	-6
DLCO	S_OP	$20	0.0%	5.8%	2,699	5.3%	2,636	-64
DLCO	W_SP	$25	0.0%	8.4%	2,417	7.7%	2,407	-10
DLCO	W_P	$20	0.0%	17.2%	2,104	13.3%	2,236	132
DLCO	W_OP	$15	0.0%	46.4%	3,709	44.6%	3,650	-60
DLCO	SH_SP	$40	2.3%	12.2%	645	14.4%	699	54
DLCO	SH_P	$25	0.0%	9.4%	2,406	8.6%	2,445	39
DLCO	SH_OP	$15	0.0%	47.8%	3,459	43.1%	3,254	-205
DPL	S_SP1	$100	3.4%	6.6%	912	10.0%	943	31
DPL	S_SP2	$75	3.3%	6.1%	693	9.1%	736	43
DPL	S_SP3	$50	9.6%	4.2%	681	13.3%	755	75
DPL	S_P	$30	8.8%	4.1%	938	12.6%	1,009	71
DPL	S_OP	$20	0.0%	6.0%	1,470	5.3%	1,478	9
DPL	W_SP	$25	2.3%	7.6%	1,271	8.9%	1,295	24
DPL	W_P	$20	0.0%	10.8%	1,890	9.9%	1,896	7
DPL	W_OP	$15	0.0%	17.4%	1,739	16.1%	1,737	-2
DPL	SH_SP	$40	2.4%	7.7%	599	10.5%	645	46
DPL	SH_P	$25	0.0%	8.7%	1,212	7.7%	1,217	5
DPL	SH_OP	$15	0.0%	18.3%	1,570	15.0%	1,555	-15
DUKE	S_SP1	$100	0.9%	19.7%	1,359	20.7%	1,398	40
DUKE	S_SP2	$75	1.3%	20.5%	1,000	21.8%	1,052	52
DUKE	S_SP3	$50	0.4%	21.4%	1,010	21.8%	1,029	19
DUKE	S_P	$30	0.0%	6.6%	1,814	6.4%	1,817	3
DUKE	S_OP	$20	0.0%	19.2%	6,408	18.8%	6,447	39
DUKE	W_SP	$25	0.0%	4.1%	1,325	3.8%	1,325	0
DUKE	W_P	$20	0.0%	23.0%	6,166	20.4%	6,412	246
DUKE	W_OP	$15	0.0%	82.7%	6,993	81.3%	6,788	-206
DUKE	SH_SP	$40	1.1%	16.8%	1,667	17.7%	1,716	49
DUKE	SH_P	$25	0.0%	9.5%	1,670	8.8%	1,684	14
DUKE	SH_OP	$15	0.0%	90.5%	8,278	88.3%	7,926	-352
EKPC	S_SP1	$100	4.5%	6.7%	860	11.1%	914	53
EKPC	S_SP2	$75	4.1%	6.2%	666	9.8%	711	45
EKPC	S_SP3	$50	9.9%	4.5%	628	14.2%	713	84
EKPC	S_P	$30	5.1%	2.4%	2,439	7.2%	2,466	27
EKPC	S_OP	$20	0.0%	4.4%	4,436	3.9%	4,435	-1
EKPC	W_SP	$25	4.0%	10.6%	1,147	14.1%	1,239	92
EKPC	W_P	$20	0.0%	33.9%	2,222	31.2%	2,092	-130
EKPC	W_OP	$15	0.0%	77.1%	6,229	74.4%	5,887	-342
EKPC	SH_SP	$40	2.7%	10.2%	763	12.2%	810	47
EKPC	SH_P	$25	0.0%	7.4%	1,833	6.8%	1,843	11
EKPC	SH_OP	$15	0.0%	53.9%	3,756	51.1%	3,547	-209

Available Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
ENT	S_SP1	$100	1.0%	24.0%	912	25.1%	965	53
ENT	S_SP2	$75	1.3%	20.8%	773	22.0%	824	52
ENT	S_SP3	$50	4.1%	19.7%	704	23.8%	864	160
ENT	S_P	$30	4.2%	17.1%	772	21.2%	914	143
ENT	S_OP	$20	0.0%	35.7%	1,903	34.2%	1,804	-99
ENT	W_SP	$25	1.2%	12.1%	984	13.0%	1,006	21
ENT	W_P	$20	0.0%	32.9%	1,685	31.7%	1,634	-51
ENT	W_OP	$15	0.0%	23.7%	1,900	20.0%	1,872	-29
ENT	SH_SP	$40	0.9%	20.2%	988	20.9%	1,017	29
ENT	SH_P	$25	0.0%	20.7%	1,037	20.6%	1,033	-4
ENT	SH_OP	$15	0.0%	22.4%	2,141	18.5%	2,149	8
FENER	S_SP1	$100	1.0%	5.8%	2,352	6.8%	2,327	-24
FENER	S_SP2	$75	2.0%	3.7%	2,079	5.6%	2,078	-2
FENER	S_SP3	$50	0.4%	2.6%	2,181	2.9%	2,168	-13
FENER	S_P	$30	0.0%	2.9%	1,922	2.8%	1,899	-23
FENER	S_OP	$20	0.0%	2.3%	3,454	2.0%	3,397	-57
FENER	W_SP	$25	0.0%	7.2%	4,114	6.4%	4,091	-22
FENER	W_P	$20	0.0%	7.9%	2,000	6.6%	2,012	13
FENER	W_OP	$15	0.0%	19.2%	2,939	17.6%	2,938	-2
FENER	SH_SP	$40	3.2%	8.3%	858	11.4%	909	52
FENER	SH_P	$25	0.0%	8.3%	3,274	7.4%	3,287	13
FENER	SH_OP	$15	0.0%	17.3%	2,839	14.1%	2,959	120
HEC	S_SP1	$100	0.0%	6.8%	1,405	6.8%	1,405	0
HEC	S_SP2	$75	1.2%	5.2%	1,382	6.1%	1,397	15
HEC	S_SP3	$50	14.3%	3.1%	1,043	17.3%	1,132	89
HEC	S_P	$30	13.5%	3.1%	1,566	16.6%	1,651	85
HEC	S_OP	$20	4.9%	4.3%	1,627	8.6%	1,675	48
HEC	W_SP	$25	5.6%	6.2%	1,417	11.1%	1,508	90
HEC	W_P	$20	3.1%	9.3%	1,337	11.5%	1,404	67
HEC	W_OP	$15	0.0%	11.0%	1,651	9.7%	1,660	8
HEC	SH_SP	$40	5.6%	8.1%	1,276	13.0%	1,364	88
HEC	SH_P	$25	2.4%	6.9%	1,528	8.5%	1,583	55
HEC	SH_OP	$15	0.0%	10.9%	1,515	9.3%	1,526	11
IP	S_SP1	$100	2.1%	10.8%	783	12.8%	827	44
IP	S_SP2	$75	2.5%	8.4%	633	10.4%	672	38
IP	S_SP3	$50	8.4%	6.3%	590	14.4%	691	100
IP	S_P	$30	6.7%	6.0%	728	12.4%	807	78
IP	S_OP	$20	9.3%	4.5%	976	13.4%	1,057	80
IP	W_SP	$25	3.1%	7.3%	992	10.1%	1,042	50
IP	W_P	$20	8.1%	5.3%	1,296	12.9%	1,392	95
IP	W_OP	$15	0.0%	8.7%	1,089	7.5%	1,097	8
IP	SH_SP	$40	3.7%	11.3%	767	14.7%	851	84
IP	SH_P	$25	2.2%	6.8%	1,006	8.8%	1,041	35
IP	SH_OP	$15	0.0%	10.0%	1,155	8.0%	1,165	10
LGE	S_SP1	$100	5.4%	5.4%	840	10.7%	891	51
LGE	S_SP2	$75	4.7%	6.0%	598	10.1%	648	50
LGE	S_SP3	$50	12.6%	4.2%	633	16.4%	730	97
LGE	S_P	$30	9.6%	3.7%	998	12.9%	1,066	68
LGE	S_OP	$20	0.0%	9.2%	1,594	7.6%	1,587	-8
LGE	W_SP	$25	2.4%	6.3%	1,436	8.0%	1,487	51
LGE	W_P	$20	4.4%	9.9%	1,620	12.7%	1,747	127
LGE	W_OP	$15	0.0%	12.9%	2,347	11.7%	2,315	-32
LGE	SH_SP	$40	3.0%	10.2%	780	12.3%	827	47
LGE	SH_P	$25	0.0%	7.4%	1,367	6.4%	1,387	20
LGE	SH_OP	$15	0.0%	13.7%	1,809	11.6%	1,779	-30

Available Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
MECS	S_SP1	$100	2.0%	10.5%	1,041	12.3%	1,041	0
MECS	S_SP2	$75	1.9%	10.2%	731	11.8%	753	23
MECS	S_SP3	$50	4.8%	7.1%	827	11.7%	888	62
MECS	S_P	$30	3.4%	5.8%	1,476	9.0%	1,512	36
MECS	S_OP	$20	0.0%	3.6%	2,126	3.1%	2,094	-32
MECS	W_SP	$25	0.0%	9.0%	2,380	8.2%	2,346	-34
MECS	W_P	$20	0.0%	7.3%	4,441	5.7%	4,569	129
MECS	W_OP	$15	0.0%	24.9%	4,841	23.3%	4,951	110
MECS	SH_SP	$40	2.9%	10.4%	749	13.0%	786	37
MECS	SH_P	$25	0.0%	9.8%	2,026	9.2%	2,019	-7
MECS	SH_OP	$15	0.0%	34.1%	3,292	29.1%	3,312	20
MGE	S_SP1	$100	5.2%	2.1%	1,802	7.3%	1,828	26
MGE	S_SP2	$75	4.3%	3.3%	1,781	7.1%	1,818	37
MGE	S_SP3	$50	6.3%	0.9%	2,570	6.9%	2,574	5
MGE	S_P	$30	4.4%	0.8%	2,710	4.9%	2,710	0
MGE	S_OP	$20	7.3%	1.5%	2,249	8.4%	2,264	15
MGE	W_SP	$25	4.1%	1.4%	1,928	5.2%	1,952	24
MGE	W_P	$20	18.9%	5.6%	2,286	23.9%	2,509	223
MGE	W_OP	$15	0.0%	12.6%	2,448	10.5%	2,496	48
MGE	SH_SP	$40	4.1%	1.6%	1,357	5.4%	1,373	16
MGE	SH_P	$25	3.3%	1.5%	2,066	4.4%	2,090	24
MGE	SH_OP	$15	0.0%	27.5%	2,680	23.0%	2,717	37
MIDAM	S_SP1	$100	2.4%	8.7%	623	11.1%	666	42
MIDAM	S_SP2	$75	2.1%	8.1%	637	9.9%	670	33
MIDAM	S_SP3	$50	6.5%	4.9%	939	11.1%	999	60
MIDAM	S_P	$30	5.6%	3.7%	942	9.0%	983	41
MIDAM	S_OP	$20	6.1%	1.5%	1,286	7.1%	1,305	18
MIDAM	W_SP	$25	4.6%	4.1%	1,099	8.3%	1,146	47
MIDAM	W_P	$20	11.9%	4.8%	1,122	15.8%	1,226	104
MIDAM	W_OP	$15	0.0%	9.4%	1,521	7.7%	1,543	22
MIDAM	SH_SP	$40	3.7%	8.5%	832	11.9%	892	60
MIDAM	SH_P	$25	4.6%	5.4%	1,240	9.5%	1,291	51
MIDAM	SH_OP	$15	0.0%	11.3%	1,515	9.1%	1,540	24
MPS	S_SP1	$100	0.6%	15.8%	884	16.3%	903	18
MPS	S_SP2	$75	1.8%	12.7%	705	14.3%	749	44
MPS	S_SP3	$50	9.3%	10.4%	733	19.6%	923	190
MPS	S_P	$30	2.3%	12.2%	760	14.4%	814	54
MPS	S_OP	$20	8.1%	3.4%	983	11.0%	1,036	53
MPS	W_SP	$25	3.5%	12.6%	885	15.7%	968	84
MPS	W_P	$20	4.2%	4.8%	1,103	8.4%	1,144	41
MPS	W_OP	$15	0.0%	9.3%	1,612	7.9%	1,647	35
MPS	SH_SP	$40	3.4%	9.7%	818	13.0%	883	65
MPS	SH_P	$25	1.9%	15.2%	992	16.8%	1,046	54
MPS	SH_OP	$15	0.0%	10.1%	1,380	8.4%	1,399	20
NEPOOL	S_SP1	$100	0.0%	0.0%	3,272	0.0%	3,272	0
NEPOOL	S_SP2	$75	0.0%	0.0%	2,452	0.0%	2,452	0
NEPOOL	S_SP3	$50	0.0%	0.0%	2,427	0.0%	2,427	0
NEPOOL	S_P	$30	0.0%	0.0%	2,607	0.0%	2,607	0
NEPOOL	S_OP	$20	0.0%	0.0%	3,091	0.0%	3,091	0
NEPOOL	W_SP	$25	0.0%	0.0%	2,553	0.0%	2,553	0
NEPOOL	W_P	$20	0.0%	0.0%	3,029	0.0%	3,029	0
NEPOOL	W_OP	$15	0.0%	0.0%	0	0.0%	0	0
NEPOOL	SH_SP	$40	0.0%	0.0%	2,483	0.0%	2,483	0
NEPOOL	SH_P	$25	0.0%	0.0%	2,548	0.0%	2,548	0
NEPOOL	SH_OP	$15	0.0%	0.0%	0	0.0%	0	0

Available Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
NIPS	S_SP1	$100	1.8%	5.2%	927	7.0%	936	9
NIPS	S_SP2	$75	3.2%	4.1%	704	6.9%	726	21
NIPS	S_SP3	$50	8.5%	3.2%	773	11.4%	828	54
NIPS	S_P	$30	6.7%	4.0%	776	10.5%	831	54
NIPS	S_OP	$20	10.5%	4.7%	1,148	14.6%	1,237	90
NIPS	W_SP	$25	3.2%	7.5%	1,114	10.1%	1,158	44
NIPS	W_P	$20	5.7%	8.4%	2,195	12.7%	2,299	104
NIPS	W_OP	$15	0.0%	13.4%	1,596	12.0%	1,571	-26
NIPS	SH_SP	$40	3.7%	7.4%	592	10.9%	642	51
NIPS	SH_P	$25	0.0%	9.3%	1,095	8.4%	1,091	-4
NIPS	SH_OP	$15	0.0%	14.7%	1,381	11.7%	1,337	-44
NSP	S_SP1	$100	6.8%	2.8%	796	9.5%	833	37
NSP	S_SP2	$75	2.9%	3.7%	704	6.2%	728	23
NSP	S_SP3	$50	7.2%	3.6%	524	10.6%	573	49
NSP	S_P	$30	5.5%	3.2%	708	8.5%	741	33
NSP	S_OP	$20	5.0%	2.8%	1,190	7.1%	1,207	17
NSP	W_SP	$25	4.6%	5.7%	876	9.8%	924	48
NSP	W_P	$20	9.2%	6.4%	1,001	14.4%	1,108	107
NSP	W_OP	$15	0.0%	7.3%	1,274	5.9%	1,288	14
NSP	SH_SP	$40	2.7%	5.3%	1,005	7.5%	1,037	32
NSP	SH_P	$25	2.2%	3.5%	891	5.3%	910	18
NSP	SH_OP	$15	0.0%	7.6%	1,162	6.1%	1,181	19
NYPP	S_SP1	$100	0.0%	2.5%	1,955	2.6%	1,955	0
NYPP	S_SP2	$75	0.0%	2.9%	1,850	2.9%	1,851	0
NYPP	S_SP3	$50	0.0%	3.6%	1,645	3.7%	1,645	0
NYPP	S_P	$30	0.0%	3.8%	1,650	4.0%	1,651	0
NYPP	S_OP	$20	0.0%	1.7%	2,758	2.2%	2,753	-5
NYPP	W_SP	$25	0.0%	1.1%	2,379	1.1%	2,379	0
NYPP	W_P	$20	0.0%	1.9%	4,345	1.9%	4,345	0
NYPP	W_OP	$15	0.0%	2.2%	5,360	3.2%	5,248	-113
NYPP	SH_SP	$40	0.0%	2.0%	1,283	2.1%	1,282	-1
NYPP	SH_P	$25	0.0%	0.8%	1,224	0.8%	1,224	0
NYPP	SH_OP	$15	0.0%	1.9%	5,454	1.9%	5,454	0
SCEG	S_SP1	$100	0.0%	22.0%	1,550	22.2%	1,549	-2
SCEG	S_SP2	$75	1.2%	13.6%	1,633	14.6%	1,658	25
SCEG	S_SP3	$50	0.0%	14.1%	1,529	14.0%	1,521	-7
SCEG	S_P	$30	0.0%	5.3%	3,741	5.0%	3,727	-14
SCEG	S_OP	$20	0.0%	17.1%	4,979	16.3%	5,001	22
SCEG	W_SP	$25	0.0%	6.1%	2,859	5.7%	2,865	6
SCEG	W_P	$20	0.0%	52.7%	4,338	42.5%	4,117	-221
SCEG	W_OP	$15	0.0%	91.0%	8,361	89.9%	8,176	-185
SCEG	SH_SP	$40	0.0%	19.0%	2,669	18.6%	2,677	9
SCEG	SH_P	$25	0.0%	9.2%	2,887	8.2%	2,940	54
SCEG	SH_OP	$15	0.0%	90.5%	8,278	88.3%	7,926	-352
SCPSA	S_SP1	$100	0.0%	20.1%	1,481	20.3%	1,480	0
SCPSA	S_SP2	$75	0.9%	18.9%	1,015	19.7%	1,043	28
SCPSA	S_SP3	$50	0.0%	19.9%	1,253	19.7%	1,248	-5
SCPSA	S_P	$30	0.0%	4.5%	5,171	4.2%	5,182	11
SCPSA	S_OP	$20	0.0%	8.8%	3,783	8.1%	3,794	11
SCPSA	W_SP	$25	0.0%	5.6%	2,180	5.2%	2,192	11
SCPSA	W_P	$20	0.0%	24.5%	5,713	17.7%	6,396	683
SCPSA	W_OP	$15	0.0%	58.9%	4,745	56.6%	4,629	-116
SCPSA	SH_SP	$40	0.0%	20.0%	2,593	19.6%	2,602	9
SCPSA	SH_P	$25	0.0%	8.8%	3,239	7.5%	3,331	92
SCPSA	SH_OP	$15	0.0%	68.7%	5,348	63.4%	4,882	-466

Available Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
SOCO	S_SP1	$100	0.0%	22.7%	2,171	22.8%	2,182	11
SOCO	S_SP2	$75	0.8%	23.4%	1,262	24.3%	1,312	50
SOCO	S_SP3	$50	1.1%	23.6%	1,154	24.7%	1,204	50
SOCO	S_P	$30	4.5%	25.7%	1,520	30.2%	1,757	237
SOCO	S_OP	$20	0.0%	4.7%	4,365	4.1%	4,426	62
SOCO	W_SP	$25	0.0%	11.8%	2,848	11.6%	2,859	11
SOCO	W_P	$20	0.0%	9.9%	7,954	8.1%	8,235	281
SOCO	W_OP	$15	0.0%	91.1%	8,379	89.2%	8,071	-308
SOCO	SH_SP	$40	0.0%	20.5%	1,961	20.3%	1,971	11
SOCO	SH_P	$25	0.0%	10.9%	1,379	10.1%	1,399	20
SOCO	SH_OP	$15	0.0%	80.5%	6,613	76.6%	6,060	-553
TVA	S_SP1	$100	4.2%	10.9%	1,099	14.9%	1,177	78
TVA	S_SP2	$75	3.4%	8.3%	984	11.0%	1,027	42
TVA	S_SP3	$50	1.9%	6.3%	872	7.7%	888	16
TVA	S_P	$30	6.8%	4.3%	1,089	11.0%	1,148	58
TVA	S_OP	$20	0.0%	6.2%	1,223	5.0%	1,217	-5
TVA	W_SP	$25	0.0%	4.1%	1,033	3.4%	1,043	10
TVA	W_P	$20	0.0%	7.8%	1,427	6.5%	1,451	24
TVA	W_OP	$15	0.0%	19.0%	1,672	17.3%	1,668	-3
TVA	SH_SP	$40	1.3%	15.2%	777	16.3%	811	35
TVA	SH_P	$25	0.0%	6.8%	1,012	5.8%	1,011	-1
TVA	SH_OP	$15	0.0%	22.7%	1,789	19.1%	1,764	-25
VP	S_SP1	$100	2.0%	5.5%	1,762	7.4%	1,766	4
VP	S_SP2	$75	1.8%	4.2%	1,893	5.8%	1,880	-13
VP	S_SP3	$50	2.0%	3.5%	1,675	5.3%	1,668	-7
VP	S_P	$30	0.0%	2.4%	1,261	2.2%	1,252	-9
VP	S_OP	$20	0.0%	4.0%	4,026	3.7%	3,971	-55
VP	W_SP	$25	0.0%	3.5%	2,848	3.1%	2,792	-56
VP	W_P	$20	0.0%	17.3%	2,244	14.2%	2,297	52
VP	W_OP	$15	0.0%	33.6%	3,368	30.8%	3,354	-14
VP	SH_SP	$40	0.0%	9.4%	965	9.1%	951	-14
VP	SH_P	$25	0.0%	5.8%	2,999	5.1%	2,985	-14
VP	SH_OP	$15	0.0%	21.2%	3,762	17.4%	3,952	190
UPP	S_SP1	$100	2.4%	1.1%	2,465	3.5%	2,465	0
UPP	S_SP2	$75	1.7%	1.4%	2,541	2.9%	2,532	-9
UPP	S_SP3	$50	1.5%	0.2%	3,362	1.7%	3,350	-12
UPP	S_P	$30	1.2%	0.2%	3,616	1.4%	3,598	-18
UPP	S_OP	$20	3.6%	0.8%	4,716	4.3%	4,663	-53
UPP	W_SP	$25	7.4%	1.5%	1,816	8.4%	1,849	34
UPP	W_P	$20	19.7%	5.2%	2,705	24.2%	2,927	222
UPP	W_OP	$15	0.0%	15.8%	2,739	12.8%	2,807	68
UPP	SH_SP	$40	0.0%	0.0%	10,000	0.0%	10,000	0
UPP	SH_P	$25	0.0%	0.0%	10,000	0.0%	10,000	0
UPP	SH_OP	$15	0.0%	0.0%	0	0.0%	0	0
WEP	S_SP1	$100	4.8%	2.5%	1,579	7.4%	1,591	12
WEP	S_SP2	$75	5.1%	3.5%	1,219	7.8%	1,261	41
WEP	S_SP3	$50	6.3%	0.8%	4,128	6.9%	4,106	-22
WEP	S_P	$30	3.0%	0.4%	6,528	3.3%	6,506	-22
WEP	S_OP	$20	0.0%	1.3%	7,441	0.9%	7,384	-57
WEP	W_SP	$25	6.7%	2.5%	806	8.6%	835	29
WEP	W_P	$20	9.8%	3.7%	1,243	13.3%	1,317	74
WEP	W_OP	$15	0.0%	4.1%	1,119	3.3%	1,132	13
WEP	SH_SP	$40	4.3%	3.6%	742	7.6%	772	30
WEP	SH_P	$25	3.6%	2.2%	788	5.4%	809	21
WEP	SH_OP	$15	0.0%	5.4%	1,241	4.1%	1,264	23

Available Economic Capacity
100 MW Transmission Path

			BASE			MERGER		
Market	Period	Price	COMED Mkt Share	PECO Mkt Share	HHI Pre-Merger	CE + PECO Mkt Share	HHI Post-Merger	HHI Chg
WPS	S_SP1	$100	2.8%	1.2%	2,136	4.0%	2,139	3
WPS	S_SP2	$75	2.4%	1.9%	2,101	3.9%	2,121	20
WPS	S_SP3	$50	6.9%	1.0%	2,159	7.6%	2,169	10
WPS	S_P	$30	5.1%	0.9%	2,205	5.7%	2,211	7
WPS	S_OP	$20	4.9%	1.1%	1,872	5.7%	1,879	7
WPS	W_SP	$25	4.4%	1.6%	1,144	5.6%	1,168	25
WPS	W_P	$20	13.4%	4.3%	1,097	17.1%	1,205	107
WPS	W_OP	$15	0.0%	6.6%	1,495	5.4%	1,510	16
WPS	SH_SP	$40	6.1%	1.8%	965	7.6%	990	25
WPS	SH_P	$25	4.7%	2.0%	1,232	6.2%	1,259	27
WPS	SH_OP	$15	0.0%	14.7%	1,317	11.5%	1,317	0
WR	S_SP1	$100	0.6%	8.8%	1,011	9.4%	1,023	12
WR	S_SP2	$75	1.6%	7.7%	1,134	9.1%	1,159	25
WR	S_SP3	$50	6.8%	4.9%	1,708	11.7%	1,774	66
WR	S_P	$30	2.9%	3.8%	2,105	6.5%	2,126	21
WR	S_OP	$20	4.2%	5.5%	1,459	9.5%	1,502	44
WR	W_SP	$25	4.0%	6.6%	2,229	10.4%	2,279	50
WR	W_P	$20	0.0%	1.2%	2,087	1.1%	2,091	4
WR	W_OP	$15	0.0%	3.8%	3,044	3.3%	3,068	24
WR	SH_SP	$40	2.6%	4.5%	1,130	7.0%	1,154	24
WR	SH_P	$25	1.7%	4.2%	2,083	5.7%	2,097	14
WR	SH_OP	$15	0.0%	4.3%	2,737	3.5%	2,738	1

Exhibit No. APP-311

Regional Generating Plant Characteristics

Utility / Region	Generation by Dispatch Price ($/MWh) <$15	$15 - $20	$20 - $25	$25 - $30	>$30	Total
COMED	9,085	-	-	468	968	10,522
PECO	4,332	411	110	1,356	1,040	7,247
	13,417	411	110	1,824	2,008	17,769

	<$15	$15 - $20	$20 - $25	$25 - $30	>$30	Total
First Tier to COMED	44,638	13,699	1,250	2,396	6,391	68,374
First Tier to PECO	47,904	23,471	8,754	9,301	16,503	105,934
	92,542	37,170	10,005	11,697	22,894	174,308

	<$15	$15 - $20	$20 - $25	$25 - $30	>$30	Total
ECAR	74,657	9,142	2,494	1,918	7,081	95,293
MAAC	20,574	11,438	3,077	4,145	12,146	51,380
MAIN	28,984	11,639	1,299	3,013	6,241	51,176
MAPP	18,977	2,209	1,047	169	4,565	26,966
NPCC	17,804	12,087	9,773	6,212	4,846	50,722
SERC	46,759	53,593	4,685	22,972	10,380	138,388
SPP	17,120	3,007	7,516	5,007	2,167	34,818
	224,874	103,116	29,891	43,436	47,426	448,742

Regional Market - First Tier to Applicants

	<$15	$15 - $20	$20 - $25	$25 - $30	>$30	Total
COMED Share (%) of First Tier	16.91%	0.00%	0.00%	16.35%	13.16%	13.34%
PECO Share (%) of First Tier	8.29%	1.72%	1.24%	12.72%	5.93%	6.40%
Combined Share (%) of First Tiers	12.66%	1.09%	1.09%	13.49%	8.06%	9.25%

Regional Market - MAIN, ECAR, PJM

	Generation by Dispatch Price ($/MWh) <$15	$15 - $20	$20 - $25	$25 - $30	>$30	Total
COMED Share (%)	7.31%	0.00%	0.00%	5.16%	3.80%	5.32%
PECO Share (%)	3.49%	1.27%	1.60%	14.94%	4.08%	3.66%
Combined Share (%)	10.80%	1.27%	1.60%	20.09%	7.88%	8.98%

Notes:
MW values based on Summer Super Peak unit ratings.
ComEd totals do not include purchases from Edison Mission (other than peakers), Elwood and Robbins
ComEd capacity in $25 - $30 range consists of planned affiliated merchant capacity and purchases.

Market Price Data
($/MWh)

Region	Period	Load Weighted Lambda (1998)	*Power Markets Week (1998)*	Destination Market Price Analyzed
ECAR	S_SP1	79.25	153.49	100.00
ECAR	S_SP2	44.94	153.49	75.00
ECAR	S_SP3	34.99	153.49	50.00
ECAR	S_P	20.65	153.49	30.00
ECAR	S_OP	17.90	13.73	20.00
ECAR	W_SP	17.72	17.99	25.00
ECAR	W_P	16.41	17.99	20.00
ECAR	W_OP	13.54	12.72	15.00
ECAR	SH_SP	40.49	27.56	40.00
ECAR	SH_P	18.99	27.56	25.00
ECAR	SH_OP	15.00	13.78	15.00
MAIN	S_SP1	100.00	122.51	100.00
MAIN	S_SP2	100.00	122.51	75.00
MAIN	S_SP3	47.55	122.51	50.00
MAIN	S_P	24.11	122.51	30.00
MAIN	S_OP	17.91	13.40	20.00
MAIN	W_SP	19.06	20.15	25.00
MAIN	W_P	15.28	20.15	20.00
MAIN	W_OP	13.50	13.06	15.00
MAIN	SH_SP	41.58	28.71	40.00
MAIN	SH_P	17.70	28.71	25.00
MAIN	SH_OP	14.72	13.67	15.00
SERC	S_SP1	29.29	112.60	100.00
SERC	S_SP2	24.61	112.60	75.00
SERC	S_SP3	20.83	112.60	50.00
SERC	S_P	17.39	112.60	30.00
SERC	S_OP	15.44	15.79	20.00
SERC	W_SP	14.94	18.90	25.00
SERC	W_P	13.61	18.90	20.00
SERC	W_OP	12.80	14.32	15.00
SERC	SH_SP	24.13	28.40	40.00
SERC	SH_P	15.94	28.40	25.00
SERC	SH_OP	13.78	15.10	15.00
MAAC	S_SP1	100.00	43.61	100.00
MAAC	S_SP2	66.62	43.61	75.00
MAAC	S_SP3	37.18	43.61	50.00
MAAC	S_P	22.93	43.61	30.00
MAAC	S_OP	17.94	15.61	20.00
MAAC	W_SP	25.77	20.18	25.00
MAAC	W_P	19.34	20.18	20.00
MAAC	W_OP	14.15	14.09	15.00
MAAC	SH_SP	49.88	24.44	40.00
MAAC	SH_P	24.35	24.44	25.00
MAAC	SH_OP	16.17	14.42	15.00

Notes:
Highest lambda capped at $ 100/MWh
Power Markets Week value equal to average of reported low and high v

Summary of Projected Merchant Plant Capacity

	New Capacity				Available Capacity			
	1999	2000	2001	Total	1999	2000	2001	Total
ECAR	1,364	2,216	3,040	7,199	1,364	2,196	2,640	6,394
MAAC	1,111	300	1,780	3,648	1,262	300	1,080	2,642
MAIN	3,103	3,848	1,640	8,633	1,147	2,701	815	4,663
MAPP	100	575	362	1,387	19	575	362	1,156
NPCC	773	3,384	7,984	12,141	563	3,024	7,284	10,871
SERC	3,407	6,174	9,937	20,908	3,088	4,277	7,081	15,891
SPP	330	2,805	1,800	5,423	170	1,030	2,300	3,500
TOTAL	**10,188**	**19,302**	**26,543**	**59,339**	**7,613**	**14,103**	**21,562**	**45,116**

Generating Plants Proposed for Operation Between 1998 and 2001

(Units with Asterisks Included in Appendix A Analysis)

Ref. No.	Operator	NERC	Project	Unit #	State	Owner-ship	Unit Type	Proj. Cap. (MW)	Avail. Cap. (MW)	Primary Fuel	Project Status	Current Proposed Online Date		Source Code
	ECAR													
***1)	American Mun Power-Ohio Inc	ECAR	Belleville	1	OH	U	HY	18	18	WAT	V	1999	1	1, 2
***2)	American Mun Power-Ohio Inc	ECAR	Belleville	2	OH	U	HY	18	18	WAT	V	1999	1	1, 2
3)	Catamount Energy	ECAR	Gauley River Power Partners		WV	I	HC	80	80	WAT	F	2001	12	3
***4)	CMS Generating & DTE Energy Services	ECAR	Rouge Steel/Ford Motor		MI	MERCH	ST	710	310	NG	U	2001		2,4,8,24,44
***5)	CMS Generating Michigan Power	ECAR	Comstock, Michigan		MI	I	GT	68	68	NG	U	2000	6	44,45
***6)	CMS Generation Michigan Power	ECAR	Gaylord, Michigan		MI	I	GT	148	148	NG	U	2000	6	6,44,45
7)	Duke	ECAR	DeSoto		IN	MERCH	NC	640	640	G	L	2001		6,44
***8)	Duke / Cinergy	ECAR	Trenton		OH	I	GT	640	640	NG	U	2000		3,6
***9)	Duke / Cinergy	ECAR	Vermillion County		IN	MERCH	NC	640	640	G	U	2000		6
10)	Dynegy	ECAR	Oldham County		KY	MERCH	GT	500	500	NG	L	2001		3,6,7,25
11)	East Kentucky Power Coop Inc	ECAR	Hazard		KY			245		coal	P			3
***12)	Enron Corp.	ECAR	Calvert City		KY	MERCH	CT	500	500	NG	U	2000		3,8,6,44
13)	Kentucky Utilities	ECAR	EW Brown		KY		GT	328	328	NG	P	1999		3,6
14)	MCN Energy	ECAR	Columbus		OH	MERCH	NC	220	200	NG	P	2000		6,4
15)	MCN Energy	ECAR	Southern West Virginia		WV	I		240	100	MTE	P			3,6
16)	National Power Partners	ECAR	RE Burger Repowering		OH	MERCH	ST	280	280	REF CL	P	2001	6	3
17)	OES/Nat'l Power Partners	ECAR	Shadyside	1-2	OH	MERCH	FB	280	280	WC	P	2001		3
18)	Primary Energy	ECAR	Amoco's Whiting Refinery		IN	MERCH	Cogen	550	550	NG	P	2001	3	39,4
19)	Primary Energy	ECAR	Inland Steel, Indiana Harbor Works		IN	I	CC	94	94	WH	V	1998	6	3,44
20)	Quixx	ECAR	VEDCO Louisville		KY	I				NG	P			3
21)	US Generating	ECAR	Covert		MI			1,000	1,000	gas	P	1999		3,6
	MAAC													
***22)	AES	MAAC	AES Ironwood		PA	I	CC	705	0	NG	U	2001	6	3,44
23)	AES	MAAC	Blue Mountain Power Project		PA			150		NG	P			3
24)	Calpine Corp.	MAAC	Ontelaunee Township		PA	MERCH	CC	575	575	NG	OT	2001		6.45
25)	CMS Generating and American Power	MAAC	Altoona Cogeneration Partners, Blair County		PA			80		NG	P			3
***26)	AES and Commonwealth Cheasapeake	MAAC	Accomac County		VA		CT	300	300	NG	U	2000		2,3,4,6
***27)	Delmarva Power & Light(Conectiv)	MAAC	Delaware City	AA	DE	U	GT		89	OT	U	1999	10	2,4
***28)	Delmarva Power & Light(Conectiv)	MAAC	Delaware City	BB	DE	U	GT		89	OT	U	1999	10	2,4

Ref. No.	Operator	NERC	Project	Unit #	State	Owner-ship	Unit Type	Proj. Cap. (MW)	Avail. Cap. (MW)	Primary Fuel	Project Status	Current Proposed Online Date		Source Code
29)	Easton Utilities Commission	MAAC	Easton 2	CC	MD	U	IC		5	FO6	P	2001		2,4
30)	GPU	MAAC	York County		PA			227		NG	P			3
***31)	PEI Powercorp	MAAC	Archbald		PA	MERCH	GT	70	70	NG/Meth	U	1999		3,6
32)	Penn Electric Co. (GPU)	MAAC	Homer City	NUG	PA	I			17	BIT	OT	1999		2,4
33)	Penn Electric Co. (GPU)	MAAC	Homer City	NUG	PA	I			17	BIT	OT	1999		2,4
***34)	Potomac Edison Co.	MAAC	AES 'Warrior Run	1	MD	NUG	ST		180	COL	V	1999	10	3,4
***35)	Star Enterprises	MAAC	Delaware Clean Energy Project		DL	J	CC	241	0	RG	V	1999		3
***36)	US Generating	MAAC	West Deptford, Mantua Creek		NJ		NC	800	800	G	T	1999		7,6,44
37)	Westcoast Energy/Columbia Energy	MAAC	Liberty Power Project		PA	MERCH	CC	500	500	NG	P	2001		6
	MAIN													
***38)	Dominion and Peoples Energy	MAIN	Elwood, IL		IL	MERCH	GT	600	0	NG	U	1999	6	6,11
***39)	Dynegy	MAIN	Rocky Road	1	IL	MERCH		250	250	NG	U	1999		3,47
***40)	Dynegy	MAIN	Rocky Road	2	IL	MERCH	CT	110	110	NG		2000		47
***41)	Enron	MAIN	Lincoln Energy Center		IL	MERCH	CT	575	575	NG		2000		47
42)	Enron Corp.	MAIN	Kendall County		IL	MERCH	CT	668	668	NG		2000	6	3,10
43)	FPL Energy	MAIN	Cerro Gordo		IA	MERCH		42		WND				44
44)	Houston Industries Power Generation	MAIN	Wood River; Roxana, IL		IL	MERCH	CC	634	634	NG	P	1999	6	3
***45)	Indeck	MAIN	Holiday Hills		IL	MERCH	CT	300	300	NG		2000		47
***46)	LS Power	MAIN	Kendall County, Minooka		IL	MERCH	CC	1,100	275	NG	U	2001		15,26,47
***47)	Mid-America	MAIN	Cordova		IL	MERCH	CT	500	500	NG		2001		47
***48)	North Chicago LLC	MAIN	North Chicago, Lake County	1	IL	MERCH	CT	180	180	NG		2000		47
***49)	North Chicago LLC	MAIN	North Chicago, Lake County	2	IL	MERCH	CT	40	40	NG		2001		47
***50)	Polsky Energy	MAIN	DePere (Phase I)	1	WI	MERCH	CC	255	75	NG	OP	1999	6	3,44
***51)	Polsky Energy	MAIN	DePere, WI (Phase II)	1	WI	MERCH	CC	254	76	NG	U	2000	6	3
52)	Polsky Energy	MAIN	Wood River Energy Center		IL	I	ST	35	35	REF	F	2000	6	3
53)	Polsky Energy & Alliant	MAIN	Southeast Wisconsin Merchant	1	WI	MERCH	GT	525	375	NG	P	2000	6	1
54)	Southern Company	MAIN	Neehah Merchant Plant	1	WI	MERCH	CT	300	300	NG	P	2000	6	6
55)	Springfield, City of	MAIN	Interstate	1			GT	20	22	NG	P	1999	7	2
56)	Springfield, City of	MAIN	Interstate	2			GT	20	22	NG	P	1999	7	2
57)	Springfield, City of	MAIN	Interstate	3			GT	20	22	NG	P	1999	7	2
58)	Springfield, City of	MAIN	Interstate	4			GT	20	22	NG	P	1999	7	2
***59)	Wisconsin Electric Power	MAIN	Concord	1-4			GT	360	44	NG	A	1999	6	2
***60)	Wisconsin Electric Power	MAIN	Germantown	1-6			GT	366	60	NG	A	2000	6	2
61)	Wisconsin Electric Power	MAIN	Paris	1-4			GT	380	44	NG	A	1999	6	2
62)	Wisconsin Electric Power	MAIN	Point B...				NP	524	12	UR	A	1999	4	2
63)	Wisconsin Public Service	MAIN	Kewaunee				NP	535	22	UR	A	2000	7	2

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	MAPP													
64)	Calenergy and Midamerican Energy Holdings	MAPP	Quad City Area		IL	MERCH	NC	500	500	NG	P	2000		6,15
65)	Enron Corp. and FPL	MAPP	Buena Vista County	1-2	IA	MERCH	WT	100	19	WND	P	1999	1	3
66)	Koch Refining	MAPP	Rosemount		MN	I	Cogen	250	100	PC	P			3
67)	Northern States Power	MAPP	Granite Falls		MN	I	CT	75	75	BIO	P	2000		3
68)	NRG Energy	MAPP	Martin County		MN			362	362	NG	P	2001		3
69)	Zond Development/Enron Wind	MAPP	NSP Phase 3		MN		WT	100	100	WND	P			3
	NPCC													
70)	AES	NPCC	AES Southington		CT	MERCH	CC	700	700	NG	P	2001		3
71)	AES	NPCC	AES Londonberry		NH	MERCH	CC	720	720	NG	P	2001		3
72)	American National Power	NPCC	ANP Gorham		ME	MERCH	CC	825	825	NG	P	2001		3
***73)	Calpine Corp.	NPCC	Westbrook		ME	MERCH	CC	540	540	NG	U	2001		3
74)	Champion	NPCC	Bucksport		ME	MERCH	Cogen	174	124	NG	P	1999		3
75)	Consolidated Edison	NPCC	ConEd Newington		NH	MERCH	CC	525	525	NG	P	2001		3
76)	Constellation Power Development	NPCC	Dracut		MA			750	750	NG	P	2000		3
***77)	Duke	NPCC	Independence Station		ME	MERCH	GT	500	500	NG	U	2000		3, 45
78)	Duke	NPCC	Newington Energy Center		NH	MERCH	CC	520	520	NG	P	2001		3, 45
***79)	El Paso Energy	NPCC	Milford		CT	MERCH	CC	544	544	NG	U	2000		3,44
***80)	El Paso Energy	NPCC	Berkshire		MA	MERCH		270	270	NG	U	1999		3,44
***81)	EMI/Calpine Corp.	NPCC	Tiverton		RI	MERCH		265	265	NG	U	2000		3,44
***82)	EMI/Calpine Corp.	NPCC	Rumford		ME	MERCH		265	265	NG	U	2000		3,44
***83)	EMI/Calpine Corp.	NPCC	Dighton		MA	MERCH	CC	169	169	NG	U	1999		3,44
84)	FPL Energy	NPCC	Bellingham, Bay State		MA	MERCH	CC	700		NG	P	2001		6
85)	PG&E Generating	NPCC	Athens		NY	MERCH	CC	1,080	1,080	NG	P	2001		6,16,17,44
***86)	PG&E Generating	NPCC	Millennium Power		MA	MERCH		360		NG	U	2000		3,44
***87)	Polsky Energy	NPCC	Androscoggin Energy, Jay		ME	MERCH	Cogen	160		NG	U	1999		3,44
88)	Power Development Corp/El Paso	NPCC	Meriden		CT	MERCH	CC	544	544	NG	P	2001		3
89)	Sempra Energy	NPCC	New Milford		CT		CC	500	500	NG	P	2001		3
90)	SUNSET ENERGY FLEET	NPCC	NEW YORK Harbor barge, Brooklyn		NY	MERCH	CC	520	520	NG	P	2001		6,27, 28
91)	Tractebel Power	NPCC	Piscataqua Power, Newington		NH	MERCH	CC	700	700	NG	P	2000		3
92)	US Generating	NPCC	Killingly		CT	MERCH	CC	810	810	NG	P	2001		3
	SERC													
93)	Alabama Electric Coop	SERC	McWilliams	CT3	AL	U	CC	500	500	NG	P	2001	1	2,4,44
94)	Alabama Power (SOCO)	SERC	APC2	1			ST	32	32	BIT	OT	2001		2
95)	Alabama Power (SOCO)	SERC	APC3	1			ST	34	34	BIT	OT	2000		2
***96)	Alabama Power (SOCO)	SERC	Barry	A1	AL	U	CC	532	532	NG	T	2000		2,4
***97)	Alabama Power (SOCO)	SERC	Barry	A2	AL	U	CC	532	532	NG	T	2001		2
***98)	Alabama Power (SOCO)	SERC	Burkville Cogen	1			CC	97	97	NG	T	1999	7	2
***99)	Alabama Power (SOCO)	SERC	McIntosh	1			CC	115	115	NG	V	1999	2	2

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100)	Alabama Power (SOCO)	SERC	Theodore	1	AL		CC	229	229	NG	P	2001	5	2
101)	Alabama Power (SOCO)	SERC	Theodore	1	AL		ST		33	BIT	OT	2000	11	2
102)	Associated Electric Coop	SERC	Choteau	3	OK	U	GT	49	49	NG	L	2001		2
103)	Associated Electric Coop	SERC	Chouteau	1	OK	U	CS	49	49	NG	P	2000	7	2,4
***104)	Associated Electric Coop	SERC	Essex	1	MO	U	GT	121	0	NG	U	1999	1	1,2
***105)	Associated Electric Coop	SERC	Nodaway Power Plant	GT1	MO	U	GT	104	114	NG	U	1999	6	1,2,4
***106)	Associated Electric Coop	SERC	Nodaway Power Plant	GT2	MO	U	GT	104	114	NG	U	1999	6	1,2,4
***107)	AECI and Duke	SERC	St. Francis	1	MO		CS	250	130	NG	OP	1999		2,6,10
108)	AECI and Duke	SERC	St. Francis	2	MO		CS	250	125	NG	L	2001	4	2,6,10
***109)	Carolina Power & Light	SERC	Asheville	GT1	NC	U	GT	212	185	NG	U	1999	6	1,2,4
110)	Carolina Power & Light	SERC	Monroe		GA	MERCH	GT	160	160	NG	P	1999		3,4,13
111)	Carolina Power & Light	SERC	Rowan	CT	NC	U	CT	600	600	NG	P	2001		2,4
***112)	Carolina Power & Light	SERC	Wayne County	1	NC	U	GT	212	195	NG	U	2000	6	1,2
***113)	Carolina Power & Light	SERC	Wayne County	2	NC	U	GT	212	195	NG	U	2000	6	1,2,4
***114)	Carolina Power & Light	SERC	Wayne County	3	NC	U	GT	211	195	NG	U	2000	6	2,4
***115)	Carolina Power & Light	SERC	Wayne County	4	NC	U	GT	211	195	NG	U	2000	6	2
116)	Carolina Power & Light	SERC	Wayne County	5	NC	U	GT	125	134	NG	IP	1998	1	2,1,4
117)	Carolina Power & Light	SERC	Wayne County	6	NC	U	GT	125	134	NG	IP	1998	1	2,3,4
118)	Carolina Power & Light	SERC	Wayne County	7	NC	U	GT	125	134	NG	IP	1998	1	2,4
119)	Carolina Power & Light	SERC	Wayne County	8	NC	U	GT	125	134	NG	IP	1998	1	2,4
120)	Carolina Power & Light	SERC	Wayne County	9	NC	U	GT	125	134	NG	IP	1998	1	2,4
121)	Carolina Power & Light	SERC	Wayne County	10	NC	U	GT	125	134	NG	IP	1998	1	2,4
***122)	Carolina Power & Light	SERC	Wayne County	GT1	NC	U	GT	211	195	NG	U	2000	6	2,4
123)	Duke	SERC	Dynegy	1			OT	200	200	OT	OT	2001	1	2
124)	Duke	SERC	Dynegy	1-5			GT	750	600	NG	U	2001	7	2
125)	Duke	SERC	Mobile Bay		AL	J	Cogen	40	40	NG	P	1998		3
126)	Dynegy	SERC	Calcasieu		LA	MERCH		155	155	NG	P	2000		2,3,22,44
127)	Dynegy	SERC	Heard County, Franklin		GA	MERCH	CT	500	500	NG	L	2001		2,3,4,13,18,22,12
***128)	Dynegy	SERC	Rockingham		NC	I	CT	800	200	NG	U	2000	6	2,3,4,18,19,20,21,44
***129)	Enron Corp.	SERC	Enron Brownsville, TN		TN	MERCH	CT	475	475	NG	U	2000		3,8,44
***130)	Enron Corp.	SERC	Enron; Caledonia, MS		MS	MERCH	GT	475	475	NG	V	1999	6	3,8
131)	Enron Corp.	SERC	Enron; Fulton, MS		MS	MERCH	GT	260	260	NG	P	1999	6	3,8
***132)	Enron Corp.	SERC	Enron; New Albany		MS	MERCH	GT	390	390	NG	V	1999	6	3,8
133)	Georgia Power (SOCO)	SERC	Athens		GA		GT	400	400	NG	P	1999		3,13
134)	LG&E Energy	SERC	Monroe		GA	MERCH	CT	450	450	NG	L	2000	6	4,29
***135)	LS Power/Cogentrix	SERC	Batesville		MS	MERCH	CC	837	0	NG	V	2000	6	3
136)	MCN Energy	SERC	Buchanan County		VA	I	ST	240	240	Coal	P	2001	12	3
137)	Mississippi Power (SOCO)	SERC	Moss Point	ALL	MS	U	CG		1,000	NG	P	2001		4
***138)	Mississippi Power (SOCO)	SERC	Victor J. Daniel, Jr.	3-4			CC	1064	1064	NG	T	2001	6	2
***139)	Oglethorpe Power	SERC	Smarr		GA	U	CT	220	220	NG	V	1999	6	4,13,44
140)	SkyGen Energy	SERC	Cherokee County/Broad River	1	SC	MERCH	GT	633	570	NG	L	2001	6	2,44, 30,31
141)	SkyGen Energy	SERC	Pine Bluff		AR	MERCH	Cogen	228		NG	F	2001		3,21,44,32
142)	Sonat Energy Services	SERC	Sonat Cataula		GA	MERCH	CT	680	465	NG	L	2000		3,35,2,4,13,23,12
***143)	Sonat Energy Services	SERC	Sonat Thomaston		GA	MERCH	CS	680	465	NG	U/V	2000	6	3,12,23,36
***144)	South Carolina Electric & Gas	SERC	Cogen South	1			ST	99	92	BIT	TS	1999	5	2
145)	South Carolina Electric & Gas	SERC	Summer	1			NP	170	150	NG	UR	2001	5	2

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146)	South Mississippi Public Service Authority(in SOCO)	SERC	Moselle				CS	250	250	NG	P	2001	1	2
***147)	Southeastern Elec. Development Corp.	SERC	Smiths		AL	I	GT	100			U	1999		3
148)	Southern Company	SERC	Goat Rock		AL	I		2,120		gas	P	2001		3
***149)	Tenaska	SERC	Heard County		GA	MERCH		950	0	NG		2001		45
150)	Tennesse Valley Authority	SERC	Gallatin	GT5			GT	85	88	NG	L	2000	6	2
151)	Tennesse Valley Authority	SERC	Johnsonville	3T17-20			GT	340	356	NG	L	2000	7	2
***152)	Tractebel Power	SERC	Red Hills Facility, Chester, MS		MS	I	ST	440	440	LIG/BIO	U	2001	6	3,41
***153)	USCE-Savannah District(in SOCO)	SERC	Richard Russell	5-8	GA		PS	300	336	WAT	TS	1999	11	2
***154)	Virginia Power	SERC	Facquier County		VA			600	600					45
	SPP													
155)	*Air Liquide America*	SPP	Geismar		LA	MERCH	Cogen	80	45	NG	P	1999		3
***156)	Cleco Corp.	SPP	Coughlin	8	LA	U	GT	750	330	NG	U	2000	6	4,45
***157)	Cogentrix Energy, Inc.	SPP	Jenks, Oklahoma		OK	MERCH	GT	800	800	NG	L	2001	6	3,33,42
158)	Duke	SPP	Glennonville, MO		MO	I	CC	250	125	NG	P	1999	6	3
159)	Empire District Electric Power	SPP	Stateline	CC	MO	U	CC		350	NG	P	2001		4
160)	Empire District Electric Power	SPP	Stateline	CT1	MO	U	CT		150	NG	P	2001		4
***161)	Golden Spread Electric Coop	SPP	Mustang		TX	MERCH	CC	488	0	NG				4
162)	KLT Power	SPP	Iatan	2	MO	I	ST	700	700	Coal	P	2000	6	3
163)	*Panda Energy*	*SPP*	*Coweta*		OK	MERCH		1,000	1,000	NG	P	2001	12	33,43
***164)	Tenaska	SPP	Frontier	1	TX	MERCH	CC	830	0	NG	P	2000		46
165)	Polsky Energy	SPP	RockGen		WI			525		NG	P	2000	6	3

NERC Project Status Codes:

F	Fully licensed; all 3rd party contracts obtained; financing obtained; no construction
L	Regulatory approval pending; no construction, but site prep started
OT	Other
P	Planned for installation; no utility authorization; no construction
TS	Construction complete, but not in commercial operation
T	Regulatory approval complete; no construction
U	*Under construction; < 50% complete*
V	Under construction; > 50% complete
OP	Project is "presently active or testing"

Ref. No.	Operator	NERC	Project	Unit #	State	Owner-ship	Unit Type	Proj. Cap. (MW)	Avail. Cap. (MW)	Primary Fuel	Project Status	Current Proposed Online Date	Source Code

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