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BEFORE THE ARIZONA CORPORATION COMMISSION

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CHAIRMAN
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IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	Docket No. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	Docket No. E-01933A-98-0471

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Rebuttal Testimony of Marylee Diaz Cortez and Dr. Richard A. Rosen, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 11th day of June, 2002.

Scott S. Wakefield
Chief Counsel

AN ORIGINAL AND EIGHTEEN COPIES
of the foregoing filed this 11th day
of June, 2002 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing hand delivered
this 11th day of June, 2002 to:

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All parties of record on the service list
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By Cheryl Fraulob
Cheryl Fraulob

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IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES

DOCKET NO. E-00000A-02-0051

REBUTTAL TESTIMONY

OF

MARYLEE DIAZ CORTEZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 11, 2002

INTRODUCTION

Q. Please state your name for the record.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Audit Manager for the Residential Utility Consumer Office (RUCO) located at 2828 N. Central Avenue, Suite 1200, Phoenix, Arizona 85004.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Have you previously provided testimony in this docket?

A. No.

Q. Please explain the purpose of your rebuttal testimony.

A. The purpose of my testimony is to provide information that has become relevant pursuant to various positions taken in direct testimony in this docket.

Q. Please identify some of the issues set forth in the parties' direct testimony that give rise to your rebuttal testimony.

A. Following are some of the issues that give rise to the need for my rebuttal testimony:

* The presence of Market Power
* The absence of a competitive retail market
* The question of whether a retail market is desirable
* The failure of the Competition Rules to provide reduced rates
* The inability for Arizona to support the development of electric competition at this time
* Uncertainty regarding what action, if any, FERC will take to regulate the wholesale market

Collectively, the above issues that were set forth in various parties' direct testimony, raise the question of whether Arizona should continue along the path set forth by the Electric Competition Rules and the various restructuring settlements between Arizona's electric utilities and the Arizona Corporation Commission (ACC). As the ACC pursues answers to this question, it is important that certain aspects of the current ACC rules and Decisions are examined and considered.

CURRENT RULES AND ACC DECISIONS

Q. What aspect of the currently effective Electric Competition Rules need to be considered in the context this docket?

A. The Electric Competition Rules permit Affected Utilities, as part of their stranded cost recovery, to seek recovery of costs incurred to transition to a restructured electric market. As a result, the Commission, in approving APS's stranded cost settlement, authorized APS to recover transition costs through an adjuster mechanism to commence on July 1, 2004. The ACC's authorization of the adjuster mechanism essentially serves as an accounting order, permitting APS to defer certain costs for future recovery.[1]

Q. Please explain the meaning and significance of an accounting order in the regulatory process.

A. An accounting order is an order from the Commission granting a utility authority to account for specific expenditures in a manner that deviates from the accounting required under Generally Accepted Accounting Principles (GAAP). The purpose of GAAP is to ensure that companies' financial statements are a fair representation of their actual financial position. By definition, an accounting order represents a deviation from GAAP. Thus, the impacts and ramifications of an accounting order should

[1] On May 31, 2002, APS filed an application for approval of the rate adjuster mechanisms referenced in the Settlement Agreement (Docket No. E-001345A-02-0403). In that filing, APS proposed to collect transition costs incurred from 1999 through 2004 in an adjuster to begin in 2005.

be thoroughly examined and considered, both at the time the order is requested and during the period it is in effect.

DEFERRAL ACCOUNTING

Q. Please explain the meaning and significance of deferral accounting in the regulatory process.

A. Deferral accounting is one of a myriad of potential GAAP deviations for which an accounting order would be required. Under GAAP, a company is required to write off all its expenses in the period in which they were incurred. In order to deviate from this rule, a regulated company must request and be granted a deferral accounting order, which allows it to defer (i.e. capitalize) these costs on its balance sheet. Deferral accounting converts expenses into assets.

Q. Under GAAP, does a company have to meet certain criteria to be eligible for deferral accounting?

A. Yes. This criteria is set forth in the Financial Accounting Standards Board Statement 71 (FAS 71). FAS 71 includes the following criteria:

* The enterprise's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third party regulator or by its own governing board

empowered by a state statute or contract to establish rates that bind customers.

* The regulated rates are designed to recover the specific enterprise's costs of providing the regulated services or products.
* It is probable that future revenue in an amount at least equal to the capitalized costs will result from inclusion of that cost in allowable costs for ratemaking purposes.
* Based on available evidence, future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

Q. In order to qualify for deferral accounting, must the utility have regulatory assurance that it will be allowed rates sufficient to recover the deferred costs?

A. Yes. In order to qualify under FAS71 for deferral accounting the regulated entity must have assurance from its regulator that it will be allowed rates sufficient to recover the deferred costs.

Q. What effect does the deferral accounting order have on a utilities' ratepayers?

A. A deferral accounting order creates a liability for ratepayers that will continue to grow in magnitude over the period in which the accounting order is in effect. This is because utility expenditures that would ordinarily be expensed in the period in which they were incurred are instead deferred and capitalized for future recovery from ratepayers. In general, the longer the accounting order is in effect the greater the liability becomes.

Q. Under the Electric Competition Rules and its settlement agreement for what type of costs was APS granted deferral accounting?

A. Pursuant to revised section 2.6(3) of the APS Settlement Agreement, the reasonable and prudent costs of compliance with the Electric Competition Rule, excepting APS's cost of transferring its generation assets to an affiliate were limited to 67% of such costs. Thus, APS is currently creating an ever-growing liability to ratepayers for the cost of restructuring the industry. In effect, as we speak the "meter is ticking" on Arizona ratepayers future utility rates.

Q. Why does this "ticking meter" create greater cause for concern than it did at the time the deferral accounting was originally authorized?

A. At the time the deferral accounting was authorized a competitive electric market was envisioned at the retail level. It was further envisioned that a competitive market would benefit Arizona consumers in the form of choice and lower prices. As testified to by many of the parties to this docket, a competitive retail market has not developed in Arizona, and lower rates certainly have not been realized. In fact, the issue of whether the competitive path mapped out in the Electric Competition Rules should continue to be pursued is at issue in this docket.

Q. Since no benefits have been realized, and the Electric Competition Rules are in question, should APS continue to be permitted to accrue an ever-mounding liability for the cost of transitioning to competition?

A. No. The liability should not be allowed to grow as long as the feasibility and desirability of electric competition remains in question.

Q. If the ACC were reluctant to rescind APS's deferral accounting order at this juncture, what other safeguards does it have at its disposal to protect ratepayers from this ever-mounting liability during its investigation of competitive markets?

A. The Commission could add certain conditions to the deferral accounting orders to protect ratepayers from the ever-mounting liability.

Q. Please provide examples of conditions that would protect ratepayers.

A. The ACC could add the following conditions:

1) Any deferrals accrued subsequent to the order in this docket are not guaranteed recovery, and will be subject to audit and review in the next rate case;

2) Any deferrals accrued subsequent to the order in this docket, if allowed for recovery, will not necessarily be afforded rate base treatment (i.e. earn a return);

3) APS will bear the burden of proving the reasonableness, prudency, necessity, and ratepayer benefit from any costs deferred subsequent to the issuance of an order in this docket.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION: University of Michigan, Dearborn
B.S.A., Accounting 1989

CERTIFICATION: Certified Public Accountant - Michigan
Certified Public Accountant - Arizona

EXPERIENCE: Audit Manager
Residential Utility Consumer Office
Phoenix, Arizona 85004
July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States. Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service
United Cities Gas Company	176-717-U	Kansas Corporation Commission

General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office

Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office

Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company Northern States Power Company	G-01970A-98-0017 G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company Mummy Mountain Water Company	W-01303A-98-0678 W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company Nicksville Water Company	W-02465A-98-0458 W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office
Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office

Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office
Southwest Gas Corporation ONEOK, Inc.	G-01551A-99-0112 G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications Citizens Utilities Company	T-01051B-99-0737 T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE	)	
GENERIC PROCEEDINGS	)	DOCKET NO. E-00000A-02-0051
CONCERNING ELECTRIC	)	
RESTRUCTURING ISSUES	)	

REBUTTAL TESTIMONY

OF

DR. RICHARD A. ROSEN

On Behalf of the Arizona
Residential Utility Consumer Office

Tellus Institute
11 Arlington Street
Boston, MA 02116-3411
Tel: 617/266-5400

June 11, 2002

TABLE OF CONTENTS

SECTION I – SUMMARY OF TESTIMONY

Q. ARE YOU THE SAME DR. RICHARD ROSEN WHO FILED DIRECT TESTIMONY ON BEHALF OF RUCO IN THIS DOCKET?

A. Yes, I am.

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY IN THIS CASE?

A. Certainly. After reviewing the direct testimony of all the witnesses in this case, I have come to the following conclusions and recommendations for the ACC:

1. The Commission should not lose sight of the fact that its continued study of electric deregulation would result in additional costs to customers. The Commission should determine what level of transition costs the utilities claim to have incurred to date, and what additional costs they might incur if the Commission continues to study the various relevant issues, as Staff recommends. That knowledge might lead the Commission to conclude that further study of the issues at this time is not cost-effective, given that 1) the likely outcome is that market power will continue to put customers at risk of higher rates than they currently pay under traditional regulation; 2) FERC is still experimenting with wholesale market designs that will yield uneven results, at best; and 3) FERC still does not understand how to monitor and mitigate market power in wholesale power markets.
2. Almost every witness in this docket seems to agree that the restructuring

process in Arizona, including divestiture, cannot possibly be completed by January 1, 2003, no matter what that process ends up consisting of. Therefore, I repeat my recommendation from my direct testimony that, at a minimum, the ACC approve a variance to delay for at least one year the implementation of the Electric Competition Rules for all utilities in Arizona, in order to give the ACC time to properly handle these complex issues.

3. Almost every witness, except the APS witnesses, agrees that Arizona utilities will have the substantial ability to exercise market power in wholesale electric markets within Arizona if all the existing generation assets of each utility are simply transferred to an unregulated affiliate of that utility. This would include monopoly-pricing power in certain Arizona load pockets near times of peak demand. This would, of course, be unacceptable. The APS application of the new FERC SMA test for market power is critically flawed, as Mr. Roach points out, and the test itself is inadequate anyway, as I discussed in my direct testimony and exhibits.

4. APS witness Hieronymus is correct that APS (or TEP) could not exercise market power with their existing generation assets in Arizona if that power were sold to Standard Offer customers on fixed-price basis under a long term PPA. Thus, as recommended in my direct testimony, a necessary condition for the ACC allowing divestiture to go forward is for all the

output of existing generation assets to be made available to Standard Offer customers on a traditional cost-of-service basis for the duration of their operational lifetime, so that ratepayers can continue to receive the economic benefits of these generating units. I agree with Staff witness Rowell that "because we know that existing cost-of-service rates are just and reasonable, we can use them as a benchmark for evaluating competitive rates during this transitional period." (Page 5) In this way, the ACC can help "ensure that consumers are no worse off under the restructured environment than they were under traditional cost-of-service regulation." (Rowell, page 4.)

5. I support the Staff recommendation that before divestiture is allowed to occur, the ACC would have to perform a comprehensive market power study for the Arizona regional wholesale power market. However, contrary to Staff, I do not believe that the utilities alone should be required to do such a study privately, in part because I do not believe that they know how to do the right kind of study. Instead, a market power study should be performed on a cooperative basis with input from all parties through the creation by the ACC of a technical advisory committee. The results of this study should be subject to review in a formal docket with expert testimony on how to interpret the results, and on the strengths and weaknesses of the study. This study must primarily consist of computer-based modeling of strategic behavior, including strategic bidding and

capacity withholding, since this is the only proper way to analyze the potential for market power in electricity markets. The use of the methodology described in Appendix A of the 1996 FERC merger guidelines is not an adequate methodology with which to evaluate the potential for generation owners to exercise market power, because it ultimately relies on the use of the HHI index.

6. The results of the recommended market power study should, then, be used by the ACC, and the other parties, to determine how and to what extent electric industry restructuring should continue to be pursued in Arizona. The market power study should include scenarios designed especially to anticipate various future approaches to restructuring, including various divestiture scenarios. There is no point in pursuing Track "B" issues in this docket until such a market power study is completed, because the appropriate structure for a competitive bidding process for Arizona will depend on the outcome of this study.

7. However, given the evidence relevant to such an analysis of the potential for the exercise of market power in Arizona that has already been entered into the record in these dockets, I agree with Mr. Pignatelli of Tucson Electric that the ACC should completely re-evaluate the costs and benefits of trying to achieve competition in the electric power industry, and that this "should include a review of the basic premise that competition is in the public interest." (Page 17) I share Mr. Pignatelli's obvious skepticism

that "competition" in this industry can ever be made to work in a way that would benefit any significant group of electricity ratepayers. Thus, in parallel with a market power study as recommended by Staff, I recommend that the ACC do what Mr. Pignatelli urges in his direct testimony, namely to require "proponents of electric competition to come forward with credible evidence of the anticipated benefits of electric competition ...to affirm or reject what seems to be the presumption that Electric Competition is the best manner for providing electric service in Arizona." (Page 18) A second set of hearings should be used for this purpose.

8. Several witnesses for independent power producers do not appear to understand how pervasive the exercise of market power is likely to be within Arizona, even if many of their recommendations are adopted by the ACC. This is a further reason why the Staff's recommended market power study should be carried out, if the ACC decides to proceed with restructuring at this time.

9. Mr. Pignatelli's recommendation that only customers with loads of 3 MW or greater be allowed to participate in retail competition within Arizona is a reasonable option for the ACC to consider, *if* traditional cost-of-service bundled retail rates are maintained for all other customers, and if divestiture is not carried out.

SECTION II – RESPONSE TO STAFF TESTIMONY

Q. DO YOU HAVE ANY OVERALL REACTION TO THE DIRECT TESTIMONY OF STAFF IN THIS DOCKET?

A. Yes. In general, I believe that the ACC Staff have done a very good job at describing the relevant issues that the Commission needs to deal with before electric industry restructuring can and should proceed in Arizona. Staff have also made some good suggestions for how the Commission should proceed with restructuring, if they decide to proceed at all. However, the Commission should first weigh the likely costs of proceeding as the Staff has suggested, versus the likely benefits of doing so. The Commission may determine, then, that the additional costs to all parties are not justified given the low probability of establishing a competitive electric wholesale market in Arizona in the foreseeable future.

Q. DO YOU HAVE MANY SIGNIFICANT DISAGREEMENTS WITH STAFF ON ANY OF THE ELECTRIC RESTRUCTURING ISSUES THAT THEY HAVE RAISED IN THEIR DIRECT TESTIMONY?

A. No. However, one issue that I disagree with Staff on is who should be responsible for performing a market power study for Arizona's wholesale electric market over the next few months. On page 10 of Mr. Rowell's testimony, he states that Staff has four basic recommendations regarding the transfer of generation assets. The first recommendation is that the utilities should be required to file a market power study and market power mitigation plan for Commission approval. My first disagreement is that I believe that the best way to perform a market power study for Arizona would be to have all parties, including the utilities, work together on such a study.

One main reason for my view is that very few, if any, such studies have ever been done before of the type which focus primarily on behavioral modeling, which is essential. Because of the path-breaking nature of such a study, it would be much better, and the results would be more consistent across all sub-regions within Arizona, if the ACC were to select a technical advisory committee from among all parties to this case. This committee could then hire a consultant to perform the study under their direction, funded using utility resources. In fact, there may be very few consultants available that are truly independent and have the requisite market power models. Either way, the methodology for such a study should be the same for all portions of Arizona, and for the surrounding regions. Similarly, since a good market power mitigation plan must flow organically from the underlying market power modeling that is performed, the same cooperative process should be used to explore different market power mitigation policies.

Q. DO YOU EXPECT THAT THE PARTIES WILL BE ABLE TO AGREE ON HOW TO CARRY OUT SUCH A COMPLEX STUDY?

A. I do not know for sure if all the parties will be able to work together on a fairly consensual basis for such an inevitably complex study. I participated on the

Technical Advisory Committee for the 1999 Colorado Restructuring Study, and that process went remarkably smoothly, so I have some basis for hope that a similar process could work here in Arizona. However, I do not expect that the modeling exercise alone will lead to agreement as to what the real potential for market power will be in Arizona, and what the best market power mitigation plan would be. On these and similar issues, I anticipate that parties will want to develop different positions, and these positions can be presented to the ACC through expert testimony in a set of hearings designed for this purpose. Disagreement must be expected on key policy issues. However, in contrast I would hope that the parties could agree that a wide range of scenarios that assume different levels of divestiture, different mixes and concentrations of ownership, different sites for new power plants, etc., should be run as part of the Staff's proposed market power study.

Q. DO SOME OF THE WITNESSES IN THIS CASE PROPOSE THE INGREDIENTS FOR SOME OF THE SCENARIOS THAT COULD BE ANALYZED AS PART OF THE PROPOSED MARKET POWER STUDY?

A. Yes. For example, Mr. Kebler of Reliant Energy Resources has proposed a particular way in which one-third of APS' existing generating capacity could be sold to other generation owners. While his proposal is premature for the ACC to consider directly at this point, because a market power study would need to be carried out first in order to determine the soundness of Mr. Kebler's proposal, it could form the basis for one of the scenario to be studied. In fact, even if, as a minimum condition, all of APS' existing generating capacity was committed to APS' Standard Offer customers under a long-term cost-of-service contract, as I have advocated, one would still need to make this scenario one of those analyzed as part of a market power study. This would need to be done in order to determine how difficult it would be to create a competitive wholesale market for generation in Arizona if only new generation capacity were deregulated.

Q. WHY DO YOU STRESS THAT STAFF's PROPOSED MARKET POWER STUDY SHOULD PRIMARILY FOCUS ON BEHAVIORAL MODELING, RATHER THAN ON OTHER METHODOLOGIES FOR ASSESSING THE EXISTENCE OF MARKET POWER?

A. As I discussed in my direct testimony, the other approaches to analyzing the potential for electric generation market power that have been used by FERC and others in the past do not work, and have no sound theoretical basis. To provide much more explication of these statements and issues I have provided Exhibits___(RAR-1, 2, 3, and 4) to support my testimony. I was a co-author of all of these documents, including the comments to FERC by the National Association of States Utility Consumer Advocates (NASUCA), of which Arizona RUCO is a member. This is another area of some disagreement that I have with Staff's testimony on market power issues, because I do not feel that they have placed nearly enough emphasis on the need for any credible market power analysis to perform behavioral modeling of strategic bidding, capacity withholding, and any other gaming strategies that have the potential to impact the market prices of electricity in Arizona.

For example, as I described in Exhibit ___(RAR-2) of my direct testimony, FERC's newly proposed SMA test for market power determines a necessary but not a sufficient condition for the successful exercise of market power in a region. In fact, if a generation owner fails FERC's SMA test, then they have monopoly-pricing power in some fraction of the year. Thus, Dr. Hieronymus' testimony in this docket on behalf of APS, which relies on the SMA test, is quite useless for the purpose of helping the ACC understand the full potential for the exercise of market power in Arizona. (In fact, Mr. Roach's critique of the FERC SMA methodology in his direct testimony nicely anticipated Dr. Hieronymus' testimony in this regard, and most of Mr. Roach's major points are correct.)

Similarly, Mr. Rowell recommends use of a market power analysis methodology similar to that used by FERC in its 1996 Appendix A merger guidelines, or similar to that recommended by the Arkansas PSC. I disagree with Mr. Rowell that such a methodology could prove to be very useful for understanding the full potential for the exercise of market power in electric markets in Arizona. In fact, I had prepared a critique of those guidelines in 1997 which I have attached here as Exhibit___(RAR-1). It is important to note that even the fairly recent Appendix A merger guidelines still rely on use of the HHI index, which I have criticized in many of the exhibits attached to this testimony. In several of these exhibits, I have shown how FERC's standard for interpreting the significance of the HHI index can yield very misleading conclusions when compared with explicit behavioral modeling of the utility system in question. Thus, I have concluded after many years of both theoretical and modeling research that the *only way* in which the potential for market power in the electric generation markets can be properly assessed is through use of the modeling of strategic behavior.

Q. MR. HIGGINS SUGGESTS THAT THE CALIFORNIA ISO HAS A MARKET POWER SCREEN THAT IS BETTER THAN FERC's NEWLY PROPOSED SMA SCREEN. DO YOU AGREE WITH MR. HIGGINS THAT THIS IS THE SCREEN THAT SHOULD BE USED TO ANALYZE THE POTENTIAL FOR MARKET POWER IN ARIZONA?

A. No, I do not agree with Mr. Higgin's suggestion in his direct testimony that the screen developed by the California ISO called the Residual Supply Index (RSI) should be used to determine the potential for the exercise of market power in Arizona's wholesale power market. As Mr. Higgins points out, this screen is better than FERC's proposed SMA screen because it does require the analyst to calculate the index for each hour, though the FERC SMA screen could be applied in each hour also. However, the RSI still does not incorporate sufficient detail regarding the structure of the market to be very useful. For example, as with the SMA screen, it does not incorporate ownership concentration, it does not include information on the shape of the cost-of-supply curve, it does not include information on the demand curve, it does not include information on what kind of power plants and power contracts are controlled by each generation owner, it does not include information on transmission constraints, etc. Thus, the RSI screen is fundamentally no better than the SMA screen. It is only a very rough screen, not a precise analytical tool for measuring the potential for market power. Whether the screen is "passed" or not is simply a "yes/no" answer. These screens provide no indications, given the structure of the market, as to "how much" market power might be exercised.

Q. JUST TO BE CLEAR, IN YOUR OPINION, WOULD THERE BE ANY USE IN USING A METHODOLOGY, AS PART OF A MARKET POWER STUDY, THAT RELIED ON FERC'S NEWLY PROPOSED SMA TEST, ON FERC'S 1996 APPENDIX A MERGER GUIDELINES, OR ON THE CALIFORNIA ISO's RESIDUAL SUPPLY INDEX?

A. No. In my opinion the use of any methodology, other than behavioral modeling, will not provide an analyst with any conclusive results regarding the potential for the exercise of market power in the utility system being analyzed. Passing these other tests for market power may be a reasonable *necessary* condition for passing a behavioral test, but it would certainly not be a *sufficient* condition for passing a more rigorous behavioral test. Therefore, the behavioral approach to simulating market power must be used no matter what else is done. For example, there is no point in wasting time attempting to replicate FERC's fairly complex Appendix A merger guidelines, because ultimately these guidelines rest solely on an interpretation of the resulting HHI index that is totally arbitrary, and without any theoretical foundation.

In this regard, I also have attached Exhibit___(RAR-5), which is a letter I received from FERC Commissioner William Massey, who clearly recognizes the serious limitations of the HHI. As Mr. Massey states, "I agree with your fundamental premise – that HHI's do not capture the dynamic nature of power markets. Market simulation models, properly structured, would be more accurate and useful."

Q. DO YOU HAVE ANY FURTHER DISAGREEMENT WITH THE FOUR BASIC STAFF RECOMMENDATIONS THAT MR. ROWELL PRESENTS ON PAGE 10 OF HIS TESTIMONY?

A. Yes, I also disagree with staff recommendation #3, which states, "other [non-reliability must-run (RMR)] generating units can be transferred [to unregulated affiliates] at the utilities' discretion." I disagree primarily because I believe that it is very likely that the market power study done to satisfy Staff recommendation #1 will show that all power plants in Arizona will contribute to the exercise of significant levels of market power, especially if they continue to be owned by the existing utility or an affiliate. Thus, Staff recommendation #3 should be clearly coupled to the fact that any transfer of generation capacity should only take place if all the output from those generating units is provided to Standard Offer customers at a traditional cost-of-service price for the entire lifetime of the generating units through an appropriate PPA. Note that if this is done for non-RMR generating units, and if the output of all RMR units is also included in a

PPA at cost-of-service prices, then there will be no need to mitigate the RMR units for the market power that they could otherwise exercise. All the potential market power from both kinds of units (RMR and non-RMR) will already be fully mitigated. Thus, if a market power study is performed as a consequence of Staff recommendation #1, it will not need to contribute to developing a market power mitigation plan for TEP's and APS' existing generating units. It will, however, provide critical information as to whether a competitive bidding process can be structured for other new generating units within Arizona, or for sources of power from outside the state.

Q. ARE THERE ANY OTHER AREAS OF DISAGREEMENT THAT YOU HAVE WITH THE DIRECT TESTIMONY OF STAFF?

A. Yes. I have a few disagreements with the direct testimony of Mr. Jerry Smith. On page 23 of his testimony, Mr. Smith states that "a proactive approach to resolving Arizona's local transmission needs should be adopted and implemented by the Commission as part of this generic restructuring case." I strongly agree with this recommendation. Then Mr. Smith states that the ACC should establish "a framework for transmission expansion that retains traditional system reliability-based service values and yet assures consumers are not harmed by others' direct access of [sic] the same transmission system for competitive wholesale market transactions." (Page 23) Establishing such a framework, he states, will be a challenge, and, again, I agree.

However, after this point in his testimony, Mr. Smith is not sufficiently clear about what such a transmission planning framework would be like, and how it would be structured. He says on page 25 that one principle for structuring this framework is that "there should be sufficient transmission import capability to reliably serve all loads in a utility's service area without limiting consumer access or benefit to more economical or less polluting generation located external to the service area." Unfortunately, this "principle" or criterion is also very vague. What does it mean that there should be no limit to consumer access to more economical generation external to a utility's service territory? I assume that Mr. Smith does not mean this literally.

What Staff seems to generally understand is that transmission planning cannot be done independently of generation planning, or at least this is what I hope they mean when this issue is discussed in their direct testimony. Generation and transmission planning are inextricably linked. One cannot do adequate transmission planning separately from generation planning and siting, even in the context of a market-based structure for wholesale generation. This implies that utilities in Arizona must return to an *integrated* transmission and generation *system* planning framework, and, specifically, an integrated *least-cost* system planning framework, as I have advocated in my prior testimony.

One of my objections to the Staff's testimony on transmission issues is that they sometimes seem to imply that new transmission lines should potentially be constructed solely for the purpose of facilitating a more competitive generation market. In the context of least-cost planning principles, this would only be appropriate if it leads to lower joint transmission and generation costs. However, once enough new transmission lines are built such that the supply system has achieved a least-cost plan, constructing more transmission will cost more on a net basis than will be saved by having a more competitive generation market.

Indeed, other witnesses in this docket have pointed out that transmission system planning should not attempt to achieve a situation where there are no transmission constraints at all, especially into load pockets. The reason is, of course, that such a system would very likely deviate from a least-cost system. This is because it is likely that investing in the last transmission line needed to eliminate a load pocket entirely would not pay for itself in generation-related savings in the long run. After all, new generation can also be built within a load pocket, and doing so is often less costly than building new generation outside a load pocket and also paying for transmission into the load pocket.

Least-cost planning implies having the optimal number of constraints in the transmission system. This will result, in turn, in total generation and transmission rates being just and reasonable. It also implies that transmission and generation rates cannot be considered to be just and reasonable independently of each other. To do so would not make sense. Because restructuring inevitably leads to an unbundling of rates and a bifurcation of regulatory functions between the ACC and FERC, this may make a coordinated determination of whether transmission and generation rates are just and reasonable more difficult.

Q. MR. SMITH ALSO RECOMMENDS THAT THE ACC SHOULD ORDER ITS

JURISDICTIONAL UTILITIES TO COMPLETE A STUDY WITHIN 30 DAYS ANALYZING THE MERITS OF THE EXISTING DEPENDENCE ON RMR GENERATION WITHIN LOAD POCKETS, WHEN COMPARED WITH BUILDING NEW TRANSMISSION TO RESOLVE LOCAL TRANSMISSION IMPORT RELIABILITY CONSTRAINTS. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No, I do not agree with this recommendation. In light of my advocacy above for a joint least-cost planning framework for new transmission and generation, I suggest that Mr. Smith should re-state his recommendation to the ACC somewhat differently. First, he should recommend that the ACC order the utilities to perform a least-cost planning analysis to determine which new transmission lines and generating units they would construct over the next 10 years under the assumption that traditional rate regulation remained in effect. Such a study would then provide a benchmark for transmission planning and new power plant siting if electric industry restructuring is pursued in Arizona, in addition to providing a price baseline to which more market-oriented solutions to achieving such a least-cost plan could be compared. Such a least-cost plan would also provide a basis for deciding which type of new independent power plants should be built, and where. Finally, this least-cost plan would assist in structuring a competitive bidding process for generation in Arizona, if the ACC decides to do so. Of course, such a least-cost planning study should also include a comprehensive and detailed consideration of potential demand-side management and fuel switching investments and programs, to the extent that they might be less expensive than supply-side options.

Secondly, requesting that such a study be done within 30 days is far too fast. A good integrated least-cost planning study would probably take closer to 6 months to complete. This is the kind of proactive study of Arizona's transmission requirements that the ACC should pursue. This would also be the correct way of determining to what extent certain designated power plants will need to be reliability must-run units for certain portions of the year. In addition, there must be the requisite degree of cooperation and communication among all the Arizona utilities so that they design transmission and generation system planning scenarios that are consistent with each other. Perhaps such a least-cost system planning study should also be performed in a more public setting with the active participation of all interested parties, similar to how I suggested that the proposed market power study be performed.

SECTION III – RESPONSE TO TUCSON ELECTRIC TESTIMONY

Q. WHAT WAS YOUR GENERAL REACTION TO MR. PIGNATELLI's DIRECT TESTIMONY?

A. My general reaction to Mr. Pignatelli's testimony was quite favorable with regard to many of the points that he raised. This was particularly true for recommendations #1 and #2 described on pages 17-18 of his direct testimony. I believe that the gist of recommendation #1 was to request that the ACC thoroughly review the likely pros and cons of electric industry restructuring in Arizona from scratch, which was exactly what I recommended in my direct testimony also. Thus, I totally agree with Mr. Pignatelli that the ACC should review the basic premise that many parties may still believe, which is that electric "competition," meaning restructuring and the deregulation of generation prices in Arizona, is in the public interest.

As I have indicated in my direct testimony, I believe there are a very limited set of conditions under which restructuring might be in the public interest, and these conditions would only apply if TEP and APS are still required to build new electric generation on a traditional, regulated, cost-of-service basis, if that proves to be the lowest-cost way of providing the new generation supplies required to meet load growth. If the ACC does not maintain cost-of-service pricing as an option under a restructured future for the electric industry in Arizona, then I believe the economic risks to ratepayers deriving from the potential exercise of market power, and other lost economic efficiencies of vertically integrated utilities, would be so great as to preclude restructuring from being in the public interest. Thus, I share Mr. Pignatelli's skepticism as expressed on page 18 of his testimony, when he says, "I have to question whether competition is, in fact, the most appropriate regime for the electric industry."

Q. DO YOU AGREE WITH MR. PIGNATELLI THAT TEP SHOULD BE GRANTED A VARIANCE TO POSTPONE COMPLIANCE WITH THE ELECTRIC COMPETITION RULES?

A. Yes. I agree with Mr. Pignatelli about the need for a variance with respect to the time period by when to comply with the Electric Competition Rules. However, as I explained in my direct testimony, I believe that *all* utilities in Arizona subject to the current competition rules should be given a variance for one full year, not six months or so, as Mr. Pignatelli advocates, until the ACC decides how it wants to either proceed to restructure the electric industry in Arizona, or, alternatively, if it wants to return to traditional cost-of-service regulation for the foreseeable future. A full year delay is especially needed now if the ACC accepts the Staff's recommendations that a market power and system planning study be undertaken, in addition to undertaking further hearings on other policy issues that require further elucidation prior to the ACC deciding the future of restructuring in Arizona.

Q. DO YOU ALSO AGREE WITH MR. PIGNATELLI's THIRD RECOMMENDATION THAT THE ACC SHOULD ADOPT TEP's TRACK B

PROCEDURAL PROPOSAL?

A. No, I do not support adoption of TEP's Track B procedural proposal. There is no need for the ACC to adopt any procedural proposal for Track B issues yet, until the studies advocated by Staff are completed, if they are done. The results of those studies will, hopefully, provide new information that is likely to be highly relevant as to how and when Track B issues are pursued by the ACC. Thus, I believe that it is quite premature for the ACC to adopt any Track B procedures or procedural schedule.

Q. DO YOU HAVE ANY SIGNIFICANT DISAGREEMENTS WITH THE TESTIMONY OF OTHER TUCSON ELECTRIC WITNESSES?

A. Yes, I do. Mr. Glaser discussed Tucson Electric's plan to divest their transmission assets into a separate affiliate from the affiliate that would own the generation assets of the company. I do not agree with such an approach for several reasons. One reason is, as I discussed in my direct testimony, that such a divestiture and unbundling process for transmission would likely provide FERC with an additional legal basis to be able to set the rates for transmission to all *retail* customers, in addition to all wholesale customers, using the TEP transmission grid. This is because all transmission services would become a set of wholesale transactions carried out by an affiliate not regulated by the ACC, between the FERC-regulated wholesale providers of generation, and TEP as a state-regulated distribution utility. If TEP's transmission lines continue to be owned by the UDC, and if the costs of transmission continue to be bundled together with distribution system costs as a joint bundled T&D rate, then FERC may have less ability to do what their Staff indicated to be their goal in their SMD whitepaper, namely to regulate the price and tariffs for *all* transmission.

Q. WHAT DO YOU CONCLUDE, THEN, ABOUT TEP's PLANNED TRANSMISSION AFFILIATE?

A. I recommend to the ACC that whatever the ACC decides with regard to how to proceed with restructuring electric generation in Arizona, the ACC should deny TEP's request to establish a separate transmission affiliate. Thus, the ACC should not allow TEP (or APS, if they make a similar request) to divest their transmission investments to a new affiliate, or to an affiliate of an RTO.

SECTION IV – RESPONSE TO APS TESTIMONY

Q. DO YOU HAVE ANY BASIC CRITICISMS OF THE TESTIMONY OF THE APS WITNESSES IN THIS CASE?

A. Yes, I have several basic criticisms of the direct testimony of the APS witnesses in this case. For obvious reasons, perhaps, the APS witnesses deny the fact that if the divestiture of the existing APS generating units proceeds as planned, APS would be able to exercise substantial market power *unless* a fixed-price PPA is signed for all of the output of those generating units for their remaining operational lifetimes. Thus, APS does not carefully delineate the conditions under which the divestiture of their generation would be appropriate.

In contrast, the APS witnesses seem to defend proceeding with divestiture under almost any conditions at all. Their main goal for restructuring seems to be to achieve the divestiture of all of their existing generating units to their own affiliate no matter what the implications of doing so would be. I find this approach to divestiture to be unacceptable because it ignores the various risks to ratepayers that could accompany divestiture under the various possible restructuring scenarios that the ACC might adopt.

Q. DO YOU AGREE WITH DR. HIERONYMUS' USE OF AND INTERPRETATION OF FERC's NEW PROPOSED SMA TEST FOR GENERATION-RELATED MARKET POWER?

A. No, I do not agree with Dr. Hieronymus' use of the new SMA test for generation-related market power that FERC has proposed. The main reason for my disagreement with Dr. Hieronymus regarding the use of this test is that it cannot succeed in detecting all, or even most, scenarios in which market power can be exercised. I have discussed the shortcomings of this test above, as well as in Exhibit___(RAR-2) of my direct testimony in this docket, so I will not repeat all of those arguments here. The main point of those arguments is simply that a utility system that passes the SMA test may still allow for the substantial exercise of market power through strategic bidding and other strategic behaviors, and, thus, at best the test can only succeed in detecting a generation owner's ability to exercise *monopoly* pricing power, if modified in a manner similar to that suggested in this docket by Mr. Roach. Clearly, the ability to exercise monopoly pricing would even be unacceptable to APS, and FERC has relied on cost-of-service or negotiated rates in similar circumstances in past cases.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Exhibit 1

A CRITIQUE OF FERC'S NEW MERGER GUIDELINES: Implications for Analyzing Market Power, Mergers, and Deregulation

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Introduction

Market power due to utility mergers has historically been of concern to players in, and regulators of, wholesale electricity markets. However, with the promise of deregulated *retail* electricity markets in many states throughout the country and the ensuing merger frenzy, the concern over market power is even greater and is shared by many more stakeholders. The exercise of market power in retail markets is a very important issue that must be given serious consideration both in current utility merger proposals and, more generally, in plans to restructure the generation industry into fully competitive bilateral contract markets and spot markets. In merger-related market power analyses, it will be necessary to distinguish a utility's increase in market power due to merging with another utility from a utility's increase in market power due purely to the introduction of retail competition. It will also be necessary to learn more about the exact conditions that allow for the exercise of market power.

Given the trend to consolidate the ownership of generation facilities and the pending introduction of deregulated electricity prices, the exercise of both *vertical* and *horizontal* market power is a strong possibility. Firms with moderate to high levels of concentration in generation markets and/or with ownership in transmission and distribution facilities may have the ability to increase generation prices above truly competitive levels. In short, the potential ability of firms to exercise market power should be evaluated in light of known or likely changes in corporate structures (e.g., utility merger, utility divestiture of generation assets) and market structures (e.g., retail competition, bilateral contract markets, poolco-type spot markets), as well as in light of the factors which the Federal Energy Regulatory Commission ("FERC") has identified in its new merger guidelines.

FERC's Analytic Screen for Market Power

Overview

In December 1996, FERC put forth an updated Policy Statement that is applicable to proposed mergers between an electric (or an electric-gas) utility with another electric, gas, or electric-gas utility. In our opinion, these new guidelines are a great improvement over FERC's old merger guidelines, which had been in place since 1966 when they were established in the Commonwealth Edison Company Case. Since that time, the changes in technology and public policy in the electric and natural gas industries have been dramatic and necessitate very careful market power analyses. FERC says in its Policy Statement that "we recognize that even in an open access environment, markets may not work perfectly or even well. This is particularly the case during the transition from a monopoly cost-of-service market structure to a competitive market-based industry."[1] The new guidelines provide an up-to-date context in which market power analyses for electric utility mergers should be performed, and follow closely the 1992 Horizontal Merger Guidelines of the Department of Justice (DOJ) and the Federal Trade Commission (FTC) that are applied to mergers in all industries.

FERC's new guidelines also identify some of the complexities of performing a sound market power analysis as part of a merger evaluation. For example, FERC stated that its "guidelines are just that – guidelines. They provide analytical guidance but do not provide a specific recipe to follow. Indeed, applying the guidelines to the electric power industry is one of our biggest analytic challenges, both because the industry is evolving very rapidly and because the industry has some unique features."[2] With regard to the first part of this quote, FERC's message appears to be that the nature of merger filings must change relative to historical submissions to FERC. We agree that any sort of "cookie-cutter approach" would be inadequate in the face of retail competition. With regard to the second part of this quote, we agree completely and think that the analysis of market power in electric and electric-gas mergers is even more complex than FERC indicated in its guidelines.

It is due to these complexities that we believe FERC's latest merger guidelines still have several weaknesses, some more serious than others. Many of these relate to the specific steps of FERC's analytic screen, as we discuss herein. However, one weakness is worth mentioning here in our discussion of the general context in which market power analyses should be performed, rather than in our discussion of the specific steps of FERC's screen. In its guidelines, FERC did not make clear that one must consider the market power that each utility may possess under both wholesale and *retail* competition before the proposed merger occurs, and then consider whether a merger between the two utilities is likely to enhance any existing market power or create market power under both types of competition. This is a significant issue for the market power analyses of utility mergers

[1] Federal Register, Vol. 61, No. 251, page 68603, *2. Discussion.*
[2] Federal Register, Vol. 61, No. 251, page 68600, *C. Use of Guidelines.*

because, as we have mentioned, it emphasizes the importance of distinguishing a utility's increase in market power due to the introduction of retail competition from a utility's increase in market power due to merging with another utility. With the simultaneous flurry of both restructuring and merger activity in this country, it is important to separately determine the relative increase in market power that each factor may cause. For certain utilities, it may be the case that gaining entrance into competitive retail markets would increase their market power much more than merging with another utility would under either wholesale or retail competition. In short, FERC's new analytical framework can easily be applied to evaluating a utility's market power both before and after the introduction of retail competition - its application should not be limited to evaluating mergers. Thus, we believe that FERC's explicit recognition of this fact would be a significant improvement to its guidelines.

FERC's Analytic Screen[3]

In its new guidelines, FERC identified three key factors that should be considered when evaluating a proposed merger: 1) the potential effect on competition, 2) the potential effect on rates[4], and 3) the potential effect on state[5] and federal regulation. It is the potential effect on competition, both wholesale and retail, that is the focus of our attention in this article.

In order to try to identify proposed mergers that could negatively affect competition, FERC adopted the Horizontal Merger Guidelines of the DOJ and the FTC as the basic framework for its guidelines. The Commission's "analytic screen" for detecting potential market power focuses on:

1. identifying relevant product markets;
2. identifying relevant geographic markets;
3. measuring supplier concentration in the identified markets; and
4. evaluating the implications of any changes in concentration.

Regarding the role of FERC's analytic screen, the Commission explicitly stated: "We intend to apply the analytic screen to mergers between firms that are not solely engaged in electricity markets, e.g., electric-gas mergers."[6] However, it is very important to recognize that FERC did not provide any details about the methodological changes that are appropriate and necessary for applying this screen to electric-gas mergers. Thus, this is one of the areas in which FERC's analytic screen could, and should, be improved.

[3] FERC's "Competitive Analysis Screen" is discussed in detail in Appendix A of FERC's Policy Statement.
[4] It is important to note that after the deregulation of generation, rate protection will only apply to the rates for transmission and distribution.
[5] FERC relies on state regulatory commissions to exercise their authority to protect state interests by detecting and mitigating market power. FERC will only step in if state commissions do not have such authority.
[6] Federal Register, Vol. 61, No. 251, page 68610, *D. Other Considerations.*

Below, where we address the four components of FERC's screen, we suggest how each one might be interpreted to analyze an electric-gas merger.

Relevant Product Markets

The first step in FERC's analytic screen is to identify relevant product markets. In general, each product sold by the utilities proposing to merge should be grouped along with those products which, from a buyer's perspective, are good substitutes for each product in order to form a single product market.

Recall the quote we cited earlier in which FERC noted that the electricity industry has some unique features. Indeed, electric product markets differ from other product markets in a number of fundamental ways. In most parts of the country, electricity cannot be stored in significant quantities, it does not have any substitutes for certain end-uses, it does not have many readily available substitutes (at least in the short term) for certain other end-uses, and it can only be transported along existing transmission and distribution lines, which cannot easily be expanded. In addition to these distinct characteristics, electric generating systems typically consist of baseload, cycling, and peaking units. These different units are designed to operate economically over different time intervals and at different capacity factors in order to provide a least-cost mix of different electricity products, which vary widely in terms of price. As we will discuss later, in competitive bilateral contract markets these different generating technologies will likely form the basis for different electric product markets which can be further subdivided into short-, medium-, and long-term submarkets.

In past utility mergers, FERC has differentiated electricity into just three wholesale product markets: non-firm energy, short-term capacity and energy, and long-term capacity and energy. FERC stated in its recent merger guidelines that "these remain reasonable products under the prevailing institutional arrangements..., [although] We would expect to see greater precision in product differentiation as market institutions develop."[7] Regarding the first part of this quote, we would argue that the way in which FERC differentiated wholesale electricity products in the past is no longer reasonable, especially for competitive retail markets. In our opinion, FERC grouped "good" substitutes with "bad" substitutes. For example, FERC did not break down long-term capacity into the three subcategories mentioned above, namely baseload, cycling, and peaking, a break down which we believe is necessary even under "prevailing institutional arrangements."

We believe that the specific structure of competitive markets will help determine how to differentiate different product markets. For those products and services sold in bilateral contract markets, it seems that the three broad product categories would be baseload, cycling, and peaking power. Contracts for these products would be further differentiated into short-, medium-, and long-term contracts, and product delivery would be either firm or interruptible. However, for those services sold in a poolco-type spot market, where

[7] Federal Register, Vol. 61, No. 251, page 68607, *B.1 Identify the Relevant Products*.

there is a single market clearing price in each hour for *all* generation, it seems that the three broad product categories would be peak, shoulder, and off-peak generation on both a daily and seasonal basis.[8] FERC unfortunately appears to have overlooked the critical, yet simple, point that the characteristics of a competitive market structure will help determine how to differentiate product markets from one another. Hence, its guidelines could be improved by including this observation and by illustrating its implications.

It is important to remember that different products may still be grouped in the same product market if they are good substitutes for one another. For example, two successive 10-year contracts for baseload power are probably a good substitute for a one 20-year contract for baseload power, even though the products are differentiated by contract duration. In order to identify good substitutes from the perspective of a buyer in the electricity market, we emphasize that one must consider three factors. First, one must consider end-use services such as space heating / cooling, water heating, cooking, industrial applications, and electric generation. Secondly, one must consider substitute fuels at the end-use. Competition may exist among fuels including electricity, gas, propane, oil, coal, and renewables. Finally, one must consider the characteristics of the end-use customer. For example, different customer groups have different demand elasticities in the short-, medium-, and long-run. In the short-run, a residential customer with electric space heating is unlikely to be able to switch immediately to an alternative fuel if electricity prices spike, whereas an industrial customer may be able to quickly switch to an alternative fuel to operate some pieces of equipment. Since price elasticities of demand are the lowest in the short-run, especially for small consumers, suppliers can exercise price discrimination across customer groups.

Furthermore, the life-cycle economics of end-use equipment may influence the potential market power of an electric supplier. Let's return again to the case of a residential customer with electric space heating equipment who is facing high electricity prices. Since this customer has already paid for the heating equipment, s/he must weigh the total cost of electricity (i.e., the unit price of electricity times the units consumed by the equipment) against, for example, the total cost of natural gas (i.e., the unit price of gas times the units consumed by the equipment) *plus* the cost of the new gas equipment. Whether or not the customer decides to switch to gas will depend, in part, on how old her/his electric space heating equipment is. In general, though, switching from electricity to natural gas will only be cost-effective for this customer when the total cost of electricity, which is driven by the unit price of electricity, becomes high enough to justify the capital investment in new gas equipment. Thus, electricity suppliers may be able to increase their prices that they charge residential space heating customers above competitive levels while still keeping their prices below the "break even point" where customers will switch fuels.[9]

[8] FERC explicitly cites the possible legitimacy of using time differentiated products, but does not connect this basis for differentiation to the types of market structures. (Federal Register, Vol. 61, No. 251, page 68607, *B.1. Identify the Relevant Products.*)

[9] This scenario assumes that the customer is "rational," in the economic sense of the term.

The above discussion about identifying relevant product markets has important implications for evaluating the market power of either an electric-electric utility merger or an electric-gas utility merger. Clearly, consideration should be given not only to "supply-side" electric product markets but also to contested end-use markets. FERC does not mention this key point in its Policy Statement. Nor does it mention that the life-cycle economics of electric end-use equipment may help determine the pricing power of unregulated suppliers in the short, medium, and long term. Finally, FERC does not mention that in electric-gas utility mergers, the electric generation division may be a gas consumer as well as an electricity producer through its ownership of gas-fired generating units, thereby potentially providing more ways for the entities in an electric-gas merger to exercise market power.

Relevant Geographic Markets

The second step in FERC's analytic screen is to identify the relevant geographic market for each product sold by the merging utilities. This involves identifying the potential suppliers that could compete in each product market. A relevant geographic market in an open access transmission environment should be determined by competitive suppliers' abilities to reach the market both *economically* and *physically*. Making this determination requires a detailed analysis of generation and transmission costs, physical transmission constraints, and the generating capacity at different locations that would actually be available to compete.

FERC explained in its Policy Statement that determining the economic capability of a competitive supplier to reach a market should be accomplished using a "delivered price test," which accounts for the supplier's generation costs and the price of transmission service, including ancillary services and losses.[10] We note that if a gas supplier is being considered, its delivered price may also include the price of storage. According to FERC (and DOJ), potential suppliers should be included in a geographic market if they could deliver the product or acceptable substitutes to a customer at a cost no greater than 5 percent above the competitive price to that customer.[11] However, we believe that a 5 percent price increase is too small to be the appropriate criterion for determining the geographic parameters of most electric product markets. One reason is that within a properly defined electric product market (i.e., a product and its substitutes), the price spread is likely to be significantly greater than 5 percent. A second reason is that a 5 percent price increase is comparable to, or even smaller than, each additional transmission tariff that might have to be paid by a competitive supplier from outside the service territory of the merging utilities. Thus, a 5 percent increase in a product's price might not be big enough to allow competitors outside of the service territory to economically reach the relevant product market. These two reasons, which are expanded upon below, also hold true for defining geographic markets for gas products. The implication of these considerations is that there is a strong interactive linkage between properly defining both product and geographic markets for electricity and gas.

[10] Federal Register, Vol. 61, No. 251, page 68607, *B.3.a Delivered Price Test.*

[11] Federal Register, Vol. 61, No. 251, page 68607, *B.3.a Delivered Price Test.*

Using changes in the delivered price to measure the geographic scope of possible competition within a product market is itself much too simplistic for industries as complex as those for electricity and gas. In the case of the electric industry, a simple price differential test cannot account for the complicated interactions between different generation sources and the system dispatch that together allow different products to substitute for one another in subtle and complex ways. Even just changing the contract duration of an electric or gas product might change the average price by more than 5 percent, and yet the two products might be excellent substitutes for each other. Applying a delivered price test of 5 percent to the electric industry for the purpose of defining geographic markets might make sense if FERC's three traditionally defined wholesale product markets (i.e., non-firm energy, short-term capacity and energy, and long-term capacity and energy) were appropriate for a fully competitive electric industry. For example, if the price of electricity were averaged over the entire load to be served by long-term energy and capacity within a given service territory, then 5 percent might be a large enough price differential to define the geographical boundaries of the relevant product market. However, as we discussed earlier, FERC's three traditionally defined product markets are not appropriate for fully competitive electric bilateral contract markets or spot markets. Thus, price differentials of 5 percent will not be large enough to identify all of the good product substitutes, and the geographical location of their suppliers, that could economically compete in the relevant product market. This point is illustrated in the examples presented below.

In a bilateral contract market for baseload power with load factors between 80-100 percent, a 5 percent price increase would certainly define too small of a range within the full range of prices for this product. For example, if an existing generating unit could offer baseload power at 20 mills per kWh at high load factors, a 5 percent price differential would imply looking only at competing generating units with delivered prices between 20 and 21 mills per kWh.[12] This would probably limit the geographic market to those baseload generators located *within* the merged utility's own service territory because transmission costs would prevent all generators located *outside* of the utility's own service territory from economically competing.[13] (And there may not even be any other units located in the utility's own service territory with a price in this narrow range!) Adding the cost of just one additional transmission tariff would almost certainly add more than 1 mill per kWh to the delivered price of the product, since transmission tariffs average about 5 mills per kWh nationally. Unless a generating unit in a neighboring service territory had a competitive price of less than about 16 mills per kWh for the relevant product, it would not likely be able to compete with a 20 mill per kWh unit in the neighboring service territory. In addition, there may be very few, if any, units actually available that could bid such a low price as 16 mills per kWh. For *all* electric products, where the marginal costs might vary from 10 mills per kWh to 160 mills per kWh, a price differential of only 5

[12] Ibid., FERC uses a very similar example on page 68608, *B.3.a Delivered Price Test.*

[13] Ibid., this would conflict with FERC's assumption that geographical markets would include at least those utilities "directly interconnected to either of the merging parties." (page 68607, *B.2. Geographic Markets: Identify Customers Who May Be Affected by the Merger.*)

percent would sub-divide the general product market into 56 price brackets. Therefore, if a 5 percent delivered price differential were used, the market power analysis would not only be too complex, but it would also be inaccurate because the relevant geographic market for each electric product would be incorrectly defined much too narrowly. Delivered price differentials as large as 30 - 50 percent may be needed to properly define electricity markets. For example, a delivered price differential of 50 percent would sub-divide the aggregate electricity market into seven price brackets, each representing an electric product market. This may be a large enough number of markets to analyze for signs of market power.

Regarding an electric supplier's *physical* access to customers and markets, we recommend that careful consideration be given to how physical transmission constraints that form load pockets could create or maintain barriers to entry into the generation market and enhance the potential abuse of market power by unregulated generation companies. When evaluating the market power of an electric utility in a contested end-use market, consideration should be given to constraints in both the electric and gas transmission/transportation and distribution systems. For example, a local distribution system for gas may not reach all customers, or control of gas supplies in an electric load pocket might exacerbate utility market power in both fuel industries.

Even if a product from a nearby region could compete economically and physically with a locally supplied electric or gas product, it would only be a viable competitive alternative if it were *available*.[14] For example, if electric generation from a given facility were already under contract, if the facility were down, or if the product could be sold more profitably elsewhere, then it would not be available to compete. All of these considerations imply that the sizes of geographic markets are likely to be different for each different electric and gas product, and they will change over time due to changes in costs (i.e., generation, transmission, ancillary services, losses), physical constraints, and plant availability. Thus, a relevant geographic market may not be nearly so extensive as many electricity analysts (including FERC) assumed in most previous market power studies once all these factors have been taken into account.

This point can be illustrated by FERC's conclusion in the Baltimore Gas and Electric Company (BG&E) / Potomac Electric Power Company (PEPCO) merger case, namely that all of PJM is the relevant market for capacity. While this may be true for low cost baseload units that are dispatched early in the merit order before any transmission congestion might occur, this may not be true for peaking capacity. Since peaking capacity is always dispatched last in the dispatch order, many transmission constraints may already have developed, and peaking units in central Pennsylvania may not be able to physically serve load in northern New Jersey. In addition, the fixed costs of transmission that must be spread over the relatively few hours of operation of a peaking unit may prevent some peaking units from economically competing with other peaking units, even if only one additional transmission tariff must be paid.

[14] Ibid., FERC supports this additional test on page 68608, *B.3.a Delivered Price Test.*

Another analytical weakness of the second step in FERC's analytic screen is that the Commission does not sufficiently stress the need to analyze relevant geographical markets based on major load centers as a focal point. In our view, the potential competition between substitutable supply-side products cannot just be considered in the abstract as FERC has typically done, such as all capacity within PJM. The analysis needs to proceed from the perspective of products competing in different end-use markets of different sizes that are located in different load centers.[15] Seen from this perspective, the geographical boundaries of each product market serving each load center will overlap in very complex patterns, and the ability of generation owners or gas producers to exercise market power in any given load center must be determined *simultaneously* with their ability to exercise market power in all other load centers in which they can compete on an economic, physical, and availability basis. Thus, we believe that in the past, FERC and DOJ have not focused sufficiently on linking electricity supplies to electricity demand in the complex ways indicated above to properly define markets. These complexities are the reason why the methodologies described in DOJ's merger guidelines cannot be used in the electric and gas industries without being revised. As we will discuss below, the only way these complex linkages can be analyzed adequately is via joint simulation modeling of electric and gas systems.

Analyzing Market Concentration

Based on FERC's new guidelines, the Commission will continue to screen mergers for market power using the Herfindahl-Hirschman Index (HHI), presumed to be an indicator of the potential for market power. The HHI is the sum of the squares of the market shares of all of the suppliers in a given market. As examples, a market in which there are five firms with equal market concentrations has an HHI of 2,000, and ten such firms means an HHI of 1,000. The DOJ and the FTC consider a market "unconcentrated" if its HHI falls below 1,000, "moderately concentrated" if its HHI lies between 1,000 and 1,800, and "highly concentrated" if its HHI is in excess of 1,800. These generic breakpoints in the full range of HHI values, called "safe harbors," have been adopted by FERC. It is important to understand that FERC is simply assuming that these safe harbors, which have in the past been applied to other industries, are valid for the electric industry. We believe that this assumption is a major weakness of FERC's new merger guidelines.

FERC correctly points out that "supply and demand conditions in electricity markets vary substantially over time, and the market [power] analysis must take these varying conditions into account. Applicants should present *separate analyses* [emphasis added] for each of the major periods when supply and demand conditions are similar."[16] Because a separate market power analysis must be done for each product market identified, FERC explicitly

[15] Ibid., FERC's only discussion of the need to focus on load occurs on page 68607 when it states that "applicants are expected to provide product-specific delivered price estimates for each destination market or customer."

[16] Federal Register, Vol. 61, No. 251, page 68607, *B.3. Geographic Markets: Identify Potential Suppliers to Each Identified Customer.*

states that "concentration statistics should be calculated using the capacity measures discussed above for each relevant market identified."[17] FERC also explicitly states that this means that the HHI and single firm market shares must be presented for each product, for each geographical market, for each key time period, etc. If taken literally, this implies the need for dozens, if not hundreds, of HHI calculations. Then, the pre- and post-merger results need to be compared.

It is important to note that FERC's requirement for HHI values for *each* electric market is a significant change relative to the way market power studies have been done in the past. However, this new approach was not taken by Baltimore Gas and Electric Company (BG&E) and Potomac Electric Power Company (PEPCO) in their analysis of market power in wholesale power markets impacted by their merger, even though this was the first merger approved by FERC since its new guidelines were issued. FERC's new requirement is also significant because it raises a very important conceptual problem that FERC seems to have ignored, namely the problem of how it will interpret the results of potentially dozens of HHI values for different products impacted by a single merger. In other words, how should an analyst weigh the results of how each HHI value compares to the generic safe harbors (which may not even be appropriate for the electric industry) in order to reach a "bottom-line" conclusion as to whether a merger will increase market power by too great an extent. Some of the changes in HHI values for a given product may pass the generic safe harbors, and some may not. What then?[18] If the index were tailored properly to each particular type of market structure, then from the definition of the index one would know how the results for each sub-market should be combined to produce a valid index of market power for the entire market. In short, there is a major omission in FERC's new market power guidelines, namely a "recipe" for how to reach an overall conclusion. Without such a recipe, one could argue that FERC's analytic screen is incomplete. However, as we discuss later, there is a solution, namely simulation modeling.

We believe that the reason why this serious conceptual problem arises in the first place is because the HHI is far too simplistic an index to measure market power in an industry as complex as the electric industry. While the HHI may or may not be a useful tool to assess the potential for market power in other industries, we do not believe that it is an appropriate measure for analyzing market power in the electric industry. This is true from both an empirical and a theoretical perspective. Thus, as we will describe below, we see no need for use of the HHI, but rather a need for a very different overall approach to analyzing market power.

First of all, there is nothing fundamental in economic theory that would lead to the conclusion that each firm's market concentration should be squared in order to weight it,

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[17] Federal Register, Vol. 61, No. 251, page 68608, *B.4. Analyze Concentration.*

[18] FERC suggests that if some products do not pass the HHI test and some do, "remedial conditions would be explored at this stage" for the products that do not pass. (Federal Register, Vol. 61, No. 251, page 68607, *A. Consistency With DOJ Guidelines.*) We would argue that one should not do a separate mitigation analysis for each for each product market differentiated by time period and region, as FERC suggests. Mitigation strategies for each product market must be coordinated.

and then simply added to the squares of the market shares of each of the other firms in the relevant market, as the HHI does. There is no theoretical basis for *squaring* each firm's market share, as opposed to, say, *cubing* the market share of each firm. It may be the case that for the electric industry, in contrast to some other industry, cubing each firm's market concentration might provide a more accurate index of market power abuse. Similarly, there is no reason to believe that the squares of each firm's market concentration should just be added together. Different firms with the same level of market concentration may be able to exercise more or less market power depending on factors such as transmission constraints, their cost structures, etc. In fact, DOJ cautioned FERC about this point by saying "not all market shares are equal."[19]

In fact, it is very likely that the same values of the HHI calculated for different electricity markets should have different interpretations, particularly if the structure, size or type of one market is very different from that of another. For example, an HHI value of 1800 may imply no significant impact on prices in one sub-market (e.g., a 20,000 MW long-run baseload market), but a serious problem in another sub-market (e.g., a 5,000 MW short-term cycling market). One cannot tell until the relevant studies for electric sub-markets are completed. In fact, in discussing its analytic screen, FERC made a similar point when it stated that it "has insufficient experience to adopt at this time specific thresholds for the various possible combinations of HHI and length of time at which the [transmission] constrained periods would be problematic."[20]

Finally, the HHI is probably not a useful measure of potential market power abuse in the electric industry, even when applied to correctly defined product and geographic markets, because the structure of the electricity generation market is *fundamentally different* from most other commodity markets to which the HHI has been applied previously. The HHI does not and cannot take transmission constraints into account, except to the extent that these constraints are used to define the relevant geographic region. It does not factor in transmission pricing constraints between generating units and consumers, it does not address the degree of substitutability of other products for electricity, and it does not address the degree of ease of entry of new generation into each sub-market.

The most important point is that a simple index like the HHI does not, and cannot, take the unique features of the electric industry structure in each region into account. For example, it does not take into account the differences between bilateral contract markets and a poolco.[21] Furthermore, in the electric industry, sub-markets do not operate in isolation from each other, and yet the HHI for one sub-market cannot take into account how that

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[19] Federal Register, Vol. 61, No. 251, page 68615, *II.B.1. Market Shares.*

[20] Federal Register, Vol. 61, No. 251, page 68609, *B.4. Analyze Concentration.*

[21] For example, an HHI of ~350 or lower is needed to avoid a 5 percent price effect in a pure poolco without contracts for differences. (Aleksandr Rudkevich, Max Duckworth, and Richard Rosen, *Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco*. Tellus Institute, 2/12/97.)

sub-market interacts with and affects other sub-markets.[22] Finally, the HHI does not take the shape of the generation supply cost curve into account which is likely to determine the relative importance of each sub-market in leading to market power within the overall market structure.

In short, the HHI is mathematically incapable of taking into account existing unique characteristics of the electric industry or potential future changes in its structure. In addition, there is no way of knowing whether an HHI of 1800, 1000, or some other value should be interpreted as the starting point for potential market power under wholesale or retail competition because, to the best of our knowledge, no adequate empirical studies of the electric utility industry have ever been done to validate that assumption, even for wholesale markets.[23] Furthermore, it is certainly true that no adequate empirical studies have ever been done for retail competition because it has never existed. Thus, there is not any solid analytical basis specific to the electric utility industry that would allow one to conclude that an HHI result of 1,000 or lower in an electric sub-market indicates that there is little or no danger of market power abuse.[24] Even former assistant attorney general William Baxter, the originator of the Guidelines, wrote that setting a safe-harbor HHI of 1,000 was "as much a political anchorage ... as because anyone thought that nicely round number was right."[25] Thus, until more detailed market power studies using the HHI have been done for relevant sub-markets in the electric industry, there is not even a valid way to interpret particular values of the HHI in terms of their potential implications for the abuse of market power, even if one believed that the mathematical structure of the HHI was appropriate.

The Need for Simulation Modeling

Based our criticisms of the HHI, we strongly oppose FERC's reliance on this index to screen for the potential exercise of market power due to mergers or its potential application to the present or future structure of the electric industry. Instead, we support relying on simulation modeling of the relevant electricity market structure.[26] Simulation modeling will allow one to *directly* compute the impact of any particular pattern of concentration of

[22] Put mathematically, the index has no "cross-terms" to account for these effects. A cross-term is a term like the square of a single company's market concentration for one product, whereby the market concentration of the company in one sub-market is multiplied by its market concentration in another sub-market.

[23] While FERC does warn against strict interpretation of HHI results, it does not acknowledge that the HHI values may not have a theoretical or empirical basis for the electric industry. (Federal Register, Vol. 61, No. 251, page 68609, *B.4. Analyze Concentration.*)

[24] Refer to the comments made by EEI and others to FERC, quoted on page 68615, *II.B.2. Measuring Market Concentration.*

[25] William F. Baxter, "Antitrust Policy," in Martin Feldstein (Ed.), American Economic Policy in the 1990s (University of Chicago Press, 1994), p. 610.

[26] By simulation modeling we simply mean any computer-based approach to simulating the behavior of an electricity market structure, including dispatch rules and transmission system behavior, as load varies over time.

resource ownership on overall market prices. Thus, the use of simulation modeling means that an index of market power is not needed. However, one will still need to identify how much of a price impact would represent unacceptable market power.

We find that recently there are a growing number of electric utility analysts who realize that simulation modeling is the only adequate approach to assessing market power.[27] Furthermore, the use of simulation modeling to analyze the degree of market power abuse that may be due to a merger is entirely consistent with FERC's new methodology. Realistically, we believe that the only way to carry out the market power assessment described by FERC is to create a simulation model, especially since FERC correctly requires separate analyses for all significantly different time periods.[28]

The market power analysis for any given product or end-use service will need to be performed simultaneously for the region / load center of interest and neighboring regions / load centers. Simulation modeling will be necessary to identify the myriad potential combinations of supply resources that could be used to meet different consumers' demands in different time periods under different assumptions about product substitutability (for both supply and end-use products), cost, transmission and distribution constraints, and resource availability. Such a model must present a sufficiently realistic analysis of the regional energy markets, including resource dispatch, fuel-switching, conservation alternatives, price elasticities of demand, and transmission/transportation system operations. The fact that aggregators and individual consumers will attempt to meet their load on a least-cost basis will provide an overall constraint on the demand for different electric products given the price differentials among them. Since relevant product markets in the electric industry will not have rigid boundaries - physical, economic, or otherwise - multi-regional models will be required. The models will also need the flexibility to accommodate different structural rules.[29] It would appear that FERC did not realize how complex its prescribed methodology would be in practice.

Conclusion

FERC's new merger guidelines, particularly its analytic screen, provide much more detail about how to analyze market power in the electric utility industry than any previous set of merger guidelines. Thus, they represent a significant step forward. In addition, FERC's new guidelines are equally applicable for analyzing the potential market power of electric and gas

[27] These analysts include Mark W. Frankena (Prepared Testimony Before the Public Service Commission of Nevada, Docket No. 95-9022), and Lewis J. Perl ("Measuring Market Power in Electric Generation") *Antitrust Law Journal*, Vol. 64, Winter 1996: pages 311-320.

[28] FERC hints at the need for simulation models when it states that its screen analysis will have to evolve with industry restructuring, and that "flow based network models that include constraints on transmission networks are likely to be needed for the screen analysis" (Federal Register, Vol. 61, No. 251, page 68610, *D. Other Considerations*). Flow based network models are one aspect of simulation modeling. Since industry restructuring is well underway at the federal level in the form of power pools proposing to become spot markets, FERC should not wait any longer to adopt simulation modeling.

[29] One simulation model that the authors recently reviewed assumed that all load centers were served by pure poolcos. This is not a very good assumption.

utilities under restructuring scenarios, not just under merger proposals. Therefore, we believe that FERC should use its new guidelines to analyze the potential for market power in recently filed power pool proposals to establish poolco-type spot markets. Similarly, state public utility commissions should use FERC's guidelines for analyzing market power in deregulated generation markets.

Though the guidelines represent a significant step forward, they still require improvement in many ways, and they still contain the rudimentary element of reliance on HHI safe harbors. We have shown why continuing to rely on the HHI is both inappropriate and impractical. In our view, this element of FERC's guidelines should be eliminated in favor of simulation modeling, which appears to be the only way of accomplishing the type of analyses that FERC now requires. Perhaps some day, when many market power analyses have been performed for a completely deregulated electric generation industry, analysts will be able to identify some simple rules of thumb or simple safe harbor guidelines that can be used to detect market power. However, that day will not come until the hard work of analyzing the potential for market power in many regions of the country has been done at a highly proficient level in a way that only simulation modeling will accomplish.

Exhibit 2

A Better Approach to Market Power Analysis

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Summary/Introduction

This paper shows that analyses of market power for wholesale electric markets are best done using electricity market simulation models rather than the more commonly used Hirschman Herfendahl Index (HHI). Market simulation models are more useful than HHI in determining price impacts due to the exercise of market power, since the HHI is far too simplistic to capture the dynamic nature of electricity markets or the behavior of market participants.

Electricity Markets and Market Power

Until restructuring in the electric industry began, wholesale electricity markets were primarily based on bilateral contracts and cost-based power pools. Distribution utilities would enter into cost-based, long-term contracts to meet baseload demand when doing so was less expensive than generating their own power. As demand varied on a short-term basis from their forecasts, distribution utilities would also enter into cost-based short-term transactions in order to match actual demand with supply.[1] Power pools arose to normalize these short-term transactions on a variable cost basis.

Restructuring of the electric industry has led several states to transform cost-based bilateral contract markets or power pools into deregulated poolco markets. These states include California, Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. Thus far, only Illinois has deregulated its electric industry without creating a formal poolco or power exchange.

Poolcos are similar to power pools in that they operate in the short term, but differ in that the price of power is determined by market forces, not regulation or costs. In areas where poolcos are established, as current bilateral contracts expire and if poolcos prove profitable[2] to generation owners, most power will eventually be purchased through poolcos rather than on contract.

In a poolco market, generation owners send bids to the system administrator for each unit they own. These bids represent the prices at which owners are willing to sell power from specific units for a specified time period, usually the next 24 hours. The system administrator dispatches units in order of lowest to highest bid as needed to meet demand for all participants on a continuous basis. The bid price of the last unit dispatched during any given hour sets the market clearing price for that hour. All units dispatched during that hour receive the same market clearing price regardless of the unit bid price.

[1] If an LSE's demand were higher than expected for a given period, exceeding supply, that LSE could buy extra power through short-term firm contracts. Conversely, if an LSE's demand were lower than expected, that LSE could sell excess power through the short-term market.

[2] Profitability is a function of the market price of electricity, costs, and risk.

A perfectly competitive poolco is one in which generation owners bid their production costs (or short-run marginal costs). Market power refers to the ability of one or more generation owner(s) to manipulate the market to their advantage for a sustained period of time, causing prices and profits to increase.

Exercising Market Power

In a poolco, generating firms have an incentive to increase the market clearing price since it is paid to all units dispatched in each time interval. There are two principal mechanisms by which firms may exercise market power in a poolco. The first mechanism, strategic bidding, involves firms' bidding prices above the production costs of their generating units with the intent of forcing up the market clearing price.[3] The benefit of "bidding up" the market clearing price can outweigh the risk of being undercut by a competitor. In fact, the strategy of "bidding up" the market clearing price is always more profitable, as will be demonstrated below, than bidding marginal costs.[4]

This first mechanism, strategic bidding, is facilitated by the fact that the bids submitted by generating firms apply to the next 24-hour period. Since the demand for electricity fluctuates over any 24-hour period, firms can anticipate these changes in demand in their construction of a strategic bidding schedule for this period. Generating firms can construct strategic bidding schedules such that market clearing prices exceed the short-run marginal costs of generation in almost every hour of the day and still remain safe from being undercut by competition.

Strategic bidding could also prove to be a factor in future bilateral contract markets. As owners find that they can "bid up" the price of electricity in poolcos and spot markets, they will only enter into future bilateral contracts if the expected profitability of those contracts is as high as what they can expect in the spot market. Therefore, strategic bidding in poolcos and spot markets is likely to have a direct impact on bilateral contract prices. If owners in a poolco market are found to have market power, then those owners would almost certainly also have market power in a bilateral contract market.

The second mechanism for exercising market power involves firms' withholding some of their capacity in the bidding process in an effort to cause more expensive units higher up the system-wide supply curve to set the market clearing price than would otherwise be the case. Firms that attempt this strategy must ensure that the foregone revenues from not dispatching some of their infra-marginal capacity are more than offset by the additional revenues paid to their actually dispatched capacity. Newbery (1995) has shown that capacity withholding may be profitable to electric generating firms whose market shares range between 10 percent and 40 percent, while Wolak and Patrick (1997) have shown empirically that this mechanism has been an effective way to exercise market power in the electricity spot market of England and Wales. These results are not surprising; capacity withholding is a classic approach to exercising market power in any market.

Market Power Measurement

HHI

[3] This paper assumes that there is a separate market for capacity in addition to the energy poolco.

[4] Rudkevich et al. proved under certain conditions that a Nash Equilibrium exists in a poolco such that any firm that deviates from strategic bidding has lower profits than firms that engaged in strategic bidding. "Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco," the *Energy Journal*. Vol 19, no. 3.

The analysis of market power in the electric industry traditionally relied on the Hirschman-Herfendahl Index (HHI), a measure of market concentration. Since most wholesale power was sold at cost-based, FERC-approved prices, market power was unlikely to be exercised at all.

The HHI is a static index that cannot capture dynamic market effects such as strategic bidding and capacity withholding. The HHI also does not account for:

- market structure;
- transmission constraints;
- transmission costs;
- the balance of supply and demand; and
- the pattern of ownership over the supply curve.

The HHI simply measures market concentration for a geographic area and/or a product market, which is defined fairly arbitrarily by FERC's Appendix A HHI methodology as the region into which electricity can flow within 5 percent of the market price.[5]

The HHI is calculated by the following formula:

$$HHI = \sum S_i^2$$

where S is the ownership share of each firm in the market, with $\sum S_i = 100\%$.[6]

The assumption underlying the use of the HHI for market power analysis is that market power is directly related to market concentration. Proponents of the HHI would argue that since a monopoly owner can exert unlimited market power, a market that resembles a monopoly lends itself better to the exercise of market power than a more competitive market. Although this is true, the ability to exercise market power in electricity markets depends on much more than market concentration.[7] We have found that there is no clear causal link between the HHI (or changes in the HHI) and changes in market price. In fact, we are unaware of any study that has ever been performed that provides a statistical link between HHI values and market power impacts in the US electric utility industry.

Even if a link between HHI values and market power were demonstrated, the FERC guidelines on how to interpret HHI are arbitrary. According to FERC, a market is "unconcentrated" if its HHI is less than 1,000; "moderately concentrated" if its HHI lies between 1,000 and 1,800; and "highly concentrated" if its HHI is greater than 1,800. For purposes of

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[5] In calculating HHI using the Appendix A methodology, a potential contradiction arises in which the market price must be defined *a priori*. Recall that HHI is calculated to serve as a proxy measure of how market power might affect the market price. How can the calculation of a proxy variable for market price impact (i.e., HHI) be directly dependent upon the variable (i.e., market price) that the proxy variable is intended to represent?

[6] If the market share of <u>each</u> firm is expressed in percentage terms, the HHI lies between 0 and 10,000. The maximum value of the HHI occurs when there is one firm only in a given industry, with a (monopolistic) 100 percent market share. The minimum value of the HHI occurs in the limit that the industry comprises a very large number of firms, each with negligible market shares.

[7] Electricity is in many ways a unique product. It has at least four properties that make it markedly different from most other products manufactured and sold in other markets: i) it cannot be stored in large quantities in most electric systems; ii) it cannot be readily substituted for, especially in the short term; iii) it can only be transported along existing transmission lines (new transmission lines require long periods of time and are expensive to erect); and iv) generating units are capital intensive, which increases the financial risk for new market entrants in a competitive market and makes maintaining significant amounts of reserve capacity uneconomical. Because of these properties, it may be easier for generators of electricity to exercise market power than for manufacturers of other products sold in competitive markets.

reference, a market with ten identically-sized firms has an HHI of 1,000, while a market with five identically-sized firms has an HHI of 2,000. No theoretical or empirical evidence supports the use of these guidelines; HHIs of 1,000 and 1,800 are round numbers with no empirical significance.

Proponents of the HHI, including FERC, may argue that the HHI can still be used as a reasonable **screening** tool, that markets with HHI below the 1,800 threshold are only moderately concentrated and, therefore, require no further market power analysis. Unfortunately, as will be shown later in this paper, the HHI seems to have absolutely no predictive power in the electric industry. In some days of the year in a given electricity market, prices can go up by 50 percent or more due to strategic bidding alone and can be easily sustained at 10 percent above competitive market prices. Yet the HHI for such a market can be well below 1,800 for **all** days of the year. Furthermore, no single relationship between HHI values and price impacts seems to hold throughout various regions of the country, indicating that the regional impacts of market power depend, at the least, on the regional supply curve.

Market Power Simulation Models & Price Impacts

The most sensible method of calculating market power impacts in an electricity market is to simulate the operation of that electricity market and, thereby, directly measure the price and revenue impacts of firms' strategic bidding and capacity withholding behavior. At Tellus Institute, we have developed a market power simulation model that calculates strategic bids using the Supply Function Equilibrium (SFE) technique originally developed by Klemperer and Meyer in their theoretical paper appearing in *Econometrica* in 1989, and then adopted by Green and Newbery of Cambridge University as a model of strategic bidding behavior in deregulated electricity markets. The SFE technique was further refined at Tellus by Dr. Aleksandr Rudkevich.[8]

The SFE method interprets the energy market as a simultaneous bidding process in which each profit-maximizing generating firm offers bids for electric energy in the form of a supply curve (or supply function which indicates how much generation the firms are willing to sell at different unit prices), while a system administrator is responsible for ordering the bids and dispatching the units so as to meet the demand for electricity at least cost in each time interval. In the Tellus model, generating firms act in self-interest and do not engage in explicit collusion, either by directly exchanging information or by agreeing to raise prices. The model does assume that each competitor's variable costs of production are known.

The outcome of this bidding process, known as the "Nash Equilibrium," is a combination of the individual bidding strategies of each firm that satisfies the following condition:

> **if, (a) one firm bids a supply curve that deviates from this strategy; and (b) all other firms bid supply curves that adhere to this strategy; then the profit of the one firm departing from this strategy will not increase.**

Generating firms are likely to adopt such Nash Equilibrium-based strategies in their daily bidding for two major reasons:

<u>Reason 1</u>. It is rewarding for a firm to bid according to the Nash Equilibrium strategy when competing firms also bid according to the Nash Equilibrium strategy.

[8] Rudkevich et al., the *Energy Journal.*

Reason 2. The Nash Equilibrium strategy is stable: any firm that deviates from this strategy has a strong incentive to return to it.

The Tellus market power model performs a simple unit dispatch, then calculates prices and revenues based on both marginal cost bids and on calculated strategic bids. Market power is then measured by comparing the difference between the marginal cost or "perfectly competitive" prices and the strategic or actual prices. In particular, the Tellus market power model calculates the Price-Cost Margin Index (PCMI).

$$PCMI = \frac{(AP - PCP)}{PCP} \times 100\%$$

where AP = Actual Price and PCP = "Perfectly Competitive" Price.

Because PCMI has the "perfectly competitive" price in its denominator, it allows comparison across various scenarios that may have different actual prices. Such a PCMI-type ratio can be computed for both the electricity prices and the revenues received by generation owners – the slight difference between these two solutions will be due to price elasticity effects for demand.[9]

With simulation models, market power can be measured directly rather than inferred erroneously from a simple, static, market concentration index like the HHI. FERC, by recently issuing Requests for Comments **(Docket # PL 98-6-000)**, seems to have recognized the importance of simulation models. We hope to demonstrate in the following sections of this paper that direct simulation models perform better than the HHI in predicting the exercise of market power.

Comparison of PCMI and HHI results

The following figures present results obtained using the Tellus Market Power model for both the New England Power Pool (NEPOOL – 25,000 MW), with 29 owners, and a large area of about 48,000 MW with 22 owners centered around Kansas City, which we refer to as the Missouri/Kansas region (MKR). **Figures 1** and **2** present the PCMI for each day of the year sorted chronologically. In this analysis, the yearly average PCMI is about 8 percent for NEPOOL and about 10 percent for MKR, which means that owners in their respective regions can increase revenues (and increase the price of electricity) by these percentages simply by bidding strategically.[10]

[9] The Tellus market power model actually uses **revenues** to calculate "PCMI" rather than **prices**. All PCMIs presented in this paper are based on revenues.

[10] The PCMIs presented in this paper differ from the PCMIs Tellus Institute found for the Missouri/Kansas region as submitted in testimony before the Missouri PUC. Our analysis submitted with that testimony used six modeled day-types rather than 365 days of load. The modeled day-types allowed us to adjust the supply curves to reflect scheduled outages as they would be planned to account for the differences in day-type demand. For the analysis contained in this paper, we developed a single supply curve that does not reflect any scheduled outages in order to easily model 365 different days of load. This new analysis is presented only in order to illustrate certain issues and is not an estimation of what we believe are the full impacts of market power.

Figure 1

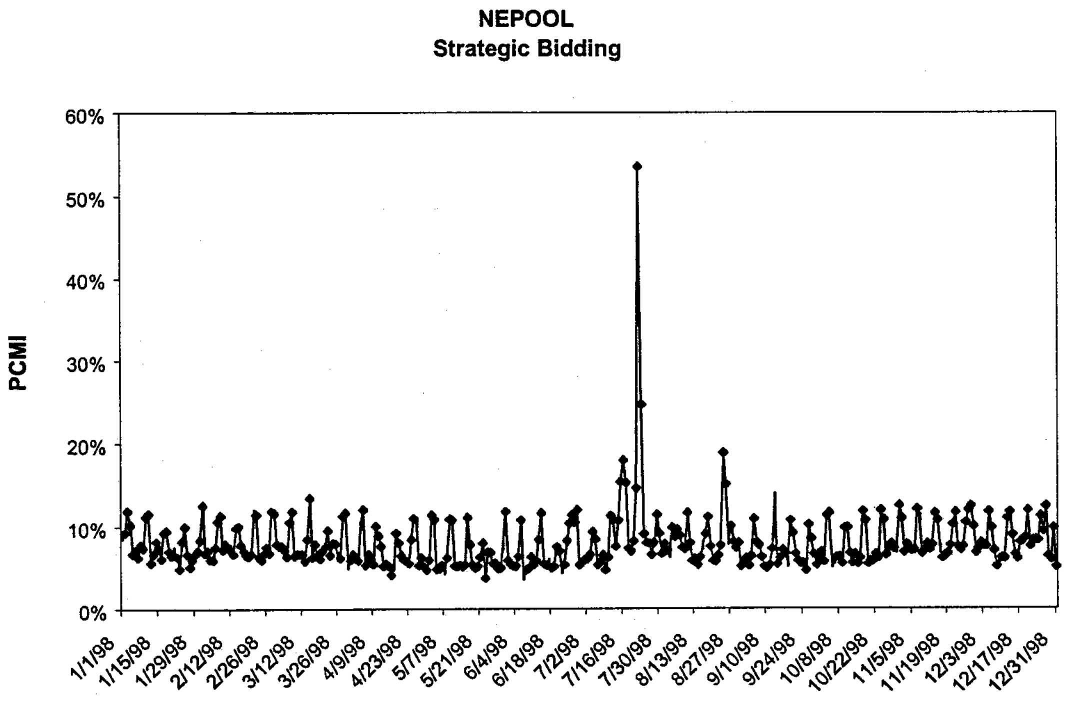
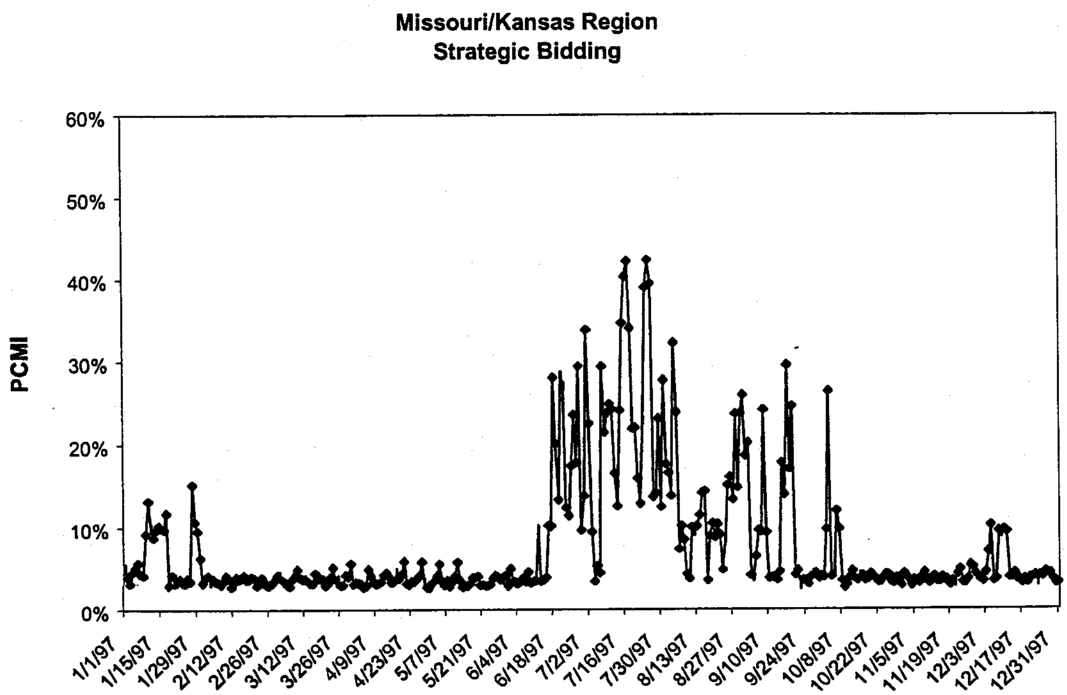


Figure 2

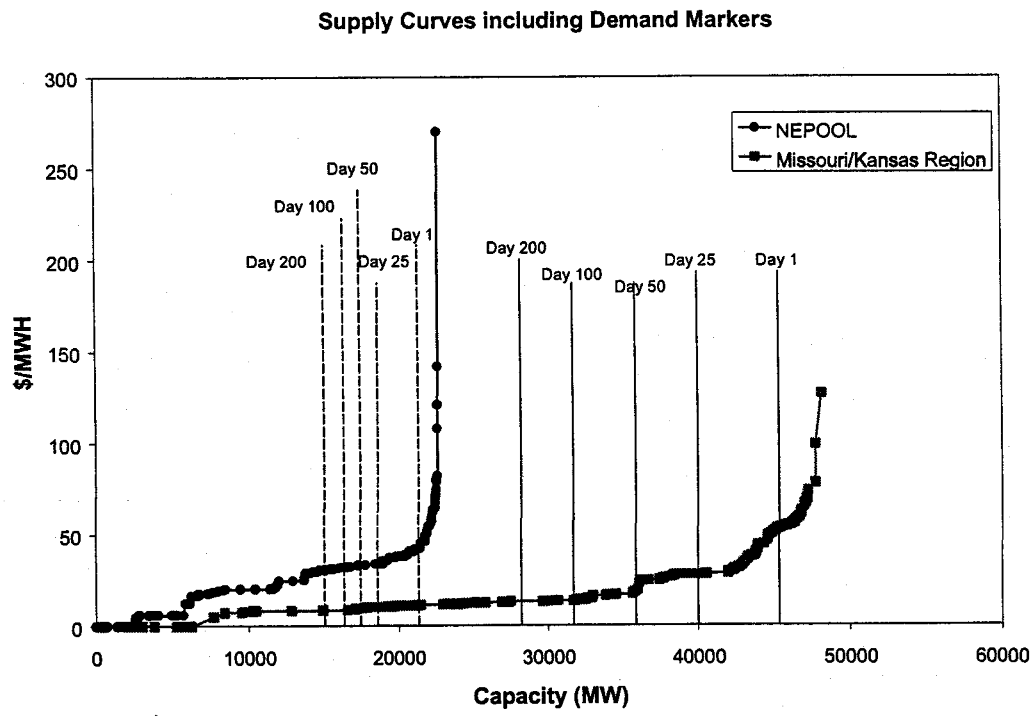


In comparing the two systems, the differences in the PCMI can be explained largely by the interaction of each system's supply and demand curves, as shown in **Figure 3**. **Figure 3** depicts each system's supply curve and selected daily peak loads. Day 1 refers to the day of the year with the highest peak load, while day 200 refers to the day of the year with the 200[th] highest peak load. Note that the section of the MKR supply curve between Day 1 and Day 25 is much steeper than the corresponding section of the NEPOOL supply curve. MKR's steeper supply curve (for days 1 through 25) explains the greater volatility, relative to NEPOOL, in PCMI during summer, the highest peak demand period. Alternatively, NEPOOL's summer PCMIs are less volatile than MKR's summer PCMIs because the section of the NEPOOL supply curve (for days 1 to 25) is flatter.

Similarly, the area between Day 50 and Day 200 on the MKR supply curve is flatter and lower in absolute cost than the corresponding section on the NEPOOL supply curve. Again, this difference in the shape of supply curves explains for low-peak days how the PCMI for MKR is lower and less volatile than the PCMI for NEPOOL.

We would expect that steeper supply curves result in higher PCMIs because in strategic bidding, owners base their bids on the expected bids of the next most expensive units on the supply curve. If the next most expensive units are only slightly more expensive, then the strategic bid will *not* be much higher than the variable production costs of the unit being bid. However, if the next most expensive unit is much more expensive to operate, then the strategic bid *will* be higher.

Figure 3



The Tellus Market Power model also calculates daily HHI values, which are shown for the two systems in **Figures 4** and **5.** The HHI changes on a daily basis because we measure the concentration of firms actually delivering power into the system in each day; as demand changes, so does ownership concentration and, therefore, HHI. Calculating the HHI for each day is equivalent to calculating it for each product market as FERC advocates as part of its Appendix A analysis for mergers. HHI values vary much less (5-15 percent) from day to day than PCMI values vary (100 – 500 percent). Furthermore, the HHI values for both systems remain well within the range considered as only "moderately concentrated" according to FERC merger guidelines. Yet the average annual PCMI for both systems exceeds the Department of Justice's 5 percent "do no harm" price impact guideline.

Information presented in **Figures 4** through **6** does not represent a merger, but we include the FERC merger guidelines in these figures to illustrate that these systems would pass FERC's HHI merger screen despite the obvious market power threat illuminated by PCMI. To illustrate the actual impacts of a merger, we present in **Figure 7** results of analysis recently submitted in testimony before FERC and the Missouri PUC.

Figure 4

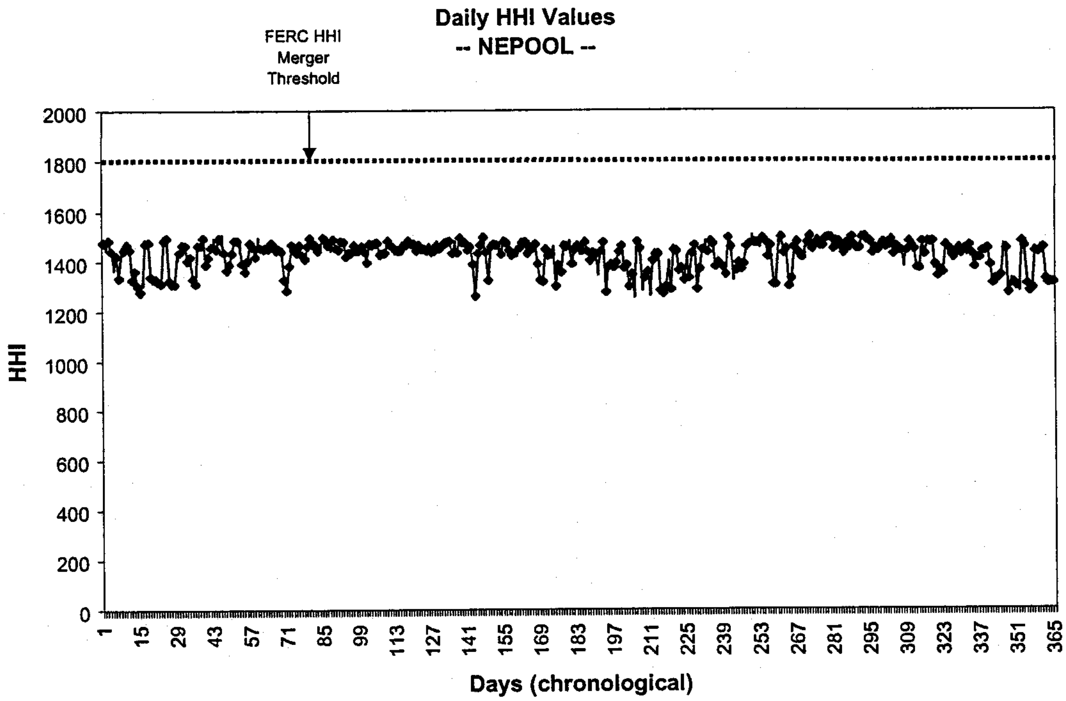


Figure 5

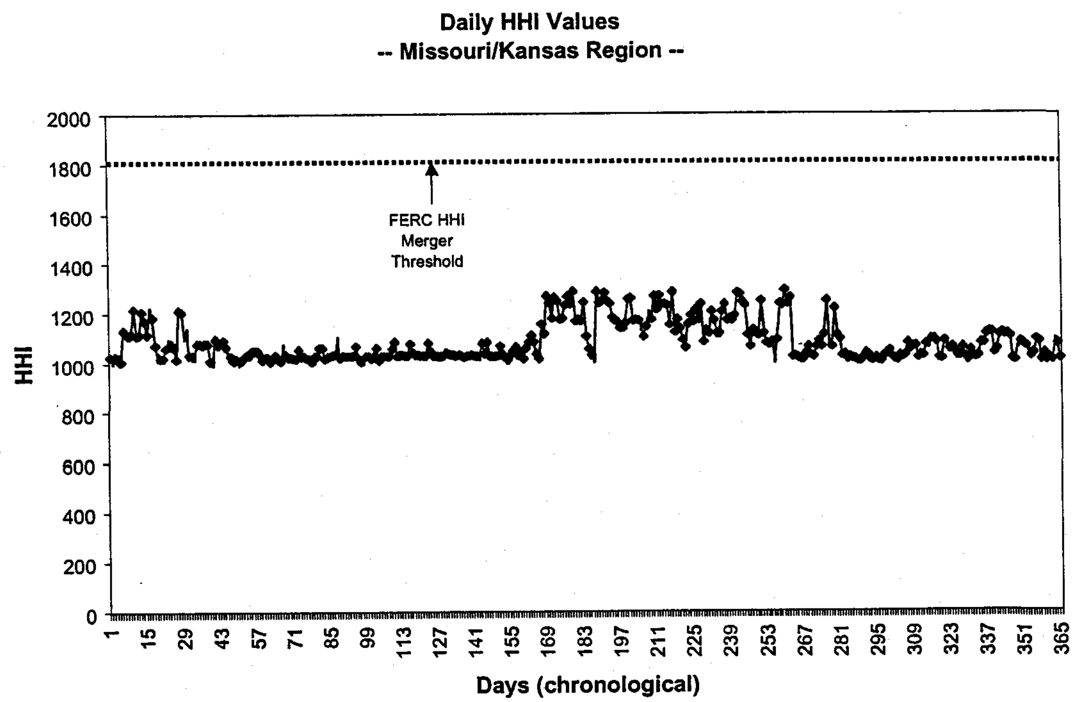
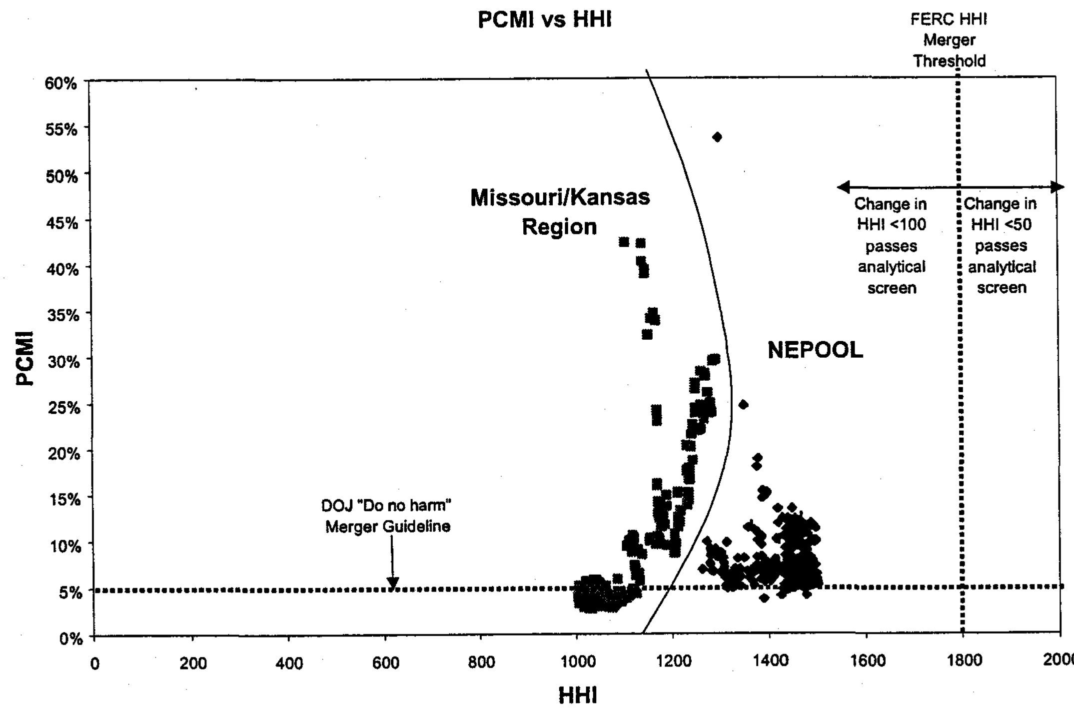


Figure 6 is a scatter plot of PCMI versus HHI for both systems for every day of the year. This graph shows that HHI cannot be used to predict market power. Higher HHIs are clearly not correlated with higher PCMI values, especially for NEPOOL. In both systems, the highest PCMIs occur during days with mid-range HHIs. For each system, HHIs stay well below the FERC threshold of 1,800 for all days of the year. In contrast, the highest NEPOOL PCMI is 54 percent, which is far above the Department of Justice 5 percent guideline. A PCMI of 54 percent means that owners of generation in NEPOOL receive 54 percent more revenue for that day due to strategic bidding than they would receive in a competitive market without strategic bidding. Yet, the HHI for that day, only 1,301, is toward the low end of the range of HHIs for the whole year – 1,262 to 1,502.

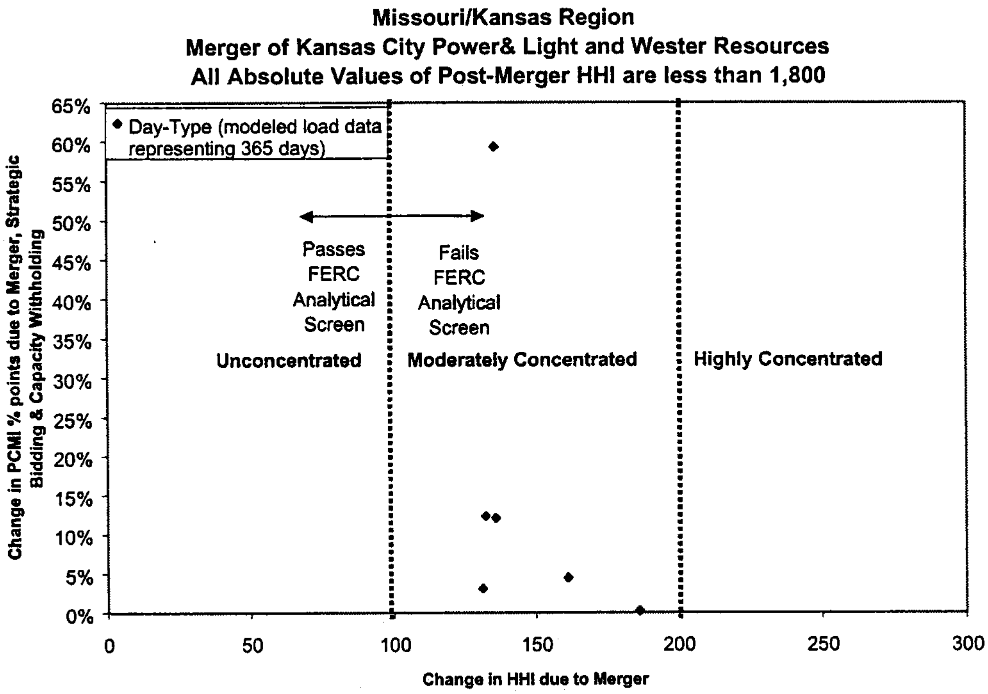
Not only does HHI fail to predict PCMI, the relationship between them is not consistent from one system to another. NEPOOL HHIs are consistently higher than MKR HHIs, yet NEPOOL PCMIs are lower on average than MKR PCMIs. This comparison alone demonstrates that market power is far more complicated than simple measures of market concentration like HHI would lead one to believe; the HHI cannot begin to capture the nuances that a market simulation model can.

Figure 6



In **Figure 7**, we show results from an analysis of the proposed merger between Kansas City Power & Light and Western Resources, which is contained in recent testimony before the Missouri PUC. This analysis is much more detailed in terms of representing supply curve outages than the other analysis presented in this paper. A consequence of greater detail on the supply side is less detail on the demand side in order to make modeling manageable. Thus, **Figure 7** contains only six data points rather than 365 because we modeled demand as six day-types.[11] We present in **Figure 7** the change in HHI and the change in PCMI percentage points as a result of the merger. All absolute HHI values are below 1,800, and all changes in HHI are between 100 and 200. Although the merger would technically fail FERC's Appendix A HHI screen, most mergers that are moderately concentrated are approved by FERC. However, the changes in PCMI clearly indicate serious market power problems.

Figure 7



Factors that Influence Market Power

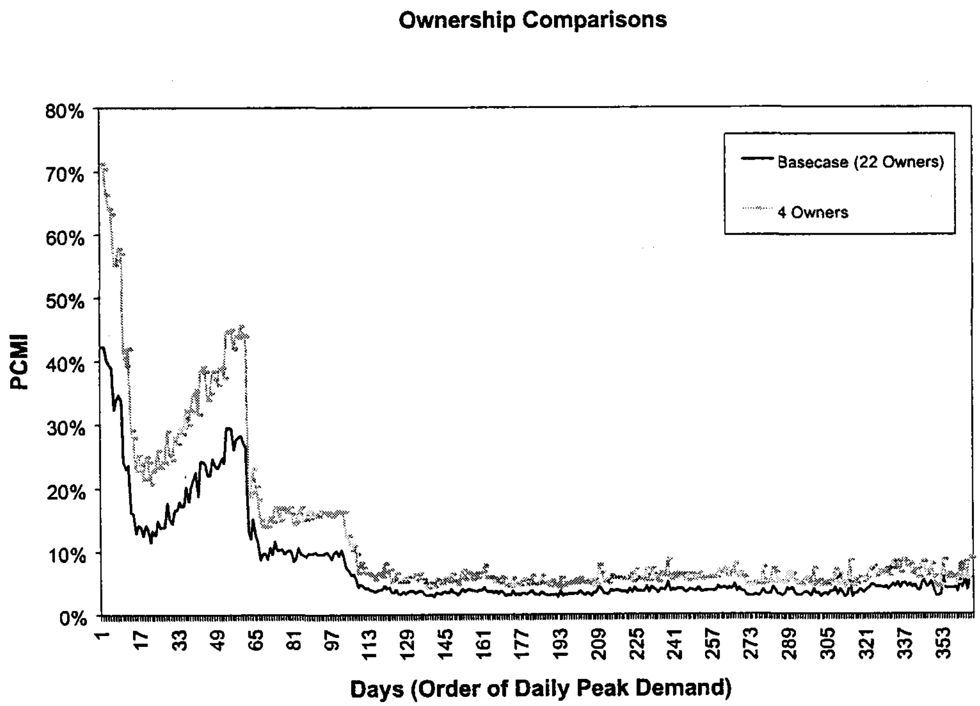
This section examines some of the factors that influence market power through various scenarios based on the MKR data. The PCMIs in the following graphs are all in order of the peak hour in each day, such that day 1's peak hour is the highest of the year and day 365's peak hour is the lowest of the year.

Figure 8 represents three scenarios based on different ownership concentrations. The basecase consists of the original supply curve with 22 owners. In the "4 owner" case, we assigned all units to four owners evenly distributed along the supply curve by ordering the units from lowest to highest marginal cost and assigning the first four units to the four owners, the next four units to the four owners, and so on. As one would expect, the PCMI increases dramatically

[11] We found that actual and modeled load (day-types) result in variations of average yearly PCMI of only about a percentage point, so day-types accurately reflect annual conditions.

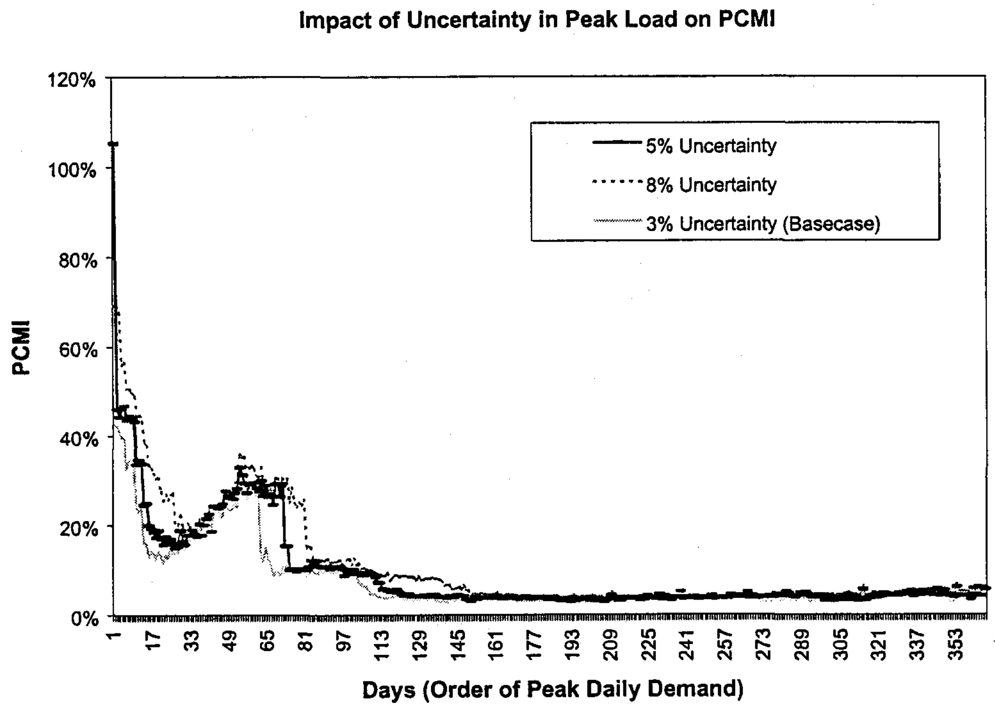
as ownership becomes more concentrated. What is less intuitive is that ownership concentration directly shifts up the PCMI each day of the year, which is not how PCMI changes as a result of changes in peak load uncertainty and supply-demand balances, as described below. Also as expected, the greatest impact of ownership concentration on market power occurs in the days with the highest daily peaks.

Figure 8



Another factor that directly influences potential market power is the uncertainty in peak load forecasts. Because owners submit bids for the next 24-hour period, they must forecast peak demand in order to determine what their strategic bids will be. Forecasted and actual demand almost always differ by several percent due to short term changes in weather and other factors. To simulate the level of uncertainty in demand forecasting, the Tellus Market Power model requires the user input a percentage uncertainty in peak load. As **Figure 9** shows, the greater the uncertainty, the higher the PCMI.

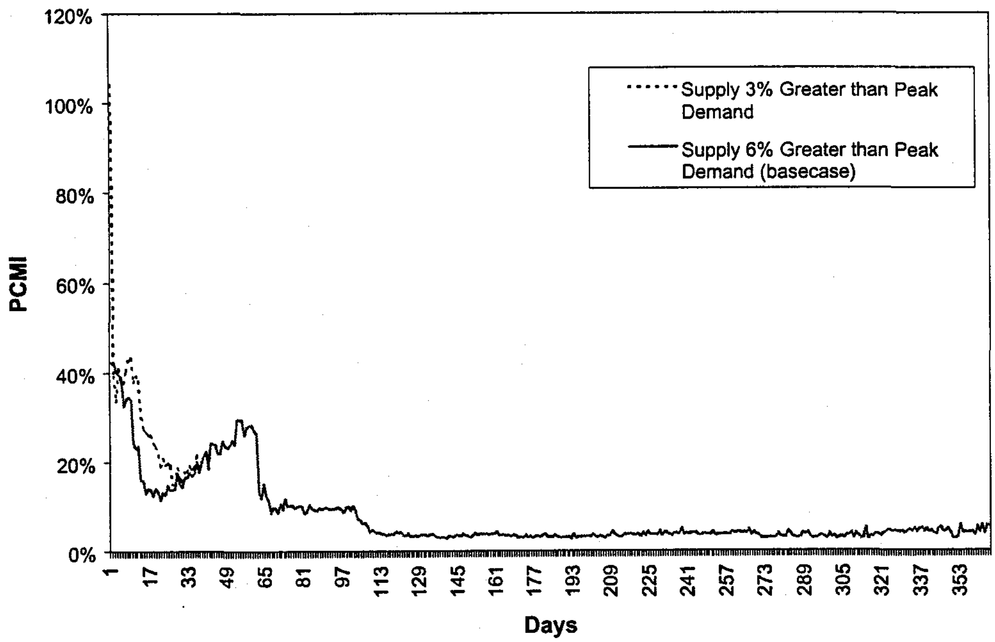
Figure 9



In addition, how closely total supply and peak demand match also affects market power considerably in the highest peak days of the year, as shown in **Figure 10**. This effect becomes negligible for lower peak demand days. For the "3 percent above peak demand" scenario, we removed about 1,200 MW of capacity from new combustion turbines located on the supply curve at around $30 per MWH. As expected, the impact on market power is such that more capacity leads to lower prices. This effect is only noticeable in high peak demand days when demand is at a level requiring electricity costing around $30 per MWH or higher.

Figure 10

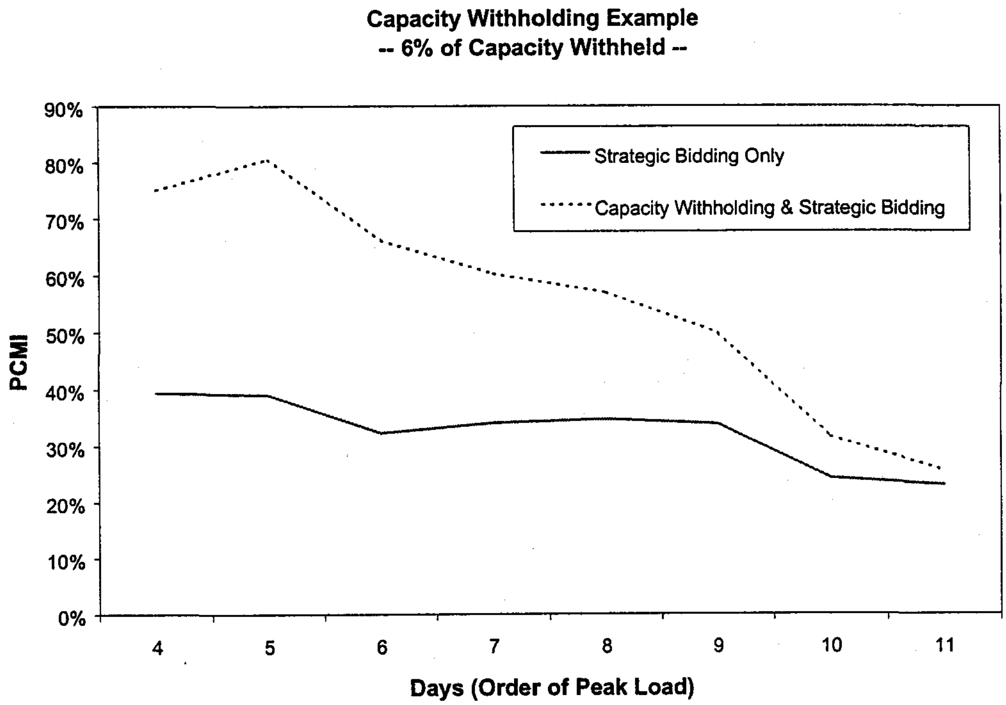
The Impact of Supply-Demand Balance



Capacity Witholding

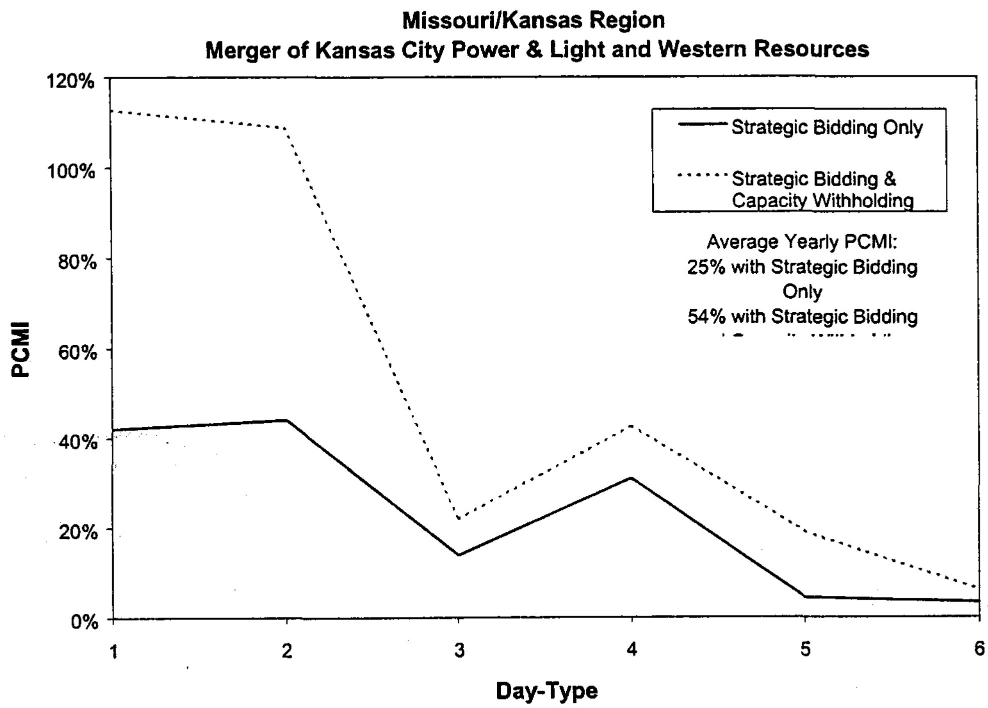
Another important factor influencing market power is the distribution of ownership over the supply curve. Ownership patterns greatly impact capacity withholding. An owner withholds capacity in the hope of raising the market clearing price only if he/she has enough other capacity that will receive the higher price to compensate for the foregone revenues of the capacity withheld. Thus, if an owner's capacity is not at least partially distributed along the supply curve, he/she will be much less likely to profitably withhold units. Although **Figure 11** does not represent capacity withholding in terms of ownership patterns, it does convey the potential windfall available to owners if they withhold. In this example, the set of units withheld was not optimal, but withholding only 6 percent of total capacity more than doubled the PCMI for several days. Therefore, owners have enormous incentive to withhold capacity and to maintain ownership patterns that allow them to profitably withhold capacity.

Figure 11



Our approach to capacity withholding in this example is akin to a "shotgun" approach in finding a set of units to withhold; the same units were withheld for each of the days presented. In reality, owners would withhold different sets of capacity each day based on changes in load. In recent testimony before the Missouri PUC and FERC, Tellus found that on average over the whole year, the PCMI went from 25 percent when firms engaged only in strategic bidding to 54 percent when they also engaged in capacity withholding (see **Figure 12**). Surprisingly, owners could achieve these enormous gains by withholding an average of only 3 percent of capacity throughout the year.

Figure 12



Conclusion

Simulation models afford greater understanding of market power since they take into account the dynamic behavior of market participants, the impact of market structure, and the shape of supply and demand curves. HHI falls short in explaining the nuances of market power due to its theoretically simplistic and empirically unsupportable proxy measures of a complex, non-linear phenomenon. Another advantage of market simulation models is that they can be used to measure the market power impacts of different supply and demand policies, including Renewable Portfolio Standards and energy efficiency programs.

Exhibit 3

Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco

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Introduction

There is widespread belief among regulators and policy analysts that deregulation of the electricity generating industry will yield economies in the cost of power supply, relative to the previously regulated regime, as a result of the introduction of competition. While competition in electric markets promises to improve efficiency, there are well recognized aspects of market behavior, especially in industries with a relatively small number of firms, that threaten to offset the benefits that would lower electricity prices. In particular, in the normal operation of markets, price can be well above the marginal cost of production as a result of pricing strategies adopted by rational firms. As competitive generation markets emerge across the U.S. in the next few years, it is important to have as much information and clarity as possible about these pricing effects, so that they can be mitigated before they manifest themselves to the detriment of consumers.

The *poolco* is one of the market structures that will be used to dispatch and sell electricity in the deregulated generation industry. California's competitive market is scheduled to commence operation on January 1, 1998, through a poolco-type Power Exchange. Elsewhere in the U.S., the states in the Pennsylvania-New Jersey-Maryland (PJM) power pool, the New England Power Pool (NEPOOL), and the New York Power Pool (NYPP), have also established plans for the introduction of region-wide poolcos to facilitate wholesale competition in the generation market.

In this paper, we present an analysis that estimates the price of electricity dispatched and sold through a poolco on the basis of bids made by rational, profit-maximizing generating firms. Our results are calculated from a closed-form mathematical formula that provides the instantaneous market clearing price of electricity when generating firms adopt bidding strategies constructed from the Nash Equilibrium.[1] This formula is derived from the analytical concept of the *supply function equilibrium* (SFE), originally

[1] The Nash Equilibrium provides a bidding strategy that, if adopted by each generating firm, results in independent profit maximization. If all firms bid in accordance with the Nash Equilibrium strategy, and one firm deviates from this strategy, then the instantaneous profit of this firm cannot increase.

developed by Klemperer and Meyer (1989) and subsequently applied by Green and Newbery (1992) in their model of the electricity spot market of England and Wales.

In our analysis, we compare the market clearing prices resulting from Nash Equilibrium-based bidding to a benchmark given by the "perfectly competitive" price of electricity in a poolco. The "perfectly competitive" price of electricity in a poolco can be thought of as the market clearing price when all firms bid the production costs (or *short-run* marginal costs) of their generating units. The frequency and magnitude of the elevated electricity prices that result from Nash-Equilibrium-based bidding can be construed as evidence of market power in a poolco, which results from tacit collusion among generating firms.

We have applied our poolco pricing model to electricity supply and demand data for Pennsylvania. We have quantified the average price mark-up, relative to the "perfectly competitive" price, that would result from Nash Equilibrium-based bidding strategies over the course of one year as a function of the number of *identical* firms in the poolco market. We have found that the Nash Equilibrium-based prices are sensitive to such factors as the average reliability of generating units, the amount of reserve capacity in the system, and the precision with which generating firms are able to predict demand for electricity on a daily basis. We present the results of such sensitivity analyses in this paper.

Our results show that, as one would expect, the market clearing price of electricity decreases as the number of generating firms bidding into the poolco increases. However, even with a relatively low market concentration (high number of competing firms), the market clearing prices are still significantly higher than "perfectly competitive" prices. Our findings have important implications for the design and operation of future electricity markets. Moreover, our findings suggest that the guidelines used by the Department of Justice[2] and the Federal Energy Regulatory Commission[3] to characterize market power in electricity markets may require revision if they are to prevent the exercise of market power in poolco-type markets.

The Poolco

The poolco model for dispatching and selling electricity is simple and well documented (Garber et al, 1994; Budhraja and Woolf, 1994). The important points to note about poolcos are the bid-based dispatch of generating units, and the payment rule whereby *all* units dispatched in each time interval receive the market clearing price, which is set by the bid price of the marginal unit required to meet demand in each time interval. Thus, regardless of their production costs, or even their bid prices, infra-marginal units dispatched in each time interval all receive the market clearing price.

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2 See U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines, Sec. 0.1 (1992), reprinted in Trade Regulation Reporter (CCH), 13,104

3 See FERC Docket No. RM 96-6-000; Order No. 592, Volume 61, No. 251. December 1996.

Some poolco proponents believe that competition in the generation industry will force firms to base their bids on the variable production costs of their generating units.[4] In fact, if all units bid their variable production costs, the resulting market clearing price of electricity assumes its "perfectly competitive" value, given by the *short-run* marginal cost of electricity generation.[5] In our analysis, we refer to this bidding practice as *production cost bidding*. However, if the downward competitive pressure on price in a poolco is insufficient to bring about production cost bidding, generating firms can employ opportunistic bidding strategies that result in stable market clearing prices significantly above the short-run marginal cost of generation.

Market Power and Market Concentration

In this section, we briefly define the concepts of market power and market concentration, as well as the numerical indicators that we use to quantify them in our analysis. Market power can generally be defined as the ability of a particular seller, or group of sellers, to influence the prices of a product to their advantage over a sustained period of time. We use the Price-Cost Margin Index (PCMI) to measure the extent of market power abuse in a poolco. The PCMI quantifies the degree to which the price of a product in a market deviates from what would be its "perfectly competitive" price. The PCMI is a retrospective indicator of market power, defined as:

$$\text{PCMI} = \frac{\text{Actual Product Price - "Perfectly Competitive" Product Price}}{\text{"Perfectly Competitive" Product Price}} * 100\%$$

where the "perfectly competitive" price is equal to the marginal cost of electricity generation.[6]

The Department of Justice (DOJ) merger guidelines state that a market can be considered competitive if prices do not exceed their "perfectly competitive" level by more than 5%.[7] This statement can be rephrased in terms of the PCMI -- if the PCMI is above 5%, then according to DOJ guidelines, a market cannot be characterized as competitive.[8]

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4 See, for example, analyses conducted by Hieronymus (1997), and affidavit submitted by Felder and Peterson (1997).

5 In a theoretical model of a poolco, owners of generating units are assumed to bid their variable production costs in each time interval. They recover their fixed costs through a margin earned in each time interval that they are dispatched, given by the difference between their variable production cost and the market clearing price. It should, however, be noted that peaking units, and possibly cycling units, which run in fewer hours of the year than baseload units, would in reality need to bid above their production costs in order to have ample opportunity to recover their fixed costs. Thus, generating units higher up the system-wide supply curve may adopt bidding strategies that more closely reflect their *long-run* marginal costs of production.

6 The PCMI has a minimum value of zero – implying a perfectly competitive market -- and an unbounded maximum value. A PCMI value of 100%, for example, means that the price of a product is twice the price that would be expected if the market were perfectly competitive.

7 See the U.S. Department of Justice and Federal Trade Commission "Statement Accompanying Release of Revised Merger Guidelines", April 2, 1992.

8 The PCMI is similar to the well known Lerner Index, in which the price margin is divided by the actual price, as opposed to the "perfectly competitive" price in the PCMI. The PCMI and Lerner Index are connected in the following way: Lerner Index = PCMI/(1+PCMI). In our analysis, we use the

Market concentration is a measure of the number of firms in a given market. The degree to which market power can be exercised in a given market is largely a function of market concentration, however, it also depends upon the structure of the market, the nature of the particular product being sold in this market[9], the ease of market entry for new firms, and the price elasticity of demand for the product. We discuss market concentration and market structure later in this paper, and also address ease of market entry and price elasticity of demand.

In our analysis, we quantify market concentration using the Herfindahl-Hirschmann Index (HHI), which is defined as:

$$HHI = \Sigma S_i^{\,2} \qquad \Sigma S_i = 100\%$$

where S_i is the share of each firm in the market.[10] It should be noted that the reciprocal of the HHI (10,000 divided by HHI) yields a number that can be interpreted as the effective number of identically-sized firms in the market.

The HHI is a simple indicator of market concentration, whose effectiveness has not been demonstrated either theoretically or empirically in the context of the electric industry. However, the HHI has recently been adopted by the FERC as a proxy for market power in evaluating proposed mergers between firms in the same market, as well as transitions to market-based pricing in power pools. In using the HHI, the FERC adopted the DOJ/FTC guidelines, which state that a market is "unconcentrated" if its HHI is less than 1,000; "moderately concentrated" if its HHI lies between 1,000 and 1,800; and "highly concentrated" if its HHI is greater than 1,800. For purposes of reference, a market with ten identically-sized firms has an HHI of 1,000, while a market with five identically-sized firms has an HHI of 2,000.

In some models of economic competition, the PCMI (or Lerner Index) and HHI are directly connected by a simple formula (Krouse, 1990). However, such models are too simple to capture pricing behavior in poolcos. As demonstrated later in this paper, the HHI thresholds outlined above may not be applicable to electricity dispatched and sold

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PCMI rather than the Lerner Index, since it has the "perfectly competitive" price in its denominator, and thus facilitates comparison across various scenarios that may have different prices.

9 Electricity is in many ways a very unique product. It has at least four properties that make it markedly different from products manufactured and sold in other markets: i) it cannot be stored in large quantities in most electric systems; ii) it cannot be readily substituted, especially in the short term; iii) it can only be transported along existing transmission lines (new transmission lines require long periods of time and are expensive to erect); and iv) generating units (especially peaking capacity) are capital intensive, which increases the risk for new market entrants in a competitive market. The implications of these properties are that it may be relatively easier for generators of electricity to exercise market power than for manufacturers of other products sold in competitive markets.

10 If the market share of each firm is expressed in percentage terms, the HHI lies between 0 and 10,000. The maximum value of the HHI occurs when there is one firm only in a given industry, with a (monopolistic) 100% market share. The minimum value of the HHI occurs in the limit that the industry comprises a very large number of firms with negligible market shares.

in poolco markets. Before describing our analytical methodology and presenting our results, we briefly discuss the mechanisms by which market power can be exercised in a poolco.

How Can Market Power Be Exercised in a Poolco?

In a poolco, there is an incentive for generating firms to increase the market clearing price, since it is paid to *all* infra-marginal units in each time interval. There are two principal mechanisms by which firms may exercise market power in a poolco. The first mechanism involves firms bidding prices above the production costs of their generating units, with the intent of forcing up the market clearing price. In a poolco, the benefit of "bidding up" the market clearing price typically outweighs the risk of being undercut by a competitor for firms owning a substantial amount of infra-marginal capacity.

This first mechanism is facilitated by the fact that the bids submitted by generating firms apply to the next twelve, or twenty-four, hour period. Since the demand for electricity fluctuates over any 12- or 24-hour period, firms can anticipate these changes in demand in their construction of a bidding schedule for this period. It appears possible for generating firms to construct bidding schedules so that electricity prices exceed the short-run marginal costs of generation in almost every hour of each day, as discussed later in this paper.

The second mechanism for exercising market power in a poolco involves firms withholding some of their capacity in the bidding process, in an effort to cause more expensive units higher up the system-wide supply curve to set the market clearing price. As is the case with the first mechanism, capacity withholding strives to increase the market clearing price. Firms that attempt this strategy must ensure that the foregone revenues from not having some of their infra-marginal capacity dispatched are more than offset by the additional revenues paid to their capacity that *is* dispatched, in each time interval. Our analysis does not consider capacity withholding, since it is not as potentially profitable to firms as simply "bidding-up" the price, in which case no capacity has to be withheld. Two market power studies have, however, shown the effectiveness of capacity withholding. Newbery (1995) has shown that capacity withholding may be profitable to firms whose market shares range between 10% and 40%, while Wolak and Patrick (1997) have shown empirically that this mechanism has been effective in exercising market power in the electricity spot market of England and Wales.

The "Game of Poolco"

In our analysis, we model a poolco as an *(n+1)*-player, *non-cooperative* game of

- *n* identical profit-maximizing generating firms, each offering bids for capacity in the form of a supply curve (or supply function)[11], and
- one poolco operator responsible for ordering the bids and dispatching units so as to meet the demand at least-cost in each time interval.

We use the analytical concept of the *supply function equilibrium* (SFE), originally developed by Klemperer and Meyer (1989) and subsequently applied by Green and Newbery (1992) in their model of the electricity spot market of England and Wales.

In accordance with the rules of the game for the *n* firms and poolco operator, we calculated analytically the bidding strategy that, if adopted by all firms, would satisfy the condition of independent profit maximization by each firm. This bidding strategy is given mathematically by the Nash Equilibrium, such that if one firm bids a supply curve that deviates from this strategy, while all other firms bid supply curves that adhere to this strategy, then the profit of the one firm departing from this strategy ***cannot* increase.** In this game with *n* identical firms, all firms employ a symmetrical Nash Equilibrium-based strategy (identical for all firms).

In deriving our formula for the market clearing price of electricity, we advanced the Klemperer-Meyer theory by relaxing the convexity and differentiability conditions, which consequently allows for "real world", step-wise supply curves to be studied.[12] We have incorporated this formula, which appears below in Figure 1, into a poolco pricing model for the special case in which:

- the generating firms are identical in size and have identical supply curves;
- there is zero price elasticity of demand;
- generating firms have perfect information about one another's production cost curves;
- generating firms have equal accuracy in predicting demand.

[11] The supply curve indicates how much generation the firms are willing to sell at different unit prices.

[12] The derivation of this formula appears in the Appendix.

Figure 1. Price Of Electricity In A Poolco As A Function Of Instantaneous Demand

$$P(Q)=c_k+\sum_{j=k}^{m-1}[c_{j+1}-c_j]\left(\frac{Q}{X_j}\right)^{n-1}$$

where

P - instantaneous market - clearing price of electricity in a given time interval.

Q - instantaneous demand in a given time interval; $X_{k-1} < Q \leq X_k$;

k - the dispatch order number of the generating unit that is on the margin in that time interval.

n - number of identical firms.

c_k - variable cost of the marginal unit given demand level of Q.

j, c_j - the dispatch order number and variable cost of those generating units that are above the margin in that time interval but that are expected to be on or below the margin in some other time interval during the 24 - hour period.

m - the dispatch order number of the most expensive unit expected to run during the 24 - hour period.

X_j - total capacity of all generating units with dispatch order not exceeding j

It is important to note that in the above formula Q is always less than X_j

Subject to these assumptions, the formula for the market clearing price of electricity resulting from Nash Equilibrium-based bidding strategies is a function of:

- the particular electric system's production cost curve (i.e., the size of the steps of capacity, and the increases in variable cost between these steps);
- the instantaneous demand for electricity;
- the maximum anticipated demand in the overall period for which bids are submitted;
- the number of identical generating firms bidding into the poolco.

The formula shows that as n increases, the market clearing price decreases and moves towards the "perfectly competitive" market clearing price that would result from production cost bidding. It can also be inferred from the formula that the production costs of generating units that are included in the supply curve but are *not* dispatched in a particular time interval can have significant influence on the market clearing price of electricity in that time interval.[13]

Although the concept of the Nash Equilibrium is widely used in economic theory to model the behavior of firms in competitive markets, it is important to emphasize two reasons why it is in the best interests of profit-maximizing firms to adopt a Nash Equilibrium-based strategy in a poolco.

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13 The magnitudes of the contributions to the market clearing price from such units not dispatched vary from hour to hour, and from day to day.

Reason 1. By definition of the Nash Equilibrium, it is rewarding for a firm to bid according to the Nash Equilibrium strategy when competing firms also bid according to the Nash Equilibrium strategy.

Reason 2. The Nash Equilibrium strategy is *stable*: the firm that decides to deviate from this strategy has a strong incentive to return to it.

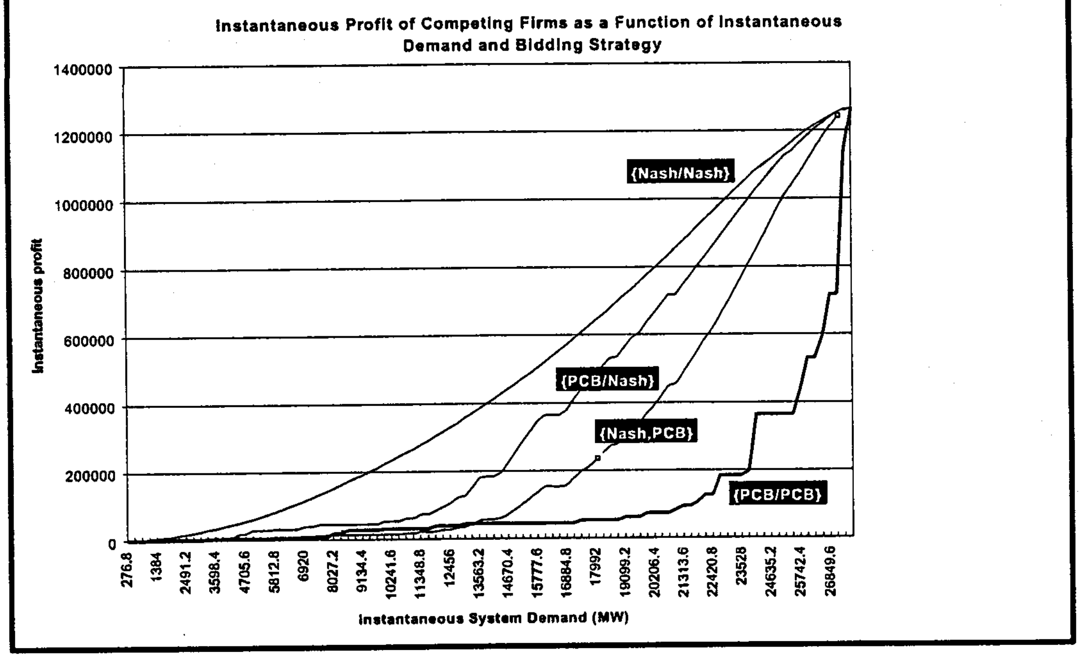
Both of these statements are illustrated by Figure 2, which shows the potential profits of two identical firms competing with one another.[14] In this figure, each curve represents the instantaneous (hourly) profits of one firm as a function of the instantaneous system demand for electricity. The highest curve, labeled {Nash/Nash}, represents the profit of each firm when both bid according to the Nash Equilibrium strategy. The lowest curve, labeled {PCB/PCB}, represents the profit when both firms use a production cost bidding strategy.

The two curves that lie in the middle, labeled {PCB/Nash} and {Nash/PCB}, represent the firms' profits when their bidding strategies are not identical -- one applies the Nash Equilibrium strategy while the other adopts a production cost bidding strategy. In this case, the higher of the two curves shows the profit of the firm that applies the production cost bidding strategy, while the lower curve shows the profit of the firm that adheres to the Nash Equilibrium strategy.

The figure shows that if one firm is applying the production cost bidding strategy, then the other firm that adheres to the Nash Equilibrium strategy has no incentive to switch to the production cost bidding strategy. Similarly, if one firm is bidding in accordance with the Nash Equilibrium, then the other firm that deviates from the Nash Equilibrium strategy can increase its profits by returning to the Nash Equilibrium strategy.

14 In Figure 2, we use the production cost curve for Pennsylvania, which we discuss later in this paper.

Figure 2



Data and Modeling Assumptions

We applied our poolco pricing model to actual 1995 data for the Pennsylvania electric system. The Pennsylvania production cost curve is representative of many electric systems around the U.S., in that it contains different types of generating units -- nuclear, coal steam, oil steam, and oil and gas combustion turbines -- which have their own specific cost and operating characteristics.[15]

We apportioned each step of capacity on the production cost curve, corresponding to one generating unit with a certain capacity and variable cost, equally among *n* firms, so that the firms each own 1/*n* of each step of capacity, and thus have identical market shares and production cost curves. Each firm's production cost curve is consequently a curve identical in shape to the Pennsylvania electric system production cost curve, but *n* times smaller in capacity (or *n* times smaller along the abscissa.)

The *premium* earned by firms through the difference between the market clearing price and the price that would result from production cost bidding (as quantified in the PCMI numerator) varies depending upon the level of demand. We calculated how this premium would vary over the course of a typical year, and then averaged over these premiums in order to obtain an *annual PCMI.* We constructed empirical demand data by dividing the 1995 PJM load duration curve (LDC)[16] into ten load segments, each of which represents

[15] The data was taken from Exhibit__(RJF-2) in testimony submitted by Randall J. Falkenberg to the Pennsylvania Public Utility Commission, Docket No. I-940032, November 1995.

[16] This data was obtained from the Federal Energy Regulatory Commission's *Electric Power Directory*, an on-line service.

different load data from days scattered through the year. Each load segment is characterized by a peak daily load and the intra-day variation in load. We estimated the anticipated peak load and intra-day load distribution for each of the ten load segments by averaging over similar types of days in the LDC. The load segments are shown in the following table:

Table 1. Load Segmentation

Load Segment	Number of Days' Data in Load Segment	First Day of Load Segment in LDC	Last Day of Load Segment in LDC	Maximum Peak Hourly Load in Load Segment	Median Hourly Load in Load Segment	Minimum Hourly Load in Load Segment
1	10	1	10	1.00	0.85	0.57
2	20	11	30	0.91	0.78	0.55
3	20	31	50	0.85	0.76	0.55
4	30	51	80	0.81	0.73	0.55
5	30	81	110	0.77	0.69	0.52
6	40	111	150	0.74	0.66	0.49
7	40	151	190	0.71	0.64	0.46
8	50	191	240	0.67	0.61	0.43
9	60	241	300	0.64	0.59	0.42
10	65	301	365	0.56	0.51	0.40

Notes: 1) The load segments contain data from different numbers of days. The load segments corresponding to days with higher peak loads contain data from fewer days. This approach was taken in order to better approximate the shape of the PJM LDC.

2) The data in the last three columns of the table are expressed as a fraction of the annual peak load.

We also made the following two assumptions in our analysis, regarding capacity outages and load uncertainty:

- In any hour of the year, some portion of the system's capacity is unavailable[17], as a result of scheduled or unscheduled outages. We modeled different levels of capacity non-availability, ranging from 10% to 19%.

- In order to ensure sufficient capacity to meet load in each hour, the firms bid a total capacity in their supply curves equal to the forecast peak load over the next 24-hour period scaled up by an "adjustment factor" X. We modeled values of X ranging from 0.25% to 6%.

[17] We assume that the unavailable capacity is uniformly distributed along the system's production cost curve.

Reference Case and Sensitivity Analysis

In our analysis, we calculated the PCMI for each of the ten daily load segments, as defined above in Table 1, as well as the *annual PCMI*, which is the weighted average for these ten load segments. We analyzed the resulting PCMI values as a function of three parameters: i) the number of identical firms; ii) the level of capacity non-availability; and iii) the accuracy of the firms' demand forecasts. Table 2 below summarizes our *reference case* and shows the numerical range of these three parameters that were analyzed as sensitivities.

Table 2. The Reference Case and Sensitivities

Parameter	***Reference Case* Value**	**Range of Sensitivity Values Analyzed**
Number of identical generating firms	5	2-30
Level of capacity non-availability[18]	15%	10%-19%
Demand forecast accuracy	3%	0.25% - 6%

In order to gauge the impact of each parameter on the PCMI, we varied the parameter over its range while maintaining the two remaining parameters at their *reference case* values. In the following section of this paper, we discuss how each of these parameters influences the PCMI.

Market Power as a Function of the Number of Identical Firms, Capacity Non-Availability, and Demand Forecast Accuracy

The PCMI is most sensitive, as one might expect, to the number of identical generating firms in the market. Figure 3 shows how the computed market clearing price varies as a function of instantaneous demand for different numbers of identical firms.[19] The figure shows that for all levels of demand with n=2, the market clearing price is significantly higher than the "perfectly competitive" poolco price that would result from production cost bidding. As n increases, the market clearing price decreases and converges towards the "perfectly competitive" market clearing price defined by the production cost curve. However, as can be seen from the figure, the level of convergence is not uniform across all levels of demand. During hours of relatively low demand, the market clearing price is closer to the "perfectly competitive" price. However, the PCMI is significant during hours of high demand, even with a large number of firms bidding into the poolco.

[18] A system reserve margin of 20% was used for all calculations.

[19] We should point out that in Figure 3, we have assumed that peak load is equal to total system capacity, purely for illustrative purposes. On days with lower peak demands, the deviation between the market clearing price and the "perfectly competitive" price would be lower.

Figure 3

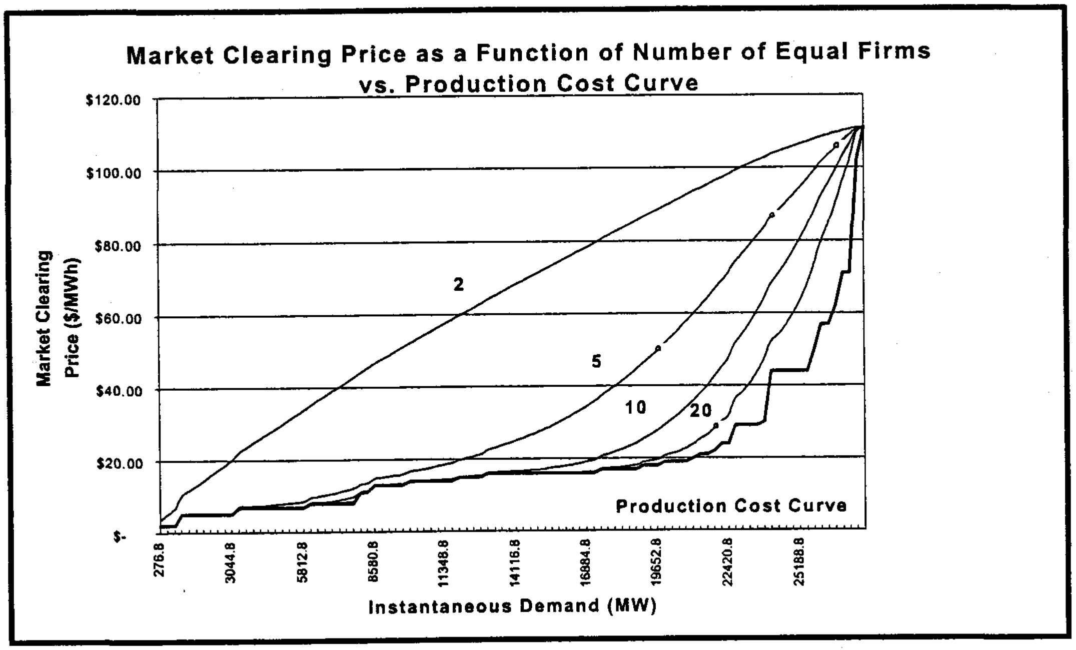


Figure 4 shows how the PCMI varies as a function of n (the number of firms) for the ten load segments representing the different types of day in the load duration curve. In this figure, the load segments are defined by the ratio of their anticipated peak daily load to the annual peak daily load.

Figure 4

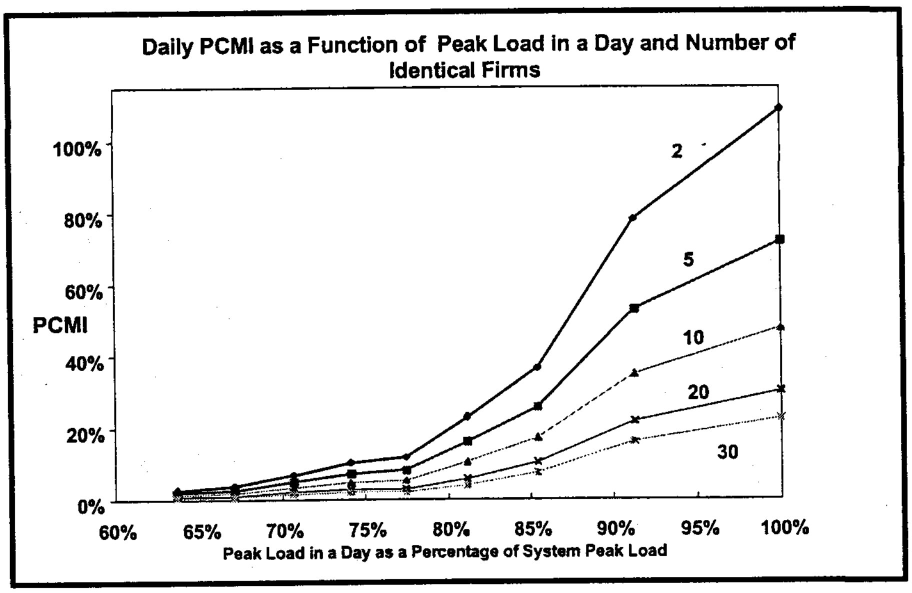
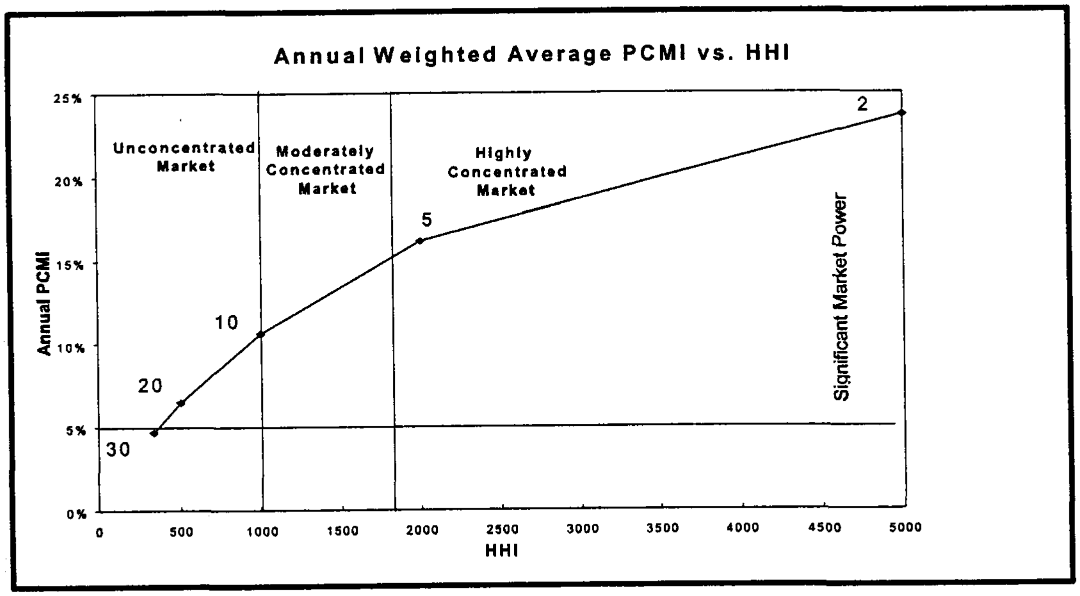


Figure 4 shows that the daily PCMI decreases as the number of firms, *n*, increases, and as the peak daily load decreases for a given *n*. The figure also illustrates the sizable differences between daily PCMI values for days with different peak loads. This indicates that the ability for generating firms to exercise market power varies substantially with the level of peak demand from one day to the next. In fact, in the case of five identical firms, the PCMI only exceeds 5% in 150 days of the year, while in the case of ten identical firms, the PCMI exceeds 5% in 80 days. Thus, when there are more firms in the market, the level of peak demand necessary to exercise market power increases. This, in turn, means that as the number of rims in the market increases, the opportunities for exercising market power are concentrated over fewer days of the year.

Figure 5 shows the *annual PCMI* as a function of the HHI (which is the inverse of the number of firms in the market.)[20]

Figure 5



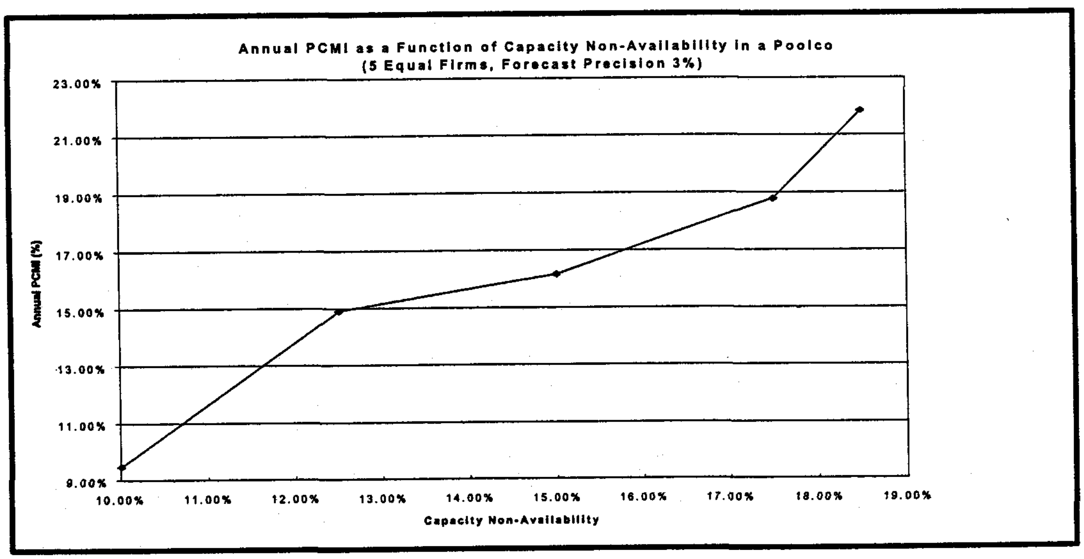
The line running from the top-right to the bottom-left of the figure shows how the *annual PCMI* varies with *n*. The abscissa shows the HHI value that corresponds to each value of *n* (for example, an HHI of 2,000 denotes *n*=5.) The abscissa is also divided into three areas -- HHI values less than 1,000; HHI values between 1,000 and 1,800; and HHI values greater than 1,800 -- which correspond to the three levels of market concentration appearing in the DOJ and FERC merger guidelines. The horizontal line at the bottom of the figure, drawn at a PCMI of 5%, corresponds to the value of the PCMI for which the DOJ believes there is an absence of market power.

[20] The annual PCMI gives the percentage by which the annual revenues of all generating firms in the poolco exceed the annual revenues that would accrue from production cost bidding.

These results show that even though the annual PCMI decreases as the number of identical generating firms bidding into the poolco increases, the price mark-ups using Pennsylvania data are significant even at relatively low values of the HHI. We find that the average price mark-up over the course of one year is 16% in a market with five identical firms, and 11% for ten identical firms. For purposes of reference, the DOJ and FERC guidelines state that a market with more than ten identical firms is "unconcentrated." In addition, we find that in order to reduce the annual PCMI to 5%, the poolco would require almost thirty identical firms. This result contrasts dramatically with observations made in the economic literature that a poolco market with four or five firms would be workably competitive (Joskow, 1995.)

Figure 6 shows the *annual PCMI* as a function of capacity non-availability in a poolco. The levels of capacity non-availability should be gauged with reference to our assumed system reserve margin of 20%. Figure 6 shows that the PCMI increases from approximately 9% to 22% as the level of unavailable capacity increases from 10% to 19%.[21] In other words, each additional percent of capacity that is not available, as a result of scheduled or unscheduled outages, results on average in a 1.5% increase in market clearing prices relative to the "perfectly competitive" price. This result can be explained by the fact that when more capacity is unavailable, the production cost curve becomes steeper. Consequently, units with higher production costs are required to meet demand in more hours, leading to higher average market clearing prices.

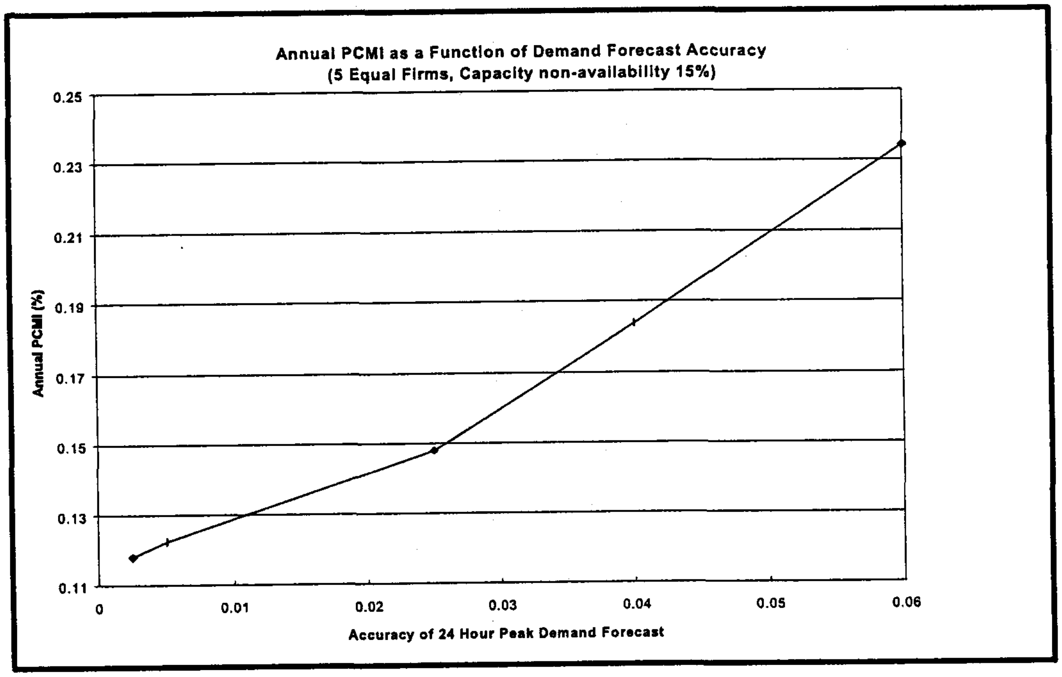
Figure 6



21 It should be noted that even when the capacity non-availability is at the maximum value of 19% in the range considered, there is still excess capacity in the system. Thus, the marginal unit required to meet demand in each hour is never the last unit on the system's production cost curve.

Figure 7 plots the *annual PCMI* as a function of the demand forecast accuracy in the twenty-four hour period for which firms must bid ahead of time. The PCMI increases from approximately 12% to 23% as the demand forecast error increases from 0.3% to 6%. In other words, each additional percent error in the demand forecast results in a roughly 2% increase in market clearing price relative to the "perfectly competitive" price. This result can be explained by the fact that when the forecast error is higher, the supply schedule submitted by firms for the next twenty-four hour period includes units higher up the production cost curve to account for this additional demand. As shown by Figure 1, the inclusion of these additional higher-cost units in the supply schedule serves to increase the instantaneous market clearing price.

Figure 7



Comparison with Other Market Power Studies

Our numerical results are comparable to those obtained by Green and Newbery in 1992, and by Andersson and Bergman in 1995. Green and Newbery found price mark-ups for a poolco with five identical firms of 17% using 1988/89 data, and 23% using forecast data for 1994. Andersson and Bergman reported price mark-ups of approximately 19% for a poolco with six identical firms. In comparison, our *reference case* for five identical firms in a poolco results in a price mark-up of 16%.

Although our results are similar to those obtained in the aforementioned two studies, we believe it important to carefully compare the key assumptions made in each study, in order to determine whether the results should indeed be comparable. Table 3 outlines the key assumptions made in our analysis and in the two aforementioned market power studies.

Table 3. Comparison of Results and Assumptions

Key assumption/ methodology	Rudkevich, Duckworth and Rosen (1997)	Green and Newbery (1992)	Andersson and Bergman (1995)
PCMI value for 5-6 identical firms	(5 firms) **9%-23%**	(5 firms) **17%-23%**	(6 firms) **18.5%**
Analytical technique	Dynamic model based on Klemperer-Meyer SFE	Dynamic model based on Klemperer-Meyer SFE	Static supply demand model closed by a conjectural-variation condition
Price elasticity of demand	zero	non-zero	non-zero
Load segmentation	Ten hourly load types	Three hourly load types	No hourly consideration of the load
Choice of SFE	The lowest in the range	The highest in the range	Not applicable
Demand forecast error	0.25% through 6%	Not considered	Not considered
Unavailability of generating units due to planned and forced outages	10% through 19% on average, applied uniformly to all ten day types	10% in winter months 30% in summer months 20% in other months	Not considered

As can be seen from the table, Andersson and Bergman adopted an analytical technique different from that employed by Green and Newbery, and from that employed in our analysis. However, there are two elements that render the Green and Newbery analysis different from our analysis: i) the choice of Supply Function Equilibrium (SFE), and ii) the assumption about the price elasticity of demand.

The Choice of SFE

As Klemperer and Meyer show, a supply function satisfying the definition of a Nash Equilibrium is generally not unique. There is a connected set of such supply functions, bounded by a Low SFE and a High SFE.[22] The Low SFE on a given day intersects the production cost curve at the point of maximum anticipated demand for that day, as shown in Figure 3. The High SFE, on the other hand, is a supply schedule based upon the assumption that each firm behaves as a monopolist in the particular hour in which maximum demand is anticipated. All solutions to the Klemperer-Meyer equation lying between the High SFE and the Low SFE constitute Nash Equilibria. The spread between the High SFE and the Low SFE can be considerable, as shown by Green and Newbery in their 1992 paper.

Green and Newbery suggested in their 1992 paper that the High SFE should be used in modeling poolco markets. They justified this assumption by stating that all firms would maximize their profits by adopting this bidding strategy. This statement, while absolutely

22 Mathematically, Klemperer-Meyer's supply function equilibrium satisfies a first order differential equation for quantity as a function of price. To obtain a unique solution of this equation, one has to apply an appropriate boundary condition.

correct, does *not* justify the fact that firms would necessarily choose the High SFE over any other valid Nash Equilibrium in constructing their bid prices. On the contrary, we believe that the use of the High SFE is the least likely bidding strategy that would be adopted by each firm. We explain this observation by considering the following illustrative example in which two competing firms can select one of two possible SFE strategies -- the High SFE or the Low SFE. The possible outcomes from each combination of choices made by the two firms are shown in Table 4. The outcomes for the first firm are shaded, while those for the second firm are left unshaded.

Table 4. Firms' Illustrative Profits Under Alternative SFE Bidding Strategies

Strategy of Firm 2 / Strategy of Firm 1	High SFE	Low SFE
High SFE	\$Maximum \$Maximum	\$High \$Minimum
Low SFE	\$Minimum \$High	\$Low \$Low

While the two strategies that can be adopted (High SFE or Low SFE) both represent Nash Equilibria, it is always more profitable for one firm to employ the *same* strategy as that of its rival. In addition, it is more risky for each firm to adopt the High SFE strategy, especially if the other firm opts for the Low SFE strategy. In this case, the firm bidding in accordance with the High SFE would fare less well than if it had opted for the Low SFE. This table thus illustrates that the High SFE strategy is the riskier of the two bidding strategies for each firm. It is for this reason that we assumed in our analysis that each firm would bid according to the Low SFE in the range.

It is, however, conceivable that over time in a repeated game, firms might employ what is called a "tit-for-tat" pricing strategy, by gradually raising their bid prices from the Low SFE towards the High SFE. As a result, their actual bids would float somewhere between these two limits, and this "tit-for-tat" pricing strategy would result in higher average market prices than those expected with the Low SFE. Consequently, to the extent that firms' profit-maximizing bids lie somewhere between the Low SFE and the High SFE, our analysis understates the extent of market power in the poolco.[23]

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23 It is also worth noting that Wolfram's empirical study of market power in the England and Wales electricity spot market concludes that "... the high average pool prices in Green and Newbery's (1992) simulations have not been realized." (Wolfram, 1995, p. 25). However, consistent with Green and Newbery, Wolfram made her comparison using the High SFE in the range. Although we were unable to perform a detailed statistical analysis of the data used by Wolfram, it is clear that the fit between actual prices and those resulting from the SFE-based model would have been better had Wolfram used the Low SFE rather than the High SFE.

Price Elasticity of Demand

The analytical technique adopted in our study is simplified significantly by assuming zero price elasticity of demand. Newbery and Green, on the other hand, incorporated a non-zero price elasticity of demand into their study by assuming that instantaneous demand for electricity is a declining linear function of price in every hour.

A recent study by Patrick and Wolak (1997) has revealed the significance of price elasticity (and cross-elasticity) of demand in countering the exercise of market power in bid-based power pools. This study revealed many complicated ways in which consumers might respond to volatile electricity prices. A proper model of electricity consumers' behavior should, in fact, be at least as detailed as models of electricity producers' behavior.

Our assumption of zero price elasticity of demand would tend to overstate the extent of market power abuse in a poolco, since consumers, especially industrial firms with curtailable loads, would have some ability to respond to high market prices. However, our initial explorations of non-zero elasticities of in a Nash Equilibrium framework indicate that the market power observed in our analysis could only be offset by very significant price elasticities of demand, somewhere in the region of -1.0.

Qualifications Regarding this Analysis

The effectiveness with which market power may be exercised by generating firms in actual deregulated markets will depend upon several interrelated factors. These include, but are not limited to, the type of market structure that emerges under deregulation (i.e., poolco markets, bilateral markets, or some hybrid of the two), the particular electric system's generation profile, the annual load profile, the ability of consumers to respond to increases in electricity prices, the intra-regional and inter-regional transmission network, the ease with which generating firms can compete in other regional markets, and the ease of entry for new generation.

Our analysis quantifies the magnitude of the price mark-ups resulting from profit-maximizing bidding strategies adopted by firms in a representative poolco market (using Pennsylvania supply and demand data), in the special case with identical firms and zero elasticity of demand. The factors most likely to influence our reported findings are the threat of entry into the poolco market, and the extent to which bilateral markets overlaid on the poolco market may help market entrants and mitigate against price volatility.

These two factors have been addressed by Newbery (1996) in a theoretical analysis of the impact of market entry and contracts on poolco prices. Newbery finds that the threat of market entry can reduce market power abuse in a poolco, and that market entry is facilitated in markets that are tight in capacity, provided new entrants compete in the price-setting part of the supply curve. While we recognize the importance of market entry and contracts in determining poolco prices, we do not explicitly address these two factors in our analysis, primarily because they cannot easily be modeled theoretically and applied to accurate empirical data.

In addition, market entry would not likely be a threat given the assumptions and the nature of the electric system modeled in our analysis. The Pennsylvania electric system that we modeled is *not* capacity-limited; we assume a 20% reserve margin (which in turn reduces the extent of market abuse relative to a situation with less excess capacity.) Thus, it is likely that new market entrants in this system would eventually be gas-fired combustion turbines, required to provide peaking capacity to meet load growth over time. Gas-fired combined cycle units, which tend to operate in baseload and cycling duty cycles, would not likely be able to compete in this poolco market in the short term. This is primarily because the system is overly baseloaded, and thus because of new gas-fired combined cycle units' relatively high variable production costs, it is doubtful whether such units could displace sufficient incumbent generation from the dispatch order (even in a profit-maximizing bidding scenario) to recover sufficient fixed costs and a return on investment.

Conclusions

The analysis presented in this paper provides a first step in characterizing and quantifying electricity pricing behavior by profit-maximizing firms in a pure poolco market with identical firms. Our principal findings are that generating firms can exercise market power in such markets by adopting mutually profit-maximizing, stable bidding strategies, consistent with the Nash Equilibrium, that lead to average prices considerably higher than those expected from production cost bidding.

Our findings have strong policy implications for the deregulation of electricity markets across the U.S., and suggest that current DOJ and FERC guidelines may not be adequate in countering the exercise of market power in bid-based power pools. The analysis of market power in poolco markets should, to the extent possible, be extended to include simulation modeling of the various bidding strategies that could be adopted by generating firms to influence market clearing prices.

Fortunately, there are several market power mitigation options available to electricity regulators and legislators. The divestiture of generation assets, to form a generation market with a larger number of smaller-sized firms (i.e., with a larger effective n), would help to constrain the instantaneous market clearing prices from a poolco that result from profit-maximizing bidding strategies. It is important that divestiture be carried out sensibly, by ensuring that divested units not all be sold to the same firm or be purchased by firms with large market shares, and that particular attention be paid to units of potentially strategic importance in exercising market power. Other options for mitigating market power include changing the bidding rules and payment rules in a poolco, imposing price caps in hours when market power abuse may be problematic, regulating must-run units and units located in load pockets, promoting real-time metering on the consumer side, and promoting contracts to mitigate against volatile and systematically raised prices.

The analysis presented in this paper should be refined, and if possible, generalized to more realistic scenarios with i) firms that have different market shares, as well as different distributions of generating units in their production cost curves; ii) non-zero price elasticities of demand; iii) imperfect information about other firms' supply curves and bids; iv) transmission constraints; and v) different payment rules (i.e., payment price for dispatched units equals each one's bid price). It is also important to study electricity pricing in other proposed models for deregulated generation markets, including purely bilateral markets, as well as hybrids of bilateral and poolco markets, as have been implemented in the England and Wales spot market, and in the Alberta Power Pool.

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Appendix

1. Solution to a Klemperer- Meyer Equation in a Special Case of $D_p = 0$. Derivation of Formula on Figure 1

A Klemperer-Meyer equation in Green- Newbery notation (Green and Newbery, (1992)) with $D_p = 0$ can be re-written in terms of $P(Q)$ as follows:

$$\frac{dP}{dQ} = (n-1)\left[\frac{P}{Q} - \frac{z(Q)}{Q}\right] \qquad (1)$$

where $z(Q)$ is a system-wide marginal cost function, P - market clearing price, Q - system demand

Substitution $P(Q) = R(Q)Q^{n-1}$ yields

$P' = R'Q^{n-1} + (n-1)RQ^{n-2} = (n-1)RQ^{n-2} - (n-1)\frac{z(Q)}{Q}$, therefore

$R' = -(n-1)\frac{z(Q)}{Q^n}$, which results in

$R(Q) = Const - (n-1)\int \frac{z(Q)}{Q^n} dQ$. That in turn gives

$P(Q) = Q^{n-1}\left[Const - (n-1)\int \frac{z(Q)}{Q^n} dQ\right]$.

Assuming that $P(Q^*) = z(Q^*)$ (taking the lowest SFE), we get

$$P(Q) = \left[\frac{z(Q^*)}{Q^{*(n-1)}} + (n-1)\int_Q^{Q^*} \frac{z(x)}{x^n} dx\right] Q^{n-1} \qquad (2)$$

Formula (2) gives a general solution of equation (1) where Q^* is a peak hour demand in a day.

Consider now a step-wise function $z(x)$:

$z(x) = c_i$ if $X_{i-1} \le x < X_i$, where
$X_1 < X_2 < \cdots < X_N$ -- cumulative capacity and c_i is a non-descending sequence of unit variable costs
$X_0 = 0$. Let m be such that $X_{m-1} < Q^* \le X_m$
For $X_{k-1} < Q \le X_k$, one can obtain:

$$\int_Q^{Q^*} \frac{z(x)}{x^n} dx = \frac{1}{n-1}\left\{c_k\left[\frac{1}{Q^{n-1}} - \frac{1}{X_k^{n-1}}\right] + c_{k+1}\left[\frac{1}{X_k^{n-1}} - \frac{1}{X_{k+1}^{n-1}}\right] + \cdots c_m\left[\frac{1}{X_{m-1}^{n-1}} - \frac{1}{Q^{*(n-1)}}\right]\right\}$$

where $z(Q^*) = c_m$

Evaluating the expression in the right hand side in the above formula, and substituting the result into (2), one can see that

$$P(Q) = c_k + \sum_{j=k}^{m-1}\left[c_{j+1} - c_j\right]\left(\frac{Q}{X_j}\right)^{n-1} \tag{3}$$

where $X_{k-1} < Q \le X_k$.

2. Proving that a Solution (3) of a Klemperer- Meyer Equation Represents a Nash Equilibrium in the Game of Poolco

We consider a one-shot game played during a one day period. We assume that m generating units running at full capacity on that day would be sufficient to meet peak demand on that day, $\hat{D}$. In other words, $\hat{D} \le X_m$.

Let $P^*(Q)$ be a solution of equation (1) given by formula (3). As one can see, $P^*(Q)$ is a continuous, monotonically ascending and piece-wise differentiable function of Q identified for all values of Q such that $0 \le Q \le X_m$.

A supply function of each symmetrical firm is equal to $q^*(p)$ which is an inverse function to $P^*(nQ)$. In other words,

$$P^*(nq^*(p)) \equiv p \tag{4}$$

Therefore, $q^*(p)$ is continuous, monotonically ascending and piece-wise differentiable function of p identified for all values of p such that $P^*(0) = c_1 \le p \le P^*(X_m) = c_m$.

For any arbitrary set of supply functions $q_1(p), \ldots, q_n(p)$ of firms $1, 2, \ldots, n$, respectively, we define the market clearing price at demand level D, $(D \le \hat{D})$ as the lowest price at which this demand level could be met. If this demand level could not be met based on those supply functions, we set the market clearing price to zero:

$$P_{MC}(D|q_1,q_2,\ldots,q_n) = \begin{cases} \min[p: q_1(p) + q_2(p)+\ldots+q_n(p) \geq D] \text{ if such } p \text{ exists;} \\ 0, \text{ otherwise} \end{cases} \tag{5}$$

Obviously, if all firms use the same supply function, $q^*(p)$, the market clearing price at demand level D will be equal to $P^*(D)$:

$$P_{MC}(D|q^*,q^*,\ldots,q^*) = \min[p: nq^*(p) \geq D] = P^*(D)$$

With the market clearing price defined by formula (5), an instantaneous profit earned by firm j when system demand equals D could be computed as

$$\pi_j(D|q_1,\ldots,q_{j-1},q_j,q_{j+1},\ldots,q_n) = P_{MC}(D|q_1,\ldots,q_{j-1},q_j,q_{j+1},\ldots,q_n)q_j - C(q_j) \tag{6}$$

where $C(q)$ is a production cost function of each firm.

If all firms use the same supply function, $q^*(p)$, they should earn the same instantaneous profit equal to

$$\pi^*(D) = P^*(D)q^*(P^*(D)) - C[q^*(P^*(D))] \tag{7}$$

Let us now assume that all firms, except firm number j, adhere to the same strategy -- to bid supply function $q^*(p)$. However, the firm number j, applies a different supply strategy, $v(p)$. The following Lemma constitutes that $q^*(p)$ represents a Nash equilibrium strategy

Lemma

$$\forall D \leq \hat{D} \qquad \pi_j(D|q^*,\ldots,q^*,v,q^*,\ldots,q^*) \leq \pi^*(D)$$

Proof

If all n firms use the same strategy, q^*, then $q^*(P^*(D))=D/n$ for any level of demand D not exceeding the peak level. However, if firm number j applies a different strategy, v, two possibilities arise:

1. Firms will serve equal portions of the total demand D, D/n, while market clearing price at that demand level equals p'; p' may deviate from $P^*(D)$.
2. All firms, except firm number j will serve equal loads because they apply identical strategies, however, load served by firm number j will be different. The market clearing price in that case may also deviate from $P^*(D)$

Consider the first possibility. Although one firm applies strategy v, instead of q^*, loads served by each firm are the same as if they all applied strategy q^*. Therefore, costs of all firms would be the same as if they all applied strategy q^*. As a result, the only factor which may change the profit of firm j is the market clearing price. By definition, the market clearing price p' is the lowest price at which system demand could be met given supply functions of all firms. In order for the market clearing price p' to increase above the level of $P^*(D)$ the latter must not allow the dispatcher to meet the demand level D. In other words,

$$(n-1)q^*(P^*(D))+v(P^*(D)) < D$$

However, as we know, $q^*(P^*(D))=D/n$. If p' **is** a market clearing price at a system demand level D, p' must be greater than $P^*(D)$. Since $q^*(p)$ is a monotonically ascending function of p,

$$q^*(p') > q^*(P^*(D)) > D/n$$

which contradicts the assumption that all firms serve identical loads at this price. Thus, in this case, the market clearing price, and the profit of firm j may only decrease.

Consider the second possibility in which firm number j serves load x not equal to D/n. As a result, other firms serve identical loads equal to $(D-x)/(n-1)$.

If $P_{MC}(D,x)$ is a market clearing price of serving total demand D, then

$$q^*[P_{MC}(D,x)] = \frac{D-x}{n-1}$$

That, combined with formula (4), yields that

$$P_{MC}(D,x) = P^*\left(n\frac{D-x}{n-1}\right) \tag{7}$$

Therefore, the profit of firm number j will be equal to

$$\pi_j(x) = xP^*\left(n\frac{D-x}{n-1}\right) - C(x) \tag{8}$$

where $0 \le x \le D$

Let us show now that the profit of firm j as a function of x reaches its global maximum at $x = D/n$. That, in fact, means that the profit reaches its maximum at $v = q^*$ and proves the lemma.

We will show this in three steps:

1. Show that $\pi_j(x)$ is a continuous piece-wise differentiable function

2. Show that $\pi'_j\left(\frac{D}{n}\right)=0$

3. Show that $\pi'_j(x)>0$ if $x<\frac{D}{n}$ and $\pi'_j(x)<0$ if $x>\frac{D}{n}$ for all values of x for which the derivative exists.

Obviously, these three conditions guarantee that $x = D/n$ is a global maximum of the profit function of firm j.

Step 1. This follows simply from the definition of the market clearing price function P^* and cost function C.

Step 2. Differentiating formula (8) yields:

$$\frac{d\pi_j}{dx}=P^*\left(n\frac{D-x}{n-1}\right)-x\frac{n}{n-1}P^{*'}\left(n\frac{D-x}{n-1}\right)-C'(x) \tag{9}$$

which at $x = D/n$ gives

$$\left.\frac{d\pi_j}{dx}\right|_{x=\frac{D}{n}}=P^*(D)-\frac{D}{n-1}P^{*'}(D)-C'\left(\frac{D}{n}\right)=P^*(D)-\frac{D}{n-1}P^{*'}(D)-z(D)\equiv 0$$

The identity in the above sequence of equations is a direct result of the Klemperer-Meyer equation (1) which function $P^*(D)$ must satisfy by definition.

Step 3.

Let $y=\frac{n}{n-1}(D-x)$; substituting y into (9) and remembering that $C'(x)=z(nx)$ yields

$$\frac{d\pi_j}{dx}=P^*(y)-x\frac{n}{n-1}P^{*'}(y)-z(nx)$$

which after replacing $P^{*'}(y)$ with the right hand side of equation (1) results in

$$\frac{d\pi_j}{dx}=P^*(y)\left[1-\frac{nx}{y}\right]+\frac{nx}{y}z(y)-z(nx)$$

As follows from formula (3), $P^*(y)$ could be represented in the following form:

$$P^*(y)=z(y)+\Delta(y)$$

where $\Delta(y)>0$

Indeed, it is easy to see from (3) that the market clearing price is always greater than the marginal cost. This substitution gives

$$\frac{d\pi_j}{dx} = \left[z(y)+\Delta(y)\right]\left[1-\frac{nx}{y}\right] + \frac{nx}{y}z(y) - z(nx) = z(y) - z(nx) + \Delta(y)\left[1-\frac{nx}{y}\right] \qquad (10)$$

Analysis of formula (10) indicates that

$$\frac{d\pi_j}{dx} > 0 \text{ if } y > nx \iff x < \frac{D}{n}$$

$$\frac{d\pi_j}{dx} < 0 \text{ if } y < nx \iff x > \frac{D}{n}$$

which completes the analysis of the second case and proves the Lemma.

Exhibit 4 OFFICE O: 98 JUN 15 FEDERAL REGULATORY CO.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Concerning the Commission's Policy On the Use of Computer Models in Merger Analysis	)))	**Docket No. PL98-6-000**

**COMMENTS OF THE
NATIONAL ASSOCIATION OF STATE UTILITY
CONSUMER ADVOCATES**

Introduction

On April 16, 1998, the Commission instituted an Inquiry Concerning the Commission's Policy On the Use of Computer Models in Merger Analysis. The Commission seeks to address whether and how computer models should be used in the analysis of mergers. In particular, the Commission asks whether computer models can play a useful role in the horizontal screen analysis described in the Appendix A guidelines of the Merger Policy Statement. [1]

A properly structured computer model can account for important physical and economic effects of mergers, and therefore assist horizontal screen analyses. Also, the model can help identify those suppliers in the geographic market capable of competing with the merged company.

Much thinking remains before settling on specific methods for modeling the effects of mergers on markets. Our comments seek to assist this thinking by making three main points. First, we explain that even the most accurate "Appendix A" analysis will fail to capture the effects of strategic corporate behavior; yet, this behavior is the essence of market power. Second, we

[1] Order No. 592, FERC Stats. & Regs. para. 31,044 (1996), order on reconsideration, 78 FERC para. 61,321 (1997).

explain that an assessment of market power does not require, and can be hampered, by fixed definitions of geographic boundaries. Third, we argue that efforts to define product markets should not impede investigation into strategic behavior.

The National Association of State Utility Consumer Advocates (NASUCA) is an organization comprised of official statutory consumer representative offices from forty states and the District of Columbia. The members of NASUCA represent utility ratepayers in the courts and before state and federal regulatory agencies that have jurisdiction over public utility companies. NASUCA was founded in 1979 to assist its member agencies in representing the interest of consumers at the state and national levels.

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I. A Model Designed Solely to Conduct an "Appendix A" Analysis Will Fail to Capture Strategic Corporate Behavior

A. The Appendix A Analysis Focuses on Market Concentration, Not Market Power

Pre-merger review should identify the ability to exercise market power and eliminate it. The Appendix A analysis, by its own admission, does not do this. The Appendix A analysis identifies market concentration by defining product and geographic markets, and then determining the changes in market shares within those markets caused by the merger. The Appendix A analysis does not, however, establish a causal link between market concentration and market power. Appendix A instead draws inferences about market power from data on market concentration, by applying the HHI index.

Concentration measures alone do not necessarily reveal the potential for unilateral action or coordinated interaction to create and maintain market power. Even where a concentration index like the HHI is relatively low, vertical integration can allow unilateral exercise of market power. Similarly, even with relatively low concentration, coordinated interaction can be possible where the market has certain characteristics, such as, product homogeneity, relatively inelastic demand, small and unsophisticated buyers, comparable cost structures by sellers, a history of coordination or collusion, frequent and relatively small transactions, excess capacity, relatively stable technology, availability of information about competitors, standardization of product, limited scope or dimensions of product competition (e.g., price only).[2] The Commission's discussion of models does not address this risk.

Therefore, overreliance on models designed to produce inputs for existing indices of market power, particularly indices which stress concentration measures, will miss market power arising from strategic corporate behavior. The HHI index is not behavioral evidence, and is not

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[2] See, e.g., FTC v. Elders Grain, Inc., 869 F.2d 901 (upholding findings of likely anti-trust violations and potential collusion where grain market's characteristics include homogeneity of product, history of collusion and excess capacity (7th Cir. 1989) ; Hospital Corp. Of Am. v. FTC, 807 F.2d 1381, 1389 (7th Cir. 1986), cert. den'd., 481 U.S. 1038 (1987) (upholding Commission's finding of anti-trust violations where market for hospital services displays factors such as history of collusion, unsophisticated buyers and inelastic demand for service).

based on empirical electric industry evidence. It is a rough screening concept that merely suggests that particular levels of concentration might facilitate or enable market power. An analysis that relies only on this screening and not on actual measures of behavior, or on facts from which one can infer or predict actual behavior, cannot reliably detect and protect against market power. This is an important gap which could be narrowed with the use of simulation modeling. However, we caution that we are aware of no model which will reliably close the gap between individual firm strategic behavior (e.g., strategic bidding and capacity withholding) and multiple firm strategic behavior (e.g., collusion, and conscious parallelism).

B. Market Power Stems Not Merely From Concentration, But from Strategic Bidding and Capacity Withholding

The notion that market power stems not merely from structural concentration, but from strategic activities intended to increase prices, flows logically from the definition of market power and its indicators. Market power is the ability of a particular seller, or group of sellers, to influence significantly the price of a product to their advantage over a sustained period of time. The indicator of market power, therefore, is a sustained margin of actual price for electric generation over the perfectly competitive price. Below we (1) explain several means by which power generation companies could exercise market power; and (2) analyze factors influencing their ability to exercise market power.

We then ask, in Part I.C, whether market concentration is either the best or a sufficient indicator of market power for use as the Commission's safe harbor screen as described in Appendix A. If not, other factors need to be taken into consideration along with market concentration, even in the initial stages of the analysis of mergers. Moreover, even if market concentration was the only factor which needed to be considered, it is important to determine the appropriate concentration threshold which should be indicative of the market power threat in a particular merger. Appendix A alone provides no theoretical or practical means for establishing such a threshold.

1. Key Methods by Which Generation Owners Exercise Market Power

a. Overview

The methods by which generation owners exercise market power may largely depend upon a particular structure of the competitive market for power. There is a range of alternative structures for such markets in place – California, England and Wales, Australia, New Zealand, Alberta (Canada), Columbia, and Chile. Other models have been proposed, such as New England Power Pool (NEPOOL), Pennsylvania-New Jersey-Maryland (PJM) system, and New York Power Pool (NYPP). These existing and proposed market structures have been studied by analysts around the world. There is a substantial and growing literature which examines the types and implication of strategic behavior of generation owners under the different market structures that already exist or are proposed. This literature, using several methodological approaches, has identified different types of strategic behavior leading toward the exercise of market power.[3]

Despite differences among their approaches, many authors have identified at least two general strategic mechanisms by which generation owners could exercise market power, known as

[3] The first approach is based on laboratory experiments that investigate the interactions for market structure and behavior of market participants in dynamic settings. [2,26,28,29] [Bracketed numbers refer to the References section at the back of this document.] The second approach is based on agent-based modeling or on a combination of agent-based modeling and laboratory experiments. [18, 24, 26] The third approach is based on game-theoretical analysis of possible strategic behavior of generation owners in various types of power markets under different market structures and modeling assumptions. [1, 3, 5-20, 27, 31, 33-35]. As suggested by Hobbs et al. [14], these studies could be classified in terms of simulated market mechanisms, representation of electric networks, and types of interactions between rival power producers.

strategic bidding and capacity withholding. We discuss each in turn.

b. Strategic Bidding

Strategic bidding, in the absence of transmission congestion constraints, involves generation owners bidding prices above the production costs of their generating units, with the intent of forcing up the market clearing price.[4] This strategy benefits generation owners especially in poolco-type market structures, where the benefit of bidding up the market clearing price can outweigh the risk of being undercut by a competitor. However, strategic bidding is also likely to be a factor in bilateral contract markets, where fixed as well as variable costs will have to be collected as part of the market clearing price.

Strategic bidding, in the presence of transmission constraints, is more complicated. It allows generating firms to increase bidding prices above competitive levels, and strategically congest certain transmission lines to their advantage.[5]

c. Capacity Withholding

Capacity withholding involves firms removing some of their capacity from the bidding process or from the market for a certain period of time, in an effort to cause more expensive units higher up the systemwide supply curve to set the market clearing price.[6] As is the case with strategic bidding, capacity withholding strives to increase the market clearing price. Firms that consider this strategy must assess the likelihood that the foregone revenues from not having some

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[4] See, e.g., 4, 5, 10-12, 21-23, 27, 30, 31.

[5] Simple examples of this types of strategic bidding are reported by Oren [20] and by Younes and Ilic [33-34]..

[6] See, e.g., [5, 23, 30].

of their inframarginal capacity dispatched are more than offset by the additional revenues paid to their capacity that is dispatched, in each time interval.

Strategic bidding and capacity withholding represent real market power threats. Empirical studies of the England and Wales competitive wholesale market indicate that actual spot prices have substantially deviated from the competitive baseline (i.e., short-run marginal costs), and that generation owners in England and Wales engage in strategic bidding and capacity withholding. [7] The experience in England and Wales demonstrates that such strategic behavior can result in the severe exercise of market power, and should be considered in merger review.

2. Factors Relevant to Exercise of Strategic Bidding or Capacity Withholding

This literature has identified several factors which may have a significant influence on a firm's ability to exercise market power, including:

1. Wholesale market structure
2. Supply-side bidding rules
3. Demand-side bidding rules
4. Power exchange rules
5. Markets for installed capacity and for ancillary services
6. Payment rules
7. Structure and duration of the standard offer and/or default service
8. Maturity of the contractual market (either contracts for differences or bilateral contracts)
9. Mix of generation capacities serving the market

[7] See Wolfram [32]; Wolak and Patric [30].

10. Load shape and ability of consumers to respond to changes in prices

11. Transfer capability and topology of the transmission network, including the existence of load pockets

12. Concentration of ownership

In short, the literature indicates that market concentration of ownership is not the only factor influencing the potential for the exercise of market power. Given this long list of contributing factors, there is no reason to presume that in the electric industry, there is a specific market concentration threshold below which regulatory concern should disappear, regardless of the presence of other factors. Yet, the existence of such a threshold is assumed by FERC in its use of the HHI-based safe harbor test.

C. Market Rules, and not Merely Market Concentration, Are Critical to Generation Owners' Ability to Bid Strategically and Withhold Capacity

To the extent Appendix A focuses only on concentration, it is insufficient. To the extent the Staff's modeling efforts focus similarly on concentration only, it, too, is insufficient.

For example, an Appendix A-type analysis does not address market rules for supplier bidding or customer bidding, even though such rules, as demonstrated by the England and Wales studies, can allow market power to flourish. In fact, consider that two analytical elements at the heart of the Appendix A-type of analysis -- computation of delivered prices and market shares -- will depend on the trading rules of the applicable power market.

Computation of delivered prices: In general, the delivered price will reflect the variable cost and the fixed cost of generation and transmission. The variable cost of power delivered to each destination area (or to each load node) would depend largely on how the cost of power generated at each generation node on the network will be allocated between load nodes of that network. (This variable cost may also depend on the allocation rule for transmission use and losses.) The fixed cost of power delivered to a load node would depend on the allocation of the capital costs for both generation and transmission capacity. Development of such allocation rules is not simple even in the case of 'point-to-point' transactions. It becomes even more complicated when system or network transactions at market prices are considered.

The specification of these allocation rules does not follow necessarily from a computer model incorporating assumptions utilizing least dispatch for generation and transmission costs when power plants are dispatched on a system-wide basis into a given model. The least cost dispatch provides the optimal level of generation at each generation node, the optimal level of power flow through each transmission link, and ensures that the total power supply meets total demand at each local node. Given that information, there can be an infinite number of ways to allocate generation usage and capacities, and transmission usage, losses and capacities and associated costs, among loads. Accurate power flow models will provide information about the least-cost dispatch given specific cost allocation rules, but will not identify or create the "right" cost allocation rules. However, a power flow model may be designed in a number of ways based on the allocation rules in place. Using different allocation rules will result in a different allocation of variable and fixed costs between generation nodes. Different allocations will result in different average prices at each load node and produce different results for the delivered price test.

Market shares: Since the choice of allocation rules would influence the price of power in each destination area, the choice must have an impact on (a) the determination of the relevant geographic market, (b) the computation of the quantity of power delivered into each destination area by each generation owner (or marketer), (c) the market share of each supplier in each market and (d) the market concentration in the form of the HHI. In short, the entire assessment of market power potential in any Appendix A-type analysis inevitably depends largely on the exchange rules relating to the allocation of variable cost and fixed cost. However, these rules remain beyond the scope of Staff's current discussion.

The Staff paper does recognize the need to allocate generation and transmission capacities and usage among power destination areas or load nodes. However, the paper does not address the inevitable ambiguity of this allocation. The paper thus notes the role played by Power Transfer Distribution Factors (PTDFs). PTDFs could be thought of as aggregated coefficients allocating power generated in a geographic area among all destination areas. According to the Staff, these factors could either be used as exogenous information or be derived endogenously using the power flow model. Using these factors as exogenous data simulated by NERC is highly problematic, because NERC's estimates are based on the existing system operations and existing power exchange rules. Endogenous derivation of these factors using the power flow model is more relevant to the task. However, as we stated earlier, creating allocation rules is a policy decision which is external to any optimization or power flow model. Therefore, one has to rely on the appropriate power flow model that reflects power exchange rules expected to be in effect in the restructured environment.

In summary, the model proposed by the Staff paper cannot carry out a direct analysis of market power because the only possible outcome of market simulation with the proposed model is a depiction of market concentration based on the least cost dispatch of generation and the system-wide assignment of transmission costs, which precludes the existence of market power by definition. This type of simulation of the least cost outcome is very important for developing a competitive baseline scenario against which other scenarios embodying various elements of strategic behavior or market power can be compared. However, the proposed model does not itself generate such strategic behavior scenarios. The proposed model thus is neither the best, nor a sufficient, indicator of market power.

II. Assessment of Market Power Does not Require Fixed Definitions of Geographic Boundaries

Modeling market power does not require a fixed definition of geographic boundaries. The Staff paper appears to assume that a main purpose of a computer model is to help define the geographic range of generating units that will serve any particular utility's load.

In fact, this geographic region can be defined quite precisely for each hour of the year, using power flow models. These models will provide a unique way of tracking the cost of power from generators to load. The geographic boundaries will in fact change from hour to hour. It is, however, not necessary to determine fixed geographical boundaries within which the generating units serve a particular utility's load in order to quantify market power. The set of all generating units that serve a particular utility's load in an hour define the appropriate "geographic market" for that hour.

Moreover, because the models will track the power from each generating unit to each utility's (or load serving entity's) load, one knows the market concentration for each generation owner serving each load in each hour. Thus, the market concentration results can be aggregated over any subset of hours in the year. For example, these results for market concentrations could be aggregated separately for peak, shoulder, and offpeak time periods. Then, HHI computations for these separate time periods could be performed.

III. Efforts to Define Product Markets Should Not Impede Investigation Into Strategic Behavior

To assess the potential for strategic behavior more reliably, FERC needs to consider the interactive effects between different portions of the supply curve (different sets of generating units), and different times of the day and year. In contrast, certain electricity products tend to represent only certain portions of the supply curve, e.g., peaking, cycling, or baseload portions. Other products are defined as short versus long term contracts.

The interactive effects include those between owners of generating units at different points in the supply curve at different times of the day or year. For example, the margins that can be made on baseload plants will depend on the prices for which peaking power is sold in certain market structures, since the price for peaking power will set the price for all power in particular hours. Thus, an appropriate approach to assessing market power and prices for a particular market structure must simultaneously take these complex factors and interactions into account. Properly used, computer models can identify opportunities for a single owner of various generating units to exercise market power by strategically increasing the market clearing price, and can assist in identifying the potential for coordinated or parallel efforts by multiple owners to achieve the same end.

For computer models to provide these results, however, they must accurately identify the real geographical markets in which producers and consumers interact, and the real products they buy and sell. The substitutability of various power supplies for each other, and the economic incentives to do so faced by owners of those supplies, is a key part of determining the real products and their prices, and must be part of any computer modeling the Commission uses to identify market power.

IV. Conclusions: The Limits of Models

Efforts to use computer models can assist the analysis of market power, whether in the context of mergers or in other contexts, such as requests to charge "market-based pricing." However, certain obvious cautions should accompany any decision by the Commission or its staff in selecting a model.

1. No single model will work for all parties and all proceedings. As noted above, an important determinant of market power will be market rules, including bidding and cost allocation rules, which may vary across contractual relationships. Models will have to vary accordingly.

2. The Commission should not use computer models as excuses to expedite merger approvals. More specifically, the Commission should not rely solely on models as screening devices for determining which mergers require more scrutiny or for expediting merger approvals. As noted above, even mergers producing HHIs which satisfy traditional thresholds can have anticompetitive effects, depending on a host of other factors, including the ease of coordinated interaction, bidding rules, and other industry characteristics. Model results should not become a procedural mechanism for excluding arguments and evidence about past and present anticompetitive practices, or about interactions between the modeled markets and other markets (such as the interactions between a modeled generation market and evolving retail markets in aggregation and metering). In short, no rule of thumb will be universally applicable in all cases or circumstances. Only those mergers which do not increase properly calculated concentration indices and which create no opportunity for anticompetitive behavior through either unilateral or

coordinated interaction should be approved without market power mitigation conditions being imposed. Computer models can identify mergers in which these behavioral and structural problems may take place, but cannot reliably identify mergers in which they will <u>not</u> take place. Thus, no safe harbors should be relied on by FERC in assessing mergers.

3. Modeling should not be confused with mitigation. Modeling can help pinpoint appropriate remedies, but the design of those remedies requires separate work, the results of which should be tested and monitored over time.

WHEREFORE, for the foregoing reasons, NASUCA respectfully requests that the Commission take these comments into account in determining the role of computer modeling in the analysis of mergers.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day, June 12, 1998, served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by first class mail or equivalent service.

L Frimerman

Larry Frimerman

Exhibit 5

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

September 14, 1999

OFFICE OF THE COMMISSIONER

Richard A. Rosen, Ph.D.
Executive Vice President
Tellus Institute
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Boston, MA 02116-3411

Dear Dr. Rosen:

Thank you for sending me your paper on market power. I agree with your fundamental premise -- that HHI's do not capture the dynamic nature of power markets. Market simulation models, properly structured, would be more accurate and useful. You may know that FERC proposed such a model in our NOPR on filing requirements for mergers. RM98-4-000. Any comments you have on our proposed model should be raised in that proceeding.

Thank you for your thoughtful comments.

Sincerely,

William L. Massey
Commissioner