BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE MARKET	)	
POWER STUDY OF OKLAHOMA GAS	)	**DOCKET No. 00-326-U**
AND ELECTRIC COMPANY	)	

Direct Testimony

of

Joe D. Pace

on behalf of

Oklahoma Gas and Electric Company

November 30, 2000

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DIRECT TESTIMONY
Of
Joe D. Pace

Q. Please state your name and business address.

A. My name is Joe D. Pace. My business address is Suite 700, 1600 M Street, NW, Washington, DC 20036.

Q. By whom are you employed and in what capacity?

A. I am an economist and director of LECG, LLC, which is a firm offering economic, strategic and accounting consulting services.

Q. Please summarize your education and professional qualifications.

A. I received my bachelor's degree from the College of William and Mary in 1966 and my master's and doctoral degrees from the University of Michigan in 1967 and 1970, respectively. I specialized in the areas of industrial organization and public utility economics. I have over 30 years experience providing consulting services in regulated and unregulated industries. On a number of previous occasions, I have submitted affidavits or presented testimony before the Federal Energy Regulatory Commission, state regulatory commissions, state and federal courts, the United States Senate, the United States House of Representatives, and the High Court of New Zealand. A summary of my professional background and qualifications is attached as Exhibit JDP-1.

Q. What is the purpose of your testimony in this proceeding?

A. LECG was retained by Oklahoma Gas & Electric Company ("OG&E") to address market power issues expected to arise in connection with the restructuring of the electric industry in Arkansas (and potentially Oklahoma). As part of that effort, we provided substantial input to OG&E's comments on the Market Power Minimum Filing Requirements ("MPMFRs") promulgated by the Arkansas Public Service Commission, as well as its comments on the Standard Service Package rules. We also prepared the report, "OG&E Market Power Study for Arkansas." The purpose of my testimony is to introduce and sponsor this report.

The report found in Exhibit JDP-2 is designed to provide a comprehensive response to the MPMFRs. Accordingly, the report addresses potential horizontal and vertical market power problems at both the wholesale and retail level. Exhibit JDP-2 was jointly authored by myself and Mr. Cliff Hamal. I have overall responsibility for the design of the study and the conclusions reached. Mr. Hamal is responsible for developing the data used in the wholesale market analysis, and for the modeling used to produce the required market shares, and HHIs. Therefore, I am sponsoring the main body of the report and Mr. Hamal is sponsoring Appendix 1 and Appendix 2 of the report.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT OF JOE D. PACE

City of Washington)
)
District of Columbia) ss:

I, the undersigned, Joe D. Pace, being duly sworn, depose and say that the contents of the foregoing Testimony on behalf of Oklahoma Gas & Electric, Inc. are true, correct, accurate and complete to the best of my knowledge, information, and belief.

/s/ Joe D. Pace
Joe D. Pace

Subscribed and sworn to before me this 29th day of November, 2000.

Charlotte S Brown
Notary Public:

April 30, 2003
My commission expires:

LECG

ECONOMICS • FINANCE

Exhibit JDP-1

JOE D. PACE

EDUCATION

B.A. (with honors), Economics, COLLEGE OF WILLIAM AND MARY, 1966.
Phi Beta Kappa

Ph.D., M.A., Economics, UNIVERSITY OF MICHIGAN, 1967, 1970.

Specializing in industrial organization, public utility economics and labor economics.

PRESENT POSITION

LECG, LLC (and predecessor companies), 1995 – present.
Director

PROFESSIONAL EXPERIENCE

PUTNAM, HAYES & BARTLETT, INC., 1990 - 1995.
Managing Director

GEORGE MASON UNIVERSITY, Summer 1994.
Adjunct Professor

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
Executive Vice President, 1988 - 1990.
Senior Vice President, 1979 - 1988.
Vice President, 1973 - 1979.
Senior Consultant, 1972 - 1973.
Senior Economist, 1970 - 1972.

WASHTENAW COUNTY PLANNING COMMISSION, 1969.
Assistant Planner, Washtenaw County Planning Commission

UNIVERSITY OF MICHIGAN, 1968 - 1969.
Instructor

PRIOR TESTIMONY, AFFIDAVITS AND EXPERT REPORTS

Testimony on behalf of Pacific Gas & Electric Company, before the California Public Utilities Commission, Application No. 99-09-053, August 11, 2000. Subject: Hydroelectric Resources and market power.

Expert Report on behalf of Hewlett-Packard Company, January 13, 2000. Subject: Class certification issues in suit brought by purchasers of HP replacement inkjet cartridges.

Testimony on behalf of Pacific Gas & Electric Company, December 20, 1999. Subject: Appropriate payments to generators operating under reliability must-run contracts. Rebuttal Testimony on same subjects February 29, 2000.

Expert Report on behalf of Powerex, November 26, 1999. Prepared Direct Testimony on February 4, 2000. Subject: open access transmission policies and market based rate authority.

Expert Report on behalf of Florida Power & Light Company, August 26, 1999. Subject: generation and transmission service market definitions, essential facility and monopoly leveraging, damages.

Testimony on behalf of Hewlett-Packard Company, June 3, 1999 and June 25, 1999. Subject: calculation of patent, trademark infringement/false advertising and antitrust damages. Expert Reports on same topics September 4, 1998, December 14, 1998, January 29, 1999 and April 30, 1999. [Sealed under protective order of the court.]

Affidavit on behalf of EME Homer City, L.P. before the United States Federal Energy Regulatory Commission, November 23, 1998, Docket No. ER98-___-000. Subject: Application for market-based rates and examination of whether EME can be expected to have market power in the wholesale electricity markets in the Pennsylvania-New Jersey-Maryland interconnection ("PJM") and New York Power Pool ("NYPP") areas.

Expert Report on behalf of Honeywell, Inc., before the United States District Court of Los Angeles, in the matter of Litton Systems, Inc. v. Honeywell, Inc., August 3, 1998. Subject: Antitrust damage claims. [Sealed under protective order of the court.]

Testimony on behalf of Pacific Gas & Electric Company before the Public Utilities Commission of the State of California, July 14 and August 28, 1998. Subject: Assessing potential market power in Northern California natural gas markets and the need for industry restructuring.

Testimony on behalf of Central Maine Power Company, The Union Water-Power Company, Cumberland Securities Corporation, Central Securities Corporation, FPL Energy Maine, Inc., et.al. before the Federal Energy Regulatory Commission, Docket No. ER98-, June 26, 1998. Subject: Analysis of the competitive effects of the proposed acquisition by FPL Energy Maine of Central Maine Power Company's non-nuclear, non-purchased power generation facilities.

Affidavit on behalf of MidAmerican Energy Holdings Company before the United States District Court for the Southern District of Iowa Central Division, Case No. 4-97-CV-80782, May 7, 1998. Subject: Scope of state regulation of the electric utility business in Iowa and elsewhere.

Testimony on behalf of New England Power Company before the New Hampshire Public Utilities Commission, Docket No. DE 97-251, March 18, 1998. Subject: Sale of generation assets to USGen New England, Inc.

Testimony on behalf of Central Maine Power Company before the State of Maine Public Utilities Commission, Docket No. 98-058, February 20, 1998. Subject: Analysis of the competitive effects of the CMP/NEHI transaction.

Affidavits on behalf of New England Power Company, The Narragansett Electric Company, *All*Energy Marketing Company, L.L.C., and USGen New England, Inc. before the Federal Energy Regulatory Commission, Docket Nos. EC98-1 and ER98-6, December 22, 1997; November 4, 1997; and October 1, 1997. Subject: Analysis of the competitive implications of the USGenNE/NEP and USGenNE/TCPL transactions.

Affidavit on behalf of Ontario Hydro before the United States Court of Appeals for the Second Circuit, No. 97-4136, June 30, 1997. Subject: Prospective Effects of Denial of Open Access Transmission to US Electricity Markets.

Expert Report on behalf of Public Service Electric and Gas Company, before the United States District Court for the Eastern District of Pennsylvania, Civil Action No. 96-CV-1705, March 28, 1997. Subject: Alleged damage resulting from nuclear plant outage.

Affidavit on behalf of NorAm Energy Services, Inc. before the Federal Energy Regulatory Commission, Docket No. EC97-24, March 26, 1997. Subject: Competitive effects of proposed gas and electric utility merger.

Affidavit on behalf of PG&E Corporation and Valero Energy Corporation before the Federal Energy Regulatory Commission, Docket No. EC97-22, March 20, 1997. Subject: Competitive effects of proposed gas and electric utility merger.

Expert Report on behalf of Honeywell, Inc., before the United States District Court for the Central District of California, March 17, 1997. Subject: Patent damages. [Sealed under protective order of the court.]

Testimony on behalf of Lone Star Gas Company and Lone Star Pipeline Company before the Railroad Commission of Texas, Gas Utilities Docket No. 8664, dated January 23, 1997. Subject: Competitive effects of proposed gas and electric utility merger.

Affidavit on behalf of NorAm Energy Services, Inc., before the Federal Energy Regulatory Commission, Docket No. ER-94-1247-001, dated September 27, 1996. Subject: Application for market-based rates.

Affidavit on behalf of Cincinnati Gas & Electric Co. and PSI Energy, Inc. before the Federal Energy Regulatory Commission, July 15, 1996. Subject: Market-based rates.

Affidavit on behalf of UGI Utilities, Inc., before the Federal Energy Regulatory Commission, July 16, 1996. Subject: Market-based rates.

Affidavit on behalf of Pacific Gas & Electric Co. before the Federal Energy Regulatory Commission, Docket No. ER96-1663-000, July 19, 1996, March 27, 1997, and August 14, 1997. Subject: Market power in restructured energy markets.

Testimony (July 22, 1996) and Affidavit (June 26, 1996) on behalf of Houston Lighting & Power Co. Subject: Whether a proposed cogeneration partnership arrangement is effectively a retail sale of electricity.

Testimony on behalf of Baltimore Gas & Electric and Potomac Electric Power Company, before the Federal Energy Regulatory Commission, Docket No. EC96-10-000, January 5, 1996, August 26, 1996, and October 15, 1996. Rebuttal Testimony on behalf of Baltimore Gas & Electric Company and Potomac Electric Power Company, before the Public Service Commission of Maryland, Case No. 8725, September 30, 1996 and November 14, 1996. Rebuttal testimony on behalf of Baltimore Gas & Electric Company and Potomac Electric Power Company before the Public Service Commission of the District of Columbia, Formal Case No. 951, October 28, 1996 and February 14, 1997.

Affidavit on behalf of PECO Energy, before the Federal Energy Regulatory Commission, December 18, 1995. Subject: Request for market-based rates.

Testimony and affidavit on behalf of Mercury Energy Power, before the High Court of New Zealand, Auckland Registry, September 29 and November 1-2, 1995. Subject: Competitive effects of proposed merger.

Expert Report on behalf of Honeywell, Inc., before the United States District Court for the Central District of California, Case No. CV-90-4823, in Litton Systems, Inc. v. Honeywell, Inc., September 1, 1995; trial testimony January 19, 1996. Subject: Antitrust damages, inertial navigation systems. [Sealed under protective order of the court.]

Testimony of behalf of WEPCo Power Company, Northern States Power Co. (Minnesota), Northern States Power Company (Wisconsin), and Cenergy, Inc. before the Federal Energy Regulatory Commission, Docket No. ER95-1357-000, ER95-1358-000, July 6, 1995, March 4, 1996, March 15, 1996, May 28, 1996 and May 31, 1996. Rebuttal Testimony before the Public Service Commission of Wisconsin concerning the Application of Wisconsin Electric Power Company, Northern States Power Company and Northern States Power Company-Wisconsin for Approval of a Series of Transactions by Which Northern States Power Company Becomes a Subsidiary of Wisconsin Energy Corporation, and Wisconsin Energy Corporation is Renamed Primergy Corporation. Docket Nos. 6630-UM-101, October 23, 1996. Subject: Competitive effects of proposed merger.

Testimony on behalf of Central Maine Power, before the Maine Public Utilities Commission, March 27, 1995. Subject: Recovery of stranded cost.

Testimony on behalf of Entergy Services, Inc., before the Federal Energy Regulatory Commission, Docket No. ER95-112-000, March 24 and June 1, 1995. Subject: Transmission comparability and market power analysis.

Testimony on behalf of Pacific Gas & Electric Company, before the State of California, San Francisco Superior Court, Power Producers Dispute Cases (Judicial Council Coordination Proceeding No. 2654; Contra Costa Superior Court No. C90-05398; San Francisco Superior Court No. 929-870), May 26 & 27, 1994. Subject: Utility incentives for dealing with QFs, the implementation of PURPA.

Affidavit on behalf of Kansas City Power & Light Company, before the Federal Energy Regulatory Commission, March 11, 1994. Subject: Open access transmission tariff and request for market-based rates.

Testimony on behalf of Pennsylvania Power and Light Company, before the Maryland Public Service Commission, Case No. 8583, January 12, 1994. Subject: Market based pricing, stranded investment, transmission issues.

Affidavit on behalf of PSI Energy, Inc., before the Federal Energy Regulatory Commission, December 28, 1993. Subject: Updated market study.

Testimony on behalf of Southern California Edison Company, before the California Public Utilities Commission, Docket Nos. I.91-10-029, R.91-10-028 and U338-E, October 23, 1991 and August 3, 1992, November 1993 and July 1994. Subject: Competitive effects of proposed electric vehicle programs.

Expert Report on behalf of South Central Bell, before the United States District Court for the Eastern District of Tennessee, Docket No. CIV-2-92-207, in the Matter of Stinnett, et al. v. BellSouth Telecommunications, Inc., November 1, 1993. Subject: Inside wire maintenance plans.

Affidavit on behalf of Public Service of Indiana, before the Federal Energy Regulatory Commission, Docket No. ER93-706-000, July 9, 1993. Subject: Pricing of parallel power flows.

Testimony on behalf of Consumers Power Company, before the Michigan Public Service Commission, Case Nos. U10143 and U10176, March 1, 1993. Subject: Economic and regulatory policy issues concerning retail wheeling.

Testimony on behalf of Pacific Gas & Electric Company, before the Federal Energy Regulatory Commission, Docket Nos. ER92-595-000, ER92-596-000, and ER92-626-000, February 9, 1993. Subject: Alleged anti-competitive provisions of transmission rate schedules.

Testimony on behalf of Cincinnati Gas & Electric Company and PSI Energy, Inc., before the Federal Energy Regulatory Commission, Docket No. EC93-6-000, December 22, 1992. Subject: Competitive effects of proposed merger.

Testimony on behalf of Delmarva Power Company, before the Federal Energy Regulatory Commission, Docket No. ER93-96-000, October 29, 1992; Docket Nos. ER92-236-000 and EL92-13-000, December 22, 1992; and Docket Nos. ER93-96-000 and EL93-11-000, August 25, 1993. Subject: Wholesale rate design, notice provisions.

Testimony on behalf of Toyota Motor Sales, USA, before the Superior Court of California, Case No. 709470, July 17, 1992. Subject: Nonprice vertical restraints.

Testimony on behalf of Entergy Services, Inc. and Gulf States Utilities, before the Federal Energy Regulatory Commission, Docket No. EC92-21-000 and ER92-806-000, August 28, 1992. Subject: Competitive effects of proposed merger.

Affidavit on behalf of Midland Cogeneration Venture Limited Partnership, before the Federal Energy Regulatory Commission, Docket Nos. RP89-186-000 and RP91-143-000, December 2, 1991. Subject: Pricing of natural gas pipeline expansion service.

Testimony on behalf of Loctite Corporation, before the Superior Court of Massachusetts, In the Matter of Van Cort Instruments, Inc. v. Loctite Corporation, Civil Action No. H-89-303, April 23, 1991. Subject: Product liability damages.

Testimony on behalf of Delmarva Power & Light Company, before the Superior Court of Delmarva, in and for New Castle County, In the Matter of Newark v. Delmarva Power & Light Company, Civil Action No. 83C-JL-10, April 17, 1991. "Newark Condemnation Report," March 1991. Subject: Proper determination of condemnation value.

Affidavit on behalf of Northeast Utilities Service Company, before the Federal Energy Regulatory Commission, Docket Nos. ER90-374-000, ER90-373-000, ER90-390-000, ER90-373-001 and ER90-390-001, December 1990. Subject: Opportunity cost pricing of transmission service.

Testimony on behalf of Kansas City Power & Light Company before Federal Energy Regulatory Commission, Docket No. EC90-16-000, November 2, 1990. Subject: Competitive effects of proposed merger.

Testimony on behalf of Southern California Edison Company and San Diego Gas and Electric Company, before the Federal Energy Regulatory Commission, Docket No. EC89-5-000, May 1989, and January 1990; and before the Public Utilities Commission of the State of California, In the Matter of the Application of SCECorp. and its Public Utility Subsidiary SCECo. (U 338-E) and San Diego Gas and Electric Company (U 902-M) for Authority to Merge San Diego Gas and Electric Company into Southern California Edison Company, Appl. 88-12-035, March and May 1990. Subject: Competitive effects of merger.

Testimony on behalf of Houston Lighting and Power Company before the Public Utility Commission of Texas, Docket No. 8650, October 11, 1989. Subject: Retail wheeling.

Testimony on behalf of Boston Edison Company, before the U.S. District Court for the District of Massachusetts, Civil Action No. 87-1881-C, In the Matter of City of Concord, Massachusetts, and Town of Wellesley, Massachusetts v. Boston Edison Company, April 24 and May 1, 1989. Subject: Market definition, price squeeze, damages.

Testimony on behalf of Public Service Electric & Gas Company, before the Board of Public Utilities of the State of New Jersey, Docket No. EM88020331, Joint Application of Public Service Electric & Gas Company and Eagle Point Cogeneration Partnership for Approval of Power Purchase and Interconnection Agreement, and Docket No. EM88020331A, Allegations of Violations by Public Service Electric & Gas Company Regarding Cogeneration and Utility Holding Company and Affiliate Relationships and Transactions, October 28 and November 7, 1988. Subject: Affiliate dealing, cogeneration contracts.

Testimony on behalf of Union Electric Company and Missouri Utilities Company, before the U.S. District Court for the Eastern District of Missouri, Southeastern Division, CA 83-2533-C, City of Malden, Missouri v. Union Electric Company and Missouri Utilities Company, June 9-10, 1988. Subject: Market definition, essential facilities, damages.

"Response to Plaintiff's Foreclosure Damage Study," submitted on behalf of Southern California Edison Company, before the U.S. District Court for the Central District of California, No. 83-8137-MRP (KCX), In the Matter of the City of Vernon v. Southern California Edison Company, June 1988. Subject: Damage causation and measurement.

"Comments Responding to BPU Staff's Assessment of Cogeneration and Small Power Production," prepared for Public Service Electric and Gas Company, filed with the Board of Public Utilities of the State of New Jersey, August 31, 1987. With John H. Landon. Subject: Guidelines for developing appropriate cogeneration policies.

Testimony on behalf of Minnesota Power & Light Company, before the Minnesota Public Utilities Commission, MPUC Docket No. 015/GR-87-223, May 15, 1987. Subject: Large industrial customer contracts and rates.

Testimony on behalf of Southern California Edison Company, before the U.S. District Court for Central District of California, Civil Action No. CV 78-810-MRP, In the Matter of Cities of Anaheim, Riverside, Banning, Colton and Azusa, California v. Southern California Edison Company, September 10-12, 1986. "Response to Plaintiff's Foreclosure Damage Study for the Period February

JOE D. PACE

EDUCATION

B.A. (with honors), Economics, COLLEGE OF WILLIAM AND MARY, 1966.
Phi Beta Kappa

Ph.D., M.A., Economics, UNIVERSITY OF MICHIGAN, 1967, 1970.

Specializing in industrial organization, public utility economics and labor economics.

PRESENT POSITION

LECG, LLC (and predecessor companies), 1995 – present.
Director

PROFESSIONAL EXPERIENCE

PUTNAM, HAYES & BARTLETT, INC., 1990 - 1995.
Managing Director

GEORGE MASON UNIVERSITY, Summer 1994.
Adjunct Professor

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
Executive Vice President, 1988 - 1990.
Senior Vice President, 1979 - 1988.
Vice President, 1973 - 1979.
Senior Consultant, 1972 - 1973.
Senior Economist, 1970 - 1972.

WASHTENAW COUNTY PLANNING COMMISSION, 1969.
Assistant Planner, Washtenaw County Planning Commission

UNIVERSITY OF MICHIGAN, 1968 - 1969.
Instructor

1978 Through December 1985," April 22, 1986.Subject: Price squeeze, transmission policies, essential facilities, damages.

Testimony on behalf of Union Electric Company, before the U.S. District Court for the Eastern District of Missouri, Eastern Division, Civil Action No. 83-2756C(c), In the Matter of Citizens Electric Corporation v. Union Electric Company, March 1986. Subject: Market definition, price squeeze, wheeling policy, damages.

Testimony on behalf of Southern California Edison Company, before the Federal Energy Regulatory Commission, Docket No. ER76-205-003, July 15, 1983, December 28, 1983, and May 1, 1984 and ER79-150-000, August 19, 1985. Subject: Price squeeze.

Testimony on behalf of Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 840293-EU, In Re: Petition of Peace River Electric Cooperative, Inc., to Settle Territorial Dispute with Florida Power & Light Company, January 11, 1985. Subject: Subsidies received by cooperative utilities.

"Expert Report of Joe D. Pace," submitted on behalf of Pennsylvania Power Company before the U.S. District Court for the Western District of Pennsylvania, Civil Action No. 77-1145, In the Matter of Borough of Ellwood City, Pennsylvania, Borough of Grove City, Pennsylvania v. Pennsylvania Power Company, March 1, 1984. Subject: Price squeeze, damages.

Testimony before the Subcommittee on Agricultural Credit and Rural Electrification of the Committee on Agriculture, Nutrition, and Forestry, United States Senate, 98th Congress, 2nd Session on S. 1300, May 15, 1984. Subject: Subsidies received by cooperative utilities.

Testimony on behalf of Monfort, before the U.S. District Court for the District of Colorado, Civil Action No. 83-F-1318, In the Matter of Monfort of Colorado, Inc. v. Cargill, Inc. and Excell Corporation, October 26, 1983. [Sealed under protective order of the Court.] Subject: Market definition.

"Expert Report of Joe D. Pace," submitted on behalf of Delmarva Power and Light Company, before the U.S. District Court for the District of Delaware, Civil Action Nos. 77-254 and 77-296, In the Matter of City of Newark, et al., and the City of New Castle v. Delmarva Power and Light Company, December 15, 1982. Subject: Price squeeze, proper cost allocation approaches.

Testimony on behalf of American Telephone & Telegraph Company, before the U.S. District Court for the District of Columbia, Civil Action No. 78-0545, In the Matter of the Southern Pacific Communications Corporation, et al., v. American Telephone & Telegraph Company, et al., June 26, 1982. Subject: Market definition, market power, entry conditions.

Testimony on behalf of American Telephone & Telegraph Company, before the U.S. District Court for the District of Columbia, Civil Action No. 74-1698, In the Matter of the U.S. Department of Justice v. American Telephone & Telegraph Company, December 21, 1981. Subject: Market definition, market power, entry conditions.

Testimony on behalf of Central Maine Power Company, before the Federal Energy Regulatory Commission, Docket No. ER-81-188-000, December 10, 1981. Subject: Transmission and bulk power alternatives for wholesale customers.

Affidavit on behalf of Deering Milliken, before the U.S. District Court, District of South Carolina, Civil Action No. 71-306, In the Matter of Deering Milliken, Inc., et al., v. Duplan Corporation, et al., November 21, 1980. Subject: Mitigation of antitrust damages in textile machine industry.

Report of Defendant's Economic Expert on behalf of Otter Tail Power Company before the U.S. District Court for the District of Minnesota, Civil Action No. 6-67-244, In the Matter of the Village of Elbow Lake, Minnesota v. Otter Tail Power Company, October 17, 1980. Subject: Bottleneck monopoly, damages.

Testimony on behalf of Connecticut Light & Power Company, before the U.S. District Court for the District of Connecticut, Docket No. CA 15609, City of Groton, et al., v. Connecticut Light & Power Company, et al., June 17 and 18, 1980. "Report of Defendant's Expert Witnesses," with Abraham Gerber, August 13, 1976. Subject: Price squeeze, stratified rates, wholesale contract provisions.

Testimony on behalf of the Pennsylvania Power Company, before the Federal Energy Regulatory Commission, Docket No. ER77-277 (Phase II), January 26, 1979. Subject: Price squeeze.

Testimony on behalf of Public Service Company of New Mexico, before the New Mexico Public Service Commission, Case No. 1419, In the Matter of The Public Service Commission's Investigation Into the Operation of the Public Service Company of New Mexico's Cost of Service Indexing and Rate Treatment of Construction Work In Progress, November 8, 1978. Subject: Measuring utility efficiency.

Testimony on behalf of Union Electric Company, before the Federal Energy Regulatory Commission, Docket Nos. ER77-614 and ER77-614 (Remand), September 18, 1978, February 9, 1979, January 21 and June 16, 1982. Subject: Price squeeze.

Testimony on behalf of Memorex Corporation, before the U.S. District Court for the Northern District of California, Docket No. MDL163-RM, In the Matter of ILC Peripherals v. IBM Corporation, Memorex Corporation v. IBM Corporation, March 13-17, 1978. Subject: Market definition, market power.

Testimony on behalf of Boston Edison Company, before the Federal Power Commission, Docket Nos. ER76-90, and ER77-588, May 20, 1977, and September 28, 1978. Docket No. E-7738 (Remand), April 14 and June 12, 1978. Subject: Price squeeze.

Testimony regarding the economic impact of lifeline rate structures: on behalf of Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. U-1345, June 25, 1975; on behalf of Jersey Central Power & Light Company, before the Board of Public Utility Commissioners of the State of New Jersey, Docket No. 757-735, November 14, 1975; on behalf of Long Island Lighting Company, before the Public Service Commission of New York, Case No. 26806, February 1976 and before the New York Assembly Committee on Corporations, Authorities and Commissions, September 24, 1975; on behalf of Madison Gas & Electric Company, before the Public Service Commission of Wisconsin, Case No. 3270-UR-1, August 26, 1975; on behalf of Massachusetts Electric Company, before the Commonwealth of Massachusetts, Department of Public Utilities, D.P.U. No. 18072, December 1975; on behalf of the Northeast Utilities Service Company, before the Connecticut Public Utilities Control Authority, June 1976; on behalf of Pacific Power & Light Company, before the Public Utilities Control Authority, June 1976; on behalf of Pacific Power & Light Company, before the Public Utility Commission of Oregon, Proceeding R-23, October 1975; before the Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, US House of Representatives, April 1, 1976; on behalf of Wisconsin Electric Power Company, before the Public Service Commission of Wisconsin, December 1975; and on behalf of Utah Power & Light Company, before the Wyoming Public Utilities Commission, November 1979, and before the Public Service Commission of Utah, Case Nos. 78-035-21 and 78-035-14, May 1, 1979.

Testimony on behalf of Toledo Edison and Cleveland Electric Illuminating Companies, et al., before the Nuclear Regulatory Commission, Docket Nos. 50-346A, 50-440A, 50-441A, 50-550A and 50-501A, Toledo Edison Company and Cleveland Electric Illuminating Company, (Davis-Besse Nuclear Power Stations, Units 1, 2 and 3) and Cleveland Electric Illuminating Company, et al. (Perry Nuclear Power Plants, Units 1 and 2), October 25, 1975. Subject: Analysis of competitive situation.

Testimony on behalf of Alabama Power Company, before the Nuclear Regulatory Commission, Docket Nos. 50-348A and 50-364A, Joseph M. Farley Plant (Units 1 and 2), August 15 and November 6, 1974. Subject: Analysis of competitive situation.

Testimony on behalf of Consumers Power Company, before the Nuclear Regulatory Commission (Atomic Energy Commission), Docket Nos. 50-329A and 50-330A, Midland Plant (Units 1 and 2), February 6, 1974 and May 21, 1974. Subject: Analysis of competitive situation.

Testimony before the Subcommittee on Antitrust and Monopoly, Committee on the Judiciary, U.S. Senate, May 13 and August 27, 1971. Subject: The relative performance of combination gas-electric utilities.

Testimony on behalf of Georgia Power & Light Company, before the Federal Power Commission, Docket No. E-7548, 1971. Subject: Productivity adjustments.

PUBLICATIONS

"Opportunity Costs as a Legitimate Component of the Cost of Transmission Service," *Public Utilities Fortnightly*, Vol. 124, No. 12, December 7, 1989, pp. 30-33, 73, with John Landon and Paul Joskow.

"Approaching the Transmission Access Debate Rationally, TRG Working Paper No. 1," prepared for the Transmission Research Working Group, Washington, D.C., November 1987, with Rodney Frame.

"Wheeling and the Obligation to Serve Problem," *The Energy Law Journal*, Vol. 8, No. 2, 1987, pp. 265-302.

"Deregulating Electric Generation: An Economist's Perspective," *Current Issues in Public Utility Economics*, edited by A.L. Danielson and D.R. Kamerschen, Lexington Books, Lexington, MA, 1983.

"Introducing Competition into the Electric Utility Industry: An Economic Appraisal," *The Energy Law Journal*, Vol. 3, No. 1, 1982, pp. 1-65, with John H. Landon.

"Alternative Scenarios for Deregulating the Electric Industry," *Electric Power - Current Issues in Regulation and Financing*, A4-4033, No. 277, April 12, 1982, pp. 755-791, with John H. Landon.

Working Paper: "Tax Losses Associated with the Construction of Electric Generating Plants by Government-Owned and Cooperative Electric Utilities," March 1981.

"Lifeline Rates: Will They Do the Job?" *Public Power*, Vol. 33, No. 6, November-December 1975, pp. 21-30.

"The Poor, the Elderly and the Rising Cost of Energy," *Public Utilities Fortnightly*, Vol. 95, No. 12, June 5, 1975, pp. 26-30.

"Rate Structures and the Changing Cost Picture," *NRECA Management Quarterly*, Summer 1973, pp. 15-20.

"The Relative Performance of Combination Gas-Electric Utilities," *The Antitrust Bulletin*, Vol. XVII, Summer 1972, pp. 519-565.

"Relevant Markets and the Nature of Competition in the Electric Utility Industry," *The Antitrust Bulletin*, Vol. XVI, No. 4, Winter 1971, pp. 725-765.

"The Subsidy Received by Publicly Owned Electric Utilities," *Public Utilities Fortnightly*, Vol. 87, April 29, 1971, pp. 19-29.

SPEECHES

"Guidance From the FERC Merger Guidelines." Speech presented at the Tenth Annual Utility M&A Symposium, New York, NY, February 3, 1997.

"Is Retail Wheeling Right For The Electric Utility Industry?" Speech presented at the Federal Bar Association's Annual Meeting, Washington, D.C., May 17, 1995.

"Whither Regulation For The Electric Industry." Speech presented at the Innovative Incentive Rate Regulation for a Competitive Electric Utility Industry Conference sponsored by the Center for Regulatory Studies and The Institute of Government and Public Affairs, Chicago, Illinois, April 28-29, 1994.

"Retail Wheeling: What's The Problem? What's The Solution?" Speech presented at the Pennsylvania Electric Association's 86th Annual Meeting, September 22, 1993.

"Retail Wheeling: Problems and Challenges." Speech presented to the Edison Electric Institute Finance Committee Meeting, Waldorf-Astoria, New York, New York, May 13, 1993.

"What Should Be Regulated?" Speech presented at the Exnet Conference on Regulatory Restructuring, Washington, D.C., March 19, 1993.

"Rolled-In Versus Incremental Pricing of Natural Gas Pipeline Service." Speech presented at the PHB Dinner Seminar Series, J.W. Marriott Hotel, Washington, D.C., April 7, 1992.

"The Implications of the Natural Gas Mega-NOPR." Speech presented at the Conference on Electricity Law and Regulation on behalf of the American Bar Association, Denver, Colorado, March 12-13, 1992.

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August, 2000

OG&E MARKET POWER STUDY FOR ARKANSAS

Exhibit JDP-2

OG&E Market Power Study for Arkansas

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Chapter I: Introduction

In compliance with the Market Power Analysis Minimum Filing Requirements ("MPMFRs"), adopted by the Arkansas Public Service Commission ("APSC" or "the Commission") in Docket No. 00-048R, Order No. 11, this study addresses the potential for Oklahoma Gas & Electric ("OG&E") to exercise market power in Arkansas after the retail electricity market there is opened to competition from other suppliers of generation and billing services. That is currently slated to happen on January 1, 2002, however a substantial delay in the commencement of retail competition now appears inevitable.[1]

On their face, the MPMFRs call for an analysis of market power issues associated with the commencement of competition in Arkansas retail electricity markets in the year 2002. It is self-evident that if retail competition does not begin before the third quarter of 2003 at the earliest, there are no potential 2002 market power issues to address. Indeed, recognizing that residential and small business customers will be entitled to continue receiving service at the same rates, and on the same terms and conditions as they do immediately prior to retail competition for at least one year after the introduction of retail competition, there is no potential for those customers to be subject to the exercise of market power before the third quarter of 2004 at the earliest.

Accordingly, this study should be viewed as providing insight into potential market power issues that may arise in Arkansas electricity markets within the first few years of open access, whenever that may occur. Of course, actual market conditions at the time retail competition commences may differ from the year 2002 assumptions used in this study. It is important to note, however, that the changes brought by a delay would likely make the markets more competitive.

[1] The Commission initiated Docket No. 00-190-U in which comments were filed by many parties for consideration by the Commission in making its recommendation to the legislature on or before January 15, 2000. A number of parties have entered into a joint stipulation which recommends that the start date for retail open access be deferred until at least October 1, 2003. The Commission has the authority to delay the implementation of retail competition until June 30, 2003; further delays require legislative approval.

The amount of new entry by independent generators is expected to increase with time. In addition, it is expected that transmission upgrades, asset sales, and general maturation of the wholesale energy market will lead to a more robustly competitive markets as time passes.

Electricity has long been provided to retail consumers by regulated, vertically integrated monopoly utilities. Direct price regulation, and controls over the provision and quality of service, have been relied upon to protect consumers from the exercise of market power in that environment. The goal of restructuring retail electricity markets in Arkansas and elsewhere is to rely more on competition and less on direct regulation to discipline the prices paid by consumers, and promote short- and long-term efficiency in the industry. If substantial market power can be exercised in the newly opened markets, these benefits may not be realized. Therefore, at the outset, it is important to establish a market structure in which market power either will not exist or will be adequately mitigated by residual regulation.

Market power is the "ability to impose on customers a significant and non-transitory price increase on a product or service in a market above the price level which would prevail in a competitive market or exclude competition in a relevant market."[2] The exercise of market power unjustifiably transfers wealth from buyers to sellers, and generally results in reducing the economic efficiency of the industry in which it is exercised.

In principle, market power problems could exist in restructured electricity markets at the wholesale level and/or at the retail level. Wholesale market power problems would exist if there were an insufficient number of generation services suppliers to discipline wholesale market prices in the relevant destination markets in the short run, or if significant impediments to new entry prevented effective competition from emerging in the long run. Retail market power problems would

[2] The Electric Consumer Choice Act of 1999, 23-19-404(d).

exist if there were an insufficient number of actual or potential retail electric suppliers to discipline prices paid by end-users.

Market power can arise from "horizontal" or "vertical" market conditions. Horizontal market power will exist if concentration and entry conditions in the market being examined (for example, wholesale electric generation services) are such that prices can be maintained above competitive levels in that market for a substantial period of time. Vertical market power will exist if one or more firms can use their control of different input or output markets to raise prices in the market being examined. For example, if incumbent electric utilities were able to use their ownership of the transmission system to create market power at the wholesale level, or their ownership of the distribution system to create market power at the retail level, that would be labeled vertical market power.

At the outset, it is important to emphasize that analyses of expected market conditions and the potential existence of market power concerns prepared in advance of the opening of traditionally regulated markets inevitably reflect uncertainties around a number of important parameters. These include: (1) how transmission deliverability and priority of access will be determined in restructured markets; (2) how congestion will be managed and what mitigation measures will be put in place by the RTO to address "local" market power problems when they arise; (3) how markets will be organized to provide load balancing services, spot energy, ancillary services and efficient price discovery; (4) the pace of deregulation in nearby states, as well as the design and duration of transition mechanisms that may be put in place to protect consumers and mitigate potential market power; (5) the magnitude and timing of new generation entry; and (6) the timing and significance of major transmission upgrades. These issues have been addressed by making reasonable assumptions given what is now known, and in some important cases, by running sensitivity analyses. However, it should be noted that as time passes, revised or alternative approaches to evaluating market conditions may be appropriate in future market power updates.

Chapter II provides a summary of the study, along with its principal conclusions. Chapter III presents an overview of the expected organization and operation of the new electricity markets in Arkansas. Chapter IV addresses wholesale market issues, defining the relevant product and geographic markets, explaining the approach used to evaluate these markets, and presenting results of the analysis. Chapter V concentrates on retail market issues, including those related to retail billing services. In addition this report has two appendices. Appendix 1 describes the modeling approach used in the wholesale market analysis and Appendix 2 provides a detailed description of the modeling and results.

Chapter II: Summary and Overview of Conclusions

This study evaluates relevant wholesale energy markets by season and time period for the base case and a number of alternative scenarios; examines installed capacity markets; and analyzes retail electric supply and billing service markets. Market share and concentration ratios are developed for all wholesale markets. In addition, potential vertical and horizontal market power concerns are addressed for all wholesale and retail markets, and entry conditions are examined carefully.

OG&E is unlikely to have market power in the markets for the supply of wholesale energy or capacity to customers in its Arkansas service area. This conclusion is founded on the following key facts.

- OG&E's market shares are below 25 percent and the HHIs are below 1,700 for all energy and capacity market scenarios examined.
- There are no significant barriers to entry into wholesale energy or installed capacity markets. A number of new generation projects are already underway in the Arkansas-Oklahoma area. Ease of entry ensures that prices will be at competitive levels over the long term.

OG&E is unlikely to have market power over the provision of retail electric supply or billing services within its Arkansas service area because:

- Access to the relevant wholesale energy and capacity markets, as well as to needed distribution services and customer information, should be assured by federal and state regulations already adopted.
- There are no significant barriers to entry by new retail competitors, aside from that potentially created by setting SSP prices too low which by definition would prevent OG&E from having exercisable market power.

Chapter III: How Restructured Electricity Markets Will Work in Arkansas

As previously noted, retail competition currently is slated for introduction in Arkansas on January 1, 2002, although its implementation seems certain to be delayed. On and after the commencement date, all retail customers of investor-owned and cooperative utilities in Arkansas will be able to choose who will provide them with generation services. In addition, the governing body of each municipal utility will have the option of allowing retail competition for its customers. Suppliers of generation services, called energy service providers or ESPs, will have to be approved by the APSC. The APSC has until six months prior to retail open access to establish standards for ESPs, giving proper regard to the reliability, financial strength and technical competence of the applicant. Affiliates of the incumbent utilities also may be approved ESPs and provide services both in their home service territories and elsewhere. Utility affiliated ESPs must comply with the APSC's Affiliate Transaction Rules - - Electric ("Affiliate Rules") designed to assure that they gain no unfair advantage over other ESPs. In general, the Affiliate Rules mandate functional separation between the utility and affiliated ESPs, govern the allocation of costs and personnel between those businesses, and require nondiscriminatory provision of services and information to all ESPs, including affiliates.

Retail customers will continue to have the option of receiving generation services from their existing utility supplier (or its retail affiliate) after the advent of retail restructuring. Customers who do not elect to take service offered at market-determined rates by ESPs will continue to receive the SSP from their utility supplier (or its ESP affiliate). During the first one or three years after retail open competition is initiated (one year for all Arkansas suppliers other than Entergy and three years for Entergy because it is seeking stranded cost recovery) - - the "rate freeze period" - - residential and small business customers will be provided with SSP service at the same rates, and on the same terms and conditions, as they were supplied prior to the commencement of retail competition. For larger commercial and industrial customers during the rate freeze period, and for all retail customers after the rate freeze period, the SSP rates offered must be "consistent with competitive market prices." The SSP will be available for an indefinite period of time. That is, there is no predetermined phase-out or termination of the SSP obligation. Retail customers who choose an alternative supplier and later return (voluntarily or involuntarily) to utility-provided service may again be served under the SSP. In the future, the APSC may consider setting the rates and other terms for providing service to such returning customers on a different basis from those applicable to SSP customers who have never left, if appropriate or necessary to prevent significant "gaming" problems.

All retail customers will continue to be provided with transmission and distribution services ("wires" service) on nondiscriminatory terms, regardless of who supplies them with generation services. The utility will provide these services at regulated rates, and, as previously discussed, will be required to deal with all competitive service suppliers on a nondiscriminatory basis. Initially, metering services also will be provided on a regulated, nondiscriminatory basis by the electric utility.

ESPs will have to provide reliable load following generation services to their retail customers. For the foreseeable future, most customers will receive the same physical generation service regardless of their choice of ESP. ESPs can be expected to attempt to differentiate their products by offering differing pricing structures or hedging options, bundling electricity with other product offerings, providing load management services or supplying "green" power. ESPs will obtain the electricity needed to serve retail loads from generators they own and/or by contracting for power in wholesale markets.

The viability of retail competition ultimately depends on the competitiveness and efficiency of the underlying wholesale markets for electricity. The wholesale market within which Arkansas ESPs will operate will be organized by the Southwest Power Pool ("SPP") regional transmission organization ("RTO"). While the SPP RTO plan was filed with the FERC only recently (October 13, 2000) and has not yet been approved, what is clear is that SPP will: (1) operate a transmission system that covers all or parts of seven states and is substantially larger than any existing operating ISO, calculate total and available transmission capacities (TTC and ATC) for the region, implement a congestion management system, engage in regional planning and have the ability to require the construction of new transmission facilities; (2) administer an open access tariff that provides non discriminatory access to the grid at non-pancaked rates and establishes generator interconnection policies; (3) be the provider of last resort for ancillary services at FERC-approved rates; and (4) set up a separate market monitoring unit to assess whether any party is withholding generation to create a transmission constraint or taking any action that hinders the provision of reliable, efficient and non discriminatory transmission service. There is considerable time before markets actually are expected to open in Arkansas for the RTO to develop the means of, and gain experience in, carrying out these functions.

Within the SPP today there is a robust bilateral market for forward and real-time energy transactions. This is expected to continue and grow stronger as the need for such trades increases in a more competitive environment. SPP is not proposing to operate a centralized spot energy market, although it will administer an energy imbalance market designed to address inadvertent deviations between loads and scheduled generation. Some details regarding the operation of the imbalance market have not been resolved, such as any limits that might be placed on ESPs using the market to address supply and demand imbalances, or on the ability of ESPs to address imbalances in real-time through bilateral transactions. The combination of the SPP's energy imbalance market, robust bilateral trading, and potential third-party-administered spot markets, should provide efficient trading options and price discovery in the region. Reasonably transparent energy markets in some form will be needed to facilitate ESP procurement of short-term supplies to provide load following service to retail customers, and to encourage the development of hedging products and efficient demand response initiatives. The commercial imperative for creating and administering such markets is strong and the market power analysis below is premised on that happening by the time Arkansas' electricity market is opened to retail competition.

Retail billing services also are slated to be open to competition concurrent with the commencement of competition for retail electric supplies. ESP's will be given the choice of sending a consolidated bill for the energy they provide and utility- provided transmission and distribution services, or sending a separate bill for their energy services and having the utility bill for its own services. In addition, utilities can elect to offer consolidated billing services as long as they are offered to all ESPs on a nondiscriminatory basis. The Commission has considered but not yet approved third party billing.

Chapter IV: Analysis of Wholesale Electricity Markets

A. Basic Analytical Approach

As noted in the introduction, market power is the "ability to impose on customers a significant and non-transitory price increase on a product or service in a market above the price level, which would prevail in a competitive market or exclude competition in a relevant market." Mechanically speaking, a single seller can exercise market power over energy or installed capacity prices in the short run in a market-driven environment in either of two essentially equivalent ways. The first is to raise its prices directly. The second is to withhold some of its capacity from the market and force buyers to call on other, higher-priced resources to meet their demands. This is not to say that such efforts will always prove to be profitable. Generally speaking, any unilateral attempt to raise prices (either by increasing prices or withholding capacity) will result in lost sales as buyers turn to alternative suppliers to meet their requirements. To determine if a price-increasing strategy is profitable, therefore, the supplier must weigh the loss in profit that will result from lower sales against the increase in profit that will result from receiving a higher price for the remaining sales that it does make.

The profitability of an individual supplier's effort to raise prices also may depend on the behavior of competing suppliers. Even when sellers do not formally coordinate their pricing strategies, they may still act in a parallel fashion, especially if the market is highly concentrated (that is, supplied by a small number of relatively large firms). In that context, whether an attempt by an individual seller to increase prices will prove profitable will depend in part on how other sellers react to that attempt. If other suppliers take advantage of the attempted price increase to expand their output significantly, that will tend to defeat the effort. On the other hand, if other suppliers respond by raising their own prices or withholding capacity, the price increase is more likely to stick and be profitable for all.

Market power can be exercised by incumbent suppliers in the long run -- that is, over a period of time within which significant expansions of capacity can profitably take place -- only if they can significantly hinder or prevent new capacity from coming into the market when it is economically justified. This would most likely be a problem if control of one or more key inputs to new generation development, such as acceptable sites, fuel supplies, fuel transportation facilities, electric transmission facilities, or environmental permits were concentrated in the hands of incumbent suppliers without a policy in place to ensure non discriminatory access to such inputs by other prospective developers.[3] New entry also could be impeded if the minimum efficient scale of new

[3] It is important to understand, however, that the fact that new capacity development may be difficult in some areas due to environmental restrictions or siting problems does not mean that incumbent suppliers will be able to exercise

generators was sufficiently large relative to total market demand that new entry would tend to depress prices below competitive levels, and if new entrants could not protect themselves from such price depression via long-term contracts. The Commissions triennial market power review will provide an opportunity to evaluate these long-run issues and assess actual entry in the market.

Market power questions traditionally have been addressed by analyzing the structure of, and competitive conditions in, one or more "relevant markets." There are two dimensions to market definition -- the product line and the geographic area. When defining the relevant product markets, the fundamental principle is to include all products that are viewed by buyers as sufficiently good substitutes for one another that competition between their suppliers places significant constraints on the prices that can be charged for each product. The basic principle for geographic market definition is the same as that for defining the product market. The aim is to determine the geographic locations of firms that are viewed by buyers as good substitute suppliers. To do this, one starts with the geographic area of interest and then identifies suppliers that serve that and proximate geographic areas that place significant competitive constraints on the prices charged in the target market. Conceptually, the narrowest plausible relevant product and geographic markets can be identified employing the "hypothetical monopolist" test. This conceptual test asks whether a hypothetical monopolist controlling all the supply of a particular product in a particular area could profitably raise prices by five percent or more, and sustain that increase for a substantial period of time. If so, that product and area constitute a plausible

market power in electricity markets in the long run. Scarcity of necessary inputs such as environmental permits or acceptable sites may drive up the cost of constructing or operating additional capacity, thereby increasing the marginal cost of producing additional electricity and leading to higher market prices. As long as the scarcity of needed inputs is "natural" - - that is, based on a societal evaluation of marginal costs of additional electricity production in the area in question - - the higher market prices may result in incumbent suppliers earning economic rent, but there is nothing inappropriate about that. Indeed, in that situation, prices must be allowed to rise at the margin in order for the market to operate efficiently. In contrast, market power exists when resource scarcity is created artificially by market participants, for example, by denying access to key inputs or pricing them above competitive levels. In this situation, prices will be driven up to levels exceeding the marginal resource cost of supplying the product. Therefore, resources will not be allocated efficiently and incumbent suppliers will earn monopoly profits.

relevant market. If not (that is, if suppliers of other products or suppliers outside the area under consideration could defeat even an attempt by a hypothetical monopolist to raise prices by five percent), the relevant product and/or geographic market clearly has been defined too narrowly.

After the relevant product and geographic markets have been identified, the next step in the analysis is to examine the basic "structure" of each market, identifying the number of suppliers in the market, determining the market share held by each supplier, and calculating market concentration measures that reflect the relative sizes of the participants in the market. The most commonly employed measure of market concentration is the Herfindahl-Hirschman Index ("HHI"). The HHI is calculated by summing the squares of the market shares of all firms in the market. Thus, if there are five firms in a market, each with a 20 percent share, the HHI is 2,000 (20 squared or 400, times 5).

Market shares and HHIs are generally used in analyses of market power as "screens" to determine whether more detailed assessments of expected competitive conditions in the relevant markets are warranted. As a general proposition, individual firms with relatively low market shares are unlikely to be able to exercise significant market power because all or a large fraction of their output can be readily replaced by other suppliers if they attempt to set their prices above competitive market levels. Also, in relatively unconcentrated markets (that is, markets not dominated by a small number of relatively large firms), it is less likely that market power can be exercised through parallel behavior because suppliers will find it too difficult to cooperate and maintain prices significantly above competitive market levels. Given this, the general approach is to establish market share and/or HHI screening levels. Market shares and HHIs below the screening levels fall into the "safe harbor" and the relevant markets are deemed to be sufficiently competitive without further analysis. Where the market shares or HHIs exceed the screening levels, further analyses of expected market conditions must be undertaken in order to determine whether significant market power problems are likely to exist.

The MPMFRs require in all cases an examination of market shares and HHIs under a variety of scenarios, an analysis of entry conditions, and a focus on potential vertical market power problems. Beyond this, in instances where the firm's energy market share is found to exceed 25 percent and the HHI is found to be over 1,000, additional analysis is required to determine whether a significant market power problem is likely to exist.[4] In contrast to the screening analysis typically employed to address market power issues, the MPMFRs specify that if the market share and HHI threshold levels are exceeded in <u>any</u> energy market, additional strategic behavioral analyses ("SBAs") must be performed for <u>all</u> relevant energy markets. If required, the SBAs are to explore whether the utility could profitably raise and sustain price increases of five percent or more in the relevant wholesale energy market.

It should be noted that even when market shares and concentration measures fall in the safe harbor range, prices exceeding competitive levels may occur in the short run in electricity markets during hours when demands are relatively high, if the available supply situation is tight. In that circumstance, suppliers will know that virtually all capacity will be needed to meet the market's requirements and they will be able to exercise market power during those times. This problem is magnified if there is relatively little forward contracting for energy, and/or if there is no installed capacity market. These circumstances combined to account for some undetermined part of the California "summer 2000 problem." However, given the evidence of expected new generation entry in the SPP area discussed below, as well as the anticipated reliance on bilateral contracting in that area, there is no indication that a "tight market" problem will emerge in this part of the country.

[4] Realistically, the HHI screen is so low that it is very unlikely to be a discriminator. If one firm has a 25 percent market share, even if the remaining 75 percent of the market were equally divided among <u>fourteen</u> firms, the HHI

B. Identification of the Relevant Product Markets

The definition of the relevant product markets begins with an examination of all distinct wholesale electricity products OG&E is expected to sell at market-determined rates, since this encompasses the range of products over which it potentially might be able to exercise market power. In this case, the primary product will be energy. Energy may be traded in a number of different ways, for example, through centrally organized daily or hourly spot markets, through individual over-the-counter markets for short-term transactions, and/or through bilateral contracts of varying durations. Regardless of the mechanics used to carry out the trades, all such energy transactions fall into a single relevant product market because buyers and sellers can be expected to arbitrage among all available trading forums.

Energy is a time-differentiated product. That is, since it is generally not feasible to store electricity, and since demand levels and available supplies change over time, energy market conditions can vary substantially by season and time period. To reflect the time-differentiated nature of this product, the analysis below examines eleven energy market conditions - - three seasons (summer, winter and spring/fall), three time periods per season (off-peak, mid-peak and peak), plus summer and winter super-peak periods.

The second potential product to consider is installed capacity. This will exist as a separate relevant product only if the rules governing restructured electricity markets impose an installed capacity requirement on market participants. California has no such requirement, but PJM and NY do. At the present time, SPP requires load serving entities ("LSEs") to maintain a 12 percent installed capacity margin, but no penalty is imposed for failing to do so. In any event, the MPMFRs require that the potential market for installed capacity be addressed and the analysis presented below does so.

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would exceed 1,000. The only real discriminator, therefore, is the 25 percent market share screen.

In addition to energy and installed capacity, a number of ancillary services are needed for the market to function, and in the future they may be provided at market-determined rates. These include regulation service, spinning reserves, supplemental reserves and replacement reserves, as well as energy imbalance service. All electric systems require such ancillary services, although each market may define and procure the services in slightly different ways. At this stage of market development, the exact requirements associated with each of these services and the quantities required have not been determined. Some flexibility in this area will be retained by the RTO to adapt to evolving circumstances. LSEs may self-supply regulation service, spinning reserves and supplemental reserves, or contract for these services bilaterally. Otherwise, the RTO will purchase needed ancillary services at regulated (initially) rates. The replacement reserve market will only be opened when the RTO has reliability concerns, and the RTO will seek bids to satisfy this requirement. Energy imbalance services will be procured by the RTO from generating units in the system that can either increase or decrease their output to keep the system in balance. The cost of procuring ancillary services will be allocated to LSEs, generally in proportion to the relative demands individual LSEs put on the system for these services.

In this way the RTO will meet FERC Order 888 requirements to make ancillary services available to all market participants. Ancillary services are currently provided under regulated rates, and this will be true in the near term (even though market based procurement should be expected at some point). Accordingly, the Arkansas MPMFRs do not require an analysis of the relevant markets for these services at this time.

C. Identification of Relevant Geographic Markets

Turning to geographic markets, it should be clear that the area of interest in this proceeding is the OG&E Arkansas service area. That is, the issue to be assessed is whether sufficient competitive alternatives will be available to meet the wholesale power requirements of the retail customers now served by OG&E in

Arkansas. The relevant destination market therefore includes those and other similarly situated customers. Similarly situated customers are customers having essentially the same wholesale electricity supply options as the OG&E Arkansas customers. The way the industry has traditionally been structured, all customers within a utility's control area have been viewed as having equal access to generation resources within that control area and to resources that can be accessed through interconnections with other control areas. Accordingly, as a starting point, it was natural to consider the control area of the utility being examined as a (or the) relevant destination market. However, as the electric utility industry restructures, it becomes more important to focus on areas separated by potentially binding transmission constraints, rather than looking at increasingly irrelevant utility service or control area boundaries.

Power Technologies, Inc. ("PTI") was retained to evaluate the transmission system in and around the OG&E service area in order to provide definitions of appropriate zones or transmission areas, along with flow limits between areas, for use in the market power analysis. PTI's analyses and conclusions are set forth in Mr. Austria's testimony. Mr. Austria concludes, as discussed in greater detail in Appendix 2, that OG&E's Arkansas customers lie within a slightly larger area within which there are no significant transmission constraints. This area, which is designed AR-FS or the greater Fort Smith area in this analysis, is forecast to have a total peak load of 975 MW by the summer of 2002. Of this, 873 MW is OG&E load, some of which is in Oklahoma. Within this area, OG&E's only generation resource is the 320 MW AES Shady Point station which is located in Oklahoma (OG&E controls no Arkansas-based generation). This is a third party owned two-unit coal-fired plant, which sells all its energy under a long-term contract to OG&E. Under the terms of the contract, the station is dispatchable and OG&E pays a variable price for the energy based on OG&E's own coal costs. OG&E is obligated to dispatch the AES units to achieve an annual capacity factor of at least 65 percent; however, because of their low energy prices, these units in fact operate at capacity factors close to 90 percent. Other resources within the AR-FS area include 59 MW of fossil capacity owned by the Arkansas Electric Cooperative Corporation ("AECC") and 302 MW of hydroelectric capacity owned by the Southwestern Power Administration ("SPA"). Under peak load conditions, with all in-area generation in service, the AR-FS area is forecast to be a net importer of about 200 MW.

The three areas directly interconnected with AR-FS are Ent-No, AR-NW, and OK-East. The Ent-No area includes the northern portion of Entergy's service territory, which contains most of its Arkansas service territory. This definition matches that used by Entergy in its recent market power filing with the Commission. The area is forecast to have 5,433 MW of load and 11,353 MW of in-area resources by the summer of 2002. The AR-NW area is located in the extreme northwest corner of Arkansas. It is forecast to have a peak load of 1,672 MW and 1,570 MW of in-area capacity by the summer of 2002. The OK-East area includes roughly half of Oklahoma. It is separated from the OK-West region by a line that starts in the middle of the Oklahoma-Kansas border, extends southeast between Tulsa and Oklahoma City and terminates near the point where Oklahoma, Arkansas, and Texas meet. The OK-East region is forecast to have 4,434 MW of load and 9,863 MW of in-area capacity by the summer of 2002. OG&E's only capacity in the OK-East region is the 1,699 MW Muskogee station. This station contains three base-loaded coal-fired units with a total capacity of 1,515 MW and one low-capacity-factor, 184 MW gas-fired steam unit.

Import capacity into the AR-FS area from the three interconnected transmission areas (OK-East, Ent-No and AR-NW) varies by season, but ranges from 936 MW to 1,970 MW. With a forecast peak load of 975 MW, it is only during extreme peak conditions that up to 39 MW must be generated within the AR-FS area. SPA has over 300 MW of hydroelectric capacity in the area which is expected to be available during peak periods and which is contracted to preference customers on a long-term basis. Thus, it will never be the case that all tielines into the area will be full, and internal OG&E generation never will be required to meet load in the AR-FS area. Mr. Austria has confirmed that there are no must run requirements in the area.

The available transmission import and export capacity is sufficiently large to assure that under virtually all circumstances, OG&E customers or their ESP suppliers in the AR-FS area will be able to purchase wholesale energy in a large relevant geographic market including one or more of the neighboring areas and suppliers interconnected with those areas.[5] In order to examine the narrowest plausible markets, the market power analysis presented below provides separate evaluations of competitive conditions when the AR-FS area is part of either the Ent-No, OK-East, or AR-NW areas. This is conservative since the AR-FS area often may be part of a single market containing two or more neighboring areas. In fact, the base case Prosym market simulation indicates that the AR-FS area is in equilibrium with all three neighboring areas 70 percent of the hours, and the combined AR-FS/OK-East market separates from both the AR-NW and Ent-No areas in only 1 percent of the hours. Lastly, under summer peak load conditions, the transmission capacity between the AR-FS and AR-NW areas is virtually zero, so these two areas are not analyzed as a single market during that period.

D. <u>Market Share and HHI Analyses for Energy Markets – Base Case</u>

The objective of this analysis is to identify competing sellers of energy whose supplies are economic and deliverable to the relevant designation market at prices within five percent of competitive market levels. There are two different measures to consider - - total economic capacity and available economic capacity. Total economic capacity looks solely at whether the resource can compete in the destination market. Available economic capacity subtracts out each supplier's native load obligation to provide a measure of the capacity likely to be available

[5] The available data on transmission limits into and out of the AR-FS area suggest that this area could plausibly separate from all these neighboring areas only during the winter peak period if large amounts of power were being wheeled through the area. However, even withholding all capacity in the AR-FS area during this period would not increase energy prices there by 5 percent and therefore, the AR-FS area fails the hypothetical monopolist test under this circumstance.

in competitive energy markets. Traditional native load obligations will no longer exist in states that have moved to an open access retail competition regime. Our analysis assumes that of nearby states, only Texas and Oklahoma will implement retail competition in the foreseeable future. However, utilities in these states can be expected to have some form of continuing SSP or other default service obligation during at least a several year period after retail competition is introduced. In Texas, residential and small commercial customers will have access to regulated default service rates for three years, or until 40 percent of the smaller customers choose an alternative supplier, whichever comes first. In Oklahoma, legislation to implement the retail competition mandated under existing law narrowly failed in 2000 (Senate Bill 22); and it would have required each electric distributor to provide default service indefinitely, with the rate set lower than existing tariffs initially and set at market rates over the longer term. The transition from historical to market rates would occur on January 1, 2004 for customers with peak load greater than 200 kW, and on March 1, 2005 for all others.

For the base case available economic capacity calculations, this study assumes that 75 percent of the customers in Arkansas, Texas and Oklahoma will continue to take regulated transition service from the utility supplier or its affiliate, and that 25 percent of the customers will switch to alternative suppliers within the first one to three years after retail competition commences. In addition, a sensitivity case assumes that as many as 40 percent of the retail customers in these three states will switch to alternative suppliers during this time. In our judgment, it is extremely unlikely that a larger percentage of customers than this will leave SSP or the equivalent service within the first three years after retail competition begins. In any event, new market power studies will be required to evaluate market conditions beyond that point.

The base case study includes all existing generation capacity, plus new capacity expected to be in service by June 1, 2002. The new capacity will largely be built by merchant generators. Mr. Coffman's testimony identifies new capacity amounting to 3,690 MW in Arkansas, 4,819 MW in Oklahoma, and over 8,500 MW in the rest of the SPP scheduled to be online by June 1, 2000. Projected capacity additions have also been included outside of SPP to accommodate growth in demand and reflect expected economic entry by merchant suppliers. A sensitivity analysis (discussed below) examines market conditions on the assumption that a lower level of new entry takes place.

The calculation of market shares and HHIs is conducted in two steps. First, the Prosym model is run to dispatch the regional electric system, determine competitive market clearing prices by transmission area, and evaluate market conditions when prices in the destination market are driven to 5 percent higher than competitive levels. Prosym is a leading electric utility production cost model commonly used for market simulations. The Prosym output is then used in the MSAT model to determine the market shares of entities that can effectively compete in the destination market in each hour. Opportunity costs are considered in evaluating potential supply sources. This is accomplished by calculating hourly clearing prices for all areas, and then only including resources from areas that are economic sources of supply to the destination market. Therefore, a resource is not considered an economic source of supply to the relevant Arkansas customers if it can sell its output at higher prices elsewhere. This is a far more conservative approach (i.e., it produces higher OG&E market shares and higher HHIs) than would be yielded by utilizing a standard FERC "Appendix A" approach which ignores market clearing prices outside the destination area. The resulting hourly data is compiled into summary market share and HHI statistics for different seasons of the year and times of day. Appendix 1 describes in greater detail how the Prosym and MSAT models are used to generate the required market shares and HHIs. Appendix 2 describes the specific data, assumptions and methodology employed in this case, and provides detailed results.

Table 1 below summarizes the results of the base case analyses for economic capacity and available economic capacity. In all cases, OG&E's market shares are below the Commission's 25 percent screening level, and the HHIs are below 1,400.

Table 1

Base Case Analysis
OG&E Market Share

Season	Period	AR-FS & OK-East	AR-FS & Ent-No	AR-FS & AR-NW
Total Economic Capacity				
Summer	Super Peak	19.1	3.6	N/A
Summer	On-Peak	17.4	4.3	12.3
Summer	Shoulder	18.8	4.7	13.5
Summer	Off-Peak	20.1	5.2	14.2
Winter	Super Peak	18.7	4.0	10.5
Winter	On-Peak	20.2	5.5	12.3
Winter	Shoulder	22.5	6.5	14.1
Winter	Off-Peak	22.0	6.3	13.8
Fall / Spring	On-Peak	17.3	4.4	11.1
Fall / Spring	Shoulder	18.8	5.3	12.5
Fall / Spring	Off-Peak	19.7	5.6	13.2
HHI Range		865 – 1,328	951 – 1,296	727 – 1,076

Season	Period	AR-FS & OK-East	AR-FS & Ent- No	AR-FS & AR-NW
Available Economic Capacity				
Summer	Super Peak	6.8	1.0	NA
Summer	On-Peak	4.0	2.3	4.7
Summer	Shoulder	6.1	3.1	6.5
Summer	Off-Peak	8.4	4.1	8.1
Winter	Super Peak	5.1	1.5	4.5
Winter	On-Peak	7.4	3.7	7.0
Winter	Shoulder	13.3	6.7	11.8
Winter	Off-Peak	13.7	6.6	11.9
Fall / Spring	On-Peak	4.1	2.1	4.3
Fall / Spring	Shoulder	6.6	3.5	6.6
Fall / Spring	Off-Peak	9.1	4.7	9.0
HHI Range		677 – 1,344	684 – 1,161	693 - 772

OG&E's market shares are highest when the AR-FS area is assumed to separate from both the Ent-No and AR-NW markets simultaneously. While theoretically possible, the Prosym market simulation discussed above indicates that this occurs in only 1 percent of the hours in the year. When the AR-FS area is in a market consisting of multiple neighboring areas, OG&E's market shares will be substantially lower than those calculated for the AR-FS/OK-East market and could be lower than any of the three markets analyzed. OG&E's market shares are substantially lower when the AR-FS area is a part of either the Ent-No or AR-NW markets (below 7 percent and 15 percent, respectively). It is also significant to note that since OG&E's resources in the AR-FS and OK-East areas are predominantly low-cost, base-load generators. As a result, OG&E's market shares are lowest during peak and super-peak periods (when many higher-cost generators are economic), and highest during off-peak periods (when only other base load generators are economic).

E. Market Share and HHI Analyses for Energy Markets – Alternative Scenarios

In addition to the base case analysis of wholesale energy markets, six alternative scenarios have been evaluated. As discussed below, these scenarios reflect different assumptions regarding SSP coverage, new entry, fuel prices, and the lack of an RTO. Detailed calculation and results for all scenarios are included in Appendix 2.

1) *Alternative SSP coverage assumptions*; The base case assumes that 75 percent of the customers in Arkansas, Oklahoma and Texas remain on regulated SSP or default service in the foreseeable future . The assumption does not affect the total economic capacity analysis, but it plays a significant role in defining available economic capacity. To test the effect of this assumption, sensitivity analyses were conducted assuming that 90 percent and 60 percent of the customers stay on this service. Since OG&E operates entirely within states assumed to implement retail competition, it is to be expected that its available

economic capacity shares will increase under the 60 percent assumption, and decrease under the 90 percent. Even with the 60 percent assumption, OG&E's share of the relevant Arkansas market for available economic capacity is at most 19.1 percent, which occurs during the winter shoulder period when prices in the AR-FS are in equilibrium with those in OK-East.

2) *Reduced new entry*; Considerable new entry is forecast by 2002, although there is no certainty that any specific merchant generator will actually be built. While not all of the forecast generation may come into service by 2002, there is also the possibility that currently unknown projects could also be completed. In the face of this uncertainty, sensitivity analyses testing the implication of the new entry assumptions can be helpful. Since OG&E's base case market shares already are below 25 percent, only a reduced new entry case is considered. For this analysis, the capacity of all new entrants is cut in half to test the effect of substantially reduced entry without passing judgement on any particular project. This results in modest changes in market shares, and in all cases OG&E's market share in the relevant Arkansas area remains below 23 percent.

3) *Alternative fuel price assumptions*; Market shares depend on the relative competitiveness of generating units, and changing fuel prices will alter the results. To measure this potential, coal and nuclear fuel costs were held constant, while the gas and oil price assumptions were varied. Gas and oil prices were increased by 20 percent and decreased by 40 percent relative to the base case assumption (where gas prices range around $4.00/mmBtu).

   High fuel price assumptions result in a modest increase in OG&E's market share for the Arkansas area, with the highest share equaling 23.2 percent in the winter shoulder period. Low fuel prices reduce OG&E's market shares modestly, relative to the base case.

4) *No RTO*; The lack of an RTO will have minimal impact on this analysis because the SPP already manages congestion and administers an open access tariff that eliminates the pancaking of transmission rates within SPP. The only RTO contingency we analyze is the possibility that Entergy will not remain in the new SPP RTO and, therefore, that the separate wheeling charges into and out of Entergy will apply. A separate scenario was run to reflect this assumption, with the transmission rate between Entergy and other SPP members set at the same price as assumed in the study for all interregional transfers outside of SPP. This rate is $2/MWh on-peak and $1/MWh off-peak, which is lower than typical maximum tariffs filed with the FERC. The use of reduced rates generally reflects discounting which can be expected as transmission owners reduce rates to facilitate trade. The analysis indicates that market shares change little in the absence of an RTO.

F. Analysis of Capacity Markets

Installed capacity refers to the capacity that is needed to ensure that the market has adequate generation reserves. ESPs may be required to contract for enough installed capacity to cover their peak loads plus a specified percentage reserve margin. Installed capacity reserves are distinct from operating reserves, which will be procured in ancillary service markets.

At this point, it is unclear whether SPP will have an installed capacity requirement or if so, what the rules will be. For example, if there is such a requirement, will it be imposed by transmission area within SPP, by control area, or on the SPP area as a whole? How will transmission available to import capacity into SPP or an area within SPP be measured? Will TTC figures be reduced to reflect capacity benefit margin ("CBM") and transmission reserve margin ("TRM"), and if so, how will these margins be calculated?

This study assumes that the narrowest plausible destination market for installed capacity relevant to customers in OG&E's Arkansas service area is the AR-FS area, and that ESPs in the SPP area collectively will have to provide or contract for installed capacity within or deliverable to the AR-FS area equal to 113.6 percent of the summer peak load in that area.[6] ESPs are assumed to be able to procure installed capacity from anywhere in the SPP region, or from interconnected regions, using firm transmission import capacity into the AR-FS area. Based on Mr. Austria's testimony, CBM is not likely to be applicable in this timeframe and firm transmission capacity is set equal to 90 percent of TTCs to allow for TRM.

Given these assumptions, the total demand for capacity in the AR-FS area is 1092 MW and the summer firm import capability under peak conditions is only 851 MW. This means that 241 MW of the assumed capacity requirement must be met by local resources. In theory, the AR-FS area could be a load pocket and a separate market for installed capacity. In practice, however, 302 MW of the generation in the AR-FS area is owned by SPA. This capacity is dedicated to preference customers and SPA has no incentive or ability to withhold it from the market. Therefore, even if OG&E withheld all of the generation from its single station in the AR-FS area from the installed capacity market, other in-area installed capacity plus imports could meet all the area's assumed capacity requirements. It follows that customers located in the AR-FS area or their ESPs would be able to shop for capacity to meet the assumed installed capacity requirement over a broader market area including either OK-East and interconnected areas, or Ent-No and interconnected areas, or both. Consistent with our energy market analysis, we have examined market shares and HHIs for the narrowest plausible market which would include either AR-FS/OK-East area plus interconnected suppliers, or the AR-FS/Ent-No area plus interconnected suppliers. OG&E's share of the relevant Arkansas market is less than 20 percent in both cases.

[6] The SPP capacity margin requirement of 12 percent translates into a reserve margin of 13.6.

G. Analysis of Entry Conditions in Wholesale Energy and Capacity Markets

A review of recent experience shows that new entry into the electricity industry is not only possible in theory, but is occurring on a large scale in practice, with tens of thousands of MWs of new merchant plant generating capacity having been announced over the past three years in the Eastern Interconnect. A substantial portion, if not the majority, of new generating facilities in the US are being built as unregulated merchant facilities. The huge volume of successful new generation project development is the best evidence that there are no significant barriers to entry into wholesale power markets. In all its investigations, FERC has never found there to be significant barriers to developing new generation sources.

Moreover, developers are showing a substantial interest in the SPP area, and in Arkansas and Oklahoma particularly. Based on information supplied by OG&E, about 4,800 MW of new merchant capacity in Oklahoma has been included in this study. Clearly, this market evidence indicates that there are no substantial barriers to entry for new generating facilities in the region. The paragraphs below further discuss potential barrier to entry into wholesale electric generation markets.

1) *Fuel and fuel transportation facilities*

Most planned new generation facilities in the U.S. and in the SPP will be relying on natural gas for fuel. Since OG&E has affiliates in the gas production and transportation businesses, we consider whether that could create a barrier to new generation development.[7]

OG&E is affiliated with Enogex, Inc. ("Enogex"), a company that through various subsidiaries is engaged in oil and natural gas exploration and production; natural gas gathering and processing; Oklahoma intrastate and interstate transmission of natural gas; and marketing of natural gas and natural gas liquids. Enogex's pipeline system spans Oklahoma's gas producing areas

[7] Note that neither OG&E nor any of its affiliates own coal supplies or coal transportation facilities.

from the Anadarko Basin in the west to the Arkoma Basin in the east, and its interstate facilities extend further east through Arkansas and into Missouri. The Enogex pipeline system is interconnected with the majority of the interstate pipelines crossing Oklahoma, and it is linked to a number of natural gas fired generation facilities in Oklahoma.

Enogex and its subsidiaries provide natural gas sales and transmission service to OG&E's gas-fired generation plants, as well as to some CSW, Associated Electric Coop and Arkansas Electric Coop units. However, Enogex operates intrastate pipeline facilities under non discriminatory access rules, and its Ozark Gas Transmission subsidiary is a FERC-regulated, open access interstate pipeline. Moreover, a multitude of natural gas pipelines crisscross Oklahoma, generally providing several gas transportation options for existing or new generation facilities. Beyond this, because of the well-developed competitive market for natural gas, Enogex cannot restrict access of potential generation competitors to natural gas supplies. Indeed, the Arkansas, Oklahoma, and Texas region has some of the largest concentrations of gas supplies and gas transportation facilities found anywhere in the world. The competitiveness of the gas supply market, coupled with open access rules for gas pipeline services, eliminate any realistic potential of gas supplies becoming an entry barrier in this region of the country.

2) *Environmental permits*

New facilities will generally require air and water environmental permits. In Arkansas, the Department of Environmental Quality grants these permits. To the extent that all potential entrants are treated equally and such permits are generally available, there are no barriers to entry. Instead, the costs of acquiring such permits or complying with other environmental requirements are simply part of the cost incurred by any entrant to the marketplace. States generally have clear procedures for obtaining needed environmental clearances and the large amount of construction activity in the region gives ample evidence that this is available.

3) *Generation sites*

The new project development activity again provides a sound basis for concluding that entry is possible and adequate sites are available. New gas-fired facilities, and in particular simple cycle combustion turbine units require far less area than traditional coal units, which has greatly eased historical concerns regarding the availability of generating sites. Viable sites also require access to natural gas, electric transmission facilities and cooling water. This region is densely covered by gas transportation facilities, and access to both gas supplies and the electric transmission network is regulated to provide equal access. Water supplies are more problematic in the region, but no evidence has been found that any entity has the ability to block access to needed water supplies or that those supplies will be inadequate to accommodate planned new entry. OG&E has no undeveloped sites in its possession, although expansion at some existing sites is possible.

4) *Availability of generating equipment*

A critical component of gas fired generating facilities is the gas turbine, and concerns have been raised that shortages in gas turbine supplies could raise a barrier to new entrants in the Arkansas region. There is no question that the market for turbines is competitive, with General Electric, Siemens Westinghouse, Alstom Power and Mitsubishi all producing turbines suitable for large, electric system applications.

A potential concern is whether large block orders of turbines placed by a limited number of developers could give them short-term market power in the supply of turbines.[8] Such orders have been placed by Duke Energy (84

[8] It should be noted that to the extent that this is a problem, it would involve a world-wide shortage of turbines and market power problem, not a localized problem in the Arkansas region.

units),[9] FPL Group (66 units),[10] Calpine (54 units),[11] PG&E National Energy (50 units),[12] Entergy (32 units),[13] Reliant Energy (19 units),[14] and Dynergy (12 units).[15] Collectively, these seven entities have contracted for 317 turbine units for delivery over the next several years. While these contracts are large, worldwide production capacity estimated at 300 units per year, thus there is no evidence that near term turbine production capacity has been cornered.

It has been alleged for some time that as a result of high demand, the lead time for a new turbine is around three years. However, it should be noted that it was only in September of this year that PG&E National Energy announced its purchase of 50 turbines from three venders, all of which are to be delivered by 2004.[16] Also, as recently as November 15, Alstom announced contracts to provide two independent combined cycle stations located in Mexico and Malaysia.[17] Each of these projects will include three gas turbines, and both are expected to be on line by mid-2002. Partnerships between developers and companies with rights to turbines or other assets are common, and this provides an additional means for a project developer to obtain the necessary equipment. Mr. Coffman reports that there are over ten different developers working in Arkansas and Oklahoma alone. Last but not least, it should be noted that OG&E does not have any rights to future turbines.

5) *Transmission access and ancillary services*

As discussed earlier, transmission access, including access to the system by new generation facilities, is managed by the SPP on an open-access basis in accordance with FERC Orders 888 and 2000. These orders also establish

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[9] www.gepower.com/en_us/abo_ge_pow/html/releases/20000202.html. dated February 2, 2000.
[10] www.fpl.com/news/2000/contents/00036.shtml dated April, 2000.
[11] www.calpine.com/news/story.asp?news=154 dated May 22, 2000.
[12] www.pgecorp.com/news/releases/000911r.html dated September 11, 2000.
[13] www.shareholder.com/entergy...19991018-17781.cfm?ReleaseID=17781 dated October 18, 1999.
[14] www.gepower.com/en_us/abo_ge_pow/html/releases/20000126.html dated January 25, 2000.
[15] www.siemens.de/kwu/e/news/kwu034e.htm dated March 31, 2000.
[16] www.pgecorp.com/news/releases/000911r.html dated September 11, 2000.
[17] www.newsroom.a....com/en/press/see_press_p.htm?IDCP=en28 dated November 15, 2000.

requirements for provision of ancillary services, which will also be managed by the SPP. In neither case can any entity withhold these services as a way of creating a barrier to new generating facilities.

6) *Contractual Agreements*

Contractual agreements could limit entry into wholesale and retail power markets if they tied up a substantial portion of the potential customer's base for a long period of time.

There are long-term contracts which do extend into the retail open access period, but these are not entry barriers. The parties entering into such agreements do so willingly, setting terms for supply for a fixed period. While these customers may not be able to shop when retail markets first open, this is not an exercise of market power. Instead, these customers are simply not part of the active market until previously negotiated contracts expire.

H. Analysis of Potential Vertical Market Power in Wholesale Energy and Capacity Markets

As noted in Chapter I, vertical market power would be a concern if the incumbent utility could use its ownership or control over an input or output market to increase and maintain prices above competitive market levels in the market under examination. In the case of wholesale electric energy or capacity markets, vertical market power would be a concern if the utility could use its ownership of electric transmission facilities, fuel or fuel transportation facilities, or access to ultimate customers through the distribution network to prevent effective competition in generation services. As discussed immediately above, control of access to and charges for use of OG&E's transmission facilities will reside in the SPP RTO, which will be regulated by the FERC and required to provide service on a non discriminatory basis to all LSEs. Furthermore, because of its open access policies, and the abundance of gas supplies and transportation facilities in

Oklahoma, OG&E's ownership of Enogex poses no vertical market power problems.

Non discriminatory access to OG&E's distribution system and customer information is assured by the Affiliate Rules and the Commission's functional separation requirements.[18] OG&E's filed functionally separated business plan calls for dividing the now integrated electric utility operations into three business activities: - - generation, transmission, and distribution/customers services ("distribution") - - and separating these operations from any affiliated ESP. The business plan provides that each existing and newly created business or subsidiary will be housed in separate facilities, and will operate independently of each other pursuant to standards of conduct governing transactions among the affiliates.

OG&E's draft policies and procedures specifically prohibit preferential treatment of its competitive affiliates. Prohibited activities include representing that customers will be treated differently if they take service from the utility-affiliated ESP; providing advantages to the utility-affiliated ESP in pricing, terms and conditions, reliability, quality, design and equipment requirements, scheduling or timing; identifying potential customers for the utility-affiliated ESP unless the same information is made simultaneously available to all other ESPs; or conditioning or tying of any service or price term to customers taking service from the utility-affiliated ESP.

The books and records of the electric utility's regulated and unregulated businesses will be maintained in a format that can be readily ascertained and readily separated by business activity. These procedures are designed to prevent cost shifting from utility-affiliated competitive businesses to regulated monopoly businesses.

[18] If the SSP responsibility is transferred from the electric utility to its affiliated ESP, that ESP will by definition gain access to information about individual customers and their load characteristics. At the customer's request, this information must be shared with other ESPs, so it is unclear if the utility affiliated ESP can gain any significant advantage as a result of the customer knowledge gained by providing SSP service.

The functional separation of businesses and the affiliate rules, along with implementing policies and procedures, will be subject to continuing supervision by the Commission. These practices are explicitly designed to address vertical market power concerns and they should be adequate to do so.

I. Wholesale Market Power Conclusions

OG&E is unlikely to have market power in the markets for the supply of wholesale energy or capacity to customers in its Arkansas service area. This conclusion is founded on the following key facts; 1) OG&E's market shares are below 25 percent and the HHIs are below 1,700 for all energy and capacity market scenarios examined; 2) There are no significant barriers to entry into wholesale energy or installed capacity markets. A number of new generation projects are already underway in the Arkansas-Oklahoma area. Ease of entry ensures that prices will be at competitive levels over the long term.

Chapter V: Analysis of Retail Electricity Markets

A. Introduction

This chapter analyzes the potential for market power problems to arise in the markets for retail electric supply and billing services. Retail electric supply involves marketing delivered electricity to end use customers. The billing services being opened to competition in Arkansas are billing production and issuance, payment processing and collection, and related call center functions. As noted in Chapter III, ESPs will have the option of providing consolidated bills covering the service they furnish along with utility-supplied distribution services, or issuing a separate bill for their services. Utilities may elect to offer consolidated billing service as long as all ESPs are offered that service on a nondiscriminatory basis.

B. Retail Electric Supply

There is no meaningful way to analyze potential market power in retail electric supply by examining market shares or concentration because the market has not yet been created. However, it is clear that the viability of competition in retail electric supply will depend upon: (a) the existence of workably competitive (or regulated) wholesale markets for generation services and mechanisms to assure that all ESPs have nondiscriminatory access to those markets; and (b) the absence of substantial horizontal or vertical barriers to retail market entry by ESPs. The structure of the wholesale market for generation services was covered in the preceding chapter of this study. Also addressed there were vertical market power issues pertinent to analyzing both wholesale and retail electricity markets. That leaves for consideration potential horizontal impediments to ESP entry into retail electric markets. The MPMFRs list nine potential retail entry barriers for consideration. Each of these is addressed below.

1) *Economies of scale relative to market size*

The retailing function - - retail customer acquisition and retention; account maintenance; load aggregation and wholesale power procurement; billing and collections - - can be expected to be characterized by economies of scale. That is, per unit costs can be expected to decline as more customers are acquired. However, there is no reason to expect this to present a serious impediment to ESP entry because many of the costs can be spread over larger operations (such as regional or national electricity retailing, or other potentially complementary businesses such as telecommunication services), or outsourced. There are many relatively cost effective ways to reach even individual residential customers, including direct mail or newspaper inserts. Moreover, ESPs can control their initial entry costs by targeting desirable loads or geographic areas, and then expanding to other parts of the market after a solid foothold is established.

Retailing costs are likely to be relatively high for residential and small commercial customers, and relatively low for large industrial or commercial customers (including those that can purchase as a block). However, these costs are not unlike those facing any entrant in any industry seeking to reach individual retail customers. Public education programs designed to inform consumers of their choices can help reduce entry costs

2) *Non-duplicable or scarce resources*

Presumably this refers to critical inputs needed to provide electric service to retail customers that are scarce or difficult to duplicate. In addition to access to wholesale power markets, this could be seen as including access to distribution wires service, metering service, and customer information. These inputs will be furnished to all ESPs on nondiscriminatory terms at regulated cost-based rates. Therefore, they should present no impediment to entry in competitive retail electric markets.

3) *Product range or differentiation*

The primary bases for product differentiation are likely to be sales of "green" power, bundling electricity sales with other services (gas, telecommunication, cable, internet services, etc.), offering promotional inducements (frequent flyer miles, etc.), providing energy management services, offering hedging or financing options (level payments, fixed long term rates), and possibly for large customers, different degrees of interruptibility. There is no reason to expect incumbent utilities to have any special advantages in attempting to differentiate their product, and therefore product differentiation should not be viewed as a barrier to entry. Indeed, the prospect of being able to differentiate products as opposed to competing only on price terms, is likely to serve as an inducement for competitors to enter the business.

4) *Cost of and access to capital/cost of entry*

The retailing function is unlikely to be very capital intensive. ESPs will of course, incur start-up costs to learn the market environment, develop information systems and product offerings, and acquire customers. Moreover, ESPs will have to be creditworthy in order to contract for wholesale power on a long-term basis. If they choose to own power plants or interests in such plants, they will have to raise the capital to do so. However, there is no shortage of capital in the U.S. economy. As discussed previously, new entrants have successfully financed tens of thousands of megawatts of new generation capacity in the last few years, and that is by far the most capital intensive area any ESP would get into. Furthermore, electricity markets can be entered by a number of large diversified firms now in or outside the industry (other electric utilities, large EWGs, gas utilities, telecommunication companies, major retailers). Therefore, there is no reason to believe that the cost of or access to capital will pose a barrier to entry.

5) *Brand loyalty (effects of incumbency and name recognition and customer inertia)*

Brand loyalty can be a barrier to entry if the incumbent's position is such that substantial sums must be spent by new entrants to overcome the perception that superior services will be provided by the incumbent. The primary concern may be that customers will assume that taking service from an affiliate of the incumbent utility will provide them with more secure or stably priced service over the long term. The Commission has adopted several steps to address this concern. These include requirements for labeling to inform customers that the competitive affiliate is not regulated by the Commission, and that purchases from the unregulated affiliate are not necessary to continue to receive quality regulated services. The Commission Staff will also coordinate customer education programs to ensure consumers have sufficient information to make informed choices about energy services in a "competitively neutral" manner.[19]

[19] Docket No. 00-097-R, Order No. 3, page 6.

If this is done, then the competitive playing field will be as level as possible and new entrants will have to earn brand loyalty the old-fashioned way. Many potential competitors have strong brands they can trade on - - Exxon, Sears, AT&T, etc. It is too early to tell what brands will prevail in retail electric markets, and over the long run one would expect national brands to develop. The development of new brands will take time, and this process is inherent in the transition to a competitive retail market.

6) *Market characteristics such as the location of the utility's service territory and mix of customers*
ESPs can be expected to concentrate their marketing efforts on the most profitable customers. In most cases, this is likely to be very large customers where a small price discount can be decisive or where other value added services (e.g., energy management services) can be offered, or where demographic conditions are favorable. Customers outside the targeted area will have fewer options. Customers in these areas will have higher acquisition costs, and competition will likely be provided by those ESPs that specialize in serving such markets efficiently and can develop a sufficient market share to gain local effectiveness.

7) *Standard service package design and price*
It is self-evident that the design and level of the generation component of the SSP can have a major impact on the viability of retail competition (and also on customer exposure to any potential exercise of market power). If SSP prices are set below competitive market levels, retail competition will not emerge but customers will be protected from the exercise of market power by the availability of the low-cost SSP service. Setting a relatively low SSP price, therefore, is tantamount to continuing the existing regulatory regime. On the other hand, if SSP prices are set above market determined levels, they will serve as no impediment to the development of competition. In that case,

customer protection from the exercise of market power will depend upon the competitiveness of wholesale and retail power markets.

The design of the generation component of SSP rates will also have important influences on how the market operates. For example, if SSP rates are fixed for relatively long periods of time, competitive ESPs are likely to have to offer comparable products. If SSP rates are not seasonally differentiated and if customers can switch between SSP and market rates, gaming will be invited.

8) *Uniformity of Business Rules*

Uniformity in business rules is desirable to reduce the cost of doing business for all ESPs. Both the Commission and potential market participants are aware of this and work is underway in a Commission-sponsored effort to develop business rules in Arkansas that seek to balance this desire for reduced costs with other objectives associated with protecting consumers and ensuring good business practices.

C. Billing Services

Earlier this year in Docket No. 00-054-U, the Commission conducted a detailed review of billing services and concluded that these functions will be competitive upon retail open access. As the Commission stated, there was "virtually no testimony contradicting that there is a ready market of suppliers and an evolving infrastructure to support these services which will result in a reasonable transition to competition for the E[lectric] U[tility] function now regulated.[20] The MPMFR calls for market power analyses for each service expected to be opened to alternative suppliers, including billing services. It will not be possible to calculate market shares and HHIs for billing services until that market is opened and some experience is gained. Therefore, the market power analysis appropriately should focus on the potential for new entry.

Competitive billing is being allowed in California, Delaware, Illinois, Maryland, Oregon, Texas, Massachusetts, and Maine. Billing services are not unique to the electric power industry, and there are a large number of entities that provide the service, in a variety of ways, in different industries.

More important than the competitiveness of billing services itself is the advantages ESPs perceive in coupling billing with the energy services they provide. ESPs want to perform the billing service to improve their customer relationships and make it easier to provide complementary products with the basic energy services. Therefore, opening billing services to competition is likely to improve the climate for all competitive energy services.

D. Retail Market Power Conclusions

OG&E is unlikely to have market power over the provision of retail electric supply or billing services within its Arkansas service area because: 1) The relevant wholesale energy and capacity markets should be workably competitive; 2) Access to those markets, as well as to needed distribution services and customer information, should be assured by federal and state regulations already adopted; 3) There are no significant barriers to entry by new retail competitors, aside from that potentially created by setting SSP prices too low which by definition would prevent OG&E from having exercisable market power.

[20] Docket No. 00-054-U, Order No. 10, page 19.

APPENDIX 1

Modeling Approach Used to Develop Wholesale Energy Market Shares and HHIs

APPENDIX 1

Modeling Approach Used to Develop Wholesale Energy Market Shares and HHIs

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APPENDIX 1

Modeling Approach Used to Develop Wholesale Energy Market Shares and HHIs

Developing wholesale energy market shares requires an assessment of the ability of suppliers to deliver energy to the destination market economically. This analysis is conducted in two stages. The first stage involves economically dispatching resources in the electric power system to determine the sources of supply in the system. This stage recognizes physical limitations of the system such as planned and forced generation unit outages and transmission limits. The Prosym family of models from Henwood Energy Services, Inc. has been used for this purpose. The Prosym model produces hourly market prices, output from each generator, and transmission system flows. The Prosym output is used by the MSAT (Market Share Analytical Tool) model to calculate market shares of competitors that can economically deliver power to the destination market. MSAT is an LECG, LLC proprietary computer model specifically designed for this purpose.

A. Overview of the Prosym Model

Prosym is a commercially available production cost model used by a large number of electric utilities and other electric market participants to evaluate the operation of electric power systems. It performs chronological market simulations on an hourly basis. Prosym's objective function is to meet system load at the lowest cost, subject to operational constraints. The model requires a vast amount of information to characterize the operational limits of the system. This detail allows the model to recognize these limitations in the hourly dispatch of the system, such that the resulting forecasts of prices, generation levels, and power flows between areas are internally consistent and feasible.

Generating units in Prosym are usually modeled individually, although some very small or distant generators are combined to reduce computing time. Unit data includes fuel costs, multi-point heat rate curves, other variable operating costs, start-up costs, ramp rates, minimum up and down times, must-run characteristics, other limitations (e.g., water availability for hydroelectric stations), forced outage rates, planned outage schedules, transarea assignment, and unit ownership, including joint ownership. Prosym has the flexibility to model situations such as:

- NUG units dispatching to contract terms, not cost-based economics;
- Scheduling of hydroelectric units to optimize value, subject to limitations on water availability and other water flow restrictions;
- Pumped storage unit operations;
- Joint ownership;
- Rational unit commitment, such as units remaining in operation at night when prices fall below variable costs, in order to avoid start-up costs, or units not starting during the peak period if prices are insufficient to recover start-up costs; and
- Recognition of spinning reserve requirements in the unit commitment logic.

System dispatch is completed under the assumption of cost-based bidding by all units in the system. Alternative bidding strategies can be employed to assess strategic bidding outcomes.

In order to address transmission constraints, the Prosym model adopts a system topography in which all generation and load is assigned to different zones called transareas. The model allows flows of power between transareas, subject to transmission limits (MWs), losses, and transmission tariffs. There are no constraints, losses or costs associated with moving energy within a transarea. Prosym recognizes the transmission paths as independent connections, with power assumed to flow across the least-cost path(s) up to the various limits of the system.

The DOJ/FTC Merger Guidelines, as well as the FERC Merger Guidelines set forth in Order 592, Appendix A, recognize that market share analyses should include the supply that could be delivered to the destination market by competitors at a cost no greater than 5 percent above the competitive market price. To perform this analysis, two Prosym runs are required. The first run is called the Base Case and results from the standard operation of the model. In the second run, called the Plus 5 percent case, a large phantom load is placed in the destination market, along with a phantom generator whose costs equal 105 percent of each hour's market clearing price for that transarea as determined in the base case run. This by definition produces market clearing prices in the destination transarea 5 percent higher than the base case prices. Accordingly, the Plus 5 percent dispatch identifies all competitors that can economically deliver energy to that market at prices within 5 percent of the competitive levels.

Prosym output used in the MSAT market share analysis includes hourly generation of individual units, hourly market clearing prices in each transarea, and hourly utility load for each transarea. These data are provided for both the Base Case and Plus 5 percent case. MSAT also incorporates the transarea definitions, transmission capacity limits, and station ownership (including joint ownership) used in Prosym.

B. Overview of the MSAT Model

MSAT is a proprietary model developed by LECG to post-process the Prosym output to calculate the market share and HHI statistics. MSAT is written in the SAS programming language. These calculations require answers to two questions.

- Which potential suppliers of capacity can economically compete in the destination market?
- How should transmission constraints be reflected in the market share calculations?

MSAT develops market share calculations by answering these questions sequentially. The MSAT program begins the process of identifying which transareas can compete for customers in the destination market by first identifying the feasible transmission paths that can be used to deliver energy to the destination market. For this discussion, a Tier I transarea is one directly connected to the destination transarea; a Tier II transarea is one whose most direct path to the destination transarea requires passing through one other transarea (i.e., a Tier I transarea); and a Tier III transarea is one that can reach the destination transarea only by passing through two intervening transareas.

MSAT places limits on feasible transmission paths. In order to be included, the transarea must be able to reach the destination market in three steps, where a step is a transfer from one transarea to another. Thus, all potential competitors must be located in Tier I, II or III. While there clearly could be cases where Tier IV generation could be competitive, the three-tier limit greatly increases the manageability of the analysis without eliminating competitors likely to be of significance in the market share calculations. Beyond this, each step of the overall transmission path must be to an equal or lower tier transarea. Thus a path from Tier II to Tier II to Tier I to Destination is permitted, but a Tier I to Tier II to Tier I to Destination path is not allowed.

The next step is to identify supply areas that are economic. To do this, transarea prices and transmission costs across each step are evaluated. For a single-step path from a Tier I transarea, the price in the Tier I transarea in the Base Case run, plus the transmission cost (both tariff rates and losses), must be equal to or less than the destination market price in the Plus 5 percent case in order for the Tier I transarea to be included as a supplier to the destination market. This is a direct test of whether the supply region can pass the economic deliverability test. For multi-step transmission paths, each transmission step must pass the economic test in order to be included in the market.

The completion of this screening analysis identifies the scope of the geographic market. Next, a determination of the quantity of power that can be delivered from each supplier to the destination market is required. For the supplier whose market power is being evaluated, OG&E in this case, the total generation of its units in the Base Case is considered. For other competitors, the quantity of power they supply in response to a 5 percent price rise is relevant, so their generation in the Plus 5 percent case is used.

In order to reflect transmission constraints, a "sequential squeeze-down" methodology is employed. For example, assume that transmission path Tier II to Tier I to Destination is found to represent an economic source of supply in a given hour, and that both transarea Tier II and Tier I have three competitors, each with 600 MW of competitive generation, and the transmission paths are also rated at 600 MW. Each of the competitors in Tier II (totaling 1,800 MW) must squeeze across the 600 MW transmission line, and MSAT allocates each competitor 200 MW of the transmission path into the Tier I transarea market. There is now 2,400 MW of competitive power in Tier I, and a transmission path of only 600 MW to the destination transarea. This results in a 25 percent squeeze-down of capacity, such that each Tier II competitor is allocated 50 MW of supply to destination market, and each Tier I competitor is allocated 150 MW of supply to the destination market.

The market share figures for each hour are then calculated based on the competitive supply within the destination market, plus that which can be imported across the transmission paths into the destination market. Market share calculations for both economic capacity and available economic capacity are determined by this process. In the available economic capacity analysis, the load obligations of a supplier is subtracted from that supplier's economic capacity before determining the quantity of energy that could be delivered to the destination market. The hourly results are then be tabulated by season and time-of-day to provide market shares and HHIs for each period.

APPENDIX 2

Detailed Description
of
Energy and Capacity Market Analyses for OG&E Arkansas

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Detailed Description of
Energy and Capacity Market Analyses for OG&E Arkansas

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APPENDIX 2

Detailed Description of

Energy and Capacity Market Analyses for OG&E Arkansas

A. Modeling and Data Used

This study evaluates the competitiveness of the relevant wholesale energy market, which in this case is the market in which retail customers or their suppliers in OG&E's Arkansas service territory will procure their power supplies. To carry out this analysis, the Prosym model has been run for the entire eastern interconnect plus ERCOT. The use of such a broad region means that even indirect influences from distant markets will be reflected. As a starting point, the full dataset associated with the Prosym model was used.[1] This provides detailed generator and transmission system characteristics for the entire region.

Several significant changes to the basic dataset have been made to better reflect current industry conditions. These are discussed below and presented in attachments to this appendix. The most significant change is to the transmission system configuration used by Prosym. Prosym generally assumes that each utility is a separate transmission area (or "transarea") with no internal transmission constraints and losses, while flows between transareas are subject to specified limits and losses. The Prosym transmission configuration was revised for this study to reflect the results of analyses by Mr. Ricardo Austria of Power Technologies, Inc. ("PTI") which are described in his detail in his testimony. As indicated there, OG&E's retail customers in Arkansas are contained within a slightly larger transmission area, referred to here as the AR-FS or Fort Smith area, which includes a small amount of load in Oklahoma currently served by OG&E, as well as 57 MW load served by American Electric Power Company ("AEP"),

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[1] The database version: EI_ERCOT_4_7_0-0 (which includes the Eastern Interconnection and ERCOT) was used. This is a proprietary product of Henwood Energy Services, Inc. It is available from the vendor and is required to replicate the results presented below.

and 45 MW of load served by Western Farmers Electric Cooperative. (All load figures are forecast for 2002.) OG&E's peak load in this area is 873 MW and the area's total peak load is 975 MW.

The AR-FS area is directly connected to three areas, called Ent-No, AR-NW, and OK-East in this study. The Ent-No area consists primarily of the northern portion of Entergy's service territory and it has a peak load of 5,433 MW. The AR-NW area is located in the northwest corner of Arkansas. This region contains 1,672 MW of load, of which 60 percent is served by AEP and the remainder is served by the Southwest Power Authority ("SPA"). The OK-East area contains about half of Oklahoma and is separated from the west by a line that starts at roughly the midpoint of the Oklahoma-Kansas border and extends southeast, between Oklahoma City and Tulsa and exits the state near the point where Arkansas, Oklahoma and Texas meet. The "bubble diagram" in Attachment 1 shows the redefined transmission areas for the SPP region used in this study. Statistics on the load and utilities included in each transmission area are provided in Attachment 2.

This reconfiguration reflects the need to model the transmission system based on underlying physical limits, rather than the ownership of transmission facilities, to properly capture market dynamics. This is required by the MPMFRs and was also the basis upon which Entergy divided its system in its market power filing. In this analysis Entergy's assumed split between Ent-No and Ent-So, as well as the transmission limits among the Entergy areas, were based on Entergy's recent market power filing with this Commission. To simplify this analysis, however, three of the Entergy-specified areas were grouped into the single Ent-So area. Transmission limits between transareas in the SPP were developed by Mr. Austria are presented in Attachment 3. The transmission limits are based on total transfer capability ("TTC"). TTCs properly measure the amount of energy that can move between areas in response to price signals. TTCs should not be reduced to reflect capacity benefit margin ("CBM") and transmission reserve margin ("TRM") because these margins do not limit real-time energy flow. Neither is it appropriate to subtract transmission capacity that already has been contracted in this analysis. Energy flowing over contracted transmission paths contributes to available supplies in the receiving market area. Moreover, transmission capacity unused by its owner is available for use by others on a real-time basis.

Four sets of TTCs have been used in the analysis, depending on season and loading levels. TTCs for typical loading levels have been used for most hours, with one set of figures covering the Summer-Fall period and another for Winter-Spring. In addition, separate peak-load-condition TTCs are used for the summer and winter super peak periods.

The transmission topography in distant areas (i.e., PJM, Florida, etc.) is based on the Prosym dataset, but has been simplified to reduce the overall complexity of the system and stay within Prosym's design limits. These distant transareas are defined in Attachment 2, and the transmission links between them are identified in Attachment 4. The rating of these distant lines are taken from the Prosym dataset, are proprietary, and are not separately reported. The Prosym transmission rating assumptions are based on a variety of inputs and reflect the best judgement of the vender of realistic, operational limits to energy flow.

Transmission costs within SPP are set to zero, to reflect the license-plate tariff structure of the pool, and Entergy is assumed to be part of the SSP. For transmission into and out of SPP, as well as among all other areas, a tariff of \$2/MWh on-peak and \$1/MWh off-peak was used. These rates are typically lower than the maximum transmission tariffs approved by the FERC. The lower values are more representative of costs actually incurred in energy transfers, and reflect the actual discounting which takes place as utilities price the service to facilitate trade.

The Prosym dataset for generating units is based on 1999 EIA Form 411 data, supplemented from various sources in order to establish the detailed operating characteristics necessary for Prosym operations such as multi-part heat rate curves. The capacity values of units in SPP were audited and corrected to match the most recently available EIA Form 411 data. The updated generating unit data is presented in Attachment 5, with resources organized by transmission areas and owner.

Within the AR-FS area there is 681 MW of generating capacity. OG&E's only resource in the area consists of its contract for the output of the AES Shady Point station, a 320 MW, 2 unit, coal-fired facility owned by AES and located just inside the Oklahoma border. OG&E purchases the output of the station under a long term, dispatchable contract, with the variable cost of energy indexed to OG&E's own coal costs. The contract requires OG&E to take energy at a minimum annual capacity factor of 65 percent. In fact, the AES station is operated as a base-loaded plant and has a capacity factor around 90 percent. Other resources in the area are hydroelectric facilities owned by SPA totaling 302 MW, and a 59 MW oil-fired station owned by the Arkansas Electric Cooperative Corp. ("AECC"). Within directly interconnected areas, OG&E's only capacity is the 1,699 MW Muskogee station in OK-East. Muskogee is a four unit station, containing three coal units with a combined capacity of 1,515 MW and a gas-fired steam unit rated at 184 MW. The remainder of OG&E's generation capacity (4,418 MW) is located in the OK-West transmission area.

No must-run obligations have been assumed to alter economic dispatch in these analyses. Mr. Austria reports that no unit in AR-FS or OK-East is required to be must-run, and this covers the region of interest where OG&E might have market power. It should be noted that this is a conservative assumption, since the addition of must-run obligations would only reduce OG&E's potential ability to exercise market power: If an OG&E unit is declared must-run, OG&E's ability to withhold the unit's output is directly curtailed.

New units that can be expected to be added in the SPP area by June 1, 2002 are identified in the testimony of Mr. Jack Coffman of OG&E. For all other regions, new units identified in the Prosym dataset with in-service dates on or before June 1, 2002 are included. Most of the new units will be either simple or combined cycle, gas-fired units, and these are assumed to have full load heat rates of 11,000 Btu/kWh and 7,100 Btu/kWh, respectively, where unit-specific data was not available. A list of all new SPP generating units included in this analysis is provided in Attachment 6.

Prosym system hourly load data, which is based on 1999 EIA Form 411 was updated using the 2000 Form 411 to reflect more recent data for the SPP utilities, including the projections for 2002. Where service territories were divided, the split of total load between the different transareas was calculated using the relative peak loads of the areas found in the load flow studies of Mr. Austria. Peak 2002 load assumptions for each SPP area are provided in Attachment 2 and was used in the available economic capacity analysis.

In areas where retail competition has been approved, incumbent utilities' regulated load obligations will be reduced as customers turn to competitive alternatives. However, utilities will remain obligated to provide standard offer or provider of last resort services at regulated rates, and evidence in other jurisdictions indicates that a substantial number of customers are likely to remain on one of those services. This regulated offering creates an obligation on the existing utility that is equivalent to the native load obligation. For this analysis, the Standard Service Package ("SSP") or its equivalent is assumed to be the source of supply for 75 percent of existing customers of investor owned utilities and electric cooperatives in states where retail competition has been authorized. The amount of switching that actually occurs depends on a number of factors, and in particular the relative price of the SSP option. By assuming 25 percent of customers choose an alternative suppler, the analysis is considering a situation where there is a fair degree of early switching by consumers. Municipal utility customers are assumed to remain with their traditional suppliers, as is permitted under the Arkansas legislation. Retail competition is assumed to be introduced at roughly the same time in Arkansas, Oklahoma and Texas, and the same default service penetration figures are assumed for each state. Assuming that Texas commences retail competition earlier than Arkansas or Oklahoma would have very little effect on the analysis.

Throughout the analysis, SPA's generation capacity is treated as fully committed. The capacity is low-cost hydroelectric generation and is fully contracted to cooperative and municipal utilities. Regardless of restructuring developments, these facilities will run and produce energy in a competitive fashion, because they have very low costs and their operations are largely under the control of the federal government.

Fuel price assumptions were based on a combination of historical costs and forward prices. For coal units, 1999 fuel costs for each SSP station were taken from FERC Form 423, and escalated according to the rate in the DOE-EIA Annual Energy Outlook – 1998, to develop the 2002 forecast. Gas prices for 2002 were developed using the futures market. Year 2002 monthly forward prices on NYMEX as of September 21, 2000 were used, and with prices around $4.00/mmBtu, these reflect the substantial price increases that occurred in the first half of the year. Delivery charges and regional prices differences were developed based on historical averages. Changes in the Prosym dataset fuel cost assumptions are presented in Attachment 7.

Restrictions on NOx and SO_2 emissions were addressed by placing a $1,500/ton and $150/ton cost, respectively, on such emissions, based on the Prosym emission rate assumptions. These costs reflect an estimate of market prices for emission credits in the 2002 timeframe.

Prosym was run using a representative week to represent each month of the year, for a total of 2,016 hours for the year. The hourly results have been compiled by season and time of day. The seasons evaluated are summer (June, July and August), winter (December, January, and February) and spring/fall. Within each season there are peak, shoulder and off-peak periods. The peak period includes 8 hours a day, 11:00 a.m. to 6:59 p.m., Monday through Friday. Off-peak includes 8 hours a day, 11:00 p.m. to 6:59 a.m., Monday through Friday, and 12 hours a day, 8:00 p.m. to 7:59 a.m., on weekends. The shoulder period consists of all other hours. In addition, two super peak periods consisting of the 100 hours with the highest load in both the summer and winter are evaluated. The peak-period TTCs were used for the summer and winter super-peak periods, with the typical loading condition TTCs used for all other periods.

B. Hypothetical Monopolist Test and Geographic Market Definition

To test whether AR-FS is a separate destination market, hypothetical monopolist test was conducted for the AR-FS market. Under this test, an area is deemed to be a separate market if an entity owning all resources in the area could profitably raise prices by 5 percent or more. Withholding of SPA capacity was not included, however. SPA is a government entity covered by power sale agreements where output is fully contracted to preference customers. As a result, there is no potential for this capacity to be withheld from the market. To conduct the hypothetical monopolist analysis, a threshold a test was conducted to determine whether market prices could be raised by 5 percent, regardless of profitability. All non-SPA capacity in the AR-FS area was withheld from the market, and as indicated in Attachment 8, prices rise by less than 5 percent in all but the summer super peak period when prices rise by 12.2%. Additional analysis indicates that no anticompetitive bidding or withholding strategies during this period would increase profits. As a result, the AR-FS market is not a separate market, and instead is part of a broader market including neighboring areas.

The neighboring regions will not always be in equilibrium with each other, however. For example, Ent-No and OK-East are connected to each other by lines of limited capacity through AR-FS. When prices between these larger markets diverge, the lines between them will congest on one side or the other of the AR-FS area. At such times, AR-FS is part of the market to which it is connected by uncongested lines. This could be either market.

Both Ent-No and OK-East are large markets that are also load pockets.[2] That is, substantial generation within each area is required to meet peak load conditions. When the transmission lines between AR-FS and Ent-No are not congested, the combined region is a single market. When AR-FS is in equilibrium with Ent-No, the combined market is a load pocket, and a hypothetical monopolist test would clearly indicate that it is a separate relevant market. The same is also true of the combined AR-FS and OK-East market. This is not true of a combined AR-FS and AR-NW market. Under extreme peak conditions, the maximum flow between these areas is only 29 MW, which is too small to allow these two areas to operate as a single market. During other times, the transfer limits between AR-FS and AR-NW increase substantially, but so do the AR-NW's transmission capacities with its neighbors. At those times, it can import over 2,700 MW and export over 4,500 MW; therefore, the combined AR-FS/AR-NW area is not a load pocket. Nevertheless, to simplify the analysis and conservatively address hypothetical market combinations with other neighbors, a combined AR-FS/AR-NW market has been evaluated for all periods except for the summer super-peak period.

Rather than try to predict when congestion might occur with each neighbor, the MSAT model has been run three times, assuming that AR-FS is part of each of

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[2] As defined on page 7 of the MPMFR, a load pocket is, "an area with constrained transmission access from other areas, such that load within the area exceeds import capability at certain times, with the result that certain generating units within the area may need to be run in order to meet load and/or provide system stability."

either the Ent-No, AR-NW, or OK-East market. Under this approach each of the three narrowest possible markets for the relevant Arkansas customers are analyzed for all periods, without any determination of the likelihood of any particular circumstance. This is clearly conservative. The market simulation indicates that the AR-FS area will be in equilibrium with all three of the neighboring areas 70 percent of the time and with two areas 87 percent of the time. OG&E's market shares are highest when the AR-FS area is assumed to be in equilibrium solely with the OK-East area, yet the simulation suggests that this will only occur in 1 percent of the hours in a year. Any time that the AR-FS area is in equilibrium with multiple neighboring areas, OG&E's market shares will be lower than the highest market share calculated for the individually coupled areas. In fact, OG&E's market share in a market consisting of three or four areas may be lower than any of the market shares presented in the analysis.

C. Market Share and HHI Results – Base Case Energy Market Analyses

The results of the base case analysis are presented in Attachment 9. A summary table is provided that presents OG&E's average delivered MWh, OG&E's market share, and the market HHI for both the total and available economic capacity analysis. Results are provided for each of the eleven periods analyzed (i.e., three time periods for each of three seasons, plus summer and winter super-peak periods), and assuming AR-FS is part of either the Ent-No or OK-East. As shown in Attachment 9, OG&E's market share in the relevant Arkansas market is highest when AR-FS is in equilibrium with only the OK-East market, because OG&E controls generation in both AR-FS (320 MW) and OK-East (1,699 MW), and this is virtually all base loaded generation. OG&E's market share of total economic capacity in this market ranges from 17.3 to 22.5 percent, and its share of available economic capacity ranges from 4.0 to 13.7 percent. OG&E's market shares are lower when the AR-FS area is in equilibrium with either the Ent-No or AR-NW areas. All HHIs are less than 1,600.

D. Market Share and HHI Analyses – Alternative Energy Market Analyses

1. Retail Open Access and SSP Penetration

Sensitivity analyses have been completed to test the impact on the available economic capacity calculations of the base case assumption that 75 percent of customers who have access to competitive markets will remain on SSP service or its equivalent. As alternatives, cases with 90 percent and 60 percent of the customers on default service where run. As shown in Attachment 10, some OG&E market shares increase, but remain under 20 percent.

2. New Entry

A low entry sensitivity analysis has been completed, in which the capacity of each new entrant included in the base case is cut in half. OG&E's market share is less than 23 percent in all periods and markets. Detailed results are presented in Attachment 11.

3. Fuel Price Scenarios

Changes in relative fuel prices can change the competitiveness of different types of generators and accordingly change the calculated market shares and HHI. Generally speaking, coal and nuclear fuel costs are relatively stable, while gas and oil prices can change dramatically. One need only look at price changes over the last year to see this volatility. The base case analysis uses recent forward prices for gas and oil, which reflect current, relatively high prices. For example, gas prices during 2002 range around $4.00/mmBtu. High and low fuel price sensitivity analyses were completed by increasing gas and oil prices by 20 percent, or reducing them by 40 percent, respectively. The low-side sensitivity was expanded beyond 20 percent in order to cover price levels of a year ago. No changes in coal or other fuels costs were assumed in these sensitivity analyses.

By not changing coal prices, the full effect of the relative fuel price change can be evaluated. The fuel price assumption in the sensitivity analysis have been presented in Attachment 7.

The results of the fuel price sensitivity analyses are presented in Attachments 12 and 13 for high and low gas/oil price assumptions, respectively. OG&E's market share in the relevant Arkansas market is 23.2 percent or lower in all periods, for all market definitions.

4. RTO operations

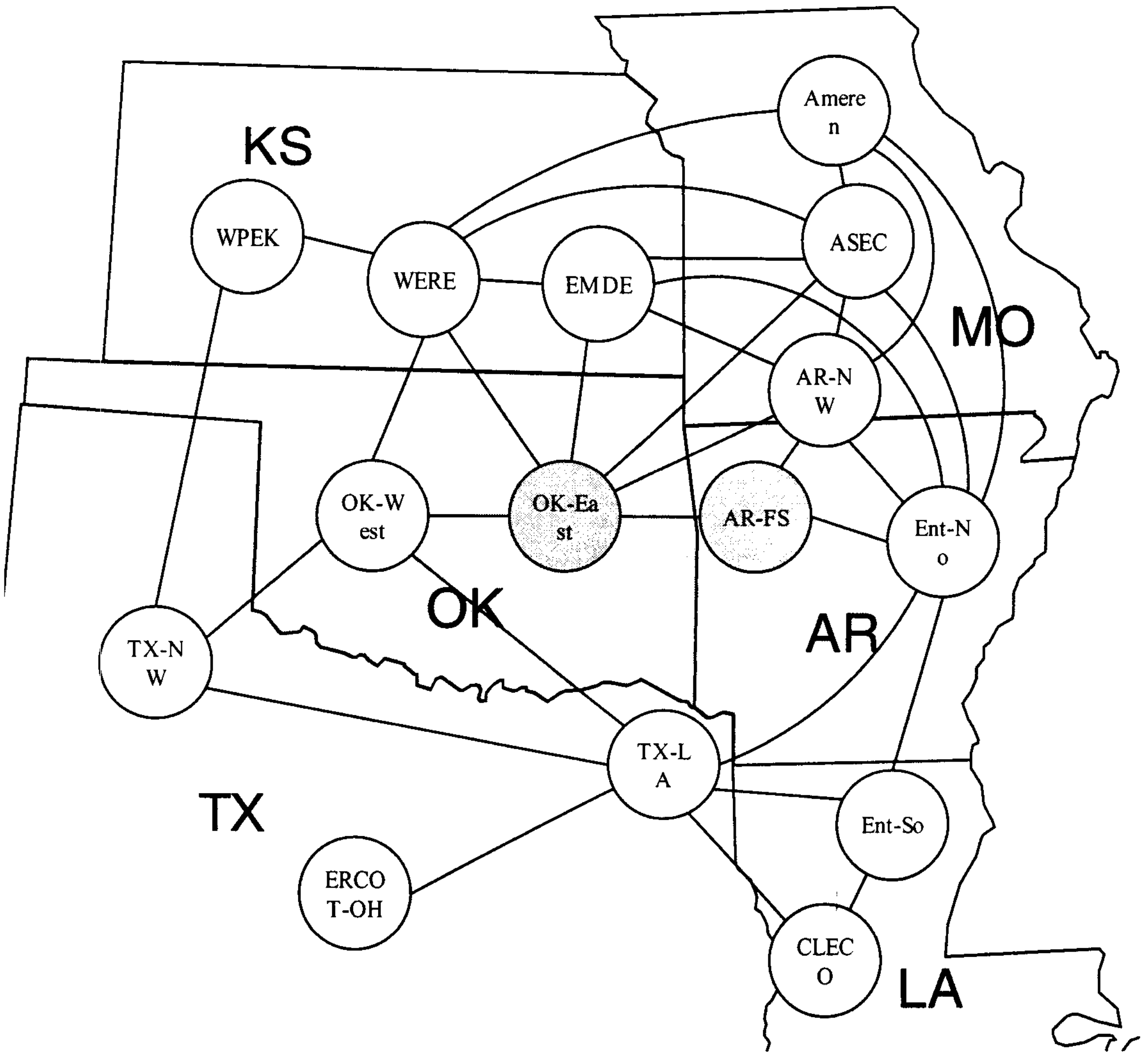
The SPP RTO has not been approved by the FERC and is not in operation, although a revised application was submitted on October 15, 2000. OG&E is part of the SPP and anticipates being part of the RTO when implemented. The MPMFRs require analyses be conducted both with and without an RTO if a utility is not a member of a FERC approved RTO. Absent a RTO, OG&E still expects to be part of the SPP; the pool has already adopted non-pancaked transmission rates and assumed responsibility for managing congestion. Therefore, assuming no RTO would have little direct impact on these analyses. The lack of an RTO could result in Entergy staying out of the SSP, however, and this would lead to incremental transmission costs for moving energy between Entergy and the SPP. To prepare a "no RTO" sensitivity analysis, transmission charges of $2/MWh on-peak and $1/MWh off-peak were applied to energy transacting between Entergy and SPP. OG&E's market shares remain below 23 percent and complete results are presented in Attachment 14.

E. Capacity Market Analyses

The capacity market analysis was completed with the same data, subject to some modifications. The market was evaluated for only summer super-peak conditions, when capacity requirements are tightest. The TTC transmission capacities were reduced by 10 percent to provide an estimate of the firm transmission capacities. Since capacity obligations typically include a requirement for reserves, and SPP has historically required a 12 percent capacity margin, demand for capacity will be 13.6 percent higher than peak energy demand. As with the energy market analysis, the capacity market is evaluated as part of a neighboring market, which is limited to either Ent-No or OK-East because transmission capability to AR-NW is insufficient to allow that areas to operate in equilibrium with AR-FS during summer super-peak periods. Capacity included in the market consists of in-area generation plus supplies that can be imported. Imported capacity is reduced prorata to reflect firm transmission limits. The results are presented in Attachment 15, which indicates that OG&E's market share is under 20 percent for the relevant Arkansas customers regardless of which transmission lines may be binding.

Attachment 1

Transmission Areas in SPP



Attachment 2

2002 Peak Load and Energy Demand by Transmission Area and by Utility

TransArea	Utility Name	Utility Abbreviation	State	Region	Peak Load (MW)	Demand (GWh)	Load Ratio
Alliant	IES Industries/Central Iowa Power Cooperative	IESC	IA	MAPP	2,498	14,528	100.0%
Alliant	Interstate Power Company	IPW	IA	MAPP	1,011	5,877	100.0%
Ameren	Union Electric Company	UE	MO	MAIN	8,060	41,182	100.0%
AR-FS	Oklahoma Gas & Electric Company	OKGE	AR	SPP	620	2,837	10.7%
AR-NW	Southwestern Electric Power Company	SOEP	AR	SPP	244	1,176	5.9%
AR-NW	Southwestern Power Administration	SWPA	AR	SERC	38	165	5.4%
AR-NW	Southwestern Power Administration	SWPA	AR	SPP	420	1,832	60.0%
ASEC	Associated Electric Co-Operative	ASEC	MO	SERC	3,897	19,702	100.0%
BPU	Board of Public Utilities, Kansas City	BPU	KS	SPP	495	2,452	100.0%
CAJN	Cajun Electric Power Coop.	CAJN	LA	SERC	1,708	7,561	100.0%
CLECO	CLECO Corp	CLECO	LA	SPP	1,968	9,752	100.0%
ECAR-TA	Allegheny Power System	APS	PA	ECAR	8,229	49,895	100.0%
ECAR-TA	American Electric Power Co.	AEP	OH	ECAR	20,407	120,268	100.0%
ECAR-TA	AMP-Ohio (Central)	AMP-C	OH	ECAR	233	1,290	100.0%
ECAR-TA	AMP-Ohio (North Central)	AMP-NC	OH	ECAR	297	1,643	100.0%
ECAR-TA	AMP-Ohio (North)	AMP-N	OH	ECAR	242	1,364	100.0%
ECAR-TA	AMP-Ohio (Northeast)	AMP-NE	OH	ECAR	351	1,978	100.0%
ECAR-TA	AMP-Ohio (Northwest)	AMP-NW	OH	ECAR	131	730	100.0%
ECAR-TA	AMP-Ohio (Southwest)	AMPSW	OH	ECAR	182	1,023	100.0%
ECAR-TA	AMP-Ohio (Western)	AMP-W	OH	ECAR	170	960	100.0%
ECAR-TA	Big Rivers Electric Co-op	BREC	KY	ECAR	1,435	10,021	100.0%
ECAR-TA	Buckeye Power, Inc.	BUCK	OH	ECAR	1,367	7,596	100.0%
ECAR-TA	Cincinnati Gas & Electric Co.	CG&E	OH	ECAR	4,858	26,960	100.0%
ECAR-TA	City of Lansing	COL	MI	ECAR	494	2,521	100.0%
ECAR-TA	Cleveland Electric Illuminating Co.	CEI	OH	ECAR	4,320	22,670	100.0%
ECAR-TA	Consumers Power Company	CPC	MI	ECAR	8,240	42,334	100.0%
ECAR-TA	Dayton Power & Light Co.	DPL	OH	ECAR	2,840	16,697	100.0%
ECAR-TA	Detroit Edison Company	DECO	MI	ECAR	11,670	56,234	100.0%
ECAR-TA	Duquesne Light Company	DLCO	PA	ECAR	2,777	14,411	100.0%
ECAR-TA	East Kentucky Power Coop.	EKPC	KY	ECAR	1,925	9,765	100.0%
ECAR-TA	Edison Sault Electric Company	ESEC	MI	ECAR	167	891	100.0%
ECAR-TA	Hoosier Energy Rural Elec.	HEC	IN	ECAR	1,100	5,300	100.0%
ECAR-TA	Indiana Municipal Power Agency	IMPA	IN	ECAR	878	4,580	100.0%
ECAR-TA	Indianapolis Power & Light	IP&L	IN	ECAR	3,047	17,330	100.0%
ECAR-TA	Kentucky Utilities Co.	KUC	KY	ECAR	3,976	20,192	100.0%
ECAR-TA	Louisville Gas & Electric	LG&E	KY	ECAR	2,445	12,418	100.0%
ECAR-TA	Municipal Cooperative Coordinated Pool (Michigan)	MCCP	MI	ECAR	1,145	5,676	100.0%
ECAR-TA	Northern Indiana Public Service	NIPS	IN	ECAR	2,965	16,106	100.0%
ECAR-TA	Ohio Edison Company	OES	OH	ECAR	6,508	34,154	100.0%
ECAR-TA	Ohio Valley Electric Corp.	OVEC	OH	ECAR	1,955	15,241	100.0%
ECAR-TA	PSI Energy, Inc.	PSI	IN	ECAR	6,150	34,132	100.0%
ECAR-TA	Southern Indiana Gas & Electric	SIGE	IN	ECAR	1,289	6,275	100.0%
ECAR-TA	Toledo Edison Company	TE	OH	ECAR	1,799	9,443	100.0%
ECAR-TA	Wabash Valley Power Association	WVPA	IN	ECAR	1,165	6,475	100.0%
ECAR-TA	Wolverine Power Supply Coop	WPSC	MI	ECAR	358	2,024	100.0%
EDE	Empire District Electric Co.	EMDE	MO	SPP	1,062	4,969	100.0%
ENT-No	Arkansas Electric Coop. Corp.	AREC	AR	SERC	2,395	11,669	100.0%
ENT-No	Entergy Corporation	ENTR	AR	SERC	3,038	16,249	15.0%
ENT-So	City of Clarksdale	CLWL	MS	SERC	56	217	100.0%
ENT-So	City of Sikeston	SIKE	MO	SERC	69	305	100.0%
ENT-So	Entergy Corporation	ENTR	LA	SERC	17,218	92,076	85.0%
ENT-So	Sam Rayburn G & T, Inc.	SRGT	TX	SERC	352	1,593	100.0%
ERCOT-OH	Brownsville Public Utilities Board	BROV	TX	ERCOT	233	1,060	100.0%
ERCOT-OH	Central Power & Light Company	CP_L	TX	ERCOT	4,580	24,667	100.0%
ERCOT-OH	City of Austin, Electric Utility Dept.	AUST	TX	ERCOT	2,324	11,618	100.0%
ERCOT-OH	City Public Service of San Antonio	CPSA	TX	ERCOT	4,018	18,923	100.0%
ERCOT-OH	Houston Lighting & Power Company	HL_P	TX	ERCOT	14,223	73,635	100.0%
ERCOT-OH	Lower Colorado River Authority	LCRA	TX	ERCOT	2,627	12,981	100.0%
ERCOT-OH	South Texas & Medina Electric Cooperative Pool	ST_M	TX	ERCOT	370	1,736	100.0%
ERCOT-OH	Texas Municipal Power Pool	TMPP	TX	ERCOT	2,922	13,430	100.0%
ERCOT-OH	Texas-New Mexico Power Company - Gulf Coast Region	TNMP	TX	ERCOT	1,120	4,560	100.0%

Attachment 2

2002 Peak Load and Energy Demand by Transmission Area and by Utility

TransArea	Utility Name	Utility Abbreviation	State	Region	Peak Load (MW)	Demand (GWh)	Load Ratio
ERCOT-OH	TU Electric Company	TUEC	TX	ERCOT	20,751	104,439	92.6%
ERCOT-OH	TU Electric Company	TUEC	TX	ERCOT	1,653	8,322	7.4%
ERCOT-OH	West Texas Utilities Company	WETU	TX	ERCOT	1,586	8,351	100.0%
FRCC	City of Lake Worth Utilities	CLWU	FL	FRCC	0	0	100.0%
FRCC	City of Tallahassee Electric Dept.	TALL	FL	FRCC	550	2,703	100.0%
FRCC	Florida Municipal Power Agency	FMPA	FL	FRCC	727	4,003	100.0%
FRCC	Florida Power & Light Company	FLPL	FL	FRCC	19,426	96,789	100.0%
FRCC	Florida Power Corporation	FLPC	FL	FRCC	8,271	39,525	100.0%
FRCC	Gainesville Regional Utilities	GAMW	FL	FRCC	436	1,992	100.0%
FRCC	Jacksonville Electric Authority	JACO	FL	FRCC	2,742	12,805	100.0%
FRCC	Kissimmee Utility Authority	KUAM	FL	FRCC	296	1,232	100.0%
FRCC	Lakeland Dept. of Electric & Water Utilities	LALW	FL	FRCC	602	2,865	100.0%
FRCC	Orlando Utilities Commission	OUC	FL	FRCC	1,108	5,107	100.0%
FRCC	Seminole Electric Cooperative, Inc.	SECI	FL	FRCC	3,321	12,962	100.0%
FRCC	Tampa Electric Company	TAEC	FL	FRCC	3,755	18,713	100.0%
FRCC	Vero Beach Municipal Utilities	VEBM	FL	FRCC	179	846	100.0%
Indep	City Power & Light, Independence	INDN	MO	SPP	303	1,082	100.0%
LA_Other	City of Alexandria	ALEX	LA	SPP	165	669	100.0%
LA_Other	City of Lafayette	LAFA	LA	SPP	426	1,906	100.0%
LA_Other	Louisiana Energy and Power Authority	LEPA	LA	SPP	253	1,082	100.0%
MAAC-TA	Atlantic Electric	AE	NJ	MAAC	2,517	11,801	100.0%
MAAC-TA	Baltimore Gas & Electric Company	BG&E	MD	MAAC	6,540	32,760	100.0%
MAAC-TA	Conectiv Energy (Delmarva Power & Light Company)	DP&L	DE	MAAC	3,644	18,185	100.0%
MAAC-TA	Jersey Central Power & Light Company	JCP&L	NJ	MAAC	4,315	22,086	100.0%
MAAC-TA	Metropolitan Edison Company	METED	PA	MAAC	2,735	13,996	100.0%
MAAC-TA	PECO Energy Company	PE	PA	MAAC	7,422	38,836	100.0%
MAAC-TA	Pennsylvania Electric Company	PENLEC	PA	MAAC	3,348	17,136	100.0%
MAAC-TA	Pennsylvania Power & Light Company	PP&L	PA	MAAC	7,140	39,239	100.0%
MAAC-TA	Potomac Electric Power Company	PEPCO	DC	MAAC	6,166	30,121	100.0%
MAAC-TA	Public Service Electric & Gas Company	PSE&G	NJ	MAAC	9,596	43,790	100.0%
MAIN-OH	Central Illinois Light Co.	CIL	IL	MAIN	1,270	6,307	100.0%
MAIN-OH	Central Illinois Public Service	CIPS	IL	MAIN	2,257	10,822	100.0%
MAIN-OH	Columbia, Missouri, Water and Light Department	CWL	MO	MAIN	243	1,086	100.0%
MAIN-OH	Commonwealth Edison Co.	CECO	IL	MAIN	21,150	95,250	100.0%
MAIN-OH	Electric Energy, Inc.	EEI	IL	MAIN	1,842	7,483	100.0%
MAIN-OH	Illinois Municipal Electric Agency	IMEA	IL	MAIN	408	1,741	100.0%
MAIN-OH	Illinois Power - Soyland Power Pool	IPSP	IL	MAIN	3,681	19,412	100.0%
MAIN-OH	Madison Gas and Electric Company	MGE	WI	MAIN	667	3,141	100.0%
MAIN-OH	Manitowoc, Wisconsin, Public Utilities	MPU	WI	MAIN	97	521	100.0%
MAIN-OH	Marquette, Michigan, Board of Light and Power	MARQ	MI	MAIN	52	282	100.0%
MAIN-OH	Marshfield, Wisconsin, Electric and Water Dept.	MARF	WI	MAIN	76	416	100.0%
MAIN-OH	Southern Illinois Power Co-operative	SIPC	IL	MAIN	235	1,197	100.0%
MAIN-OH	Springfield, Illinois - City Water Light & Power	CWLP	IL	MAIN	476	2,031	100.0%
MAIN-OH	Upper Peninsula Power Company	UPP	MI	MAIN	162	894	100.0%
MAIN-OH	Wisconsin Electric Power Company	WEP	WI	MAIN	5,684	30,523	100.0%
MAIN-OH	Wisconsin Power and Light Company	WPL	WI	MAIN	2,368	12,874	100.0%
MAIN-OH	Wisconsin Public Power Inc. MAIN	WPPIM	WI	MAIN	664	4,089	100.0%
MAIN-OH	Wisconsin Public Service Corporation	WPS	WI	MAIN	1,914	11,578	100.0%
MAPP-OH	Ames Municipal Electric System	AMES	IA	MAPP	113	478	100.0%
MAPP-OH	Basin Electric Power Cooperative	BEPC	ND	MAPP	1,141	6,141	100.0%
MAPP-OH	Cooperative Power Association (Great River Energy)	CP	MN	MAPP	881	5,058	100.0%
MAPP-OH	Corn Belt Power Coop	CBPC	IA	MAPP	258	1,259	100.0%
MAPP-OH	Dairyland Power Cooperative (GSE)	DPC	WI	MAPP	762	4,375	100.0%
MAPP-OH	Hastings Utilities (NE)	HSTG	NE	MAPP	94	430	100.0%
MAPP-OH	Heartland Consumers Power District	HCPD	SD	MAPP	92	566	100.0%
MAPP-OH	Hutchinson Utilities Commission	HUC	MN	MAPP	63	329	100.0%
MAPP-OH	Lincoln Electric System	LES	NE	MAPP	732	3,340	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	3,766	2,330	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	3,538	1,932	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	3,250	1,925	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	2,871	1,620	100.0%

Attachment 2

2002 Peak Load and Energy Demand by Transmission Area and by Utility

TransArea	Utility Name	Utility Abbreviation	State	Region	Peak Load (MW)	Demand (GWh)	Load Ratio
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	2,723	1,527	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	2,775	1,464	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	2,716	1,451	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	2,833	1,508	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	2,718	1,469	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	2,991	1,728	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	3,372	1,949	100.0%
MAPP-OH	Manitoba Hydro	MH	MB	MAPP	2,698	2,267	100.0%
MAPP-OH	Minnesota Power, Inc	MP	MN	MAPP	1,475	10,580	100.0%
MAPP-OH	Minnkota Power Cooperative, Inc.	MPC	ND	MAPP	770	3,379	100.0%
MAPP-OH	Missouri Basin Municipal Pwr Agency	MBMP	SD	MAPP	259	1,489	100.0%
MAPP-OH	Montana-Dakota Utilities Co.	MDU	SD	MAPP	427	2,125	100.0%
MAPP-OH	Municipal Energy Agency of Nebraska	MEAN	NE	MAPP	73	622	100.0%
MAPP-OH	Muscatine Power & Water	MPW	IA	MAPP	156	1,012	100.0%
MAPP-OH	Northern States Power Company	NSP	MN	MAPP	7,815	43,082	100.0%
MAPP-OH	Northwestern Public Service Company	NWPS	SD	MAPP	295	1,312	100.0%
MAPP-OH	Otter Tail Power Company	OTP	MN	MAPP	685	4,176	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,774	1,769	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,710	1,540	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,552	1,584	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,373	1,419	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,190	1,358	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,331	1,364	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,376	1,443	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,393	1,466	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,271	1,446	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,430	1,558	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,687	1,637	100.0%
MAPP-OH	SaskPower	SPC	SK	MAPP	2,843	1,810	100.0%
MAPP-OH	Southern MN Municipal Power Agency/Rochester PU	SMMP	MN	MAPP	529	2,710	100.0%
MAPP-OH	United Power Association (Great River Energy)	UPA	MN	MAPP	1,220	6,382	100.0%
MAPP-OH	WAPA - Upper Missouri (east)	WAUM		MAPP	1,909	10,131	100.0%
MAPP-OH	Wisconsin Public Power Inc.	WPPI	WI	MAPP	59	308	100.0%
MIDAM	Midamerican Energy Co.	MEC	IA	MAPP	4,041	19,722	100.0%
MIDAM	Midwest Energy Inc.	MIDW	KS	SPP	202	973	100.0%
MIPU	Missouri Public Service Company	MIPU	MO	SPP	1,325	5,532	100.0%
NPCC-TA	Bangor Hydro-Electric Company	BHE	ME	NPCC	281	1,946	100.0%
NPCC-TA	Boston Edison Company	BECO	MA	NPCC	2,903	16,137	100.0%
NPCC-TA	Central Hudson Gas & Electric Corporation	CEHG	NY	NPCC	970	5,117	100.0%
NPCC-TA	Central Maine Power Company	CMP	ME	NPCC	1,444	8,872	100.0%
NPCC-TA	Central Vermont Public Service Corp.	CVPS	VT	NPCC	433	2,522	100.0%
NPCC-TA	Commonwealth Energy System Companies	CES	MA	NPCC	1,098	5,782	100.0%
NPCC-TA	Consolidated Edison Company of New York, Inc.	COEN	NY	NPCC	201	876	2.0%
NPCC-TA	Consolidated Edison Company of New York, Inc.	COEN	NY	NPCC	8,946	38,959	87.7%
NPCC-TA	Consolidated Edison Company of New York, Inc.	COEN	NY	NPCC	1,058	4,609	10.4%
NPCC-TA	Eastern Utilities Associates Companies	EUA	MA	NPCC	981	5,044	100.0%
NPCC-TA	Green Mountain Power	GMP	VT	NPCC	295	2,081	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	33,430	19,491	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	31,229	17,547	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	28,965	16,940	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	25,174	14,333	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	20,541	13,088	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	18,238	11,992	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	18,748	12,598	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	18,717	12,613	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	19,110	12,264	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	22,922	13,890	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	27,152	15,854	100.0%
NPCC-TA	Hydro-Quebec	HYQB	QC	NPCC	31,215	18,842	100.0%
NPCC-TA	Long Island Power Authority	LIPA	NY	NPCC	4,385	19,278	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	170	93	100.0%

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TransArea	Utility Name	Utility Abbreviation	State	Region	Peak Load (MW)	Demand (GWh)	Load Ratio
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	161	84	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	156	88	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	150	80	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	147	83	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	148	80	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	153	87	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	158	89	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	154	85	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	163	88	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	175	89	100.0%
NPCC-TA	Maritime Electric Company, Limited	MECL	PE	NPCC	191	95	100.0%
NPCC-TA	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	NPCC	546	2,855	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	3,021	1,697	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	2,951	1,496	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	2,617	1,503	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	2,345	1,274	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	1,803	1,171	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	1,603	1,012	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	1,510	1,030	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	1,473	1,042	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	1,605	1,054	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	2,044	1,183	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	2,483	1,297	100.0%
NPCC-TA	New Brunswick Power Corp.	NBPC	NB	NPCC	2,759	1,548	100.0%
NPCC-TA	New England Electric System Operating Companies	NEP	MA	NPCC	4,531	24,225	100.0%
NPCC-TA	New England Power Pool	NEPOOL		NPCC	5,294	14,524	100.0%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	10	62	0.3%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	1,660	10,657	50.3%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	100	642	3.0%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	37	239	1.1%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	14	89	0.4%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	229	1,468	6.9%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	5	30	0.1%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	589	3,778	17.8%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	465	2,982	14.1%
NPCC-TA	New York Power Authority	POAS	NY	NPCC	196	1,261	5.9%
NPCC-TA	New York State Electric & Gas Corp	NEYE	NY	NPCC	91	610	4.0%
NPCC-TA	New York State Electric & Gas Corp	NEYE	NY	NPCC	13	86	0.6%
NPCC-TA	New York State Electric & Gas Corp	NEYE	NY	NPCC	536	3,594	23.8%
NPCC-TA	New York State Electric & Gas Corp	NEYE	NY	NPCC	268	1,796	11.9%
NPCC-TA	New York State Electric & Gas Corp	NEYE	NY	NPCC	198	1,328	8.8%
NPCC-TA	New York State Electric & Gas Corp	NEYE	NY	NPCC	74	495	3.3%
NPCC-TA	New York State Electric & Gas Corp	NEYE	NY	NPCC	1,071	7,186	47.6%
NPCC-TA	Niagara Mohawk Power Corp	NIMP	NY	NPCC	0	0	0.0%
NPCC-TA	Niagara Mohawk Power Corp	NIMP	NY	NPCC	1,274	7,950	20.4%
NPCC-TA	Niagara Mohawk Power Corp	NIMP	NY	NPCC	2,141	13,362	34.3%
NPCC-TA	Niagara Mohawk Power Corp	NIMP	NY	NPCC	803	5,011	12.9%
NPCC-TA	Niagara Mohawk Power Corp	NIMP	NY	NPCC	2,026	12,645	32.5%
NPCC-TA	Northeast Utilities Companies	NU	CT	NPCC	6,622	35,855	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,979	1,081	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,935	1,013	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,830	946	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,709	890	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,472	856	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,361	845	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,307	856	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,309	857	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,387	867	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,628	957	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	1,828	1,002	100.0%
NPCC-TA	Nova Scotia Power Inc.	NSPI	NS	NPCC	2,060	1,093	100.0%

Attachment 2

2002 Peak Load and Energy Demand by Transmission Area and by Utility

TransArea	Utility Name	Utility Abbreviation	State	Region	Peak Load (MW)	Demand (GWh)	Load Ratio
NPCC-TA	Ontario Hydro	ONHY	ON	NPCC	1,659	10,504	7.1%
NPCC-TA	Ontario Hydro	ONHY	ON	NPCC	964	6,099	4.1%
NPCC-TA	Ontario Hydro	ONHY	ON	NPCC	1,285	8,132	5.5%
NPCC-TA	Ontario Hydro	ONHY	ON	NPCC	12,626	79,923	54.3%
NPCC-TA	Ontario Hydro	ONHY	ON	NPCC	4,387	27,771	18.9%
NPCC-TA	Ontario Hydro	ONHY	ON	NPCC	2,353	14,894	10.1%
NPCC-TA	Orange & Rockland Utilities, Inc.	ORRU	NY	NPCC	1,225	5,467	100.0%
NPCC-TA	Rochester Gas & Electric Corporation	ROGE	NY	NPCC	1,632	7,619	100.0%
NPCC-TA	The United Illuminating Company	UI	CT	NPCC	1,195	6,025	100.0%
NPCC-TA	UNITIL Power Corp. Companies	UNITIL	NH	NPCC	242	1,311	100.0%
NPPD	Nebraska Public Power District	NPPD	NE	MAPP	2,206	10,734	100.0%
OK-East	Grand River Dam Authority	GRRD	OK	SPP	1,404	6,011	100.0%
OK-East	KAMO Electric Coop.	KAMO	OK	SPP	470	2,304	100.0%
OK-East	Oklahoma Gas & Electric Company	OKGE	OK	SPP	1,143	5,231	19.6%
OK-East	Oklahoma Municipal Power Authority	OMPA	OK	SPP	20	70	3.1%
OK-East	Public Service Company of Oklahoma	PSOK	OK	SPP	2,470	11,123	60.4%
OK-East	Southwestern Power Administration	SWPA	OK	SPP	234	1,021	33.4%
OK-West	Oklahoma Gas & Electric Company	OKGE	OK	SPP	4,058	18,567	69.7%
OK-West	Oklahoma Municipal Power Authority	OMPA	OK	SPP	623	2,198	96.9%
OK-West	Public Service Company of Oklahoma	PSOK	OK	SPP	1,618	7,283	39.6%
OK-West	Southwestern Power Administration	SWPA	OK	SPP	8	36	1.2%
OK-West	Western Farmers Electric Cooperative	WEFA	OK	SPP	1,085	5,187	100.0%
OPPD	Omaha Public Power District	OPPD	NE	MAPP	2,169	9,584	100.0%
SOEP	Southwestern Electric Power Company	SOEP	LA	SPP	3,884	18,726	94.1%
Southern	Alabama Electric Cooperative, Inc.	ALEC	AL	SERC	1,842	7,939	100.0%
Southern	Alabama Power Company	ALAP	AL	SERC	11,398	66,631	100.0%
Southern	Georgia Power Company	GEPC	GA	SERC	18,015	102,688	100.0%
Southern	Gulf Power Company	GUPC	FL	SERC	2,366	12,158	100.0%
Southern	Mississippi Power Company	MIPR	MS	SERC	2,554	14,239	100.0%
Southern	Oglethorpe Power Corporation	OPC	GA	SERC	6,928	30,053	100.0%
Southern	Savannah Electric and Power Company	SAEP	GA	SERC	929	4,761	100.0%
Southern	South Mississippi Electric Power Association	SMEPA	MS	SERC	1,183	5,659	100.0%
SPRM	City Utilities, Springfield	SPRM	MO	SPP	732	3,199	100.0%
STJO	St. Joseph Power & Light Co.	STJO	MO	MAPP	403	1,922	100.0%
SUNE	Sunflower Electric Power Corp.	SUNC	KS	SPP	420	2,118	100.0%
TEVA	Tennessee Valley Authority	TEVA	TN	SERC	30,407	166,189	100.0%
TX-NW	Northeast Texas Electric Coop.	NTEC	TX	SPP	594	2,658	100.0%
TX-NW	Southwestern Public Service Company	SWPS	TX	SPP	3,781	22,133	100.0%
VACAR	Carolina Power & Light Company	CPL	NC	SERC	11,032	58,986	95.0%
VACAR	Carolina Power & Light Company	CPL	NC	SERC	581	3,105	5.0%
VACAR	Duke Power Company	DUPC	NC	SERC	18,584	100,697	100.0%
VACAR	Nantahala Power & Light Company	NANT	NC	SERC	305	1,246	100.0%
VACAR	Old Dominion Electric Cooperative	ODEC	VA	SERC	1,490	6,558	100.0%
VACAR	Santee Cooper (SCPSA)	SOCA	SC	SERC	4,188	21,428	100.0%
VACAR	South Carolina Electric & Gas Company	SOCG	SC	SERC	4,123	21,803	100.0%
VACAR	Virginia Power Company	VIEP	VA	SERC	16,368	85,096	100.0%
WERE	Kansas City Power & Light Co.	KACP	MO	SPP	3,611	15,523	100.0%
WERE	Kansas Gas & Electric Co.	KAGE	KS	SPP	2,278	10,764	100.0%
WERE	Kansas Power & Light Co.	KAPL	KS	SPP	2,703	11,724	100.0%
WPEK	WestPlains Energy Kansas	WPEK	KS	SPP	513	2,650	100.0%

Attachment 3

Summer Fall Typical TTCs

From

	To	AR-NW	TX-NW	OK-West	OK-East	TX-LA	AR-FS	CLEC	PSCO	SEPC	EDE	GRDA	INDN	KACY	KCPL	LAFA	LEPA	MIDW	MPS	OKGE	OMPA	SECI	SPA	SPRM	SPS	WFEC	WPEK	WR	ENT-N	ENT-S	AECI	Ameren	NPPD	ERCOT
AR-NW	Southwest Power Adm				710		480				310													530					310		420	460		
TX-NW	Western part of CSW			140																					170									
OK-West	Parts of SWPA, CSW, OGE,WFEC and OMPA		180		2260	1150																			780			1230						
OK-East	AECI, parts of SWPA, CSW, GRDA, OGE, WFEC, OMPA	830		670			650				150																	890			1060			
TX-LA	Rest of CSW			500				750																					910	900				220
AR-FS	Parts of SWPA, CSW and OGE	530			660																								780					
CLEC	Central Louisiana Electric Company					660										200	90													490				
SEPC	Southwest Electric Power Company							850															1100		550	560								600
EDE	Empire District Electric	690			1050				1100			760											990	280				620	520		980			
INDN	City Power and Light, Independence, Missou														540				530												430			
KACY	Board of Public Utilities, Kansas City														420																			
KCPL	Kansas City Power and Light												600	560					310									230			780	1460		
LAFA	City of Lafayette, Louisiana							310																						80				
LEPA	Louisiana Energy and Power Authority							90																										
MIDW	Midwest Energy, Inc																					170					100	130						
MPS	Missouri Public Service Company												580		920													590			890	940		
SECI	Sunflower Electric Power Corp																	130									100						350	
SPRM	City Utilities, Springfield, Missouri	620									500												440								500			
SPS	Southwestern Public Service Co		180	450						250												270					270							
WPEK	West Plains Energy																	90				320			60			120						
WR	Western Resources			630	690				930		510			550	1410			190	420	910							220				600	570		
ENT-N	Entergy - North	1090				1170	530		2020		460					130				690			580								1020	1350		
ENT-S	Entergy - South					1210		320								310																		
AECI		1450			960				1360		410	710	740		1360				450				1200	360		360		820	700			2020	270	
AMEREN		450													1270				500				770						1410		550			
NPPD	Nebraska Power																														280			
ERCOT	Electric Reliability Council of Texas					220				600																								

Winter Spring Typical TTCs

From

	To	AR-NW	TX-NW	OK-West	OK-East	TX-LA	AR-FS	CLEC	PSCO	SEPC	EDE	GRDA	INDN	KACY	KCPL	LAFA	LEPA	MIDW	MPS	OKGE	OMPA	SECI	SPA	SPRM	SPS	WFEC	WPEK	WR	ENT-N	ENT-S	AECI	Ameren	NPPD	ERCOT
AR-NW	Southwest Power Adm	x			900		500				950													570					580		660	540		
TX-NW	Western part of CSW		x	140																					160									
OK-West	Parts of SWPA, CSW, OGE,WFEC and OMPA		180	x	2260	840																			750			1050						
OK-East	AECI, parts of SWPA, CSW, GRDA, OGE, WFEC, OMPA	880		680	x		740				720																	470			750			
TX-LA	Rest of CSW			560		x		800																					870	580				220
AR-FS	Parts of SWPA, CSW and OGE	590			550		x																						750					
CLEC	Central Louisiana Electric Company					580		x		50						190														530				
PSCO	Public Service Company of Oklahoma								x		710	920					20			1740	210							500	260		270			
SEPC	Southwest Electric Power Company							810		x													1540		530	530					330			600
EDE	Empire District Electric	670			790				710		x	540											660	250				620	480		410			
GRDA	Grand River Dam Authority								1640		840	x								950			1210								210			
INDN	City Power and Light, Independence, Missou												x		610				410												230			
KACY	Board of Public Utilities, Kansas City													x	450													440						
KCPL	Kansas City Power and Light												700	580	x				390									730			190	840		
LAFA	City of Lafayette, Louisiana							320								x														120				
LEPA	Louisiana Energy and Power Authority							90									x																	
MIDW	Midwest Energy, Inc																	x				170					70	110						
MPS	Missouri Public Service Company												610		1060				x									690			400	820		
OKGE	Okahoma Gas and Electric								960			620								x	160		1560			110		740	780					
OMPA	Oklahoma Municipal Power Authority								350	110										550	x					360								
SECI	Sunflower Electric Power Corp																	50				x			90		110						390	
SPA	Southwestern Power Administration									1090	700	560								880			x	570		380			670			600		
SPRM	City Utilities, Springfield, Missouri	600									710												450	x							460			
SPS	Southwestern Public Service Co		170	290						290												270			x		290							
WFEC	Western Farmers Electric Coop									530										950	260		760			x					360			
WPEK	West Plains Energy																	130				340			100		x	90						
WR	Western Resources			670	930				1280		760			580	1000			210	660	890							250	x			130			
ENT-N	Entergy - North	1030				1160	490		1870		840					20				910			800						x		1020	690		
ENT-S	Entergy - South					1180		450								390														x				
AECI		1300			1520				1590		730	990	670		980				540				1430	420		350		890	170		x	1730	630	
AMEREN		420													880				610				870						920			x		
NPPD	Nebraska Power																														190		x	
ERCOT	Electric Reliability Council of Texas					220				600																								x

Attachment 3

Summer Peak TTCs

From

To		AR-NW	TX-NW	OK-West	OK-East	TX-LA	AR-FS	CLEC	SEPC	EDE	GRDA	INDN	KACY	KCPL	LAFA	LEPA	MIDW	MPS	SECI	SPRM	SPS	WPEK	WR	ENT-N	ENT-S	AECI	Ameren	NPPD	ERCOT
AR-NW	Southwest Power Adm	x			25		29			56										139						418	2		
TX-NW	Western part of CSW		x	108																	159								
OK-West	Parts of SWPA, CSW, OGE,WFEC and OMPA		151	x	1448	461															47		1012						
OK-East	AECI, parts of SWPA, CSW, GRDA, OGE, WFEC, OMPA			672	x		625																368			23			
TX-LA	Rest of CSW			325		x		663																776	295				220
AR-FS	Parts of SWPA, CSW and OGE				438		x																	508					
CLEC	Central Louisiana Electric Company							x							144	95									472				
SEPC	Southwest Electric Power Company							451	x												319								600
EDE	Empire District Electric				605					x										6				278		92			
INDN	City Power and Light, Independence, Misso											x		174				153											
KACY	Board of Public Utilities, Kansas City												x	115															
KCPL	Kansas City Power and Light											511	498	x									139				1328		
LAFA	City of Lafayette, Louisiana							291							x														
LEPA	Louisiana Energy and Power Authority							25								x													
MIDW	Midwest Energy, Inc																x		141			96	118						
MPS	Missouri Public Service Company											317		431				x					124			178	269		
SECI	Sunflower Electric Power Corp																126		x									241	
SPRM	City Utilities, Springfield, Missouri									197										x						74			
SPS	Southwestern Public Service Co		167	145					115												x								
WPEK	West Plains Energy																		281		48	x	120						
WR	Western Resources			386	483					228			399	87			89					213	x				575		
ENT-N	Entergy - North	225				1095	528			72					126									x		659			
ENT-S	Entergy - South					442																			x				
AECI		440			268					19		555		373									248			x	2016	162	
AMEREN		22												196				2						363			x		
NPPD	Nebraska Power																											x	
ERCOT	Electric Reliability Council of Texas					220			600																				x

Winter Peak TTCs

From

To		AR-NW	TX-NW	OK-West	OK-East	TX-LA	AR-FS	CLEC	SEPC	EDE	GRDA	INDN	KACY	KCPL	LAFA	LEPA	MIDW	MPS	SECI	SPRM	SPS	WPEK	WR	ENT-N	ENT-S	AECI	Ameren	NPPD	ERCOT
AR-NW	Southwest Power Adm	x			195		252			389										572						663	184		
TX-NW	Western part of CSW		x	128																	163								
OK-West	Parts of SWPA, CSW, OGE,WFEC and OMPA		176	x	2264	738															748		983						
OK-East	AECI, parts of SWPA, CSW, GRDA, OGE, WFEC, OMPA	551		683	x		735			682													245			751			
TX-LA	Rest of CSW			480		x		674																872	276				220
AR-FS	Parts of SWPA, CSW and OGE	392			550		x																	754					
CLEC	Central Louisiana Electric Company					195		x							194										535				
SEPC	Southwest Electric Power Company							412	x												526								600
EDE	Empire District Electric	432			583					x	28									253			618	11		39			
INDN	City Power and Light, Independence, Misso											x		395				409											
KACY	Board of Public Utilities, Kansas City												x	446									436						
KCPL	Kansas City Power and Light											704	580	x				392					731				395		
LAFA	City of Lafayette, Louisiana							310							x										70				
LEPA	Louisiana Energy and Power Authority							64								x													
MIDW	Midwest Energy, Inc																x		163			74	115						
MPS	Missouri Public Service Company											574		1056				x					693			41	13		
SECI	Sunflower Electric Power Corp																47		x		86	113						392	
SPA	Southwestern Power Administration									581										571							338		
SPRM	City Utilities, Springfield, Missouri	365								658										x						43			
SPS	Southwestern Public Service Co		170	286					287										268		x	292							
WPEK	West Plains Energy																135		302		70	x	92						
WR	Western Resources			534	710					676			576	997			193	656				253	x						
ENT-N	Entergy - North	885				791	488			597														x		454	383		
ENT-S	Entergy - South					550									387										x				
AECI		1224			469					573		671		980				539		425			886			x	790	167	
AMEREN		308												884				610						56			x		
NPPD	Nebraska Power																											x	
ERCOT	Electric Reliability Council of Texas					220			600																				x

Attachment 4

List of Transmission Paths

From TA	From Region	To TA	To Region
Alliant	MAPP	Ameren	MAIN
Alliant	MAPP	ASEC	SERC
Alliant	MAPP	MAIN-OH	MAIN
Alliant	MAPP	MAPP-OH	MAPP
Alliant	MAPP	MIDAM	MAPP
Ameren	MAIN	Alliant	MAPP
Ameren	MAIN	ASEC	SERC
Ameren	MAIN	ENT-No	SERC
Ameren	MAIN	MAIN-OH	MAIN
Ameren	MAIN	MIDAM	MAPP
Ameren	MAIN	MIPU	SPP
Ameren	MAIN	AR-NW	SPP
Ameren	MAIN	TEVA	SERC
Ameren	MAIN	WERE	SPP
AR-FS	SPP	ENT-No	SERC
AR-FS	SPP	OK-East	SPP
AR-FS	SPP	AR-NW	SPP
AR-NW	SPP	Ameren	MAIN
AR-NW	SPP	ASEC	SERC
AR-NW	SPP	EDE	SPP
AR-NW	SPP	ENT-No	SERC
AR-NW	SPP	AR-FS	SPP
AR-NW	SPP	OK-East	SPP
AR-NW	SPP	OK-West	SPP
AR-NW	SPP	SOEP	SPP
AR-NW	SPP	SPRM	SPP
AR-NW	SPP	WERE	SPP
AR-NW	SPP	WPEK	SPP
ASEC	SERC	Alliant	MAPP
ASEC	SERC	Ameren	MAIN
ASEC	SERC	EDE	SPP
ASEC	SERC	ENT-No	SERC
ASEC	SERC	Indep	SPP
ASEC	SERC	MAIN-OH	MAIN
ASEC	SERC	MAPP-OH	MAPP
ASEC	SERC	MIDAM	MAPP
ASEC	SERC	MIPU	SPP
ASEC	SERC	OK-East	SPP
ASEC	SERC	OK-West	SPP
ASEC	SERC	SPRM	SPP
ASEC	SERC	STJO	MAPP
ASEC	SERC	AR-NW	SPP
ASEC	SERC	TEVA	SERC
ASEC	SERC	WERE	SPP
BPU	SPP	WERE	SPP
CAJN	SERC	CLECO	SPP
CAJN	SERC	ENT-So	SERC
CLECO	SPP	CAJN	SERC

Attachment 4

List of Transmission Paths

From TA	From Region	To TA	To Region
CLECO	SPP	ENT-So	SERC
CLECO	SPP	LA_Other	SPP
CLECO	SPP	SOEP	SPP
ECAR-TA	ECAR	MAAC-TA	MAAC
ECAR-TA	ECAR	MAIN-OH	MAIN
ECAR-TA	ECAR	NPCC-TA	NPCC
ECAR-TA	ECAR	TEVA	SERC
ECAR-TA	ECAR	VACAR	SERC
EDE	SPP	ASEC	SERC
EDE	SPP	ENT-No	SERC
EDE	SPP	OK-East	SPP
EDE	SPP	SPRM	SPP
EDE	SPP	AR-NW	SPP
EDE	SPP	WERE	SPP
ENT-No	SERC	Ameren	MAIN
ENT-No	SERC	ASEC	SERC
ENT-No	SERC	EDE	SPP
ENT-No	SERC	ENT-So	SERC
ENT-No	SERC	AR-FS	SPP
ENT-No	SERC	OK-East	SPP
ENT-No	SERC	OK-West	SPP
ENT-No	SERC	SOEP	SPP
ENT-No	SERC	AR-NW	SPP
ENT-No	SERC	TEVA	SERC
ENT-So	SERC	CAJN	SERC
ENT-So	SERC	CLECO	SPP
ENT-So	SERC	ENT-No	SERC
ENT-So	SERC	LA_Other	SPP
ENT-So	SERC	SOEP	SPP
ENT-So	SERC	Southern	SERC
ENT-So	SERC	TEVA	SERC
ERCOT-OH	ERCOT	SOEP	SPP
FRCC	FRCC	Southern	SERC
Indep	SPP	ASEC	SERC
Indep	SPP	MIPU	SPP
Indep	SPP	WERE	SPP
LA_Other	SPP	CLECO	SPP
LA_Other	SPP	ENT-So	SERC
MAAC-TA	MAAC	ECAR-TA	ECAR
MAAC-TA	MAAC	NPCC-TA	NPCC
MAAC-TA	MAAC	VACAR	SERC
MAIN-OH	MAIN	Alliant	MAPP
MAIN-OH	MAIN	Ameren	MAIN
MAIN-OH	MAIN	ASEC	SERC
MAIN-OH	MAIN	ECAR-TA	ECAR
MAIN-OH	MAIN	MAPP-OH	MAPP
MAIN-OH	MAIN	MIDAM	MAPP
MAIN-OH	MAIN	TEVA	SERC

Attachment 4

List of Transmission Paths

From TA	From Region	To TA	To Region
MAPP-OH	MAPP	Alliant	MAPP
MAPP-OH	MAPP	ASEC	SERC
MAPP-OH	MAPP	MAIN-OH	MAIN
MAPP-OH	MAPP	MIDAM	MAPP
MAPP-OH	MAPP	NPCC-TA	NPCC
MAPP-OH	MAPP	NPPD	MAPP
MAPP-OH	MAPP	OPPD	MAPP
MIDAM	MAPP	Alliant	MAPP
MIDAM	MAPP	Ameren	MAIN
MIDAM	MAPP	ASEC	SERC
MIDAM	MAPP	MAIN-OH	MAIN
MIDAM	MAPP	MAPP-OH	MAPP
MIDAM	MAPP	NPPD	MAPP
MIDAM	MAPP	OPPD	MAPP
MIDAM	MAPP	STJO	MAPP
MIDAM	SPP	SUNE	SPP
MIDAM	SPP	WERE	SPP
MIDAM	SPP	WPEK	SPP
MIPU	SPP	Ameren	MAIN
MIPU	SPP	ASEC	SERC
MIPU	SPP	Indep	SPP
MIPU	SPP	WERE	SPP
NPCC-TA	NPCC	ECAR-TA	ECAR
NPCC-TA	NPCC	MAAC-TA	MAAC
NPCC-TA	NPCC	MAPP-OH	MAPP
NPPD	MAPP	MAPP-OH	MAPP
NPPD	MAPP	MIDAM	MAPP
NPPD	MAPP	OPPD	MAPP
NPPD	MAPP	STJO	MAPP
NPPD	MAPP	SUNE	SPP
OK-East	SPP	ASEC	SERC
OK-East	SPP	EDE	SPP
OK-East	SPP	ENT-No	SERC
OK-East	SPP	AR-FS	SPP
OK-East	SPP	OK-West	SPP
OK-East	SPP	SOEP	SPP
OK-East	SPP	AR-NW	SPP
OK-East	SPP	WERE	SPP
OK-East	SPP	WPEK	SPP
OK-West	SPP	ASEC	SERC
OK-West	SPP	ENT-NO	SERC
OK-West	SPP	OK-East	SPP
OK-West	SPP	SOEP	SPP
OK-West	SPP	AR-NW	SPP
OK-West	SPP	TX-NW	SPP
OK-West	SPP	WERE	SPP
OK-West	SPP	WPEK	SPP
OPPD	MAPP	MAPP-OH	MAPP

Attachment 4

List of Transmission Paths

From TA	From Region	To TA	To Region
OPPD	MAPP	MIDAM	MAPP
OPPD	MAPP	NPPD	MAPP
OPPD	MAPP	WERE	SPP
SOEP	SPP	CLECO	SPP
SOEP	SPP	ENT-So	SERC
SOEP	SPP	ENT-NO	SERC
SOEP	SPP	ERCOT-OH	ERCOT
SOEP	SPP	OK-East	SPP
SOEP	SPP	OK-West	SPP
SOEP	SPP	AR-NW	SPP
SOEP	SPP	TX-NW	SPP
Southern	SERC	ENT-So	SERC
Southern	SERC	FRCC	FRCC
Southern	SERC	TEVA	SERC
Southern	SERC	VACAR	SERC
SPRM	SPP	ASEC	SERC
SPRM	SPP	EDE	SPP
SPRM	SPP	AR-NW	SPP
STJO	MAPP	ASEC	SERC
STJO	MAPP	MIDAM	MAPP
STJO	MAPP	NPPD	MAPP
STJO	MAPP	WERE	SPP
SUNE	SPP	MIDAM	SPP
SUNE	SPP	NPPD	MAPP
SUNE	SPP	WPEK	SPP
TEVA	SERC	Ameren	MAIN
TEVA	SERC	ASEC	SERC
TEVA	SERC	ECAR-TA	ECAR
TEVA	SERC	ENT-So	SERC
TEVA	SERC	ENT-No	SERC
TEVA	SERC	MAIN-OH	MAIN
TEVA	SERC	Southern	SERC
TEVA	SERC	VACAR	SERC
TX-NW	SPP	OK-West	SPP
TX-NW	SPP	SOEP	SPP
TX-NW	SPP	WPEK	SPP
VACAR	SERC	ECAR-TA	ECAR
VACAR	SERC	MAAC-TA	MAAC
VACAR	SERC	Southern	SERC
VACAR	SERC	TEVA	SERC
WERE	SPP	Ameren	MAIN
WERE	SPP	ASEC	SERC
WERE	SPP	BPU	SPP
WERE	SPP	EDE	SPP
WERE	SPP	Indep	SPP
WERE	SPP	MIDAM	SPP
WERE	SPP	MIPU	SPP
WERE	SPP	OK-East	SPP

Attachment 4

List of Transmission Paths

From TA	From Region	To TA	To Region
WERE	SPP	OK-West	SPP
WERE	SPP	OPPD	MAPP
WERE	SPP	STJO	MAPP
WERE	SPP	ASEC	SPP
WERE	SPP	WPEK	SPP
WPEK	SPP	MIDAM	SPP
WPEK	SPP	OK-East	SPP
WPEK	SPP	OK-West	SPP
WPEK	SPP	SUNE	SPP
WPEK	SPP	AR-NW	SPP
WPEK	SPP	TX-NW	SPP
WPEK	SPP	WERE	SPP

List of Transmission Path Among Transmission Areas

	From TA																																		
To TA	Alliant	Ameren	ASEC	BPU	CAJN	CLECO	ECAR-TA	EMDE	ENTR	ENTR-NorthAR	ERCOT-OH	FRCC	Indep	LA_Other	MAAC-TA	MAIN-OH	MAPP-OH	MIDAM	MIPU	NPCC-TA	NPPD	OK-Ark	OKEast	OKWest	OPPD	SOEP	Southern	SPRM	STJO	SUNE	SWPA	SWPS	TEVA	VACAR	WERE	WPEK
Alliant		1	1													1	1	1																		
Ameren	1		1							1						1		1	1												1		1		1	
ASEC	1	1						1		1			1			1	1	1	1				1	1				1	1		1		1		1	
BPU																																			1	
CAJN						1			1																											
CLECO					1				1					1												1										
ECAR-TA															1	1				1													1	1		
EMDE			1							1													1					1			1				1	
ENTR					1	1				1				1												1	1						1			
ENTR-NorthAR		1	1					1	1													1	1	1		1					1		1			
ERCOT-OH																										1										
FRCC																											1									
Indep			1																1																1	
LA_Other						1			1																											
MAAC-TA							1													1														1		
MAIN-OH	1	1	1				1										1	1															1			
MAPP-OH	1		1													1		1		1	1				1											
MIDAM	1	1	1													1	1				1				1				1	1					1	1
MIPU		1	1										1																						1	
NPCC-TA							1								1		1																			
NPPD																	1	1							1				1	1						
OK-Ark										1													1								1					
OKEast			1					1		1												1		1		1					1				1	1
OKWest			1							1													1			1					1	1			1	1
OPPD																	1	1			1														1	
SOEP						1			1	1	1												1	1							1	1				
Southern									1			1																					1	1		
SPRM			1					1																							1					
STJO			1															1			1														1	
SUNE																		1			1															1
SWPA		1	1					1		1												1	1	1		1		1							1	1
SWPS																								1		1										1
TEVA		1	1				1		1	1						1											1							1		
VACAR							1								1												1						1			
WERE		1	1	1				1					1					1	1				1	1	1				1		1					1
WPEK																		1					1	1						1	1	1			1	

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
AR-FS	Arkansas Electric Coop. Corp.	Fitzhugh 1	59	52.74	Natural Gas
	Arkansas Electric Coop. Corp. Total		59		
	Oklahoma Gas & Electric Company	AES 1	160	15.14	Coal
		AES 2	160	15.14	Coal
	Oklahoma Gas & Electric CompanyTotal		320		
	Southwestern Power Administration	Dam #2 1-3	35	0.00	Hydro
		Dardanelle 1-4	152	0.00	Hydro
		Ozark 1-5	115	0.00	Hydro
	Southwestern Power Administration Total		302		
AR-FS Total			**681**		
AR-NW	Empire District Electric Co.	Ozark Beach 5-8	16	0.00	Hydro
	Empire District Electric Co. Total		16		
	Central & South West Corp.	Flint Creek 1	264	20.20	Coal
	Central & South West Corp. Total		264		
	Southwestern Power Administration	Beaver 1-2	129	0.00	Hydro
		Blakely Mtn 1-2	75	0.00	Hydro
		Bull Shoals 1-8	345	0.00	Hydro
		Degray	40	0.00	Hydro
		Greers Ferry 1-2	110	0.00	Hydro
		Norfork 1-2	92	0.00	Hydro
		Stockton	55	0.00	Hydro
		Table Rock 1-4	230	0.00	Hydro
		Degray	28	0.00	Pump Storae
		Harry S. Truman	186	0.00	Pump Storae
	Southwestern Power Administration Total		1,290		
AR-NW Total			**1,570**		
BPU	Board of Public Utilities, Kansas City	Nearman Creek 1	235	13.73	Coal
		Quindaro ST2	135	15.21	Coal
		Quindaro ST1	73	20.84	Coal
		Quindaro GT 2	47	67.59	Fuel Oil
		Quindaro GT 3	47	67.59	Fuel Oil
		Quindaro GT 1	14	82.81	Fuel Oil
	Board of Public Utilities, Kansas CityTotal		551		
BPU Total			**551**		
CLECO	CLECO Corp	Dolet Hills 1	650	14.94	Coal
		Rodemacher 2	523	15.44	Coal
		Teche 1	23	21.00	Coal
		CLECO Evangeline 1a	250	27.34	Natural Gas
		CLECO Evangeline 1b	250	27.34	Natural Gas
		CLECO Evangeline 1c	250	27.34	Natural Gas
		CLECO Evangeline 1d	250	27.34	Natural Gas
		Teche 2	48	39.34	Natural Gas
		Teche 3	367	41.03	Natural Gas
		NewGT_CLECOSouth 1	150	46.17	Natural Gas
		NewGT_CLECO 1	160	46.17	Natural Gas
		NewGT_CLECO 2	160	46.17	Natural Gas
		NewGT_CLECO 3	160	46.17	Natural Gas
		NewST_CLECO 1	368	47.70	Natural Gas
		Franklin GT 1	7	88.03	Natural Gas
		Inter-CELE 1	143	175.16	INTLOAD
	CLECO Corp Total		3,759		
	Dynegy	Calcasieu 1	175	46.17	Natural Gas
	Dynegy Total		175		
CLECO Total			**3,934**		
EMDE	Empire District Electric Co.	Asbury 2	20	17.04	Coal
		Riverton 8	54	18.20	Coal
		Riverton 7	38	18.82	Coal
		Asbury 1	193	26.25	Coal
		Stateline-2 2	152	50.24	Natural Gas

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
		NewGT_EMDE 1	300	51.94	Natural Gas
		Stateline-1 1	101	51.94	Natural Gas
		NewST_EMDE 1	350	58.36	Natural Gas
		Riverton GT 10	16	60.04	Natural Gas
		Riverton GT 11	16	60.04	Natural Gas
		NewST_EMDE 2	200	60.06	Natural Gas
		Riverton GT 9	12	67.06	Natural Gas
		Empire EC GT 1	90	67.12	Natural Gas
		Empire EC GT 2	90	67.12	Natural Gas
		Inter-EMDE 1	14	175.16	INTLOAD
	Empire District Electric Co. Total		1,646		
EMDE Total			**1,646**		
Ent-No	Arkansas Electric Coop. Corp.	AREC Coop	213	0.00	Hydro
		ClydeT.Ellis 1-3	17	0.00	Hydro
		HS9 (Whillock)	18	0.00	Hydro
		Independence 2	842	15.28	Coal
		Independence 1	836	15.50	Coal
		McClellan 1	134	44.72	Natural Gas
		NewGT_AREC 1	110	45.60	Natural Gas
		Bailey 1	122	45.65	Natural Gas
		Inter-AREC 1	606	175.16	INTLOAD
	Arkansas Electric Coop. Corp. Total		2,898		
	City of North Little Rock	Murray 1-2	42	0.00	Hydro
	City of North Little RockTotal		42		
	Entergy Corporation	Remmel 1-3	11	0.00	Hydro
		Ark Nuc One 1	836	8.13	Nuclear
		Ark Nuc One 2	858	8.39	Nuclear
		White Bluff 1	815	15.14	Coal
		White Bluff 2	844	15.19	Coal
		NewGT_ENTRNAR 1	144	46.17	Natural Gas
		NewGT_ENTRNAR 2	103	46.17	Natural Gas
		NewGT_ENTRNAR 3	55	46.17	Natural Gas
		Lake Catherine 3	106	46.83	Natural Gas
		Lake Catherine 4	547	48.95	Natural Gas
		Lynch 4	6	50.03	Fuel Oil
		Moses 2	72	53.58	Natural Gas
		Moses 1	72	55.10	Natural Gas
		Lake Catherine 2	51	56.60	Natural Gas
		Lake Catherine 1	52	57.12	Natural Gas
		Blytheville GT 1	62	60.02	Fuel Oil
		Blytheville GT 2	62	67.54	Fuel Oil
		Blytheville GT 3	64	68.11	Fuel Oil
		Mabelvale GT 1	18	69.66	Fuel Oil
		Mabelvale GT 2	19	69.66	Fuel Oil
		Mabelvale GT 4	18	69.66	Fuel Oil
		Mabelvale GT 3	18	73.60	Fuel Oil
	Entergy Corporation Total		4,833		
	GenPower LLC of Dell	NewGT_GenPower 1	200	45.60	Natural Gas
		NewGT_GenPower 2	200	45.60	Natural Gas
		NewGT_GenPower 3	200	45.60	Natural Gas
	GenPower LLC of Dell Total		600		
	Panda Energy	NewCC_Panda 1	275	27.99	Natural Gas
		NewCC_Panda 2	275	27.99	Natural Gas
		NewCC_Panda 3	275	27.99	Natural Gas
		NewCC_Panda 4	275	27.99	Natural Gas
		NewCC_Panda 5	275	27.99	Natural Gas
		NewCC_Panda 6	275	27.99	Natural Gas
		NewCC_Panda 7	275	27.99	Natural Gas
		NewCC_Panda 8	275	27.99	Natural Gas

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
	Panda Energy Total		2,200		
	SkyGen	New_Pine Bluff 1a	230	28.30	Natural Gas
	SkyGen Total		230		
	Southern Company Services	NewCC_Southern 1	275	27.99	Natural Gas
		NewCC_Southern 2	275	27.99	Natural Gas
	Southern Company Services Total		550		
Ent-No Total			**11,353**		
Ent-So	American Electric Power Co.	NewCG_AEP-DOW 1	100	27.34	Natural Gas
		NewCG_AEP-DOW 2	100	27.34	Natural Gas
		NewCG_AEP-DOW 3	100	27.34	Natural Gas
		NewCG_AEP-DOW 4	100	27.34	Natural Gas
		NewCG_AEP-DOW 5	100	27.34	Natural Gas
		NewCG_AEP-DOW 6	100	27.34	Natural Gas
		NewCG_AEP-DOW 7	100	27.34	Natural Gas
		NewCG_AEP-DOW 8	100	27.34	Natural Gas
		NewCG_AEP-DOW 9	100	27.34	Natural Gas
	American Electric Power Co. Total		900		
	City of Clarksdale	L.L.Wilkins 8	15	39.09	Natural Gas
		L.L.Wilkins 6	6	64.51	Natural Gas
		L.L.Wilkins 7	9	64.55	Natural Gas
		L.L.Wilkins 9	21	68.42	Natural Gas
	City of Clarksdale Total		50		
	City of Ruston	Ruston Dsl 1	11	54.40	Fuel Oil
	City of Ruston Total		11		
	City of Sikeston	Sikeston 1	233	15.21	Coal
		Coleman IC 1&2	4	49.93	Natural Gas
		Peaking 1	4	49.93	Natural Gas
	City of Sikeston Total		241		
	Cogentrix	Batesville 1	400	27.34	Natural Gas
		Batesville 2	400	27.34	Natural Gas
		NewGT_Cogtrix 1	267	46.17	Natural Gas
		NewGT_Cogtrix 2	267	46.17	Natural Gas
		NewGT_Cogtrix 3	267	46.17	Natural Gas
	Cogentrix Total		1,601		
	Conoco Global Power	Sabine-Conoco 1	100	27.34	Natural Gas
	Conoco Global Power Total		100		
	Enron Corporation	NewGT_Enron 1	180	45.02	Natural Gas
		NewGT_Enron 2	180	45.02	Natural Gas
		NewGT_Enron 3	180	45.02	Natural Gas
	Enron Corporation Total		540		
	Entergy Corporation	Carpenter 1-2	59	0.00	Hydro
		Waterford 3	1,075	7.58	Nuclear
		Grand Gulf 1	1,204	8.56	Nuclear
		NewCC_ENTR 1	250	28.05	Natural Gas
		NewCC_ENTR 2	250	28.05	Natural Gas
		Nine Mile 4	748	35.37	Natural Gas
		Nine Mile 3	135	39.48	Natural Gas
		Gypsy 1	244	39.80	Natural Gas
		Sterlington 7	203	40.04	Natural Gas
		Nine Mile 2	107	41.41	Natural Gas
		Baxter Wilson 2	771	42.20	Natural Gas
		Sterlington 6	224	42.47	Natural Gas
		Waterford 2	411	42.55	Natural Gas
		Nine Mile 5	763	42.68	Natural Gas
		Waterford 1	411	42.96	Natural Gas
		Michoud 2	244	43.39	Natural Gas
		Gypsy 3	573	44.41	Natural Gas
		Andrus 1	761	44.72	Natural Gas
		Rex Brown 4	231	44.89	Natural Gas

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
		Michoud 1	113	45.37	Natural Gas
		Monroe 12	74	45.54	Natural Gas
		Baxter Wilson 1	550	46.07	Natural Gas
		NewGT_ENTR 1	155	46.17	Natural Gas
		NewGT_ENTR 2	143	46.17	Natural Gas
		Couch 2	131	46.36	Natural Gas
		Gypsy 2	436	47.79	Natural Gas
		Delta 1	104	49.68	Natural Gas
		Rex Brown 3	76	50.10	Natural Gas
		Delta 2	103	51.40	Natural Gas
		Nine Mile 1	74	52.23	Natural Gas
		A.B. Paterson 4	87	52.77	Natural Gas
		Natchez 1	73	52.77	Natural Gas
		Neches 4 4	40	52.77	Natural Gas
		Neches 5 5	60	52.77	Natural Gas
		Neches 6 6	60	52.77	Natural Gas
		Neches 8 8	105	52.77	Natural Gas
		Michoud 3	561	54.04	Natural Gas
		Monroe 11	41	54.52	Natural Gas
		Monroe 10	23	57.34	Natural Gas
		Rex Brown 1	36	59.83	Natural Gas
		A.B. Paterson 3	56	60.10	Natural Gas
		A.B. Paterson 5	16	77.53	Fuel Oil
		Buras GT 8	19	77.61	Natural Gas
		Rex Brown GT 5	11	82.74	Fuel Oil
		DCLM-ENTR 1	72	117.06	DCLM
		Inter-ENTR 1	1,224	175.16	INTLOAD
	Entergy Corporation Total		13,107		
	Gulf States Utilities Company	Toledo Bend	81	0.00	Hydro
		Riverbend 1	936	17.15	Nuclear
		Nelson 6	385	19.24	Coal
		Sabine 2	230	36.08	Natural Gas
		Willow Glen 1	172	39.15	Natural Gas
		Willow Glen 4	568	40.68	Natural Gas
		Sabine 4	530	40.72	Natural Gas
		Sabine 3	420	41.17	Natural Gas
		Sabine 1	230	41.23	Natural Gas
		Nelson 3	154	41.67	Natural Gas
		Willow Glen 5	559	41.81	Natural Gas
		Sabine 5	485	42.13	Natural Gas
		Willow Glen 2	224	42.68	Natural Gas
		Nelson 4	500	42.78	Natural Gas
		Lewis Creek 1	266	42.88	Natural Gas
		Lewis Creek 2	266	43.48	Natural Gas
		Willow Glen 3	522	44.67	Natural Gas
	Gulf States Utilities Company Total		6,528		
	Louisville Gas & Electric	Port Arthur Proj 1	80	44.13	Natural Gas
	Louisville Gas & Electric Total		80		
	Mississippi Power & Light (ENTERGY)	Mid-America Ind 1	258	28.90	Natural Gas
		Mid-America Ind 2	258	28.90	Natural Gas
	Mississippi Power & Light (ENTERGY) Total		516		
	Nations Energy	NewGT_NAENG 3	110	46.17	Natural Gas
	Nations Energy Total		110		
	Reliant Energy	Orange-Bayer 1	60	27.34	Natural Gas
	Reliant Energy Total		60		
	RS Cogentrix/PPG Industries, Inc.	NewGT_RSCogen 1	213	46.17	Natural Gas
		NewGT_RSCogen 2	213	46.17	Natural Gas
	RS Cogentrix/PPG Industries, Inc. Total		426		
	Sho-Me Power Electric Coop	Niangua 1-2	3	0.00	Hydro

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
	Sho-Me Power Electric Coop Total		3		
	SkyGen	NewCC_SkyGen 1	240	27.62	Natural Gas
		NewCC_SkyGen 2	240	27.62	Natural Gas
		NewCC_SkyGen 3	250	28.05	Natural Gas
	SkyGen	NewCC_SkyGen 4	250	28.05	Natural Gas
	SkyGen Total		980		
	Southwestern Power Administration	Robert D. Willis	7	0.00	Hydro
		Sam Rayburn 1-2	52	0.00	Hydro
	Southwestern Power Administration Total		59		
	Tenaska, Inc.	Tenaska Frontier 1b	415	27.34	Natural Gas
	Tenaska, Inc. Total		415		
Ent-So Total			**25,727**		
Indep	City Power & Light, Independence	Missouri City 1	19	18.54	Coal
		Missouri City 2	19	18.54	Coal
		Blue Valley 2	21	21.45	Coal
		Blue Valley ST1	21	21.45	Coal
		Blue Valley 3	51	24.63	Coal
		Blue Valley GT1	50	52.36	Natural Gas
		Station H 1	19	66.32	Natural Gas
		Station H 2	20	66.32	Natural Gas
		Station I 1	19	68.82	Fuel Oil
		Station I 2	19	68.82	Fuel Oil
		Jackson Square 1	15	73.39	Fuel Oil
		Jackson Square 2	15	73.39	Fuel Oil
		Inter-INDN 1	1	175.16	INTLOAD
	City Power & Light, Independence Total		289		
Indep Total			**289**		
LA_Other	City of Lafayette	Bonin 2	75	42.53	Natural Gas
		Bonin 3	175	44.23	Natural Gas
		Bonin 1	45	48.29	Natural Gas
		Rodemacher 4	25	52.33	Natural Gas
		Rodemacher 3	13	58.53	Natural Gas
	City of Lafayette Total		333		
	Louisiana Energy and Power Authority	Morgan City 4	36	45.06	Natural Gas
		Houma 14	10	45.12	Natural Gas
		Morgan City 3	20	46.63	Natural Gas
		Morgan City 1	6	51.33	Natural Gas
		Morgan City 2	6	51.33	Natural Gas
		New Roads Dsl 1	9	53.90	Fuel Oil
		Plaquemine 2	24	56.67	Natural Gas
		Plaquemine 1	20	57.72	Natural Gas
		Houma 16	39	58.34	Natural Gas
		Houma 15	24	58.49	Natural Gas
		Houma Dsl 12	3	70.39	Fuel Oil
		Houma Dsl_6~10 1	13	70.39	Fuel Oil
		Morgan City IC 1	4	70.39	Fuel Oil
		Plaqumaine IC 1	2	70.39	Fuel Oil
	Louisiana Energy and Power Authority Total		215		
LA_Other Total			**548**		
MIDAM	Enron Corporation	Storm Lake II 1	29	25.30	Wind
	Enron Corporation Total		29		
	IES Industries/Central Iowa Power Cooperative	Panora 2	3	59.32	Fuel Oil
	IES Industries/Central Iowa Power Cooperative Total		3		
	Midamerican Energy Co.	Moline Hydro 1-4	3	0.00	Hydro
		Louisa 1	700	11.56	Coal
		Neal South 4	624	11.79	Coal
		Neal North 3	515	12.46	Coal
		Neal North 2	300	13.23	Coal
		Council Bluffs 3	675	13.37	Coal

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
		Neal North 1	135	15.70	Coal
		Council Bluffs 2	88	16.87	Coal
		Riverside 5	130	21.44	Coal
		Council Bluffs 1	43	21.55	Coal
		Wisdom Spencer 1	37	22.08	Coal
		Riverside 3	5	22.57	Coal
		Storm Lake I 1	41	26.17	Wind
		Geneseo Diesels ALL	17	42.44	Natural Gas
		Sycamore 1	75	46.92	Natural Gas
		Sycamore 2	75	46.92	Natural Gas
		Nimeca Diesels ALL	46	54.77	Fuel Oil
		Moline 1	16	57.72	Natural Gas
		Moline 2	16	57.72	Natural Gas
		Moline 3	16	57.72	Natural Gas
		Moline 4	16	57.72	Natural Gas
		Electrifarm 3	68	59.27	Fuel Oil
		Esterville 7	15	59.32	Fuel Oil
		Pleasant Hill 1	35	60.67	Fuel Oil
		Pleasant Hill 2	35	60.67	Fuel Oil
		Electrifarm 1	56	61.29	Fuel Oil
		Indianola 7	33	61.86	Fuel Oil
		Electrifarm 2	67	61.86	Fuel Oil
		River Hills 1	15	64.63	Natural Gas
		River Hills 2	15	64.63	Natural Gas
		River Hills 3	15	64.63	Natural Gas
		River Hills 4	15	64.63	Natural Gas
		River Hills 5	15	64.63	Natural Gas
		River Hills 6	15	64.63	Natural Gas
		River Hills 7	15	64.63	Natural Gas
		River Hills 8	15	64.63	Natural Gas
		Coralville GT 1	16	64.89	Natural Gas
		Coralville GT 2	16	64.89	Natural Gas
		Coralville GT 3	16	64.89	Natural Gas
		Coralville GT 4	16	64.89	Natural Gas
		Pleasant Hill 3	78	65.47	Fuel Oil
		Webster City 1	21	75.84	Fuel Oil
		Parr 1	16	77.81	Fuel Oil
		Parr 2	16	77.81	Fuel Oil
		Wisdom Spencer GT1	20	86.19	Fuel Oil
	Midamerican Energy Co. Total		4,212		
	Midwest Energy Inc.	Great Bend 5&6 5	6	45.46	Natural Gas
		Great Bend 1-4 1	4	51.23	Natural Gas
		Bird City 1	2	52.45	Fuel Oil
		Bird City 2	2	52.45	Fuel Oil
		Ellis 1	1	64.30	Fuel Oil
		Ellis 2	2	64.30	Fuel Oil
		Ellis 4	1	64.30	Fuel Oil
		Ellis 5	1	64.30	Fuel Oil
		Colby GT 1	13	74.95	Natural Gas
	Midwest Energy Inc. Total		32		
MIDAM Total			**4,275**		
MIPU	Missouri Public Service Company	Sibley 3	395	22.89	Coal
		Sibley 2	54	25.78	Coal
		Sibley 1	54	27.55	Coal
		Ralph Green GT 3	74	48.20	Natural Gas
		Greenwood GT 3	62	58.13	Fuel Oil
		Greenwood GT 2	62	59.15	Fuel Oil
		Greenwood GT 1	62	59.28	Fuel Oil
		Greenwood GT 4	61	59.66	Fuel Oil

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
		Nevada GT 1	20	62.19	Fuel Oil
		Kansas City Intl 2	18	73.76	Natural Gas
		Kansas City Intl 1	15	75.09	Natural Gas
	Missouri Public Service Company Total		875		
MIPU Total			**875**		
OK-East	Associated Electric Co-Operative	Chouteau 1a	265	27.02	Natural Gas
		Chouteau 1b	265	27.02	Natural Gas
	Associated Electric Co-Operative Total		530		
	Calpine Corporation	NewGT_Calpine 1	250	45.60	Natural Gas
		NewGT_Calpine 2	250	45.60	Natural Gas
		NewGT_Calpine 3	250	45.60	Natural Gas
		NewGT_Calpine 4	250	45.60	Natural Gas
	Calpine Corporation Total		1,000		
	Central & South West Corp.	NewCC_CSWP 1	315	28.98	Natural Gas
	Central & South West Corp. Total		315		
	Cogentrix	NewCC_Cogenrix 1	200	28.40	Natural Gas
		NewCC_Cogenrix 2	200	28.40	Natural Gas
		NewCC_Cogenrix 3	200	28.40	Natural Gas
		NewCC_Cogenrix 4	200	28.40	Natural Gas
	Cogentrix Total		800		
	Grand River Dam Authority	Markham 1-4	114	0.00	Hydro
		Pensacola 1-6	97	0.00	Hydro
		Salina Units 1-6	260	0.00	Pump Storage
		GRDA 2	520	12.24	Coal
		GRDA 1	490	14.75	Coal
	Grand River Dam Authority Total		1,480		
	KAMO Electric Coop.	New_KAMO 1	166	37.93	Natural Gas
		NewGT_AECI 1	198	45.60	Natural Gas
		NewGT_AECI 2	198	45.60	Natural Gas
		Inter-KAMO 1	8	175.16	INTLOAD
	KAMO Electric Coop. Total		570		
	Oklahoma Gas & Electric Company	Muskogee 5	500	12.79	Coal
		Muskogee 6	515	12.97	Coal
		Muskogee 4	500	13.04	Coal
		Muskogee 3	184	43.88	Natural Gas
	Oklahoma Gas & Electric Company Total		1,699		
	Oklahoma Municipal Power Authority	Pawhuska IC 1	1	58.61	Fuel Oil
		Pawhuska IC 2	2	58.61	Fuel Oil
		Pawhuska IC 3	3	58.61	Fuel Oil
		Pawhuska IC 5	2	58.61	Fuel Oil
	Oklahoma Municipal Power Authority Total		7		
	Central & South West Corp.	Northeastern 3	450	17.53	Coal
		Northeastern 4	450	17.88	Coal
		Riverside 2	460	40.21	Natural Gas
		Northeastern 2	470	40.60	Natural Gas
		Riverside 1	457	42.62	Natural Gas
		Northeastern 1	157	46.60	Natural Gas
		Tulsa 4	165	47.88	Natural Gas
		Northeastern Dsl 1	4	53.90	Fuel Oil
		Riverside Dsl 1	3	53.90	Fuel Oil
		Tulsa Dsl 1	8	53.90	Fuel Oil
		Tulsa 2	165	54.85	Natural Gas
		Inter-PSOK 1	224	175.16	INTLOAD
	Central & South West Corp. Total		3,013		
	Southwestern Power Administration	Eufaula 1-3	90	0.00	Hydro
		Ft. Gibson 1-4	50	0.00	Hydro
		Keystone 1-2	70	0.00	Hydro
		R S Kerr 1-4	114	0.00	Hydro
		Tenkiller Fy 1-2	40	0.00	Hydro

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
		Webbers Fall 1-3	60	0.00	Hydro
	Southwestern Power Administration Total		424		
OK-East Total			**9,838**		
OK-West	Duke Power Company	NewCC_DUKE 1	250	27.71	Natural Gas
		NewCC_DUKE 2	250	27.71	Natural Gas
	Duke Power Company Total		500		
	EnergyTix	NewCC_Enegix 1	275	28.40	Natural Gas
		NewCC_Enegix 2	275	28.40	Natural Gas
		NewCC_Enegix 3	275	28.40	Natural Gas
	EnergyTix Total		825		
	Kiowa Power Partners	NewCC_Kiowa 1	300	28.81	Natural Gas
		NewCC_Kiowa 2	300	28.81	Natural Gas
		NewCC_Kiowa 3	300	28.81	Natural Gas
		NewCC_Kiowa 4	300	28.81	Natural Gas
	Kiowa Power Partners Total		1,200		
	New Century Energies	Comanche Dsl 2	4	53.36	Fuel Oil
	New Century Energies Total		4		
	Oklahoma Gas & Electric Company	Sooner 2	515	12.18	Coal
		Sooner 1	505	12.36	Coal
		Horseshoe Lake 7ST	239	40.85	Natural Gas
		Seminole 2	507	41.94	Natural Gas
		Seminole 3	500	42.06	Natural Gas
		Mustang 4	260	43.17	Natural Gas
		Seminole 1	530	43.60	Natural Gas
		Conoco GT 1	35	44.26	Natural Gas
		Conoco GT 2	35	44.35	Natural Gas
		Arbuckle 1	74	44.40	Natural Gas
		Horseshoe Lake 6	178	44.89	Natural Gas
		Horseshoe Lake 8	404	45.01	Natural Gas
		NewGT_OGE 1	95	45.60	Natural Gas
		NewGT_OGE 2	115	45.60	Natural Gas
		Mustang 3	122	48.97	Natural Gas
		Horseshoe Lake 7GT	19	63.35	Natural Gas
		Woodward GT 1	11	74.38	Natural Gas
		Tinker 5A	32	75.36	Natural Gas
		Tinker 5B	32	75.36	Natural Gas
		Seminole GT 1	15	83.20	Natural Gas
		Enid GT 1	10	85.66	Natural Gas
		Enid GT 2	10	85.66	Natural Gas
		Enid GT 3	11	85.66	Natural Gas
		Enid GT 4	10	85.66	Natural Gas
		Inter-OKGE 1	155	175.16	INTLOAD
	Oklahoma Gas & Electric Company Total		4,418		
	Oklahoma Municipal Power Authority	Kaw Hydro	26	0.00	Hydro
		Kingfisher 1-5 5	8	36.98	Fuel Oil
		NewGT_OMPA 1	39	40.39	Natural Gas
		Ponca 2	39	51.23	Natural Gas
		Ponca City OMPA 1	20	52.73	Natural Gas
		Fairview 4	1	56.29	Fuel Oil
		Ponca City Dsl 1	5	64.30	Fuel Oil
		Ponca City Dsl 10	2	64.30	Fuel Oil
		Ponca City Dsl 4	2	64.30	Fuel Oil
		Ponca City Dsl 7	2	64.30	Fuel Oil
		Ponca City Dsl 8	3	64.30	Fuel Oil
		Ponca City Dsl 9	5	64.30	Fuel Oil
		Mangum 1-6 1	6	65.68	Fuel Oil
		Ponca City GT 1	42	86.75	Natural Gas
	Oklahoma Municipal Power Authority Total		200		
	OneOK	NewGT_ONEOK 1	150	45.60	Natural Gas

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
		NewGT_ONEOK 2	150	45.60	Natural Gas
	OneOK Total		300		
	Central & South West Corp.	Comanche 1G1	78	32.70	Natural Gas
		Comanche 1G2	78	32.77	Natural Gas
		Comanche 1S	117	36.87	Natural Gas
		Southwestern 3	315	44.12	Natural Gas
		Southwestern 2	79	56.05	Natural Gas
		Southwestern Dsl 1	2	57.06	Fuel Oil
		Weleetka Dsl 1	4	57.06	Fuel Oil
		Weleetka GT 4	55	69.67	Natural Gas
		Weleetka GT 5	54	72.74	Natural Gas
		Weleetka GT 6	54	73.67	Natural Gas
	Central & South West Corp. Total		836		
	Southwestern Power Administration	Broken Bow 1-2	115	0.00	Hydro
		Denison 1-2	80	0.00	Hydro
	Southwestern Power Administration Total		195		
	Western Farmers Electric Cooperative	Hugo 1	405	15.58	Coal
		Hugo 2	475	15.69	Coal
		Anadarko 4	94	35.68	Natural Gas
		Anadarko 5	94	35.68	Natural Gas
		Anadarko 6	94	35.68	Natural Gas
		Moreland 2	143	42.46	Natural Gas
		Anadarko 3	45	45.19	Natural Gas
		Moreland 3	143	46.01	Natural Gas
		Moreland 1	51	48.82	Natural Gas
		Anadarko 1	15	54.98	Natural Gas
		Anadarko 2	15	54.98	Natural Gas
		Inter-WEFA 1	47	175.16	INTLOAD
	Western Farmers Electric Cooperative Total		1,621		
OK-West Total			**10,099**		
SPRM	Calpine Corporation	NewST_Aq-Calpine 1	208	14.71	Coal
		NewGT_Aq-Calpine 1	186	45.60	Natural Gas
		NewGT_Aq-Calpine 2	186	45.60	Natural Gas
	Calpine Corporation Total		580		
	City Utilities, Springfield	Southwest ST 1	178	13.39	Coal
		James River 4	56	18.81	Coal
		James River 1	21	20.61	Coal
		James River 2	21	20.61	Coal
		James River 5	97	21.08	Coal
		James River 3	42	27.91	Coal
		Southwest 2	52	56.62	Natural Gas
		Southwest GT 1	52	66.32	Natural Gas
		James River GT 1	75	66.49	Fuel Oil
		James River GT 2	84	66.49	Fuel Oil
		MainStreet GT 1	12	68.82	Fuel Oil
	City Utilities, Springfield Total		690		
	Trigen	NewGT_Trigen 1	15	45.60	Natural Gas
	Trigen Total		15		
SPRM Total			**1,285**		
SUNE	Sunflower Electric Power Corp.	Holcomb 1	360	14.28	Coal
		Garden City S2	98	41.45	Natural Gas
		City of Goodland 7	17	49.93	Natural Gas
		City of Hill IC 1-6	7	49.93	Natural Gas
		City of Johnson 1-7	6	49.93	Natural Gas
		City of Oberlin 4	6	49.93	Natural Gas
		City of Sharon 1-4	3	49.93	Natural Gas
		CityofSt.Francis 2-5	6	49.93	Natural Gas
		Garden City GT S4	50	60.66	Natural Gas
		Garden City GT S5	50	60.66	Natural Gas

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
		Garden City GT S3	12	68.96	Natural Gas
	Sunflower Electric Power Corp. Total		613		
SUNE Total			**613**		
TX-LA	Lower Colorado River Authority	Marshall Ford 1-3	102	0.00	Hydro
	Lower Colorado River AuthorityTotal		102		
	Central & South West Corp.	Pirkey 1	580	14.96	Coal
		Welsh 2	528	18.56	Coal
		Welsh 1	528	19.59	Coal
		Welsh 3	528	20.53	Coal
		Wilkes 3	348	38.35	Natural Gas
		Wilkes 2	357	39.98	Natural Gas
		Knox Lee 5	344	41.41	Natural Gas
		Wilkes 1	177	41.84	Natural Gas
		Lieberman 4	108	43.50	Natural Gas
		Arsenal Hill 5	110	47.67	Natural Gas
		Knox Lee 4	77	49.45	Natural Gas
		Lieberman 3	110	49.74	Natural Gas
		Lone Star 1	50	50.85	Natural Gas
		Lieberman 2	26	57.95	Natural Gas
		Knox Lee 3	32	61.90	Natural Gas
		Knox Lee 2	31	69.12	Natural Gas
		Inter-SOEP 1	135	175.16	INTLOAD
	Central & South West Corp. Total		4,069		
	Southwestern Power Administration	Narrows 1-3	26	0.00	Hydro
	Southwestern Power Administration Total		26		
TX-LA Total			**4,197**		
TX-NW	Duke Energy Power Services	Attala 1	125	45.60	Natural Gas
		Attala 2	125	45.60	Natural Gas
		Attala 3	125	45.60	Natural Gas
		Attala 4	125	45.60	Natural Gas
		McClain Energy 1	125	45.60	Natural Gas
		McClain Energy 2	125	45.60	Natural Gas
		McClain Energy 3	125	45.60	Natural Gas
		McClain Energy 4	125	45.60	Natural Gas
	Duke Energy Power Services Total		1,000		
	Golden Spread Electric Cooperative	Mustang GSE CC 1	243	26.43	Natural Gas
		Mustang GSE CC 2	243	26.43	Natural Gas
	Golden Spread Electric Cooperative Total		486		
	Southwestern Public Service Company	Celanese 2	26	14.61	Coal
		Harrington 3	360	17.50	Coal
		Harrington 2	360	18.03	Coal
		Harrington 1	346	18.24	Coal
		Tolk 1	540	21.97	Coal
		Tolk 2	540	22.46	Coal
		Nichols 1	107	38.51	Natural Gas
		Cunningham 2	196	40.71	Natural Gas
		Nichols 2	106	40.73	Natural Gas
		Jones 1	243	41.95	Natural Gas
		Nichols 3	244	41.96	Natural Gas
		Plant X 4	189	43.76	Natural Gas
		Maddox 1	118	44.41	Natural Gas
		Cunningham 4	122	45.60	Natural Gas
		Plant X 3	103	46.25	Natural Gas
		Jones 2	243	46.53	Natural Gas
		Cunningham 1	71	46.81	Natural Gas
		Plant X 2	102	47.04	Natural Gas
		Cunningham 3	122	50.88	Natural Gas
		Moore County 1	48	52.26	Natural Gas
		Celanese 1	13	53.40	Natural Gas

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
		Plant X 1	48	54.78	Natural Gas
		Tucumcari IC 3	1	56.95	Fuel Oil
		Tucumcari IC 4	2	56.95	Fuel Oil
		Tucumcari IC 5	1	56.95	Fuel Oil
		Tucumcari IC 6	3	56.95	Fuel Oil
		Tucumcari IC 8	3	56.95	Fuel Oil
		Tucumcari IC 9	5	56.95	Fuel Oil
		Maddox GT 2	66	59.45	Natural Gas
		Riverview 1	25	63.00	Natural Gas
		Carlsbad GT 5	16	72.49	Natural Gas
		Maddox GT 3	10	80.71	Natural Gas
		DCLM-SWPS 1	316	117.06	DCLM
		Inter-SWPS 1	9	175.16	INTLOAD
	Southwestern Public Service Company Total		4,704		
TX-NW Total			**6,190**		
WERE	Kansas City Power & Light Co.	Lacygne 2	674	8.72	Coal
		Iatan 1	670	10.70	Coal
		Hawthorn 5R	550	14.11	Coal
		Montrose 3	176	15.85	Coal
		Montrose 1	170	15.92	Coal
		Montrose 2	164	15.95	Coal
		Jeffrey EC 3	742	16.98	Coal
		Lacygne 1	688	17.84	Coal
		Jeffrey EC 1	744	17.95	Coal
		Jeffrey EC 2	741	18.15	Coal
		Higginsville 4	38	50.24	Natural Gas
		Hawthorn 6	141	50.94	Natural Gas
		Northeast IC 19	2	53.90	Fuel Oil
		Grand Ave 9	37	60.02	Natural Gas
		Northeast 11	56	64.67	Fuel Oil
		Northeast 13	56	65.09	Fuel Oil
		Northeast 18	58	66.54	Fuel Oil
		Northeast 16	58	67.06	Fuel Oil
		Northeast 15	58	68.31	Fuel Oil
		Northeast 12	56	68.77	Fuel Oil
		Northeast 14	58	68.86	Fuel Oil
		Northeast 17	59	68.89	Fuel Oil
		Inter-KACP 1	134	175.16	INTLOAD
	Kansas City Power & Light Co. Total		6,130		
	Kansas Gas & Electric Co.	Wolfcreek 1	1,170	11.48	Nuclear
		Murray Gill EC 3	108	42.48	Natural Gas
		Gordon Evans EC 2	376	43.00	Natural Gas
		Gordon Evans EC 1	151	46.01	Natural Gas
		Murray Gill EC 1	44	47.21	Natural Gas
		Murray Gill EC 4	106	50.36	Natural Gas
		Murray Gill EC 2	74	51.10	Natural Gas
		NewGT_KG&E 1	151	51.94	Natural Gas
		Wichita EC 5	3	109.98	Fuel Oil
		Inter-KAGE 1	164	175.16	INTLOAD
	Kansas Gas & Electric Co. Total		2,347		
	Kansas Power & Light Co.	Tecumseh 8	158	20.33	Coal
		Lawrence 5	394	20.52	Coal
		Tecumseh 7	85	21.79	Coal
		Lawrence 4	119	21.90	Coal
		Lawrence 2	26	29.49	Coal
		Lawrence 3	59	30.24	Coal
		Hutchinson EC 2	18	52.41	Fuel Oil
		Hutchinson EC 1	18	52.50	Fuel Oil
		Hutchinson EC 4	191	53.38	Fuel Oil

Attachment 5

2002 Summer Generation Unit Capacity, Fuel Type, and Full-Load Incremental Cost by TransArea

TransArea	Utility Name	Unit Name	Capacity (MW)	Full-Load Incremental Cost ($/MWh)	Fuel Type
		Abilene GT 1	70	57.45	Natural Gas
		Hutchinson EC GT 3	55	60.74	Natural Gas
		Hutchinson EC GT 1	53	61.08	Natural Gas
		Hutchinson EC GT 2	52	61.37	Natural Gas
		Hutchinson EC GT 4	83	65.32	Fuel Oil
		Hutchinson EC 3	28	70.18	Fuel Oil
		Tecumseh GT 2	21	72.68	Fuel Oil
		Tecumseh GT 1	20	73.39	Fuel Oil
		Inter-KAPL 1	27	175.16	INTLOAD
	Kansas Power & Light Co. Total		1,477		
WERE Total			**9,953**		
WPEK	WestPlains Energy Kansas	Judson Large 4	143	43.72	Natural Gas
		Arthur Mullergre 3	96	44.26	Natural Gas
		Cimarron Riv G 2	14	56.05	Natural Gas
		Clifton 2	3	56.24	Fuel Oil
		Cimarron River 1	58	58.36	Natural Gas
		Clifton GT 1	71	60.02	Natural Gas
		Inter-WEPL 1	50	175.16	INTLOAD
	WestPlains Energy Kansas Total		434		
WPEK Total			**434**		

Attachment 6

Announced Generation Plants to be Online Prior to Summer Peak of 2002

State	Company	Plant Capacity (Mw)	Add'n Capacity	Type	TransArea
Arkansas	Arkansas Electric Cooperative	110	110	CT	Ent-No
Arkansas	GenPower LLC of Dell	600	600	CT	Ent-No
Arkansas	Kinder Morgan & Southern Energy	550	550	GT	Ent-No
Arkansas	Panda Energy	2,200	2,200	CC	Ent-No
Arkansas	Skygen Energy	230	230	Cogen/ CC	Ent-No
Arkansas	**Total**	**3,690**	**3,690**		
Kansas	Western Resources	151	151	GT	WERE
Kansas	**Total**	**151**	**151**		
Louisiana	AEP / Dow Chemical Co.	900	900	CoGen	Ent-So
Louisiana	CLECO & Southern Energy	150	150	GT	CLECO
Louisiana	CLECO and Calpine Corp	1,000	1,000	CC	CLECO
Louisiana	Cogentrix Energy	800	800	CC	Ent-So
Louisiana	Enron	540	540	GT	Ent-So
Louisiana	Entergy & PPG Industries	500	500	CC	Ent-So
Louisiana	Nations Energy	110	110	CoGen	Ent-So
Louisiana	RS Cogen / PPG Industries, Inc	425	425	CC	Ent-So
Louisiana	Skygen Energy	240	240	Unknown	Ent-So
Louisiana	Skygen Energy	240	240	Unknown	Ent-So
Louisiana	Skygen Energy	500	500	CC	Ent-So
Louisiana	**Total**	**5,405**	**5,405**		
Missouri	Calpine/Aquila	372	372	GT	SPRM
Missouri	Calpine/Aquila	208	208	CC	SPRM
Missouri	Duke Energy	250	250	CC	ASEC
Missouri	Duke Energy North America	640	640	GT	ASEC
Missouri	Empire District Electric & Western Resources	500	350	CC	EDE
Missouri	KCP&L	550	74	Coal	WERE
Missouri	Univ of Missouri	26	26	CC	ASEC
Missouri	**Total**	**2,546**	**1,920**		
Oklahoma	AEP - PSO	315	155	CC	OK-East
Oklahoma	Calpine	1,000	1,000	GT	OK-East
Oklahoma	Cogentrix Energy	800	800	CC	OK-East
Oklahoma	Duke Energy	500	500	CC	OK-West
Oklahoma	Energetix	825	825	CC	OK-West
Oklahoma	Kiowa Power Partners	1,200	1,200	CC	OK-West
Oklahoma	OMPA	39	39	Unknown	OK-West
Oklahoma	ONEOK	300	300	GT	OK-West
Oklahoma	**Total**	**4,979**	**4,819**		
Texas	CONOCO GLOBAL POWER	420	420	CoGen	Ent-So
Texas	**Total**	**420**	**420**		
ALL States	**Total**	**17,191**	**16,405**		

Attachment 7

Forecast of Permian Basin Natural Gas Price

($/mmBtu)

Date	Henry Hub Price[1]	Price Difference[2]	Permian Price[3]
JAN 2002	4.640	0.072	4.568
FEB 2002	4.413	0.133	4.280
MAR 2002	4.188	0.091	4.097
APR 2002	3.948	0.128	3.820
MAY 2002	3.843	0.116	3.727
JUN 2002	3.821	0.128	3.693
JUL 2002	3.830	0.064	3.766
AUG 2002	3.840	0.063	3.777
SEP 2002	3.835	0.074	3.761
OCT 2002	3.838	0.106	3.732
NOV 2002	3.930	0.103	3.827
DEC 2002	4.005	0.159	3.846

Sensitivity Analysis

High Case[4] ($/mmBtu)		Low Case[5] ($/mmBtu)	
Henry Hub Price	Permian Price	Henry Hub Price	Permian Price
5.568	5.496	2.784	2.712
5.296	5.162	2.648	2.514
5.026	4.935	2.513	2.422
4.738	4.610	2.369	2.241
4.612	4.495	2.306	2.190
4.585	4.457	2.293	2.165
4.596	4.532	2.298	2.234
4.608	4.545	2.304	2.241
4.602	4.528	2.301	2.227
4.606	4.500	2.303	2.197
4.716	4.613	2.358	2.255
4.806	4.647	2.403	2.244

Note:

1. Henry Hub price is the NYMEX Future Contract "Most Recent Settle" price posted on Sept 21, 2000.
2. Price Difference is derived from difference in cash prices between Henry Hub and Permian (source: Natural Gas Week, 5/1/00). It is an average of prices of 1997, 1998, 1999, and a part of 2000, in 2000 dollars.
3. Permian Price equals Henry Hub Price minus Price Difference (also in 2000 dollars).
4. The High Case is 20% above the Base Case forecast.
5. The Low Case is 40% below the Base Case forecast.

Attachment 7

Coal Prices

Company Name	Plant Code	Plant Name	1999 Average Cost ($/mmBtu)*	2002 Average Gas Prices ($/mmBtu)**
Empire Dist Electric	2076	Asbury	1.031	1.087
Independence, City of	2132	Blue Valley	1.322	1.395
Central Louisiana Electric	51	Dolet Hills	1.337	1.410
Southwestern Electric Power(CSW)	6138	Flint Creek	1.395	1.472
Grand River Dam Authority	165	GRDA 1 & 2	0.857	0.905
Southwestern Public Service	6193	Harrington	1.193	1.259
Kansas City Power and Light	2079	Hawthorne	0.680	0.718
Sunflower Electric Power Corp	108	#1	1.063	1.122
Western Farmers Electric Coop	6772	Hugo	1.048	1.106
Kansas City Power and Light	6065	Iatan	0.741	0.782
City Utilities of Springfield	2161	James River	1.131	1.193
KP&L, A Western Resources Co	6068	Jeffrey	1.106	1.167
Kansas City Power and Light	1241	La Cygne	0.678	0.715
KP&L, A Western Resources Co	1250	Lawrence	1.070	1.129
Kansas City Power and Light	2080	Montrose	0.906	0.955
Oklahoma Gas and Electric	2952	Muskogee	0.847	0.893
Kansas City Bd Public Utilities	6064	Creek	0.671	0.708
Public Serv Co of Oklahoma (CSW)	2963	Northeast	1.180	1.245
Southwestern Electric Power(CSW)	7902	Pirkey	1.152	1.215
Kansas City Bd Public Utilities	1295	Quindaro	0.880	0.928
Empire Dist Electric	1239	Riverton	1.156	1.220
Missouri Public Service	2094	Sibley	0.885	0.934
Oklahoma Gas and Electric	6095	Sooner	0.790	0.833
City Utilities of Springfield	6195	Southwest	1.009	1.065
KP&L, A Western Resources Co	1252	Tecumseh	1.031	1.087
Southwestern Public Service	6194	Tolk	1.760	1.857
Southwestern Electric Power(CSW)	6139	Welsh Station	1.526	1.610

**From 1999 FERC Form 423.

**The 2002 Average Gas Prices were calculated from the 1999 nominal prices by applying the DOE-EIA 1998 Annual Energy Outlook's real escalation rate and the CEC 1998 Natural Gas Market Outlook's inflation rate.

Source: OKG

Attachment 8

Geographical Market Analysis

Price Increase From Withholding All Competitive Generation

Season	Period	Base Case Price ($/MWh)	Price Under Withholding ($/MWh)	Increase (%)
Summer	Super-Peak	90.2	101.2	12.2
Summer	On-Peak	68.5	71.1	3.8
Summer	Shoulder	33.0	33.8	2.3
Summer	Off-Peak	18.1	18.2	0.3
Winter	Super-Peak	57.1	56.9	-0.4
Winter	On-Peak	29.7	30.4	2.5
Winter	Shoulder	34.6	35.0	1.2
Winter	Off-Peak	14.3	14.5	1.5
Fall/Spring	On-Peak	39.0	38.3	-1.9
Fall/Spring	Shoulder	32.8	33.0	0.5
Fall/Spring	Off-Peak	14.9	15.0	0.4

Evaluation of Bidding Strategies During the Summer Super-Peak Period

Strategy	Average Price	Price Increase (%)	Change in Profits ($)*
Base Case	90.21		
All local generation but one AES unit bid at 500% of variable cost.	90.25	0.0	-29,112
All local generation but one AES unit bid at 1000% of variable cost.	96.22	6.7	-577,433
All local generation but one AES unit bid at 1500% of variable cost.	94.11	4.3	-624,666
All local units withheld except one AES unit and second one at minimum loading.	94.71	5.0	-611,096
All local units withheld except one AES unit.	96.21	6.7	-990,842
All local units withheld except one AES unit at minimum loading.	99.67	10.5	-1,738,412

*The change in profits is calculated for the competitive AR-FS generation.

Attachment 9
Summary of O G & E's Market Position
Base Case

Total Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	1,692	19.1	1,328	403	3.6	1,296	NA	NA	NA
Summer	On - Peak	1,668	17.4	896	603	4.3	1,027	585	12.3	737
Summer	Shoulder	1,758	18.8	891	648	4.7	1,018	624	13.5	742
Summer	Off - Peak	1,769	20.1	962	676	5.2	1,022	627	14.2	794
Winter	Super-Peak	1,825	18.7	1,068	517	4.0	1,163	517	10.5	1,076
Winter	On - Peak	1,724	20.2	952	695	5.5	978	725	12.3	745
Winter	Shoulder	1,752	22.5	1,033	768	6.5	1,015	771	14.1	764
Winter	Off - Peak	1,726	22.0	1,010	754	6.3	972	760	13.8	760
Fall / Spring	On - Peak	1,469	17.3	865	591	4.4	1,001	578	11.1	727
Fall / Spring	Shoulder	1,490	18.8	909	653	5.3	953	613	12.5	766
Fall / Spring	Off - Peak	1,512	19.7	937	675	5.6	951	637	13.2	787

Available Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	327	6.8	1,344	73	1.0	1,161	NA	NA	NA
Summer	On - Peak	247	4.0	753	216	2.3	814	155	4.7	746
Summer	Shoulder	363	6.1	682	285	3.1	795	198	6.5	723
Summer	Off - Peak	481	8.4	722	360	4.1	759	236	8.1	772
Winter	Super-Peak	284	5.1	817	123	1.5	1,046	114	4.5	786
Winter	On - Peak	370	7.4	712	320	3.7	744	248	7.0	693
Winter	Shoulder	633	13.3	757	540	6.7	753	379	11.8	724
Winter	Off - Peak	657	13.7	736	525	6.6	730	376	11.9	715
Fall / Spring	On - Peak	217	4.1	705	199	2.1	794	146	4.3	730
Fall / Spring	Shoulder	337	6.6	677	306	3.5	694	210	6.6	702
Fall / Spring	Off - Peak	457	9.1	690	395	4.7	684	278	9.0	706

Attachment 10
Summary of O G & E's Market Position
High/Low SPP Penetration Case

Available Economic Capacity Analysis, 90% Remain on SSP

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	136	3.2	1,407	72	1.1	1,220	NA	NA	NA
Summer	On - Peak	80	1.4	763	153	1.7	773	110	3.3	753
Summer	Shoulder	159	2.9	687	212	2.4	739	142	4.7	718
Summer	Off - Peak	211	4.0	705	246	2.9	687	154	5.3	746
Winter	Super-Peak	123	2.4	791	110	1.4	988	102	4.0	778
Winter	On - Peak	119	2.6	728	193	2.4	688	146	4.1	689
Winter	Shoulder	308	7.2	676	359	4.8	656	240	7.5	643
Winter	Off - Peak	339	7.8	659	358	4.8	646	246	7.8	648
Fall / Spring	On - Peak	79	1.6	722	125	1.4	744	90	2.7	734
Fall / Spring	Shoulder	132	2.8	671	175	2.1	636	119	3.7	687
Fall / Spring	Off - Peak	216	4.7	666	262	3.3	617	177	5.8	673

Available Economic Capacity Analysis, 60% Remain on SSP

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	529	9.8	1,318	74	1.0	1,127	NA	NA	NA
Summer	On - Peak	498	7.5	768	281	2.8	872	208	6.3	754
Summer	Shoulder	649	10.0	717	369	3.8	865	268	8.8	747
Summer	Off - Peak	834	13.2	791	485	5.2	839	338	11.5	821
Winter	Super-Peak	529	9.8	1,318	74	1.0	1,127	125	5.0	804
Winter	On - Peak	759	13.6	776	471	5.2	817	383	10.7	731
Winter	Shoulder	1,017	19.1	910	691	8.1	855	512	15.7	830
Winter	Off - Peak	1,011	18.9	875	657	7.7	822	497	15.5	808
Fall / Spring	On - Peak	469	8.1	717	305	3.0	854	235	6.9	741
Fall / Spring	Shoulder	636	11.4	732	438	4.8	765	314	9.8	740
Fall / Spring	Off - Peak	753	13.8	765	520	5.9	761	381	12.3	762

Attachment 11
Summary of O G & E's Market Position
Reduced Entry Case

Total Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	1,807	21.2	1,586	424	4.3	1,390	NA	NA	NA
Summer	On - Peak	1,706	17.9	983	589	4.6	1,082	573	12.3	782
Summer	Shoulder	1,770	19.7	977	619	4.9	1,081	597	13.5	775
Summer	Off - Peak	1,782	20.5	1,007	643	5.2	1,069	603	14.2	813
Winter	Super-Peak	1,822	18.8	1,161	485	4.1	1,248	481	10.0	1,146
Winter	On - Peak	1,728	20.0	998	678	5.5	1,007	706	12.0	775
Winter	Shoulder	1,741	22.4	1,072	709	6.2	1,065	723	13.7	779
Winter	Off - Peak	1,733	21.9	1,054	720	6.3	1,025	734	13.6	787
Fall / Spring	On - Peak	1,470	17.5	948	567	4.5	1,051	556	11.0	771
Fall / Spring	Shoulder	1,489	18.8	963	610	5.3	1,017	592	12.4	794
Fall / Spring	Off - Peak	1,516	19.5	976	638	5.5	1,001	610	12.9	822

Available Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	422	9.4	1,707	97	1.7	734	NA	NA	NA
Summer	On - Peak	353	5.8	879	232	2.7	730	166	5.2	784
Summer	Shoulder	453	7.9	741	296	3.5	728	204	6.9	722
Summer	Off - Peak	613	10.6	771	368	4.4	744	242	8.8	772
Winter	Super-Peak	292	5.4	1,061	114	1.6	1,012	100	4.3	946
Winter	On - Peak	376	7.3	782	303	3.7	722	229	6.6	722
Winter	Shoulder	624	13.1	783	452	5.8	755	329	10.5	727
Winter	Off - Peak	655	13.3	778	471	6.1	723	342	11.0	717
Fall / Spring	On - Peak	243	4.6	813	189	2.2	762	139	4.3	779
Fall / Spring	Shoulder	368	7.3	755	272	3.4	709	195	6.4	731
Fall / Spring	Off - Peak	479	9.4	754	349	4.4	702	249	8.4	745

Attachment 12
Summary of O G & E's Market Position
High Fuel Case

Total Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	1,694	19.1	1,321	411	3.7	1,294	NA	NA	NA
Summer	On - Peak	1,668	17.6	916	590	4.3	1,047	573	12.4	743
Summer	Shoulder	1,756	19.5	926	637	4.8	1,043	609	13.7	752
Summer	Off - Peak	1,760	20.5	984	663	5.3	1,047	619	14.4	800
Winter	Super-Peak	1,829	18.9	1,064	519	4.0	1,160	520	10.5	1,079
Winter	On - Peak	1,729	20.1	947	704	5.6	974	736	12.3	746
Winter	Shoulder	1,762	23.2	1,067	759	6.6	1,040	765	14.3	770
Winter	Off - Peak	1,747	22.2	1,011	765	6.4	971	776	14.0	760
Fall / Spring	On - Peak	1,473	17.7	881	592	4.5	1,010	574	11.2	732
Fall / Spring	Shoulder	1,487	19.4	939	660	5.5	978	621	12.9	770
Fall / Spring	Off - Peak	1,514	19.8	941	674	5.7	958	635	13.2	788

Available Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	327	6.8	1,332	81	1.2	1,164	NA	NA	NA
Summer	On - Peak	247	4.1	755	201	2.1	800	145	4.5	732
Summer	Shoulder	345	6.1	684	265	3.0	786	182	6.4	710
Summer	Off - Peak	467	8.4	725	343	4.0	745	226	7.9	763
Winter	Super-Peak	256	4.8	798	118	1.4	1,041	110	4.4	793
Winter	On - Peak	368	7.4	712	330	3.9	723	254	7.1	694
Winter	Shoulder	638	13.8	776	540	6.9	766	389	12.2	753
Winter	Off - Peak	672	14.0	743	551	6.9	719	394	12.3	718
Fall / Spring	On - Peak	217	4.2	702	198	2.1	776	144	4.3	716
Fall / Spring	Shoulder	334	6.9	682	309	3.7	698	214	6.8	694
Fall / Spring	Off - Peak	455	9.2	692	395	4.7	680	276	9.0	706

Attachment 13
Summary of O G & E's Market Position
Low Fuel Case

Total Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	1,713	18.8	1,297	418	3.6	1,250	NA	NA	NA
Summer	On - Peak	1,657	16.2	865	580	4.0	989	566	11.6	702
Summer	Shoulder	1,703	17.3	829	576	4.0	977	562	12.1	692
Summer	Off - Peak	1,709	18.5	899	587	4.4	986	551	12.7	719
Winter	Super-Peak	1,831	18.0	1,022	491	3.8	1,157	498	10.1	1,061
Winter	On - Peak	1,721	19.3	919	666	5.1	968	706	11.7	728
Winter	Shoulder	1,740	21.8	1,000	728	6.0	989	737	13.6	751
Winter	Off - Peak	1,724	21.4	980	730	6.0	954	752	13.5	748
Fall / Spring	On - Peak	1,417	15.6	808	562	4.1	977	566	10.4	687
Fall / Spring	Shoulder	1,413	17.1	854	601	4.8	930	571	11.5	713
Fall / Spring	Off - Peak	1,432	18.0	881	619	5.1	927	588	12.1	747

Available Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	333	6.7	1,244	89	1.2	1,082	NA	NA	NA
Summer	On - Peak	286	4.3	765	202	2.0	844	152	4.3	761
Summer	Shoulder	361	5.6	673	249	2.6	819	181	5.4	729
Summer	Off - Peak	460	7.4	682	296	3.2	798	200	6.5	710
Winter	Super-Peak	336	5.7	818	115	1.4	1,069	109	4.4	816
Winter	On - Peak	376	7.0	717	279	3.1	779	222	6.1	693
Winter	Shoulder	592	12.1	721	469	5.7	756	336	10.5	717
Winter	Off - Peak	642	12.9	704	495	6.0	732	357	11.3	679
Fall / Spring	On - Peak	203	3.4	695	171	1.7	803	133	3.6	711
Fall / Spring	Shoulder	316	5.8	666	269	3.0	723	186	5.8	672
Fall / Spring	Off - Peak	413	7.8	660	331	3.9	700	233	7.5	672

Attachment 14
Summary of O G & E's Market Position
No RTO Case

Total Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	1,697	19.2	1,335	407	3.6	1,292	NA	NA	NA
Summer	On - Peak	1,671	17.4	897	602	4.3	1,026	591	12.5	734
Summer	Shoulder	1,758	18.5	872	641	4.7	1,012	620	13.3	744
Summer	Off - Peak	1,763	20.1	962	679	5.2	1,021	635	14.5	794
Winter	Super-Peak	1,827	18.5	1,054	517	4.0	1,159	519	10.5	1,069
Winter	On - Peak	1,730	20.3	958	697	5.5	977	753	12.8	741
Winter	Shoulder	1,754	22.5	1,036	773	6.6	1,023	790	14.6	772
Winter	Off - Peak	1,731	22.1	1,010	762	6.4	967	786	14.2	762
Fall / Spring	On - Peak	1,479	17.4	872	598	4.4	994	601	11.6	721
Fall / Spring	Shoulder	1,492	18.9	914	665	5.4	946	643	13.0	765
Fall / Spring	Off - Peak	1,511	19.7	937	678	5.7	950	648	13.5	789

Available Economic Capacity Analysis

Season	Period	AR-FS & OK-East			AR-FS & Entergy North			AR-FS & AR-NW		
		Ave. MWH	Share	HHI	Ave. MWH	Share	HHI	Ave. MWH	Share	HHI
Summer	Super-Peak	327	6.9	1,353	78	1.1	1,155	NA	NA	NA
Summer	On - Peak	244	4.0	749	211	2.2	814	151	4.6	732
Summer	Shoulder	367	6.0	680	290	3.2	784	197	6.5	744
Summer	Off - Peak	471	8.2	715	364	4.1	759	240	8.4	759
Winter	Super-Peak	290	5.2	808	125	1.5	1,038	116	4.6	785
Winter	On - Peak	365	7.4	700	322	3.7	741	252	7.4	654
Winter	Shoulder	622	13.2	754	543	6.9	761	386	12.3	723
Winter	Off - Peak	653	13.7	727	542	6.8	727	389	12.4	694
Fall / Spring	On - Peak	218	4.1	696	206	2.1	790	153	4.7	682
Fall / Spring	Shoulder	331	6.6	676	320	3.7	692	222	7.1	673
Fall / Spring	Off - Peak	451	9.1	683	402	4.8	683	282	9.4	685

Attachment 15

Total Capacity Analysis
Combined AR-FS and OK-East Region

Utility	Capacity MW	Squeezed Capacity MW	Share %	HHI
OG&E in OK-East & AR-FS	2,019	2,019		
OG&E in OK-West		265		
OG&E Total	2,019	2,284	19.1	366
SPA in OK-East & AR-FS	726	726		
SPA in OK-West		12		
SPA Total	726	738	6.2	38
AECC in OK-East & AR-FS	59	59		
AECC in Ent-No		117		
AECC Total	59	176	1.5	2
Associated Electric Co-Operative	530	530	4.4	20
Calpine Corporation	1,000	1,000	8.4	70
Central & South West. Corp.	315	315	2.6	7
Cogentrix	800	800	6.7	45
Grand River Dam Authority	1,480	1,480	12.4	154
KAMO Electric Coop.	570	570	4.8	23
Oklahoma Municipal Power Authority	7	7	0.1	0
Public Service Company of Oklahoma	3,013	3,013	25.2	637
OK-West Imports				
Duke Power Company	500	30	0.3	0
Energytix	825	49	0.4	0
Kiowa Power Partners	1,200	72	0.6	0
New Century Energies	4	0	0.0	0
Oklahoma Gas & Electric Company	4,418	265	*	*
Oklahoma Municipal Power Authority	200	12	0.1	0
OneOK	300	18	0.2	0
Public Service Company of Oklahoma	836	50	0.4	0
Southwestern Power Administration	195	12	*	*
Western Farmers Electric Cooperative	1,621	97	0.8	1
OK-West Imports Total**	10,099	605		
Ent-No Imports				
Arkansas Electric Coop. Corp.	2,898	117	*	*
Entergy Corporation	4,833	195	1.6	3
GenPower LLC of Dell	600	24	0.2	0
Panda Energy	2,200	89	0.7	1
SkyGen	230	9	0.1	0
Southern Company Services	550	22	0.2	0
City of North Little Rock	42	2	0.0	0
Ent-No Imports Total**	11,353	457		
WERE Imports		331	2.8	8
ASEC Imports		21	0.2	0
Total Capacity in Combined OK-East & AR-FS Market		11,934	100.0	1,375

* Total figures for OK-West and Ent-No include the capacity listed above under OG&E, SPA, and AECC that is located in the OK-West and Ent-No regions.
** Capacity from neighboring regions has been limited to 90 percent of the transmision line TTC, and utility capacity has been reduced pro-rata.

Source: EIA Form 411 and new entrants from Mr. Jack Coffman's testimony.

Attachment 15

Total Capacity Analysis
Combined AR-FS and Ent-No Region

Utility	Capacity MW	Squeezed Capacity MW	Share %	HHI
Entergy Corporation in AR-FS & Ent-No	4,833	4,833		
Entergy Corporation in Ent-So		78		
Entergy Corporation Total	4,833	4,911	31.1	965
OG&E in AR-FS & Ent-No	320	320		
OG&E in OK-East		103		
OG&E Total	320	423	2.7	7
SPA in AR-FS & Ent-No	302	302		
SPA in OK-East		26		
SPA in Ent-So		0		
SPA Total	302	328	2.1	4
AECC	2,957	2,957	18.7	350
City of North Little Rock	42	42	0.3	0
GenPower LLC of Dell	600	600	3.8	14
Panda Energy	2,200	2,200	13.9	194
SkyGen	230	230	1.5	2
Southern Company Services	550	550	3.5	12
OK-East Imports				
Associated Electric Co-Operative	530	32	0.2	0
Calpine Corporation	1,000	60	0.4	0
Central & South West. Corp.	315	19	0.1	0
Cogentrix	800	48	0.3	0
Grand River Dam Authority	1,480	89	0.6	0
KAMO Electric Coop.	570	34	0.2	0
Oklahoma Gas & Electric Company	1,699	103	*	*
Oklahoma Municipal Power Authority	7	0	0.0	0
Public Service Company of Oklahoma	3,013	182	1.2	1
Southwestern Power Administration	424	26	*	*
OK-East Imports Total**	9,838	594		
Ent-So Imports				
American Electric Power Co.	900	5	0.0	0
City of Clarksdale	50	0	0.0	0
City of Ruston	11	0	0.0	0
City of Sikeston	241	1	0.0	0
Cogentrix	1,601	10	0.1	0
Conoco Global Power	100	1	0.0	0
Enron Corporation	540	3	0.0	0
Entergy Corporation	13,107	78	*	*
Gulf States Utilities Company	6,528	39	0.2	0
Louisville Gas & Electric	80	0	0.0	0
Mississippi Power & Light	516	3	0.0	0
Nations Energy	110	1	0.0	0
Reliant Energy	60	0	0.0	0
RS Cogentrix/PPG Industries, Inc.	426	3	0.0	0
Sho-Me Power Electric Coop	3	0	0.0	0
SkyGen	980	6	0.0	0
Southwestern Power Administration	59	0	*	*
Tenaska, Inc.	415	2	0.0	0
Ent-So Imports Total**	25,727	153		
AECI Imports		593	3.8	14
AR-NW Imports		203	1.3	2
City of Lafayette		117	0.7	1
EDE Imports		65	0.4	0
TVA Imports		1,062	6.7	45
TX-LA Imports		986	6.2	39
Total Capacity in Combined OK-East & AR-FS Market		15,806	100.0	1,652

* Total figures for OK-East and Ent-So include the capacity listed above under Entergy, OG&E, and SPA that is located in the OK-East and Ent-So region.
** Capacity from neighboring regions has been limited to 90 percent of the transmision line TTC, and utility capacity has been reduced pro-rata.

Source: EIA Form 411 and new entrants from Mr. Jack Coffman's testimony.