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III.A.6 Distribution Loss Factor

Q: Please explain the methodology used to calculate the cost of distribution losses incurred to serve the Ohio Companies' standard service offer load.

A: I have calculated each direct cost component described above based on the assumption that the relevant service was delivered to the Ohio Companies' distribution systems, rather than the customer's meter. As such, these costs are shown gross of losses that occur on the distribution network as the services are delivered to the customer. In order to convert these costs to a customer-metered basis, I have used loss factors for each customer class that were provided to me by FirstEnergy. The results of this analysis are presented in Exhibit 5.

III.B Calculation of Expected Margin

Q: Please explain why it is necessary to include a margin in the expected market-rate offer price.

A: The commitment to meet the Ohio Companies' standard service offer load represents a substantial commitment of capital resources, and these capital resources are exposed to substantial risk. Economic reasoning, as well as extensive experience with previous similar procurements, shows that potential suppliers will not make such a commitment without an expectation of earning a margin to compensate for these risks.

III.B.1 Capital Costs and Risks

Q: Please describe the nature of the capital commitment made by a supplier of full requirements electric service to meet the Ohio Companies' standard service offer obligation.

A: The supplier must have adequate capital to function efficiently in energy markets, including the ability to enter forward contracts and other derivative instruments for the purpose of obtaining sufficient, diversified generation supply and for hedging any costs and/or risk associated with providing the standard service offer.

For example, if a supplier enters a forward contract for the purpose of hedging future expected load obligations, the supplier may be required to post letters of credit or provide other assurances of performance to its trading partners. In addition, if market prices move substantially lower, the supplier may have a significant credit exposure to cover.[8] Also, the supplier must have adequate capital to fund the delay between the incurrence of expenses and the collection of revenues.

Q: Please describe the main risks that a supplier would bear if it were to commit to supply full requirements services to meet the Ohio Companies' standard service offer requirements.

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[8] As explained below, a decline in market prices is also likely to decrease the level of standard service offer load as customers will be able to get service at lower prices from alternative providers, leaving the supplier with excess supplies at above market prices.

A: The main risks a supplier faces include shopping risk, load variability risk, price variability risk, regulatory risk, and bidding risk.

Shopping Risk

Q: **Please define shopping risk.**

A: Shopping risk exists because customers have the right to elect to receive retail electricity service from alternate competitive suppliers at any point in time. Moreover, customers have the right to return to their standard offer service provider having shopped earlier in response to market conditions. This means that the supplier of full requirements service to supply the Ohio Companies' standard service offer load may lose load if market prices drop sufficiently to enable successful entry by competitive suppliers. Conversely, the supplier is exposed to further risk in that retail customers may switch from alternative suppliers to standard service offer if market conditions make such movement attractive.

Because customers can switch between alternative suppliers and the standard service offer, the supplier of full requirements electric service to meet the Ohio Companies' standard service offer obligation can not know with certainty how many customers will be taking standard service offer at any time in the future. This uncertainty makes it very difficult for the supplier to hedge its costs of providing electric service.

For example, assume the supplier hedges by purchasing forward contracts for electricity. In the event that electricity market prices subsequently drop, customers are likely to switch away from the standard service offer, leaving the supplier with too much power at above market prices. Alternatively, if the supplier decides not to hedge and market prices subsequently rise, then customers will tend to switch to standard service offer and the supplier will be forced to purchase electricity at the elevated prices to cover the standard service offer obligation.

Q: **Is there evidence that a supplier bidding to provide full requirements service to meet the Ohio Companies' standard service offer load would face shopping risk?**

A: Yes. Industrial customers virtually always present a high level of shopping risk, since they tend to be sophisticated buyers with large loads and relatively lower load-shaping costs,[9] making them attractive customers for competitive retail suppliers. Since the inception of the transition period to retail competition, shopping by non-industrial retail customers in the Ohio Companies' service territories has been highly variable, with shopping reaching a high of 69 percent for residential customers and 75 percent for commercial customers in 2004.[10] Most of the shopping by residential and

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[9] For example, Exhibit 3 shows that load-shaping costs for industrial customers in 2009 are $2.26 per MWh whereas load-shaping costs for residential and commercial customers are $4.95 and $5.02, respectively.

[10] The Public Utilities Commission of Ohio, "The Ohio Retail Electric Choice Programs Report of Market Activity: January 2003 – July 2005", August 2005 at Appendix B ("PUCO 2005 Electric Choice Report").

commercial customers has occurred within government aggregation programs.

Q: **Please describe Ohio's government aggregation program.**

A: Senate Bill 3 (SB3) of 1999 permits government entities such as municipalities and townships to establish governmental aggregation programs, whereby the governmental entity can establish supply arrangements for electricity on behalf of its residents.[11] Importantly, residential customers are automatically enrolled in the aggregation group unless they elect to opt out and submit a signed form to that effect. The result of these parameters is that governmental aggregation has been a source of substantial shopping risk by residential and commercial customers, who as individual consumers would typically represent a smaller shopping risk because of the relatively high cost of marketing to a single customer. Governmental aggregation of such customers makes it much more cost-effective for suppliers to market to them.

Q: **Why is this an issue for the Ohio Companies?**

A: Government aggregation substantially increases the shopping risk faced by a supplier of full requirements electric service to meet the Ohio Companies' standard service offer obligations. Residential and small commercial customers in Ohio have shopped at very high rates relative to customers in

[11] PUCO 2005 Electric Choice Report at 1.

other states with retail competition for electricity.[12] Most of these customers in Ohio who have been served by alternative suppliers have been served through government aggregation programs.[13]

Approximately 50 percent of the Ohio Companies' residential customers and commercial customers reside in government jurisdictions that have established governmental aggregation programs. For the purposes of my analysis during each of the years 2009, 2010, and 2011, I assume these aggregated residential customers and aggregated commercial customers present the same level of shopping risk as industrial customers. Further, because the law allows government entities to establish governmental aggregation programs so long as certain criteria are met, it is reasonable to assume that virtually all of the residential and commercial customers in the Ohio Companies' service areas could receive retail generation under a governmental aggregation program if market conditions were favorable. In my analysis, I treat 50 percent, 75 percent and 100 percent of these customers as taking generation service as part of a governmental aggregation group for the years 2009, 2010, and 2011, respectively.

Load Variability Risk

Q: **Please define load variability risk.**

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[12] Littlechild, S. (2007) "Municipal Aggregation and Retail Competition in the Ohio Energy Sector." *Electricity Policy Research Group Working Papers*, No.EPRG 07/15. Cambridge: University of Cambridge.
[13] *Ibid.*

A: Load variability arises because real time customer demand is driven by factors which are unpredictable and outside of the control of the participants in the marketplace. These factors include, for example, weather and changing macroeconomic conditions. Because of these factors, the supplier cannot be certain of future load for any customer taking standard offer service. This uncertainty makes hedging extremely difficult, since a drop in load is often accompanied by a drop in market prices, and the supplier who hedges risks being left with excess supplies at above-market prices. And, alternatively, since an increase in load is often accompanied by an increase in market prices, the supplier who does not hedge risks being required to make purchases in the spot market at elevated prices.

Price Variability Risk

Q: **Please define market price variability risk.**

A: Price variability risk arises both because electricity prices are volatile and because suppliers of the standard service offer are unable to perfectly hedge their future needs owing to shopping risk and load variability. A supplier who bids to provide full requirements electric service to meet standard service offer service obligations can be fairly certain the actual market price at the time the service is delivered will be higher or lower than the market price that was expected at the time the bid was prepared. The supplier can hedge some of its costs in forward markets, but forward contracts are typically traded as "blocks" (i.e., fixed quantities of power per hour) and thus do not perfectly fit the shape of actual customer load. Thus, the supplier cannot avoid having to buy and/or sell some power in short-term markets.

Regulatory Risk

Q: **Please define regulatory risk as it pertains to suppliers bidding to provide full requirements service for the Ohio Companies' standard service offer.**

A: Providers of full requirements service for the Ohio Companies' standard service offer face regulatory risk in that the costs they incur to provide the service can be affected by changes in regulatory policies. Well-recognized sources of such risk in the Ohio Companies' service territories include the possibility of future environmental regulations such as controls on greenhouse gas emissions and the possibility that the Midwest ISO will institute changes to the design of its markets or rules.

R.C. 4928.64 requires that 0.25 percent of the electricity supply used to meet a company's standard service offer obligation is to be provided from renewable energy resources by the end of 2009, .50 percent by the end of 2010, and 1 percent by the end of 2011, and that this required renewable energy resource component will increase each year until 2024, when it will be fixed at 12.5 percent. In my opinion, while compliance with these renewable energy resource requirements may have a significant impact on the Companies in terms of absolute dollars, i.e., costing millions of dollars, such requirements are unlikely to have a significant effect on the total cost of the provision of full requirements electric service to meet the Ohio Companies' entire standard service offer obligation over the years 2009, 2010, and 2011. But whatever the actual level, the expected impact of meeting these requirements will be additive to the price of the standard service offer.

Bidding Risk

Q: **Please define bidding risk.**

A: Bidding risk arises because once an offer is submitted the bidder is typically required to keep the offer "open" for some period of time for review and acceptance by the regulator. For example, R.C. 4928.142 provides that the utility's market-rate offer will become effective only if the PUCO does not find that certain criteria have not been met, and that the PUCO must complete this review within three days of the conclusion of the bidding process. During the time the bid is kept open, market prices may change substantially, making it difficult or impossible for the supplier to hedge the price that it offered.

III.B.2 Calculation of Expected Margin

Q: **Please explain how you calculate the margins you apply in calculating market-offer prices for the standard service offer.**

A: I rely upon publicly available analysis of recent solicitations conducted in other jurisdictions as evidence of the competitive margin included in a market-clearing offer. I have calculated two separate margins for each year, one for customer classes that are perceived to represent only a small risk of shopping and another for customers that are perceived to represent a much higher shopping risk.

Q: **Please explain how you calculate margins for low shopping risk customers.**

A: First, there are very few customers who present no shopping risk, because most customers have the right to shop. However, data show that shopping behavior by residential and small commercial customers is quite different, depending on whether or not they are part of government aggregation programs. In my opinion, it is unlikely that large numbers of non-aggregated residential and small commercial customers will shop and so I have designated them "low shopping risk" for the purpose of my analysis to distinguish them from the higher risk shopping customers.

Q: **Please explain the source of the data you rely upon for your calculation of margins.**

A: I base my analysis on publicly available analyses of solicitations conducted in 2006 and 2007 in various jurisdictions for the purpose of procuring full requirements service to meet standard offer load. There have been numerous such solicitations on behalf of residential and small commercial customers, and fewer such solicitations on behalf of larger commercial and industrial customers. Exhibit 6 shows that the estimated margins for these solicitations have ranged from 7 to 25 percent for residential and small commercial customers.

Generally, the margins are lower for the nearer time periods given that risk is, other things equal, proportional to the time that risk must be borne. For example, as shown in Exhibit 6 the average margin for residential solicitations for standard offer service within a time period of roughly one year from the service start date is 12.26 percent. For solicitations within two years from the service start date, the margins average 14.68 percent. Assuming the bidders applied an average 12.26 percent factor for the first year, this implies a 17.11 percent margin for the second year. For solicitations within three years, the margins average 16.36 percent. Assuming the bidders applied an average 12.26 percent margin for the first year and a 17.11 percent margin for the second year, this implies a 19.72 percent margin for the third year.

Based on these data, I use margins for "low shopping risk" customers of 10 percent, 15 percent, and 20 percent for 2009, 2010, and 2011, respectively.

Q: **Please explain how you calculate margins for "high shopping risk" customers.**

A: In the service territories of the Ohio Companies these customers include industrial customers as well as all residential and commercial customers that are located within government aggregation areas. There are fewer data available on which to form a market-based expectation of margins for customers that are perceived to represent a substantial shopping risk. Exhibit

7 presents the margins calculated for solicitations conducted in 2006 and 2007 to procure full requirements service to meet the standard service offer obligations for non-residential customers. The margins exhibit a wide range, from 14 to 68 percent. Generally, they are higher than the non-residential risk factors by a factor of two. I have thus used margins of 20 percent, 30 percent, and 40 percent for these "high shopping risk" customers.

IV CONCLUSION

Q: **Please summarize your results.**

A: The results of my calculations of market-offer rate prices are shown in Exhibits 8, 9, and 10. Each exhibit presents the cost factors that are described in this testimony and that are included in the final calculation of expected market-rate offer prices. As shown in Exhibits 8, 9, and 10, the expected market-rate offer prices for each year are:

- 2009: $90.47/MWh
- 2010: $98.34/MWh
- 2011: $105.49/MWh[14]

Q: **In your opinion, are these the prices that you expect would result from a competitive bidding process pursuant to Section 4928.142?**

A: Yes.

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[14] These prices are calculated using market data as of July 15, 2008.

Q: **Does this conclude your direct testimony?**

A: Yes.

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PROFESSIONAL EXPERIENCE

FTI Consulting, Inc.
Senior Managing Director,
Head, Global Energy, May 2007-Present

Lexecon, an FTI Company, Cambridge, MA
(formerly Lexecon Inc.)
Senior Managing Director, December 2003 – May 2007

Lexecon Inc., Cambridge, MA
(formerly The Economics Resource Group, Inc.)
Managing Senior Vice President, August 2003 – November 2003
Senior Vice President, July 1999 – December 2003

> Jointly responsible for the continuing growth in the economics practice, including the strategic focus and business development related to Lexecon's various practices. Directly responsible for numerous clients, including energy, regulated industries, health services, intellectual property and transportation matters. Head of the Lexecon/FTI offices in Harvard Square (Cambridge), Houston and Tucson.

The Economics Resource Group, Inc., Cambridge, MA
CEO, 1993 - July 1999

> Responsible for the strategic focus and development of the management consulting and litigation support services firm in new areas of business. Directly responsible for many energy, transportation and other industry clients.

Coho Resources, Inc., Dallas, TX
Senior Vice President, 1992 - 1993, *Board of Directors,* 1990 - 1993

> Responsible for marketing, business development, and all regulatory matters within this oil and gas exploration and production company. Oversaw oil and gas sales. Negotiated pipeline/transportation agreements. Implemented risk management programs and directed acquisitions/divestitures.

AUS Consultants, Industry Analysis Group, suburban Philadelphia, PA
President, 1988 - 1992

Co-founder of the Group. Responsible for the operation of the consulting firm which had over 200 industry clients. Directly responsible for oil and refined products clients, oil pipeline clients and gas utilities. Coordinated the energy risk management and fuel supply management practices.

Chase Econometrics/WEFA, Bala Cynwyd, PA
Senior Vice President, 1986 - 1988

Responsible for the development, enhancement and execution of all consulting services in each of the following areas of this Chase Manhattan Bank subsidiary: oil, gas, coal, electric utilities, non-ferrous metals, steel, plastics and packaging materials.

Atlantic Richfield Company, Los Angeles, CA
Director, Energy Studies, and Director, Market Research, 1980 - 1985

Responsible for the design and implementation of market-related plans/projects for senior management in the U.S. and foreign oil markets, natural gas markets, refining/marketing and metals markets.

General Motors Corporation, Detroit, MI
Senior Staff Associate, 1976 - 1980

Responsible for economic and regulatory policy, energy and long-range marketing strategies, product development strategies for senior management. Worked with every division, plus the technical staffs.

University of Texas, San Antonio, TX
Assistant Professor and Consultant to Industry, 1976
Virginia Tech, Blacksburg, VA
Instructor, School of Business, and Consultant to Industry, 1974 - 1975

Responsible for classes in economics, marketing, finance and statistics.

U.S. Army
Commissioned Officer, 1967 - 1970

EDUCATION

Virginia Tech, Blacksburg, VA
Ph.D. in Economics, 1976
Dissertation: "A Variable Risk Hypothesis for Foreign Exchange Rate Behavior"

University of Texas, Arlington, TX
M.A. in Economics and Marketing, 1973
B.B.A. in Business, 1972

TESTIMONY BEFORE COURTS

Unocal Wright

In the United States District Court, Eastern District of Texas, Texarkana Division. United States of America ex rel. Harrold E. (Gene) Wright, vs. Chevron USA, Inc, et al, Defendants. Civil Action No. 5:03CV264, Judge David Folsom. Expert Report of on Behalf of Union Oil Company of California, April 1, 2008. Written, Confidential.

Mobil Cerro Negro, Ltd.

In the High Court of Justice, Queen's Bench Division, Commercial Court, Claim No 2008 Folio 61, Mobil Cerro Negro Ltd v. Petróleos de Venezuela, S.A., Defendants, First Affidavit on Behalf of Defendants, February 26, 2008.

Tesoro Petroleum Corporation and Subsidiaries

Before The Office Of Administrative Hearings State Of Alaska, In The Matter of: Tesoro Petroleum Corporation and Subsidiaries, Oil and Gas Corporate Income Tax, Tax Period 1994-1998, OAH No. 05-0155-TAX. Expert Report on Behalf of Appellant, November 16, 2007; Testimony before Trial May 8, 2008 and May 15, 2008.

General Atomics Technologies Corp.

In the United States District Court for the District of Colorado, Civil Action No. 06-CV-00848-REB-CBS, ConverDyn, Plaintiff, v. James Neal Blue, Heathgate Resources Pty., Ltd., General Atomic Technologies Corporation, and Nuclear Fuels Corporation, Defendants, Expert Report on Behalf of Defendant, September 17, 2007.

General Atomics Technologies Corp.

In the United States District Court for the Northern District of Illinois, Eastern Division, Case No. 06 C 5516, Exelon Generation Company, LLC, a limited liability company, Plaintiff, v. General Atomics Technologies Corp., a Delaware corporation, Defendant, Expert Report on Behalf of Defendant, September 5, 2007.

Nuclear Fuels Corp.

In the United States District Court for the Northern District of Illinois, Eastern Division, Case No. 06 C 5515, Exelon Generation Company, LLC, a limited liability company, Plaintiff, v. Nuclear Fuels Corp., a Delaware corporation, Defendant, Expert Report on Behalf of Defendant, September 5, 2007.

Peabody COALSALES Company

In the matter of Arbitration between Peabody COALSALES Company N/K/A Coalsales II, LLC vs Dynegy Coal Trading & Transportation, LLC Illinois. Expert Report providing testimony regarding the setting of coal prices pursuant to a contract re-opener clause. October 31, 2006.

Official Committee of Unsecured Creditors in the Entergy New Orleans, Inc. Bankruptcy

In the United States District Court for the Eastern District of Louisiana, In Re: Entergy New Orleans, Inc. Chapter 11 Section B. Expert Report providing testimony regarding the expected price of fuel for electricity generation under three base load contracts, October 12, 2006.

Yemen Exploration & Production Company

Before The International Chamber of Commerce, (Case No. 14108/EC). Yemen Exploration & Production Company, Claimant, v. Republic of Yemen, Respondent, Statement of Expert Witness Scott T. Jones, September 1, 2006; Supplemental Report, March 9, 2007; 2nd Supplemental Report, June 16, 2007, 3rd Supplemental Report, June 29, 2007; Testimony before the Tribunal, September 21, 2007.

Valencia and Singleton

In the United States District Court for the Southern District of Texas, Houston Division, United States of America, vs. Michelle Valencia and Greg Singleton. Report of testimony on Behalf of the plaintiffs in this criminal matter involving allegations about prices reported to publications that list natural gas trading information, July 6, 2006.

L-3 Communications, Inc.

In the United States District Court for the Southern District of New York, L-3 Communications Corporation v. OSI Systems, Inc. Provided expert damages testimony on Behalf of L-3 Communications in a failed negotiation to transfer certain business assets. Deposition July 15, 2005; Trial testimony May 23, 2006.

Jerry Alfred Futch, Jr.

In the United States District Court for the Southern District of Texas, Houston Division, Criminal Action No. H-04-511, United States of America, vs. Jerry Alfred Futch, Jr., Defendant. Expert Report of Scott T. Jones, Ph.D. and Charles Augustine, MPP, testimony on Behalf of the plaintiffs in this criminal matter involving allegations about prices reported to publications that list natural gas trading information January 17, 2006. Response of Scott T. Jones, Ph.D. and Charles Augustine, MPP, To Report of Matthew P. O'Loughlin, February 13, 2006.

NEGT Gas

In the Matter of the Arbitration Between Mirant Americas Energy Marketing, LP, Claimant, and NEGT Energy Trading-Gas Corporation; Gas Transmission Northwest Corporation; National Energy & Gas Transmission, Inc.; NEGT Energy Trading Holdings Corporation; and NEGT Energy Trading-Power, L.P., Respondents. Expert Report on Behalf of Respondents, December 2005. Dispute involved terminated natural gas purchase and sale contracts, claimed breach of contracts, and calculation of damages.

Calpine Corporation

In the Court of Chancery of the State of Delaware in and for New Castle County, Calpine Corporation v. The Bank of New York and Wilmington Trust Company, Dispute between senior debt holders and the company over the disposition of monies from the sale of producing natural gas and steam reserves. Expert Report, November 2, 2005; Deposition November 3, 2005; Trial testimony November 12, 2005.

Travelers

In the Matter of the Arbitration between the Travelers Indemnity Company and Travelers Casualty & Surety Company, Petitioner, and Everest Reinsurance Company, Respondent, Dispute arose over the interpretation of long-term, fixed price forward (physical) contracts (the "Enron-Mahonia" contracts) for the delivery of natural gas at three points in Zone 3 (southern Louisiana). Respondent claims that the contracts were financial vehicles rather than industry standard contracts for physical delivery. Rebuttal Report, October 10, 2005. Deposition testimony, October 21, 2005.

Securities and Exchange Commission (SEC)

In the United States District Court for the Southern District of Texas, Houston Division, Securities and Exchange Commission v. Preston Hopper, Tamela Palla, and Terry Woolley. Provided testimony involving the behavior of trading and financial management in major electricity and natural gas companies from 1999-2002. Expert Report September 1, 2005.

Allegheny Energy, Inc.

In the United States District Court for the Southern District of New York, Allegheny Energy, Inc v. Merrill Lynch & Co., Inc. Provided expert testimony on fraudulent behavior with regard to trading, breach of contract and damages. Oral Testimony, January 6, 2005. Trial Testimony, May 16 – 17, 2005.

Biomedical Systems Corporation

United States District Court, Eastern District of Missouri, Eastern Division, Biomedical Systems Corporation vs. GE Marquette Medical Systems, Inc., Docket No. 4:99CV01590 CAS, lost income/damages calculation in a medical device breach of contract/failure to perform suit.. Expert report, August 31, 2000; deposition, September 19, 2000; supplemental expert report, February 16, 2001; deposition, February 23, March 2, 2001; Trial testimony, March 27-29, 2001. Upheld on appeal, 2004.

Frontier Oil Corporation

In the Court of Chancery of the State of Delaware, In and For New Castle County, Frontier Oil Corporation v. Holly Corporation. Provided damages testimony related to the economic and financial implications arising from the failed merger between Frontier and Holly. Expert report, November 7, 2003; deposition, November 26, 2003; trial testimony, February 25 – 26, 2004.

Peabody Energy Corporation

United States District Court, Eastern District of Missouri, Eastern Division, Caballo Coal Company, et al., v. Indiana Michigan Power Company, et al. Provided expert testimony on damages stemming from the economics of long-term vs. short-term contracts in the coal industry. Expert report, April 14, 2003; deposition, June 16, 2003; rebuttal report, November 17, 2003; case settled, summary judgment, March 29, 2004.

PacifiCorp

United States District Court for the District of Idaho, Snake River Valley Electric Association v. PacifiCorp. Provided expert testimony on the use of electricity market price indices in estimating damages. Expert report, August 20, 2002; trial testimony, October 16, 2002.

Matthew Ratteree

United States District Court, Southern District of Texas, Houston Division, Coral Finance, L.P., vs. Matthew Ratteree, damages calculation in a suit involving failure to perform under the terms of an asset purchase agreement. Expert report, June 28, 2002.

NESI Power Marketing, Inc.

United States District Court, District of Connecticut, Bridgeport Division, In re: The Power Company of America, LP, Debtor; Goldin Associates, LLC, Trustee for the PCA Liquidating Trust, v. NESI Power Marketing, Inc., expert testimony regarding power market events and bankruptcy litigation. Presentation to mediator, April 12, 2001; expert report, August 23, 2002; deposition, September 4, 2002; trial testimony, July 15-17, 2003.

City of Springfield, IL, City Water, Light and Power

LG&E Energy Marketing v. City of Springfield, Illinois, City Water, Light and Power, in the United States District Court, Western District of Kentucky, Louisville Division, Civil Action No. 3:98 CV 485 H, expert report analyzing the economic implications and content of LG&E Energy Marketing's claims for damages allegedly incurred by LEM arising from the failure of the City of Springfield, Illinois, City Water, Light and Power to deliver in connection with a physical daily call option sold by CWLP to LEM on August 20, 1997, August 26, 1999; deposition testimony, October 25-26, 1999.

City of Springfield, IL, City Water, Light and Power

El Paso Energy Marketing Company v. City of Springfield, Illinois, City Water, Light and Power and Amerex Power, Ltd., in the District Court of Harris County, Texas, 133rd District Court, Case No. 98-31856, testimony regarding the application of economic theories and principles to the electric industry, including the history and performance of wholesale electric markets, price formation, and damages related to the price spikes from the summer of 1998, Oral Testimony: June 25, 1999.

Pennsylvania Power & Light Company

PP&L, Inc., v. John M. Quain, Chairman, Pennsylvania Public Utility Commission, et al., before the United States District Court for the Eastern District of Pennsylvania, Civil Case No. 98-CV-5083. Testimony in support of PP&L's request for a temporary restraining order enjoining defendants from implementing and enforcing a Capacity Order fixing the price of capacity in PJM prior to the start of full retail competition, Trial Testimony: October 2, 1998.

Kansas Pipeline Operations Company, Inc.

Expert Report and Affidavit in Support of KPOC's Complaint for Damages before the United States District Court for the Western District of Missouri, Case No. 97-0642-CV-W-4. Damages estimate stemming from Panhandle Eastern Pipe Line Company's obstruction of KPOC's attempts to construct and operate a gas pipeline lateral from an interconnection with

PEPL's system to local distribution companies serving the Kansas City metropolitan area, July 2, 1998; rebuttal report, October 27, 1998; Oral Testimony, February 9 and 11, 1999.

BP Exploration (Alaska), Inc.

Before the Superior Court for the State of Alaska, Third Judicial District, Anchorage, AK, In the Matter of Prudhoe Bay Unit Litigation, Case No. 3AN-95-8960CI, testimony in damages proceeding involving the quantity, quality, and fair market value of the crude oil and the facilities used to produce/transport hydrocarbons from the Prudhoe Bay Unit. Oral Testimony: November 19, 1996.

Koch Industries, Inc.

Before the United States District Court, Eastern District of Oklahoma, In the Matter of Petro Source Partners, Ltd. vs. Koch Industries, Inc., Koch Gathering Systems, Inc., and Koch Oil Company, Case No. 95-356-B, testimony in an antitrust proceeding involving the market for crude oil and gas liquid sales, transportation and trading in Oklahoma, Kansas, and Texas. Oral Testimony: August 28, 1996.

Koch Industries, Inc.

Before the United States District Court, Eastern District of Oklahoma, Muskogee, OK, In the Matter of Petro Source Partners, Ltd. (plaintiff) vs. Koch Industries, Inc., Koch Gathering Systems, Inc., and Koch Oil Company (defendants), Case No. 95-356-B, written testimony in Support of the Brief of Defendant's Motion for Summary Judgment (with exhibits), August 23, 1996.

Exxon Corporation and Exxon Company USA

Before the Superior Court of the State of California for the County of Los Angeles, In the Matter of The People of the State of California and the City of Long Beach vs. Chevron Corporation; Unocal Corporation; Mobil Oil Corporation; Shell California Production; Texaco Inc.; Exxon Corporation; Exxon Company, USA, No. C 587 912. Oil price dispute. Oral testimony: December 7, 1994.

El Paso Natural Gas Company

Before the U.S. District Court for the Northern District of California, In the Matter of Jonathan C. S. Cox vs. El Paso Natural Gas Company. Oral testimony in a South Texas producing property, natural gas price/contract dispute matter, November 29, 1994.

Mariposa Pipeline Company

Before the Superior Court of the State of California for the County of Santa Barbara, In the Matter of Mariposa Pipeline Company vs. Gaviota Terminal Company, Case No. 194428. Testimony in a condemnation proceeding and rate case focusing on the market value of pipeline and terminal facilities (both marine and on-shore) for heavy crude oil, gas liquids, and emissions recovery plant/equipment in a limited-life producing property. Trial Testimony: April 18, 1994.

TESTIMONY BEFORE REGULATORY AGENCIES

Northern Natural Gas

Before the Federal Energy Regulatory Commission (FERC), Docket No. RP08-29-000, *Rockies Express Shippers, Complainants, v. Northern Natural Gas Company, Respondent,* Prepared Answering Testimony on behalf of Respondent, May 2008. Prepared Surrebuttal Testimony on behalf of Respondent, July 2008.

FirstEnergy Corp.

Before the Pennsylvania Public Utility Commission, Petition of Metropolitian Edison Company for Approval of a Rate Transition Plan (Metropolitian Edison Company Docket No. R-00061366) and Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan (Pennsylvania Electric Company Docket No. R-00061367), Direct Testimony of Scott T. Jones, April 10, 2006, Hearing August 24, 2006.

FirstEnergy Solutions Corp.

United States of America, Before the Federal Regulatory Commission, FirstEnergy Solutions Corp. Testimony confirming the auction price result of the Competitive Bidding Process carried out by the Ohio Public Utilities Commission in December 2004, and establishing that Solutions is not charging a rate greater than market prices for wholesale electricity sold to its affiliated Ohio based regulated distribution companies, March 15, 2006.

Cook Inlet Power, LP

In the matter of Arbitration between City Energy, LLC and Cook Inlet Power, LP. American Arbitration Association, Southfield, Michigan. Breach of Contract Dispute. Provided expert testimony on electric power supply agreements, power trading, and damages calculations. Oral Testimony, October 15, 2004.

PPL Montana, LLC, and Puget Sound Energy, Inc.

In the Matter of Arbitration Between Western Energy Company and Puget Sound Energy, Inc., and PPL Montana, LLC. Provided expert testimony on reasonable profit in coal supply agreements as part of a damages case created by a contract "re-opener". Expert report, November 3, 2003; supplemental expert report, December 12, 2003; oral testimony, March 5, 2004.

PPL Corporation

Before the Pennsylvania Public Utility Commission, C&D Technologies et al v. PPL Corporation. Provided testimony describing market forces and quantitative support for the reasonableness of PP&L's buy-through prices and rate structure supporting their interruptible tariffs, January 28, 2004.

Griffith Energy LLC

United States of America, Before the Federal Energy Regulatory Commission, Griffith Energy LLC, market power analysis in support of application for renewal of authority to sell electric energy and capacity at market-based rates, October 27, 2003.

PPL Montana, LLC, PPL Southwest Generation Holdings, LLC, PPL Sundance Energy, LLC, PPL University Park, LLC

United States of America, Before the Federal Energy Regulatory Commission, PPL Montana, LLC, PPL Southwest Generation Holdings, LLC, PPL Sundance Energy, LLC, PPL University Park, LLC, market power analysis in support of application for renewal of authority to sell electric energy and capacity at market-based rates, July 17, 2003.

PPL Brunner Island, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC

United States of America, Before the Federal Energy Regulatory Commission, PPL Brunner Island, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, market power analysis in support of application for renewal of authority to sell electric energy and capacity at market-based rates, January 27, 2003.

PPL Montana, LLC, PPL Colstrip I, LLC, PPL Colstrip II, LLC

United States of America, Before the Federal Energy Regulatory Commission, PPL Montana, LLC, PPL Colstrip I, LLC, PPL Colstrip II, LLC, market power analysis in support of application for authority to sell electric energy and capacity at market-based rates, August 26, 2002.

PPL Lower Mount Bethel Energy, LLC

United States of America, Before the Federal Energy Regulatory Commission, Lower Mount Bethel Energy, LLC, market power assessment in support of application for authority to sell electric energy, capacity, and specified ancillary services at market-based rates, August 1, 2002.

PPL Sundance Energy, LLC, and PPL University Park, LLC

United States of America, Before the Federal Energy Regulatory Commission, PPL Sundance Energy, LLC, and *PPL University Park, LLC*, market power assessments in support of application for authority to sell electric energy, capacity, and specified ancillary services at market-based rates, March 15, 2002.

PPL EnergyPlus, LLC

United States of America, Before the Federal Energy Regulatory Commission, PPL EnergyPlus, LLC, market power analysis update in support of PPL's application for continued use of market-based rates for wholesale energy, capacity and ancillary services, December 17, 2001; supplemental affidavit, January 22, 2002; second supplemental affidavit, February 20, 2002.

PPL Montana, LLC, and PPL EnergyPlus, LLC

United States of America, Before the Federal Energy Regulatory Commission, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange; Investigation of Practices of the California Independent System Operator and the California Power Exchange. Testimony supporting PPL Montana and PPL EnergyPlus in a suit claiming refunds from them for sale of energy into California markets. Issue 1 prepared responsive testimony, November 6, 2001; deposition, December 4, 2001; oral testimony, March 14, 2002.

PPL Montana, LLC, and PPL EnergyPlus, LLC

United States of America, Before the Federal Energy Regulatory Commission, Puget Sound Energy, Inc., v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale into Electric Energy and/or Capacity Markets in the Pacific Northwest, including Parties to the Western Systems Power Pool Agreement. Testimony supporting PPL Montana and PPL EnergyPlus in a suit claiming refunds from them for sale of energy into Northwest markets. Prepared responsive testimony, August 27, 2001; oral testimony, September 6, 2001.

PPL Wallingford Energy, LLC

United States of America, Before the Federal Energy Regulatory Commission, PPL Wallingford Energy, LLC, Docket No. ER01-1559-000, affidavit in support of PPL Wallingford's application for authority to sell electric energy, capacity, and ancillary services at market-based rates and to resell transmission rights and associated ancillary services, March 15, 2001.

PPL Electric Utilities Corporation

Before the Pennsylvania Public Utility Commission, Docket Number C-00003811, Hofmann Industries Inc. t/a Bernard M. Hofmann v. PPL Electric Utilities Corporation. Written testimony supporting PPL Electric Utilities' Provider of Last Resort tariffs as approved by the PPUC. The case involves an attempt by the Opposing Parties to redefine negotiated, approved tariffs for a group of returning commercial and industrial customers, including the one-year stay requirement; direct testimony, November 3, 2000, January 29, 2001.

Potomac Electric Power Company

United States of America, Before the Federal Energy Regulatory Commission, Joint Application of Potomac Electric Power Company, Southern Energy Chalk Point, LLC, Southern Energy Mid-Atlantic, LLC, Southern Energy Peaker, LLC, Southern Energy Potomac River, LLC, Allegheny Energy Supply Company, LLC, PPL Montour, LLC, and Potomac Power Resources, Inc., for Authorization of the Disposition of Jurisdictional Facilities under Section 203 of the Federal Power Act, Disclaimer of Jurisdiction Relating to Certain Passive Participants, Waiver of Orders 888 and 990 with Respect to Certain Limited Transmission Facilities, and Request for Expedited Approval, Docket Nos. EC00-141-000 and ER00-3727-000. Affidavit examining the potential competitive impact of Pepco's divestiture of direct ownership interests in generation assets and power purchase entitlements in connection with electricity industry restructuring in Maryland and the District of Columbia, September 20, 2000.

PPL Electric Utilities Corporation

United States of America, Before the Federal Energy Regulatory Commission, PPL Electric Utilities Corporation, Docket No. ER00-1712-001, market power analysis update in support of PPL's application for continued use of market-based rates for wholesale energy, capacity and ancillary services, July 17, 2000.

PP&L, Inc.

Before the Pennsylvania Public Utility Commission, Docket Number P-00001788, Petition of PP&L Industrial Customer Alliance for a Declaratory Order Prohibiting the Implementation of a Tariff Interpretation Change for Billing PP&L Rate Schedule IS-P and IS-T Customers. Oral testimony in dispute over interruptible service tariffs for large industrial customers, in support of PPL Electric Resources IS-P and IS-T tariffs and tariff policy, February 24, 2000.

PP&L Resources, Inc.

United States of America, Before the Federal Energy Regulatory Commission, PPL Martins Creek, LLC; PPL Montour, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC; and PPL Susquehanna, LLC, Docket No. ER00-744-000. Affidavit in support of the realigned companies' application for authority to sell electric energy, capacity, and ancillary services at market-based rates, to resell transmission rights and associated ancillary services, and for acceptance of power sales agreements, December 7, 1999.

FirstEnergy Corp.

Before the Public Utilities Commission of Ohio, In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, the Toledo Edison Company, and The Cleveland Electric Illuminating Company: for Approval of an Electric Transition Plan and for Authorization to Recover Transition Revenues (Case No. 99-1212-EL-ETP); for Approval of New Tariffs (Case No. 99-1213-EL-ATA); for Certain Accounting Authority (Case No. 99-1214-EL-AAM). Direct testimony providing estimates of market-clearing electricity prices (energy and capacity) and generation output by power plant which were used in determination of market value of FirstEnergy's generation assets as part of the Company's determination of stranded costs, December 22, 1999; supplemental testimony, April 4, 2000; deposition, April 7, 2000; oral testimony, May 4, 2000.

Joint testimony (with Dr. Susan F. Tierney) providing an explanation of the economic and policy contest in which the FirstEnergy Companies were requesting recovery of transition costs and, separately, the calculation of the market value of the Companies' generation assets, December 22, 1999; supplemental testimony, April 4, 2000; deposition, April 7, 2000.

Marathon Ashland Petroleum LLC

United States of America, Before the Federal Energy Regulatory Commission, Colonial Pipeline Company, Docket No. OR99-16-000, prepared direct testimony evaluating Colonial's petition to construct a stub pipeline and challenging Colonial's justification for the project, August 5, 1999.

TransMontaigne Product Services Inc.

United States of America, Before the Federal Energy Regulatory Commission, TE Products Pipeline Company, L.P., Docket No. OR99-6-000, prepared direct testimony evaluating TEPPCO's application for authority to charge market-based rates in several origin and destination markets, challenging TEPPCO's methodology used to determine the relevant geographic market facing shippers of refined petroleum product, July 26, 1999.

Lion Oil Company

United States of America, Before the Federal Energy Regulatory Commission, TE Products Pipeline Company, L.P., Docket No. OR99-6-000, prepared direct testimony evaluating TEPPCO's application for authority to charge market-based rates in the El Dorado, AR, origin market and the Little Rock destination market, and evaluating TEPPCO's approach regarding the definition of the relevant geographic market in which shippers of refined petroleum products operate, July 26, 1999.

WPS Power Development, Inc.

United States of America, Before the Federal Energy Regulatory Commission, Sunbury Generation, LLC, Docket No. ER99-3420-000, prepared direct testimony supporting PDI's newly-acquired Sunbury generation facility's application for authority to charge wholesale and retail market-based rates in and outside of PJM, June 30, 1999.

TransMontaigne Product Services Inc.

United States of America, Before the Federal Energy Regulatory Commission, Colonial Pipeline Company, Docket No. OR99-005-000, testimony evaluating and opposing Colonial's application for authority to charge market-based rates on its interstate pipeline system in Texas, Louisiana and Mississippi; prepared direct testimony, June 8, 1999; prepared reply testimony, August 23, 1999.

Penobscot Hydro, LLC

United States of America, Before the Federal Energy Regulatory Commission, Penobscot Hydro, LLC, Docket No. ER99-1940-000, prepared direct testimony in support of Penobscot's application for authority to sell energy, capacity, and ancillary services at market-based rates in and outside of the New England interconnection, February 25, 1999.

Baltimore Gas and Electric Company

Prepared Direct Testimony before the Public Service Commission of Maryland, Case No. 8794. Fuel price forecast testimony in support of BGE's estimated market-clearing electric energy prices for PJM as part of the Company's restructuring filing before the PSC, July 1, 1998; rebuttal report, March 22, 1999.

Pennsylvania Power & Light Company, PFG Gas, Inc., North Penn Gas Company

Prepared Rebuttal Testimony before the Pennsylvania Public Utility Commission, Docket Nos. A-120650F0006, A-122050F0003, Statement No. 2. Economic benefits and an expanded market power analysis in support of the application to merge the utilities, February 17, 1998.

Pennsylvania Power & Light Company, PFG Gas, Inc., North Penn Gas Company

Prepared Direct Testimony before the Pennsylvania Public Utility Commission, Docket Nos. A-120650F0006, A-122050F0003. Economic analysis and market power determination in support of the application of Pennsylvania Power & Light Company, PFG Gas, Inc., and North Penn Gas Company for approval of a proposed merger, December 22, 1997.

Pennsylvania Power & Light Company

Before the Pennsylvania Public Utility Commission, Docket No. R-00973975. Economic theory and regulatory policy principles supporting stranded cost recovery for PP&L, Inc., from UGI Utilities, Inc., customers subject to an ongoing power supply agreement. Also, market-clearing prices for energy and capacity for UGI's two facilities in PJM under conditions of retail and wholesale competition, 1999-2001. Re: PAPUC v. UGI Utilities, Inc. - Application of UGI

Utilities, Inc., for Approval of its Restructuring Plan under §2806 of the Public Utility Code. Prepared direct testimony, November 21, 1997; surrebuttal testimony, March 2, 1998.

Pennsylvania Power & Light Company

Before the Pennsylvania Public Utility Commission, Docket No. R-00973954. Market-clearing prices for energy and capacity, plus unit revenue estimates for PP&L and PJM facilities to support the company's stranded cost recovery and corporate restructuring filing in accordance with the State of Pennsylvania, Electricity Generation Customer Choice and Competition Act of 1996, Harrisburg, PA. Prepared rebuttal testimony, August 4, 1997; direct examination, August 25, 1997.

Pennsylvania Power & Light Company

Affidavit in Support of PP&L's Petition before the Federal Energy Regulatory Commission, Docket No. ER97-3055-000. Application for Authority to Sell Energy and Capacity at Market-Based Rates. Market power analysis of the Pennsylvania-New Jersey-Maryland Interconnection ("PJM pool") in support of the application to sell electricity at market-based rates, May 23, 1997.

Pennsylvania Power & Light Company

Before the Federal Energy Regulatory Commission, Docket No. SC97-1-000. Market price of electric energy and capacity in a competitive environment. The formation of market prices support PP&L's claim for stranded cost relief before the Commission in response to comments by the staff and plaintiffs in this matter. Prepared rebuttal testimony, April 22, 1997; oral testimony, June 19, 1997.

Pennsylvania Power & Light Company

Prepared Direct Testimony before the Pennsylvania Public Utility Commission, Docket No. R-00973954. Market price and revenue estimates for PP&L and PJM to support the company's stranded cost recovery and corporate restructuring filing in accordance with the State of Pennsylvania, Electricity Generation Customer Choice and Competition Act of 1996, April 1, 1997.

BP America, Inc.

Affidavit in Support of BP's Petition before the United States Internal Revenue Service. Tax dispute involving the transfer of North West Shelf net profits royalty interest (NPRI) owned by BP Property Developments Australia (BPPDA) to Standard Oil Company, a subsidiary of BP America. Testimony as to the fair market value of the property, February 28, 1997.

BP Exploration (Alaska), Inc.

Before the State of Alaska, Department of Natural Resources and Department of Revenue, Joint Hearing In the Matter of the Appropriate Reservoir Management for Optimization of Natural Gas Liquids Blending and Utilization; and Economic and Physical Recovery within the Prudhoe Bay Unit. Prepared direct testimony involving the valuation and use of hydrocarbon producing properties as well as the valuation of facilities used on the North Slope for transportation and treatment, August 22, 1995.

BP Exploration (Alaska), Inc.

Before the State of Alaska, Alaska Oil and Gas Conservation Commission In the Matter of a Hearing to Review the Plan of Development and Operation and Other Agreements as They Affect Natural Gas Liquid Throughput, Miscible Injectant Utilization and Ultimate Recovery from Prudhoe Bay. Prepared direct testimony, May 12, 1995; rebuttal testimony, June 12, 1995.

Northern Natural Gas Company

Before the Federal Energy Regulatory Commission, Docket No. RP95-185-000, prepared direct testimony in a natural gas pipeline rate case, regarding market-based storage, March 13, 1995.

Florida Gas Transmission Company

Before the Federal Energy Regulatory Commission, Docket No. RP95-103-000, prepared direct testimony in a natural gas pipeline rate case, regarding incentive rate-making and market-based rates, January 10, 1995.

Association of Oil Pipelines

Before the Federal Energy Regulatory Commission, In the Matter of Market-Based Ratemaking for Oil Pipelines, Notice of Inquiry, Docket No. RM94-1-000; testimony, January 25, 1994.

ARCO Pipe Line Company and Four Corners Pipe Line Company

Before the Federal Energy Regulatory Commission, In the Matter of Market-Based Ratemaking for Oil Pipelines, Notice of Inquiry, Docket No. RM94-1-000; testimony, January 24, 1994.

Santa Fe Pacific Pipe Line Company

Before the Federal Energy Regulatory Commission, Docket No. IS92-39-000, testimony about the market facing shippers on a southwest U.S. petroleum products pipeline, May 24, 1993.

Buckeye Pipe Line Company, L.P.

Before the Federal Energy Regulatory Commission Technical Conference, In the Matter of the Interstate Oil Pipe Line Industry, Docket No. OR92-6-000. Expert testimony on the matter of market-based rates for oil pipelines, April 30, 1992.

Williams Pipe Line Company

Before the Federal Energy Regulatory Commission, In the Matter of Williams Pipe Line Company, Docket No. IS90-21-000. Bifurcated rate case, oil pipeline market power showing, Phase I; prepared direct testimony, July 12, 1990; prepared supplemental direct testimony, February 4, 1991; prepared rebuttal direct testimony, May 28, 1991; oral testimony, July 1991.

ARCO Pipe Line Company
Before the Federal Energy Regulatory Commission, Docket No. IS90-34-000. Bifurcated rate case, oil pipeline market power showing, Phase I; prepared direct testimony, February 1991.

Amoco Pipe Line Company
Before the Federal Energy Regulatory Commission, Docket No. IS90-30-000. Bifurcated rate case, Rocky Mountain crude oil pipeline market power showing, Phase I; prepared direct testimony, August 1990.

Hawaiian Electric Company, Inc.
Before the Public Utilities Commission of the State of Hawaii on Behalf of Hawaiian Electric Company for approval of AES Power Purchase Contract, Docket No. 6177; testimony, November 1989.

Buckeye Pipe Line Company, L.P.
Before the Federal Energy Regulatory Commission, Docket IS87-14-000. Bifurcated rate case, oil pipeline market power showing, Phase I; testimony, October 1988.

Sacramento Municipal Utility District
Before the Sacramento Municipal Utility District Board, In the Matter of the Rancho Seco Nuclear Facility; testimony, May 1988.

U.S. Senate
Before the U.S. Senate Committee on Energy and Natural Resources, Senator Bennett A. Johnson, Chairman, Oversight Hearing on the World Oil Outlook; testimony, March 11, 1987.

SELECTED INDUSTRY PROJECTS

Retained as the lead industry expert and witness in an international arbitration between a leading financial institution and an exploration/production company. Dispute involves the production, pricing and determination of costs associated with the oil and gas as well as the terms and conditions of the underlying loans used to acquire and exploit properties in the U.S. and Latin America. To be heard in the High Court of Justice, Queen's Bench Division, London, 2006-2007.

Retained as the lead industry expert, by the Unsecured Creditors to analyze existing Power Purchase Agreements (PPA), fuel costs and coal market conditions facing Entergy New Orleans (ENO) and it's sister companies in the wake of hurricane Katrina. Provided detail regarding the "value" of these long-term contracts relating to the alleged cost of service to ENO's customers under these contracts. The US Bankruptcy Court, Eastern District of Louisiana has to rule on a request by ENO to assume the PPA's. 2006.

Lead industry expert in a dispute between two energy companies involving a claim and counterclaim for damages related to the failure to consummate an agreement. Claims for damages included the potential for loss of income related to contamination of property, improper valuation of assets, nonperformance related to contract terms and conditions, and improper representation of the claims and counterclaims. Matter is on appeal before the Court of Appeals in Colorado. 2005.

Lead industry expert in a medical devices contract dispute involving a major financial institution and a medical devices manufacturer/distributor. The report led to testimony before a jury in Missouri where the key issue was lost wages/income related to the failed consummation of the agreement between the parties. The $75 million award to my client was upheld on appeal to the Superior Court, State of Missouri. 2004.

Lead industry expert in the second phase of a case involving a major northwest U.S. oil pipeline's construction proposal to deliver significantly more product into eastern Washington. The Second Supplemental Report (March 1999) specifies the competitive arguments that ought to underlie the regulatory policy issues facing the Forest Service, who is charged with approving the pipeline expansion. The report concludes that all the alternatives to the pipeline's proposal are less economically efficient and ought to be abandoned. An Affidavit (November 1999) analyzes the Draft Environmental Impact Statement and the "Final Specialist Report, Supply & Demand Analysis" pertaining to the proposed pipeline. 2003.

Lead damages witness in an arbitration between First Energy ("FE") and NRG over a breach of contract involving the purchase of three of FE's Ohio-based electricity generation facilities (the "lake plants"). Provided a damages report to the arbitration panel on Behalf of FE. FE settled with NRG prior to hearing. FE received several hundred million dollars as part of the settlement. 2002-2003.

Lead negotiator and consultant to the municipal government of the City of Springfield, Illinois, seeking to market its excess electric generation capacity. Advised the utility management and the City government regarding the structure of the sales agreement, the terms and conditions of the agreement, and the disposition of damages related to events from the summer of 1998. Testified three times before the City Council in support of the completed contract which results in a revenue-sharing scheme and a $30 million up-front payment. 2000.

Leader and project manager for a multi-disciplinary, multi-organization study of the petrochemical industry in a Southeast Asian nation. The team consisted of Harvard and INSEAD, faculty at the University of Indonesia, international petrochemical consultants, and Lexecon professional staff. The project found that while the petrochemical industry is sound and competitive, it has been severely hurt by the Asian crisis and various government policies that are no longer working to promote the survival of the industry. The report recommended a variety of changes to government policy that will encourage the infusion of foreign direct investment. 1999.

Lead market power analyst for a major independent oil company seeking Federal Trade Commission permission for a proposed merger. The project was a market power and market structure assessment of crude oil and refined product transportation and storage assets in Texas, Oklahoma, Colorado, and New Mexico. The assessment included conducting a series of in-the-field interviews as well as developing the inputs for measures of market concentration and possible mitigation strategies. 1999.

Lead author of a special client study providing an assessment of a major crude oil pipeline company's ability to exercise market power in its origin and destination markets. The study also used the information gathered in the market power study to provide a vivid picture of the company's current and prospective competitive environment. The study analyzed how changes inside and outside the relevant markets were likely to affect the pipeline over the next few years. 1998.

Lead strategic market consultant for a team advising the non-regulated subsidiary of a major Mid-Atlantic electric utility on wholesale electric market strategies ranging from asset acquisitions to pricing for energy and capacity. This wide-ranging assignment included the use of financial instruments for risk management, competitor analysis, and the assessment of target markets for direct sales to industrial users as well as sales into power pools. 1998.

Lead economist for a major investor-owned utility that wanted to assess the going-forward market value of three generation facilities. The company had to decide whether to maintain, sell, or partially dismantle its assets in order to strategically reposition its electric generation business. The project included the impact on the firm's portfolio of generation assets given a unionized labor force and increasingly costly emissions compliance costs. 1998.

Lead economic and industry expert for Colorado Interstate Gas Pipeline in a case involving competing gas pipeline projects to serve a major western metropolitan area. The report required that issues of market power and affiliate self-dealing be defined and sorted out from other competitive issues stemming from right-of-way conflicts, local market requirements, and the extent of the relevant geographic market. 1998.

Lead industry expert and financial economist for a major oil company who wanted to conduct a (confidential) "events study" to assess, in advance, what the impact of a major press release would have on the price of its publicly-traded shares. 1998.

Lead economic and industry valuation expert in the hostile takeover attempt by Union Pacific Resources, Inc., of Pennzoil Company. Prepared *Valuation of Pennzoil Company* for the Chancery Court in Delaware based on proprietary documents provided by Pennzoil through discovery. The report required that all of Pennzoil's operations and plans be modeled and integrated into a valuation by business segment (upstream and downstream) and collectively as enterprise value. 1997.

Lead industry expert in a case involving the construction of an oil products pipeline with planned access through national forest and private lands. The route and several alternate routes were heavily protested by private interests that argued potential environmental damage outweighed the economic benefits of constructing the pipeline needed to serve the fast-growing markets of Washington, Idaho, and Montana. Several reports were produced for the Forest Service on Behalf of the pipeline. 1997.

Senior market strategist to Columbia Gulf Transmission regarding their Gulf Coast corporate, marketing, and regulatory strategy. The proprietary projects included asset acquisition and divestiture, developing alternative marketing opportunities for jurisdictional and non-jurisdictional businesses, rate design, and planned expert testimony. 1997.

Senior market strategist on electric industry restructuring for a major investor-owned utility in the northeast. Responsible for directing a team charged with rate design, market analysis, corporate restructuring and strategy. Project included an assessment of expected market-clearing prices, market structure, and strategies under conditions of competitive wholesale prices. 1996.

Senior energy economist as part of a team advising a major southwestern U.S. investor-owned electric utility regarding strategy and testimony needed to support a petition against the merger of competing firms. The work considered competitive conditions throughout Texas, Oklahoma, New Mexico, and Louisiana as well as interconnects with Mexico. 1994-1995.

Senior energy economist to the Single Participating Area (SPA) team for BP Exploration, Inc., formed as a result of *Order 360*, Alaska Oil and Gas Conservation Commission, September 1995. Team member (on-site) from November 1995 to August 1996. The issues were: the value of the hydrocarbons produced 1995-2030 from the Prudhoe Bay Unit; the market value of the facilities used to treat and transport those hydrocarbons; the probable value of alternative uses for natural gas from the North Slope in the global market; the use of various valuation techniques as applied to the hydrocarbon resources from the PBU; and the impact of oil and gas production on the workforce/economy of Alaska. All work was proprietary and considered highly confidential. 1995-1996

SELECTED INDUSTRY STUDIES/ASSIGNMENTS

"The Natural Gas Liquids Business: South Louisiana and the Gulf Coast", A study that provided facts in support of a non-jurisdictional business opportunity for Columbia Gulf Transmission Company, a subsidiary of Columbia Gas. The company was considering an expansion of its primary business to related energy assets. 1996.

"The Relationship Between Fuel Oil and Natural Gas Prices in the 1990's," proprietary client report that examined the statistical relationships that are embedded in the way oil and gas prices move together. The objective was to provide a risk management tool to the client to use when hedging exposure to oil price changes linked to gas procurement contracts. 1993.

"An Assessment of Competition: Amoco Pipe Line Company's Rocky Mountain Crude Oil System," prepared by AUS Consultants. March 1992.

"Competition in the Atlantic Pipe Line Company Market: Theory and Evidence of the Battle for Transportation Services," proprietary study prepared for Sun/Atlantic Pipe Line Company. April 1990.

"Competition in the Williams Pipe Line Company Market: Theory and Evidence of the Battle for Transportation Services" (2 volumes), proprietary study prepared for Williams Pipe Line Company. February 1990.

"The Competitive Environment Faced by Sun Pipe Line Company's FERC-Regulated Crude Oil System," (2 volumes), proprietary study prepared for Senior Management of the Sun Pipe Line Company. November 1989.

"Sun Pipe Line Company Market Analysis of the Eastern Products System, 1985-1988," proprietary study prepared for Sun Pipe Line Company. July 1989.

"An Analysis of Refined Product Use in Buckeye Pipe Line Company, L.P. Market Areas: 1989-1994," proprietary study prepared for the Senior Management of Buckeye. June 1989.

"Market Analysis of Ohio and Indiana for Refined Petroleum Product Pipelines", proprietary study prepared for Buckeye Pipe Line Company, L.P. June 1989.

"Standing on the Brink: The North American Natural Gas Market," published by Chase Econometrics. Detailed analysis of the prospects of gas producers, distributors, IPP's/co-gen and transmission companies in the rapidly unfolding environment of deregulated markets. 1988.

"Power Wheeling in North America," published by Chase Econometrics. The first market analysis of its kind, showing the detailed quantitative effects of open access in North America. The work covered all NERC regions including Canada. 1988.

"Natural Gas Procurement: Supply Options and Solutions" (with Matt Dutzman), produced for several pipelines and utilities. Complete analysis of the natural gas industry's evolving market. The study included the role of brokers, IPP's, co-gen plus several scenarios regarding the evolving relationship between gas buyers and sellers. 1988.

"The Impact of a Gasoline Tax," proprietary study prepared for Mobil Oil Corporation. This widely quoted study demonstrated the impact of either a 25 or 50 cent per gallon gas tax on the auto, gasoline and labor markets. 1987.

"China's Energy Supply/Demand Balance," proprietary study prepared for the Atlantic Richfield Company. Demonstrated that China could remain an important exporter of energy if it instituted certain measures to conserve domestic demand during the 1990s. 1987.

"U.S. Oil and Gas Drillings: Beyond the Current Crisis," published by WEFA, demonstrated why drilling activity could sink toward 1,000 active rigs before recovering in the 1990s. January 1987.

"The Next Oil Shock," published by Chase Econometrics (2 volumes). Complete global analysis of the prospects for much higher oil and gas prices by 1992 once energy consuming-countries become increasingly dependent on oil from countries in politically unstable regions or those nations hostile to the United States. 1986.

"Oil and Natural Gas Supply/Demand Balances" (Oil and Gas Market Trends Team Member), National Petroleum Council, Washington, DC. 1986.

PUBLICATIONS: REFEREED JOURNALS AND TRADE PRESS

"Accounting for Uncertainty in Discounted Cash Flow Valuation of Upstream Oil and Gas Investments" (with William H Knull III, Timothy J Tyler and Richard D Deutsch), *Journal of Energy & Natural Resources Law*, Vol. 25, No. 3, 2007.

"Accounting for Uncertainty in Discounted Cash Flow Valuation of Upstream Oil and Gas Investments" (with W H Knull III, TJ Tyler and RD Deutsch), *Transnational Dispute Management*, Vol. 4, issue 6, November 2007.

"Electric Company Affiliate Transfer and Self Build Policies: Renewed Regulatory Challenges" (with J. Cavicchi), *The Electricity Journal*, Vol. 25, No. 3, 2004.

"Market Share in Generation: The Impact of Retail Competition on Investor-Owned Utilities" (with M. Krepps), *Public Utilities Fortnightly*, July 1, 1998.

"Regulatory Reform and the Economics of Contract Confidentiality: The Example of Natural Gas Pipelines" (with J. Kalt, A. Jaffe, and F. Felder), *Regulation*, No. 1, 1996.

"Natural Gas Pipelines: Roadmap to Reform" (with F. Felder), *Public Utilities Fortnightly*, April 1, 1995.

"Focusing In On Futures and Options" (with F. Felder), *Electric Perspectives*, Edison Electric Institute, January/February 1995.

"Using Derivatives in Real Decision Making" (with F. Felder), *Public Utilities Fortnightly*, October 15, 1994.

"OCTG Markets are Hammered by Natural Gas," *Center Lines*, Cleveland, OH, January 1992.

"Least-Cost Planning for Investor-Owned Natural Gas Distribution Companies: What's Needed and What's Not" (with G. Schink), *City Gate Magazine*, Pennsylvania Gas Association, Harrisburg, PA, June 1989.

"Oil and Natural Gas Markets: Change is on the Way," *Chemical Marketing & Management*, Vol. 2, No. 4, summer 1987.

"Energy Resources and the Global Marketplace," *The Canadian Mining and Metallurgical Bulletin*, spring 1987.

"Forecasting Oil Prices to 1995," *Hydrocarbon Processing*, Vol. 66, No. 8, August 1987.

"Negotiating Agreements for China's Energy Future," *East Asian Executive Reports*, Vol. 8, No. 4, April 1986.

"Multiple Scenario Planning–Atlantic Richfield's Experience," *Journal of Business Forecasting*, Vol. 4, No. 3, 1985.

"Exchange Rate Movements and Oil Demand," in M. Wionczek, ed., *Strategic Planning in the Oil and Gas Industry*, Westview Press, 1985.

"Political Instability and Foreign Direct Investments: The Motor Vehicle Industry, 1948-65" (with K. Bollen), *Social Forces*, Vol. 60, No. 4, June 1982.

"A Perspective on the Cost of Energy Technologies," *SAE Transactions*, Spring 1982.

"Political Instability's Impact on Output: Motor Vehicles Production in Argentina, Brazil, and Mexico" (with K. Bollen), *Studies in Comparative International Development*, Vol. 17, No. 4, 1982.

"Aluminum Markets and Supply Elasticity," *Light Metals Age*, May 1981.

Authored: "Undervaluation and the Dollar, 1974-1978", *The Financial Review*, 15(4), Pg. 49, 1980.

PUBLICATIONS IN PROCEEDINGS

"To Be or Not to Be, a Restructured Regional Powerhouse or a Boutique Wires Company," The Maguire Energy Institute Conference: Electricity Deregulation Report Card, Dallas, TX, November 1, 2000.

"Same Sharks-New Meat: Never Jump in the Water without Protection" (with J. Farr), The Maguire Oil and Gas Institute Energy Trends Conference: The New Energy Marketer, Dallas, TX, November 29, 1998.

"Estimating Market-Clearing Prices for Energy and Capacity: Competitive Markets and Stranded Costs" (with F. Felder and H. Tookes), Electric Utility Consultants, Inc., Denver, CO, December 2, 1997.

"Strategies by Electric Generators Will Impact Additions to Capacity and Natural Gas Pipeline Opportunities," Institute of Gas Technology, Washington, DC, November 7, 1997.

"The Golden Handcuffs: Securitization of Stranded Assets and the Utility's Earnings per Share," The Center for Business Intelligence, Hilton Head, SC, June 24, 1997.

"Valuing Assets: Using Options Methods Applied to Standard Costs" [with Mathew B. Krepps] Presented at the 17th annual North American Conference of the U.S. Association for Energy Economics. June 1997

"Twenty Years Is a Long Time: Tomorrow's Oil & Gas Market with Lessons from the Past," in *20th Annual Petrochemical Review*, DeWitt & Company, Houston, TX, pp. A-1 to A-18, March 22, 1995.

"Fuel-Switching Between Distillates and Natural Gas: The Search for a New Rule of Thumb," in *The World Oil & Gas Industries in the 21st Century*, Proceedings from the 16th Annual North American Conference, International Association of Energy Economists, Dallas, TX, November 9, 1994.

"Acorns Do Not Fall Far from the Tree: Why Natural Gas Prices Will Not Go Their Own Way" in *1994 Petrochemical Review*, DeWitt & Company, Houston, TX, March, 1994.

"The Energy Market Outlook: Costs Going Down and Reliability Improving," in *Forecast '94*, Steel Service Center Institute, Chicago, IL, September 27, 1993.

"Good News for the Petrochemicals: Will the Energy Market Play Along?" in *1993 Petrochemical Review*, DeWitt & Company, Houston, TX, pp. 1-16, March, 1993.

"New Age Energy Markets," in *1992 Petrochemical Review*, DeWitt & Company, Houston, TX, pp. 1-21, March 1992.

"Energy & Oil—What Can We Anticipate in the Near Term?," in *1991 Petrochemical Review*, DeWitt & Company, Houston, TX, March 1991.

"Oil & Gas Market Outlook: Opportunities for New Mexico Producers, 1990-95," in *Proceedings: Oil and Gas '91*, Robert O. Anderson School of Business, University of New Mexico, February 13, 1991.

"Clearing Away the Fog: A Look at Oil and Gas in the 1990s," in *1990 Petrochemical Review*, DeWitt & Company, Houston, TX, pp. 1-16, March 1990.

"Time to Get on With the Job at Hand," in *Forward to the Nineties*, The Alliance, Anchorage, AK, pp. 1-15, January 1990.

"Energy Markets: Have Petrochemical Producers Found a Safe Haven or Just the Eye of the Storm?" in *1989 Petrochemical Review*, DeWitt & Company, pp. 1-16, March 1989.

"Alaska-On the Threshold of a Dream," in *Proceedings* from Meet Alaska, 1989, The Alliance, pp. 1-9, January 1989.

"Crude Oil Outlook," in *1988 Petrochemical Review*, DeWitt & Company, Houston, TX, pp. 1-20, March 1988.

"Oil and Natural Gas Markets: Change is on the Way," in *Review and Forecast: Prospects for Profitability*, The Chemical Marketing Research Association, pp. 174-179, May 1987.

"Petroleum Product Market in Transition," in *Proceedings*, National Petroleum Refiners Association, San Antonio, TX, pp. 15-25, April 1987.

"Low World Crude Oil Price - How Long Do We Have?", in *1987 Petrochemical Review*, DeWitt & Company, Houston, TX, pp. 1-15, April 1987.

"OPEC May Stumble, But It Won't Fall," *The New York Times*, February 8, 1987.

OTHER PROFESSIONAL ACTIVITIES

Invited Speaker (Partial Listing)

American Association of Energy Economics, American Gas Association, American Petroleum Institute, Association of Oil Pipelines, Canadian Energy Research Institute, Canadian Petroleum Association, Center for Business Intelligence, Central Electricity Generating Board of the U.K., DeWitt Petrochemical, Energy Daily, Gas Daily and Gas Buyer's Guide, Georgia Mining Association, Independent Petroleum Association of Canada, International Association of Energy Economists, Institute of Gas Technology, Maguire Oil and Gas Institute (SMU), National Association of Business Economists, National Petroleum Council, Oil Daily, Remedies in Commercial, Investment and Energy Arbitrations, Society of Gas Operators, Society of Rate of Return Analysis, State of North Dakota, State of Texas, Steel Service Center Institute, Transportation Research Board, U.S. Association of Energy Economists, University of New Mexico, University of Southern California, University of Texas (Arlington)

Directorships and Advisory Committees

COHO Resources, Inc., Dallas, TX. Director, 1990-93 (an oil and gas exploration and production company)

Remuda Corporation, Denver, CO. Advisory Committee, 1991-1996 (a natural gas exploration, production and marketing company)

Member, National Petroleum Council, Economic and Environmental Impacts Task Group of the Committee on U.S. Oil & Gas Outlook, 1987

Professional Associations and Certifications

Petroleum Economics & Management Program, Northwestern University
International Association of Energy Economists
National Association of Business Economists
American Economic Association

Exhibit 2

ROUND-THE-CLOCK ENERGY PRICES AT CINERGY HUB

Year	2009	2010	2011
Price	$55.71	$54.85	$53.94

Notes:
[1] Based on July 15, 2008 forwards.

Source:
[A] Platts Megawatt Daily.

Exhibit 3

CALCULATION OF LOAD-SHAPING COSTS

Year	Customer Class	Total Cost	Load (MWh)	Load-Weighted Cost ($/MWh)	Average LMP	Load-Shaping Ratio	Round-the-Clock Price	Load-Shaped Price	Load-Shaping Cost
		[A]	[B]	[C] = [A]/[B]	[D]	[E] = [C]/[D]	[F]	[G] = [E]*[F]	[H] = [G]-[F]
2009	Residential	$1,847,117,897	36,687,229	$50.35	$45.83	1.10	$55.71	$61.21	$5.50
	Commercial	$1,597,266,940	31,684,511	$50.41	$45.83	1.10	$55.71	$61.28	$5.57
	Industrial	$2,264,111,678	47,280,915	$47.89	$45.83	1.04	$55.71	$58.21	$2.50
	Street Lights	$27,058,848	701,511	$38.57	$45.83	0.84	$55.71	$46.89	($8.82)
	All Classes	$5,735,555,363	116,354,166	$49.29	$45.83	1.08	$55.71	$59.92	$4.22
2010	Residential	$1,847,117,897	36,687,229	$50.35	$45.83	1.10	$54.85	$60.26	$5.41
	Commercial	$1,597,266,940	31,684,511	$50.41	$45.83	1.10	$54.85	$60.34	$5.49
	Industrial	$2,264,111,678	47,280,915	$47.89	$45.83	1.04	$54.85	$57.32	$2.47
	Street Lights	$27,058,848	701,511	$38.57	$45.83	0.84	$54.85	$46.17	($8.68)
	All Classes	$5,735,555,363	116,354,166	$49.29	$45.83	1.08	$54.85	$59.00	$4.15
2011	Residential	$1,847,117,897	36,687,229	$50.35	$45.83	1.10	$53.94	$59.27	$5.32
	Commercial	$1,597,266,940	31,684,511	$50.41	$45.83	1.10	$53.94	$59.34	$5.40
	Industrial	$2,264,111,678	47,280,915	$47.89	$45.83	1.04	$53.94	$56.37	$2.43
	Street Lights	$27,058,848	701,511	$38.57	$45.83	0.84	$53.94	$45.40	($8.54)
	All Classes	$5,735,555,363	116,354,166	$49.29	$45.83	1.08	$53.94	$58.03	$4.08

Notes:
[1] Column [A] is the annual sum of the product of hourly LMPs and hourly loads.
[2] Based on July 15, 2008 forwards and historical LMP prices for September 1, 2005 through August 31, 2007.

Sources:
[A] MISO.
[B] FirstEnergy Corp.

Exhibit 4

CALCULATION OF CAPACITY COSTS

Year	Customer Class	Total Load (MWh)	Peak Hourly Load (MW)	Required Capacity (MW)	Cost per KW-Month	Annual Cost per MW	Total Annual Cost	Cost per MWh
		[A]	[B]	[C] = [B]*1.135	[D]	[E] = [D]*1000*12	[F] =[C]*[E]	[G] = [F]/[A]
2009	Residential	18,770,939	5,123	5,815	$2.20	$26,400	$153,505,863	$8.18
	Commercial	16,379,275	3,063	3,477	$2.20	$26,400	$91,794,302	$5.60
	Industrial	24,200,167	3,555	4,035	$2.20	$26,400	$106,533,794	$4.40
	All Customers	59,760,303	11,745	13,331	$2.20	$26,400	$351,932,802	$5.89
2010	Residential	19,025,154	5,339	6,060	$2.20	$26,400	$159,979,864	$8.41
	Commercial	16,606,184	3,188	3,618	$2.20	$26,400	$95,522,696	$5.75
	Industrial	24,252,174	3,393	3,852	$2.20	$26,400	$101,682,519	$4.19
	All Customers	60,293,435	11,924	13,533	$2.20	$26,400	$357,283,922	$5.93
2011	Residential	19,287,042	4,716	5,353	$2.20	$26,400	$141,320,001	$7.33
	Commercial	16,836,291	3,875	4,398	$2.20	$26,400	$116,099,865	$6.90
	Industrial	24,304,401	3,511	3,985	$2.20	$26,400	$105,203,709	$4.33
	All Customers	60,837,656	12,105	13,740	$2.20	$26,400	$362,724,393	$5.96

Source:
[A] FirstEnergy Corp.

Exhibit 5

CALCULATION OF DISTRIBUTION LOSSES

Year	Customer Class	Direct Cost at Load Zone per MWh	Total Load at Zone (MWh)	Total Cost at Load Zone	Distribution Loss Factor	Total Load at Meter	Direct Cost at Customer Meter per MWh	Cost of Distribution Loss per MWh
		[A]	[B]	[C] = [A]*[B]	[D]	[E] = [B]*(1-[D])	[F] = [C]/[E]	[G] = [F]-[A]
2009	Residential	$77.58	36,687,229	$2,846,249,298	6.32%	34,368,596	$82.82	$5.23
	Commercial	$75.09	31,684,511	$2,379,050,373	5.97%	29,792,945	$79.85	$4.77
	Industrial	$70.81	47,280,915	$3,348,135,321	1.51%	46,566,973	$71.90	$1.09
	Street Light	$55.09	701,511	$38,645,294	6.32%	657,176	$58.81	$3.72
	All Customers	$74.01	116,354,166	$8,611,566,897	4.28%	111,374,208	$77.32	$3.31
2010	Residential	$76.87	36,687,229	$2,820,091,598	6.32%	34,368,596	$82.05	$5.19
	Commercial	$74.29	31,684,511	$2,353,789,490	5.97%	29,792,945	$79.00	$4.72
	Industrial	$69.71	47,280,915	$3,295,779,684	1.51%	46,566,973	$70.78	$1.07
	Street Light	$54.37	701,511	$38,137,948	6.32%	657,176	$58.03	$3.67
	All Customers	$73.12	116,354,166	$8,508,294,510	4.28%	111,374,208	$76.39	$3.27
2011	Residential	$74.79	36,687,229	$2,743,863,215	6.32%	34,368,596	$79.84	$5.05
	Commercial	$74.43	31,684,511	$2,358,421,125	5.97%	29,792,945	$79.16	$4.73
	Industrial	$68.89	47,280,915	$3,257,408,233	1.51%	46,566,973	$69.95	$1.06
	Street Light	$53.60	701,511	$37,602,588	6.32%	657,176	$57.22	$3.62
	All Customers	$72.19	116,354,166	$8,399,053,823	4.28%	111,374,208	$75.41	$3.23

Notes:

[1] Column [A] includes the calculated costs of round-the-clock energy, locational adjustment, capacity, transmission and ancillary services.

[2] Column [B] is the total load for September 2005 through August 2007.

[3] A distribution loss was calculated for each customer class which ranged from 1.51% to 6.32%.

[4] An average transmission and ancillary services annual rate of $7.50 was used for all customer classes.

Source:

[A] FirstEnergy Corp.

Exhibit 6

OBSERVED MARGINS FROM SOLICITATIONS FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS

State	Utility	Auction Date	Service Start Date	Product / Customer Class	Duration (Months)	Observed Margin	Average Observed Margin
IL	COMED	9/5/2006	1/1/2007	CPP-B	17	7.00%	
MD	PEPCO	1/23/2006	6/1/2006	Residential	12	7.90%	
MD	DPL	1/23/2006	6/1/2006	Residential	12	13.00%	
DE	DPL	1/9/2006	5/1/2006	Residential	13	15.40%	
IL	Ameren	9/5/2006	1/1/2007	BGS-FP	17	18.00%	12.26%
MD	PEPCO	1/23/2006	6/1/2006	Residential	24	9.10%	
IL	COMED	9/5/2006	1/1/2007	CPP-B	29	11.00%	
MD	DPL	1/23/2006	6/1/2006	Residential	24	14.20%	
DE	DPL	1/9/2006	5/1/2006	Residential	25	18.10%	
IL	Ameren	9/5/2006	1/1/2007	BGS-FP	29	21.00%	14.68%
NJ	ACE	2/5/2007	6/1/2007	BGS FP-Residential	36	9.80%	
IL	COMED	9/5/2006	1/1/2007	CPP-B	41	12.00%	
NJ	ACE	2/6/2006	6/1/2006	BGS FP-Residential	36	12.70%	
NJ	JCPL	2/6/2006	6/1/2006	BGS FP-Residential	36	15.10%	
NJ	JCPL	2/5/2007	6/1/2007	BGS FP-Residential	36	17.90%	
DE	DPL	1/9/2006	5/1/2006	Residential	37	22.00%	
IL	Ameren	9/5/2006	1/1/2007	BGS-FP	41	25.00%	16.36%

Sources:

[A] Illinois Commerce Commission & Boston Pacific Company, The September 2006 Illinois Auction: *Post-Auction Public Report of the Staff*, December 6, 2006.

[B] Direct Testimony of Frank C. Graves in the matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service For Residential and Small Commercial Customers in Maryland, Case No. 9117, September 14, 2007.

Exhibit 7

OBSERVED MARGINS FROM SOLICITATIONS FOR LARGE COMMERCIAL AND INDUSTRIAL CUSTOMERS

State	Utility	Auction Date	Service Start Date	Product / Customer Class	Duration (Months)	Observed Margin	Average Observed Margin
MD	PEPCO	1/23/2006	6/1/2006	Type II-B Non-Residential SOS	12	14.00%	
MD	DPL	1/23/2006	6/1/2006	Type II-A Non-Residential SOS	4	15.60%	
MD	DPL	1/23/2006	6/1/2006	Type I Non-Residential SOS	12	17.10%	
MD	DPL	1/23/2006	6/1/2006	Type II-A Non-Residential SOS	8	18.10%	
MD	PEPCO	1/23/2006	6/1/2006	Type I Non-Residential SOS	12	18.80%	
DE	DPL	1/9/2006	5/1/2006	Large General Service - Secondary	13	29.00%	
DE	DPL	1/9/2006	5/1/2006	General Service - Primary	13	38.60%	
DE	DPL	1/9/2006	5/1/2006	Medium General Service - Secondary	13	39.80%	
MD	PEPCO	1/23/2006	6/1/2006	Type II-A Non-Residential SOS	4	44.40%	
MD	PEPCO	1/23/2006	6/1/2006	Type II-A Non-Residential SOS	8	47.40%	
IL	COMED	9/5/2006	1/1/2007	CPP-A	17	53.00%	
IL	Ameren	9/5/2006	1/1/2007	BGS-LFP	17	68.00%	33.65%

Sources:

[A] Illinois Commerce Commission & Boston Pacific Company, The September 2006 Illinois Auction: *Post-Auction Public Report of the Staff*, December 6, 2006.

[B] Direct Testimony of Frank C. Graves in the matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service For Residential and Small Commercial Customers In Maryland, Case No. 9117, September 14, 2007.

Exhibit 8

ANALYSIS OF MARKET-RATE OFFER PRICES

2009

	Residential High Shopping Risk	Residential Low Shopping Risk	Commercial High Shopping Risk	Commercial Low Shopping Risk	Industrial	Streetlight	Total
Forecast Load (MWh)	8,792,308	8,792,308	7,700,716	7,700,716	23,834,744	384,015	57,202,582
Direct Costs: ($/MWh)							
Round the Clock Energy Price	$55.71	$55.71	$55.71	$55.71	$55.71	$55.71	$55.71
Locational Adjustment	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70
Load Shaping	$5.50	$5.50	$5.57	$5.57	$2.50	-$8.82	$4.22
Capacity Price	$8.18	$8.18	$5.60	$5.60	$4.40	$0.00	$5.89
Transmission and Ancillary Services	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50
Distribution Losses	$5.23	$5.23	$4.77	$4.77	$1.09	$3.72	$3.31
Total Direct Cost per MWh	$82.82	$82.82	$79.85	$79.85	$71.90	$58.81	$77.32
Total Direct Cost	$728,138,566	$728,138,566	$614,923,818	$614,923,818	$1,713,702,712	$22,582,048	$4,422,960,216
Margin	20%	10%	20%	10%	20%	10%	17%
Total Price per MWh	$99.38	$91.10	$95.82	$87.84	$86.28	$64.69	$90.47
Total Cost	$873,766,279	$800,952,423	$737,908,581	$676,416,200	$2,056,443,254	$24,840,252	$5,174,935,177

Notes:

[1] Based on July 15, 2008 forwards.

[2] Assumes 50% of residential and commercial customers participate in government aggregation programs.

Exhibit 9

ANALYSIS OF MARKET-RATE OFFER PRICES
2010

	Residential High Shopping Risk	Residential Low Shopping Risk	Commercial High Shopping Risk	Commercial Low Shopping Risk	Industrial	Streetlight	Total
Forecast Load (MWh)	13,367,073	4,455,691	11,711,096	3,903,699	23,885,967	384,015	57,712,876
Direct Costs: ($/MWh)							
Round the Clock Energy Price	$54.85	$54.85	$54.85	$54.85	$54.85	$54.85	$54.85
Locational Adjustment	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70
Load Shaping	$5.41	$5.41	$5.49	$5.49	$2.47	-$8.88	$4.15
Capacity Price	$8.41	$8.41	$5.75	$5.75	$4.19	$0.00	$5.93
Transmission and Ancillary Services	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50	$7.50
Distribution Losses	$5.19	$5.19	$4.72	$4.72	$1.07	$3.87	$3.27
Total Direct Cost per MWh	$82.05	$82.05	$79.00	$79.00	$70.78	$58.03	$76.39
Total Direct Cost	$1,096,826,047	$342,502,214	$869,997,801	$289,999,267	$1,665,003,382	$20,877,135	$4,220,202,509
Margin	30%	15%	15%	30%	30%	15%	29%
Total Price per MWh	$106.67	$94.36	$90.86	$102.71	$92.01	$66.74	$98.34
Total Cost	$1,425,873,861	$420,449,985	$1,202,804,574	$400,934,858	$2,197,689,509	$25,628,422	$5,675,456,542

Notes:

[1] Based on July 16, 2008 forwards.

[2] Assumes 75% of residential and commercial customers participate in government aggregation programs.

Exhibit 10

ANALYSIS OF MARKET-RATE OFFER PRICES
2011

	Residential	Commercial	Industrial	Streetlight	Total
Forecast Load (MWh)	18,068,101	15,831,164	23,937,405	384,015	58,233,804
Direct Costs: ($/MWh)					
Round the Clock Energy Price	$53.94	$53.94	$53.94	$53.94	$53.94
Locational Adjustment	$0.70	$0.70	$0.70	$0.70	$0.70
Load Shaping	$5.32	$5.40	$2.43	-$8.54	$4.08
Capacity Price	$7.33	$6.90	$4.33	$0.00	$5.96
Transmission and Ancillary Services	$7.50	$7.50	$7.50	$7.50	$7.50
Distribution Losses	$5.05	$4.73	$1.06	$3.62	$3.23
Total Direct Cost per MWh	$79.84	$79.16	$69.95	$57.22	$75.41
Total Direct Cost	$1,442,491,178	$1,253,201,098	$1,674,446,359	$21,972,752	$4,391,580,987
Margin	40%	40%	40%	20%	40%
Total Price per MWh	$111.77	$110.82	$97.93	$68.66	$105.49
Total Cost	$2,019,487,650	$1,754,481,537	$2,344,224,903	$26,367,302	$6,142,917,922

Notes:

[1] Based on July 15, 2008 forwards.

[2] Assumes 100% of residential and commercial customers participate in government aggregation programs.

[Company Exhibit 7]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant To R.C. § 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 08-_____-EL-SSO

DIRECT TESTIMONY OF

FRANK C. GRAVES

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

DIRECT TESTIMONY OF FRANK C. GRAVES

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, business address, and for whom you are testifying.

A. I am Frank C. Graves, Principal of *The Brattle Group,* located at 44 Brattle Street, Cambridge, Massachusetts, 02138. I am testifying on behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, the "Ohio Companies")

Q. Can you briefly summarize your experience and qualifications?

A. I have over 25 years of experience in assisting utilities with the design and implementation of long-range planning, investment, and operating policies, and in assisting their counsel with regulatory compliance and policy review. My work has involved market design and performance evaluations, capacity expansion, network modeling, investment and contract prudence reviews, estimation of marginal costs, price forecasting, design and pricing of new services, risk management, and financial simulation and valuation assessments. I have testified on the economics of electric and gas industry restructuring before the FERC and state regulatory commissions, covering such topics as stranded cost recovery, the design and pricing of Standard Offer Service, and the merits of various mechanisms for procuring retail power supplies. I am the author of several articles on energy and finance planning issues and a member of several professional societies, including the American Finance Association (AFA), the International Association of Energy Economists (IAEE) and the Institute of Electrical and

Electronic Engineers (IEEE). I hold an M.S. in Management degree with a concentration in finance from the MIT Sloan School of Management, and a B.A. degree in mathematics from Indiana University. Further details on my experience are provided in my resume attached as Appendix A.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. Under recently passed Ohio legislation (Am. Sub. S.B. 221), Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company ("the Ohio Companies") are obliged to file an "electric security plan" (ESP). In order to approve the ESP filed by the Ohio Companies, the Public Utilities Commission of Ohio (PUCO) must determine whether the ESP in the aggregate is more favorable than the expected results of a market-rate offer. One aspect of the ESP that will be part of that determination is the pricing of retail generation service. My testimony addresses the expected result of a market-rate offer (MRO) for retail generation service, as well as the following issues:

- What is the nature of the generation service product proposed to be supplied under the ESP by the Ohio Companies to standard-service-offer (SSO) customers?
- What constitutes a market price for that product?
- What are reasonable methods for determining a market price for providing generation service to SSO customers?

- Using those methods, what are useful market pricing benchmarks based on currently available information?

Q. What are your principal findings and observations?

A. My findings and observations are as follows:

- The relevant product for establishing a market price benchmark is the expected cost of electricity supply for retail electric generation service to SSO customers in the Ohio Companies' service territory over the next three years. 2009-2011. The components of that service include generation, capacity, and ancillary services, together with all transmission and transmission-related services including network services, congestion costs, and other costs incurred in delivering electric generation to the Ohio Companies' service territory.

- There are significant pricing and volumetric risks associated with supplying this product, including the prospect of opportunistic customer switching between SSO and competitive retail electric supply, as facilitated in Ohio by governmental aggregation programs.

- I describe two methodologies for determining a market price benchmark for supplying electric generation service to SSO customers: (i) a "comparables" method that relies upon prices for providing generation service to SSO-equivalent customers obtained from competitive procurements held in other jurisdictions; and (ii) a "modified constructed cost" method that determines a market price benchmark by adding up the prices of the individual cost components of generation service (*e.g.*, energy, capacity, ancillary services, network service, etc.) and adds an appropriate premium in consideration of pricing and volumetric risk.

- I then offer initial estimates of market price benchmarks using these methodologies.

III. CONSIDERATIONS AFFECTING THE MARKET PRICE OF THE STANDARD SERVICE OFFER (SSO)

Q. What is the nature of the electric generation service product being supplied by the Ohio Companies to SSO customers?

A. Before determining a reasonable market price for a particular product, one must define the characteristics of that product. In this case, the product in question is the supply of electric generation service to SSO customers in the Ohio Companies' service territory, which includes the purchase of energy, capacity, ancillary services, transmission services, and any other services needed to meet the electricity demand of those customers at all times.

Q. What are the risks associated with supplying that product?

A. To provide electric generation "service" sufficient to meet SSO customer load, the supplier is subject to pricing risk due to volatility in electric power prices and volumetric risk that stems from load uncertainty produced by changes in weather, economic conditions, and customer switching. In Ohio, the presence of government aggregation facilitates customer-switching behavior, and thereby raises the cost of providing the SSO product. This occurs because through governmental aggregation, competitive suppliers may obtain large groups of customers at one time and avoid the marketing costs involved in acquiring customers on a one-by-one basis. The potential for large-scale customer switching facilitated through governmental aggregation increases the risks faced by SSO suppliers.

Q. Is it possible through hedging to reduce or eliminate the price and volumetric risks associated with supplying standard-service-offer customers?

A. A potential supplier of SSO customers can purchase forwards and other financial products to alleviate some of the pricing risk, but there would be an expected cost increase associated with reducing this risk exposure. Increased hedging activity could raise the expected cost of serving SSO customers. Since uncertainty exists with respect to customer load, the supplier of SSO customers still will be obliged to make some future purchases (or sales) at uncertain prices. Given the positive correlation exhibited between price and load (*i.e.*, high prices are often associated with high load conditions), this uncertainty effectively increases the cost of providing generation service to SSO customers.

Q. How does customer-switching risk raise the cost of supplying SSO customers?

A. Customer-switching rights are effectively like granting call options to SSO customers. The customer has the option to choose between SSO and the offerings of competitive retail electric suppliers based on which offers the lower price. A potential customer has the incentive to use SSO when there is a financial benefit to doing so, such as when the

SSO price is below current competitive retail prices. Conversely, there is an incentive to use competitive retail supply when the SSO price is above that offered by competitive retail suppliers. Since competitive retail prices typically track wholesale forward prices in electric power markets, the financial benefit of using SSO increases as the difference increases between the current forward price and the SSO price. This financial benefit to customers, however, is the mirror image of the financial cost that the SSO supplier incurs in allowing customers to opportunistically switch to or away from SSO.

Some of the potential risk from opportunistic customer switching is mitigated by the perceived costs associated with shopping around for the best offer, such as the required search time and other transaction costs. These costs, though, are largely eliminated through governmental aggregation in Ohio, which allows retail electric customers to let their communities do their shopping for them. In fact, as shown in Exhibit 1, the Ohio Companies have experienced larger amounts of customer switching to competitive retail suppliers than utilities in other states (such as New Jersey, Pennsylvania, and Illinois) during certain past periods, and those switching rates have fluctuated with market conditions. Relative to other states, we therefore might reasonably expect that the cost to SSO suppliers associated with customer switching is potentially greater in Ohio. Consequently, in that circumstance, the "premium" for customer-switching risk that is embedded in standard-offer pricing in other states would be less than the premium required to compensate for customer-switching risk in Ohio.

IV. DETERMINING A MARKET PRICE BENCHMARK

Q. What constitutes a "market price" for a product?

A. A market price for a given product can be determined from transactions involving a willing seller and a willing buyer, where the transaction is at arm's length. Of course, the price of such transactions will generally change over time, so one must take into account the time frame and the prevailing circumstances before using the observed price as a reference for other transactions.

Q. Is it feasible and reasonable to look at comparable transactions in order to determine a market price for the type of product offered in the ESP?

A. Yes. In this situation, there are no "exact duplicate" transactions to which we can turn for a reference price, but there have been several meaningfully similar "comparable" transactions that can be adjusted for some known differences between the features of those "comparables" and the sale of the products now in question. This is a commonly used technique in performing valuations of different types of products and assets, including generation plants, businesses of various types, and homes for sale.

Q. Have you performed such analysis of comparable transactions for purposes of determining a market price for generation service offered to SSO customers by the Ohio Companies?

A. Yes, I have examined the procurement of SSO supply that has been held in other jurisdictions, particularly the New Jersey and Illinois full-requirements standard-offer service auctions and recent full-requirements procurements in Pennsylvania.[1] These results have then been adjusted to make them more aligned with the market conditions existing in Ohio Companies' service territories.

Q. How have you adjusted the procurement results from other jurisdictions to make them more aligned with Ohio market conditions?

A. The same types of adjustments were made to all of the auction results I evaluated. Let's take the New Jersey procurement results as an example. I have taken the procurement prices and adjusted them for location (i.e., transmission congestion premiums or savings for delivery into Ohio vs. New Jersey) and "load shape" based on historical differences in the weighted LMPs relevant to the designated New Jersey utility and the Ohio Companies' service territories. I also adjusted for differences in forward energy prices and capacity market prices prevailing as of July 15, 2008 vs. the corresponding prices in New Jersey at the time of its auctions, scaling the New Jersey results up or down as needed based on the percentage change in those price components. I display the resulting "Ohio-adjusted" auction results in Exhibit 2.

Q. Do you consider the results in Exhibit 2 to be indicative of the range of market prices for generation service that would likely prevail in the Ohio Companies' service territory as a result of a competitive bid process?

A. Yes I do, based on the information available at this time. There is a range of possible results, for several reasons. First, market conditions can and will change, so the precise

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1 I was unable to use certain prior standard-offer service procurements results, such as those in Maryland and Delaware (and for Penn Power), because there was insufficient publicly available data regarding load patterns and other factors to allow me to reliably adjust the results for relevant differences in market conditions affecting the utility conducting the procurement and the Ohio Companies.

results of an SSO procurement would depend on when it occurred. Closely related, each supplier will have different forecasts for some of the key drivers of future cost, as well as different risk tolerances for the financial performance uncertainty.

However, these results should be considered conservative estimates of a benchmark SSO market price. In particular, Exhibit 2 is based mainly on procurement results pertaining to residential customers in jurisdictions other than Ohio. There are reasons to expect that the Ohio Companies' customer-switching risk will be greater than that reflected in the adjusted comparables used above. Due to the prospect of governmental aggregation, the switching risk associated with residential customers may be greater in Ohio than in the jurisdictions used in my "comparables" analysis. In addition, the Ohio Companies' SSO load obligation extends to industrial and commercial customers, as well as residential customers. Industrial and commercial customers in most jurisdictions have shown a much greater propensity to switch to competitive retail suppliers than residential customers, implying that the switching risk associated with these customers is higher than for residential customers only. Those non-residential SSO customers represent about 70% of total SSO demand. To the extent that the customer-switching risk faced by the Ohio Companies is greater than that of the comparables used in Exhibit 2, the market price for generation service offered to SSO customers by the Ohio Companies would be even higher than the estimates provided, in order to reflect that additional risk.

Q. Did you perform any other analyses of market prices relevant to the Ohio Companies' service territories?

A. Yes, I also performed a "modified constructed cost" analysis to estimate a market price for the SSO. That process involved taking forward prices for energy and capacity. I then made adjustments to account for locational differences in the delivery point of the forward contract (*e.g.*, PJM West, or Cinergy) and the Ohio Companies' service territories. I further adjusted the forward energy prices, which are for a fixed amount of MW over a specified time period, to take into account the Ohio Companies' load shape.[2] I also add in costs for network service, ancillary services, and capacity. Including these various components allows me to construct an estimate of "no-risk" costs that might be offered if there were no customer switching, credit risk, positively correlated load and price uncertainty, or administrative costs to providing retail service. All of these factors could justify including a premium in a bid to supply retail power service.[3] These factors are not reflected in the "no-risk" prices, so those prices would not fully compensate SSO suppliers. In essence, these no-risk costs just reveal the direct costs of the key, wholesale electric market components of the likely total cost, for the dates and time periods when these transactions were evaluated.

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2 This adjustment is based on the difference between the simple average LMP and the load-weighted average LMP relevant to the Ohio Companies' service territories.

3 Since the daily load that eventually must be served is uncertain, it is inevitable that some portion of the demand will be served with spot purchases or sales that balance any forward supplies taken for the expected load against the actual, realized load. Since higher loads tend to be associated with higher spot prices, and lower loads with lower prices, you will tend to buy supplemental power at a premium and sell/dump unneeded power at a loss. Thus, these balancing transactions will impose a net cost above the level that would arise if there was no load uncertainty. This contributes to a risk premium for retail electric service.

The results of my modified constructed cost analysis are contained in Exhibits 3 and 4 based on PJM West forward prices, and Exhibits 5 and 6 based on Cinergy forward prices.

Q. How did you determine the premium to add to the "no risk" cost in order to cover the omitted risk factors, such as unanticipated load changes?

A. To account for these costs and risks, I include the "risk premiums" that have arisen in prior standard-offer service supply procurements, such as those that have been conducted in New Jersey, Illinois, Maryland, and Delaware. I analyzed this issue recently in testimony submitted before the Maryland Public Service Commission, when it was considering the pros and cons of full requirements auctions for coverage of their Standard Offer Service. The relevant portions of that analysis are attached as Exhibit 7 for use in this proceeding.

Exhibit 7 also contains estimates of the "no-risk" portion of the cost associated with standard-offer supply procurements, using a cost-component methodology analogous to that described above. I compare these no-risk cost estimates with the actual procurement prices to determine implied premiums for customer switching, credit risk, and load-following uncertainties (plus any other unaccounted-for factors in my analysis). As can be seen from the last column of this exhibit, the estimated risk premium for residential customers has typically been between about 2 and 20 percent, even though residential switching rates in these jurisdictions is not affected by governmental aggregation. Exhibit 7 also shows that risk premiums have been significantly higher for nonresidential (*i.e.*, commercial and industrial) customers, as much as 30-50 percent based on prior experience in Maryland and Delaware. In those states, customer-switching rates to competitive retail suppliers are significantly higher for commercial and industrial customers than for residential customers.

In the modified constructed cost analysis described in Exhibits 4 and 6, I have used 9.8 percent, 16.0 percent, and 27.6 percent as "low," "medium," and "high" risk premiums for purposes of determining a market pricing benchmark. These percentages were derived in the following fashion. I took the range of auction risk premiums, as shown in Exhibit 7, for all residential customer auctions where the duration of the service period was 24 months or greater. Since longer periods with set rates are associated with greater customer-switching risk, and since the Ohio Companies are proposing a rate plan to cover a three-year period, it is appropriate to use the risk premiums from standard-offer service supply auctions of similar duration. Using this distribution of risk premiums, I then identified the risk-premium level for residential customers that was associated with the 25^{th} percentile, 50^{th} percentile, and 75^{th} percentile benchmarks of the cumulative distribution.

For nonresidential customers, I performed a similar analysis except that I used all of the auction results to be conservative, even though many of those auctions were for a service period significantly less than 24 months.

I then calculated the load-weighted average of the residential and non-residential risk premium benchmarks, based on the shares of forecasted residential and non-residential load in the Ohio Companies' service territory for 2009, 2010, and 2011. The results of this analysis are shown in Exhibit 8, which provides the "low," "medium," and "high" risk premiums used in my modified constructed cost analysis.

Q. Do you consider the results contained in Exhibits 4 and 6 to be indicative of a market price for generation service that would prevail in the Ohio Companies' service territories?

A. Yes, I do, based on the information available at this time. However, like Exhibit 2, those results still may be considered conservative estimates. First, I have used bilateral capacity forward prices for the Ohio area in my analysis, as supplied to me by the Ohio Companies. (These are $69.17 per MW-day in 2009, $82.50 per MW-day in 2010, and $95.45 per MW-day in 2011, as of July 15, 2008). However, there is substantial uncertainty surrounding future capacity price levels and the nature of the future capacity market within MISO, which may cause suppliers of generation service under market-based pricing to require an increased risk premium to cover their capacity obligations. More significantly, customer-switching risk in the Ohio Companies' service territories may be greater than was expected in the other jurisdictions due to the presence of governmental aggregation and large-customer inclusion in SSO service. As a result, the relevant risk premium for customer switching may be higher than that observed elsewhere. Finally, recent power and fuel prices have been quite high by historical standards, and it is difficult to tell how likely it is that recent price levels will be sustained for the next few years. If suppliers are experiencing greater uncertainty of this type today than they would have felt at the time of past auctions, their risk premiums may be higher.

V. RESULTS

Q. What results have you obtained based on the analysis that you have conducted?

A. As described above, I used two methodologies to determine a market price benchmark for supplying electric generation service to the Ohio Companies' SSO customers: (1) a "comparables" method that relies upon prices for providing generation service to SSO customers obtained from competitive procurements held in other jurisdictions; and (2) a "modified constructed cost" method that determines a market price benchmark by adding up the prices of the individual cost components of generation service and including an appropriate premium in consideration of pricing and volumetric risk.

- My analysis using the "comparables" method indicates that the market price benchmarks for providing electric generation service range from \$76.35 per MWh to \$93.80 per MWh, based on adjusted results from standard-offer-service supply auctions conducted in New Jersey, Pennsylvania, and Illinois where the service period ends in 2010
- My analysis using the "modified constructed cost" method indicate that the market pricing benchmarks for providing electric generation service are as follows:
    - 2009 -- \$91.57 per MWh in the "low" risk premium case and \$106.37 per MWh in the "high" risk premium case
    - 2010 -- \$89.07 per MWh in the "low" risk premium case and \$103.46 per MWh in the "high" risk premium case

- 2011 -- $87.55 per MWh in the "low" risk premium case and $101.70 per MWh in the "high" risk premium case

These estimates are derived from PJM West forward prices that are then adjusted based on historical differences between the LMPs relevant to PJM West and the Ohio Companies' service territories. Adjustments are also made for capacity costs, ancillary services and transmission costs, and the effect of load shape on energy costs.

- If Cinergy forward prices are considered in addition to PJM West forward prices, then the price benchmarks are as follows:
  - 2009 -- $83.29 per MWh in the "low" risk premium case and $96.75 per MWh in the "high" risk premium case
  - 2010 -- $82.79 per MWh in the "low" risk premium case and $96.17 per MWh in the "high" risk premium case
  - 2011 -- $83.39 per MWh in the "low" risk premium case and $96.87 per MWh in the "high" risk premium case

These pricing benchmarks are based on forward prices in mid-July, 2008.

Q. Do you have an opinion about where in this range the ESP parameters should be drawn?

A. Yes, I do. I believe it is likely that customer-switching risk is greater in Ohio than has been the case in other states at the time of their auctions from which I have drawn comparables. The switching risk is higher in Ohio because governmental aggregation effectively lowers switching costs for customers and lowers customer acquisition costs for retail providers. Also, there are many large commercial and industrial customers eligible for fixed-price SSO in Ohio, and prices are generally high and volatile right now. On the other hand, I understand that a charge will be applied to any customers who wish to leave SSO with the right to return to the fixed SSO price in the future. Accordingly, the results based on the mid-level risk premium are about what I would expect a market solicitation to include.

With respect to the procurement sourcing, it is not possible for me to know whether a potential supplier would be more likely to use PJM-West or Cinergy hub contracts. For this factor, I would suggest giving equal weight to both possibilities, and use the mid-point between the two as an ESP base. This would result in a market reference price for ESP of around $92 to $90/MWh over the next three years, which is in the center of the price range that I found using the adjusted procurement results shown in Exhibit 2.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit 1: Customer Switching History
(All Customers)

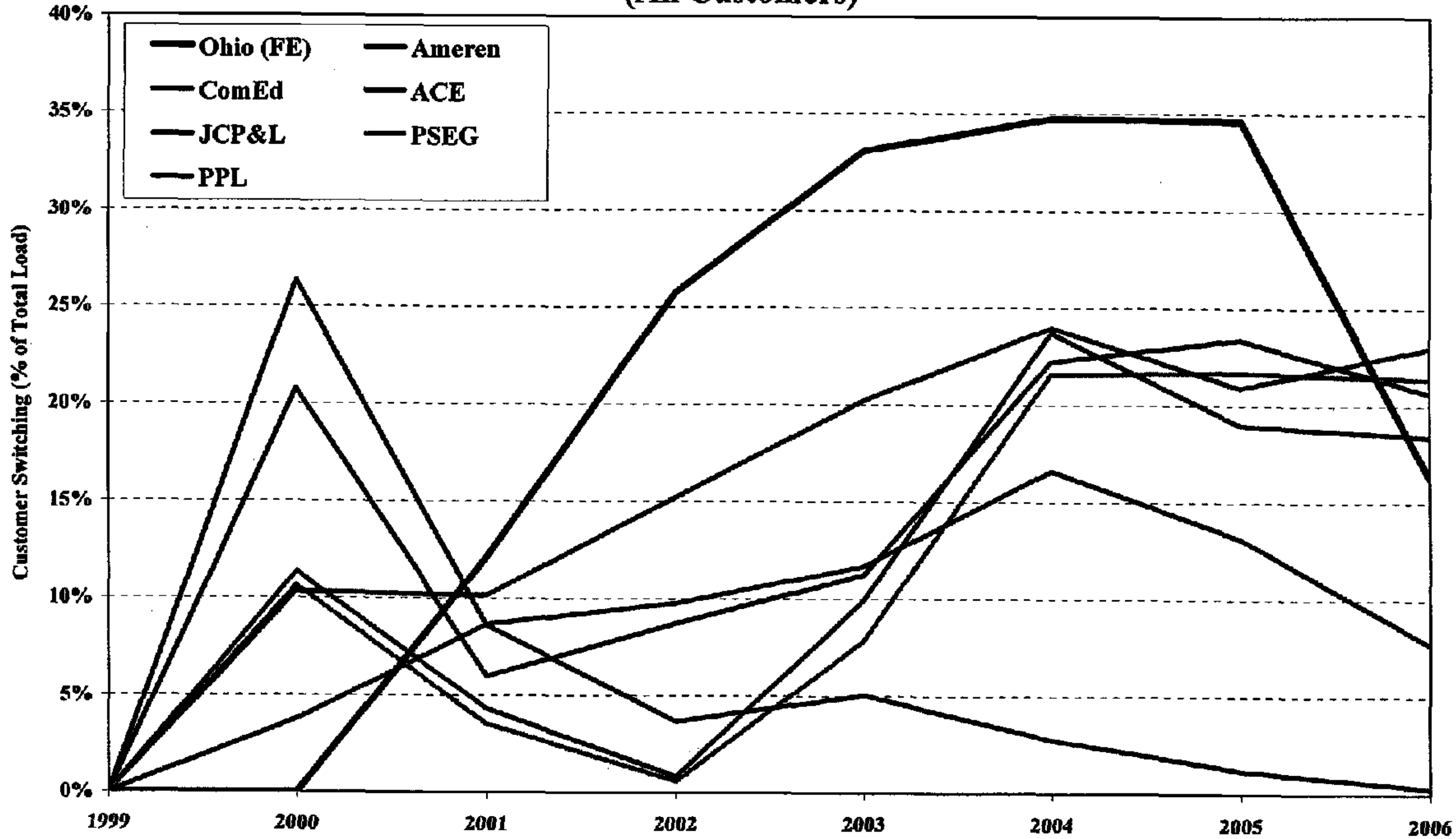

Exhibit 2: Adjusted Procurement Results

EDC	Date	State	Start Date	End Date	Result	Energy Component	Forward Adjustment	Congestion Adjustment	Load Shape Adjustment	Capacity Component	Capacity Price Adjustment	Adjustment Factor	Adjusted Result
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
ComEd	9/5/2006	IL	1/1/2007	5/31/2010	$63.33	99.67%	12.89%	-0.46%	-2.17%	0.33%	3141%	120.56%	$76.35
Ameren	9/5/2006	IL	1/1/2007	5/31/2010	$66.05	99.71%	12.89%	2.23%	-3.13%	0.29%	3471%	121.88%	$80.50
ACE	2/5/2007	NJ	6/1/2007	5/31/2010	$99.59	77.95%	31.68%	-26.12%	-6.56%	22.05%	-69.26%	83.95%	$83.60
JCP&L	2/5/2007	NJ	6/1/2007	5/31/2010	$99.64	77.10%	31.68%	-24.04%	-5.87%	22.90%	-70.43%	85.23%	$84.93
PSE&G	2/5/2007	NJ	6/1/2007	5/31/2010	$98.88	80.41%	31.68%	-27.54%	-2.95%	19.59%	-65.17%	88.18%	$87.20
Rockland	2/5/2007	NJ	6/1/2007	5/31/2010	$109.99	79.17%	31.68%	-27.37%	-4.34%	20.83%	-70.54%	85.28%	$93.80
ACE	2/5/2008	NJ	6/1/2008	5/31/2011	$116.50	83.31%	18.43%	-26.12%	-6.56%	16.69%	-65.30%	77.23%	$89.97
JCP&L	2/5/2008	NJ	6/1/2008	5/31/2011	$114.09	83.92%	18.43%	-24.04%	-5.87%	16.08%	-63.22%	80.20%	$91.50
PSE&G	2/5/2008	NJ	6/1/2008	5/31/2011	$111.50	85.23%	18.43%	-27.54%	-2.95%	14.77%	-59.02%	81.00%	$90.31
Rockland	2/5/2008	NJ	6/1/2008	5/31/2011	$120.49	83.76%	18.43%	-27.37%	-4.34%	16.24%	-65.51%	78.23%	$94.26
PP&L	7/23/2007	PA	1/1/2010	12/31/2010	$90.62	93.34%	30.67%	-23.10%	-0.32%	6.66%	11.81%	107.55%	$97.46
PP&L	10/1/2007	PA	1/1/2010	12/31/2010	$93.57	93.55%	27.54%	-23.10%	-0.32%	6.45%	11.81%	104.61%	$97.89
PP&L	3/24/2008	PA	1/1/2010	12/31/2010	$96.88	87.79%	11.12%	-23.10%	-0.32%	12.21%	-42.97%	83.95%	$81.33

Notes:

[1] Electric Distribution Company (EDC) served by the auction.
[2] Date auction was held.
[3] State where the EDC is located.
[4] Start date of full requirements service.
[5] End date of full requirements service.
[6] Result of procurement process.
[7] Portion of the procurement result estimated to represent Energy, Ancillary Services, Risk Premium, and all other non-Capacity costs.
[8] Adjustment from change in forward prices from auction date to July 15, 2008.
[9] Adjustment caused by locational differences in wholesale energy prices.
[10] Adjustment for the difference in load shape between the EDC and First Energy.
[11] Portion of the procurement result estimated to represent Capacity.
[12] Adjustment from the change in capacity prices from the auction date and EDC location to MISO DNR forwards for 2009, 2010, 2011.
[13] = ([7] * (1 + [8] + [9] + [10])) + ([11] * (1 + [12]))
[14] = [6] * [13]

Exhibit 3: Constructed Cost Method (Using PJM West Forward) - Estimated Energy, Nits & AS Cost (2009-2011)

Month	PJM West Forward Peak	PJM West Forward Off Peak	Congestion Adjustment Peak	Congestion Adjustment Off Peak	Load Shape Adjustment Peak	Load Shape Adjustment Off Peak	Ancillary & Nits Adder	Adjusted Forward (w/ AS) Peak	Adjusted Forward (w/ AS) Off Peak	FE Load Peak	FE Load Off Peak	Energy, Nits & AS Costs Peak	Energy, Nits & AS Costs Off Peak	Total
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Jan-09	$107.67	$80.67	-13.44%	-37.21%	0.70%	1.23%	$7.64	$101.60	$59.28	2,697,570	2,610,245	$274,076,162	$154,744,262	$428,820,424
Feb-09	$107.67	$80.67	-18.12%	-40.46%	0.70%	1.09%	$7.64	$96.55	$56.56	2,528,625	2,219,048	$244,146,691	$125,498,348	$369,645,040
Mar-09	$97.81	$66.50	-19.32%	-56.28%	0.50%	1.45%	$7.64	$87.04	$37.68	2,609,756	2,368,464	$227,163,565	$89,241,412	$316,404,977
Apr-09	$93.00	$66.50	-11.15%	-35.80%	0.77%	1.48%	$7.64	$90.99	$51.32	2,513,141	2,085,273	$228,659,929	$107,012,669	$335,672,598
May-09	$91.13	$56.25	-5.31%	-27.25%	2.04%	3.13%	$7.64	$95.79	$50.32	2,341,560	2,350,454	$224,293,741	$118,278,844	$342,572,585
Jun-09	$104.19	$66.33	-17.03%	-40.33%	2.06%	4.69%	$7.64	$96.23	$50.33	2,836,095	2,263,373	$272,916,281	$113,910,130	$386,826,410
Jul-09	$120.56	$77.33	-18.17%	-40.01%	6.55%	9.06%	$7.64	$114.20	$61.04	3,045,387	2,403,178	$347,775,305	$146,686,553	$494,461,858
Aug-09	$120.56	$77.33	-23.27%	-47.45%	5.76%	6.27%	$7.64	$107.09	$53.13	2,719,770	2,562,314	$291,260,030	$136,124,031	$427,384,061
Sep-09	$95.50	$65.50	-18.02%	-45.99%	0.72%	1.45%	$7.64	$86.62	$43.96	2,487,275	2,187,866	$215,452,359	$96,189,425	$311,641,784
Oct-09	$88.69	$64.17	-16.26%	-27.25%	0.55%	1.21%	$7.64	$82.40	$55.10	2,525,102	2,226,328	$208,064,194	$122,659,737	$330,723,931
Nov-09	$88.69	$64.17	-19.56%	-41.75%	1.38%	2.28%	$7.64	$80.21	$46.48	2,327,925	2,332,993	$186,715,439	$108,448,436	$295,163,875
Dec-09	$88.69	$64.17	-15.68%	-29.67%	3.15%	3.70%	$7.64	$85.22	$55.14	2,660,248	2,448,398	$226,710,960	$135,016,473	$361,727,433
	$100.35	$69.13	-16.28%	-39.12%	2.07%	3.09%	$7.64	$93.66	$51.69	31,292,456	28,057,925	$2,947,234,656	$1,453,810,320	$4,401,044,976
Jan-10	$102.56	$76.36	-13.44%	-37.21%	0.70%	1.23%	$7.64	$97.14	$56.53	2,392,001	2,735,483	$251,781,239	$154,623,326	$406,404,565
Feb-10	$102.56	$76.36	-18.12%	-40.46%	0.70%	1.09%	$7.64	$92.33	$53.94	2,552,146	2,246,512	$235,638,593	$121,182,228	$356,820,821
Mar-10	$93.16	$62.95	-19.32%	-56.28%	0.50%	1.45%	$7.64	$83.27	$36.07	2,751,694	2,304,092	$229,139,518	$83,119,186	$312,258,704
Apr-10	$88.58	$62.95	-11.15%	-35.80%	0.77%	1.48%	$7.64	$87.03	$48.99	2,532,483	2,104,099	$220,393,387	$103,070,059	$323,463,446
May-10	$86.80	$53.25	-5.31%	-27.25%	2.04%	3.13%	$7.64	$91.60	$48.04	2,304,480	2,386,357	$211,092,550	$114,645,379	$325,737,929
Jun-10	$99.24	$62.79	-17.03%	-40.33%	2.06%	4.69%	$7.64	$92.82	$48.05	2,891,131	2,265,664	$266,045,932	$108,859,662	$374,905,594
Jul-10	$114.83	$73.20	-18.17%	-40.01%	6.55%	9.06%	$7.64	$109.14	$58.19	2,844,660	2,601,907	$310,454,041	$151,395,722	$461,849,763
Aug-10	$114.83	$73.20	-23.27%	-47.45%	5.76%	6.27%	$7.64	$102.37	$50.70	2,866,934	2,499,296	$293,476,262	$126,704,239	$420,180,500
Sep-10	$90.96	$62.00	-18.02%	-45.99%	0.72%	1.45%	$7.64	$82.87	$42.02	2,510,772	2,211,363	$208,067,796	$92,931,997	$300,999,793
Oct-10	$84.48	$60.74	-16.26%	-27.25%	0.55%	1.21%	$7.64	$78.85	$52.56	2,423,289	2,336,398	$191,069,430	$122,802,505	$313,871,935
Nov-10	$84.48	$60.74	-19.56%	-41.75%	1.38%	2.28%	$7.64	$76.76	$44.41	2,474,883	2,262,929	$189,971,327	$100,496,487	$290,467,814
Dec-10	$84.48	$60.74	-15.68%	-29.67%	3.15%	3.70%	$7.64	$81.54	$52.61	2,820,890	2,364,049	$230,005,319	$124,366,659	$354,371,978
	$95.58	$65.44	-16.28%	-39.12%	2.07%	3.09%	$7.64	$89.58	$49.34	31,565,363	28,318,150	$2,837,135,394	$1,404,197,449	$4,241,332,842
Jan-11	$98.77	$75.92	-13.44%	-37.21%	0.70%	1.23%	$7.64	$93.83	$56.24	2,533,247	2,864,566	$237,700,690	$161,106,624	$398,807,313
Feb-11	$98.77	$75.92	-18.12%	-40.46%	0.70%	1.09%	$7.64	$89.20	$53.67	2,491,579	2,323,669	$222,253,314	$124,719,494	$346,972,808
Mar-11	$89.72	$62.58	-19.32%	-56.28%	0.50%	1.45%	$7.64	$80.48	$35.91	2,690,890	2,375,456	$216,559,817	$85,301,358	$301,861,175
Apr-11	$85.31	$62.58	-11.15%	-35.80%	0.77%	1.48%	$7.64	$84.09	$48.75	2,464,040	2,200,415	$207,212,606	$107,259,811	$314,472,417
May-11	$83.60	$52.94	-5.31%	-27.25%	2.04%	3.13%	$7.64	$88.50	$47.81	2,219,680	2,581,600	$196,441,845	$123,419,559	$319,861,404
Jun-11	$95.58	$62.42	-17.03%	-40.33%	2.06%	4.69%	$7.64	$88.90	$47.81	2,817,410	2,354,900	$250,481,849	$112,594,668	$363,076,517
Jul-11	$110.59	$72.77	-18.17%	-40.01%	6.55%	9.06%	$7.64	$105.39	$57.89	2,765,486	2,716,887	$291,446,901	$157,288,538	$448,735,439
Aug-11	$110.59	$72.77	-23.27%	-47.45%	5.76%	6.27%	$7.64	$98.87	$50.45	2,766,139	2,646,738	$273,481,063	$133,517,198	$406,998,260
Sep-11	$87.60	$61.64	-18.02%	-45.99%	0.72%	1.45%	$7.64	$80.09	$41.83	2,418,137	2,364,316	$193,672,531	$98,887,744	$292,560,276
Oct-11	$81.36	$60.39	-16.26%	-27.25%	0.55%	1.21%	$7.64	$76.22	$52.30	2,332,489	2,437,069	$177,776,027	$127,458,152	$305,234,178
Nov-11	$81.36	$60.39	-19.56%	-41.75%	1.38%	2.28%	$7.64	$74.21	$44.20	2,422,685	2,398,623	$179,780,094	$106,010,489	$285,790,583
Dec-11	$81.36	$60.39	-15.68%	-29.67%	3.15%	3.70%	$7.64	$78.81	$52.35	2,770,658	2,471,055	$218,348,007	$129,350,752	$347,698,758
	$92.05	$65.06	-16.28%	-39.12%	2.07%	3.09%	$7.64	$86.55	$49.10	30,692,440	29,735,293	$2,665,154,743	$1,466,914,387	$4,132,069,130

Notes:

[1] Peak forward curve for PJM West Hub.
[2] Off peak forward curve for PJM West Hub.
[3] Difference in historic average monthly FE & PJM West peak LMPs.
[4] Difference in historic average monthly FE & PJM West off peak LMPs.
[5] FE control area average monthly peak load shape factor.
[6] FE control area average monthly off peak load shape factor.
[7] FE provided projected price for Nits and ancillary services.
[8] = [1] + ([1] * [3]) + ([1] * [5]) + [7]
[9] = [2] + ([2] * [4]) + ([2] * [6]) + [7]
[10] Projected FE peak load.
[11] Projected FE off peak load.
[12] = [8] * [10]
[13] = [9] * [11]

Exhibit 4: Constructed Cost Method (Using PJM West Forward)
Calculation of Generation Service Price (2009-2011)

		2009	2010	2011
Energy, Nits & Ancillary Costs ($)	[1]	$4,401,044,976	$4,241,332,842	$4,132,069,130
Capacity Cost ($/MW-day)	[2]	$69.17	$82.50	$95.45
Peak Capacity Plus Reserve Margin (MW)	[3]	13,327	13,530	13,736
Total Capacity Cost ($)	[4]	$336,468,544	$407,414,231	$478,542,931
Total Procurement Costs ($)	[5]	$4,737,513,520	$4,648,747,073	$4,610,612,061
Total Projected Load (MWh)	[6]	56,818,797	57,321,168	57,833,934
Total Procurement Costs ($/MWh)	[7]	$83.38	$81.10	$79.72
Estimated 25th Percentile Risk Premium (%)	[8]	9.82%	9.82%	9.82%
Projected Low Market Price ($/MWh)	[9]	$91.57	$89.07	$87.55
Estimated 50th Percentile Risk Premium (%)	[10]	15.96%	15.96%	15.96%
Projected Median Market Price ($/MWh)	[11]	$96.68	$94.04	$92.44
Estimated 75th Percentile Risk Premium (%)	[12]	27.57%	27.57%	27.57%
Projected High Market Price ($/MWh)	[13]	$106.37	$103.46	$101.70

Notes:

[1] See column [14] in Exhibit 3.
[2] FE provided forward prices for MISO DNR.
[3] Peak hour of projected FE Load plus 13.5% reserve margin.
[4] = [2] * [3]
[5] = [1] + [4]
[6] See column [14] in Exhibit 3.
[7] = [5] / [6]
[8] Calculated from study of previous auctions.
[9] = [7] * (1 + [8])
[10] Calculated from study of previous auctions.
[11] = [7] * (1 + [10])
[12] Calculated from study of previous auctions.
[13] = [7] * (1 + [12])

Exhibit 5: Constructed Cost Method (Using Cinergy Forward) - Estimated Energy, Nits & AS Cost (2009-2011)

Month	Cinergy Forward Peak	Cinergy Forward Off Peak	Congestion Adjustment Peak	Congestion Adjustment Off Peak	Load Shape Adjustment Peak	Load Shape Adjustment Off Peak	Ancillary & Nits Adder	Adjusted Forward (w/ AS) Peak	Adjusted Forward (w/ AS) Off Peak	FE Load Peak	FE Load Off Peak	Energy, Nits & AS Costs Peak	Energy, Nits & AS Costs Off Peak	Total
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Jan-09	$79.00	$46.50	2.97%	0.77%	0.70%	1.23%	$7.64	$89.55	$55.07	2,697,570	2,610,245	$241,559,713	$143,752,251	$385,311,964
Feb-09	$79.00	$46.50	2.36%	1.95%	0.70%	1.09%	$7.64	$89.05	$55.55	2,528,625	2,219,848	$225,181,943	$123,278,727	$348,460,670
Mar-09	$73.31	$40.50	-0.47%	-8.32%	0.50%	1.45%	$7.64	$80.98	$45.36	2,609,756	2,368,464	$211,326,179	$107,433,388	$318,759,568
Apr-09	$73.31	$40.50	-1.20%	-4.55%	0.77%	1.48%	$7.64	$80.63	$46.90	2,513,141	2,085,273	$202,646,773	$97,789,484	$300,436,256
May-09	$67.25	$34.25	-3.22%	-3.48%	2.04%	3.13%	$7.64	$74.10	$41.77	2,341,560	2,350,454	$173,500,184	$98,180,319	$271,680,502
Jun-09	$75.50	$34.25	-3.81%	-3.73%	2.06%	4.69%	$7.64	$81.82	$41.22	2,836,095	2,263,373	$232,044,367	$95,556,493	$327,600,860
Jul-09	$90.25	$41.00	5.27%	-0.87%	6.55%	9.06%	$7.64	$108.56	$52.08	3,045,387	2,403,178	$330,615,533	$124,958,707	$455,574,240
Aug-09	$90.25	$41.00	-1.74%	-5.17%	5.76%	6.27%	$7.64	$101.52	$49.09	2,719,770	2,562,314	$276,117,156	$125,789,275	$401,906,431
Sep-09	$71.50	$34.25	-0.05%	-4.25%	0.72%	1.45%	$7.64	$79.62	$40.93	2,487,275	2,187,866	$198,032,725	$89,550,788	$287,583,513
Oct-09	$66.88	$36.50	-1.21%	-0.94%	0.55%	1.21%	$7.64	$74.08	$44.24	2,525,102	2,226,320	$187,054,587	$98,482,621	$285,537,207
Nov-09	$66.88	$36.50	-4.71%	-2.85%	1.38%	2.28%	$7.64	$72.29	$43.93	2,327,925	2,332,993	$168,288,711	$102,495,075	$270,783,785
Dec-09	$66.88	$36.50	1.23%	1.79%	3.15%	3.70%	$7.64	$77.45	$46.14	2,660,248	2,448,398	$206,043,529	$112,974,667	$319,018,196
	$75.00	$39.02	-0.38%	-2.47%	2.07%	3.09%	$7.64	$84.14	$46.93	31,292,456	28,057,925	$2,652,411,397	$1,320,241,795	$3,972,653,192
Jan-10	$75.13	$47.67	2.97%	0.77%	0.70%	1.23%	$7.64	$85.54	$56.26	2,592,001	2,735,483	$221,715,344	$153,905,293	$375,620,636
Feb-10	$75.13	$47.67	2.36%	1.95%	0.70%	1.09%	$7.64	$85.07	$56.76	2,552,146	2,246,512	$217,107,082	$127,505,563	$344,612,645
Mar-10	$69.72	$41.52	-0.47%	-8.32%	0.50%	1.45%	$7.64	$77.39	$46.31	2,751,694	2,304,092	$212,943,024	$106,694,392	$319,637,416
Apr-10	$69.72	$41.52	-1.20%	-4.55%	0.77%	1.48%	$7.64	$77.06	$47.88	2,532,483	2,104,099	$195,158,670	$100,744,990	$295,903,660
May-10	$63.96	$35.11	-3.22%	-3.48%	2.04%	3.13%	$7.64	$70.84	$42.63	2,304,480	2,386,357	$163,257,106	$101,723,869	$264,980,975
Jun-10	$71.80	$35.11	-3.81%	-3.73%	2.06%	4.69%	$7.64	$78.19	$43.09	2,891,131	2,265,664	$226,050,825	$97,619,130	$323,669,955
Jul-10	$85.83	$42.03	5.27%	-0.87%	6.55%	9.06%	$7.64	$103.62	$53.11	2,844,660	2,601,907	$294,772,738	$138,188,182	$432,960,921
Aug-10	$85.83	$42.03	-1.74%	-5.17%	5.76%	6.27%	$7.64	$96.93	$50.13	2,866,934	2,499,296	$277,884,162	$125,295,313	$403,179,475
Sep-10	$68.00	$35.11	-0.05%	-4.25%	0.72%	1.45%	$7.64	$76.10	$41.77	2,510,772	2,211,363	$191,058,303	$92,359,839	$283,418,142
Oct-10	$63.61	$37.42	-1.21%	-0.94%	0.55%	1.21%	$7.64	$70.83	$45.15	2,423,289	2,336,398	$171,632,555	$105,497,529	$277,130,084
Nov-10	$63.61	$37.42	-4.71%	-2.85%	1.38%	2.28%	$7.64	$69.13	$44.84	2,474,883	2,262,929	$171,081,207	$101,477,849	$272,559,056
Dec-10	$63.61	$37.42	1.23%	1.79%	3.15%	3.70%	$7.64	$74.04	$47.11	2,820,890	2,364,049	$208,846,933	$111,366,608	$320,213,541
	$71.33	$40.00	-0.38%	-2.47%	2.07%	3.09%	$7.64	$80.39	$47.92	31,565,363	28,318,150	$2,551,507,948	$1,362,378,559	$3,913,886,507
Jan-11	$73.21	$50.05	2.97%	0.77%	0.70%	1.23%	$7.64	$83.54	$58.69	2,533,247	2,864,566	$211,626,902	$168,131,995	$379,758,898
Feb-11	$73.21	$50.05	2.36%	1.95%	0.70%	1.09%	$7.64	$83.08	$59.21	$2,491,579	$2,323,669	$207,005,312	$137,591,369	$344,596,681
Mar-11	$67.93	$43.59	-0.47%	-8.32%	0.50%	1.45%	$7.64	$75.60	$48.24	$2,690,890	$2,375,456	$203,422,634	$114,591,493	$318,014,127
Apr-11	$67.93	$43.59	-1.20%	-4.55%	0.77%	1.48%	$7.64	$75.28	$49.89	$2,464,040	$2,280,415	$185,495,710	$109,783,872	$295,279,582
May-11	$62.32	$36.86	-3.22%	-3.48%	2.04%	3.13%	$7.64	$69.22	$44.38	$2,219,680	$2,581,600	$153,650,375	$114,562,680	$268,213,055
Jun-11	$69.96	$36.86	-3.81%	-3.73%	2.06%	4.69%	$7.64	$76.34	$44.86	$2,817,410	$2,354,900	$215,187,462	$105,637,597	$320,825,059
Jul-11	$83.63	$44.13	5.27%	-0.87%	6.55%	9.06%	$7.64	$101.16	$55.38	$2,765,486	$2,716,887	$279,758,450	$150,471,687	$430,230,137
Aug-11	$83.63	$44.13	-1.74%	-5.17%	5.76%	6.27%	$7.64	$94.64	$52.26	$2,766,139	$2,646,738	$261,777,963	$138,310,181	$400,088,144
Sep-11	$66.26	$36.86	-0.05%	-4.25%	0.72%	1.45%	$7.64	$74.34	$43.47	$2,418,137	$2,364,316	$179,762,362	$102,782,324	$282,544,685
Oct-11	$61.97	$39.29	-1.21%	-0.94%	0.55%	1.21%	$7.64	$69.21	$47.03	$2,332,489	$2,437,069	$161,420,417	$114,614,438	$276,034,855
Nov-11	$61.97	$39.29	-4.71%	-2.85%	1.38%	2.28%	$7.64	$67.55	$46.70	$2,422,685	$2,398,623	$163,651,195	$112,024,713	$275,675,908
Dec-11	$61.97	$39.29	1.23%	1.79%	3.15%	3.70%	$7.64	$72.33	$49.08	$2,770,658	$2,471,055	$200,408,423	$121,283,939	$321,692,362
	$69.50	$42.00	-0.38%	-2.47%	2.07%	3.09%	$7.64	$78.33	$49.93	30,692,440	29,735,293	$2,423,167,205	$1,489,786,289	$3,912,953,494

Notes:

[1] Peak forward curve for Cinergy Hub.
[2] Off peak forward curve for Cinergy Hub.
[3] Difference in historic average monthly FE & Cinergy peak LMPs.
[4] Difference in historic average monthly FE & Cinergy off peak LMPs.
[5] FE control area average monthly peak load shape factor.
[6] FE control area average monthly off peak load shape factor.
[7] FE provided projected price for Nits and ancillary services.
[8] = [1] + ([1] * [3]) + ([1] * [5]) + [7]
[9] = [2] + ([2] * [4]) + ([2] * [6]) + [7]
[10] Projected FE peak load.
[11] Projected FE off peak load.
[12] = [8] * [10]
[13] = [9] * [11]

Exhibit 8: TBG Estimated Risk Premium Summary Statistics

	Average Risk Premium	25th Percentile	50th Percentile	75th Percentile
Residential Auctions over 24 Months	11.03%	8.58%	11.44%	14.21%
All Non-Residential Auctions	21.91%	10.40%	18.06%	33.79%
Weighted Average	18.45%	9.82%	15.96%	27.57%

FRANK C. GRAVES
Principal

Mr. Graves is a Principal of *The Brattle Group* who specializes in finance and regulatory economics. In the area of financial economics, he has assisted companies with securities litigation suits, special purpose audits, tax disputes, risk management, and cost of capital estimation. In regulatory economics, he has assisted utilities in capacity expansion, network modeling, investment and contract prudence reviews, estimation of marginal costs, design and pricing of new services, financial simulation and asset and contract valuation. He has testified before the FERC and many state regulatory commissions, as well as in state and federal courts, on such matters as the economics of gas and electric industry restructuring, breach of contract disputes, alleged securities fraud, risk management and resource planning, and adequacy of market competition. He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

REPRESENTATIVE CONSULTING EXPERIENCE

Regulated Industry Restructuring

- Many utilities experienced significant "rate shock" when they recently ended "rate freeze" periods that had been implemented with earlier retail restructuring. The adverse customer and political reactions have lead to proposals to annual procurement auctions and to return to utility-owned or managed supply portfolios. Mr. Graves has assisted utilities and wholesale gencos with analyses of whether alternative supply procurement arrangements could be beneficial.

- As a result of vertical unbundling, many utilities must procure a substantial portion of their power from resources they do not own or operate. Market prices for such supplies are quite volatile. In addition, utilities may face future customer switching to or from their supply service, especially if they are acting as provider of last resort (POLR). This problem is a blending of risk management with the traditional least-cost Integrated Resource Planning (IRP). Regulatory standards for findings of prudence in such a hybrid environment are often not well understood or articulated, leaving utilities at risk for cost disallowances that can jeopardize their credit-worthiness. Mr. Graves has assisted several utilities in devising updated procurement mechanisms and associated regulatory guidelines that clarify the conditions for approval of plans, in order to make possible the expedited procurement of power from wholesale market suppliers.

- There is a strong tendency in electric restructuring to impose "provider of last resort" (POLR) transitional supply obligations on the incumbent distribution companies. Unfortunately, POLR obligations that are extremely protective of customers harm the development of competitive retail power markets and can impose extreme, viability-threatening costs or risks on distcos. Mr. Graves developed policy papers and tutorials on this problem for the Edison Electric Institute, and advised several utilities on the design and valuation of alternative POLR specifications and coverage strategies.

- Public power authorities and cooperatives face risks from wholesale restructuring if their sales-for-resale customers are free to switch to or from supply contracting with other wholesale suppliers. Such switching can create difficulties in servicing the significant debt capitalization of these public power entities, as well as equitable problems with respect to non-switching customers. Mr. Graves has lead analyses of this problem, and has designed alternative product pricing, switching terms and conditions, and debt capitalization policies to cope with the risks.

- As a means of unbundling to retain ownership but not control of generation, some utilities turned to divesting output contracts. Mr. Graves was involved in the design and approval of such agreements for an entire fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units, and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.

- Mr. Graves worked with the executive committees of several utilities in designing regulatory strategies for influencing the pace and procedures associated with the transition to retail electric access. These included comprehensive business strategies and integrated planning tools for service unbundling and pricing, incentive ratemaking, corporate reorganization, market forecasting, asset valuation, and risk management.

- Mr. Graves contributed to the design and pricing of unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundlings that were insensitive to system operations.

- For several natural gas pipeline companies, Mr. Graves evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.

- Mr. Graves assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves' work in this area has helped several utilities develop long term planning models for managing their generation assets in a competitive market. Mr. Graves has assisted a leasing company with analyses of the tax-legitimacy of complex leasing transactions by reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

Market Competition

- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power. Mr. Graves assisted several utilities in evaluating the competitive impacts of potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, along with mechanisms for incorporating physical flow limits in FERC Delivered Price Test (DPT) for mergers. He has also assessed the adequacy of mitigation measures (divestitures and conduct restrictions) under the DPT, Market-Based Rates, and other tests of potential market power arising from proposed mergers.

- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the quality of competition in the wholesale generation markets can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves helped one of the largest

ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.

- Vertical market power arises when sufficient control of an upstream market creates a competitive advantage in a downstream market. It is possible for this problem to arise in power supply, in settings where the likely marginal generation is dependent on very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.

- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of a proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of the process for soliciting and ranking bids to buy tranches of capacity over the line.

- Many regions have misgivings about whether the preconditions for retail electric access are truly in place. In one such region, Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak transmission grid made adequate competition among numerous generation suppliers very implausible.

- Mr. Graves assisted one of the early ISOs with its initial market performance assessment and its design of market monitoring tests for diagnosing the quality of prevailing competition.

Financial Analysis

- For a defendant in a sentencing hearing for securities' fraud, Mr. Graves prepared an analysis of how the defendant's role in the corporate crisis was confounded by other concurrent events and disclosures that made loss calculations unreliable. At trial, the Government stipulated that it agreed with Mr. Graves' analysis.

- For the U.S. Department of Justice, Mr. Graves prepared an event study quantifying bounds on the economic harm to shareholders that had likely ensued from revelations that Dynegy Corporation's "Project Alpha" had been improperly represented as a source of operating income rather than as a financing. The event study was presented in the re-sentencing hearing of Mr. Jamie Olis, the primary architect of Project Alpha.

- Mr. Graves has assisted leasing companies with analyses of the tax-legitimacy of complex leasing transactions. These analyses involved reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent, purpose and cost of defeasance, and compliance with prevailing guidelines for true-lease status.

- For a utility facing significant financial losses from likely future costs of its Provider of Last Resort obligations, Mr. Graves prepared an analysis of how optimal hindsight coverage would have compared in costs to a proposed restructuring of the obligation. He also reviewed the prudence of prior, actual coverage of the obligation in light of conventional risk management practices and prevailing market conditions of credit constraints and low long-term liquidity.

- Several banks have been accused of aiding and abetting Enron's fraudulent schemes and have been sued for damages. Mr. Graves analyzed how the stock market had reacted to one bank's equity-analyst reports endorsing Enron as a "buy," to determine if those reports induced statistically significant positive abnormal returns. He showed that individually and collectively they did not have such an effect. Testimony was presented.

- Mr. Graves lead an analysis of whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil" of limited liability. The analysis investigated the presence of untenable debt capitalization in the subsidiary, overlapping management staff, the adherence to normal corporate governance protocols, and other kinds of evidence of excessive parental control.

- As a tax-revenue enhancement measure, the IRS was considering a plan to recapture deferred taxes associated with generation assets that were divested or reorganized during state restructurings for retail access. Mr. Graves prepared a white paper demonstrating the unfairness and adverse consequences of such a plan, which was instrumental in eliminating the proposal.

- In a dispute over damages from a prematurely terminated long-term power tolling contract, Mr. Graves presented evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. The amount of damages was dramatically larger under a two-discount rate calculation, which was the position adopted by the court.

- The energy and telecom industries have been plagued by allegations regarding trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded financial collapse and subsequent shareholder suits. Mr. Graves lead research on accounting and financial evidence, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.

- Dramatic natural gas price increases in the U.S. have put several natural gas and electric utilities in the position of having to counter claims that they should have hedged more of their fuel supplies at times in the past. Mr. Graves developed testimony to rebut this hindsight criticism and risk management techniques for fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.

- As a means of calculating its stranded costs, a utility used a partial spin-off of its generation assets to a company that had a minority ownership from public shareholders. A dispute arose as to whether this minority ownership might be depressing the stock price, if a "control premium" was being implicitly deducted from its value. Using event studies and structural analyses, Mr. Graves identified the key drivers of value for this partially spun-off subsidiary, and he showed that value was not being impaired by the operating, financial and strategic restrictions on the company. He also reviewed the financial economics literature on empirical evidence for control premiums, which he showed reinforced the view that no control premium de-valuation was likely to be affecting the stock.

- A large public power agency was concerned about its debt capacity in light of increasing competitive pressures to allow its resale customers to use alternative suppliers. Mr. Graves lead a team that developed an Economic Balance Sheet representation of the agency's electric assets and liabilities in market value terms, which was analyzed across several scenarios to determine safe levels of debt financing. In addition, new service pricing and upstream supply contracting arrangements were identified to help reduce risks.

- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to valuation and development decisions. Mr. Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.

- A major telecommunications firm was concerned about when and how to reenter the Pacific Rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together should it face financial distress, while offering strong returns under good performance.

- There are many risks associated with operations in a foreign country, related to the stability of its currency, its macro economy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.

- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan of reorganization, which was approved. Testimony was provided on cost-of-service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.

- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reappraisal of these assets. Traditional valuation methods, *e.g.*, based on the replacement costs of comparable assets, can be misleading because they do not consider market conditions. Mr. Graves testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.

- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spin-off of transmission, and new marketing programs were among the many components of the proposed new business plan.

- As a means of reducing supply commitment risk, some utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves assisted several of these utilities in the development of valuation models for comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power.

- For the World Bank and several investor-owned electric utilities, Mr. Graves presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as price caps and floors) for natural gas pipelines.

- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.

- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.

- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the company. This defined an economic priority ladder for efforts to reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.

- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to the risks of bonds and stocks to estimate project-specific discount rates and their probable bounds.

Utility Planning and Operations

- The potential introduction of environmental restrictions or fees for CO_2 emissions has made generation expansion decisions much more complex and risky. Mr. Graves helped one utility assess these risks in regard to a planned baseload coal plant, finding that the value of flexibility in other technologies was high enough to prefer not building a conventional coal plant.

- Mr. Graves has helped design, implement, and gain regulatory approvals for a natural gas procurement hedging program for a western U.S. gas and electric utility. A model of how gas forward prices evolve over time was estimated and combined with a statistical model of the term structure of gas volatility to simulate the uncertainty in the annual cost of gas at various times during its procurement.

- Generation planning for utilities has become very complex and risky due to high natural gas prices and potential CO2 restrictions of emission allowances. Some of the scenarios that must be considered would radically alter system operations relative to current patterns of use. Mr. Graves has assisted utilities with long range planning for how to measure and cope with these risks, including what kinds of regulatory communications to pursue to manage expectations in this difficult environment.

- Several utilities with coal-fired power plants have faced allegations from the U.S. EPA that they have conducted past maintenance on these plants which should be deemed "major modifications", thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. For another utility, Mr. Graves developed retrospective estimates of changes in emissions before and after repairs using production costing simulations. In a third, he reviewed contemporaneous corporate planning documents to show that no increase in emissions would have been expected from the repairs, due to projected reductions in future use of the plant as well as higher efficiency. In all three cases, testimony was presented.

- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but it has not fulfilled this duty. As a result, nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared testimony on the incremental costs being borne by three nuclear operating companies with shutdown units as a result of this federal failure to perform.

- Capturing the full value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable market prices.

- The impacts of transmission open access and generation competition on utility financial health are well documented. In addition, there substantial impacts on fuel suppliers, due to revised dispatch, repowerings and retirements, changes in expansion mix, and altered load shapes and load growth under more competitive pricing. For EPRI, Mr. Graves contributed to a study that projected changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.

- Mr. Graves led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of its traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas program also included numerous adjustments to the gas company's rate design, such as designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.

- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.

- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive.

Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.

- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.

- Mr. Graves helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probable need.

- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. The tariff design, a commodity charge on a per-cash-in/cash-out at spot market gas prices with penalties for very deep imbalances, or an incremental storage inventory and withdrawal capacity used on-peak, were shown to be cheaper, more efficient, and less complex to administer. This analysis helped the parties reach a settlement based on the cash-in/cash-out design.

- The Clean Air Act Amendment authorized electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO_2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers or SCRs, until the present value cost of such investments is significantly below that projected from relying on EAs.

- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a major reorganization. The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.

- Mr. Graves helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.

- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.

- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves designed and supervised market analyses that compared the marginal operating costs of all power plants not needed to meet target reserves to the marginal costs for 50 to 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.

- Mr. Graves specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.

- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies affect the relative attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe "front end load" while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This "value of service" framework was generalized for the Electric Power Research Institute.

- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.

- For a major electronic and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.

- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.

- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. Planning tools were developed for balancing gas portfolios to customer group demands.

- For a Midwestern electric utility, Mr. Graves extended a regulatory *pro forma* financial model to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).

- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.

- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial *pro forma* simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.

- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and local taxpayers.

Electric and Gas Transmission

- For a utility seeking FERC approval for the purchase of an affiliate's generating facility, Mr. Graves analyzed how transmission constraints affecting alternative supply resources altered their usefulness to the buyer.

- As part of a generation capacity planning study, he lead an analysis of how congestion premiums and discounts relative to locational marginal prices (LMPs) at load centers affected the attractiveness of different potential locations for new generation. At issue was whether the prevailing LMP differences would be stable over time, as new transmission facilities were completed, and whether new plants could exacerbate existing differentials and lead to degraded market value at other plants.

- Mr. Graves assisted a genco with its involvement in the negotiation and settlement of "regional through and out rates" (RTOR) that were to be abolished when MISO joined PJM. His team analyzed the distribution of cost impacts from several competing proposals, and they commented on administrative difficulties or advantages associated with each.

- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to assess the inadequacies in the physical capabilities and economic incentives to manage voltages at adequate levels. The *Brattle* team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.

- Mr. Graves conducted a cost-of-service analysis for the pricing of ancillary services provided by the New York Power Authority.

- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves wrote a primer on how to define and measure the cost of electric utility transmission capacity for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the estimation of marginal costs of transmission. The implications for a variety of policy issues are also discussed.

- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves worked to develop alternative pricing mechanisms and service mixes for pipelines that would provide more dynamically efficient signals and incentives.

- Mr. Graves analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result from a proposed unbundling of services.

PROFESSIONAL MEMBERSHIPS

IEEE Power Engineering Society
Mathematical Association of America
American Finance Association
International Association for Energy Economics
Energy Modeling Forum (Stanford University)

EXPERT TESTIMONY

Oral direct testimony in the United States Court of Federal Claims (No. 04-106C), on behalf of plaintiff Dairyland Power Cooperative in regard to the Government's performance in accepting spent nuclear fuel under contractual obligations established in 1983, July 17, 2008.

Direct testimony for Delmarva Power & Light on risk characteristics of a possible managed portfolio for Standard Offer Service for residential and small commercial and industrial customers as part of Delmarva's IRP filings (PSC Docket No. 07-20), March 20, 2008 and May 15, 2008.

Direct testimony before the Public Service Commission of Maryland on behalf of Potomac Electric Power Company and Delmarva Power & Light Company, Case No. 9117, September 14, 2007, regarding portfolio management alternatives for supplying Standard Offer Service.

Direct testimony before the Arizona Commerce Commission on behalf of New West Energy Corporation, Docket No. E-03964A-06-0168, August 31, 2007, in regard to preconditions for effective retail electric competition.

Direct and rebuttal testimony before the Corporation Commission of the State of Oklahoma, Case No. PUD 200700012, January 17, 2007 and June 18, 2007, on behalf of Oklahoma Gas & Electric Company (OG&E) regarding the application of OG&E for an order of commission granting preapproval to construct Red Rock Generating Facility and authorizing a recovery rider.

Testimony in U.S. District Court of New York SI:04Cr733 (TPG), on behalf of defendant Mark Kaiser in regard to whether defendant's role in accounting misrepresentations could be reliably associated with losses to shareholders.

Rebuttal testimony before the Illinois Commerce Commission on behalf of Midwest Generation EME L.L.C. and Edison Mission Marketing and Trading, Docket Number 06-0800, April 6, 2007, on whether proposed benchmarks for evaluating the Illinois retail supply auctions are reasonable and useful.

Direct and rebuttal testimony before the United States District Court, Southern District of Texas, Houston Division, on behalf of the U.S. Department of Justice, Criminal Number H-03-217, September 12, 2006, on the shareholder impacts of Dynegy's Project Alpha for the sentencing of Jamie Olis.

Direct and rebuttal testimony before the Pennsylvania Public Utility Commission, Docket Nos. R-00061366 and R-00061367, August 24, 2006, on the need for POLR rate cap relief for Metropolitan Edison and Pennsylvania Electric, and the prudence of their past supply procurement for those obligations, on behalf of FirstEnergy Corp.

Direct testimony before the United States District Court, Southern District of Texas, Houston Division, on behalf of the Deutsche Bank Entities, Docket No. H-01-3624, February 2006, regarding Deutsche Bank Entities' opposition to Enron Corp's amended motion for class certification.

Expert report and rebuttal report before the United States Court of Federal Claims on behalf of Pacific Gas and Electric Company, Docket No. 04-0074C, into which has been consolidated No. 04-0075C, November 2005, regarding the non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Direct testimony before the Illinois Commerce Commission on behalf of Midwest Generation EME, LLC, Docket No. 05-0159, June 8, 2005, regarding the appropriate load caps for a POLR auction.

Affidavit to the Federal Energy Regulatory Commission on behalf of Dominion Energy, Inc., Docket No. EC05-43-000, April 11, 2005, regarding unmitigated market power concerns arising from the Exelon – PSEG Merger.

Expert and rebuttal reports and oral testimonies before the American Arbitration Association on behalf of Liberty Electric Power, LLC, Case No. 70 198 4 00228 04, December 2004, regarding damages under termination of a long-term tolling contract.

Oral direct and rebuttal testimony before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, Docket No. 98-154 C, July 2004 (direct) and August 2004 (rebuttal), regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Direct, supplemental and rebuttal testimony before the Public Service Commission of Wisconsin, on behalf of Wisconsin Public Service Corporation and Wisconsin Power and Light Company, Docket No. 05-EI-136, February 27, 2004 (direct), May 4, 2004 (supplemental) and May 28, 2004 (rebuttal) in regard to the benefits of the proposed sale of the Kewaunee nuclear power plant.

Direct and rebuttal testimony before the Public Utility Commission of Texas on behalf of CenterPoint Energy Houston Electric LLC, Reliant Energy Retail Services LLC, and Texas Genco LP, Docket No. 29526, March 2004 (direct) and June 2004 (rebuttal), in regard to the effect of Genco separation agreements and financial practices on stranded costs and on value of control premiums implicit in Texas Genco Stock price.

Rebuttal and additional testimony before the Illinois Commerce Commission, on behalf of Peoples Gas Light and Coke Company, Docket No. 01-0707, November 2003 (rebuttal) and January 2005 (additional rebuttal), in regard to prudence of gas contracting and hedging practices.

Rebuttal testimony before the State Office of Administrative Hearings on behalf of Texas Genco and CenterPoint Energy, Docket No. 473-02-3473, October 23, 2003, regarding proposed exclusion of part of CenterPoint's purchased power costs on grounds of including "imputed capacity" payments in price.

Rebuttal testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Ameren Energy Generating Company and Union Electric Company, Docket No. EC03-53-000, October 6, 2003, in regard to evaluation of transmission limitations and generator responsiveness in generation procurement.

Rebuttal testimony before the New Jersey Board of Public Utilities on behalf of Jersey Central Power & Light Company, Docket No. ER02080507, March 5, 2003, regarding the prudence of JCP&L's power purchasing strategy to cover its provider-of-last-resort obligation.

Oral testimony (February 17, 2003) and expert report (April 1, 2002) before the United States District Court, Southern District of Ohio, Eastern Division on behalf of Ohio Edison Company and Pennsylvania Power Company, Civil Action No. C2-99-1181, regarding coal plant maintenance projects alleged to trigger New Source Review.

Expert Report before the United States District Court on behalf of Duke Energy Corporation, Docket No. 1:00CV1262, September 16, 2002, regarding forecasting changes in air pollutant emissions following coal plant maintenance projects.

Direct testimony before the Public Utility Commission of Texas on behalf of Reliant Energy, Inc., Docket No. 26195, July 2002, regarding the appropriateness of Reliant HL&P's gas contracting, purchasing and risk management practices, and standards for assessing HL&P's gas purchases.

Direct and rebuttal testimonies before the Public Utilities Commission of the State of California on behalf of Southern California Edison, Application No. R. 01-10-024, May 1, 2002, and June 5, 2002, regarding Edison's proposed power procurement and risk management strategy, and the regulatory guidelines for reviewing its procurement purchases.

Rebuttal testimony before the Texas Public Utility Commission on behalf of Reliant Resources, Inc., Docket No. 24190, October 10, 2001, regarding the good-cause exception to the substantive rules that Reliant Resources, Inc. and the staff of the Public Utility Commission sought in their Provider of Last Resort settlement agreement.

Direct testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Northeast Utilities Service Company, Docket No. ER01-2584-000, July 13, 2001, in regard to competitive impacts of a proposed merchant transmission line from Connecticut to Long Island.

Direct testimony before the Vermont Public Service Board on behalf of Vermont Gas Systems, Inc., Docket No. 6495, April 13, 2001, regarding Vermont Gas System's proposed risk management program and deferred cost recovery account for gas purchases.

Affidavit on behalf of Public Service Company of New Mexico, before the Federal Energy Regulatory Commission (FERC), Docket No. ER96-1551-000, March 26, 2001, to provide an updated application for market based rates.

Affidavit on behalf of the New York State Electric and Gas Corporation, April 19, 2000, before the New York State Public Service Commission, *In the Matter of Customer Billing Arrangements*, Case 99-M-0631.

Supplemental Direct and Reply Testimonies of Frank C. Graves and A. Lawrence Kolbe (jointly) on behalf of Southern California Edison Company, Docket Nos. ER97-2355-00, ER98-1261-000, ER98-1685-000, November 1, 1999, regarding risks and cost of capital for transmission services.

Expert report before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, *Connecticut Yankee Atomic Power Company, Plaintiff v. United States* *of America,* No. 98-154 C, June 30, 1999, regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Maine Yankee Atomic Power Company, *Maine Yankee Atomic Power Company, Plaintiff v. United States of America,* No. 98-474 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.

Expert report before the United States Court of Federal Claims on behalf of Yankee Atomic Electric Company, *Yankee Atomic Electric Company, Plaintiff v. United States of America,* No. 98-126 C, June 30, 1999, regarding the damages from non-performance of the U.S. Department of Energy in accepting spent nuclear fuel and high-level waste under the terms of its contract.
Prepared direct testimony before the Federal Energy Regulatory Commission on behalf of National Rural Utilities Cooperative Finance Corporation, Inc., *Cities of Anaheim and Riverside, California v. Deseret Generation & Transmission Cooperative,* Docket No. EL97-57-001, March 1999, regarding cost of service for rural cooperatives versus investor-owned utilities, and coal plant valuation.

Expert report and oral examination before the Independent Assessment Team for industry restructuring appointed by the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation, January 1999, regarding the cost of capital for generation under long-term, indexed power purchase agreements.

Oral testimony before the Commonwealth of Massachusetts Appellate Tax Board on behalf of Indeck Energy Services of Turners Falls, Inc., *Turners Falls Limited Partnership, Appellant vs. Town of Montague, Board of Assessors, Appellee,* Docket Nos. 225191-225192, 233732-233733, 240482-240483, April 1998, regarding market conditions and revenues assessment for property tax basis valuation.

Direct and joint supplemental testimony before the Pennsylvania Public Utility Commission on behalf of Pennsylvania Electric Company and Metropolitan Edison Company, No. R-00974009, *et al.,* December 1997, regarding market clearing prices, inflation, fuel costs, and discount rates.

Direct Testimony before the Pennsylvania Public Utilities Commission on behalf of UGI Utilities, Inc., Docket No. R-00973975, August 1997, regarding forecasted wholesale market energy and capacity prices.

Testimony before the Public Utilities Commission of the State of California on behalf of the Southern California Edison Company, No. 96-10-038, August 1997, regarding anticompetitive implications of the proposed Pacific Enterprises/ENOVA mergers.

Direct and supplemental testimony before the Kentucky Public Service Commission on behalf of Big Rivers Electric Corporation, No. 97-204, June 1997, regarding wholesale generation and transmission rates under the bankruptcy plan of reorganization.

Affidavit before the Federal Energy Regulation Commission on behalf of the Southern California Edison Company in Docket No. EC97-12-000, March 28, 1997, filed as part of motion to intervene and protest the proposed merger of Enova Corporation and Pacific Enterprises.

Direct, rebuttal, and supplemental rebuttal testimony before the State of New Jersey Board of Public Utilities on behalf of GPU Energy, No. EO97070459, February 1997, regarding market clearing prices, inflation, fuel costs, and discount rates.

Oral direct testimony before the State of New York on behalf of Niagara Mohawk Corporation in *Philadelphia Corporation, et al., v. Niagara Mohawk*, No. 71149, November 1996, regarding interpretation of low-head hydro IPP contract quantity limits.

Oral direct testimony before the State of New York on behalf of Niagara Mohawk Corporation in *Black River Limited Partnership v. Niagara Mohawk Power Corporation*, No. 94-1125, July 1996, regarding interpretation of IPP contract language specifying estimated energy and capacity purchase quantities.

Oral direct testimony on behalf of *Eastern Utilities Associates* before the Massachusetts Department of Public Utilities, No. 96-100 and 2320, July 1996, regarding issues in restructuring of Massachusetts electric industry for retail access.

Affidavit before the Kentucky Public Service Commission on behalf of *Big Rivers Electric Corporation* in PSC Case No. 94-032, June 1995, regarding modifications to an environmental surcharge mechanism.

Rebuttal testimony on behalf of utility in *Eastern Energy Corporation v. Commonwealth Electric Company*, American Arbitration Association, No. 11 Y 198 00352 04, March 1995, regarding lack of net benefits expected from a terminated independent power project.

Direct testimony before the Pennsylvania Public Utility Commission on behalf of Pennsylvania Power & Light Company in *Pennsylvania Public Utility Commission et al. v. UGI Utilities, Inc.*, Docket No. R-932927, March 1994, regarding inadequacies in the design and pricing of UGI's proposed unbundling of gas transportation services.

Direct testimony before the Pennsylvania Public Utility Commission, on behalf of Interstate Energy Company, *Application of Interstate Energy Company for Approval to Offer Services in the Transportation of Natural Gas*, Docket No. A-140200, October 1993, and rebuttal testimony, March 1994.

Direct testimony before the Pennsylvania Public Utility Commission, on behalf of Procter & Gamble Paper Products Company, *Pennsylvania Public Utility Commission v. Pennsylvania Gas and Water Company*, Docket No. R-932655, September 1993, regarding PG&W's proposed charges for transportation balancing.

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[Company Exhibit 8]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant To R.C. § 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 08-_____-EL-SSO

DIRECT TESTIMONY OF

MICHAEL J. VILBERT

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

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I. INTRODUCTION AND SUMMARY

Q1. Please state your name and address for the record.

A1. My name is Michael J. Vilbert. My business address is The Brattle Group, 44 Brattle Street, Cambridge, MA 02138, USA.

Q2. Please describe your job and educational experience.

A2. I am a Principal of The Brattle Group, ("Brattle"), an economic, environmental and management consulting firm with offices in Cambridge, Washington, London, San Francisco and Brussels. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy and a Ph.D. in finance from the Wharton School of Business at the University of Pennsylvania.

Q3. What is the purpose of your testimony in this proceeding?

A3. I have been asked by the FirstEnergy Company to address provisions of the Am. Substitute Senate Bill No. 221 ("S.B. 221") with regard to the significantly excessive earnings test within the meaning of Section 4928.143(F) of the Revised Code ("R.C.") for a utility's Electric Security Plan ("ESP"). Specifically, I propose a method of implementing the significantly excessive earnings test that provides a statistical test consistent with the language of the statute.

Q4. Are you intending to provide legal interpretation of the statutory requirements?

A4. No. Nothing in my testimony is intended to imply a legal opinion. The statute mandates an evaluation of an Ohio electric utility's earnings which involves consideration of economic and financial principles. As an expert in financial and regulatory economics, I am offering guidance as to how such an evaluation should be undertaken with proper application of these principles.

Q5. Please summarize your testimony.

A5. S.B. 221 mandates an annual test to determine whether the electric utilities in Ohio have earned significantly excessive earnings compared to other publicly traded companies of comparable business and financial risk, but the legislation does not specify how this test is to be performed. It is important that the test be well designed.

A poorly designed test for significantly excessive earnings could impose asymmetric risk on the electric utilities and could discourage the utilities from pursuing measures that would increase the efficiency of their service, because any increase in profits from such efficiency measures may result in a determination of significantly excessive earnings.

My testimony proposes a test that provides an economic interpretation of the language of statute. The test is relatively easy to apply and uses readily available information. The test also mitigates the potential to impose asymmetric risk on the utilities by guarding against incorrectly determining that significantly excessive earnings have occurred. If asymmetric risk were imposed upon the utilities, it would require an increase in the utilities' allowed returns so that they could again expect to earn their cost of capital on average.

Q6. Are you sponsoring any attachments to the filing?

A6. Yes. I am sponsoring Attachment H to the extent that it addresses matters within the scope of my testimony with regard to the economic interpretation of the significantly excessive earnings portion of the statute. In particular, I do not sponsor that portion of Attachment H which addresses the adjustment to earnings pursuant to paragraph A.3.f. of the Plan. That is sponsored by Mr. David Blank.

II. PROPOSED TEST OF SIGNIFICANTLY EXCESSIVE EARNINGS

A. Test Outline

Q7. Please outline the method you propose.

A7. The annual test of significantly excessive earnings compares the utility's earnings to the average earned return of companies that have comparable business risk to the utility, making appropriate adjustments for differences in capital structure. The utility's earnings may be deemed significantly excessive if they are greater than a threshold that is significantly higher than the average return earned by comparable companies.

Q8. Is the earned return on equity ("ROE") an accounting measure of return on book equity or a return on the market value of equity?

A8. The law uses the term "earnings," which indicates that it envisions an accounting measure of the return on the utility's book value of equity: "... the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings ...."[1] In addition, the statute specifically requires that the "revenues, expenses, or earnings of any affiliate or parent company" not be considered in implementing the test of significantly excessive earnings.[2] As a result, if the utility is not itself publicly traded, its ROE measure can only be based on accounting data.

Q9. What is the implication of the measure of return for the utility being an accounting-based return on book equity?

A9. The implication is that the test of significantly excessive earnings for the sample of companies of comparable business and financial risk should also be based upon a measure of the accounting-determined return on equity. Otherwise the test would not be evaluating comparable measures of earnings. This point is discussed in more detail below.

Q10. What metric do you have in mind when testing for "significantly excessive earnings"?

A10. The statute is not explicit in defining the term, but I interpret the language as suggesting two characteristics that should be incorporated into the test. First, economists frequently refer to a test result that is "statistically significant" at some confidence level. "Significantly" excessive therefore suggests a statistical test is appropriate. Second, significantly "excessive" implies earnings well beyond what is normal, proper and reasonable. The language seems to recognize that there will be fluctuations in earned returns due to normal variations in economic conditions so that simply earning more than authorized would not reach the level of being significantly excessive. As discussed below, it is important to avoid erroneously concluding that

[1] R.C. 4928.143(F).

[2] R.C. 4928.143(F).

significantly excessive earnings have occurred because of the negative incentive signal it would send to the utility as well as because it would impose asymmetric risk on the utility.

B. EARNINGS METRIC

Q11. What measure of return on equity do you use for the sample companies?

A11. I use an accounting measure of return on equity, which I then adjust for differences in capital structure between sample companies, as required by the statute. As a measure of the earnings that accrue to shareholders, I rely on net income before non-recurring gains or losses. As a measure of shareholders' equity, I use the average of the beginning-of-year and end-of-year book value of equity from each company's balance sheet, as reported by *Value Line*.

Q12. Why do you rely on accounting values rather than market values?

A12. I use book values because it is the only possibility consistent with the language of the law. Specifically, the statute reads: "In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expenses, or earnings of any affiliate or parent company."[3] Most electric utilities operating in Ohio are subsidiaries of larger companies so they are not themselves publicly traded. This is true for FirstEnergy's subsidiaries that operate in Ohio. It is therefore not possible to construct a market-based measure of earnings for the utility, without relying on information of its parent company. As noted above, the law uses the term "earnings," which indicates that it envisions an accounting measure of the return on the utility's book value of equity.

Q13. But could you not use market values for the set of comparable companies?

A13. Yes, but in that case a comparison would have to be made between an accounting measure of returns for the utility, and a market-based measure of returns for the sample companies. Such a comparison cannot be properly made in the case of earned returns. A company's stock return, the market-based measure of return, is driven not only by realized earnings, but also, or even mostly, by expectations about future

[3] R.C. 4928.143(F).

earnings. To the contrary, an accounting measure of return, such as net income divided by common equity, does not capture expectations about future earnings. It is therefore inappropriate to base the test of significantly excessive earnings comparing book-based with market-based measures of earned returns. Indeed, the statute itself makes reference to historical rather than forward-looking measures of return.[4]

Q14. How is this different from setting the allowed ROE based on market measures of returns?

A14. The key difference is that the allowed ROE is set equal to the *expected* rate of return on equity, whereas in the current matter, the test of significantly excessive earnings must be based on *earned*, or realized, returns. The expected rate of return is the rate that investors can expect to obtain by financing investments of comparable risk, and it is determined in the market. The allowed ROE is therefore set equal to this expectation, in order to allow the utility to attract investors, who would otherwise invest in these alternative investments. The only way to estimate expectations about the future is to use information embedded in stock prices, which by their very nature reflect the information and beliefs investors currently hold about future cash flows. In the case of a test of significantly excessive earnings, which considers what the utility and comparable firms have earned in the past year, there is no need to measure expectations, and therefore no need to rely on stock prices. It would be particularly inappropriate to compare an accounting measure of returns for the utility, which does not incorporate expectations about future performance, with a measure based on stock prices for the sample companies, which does incorporate such expectations.

Q15. More specifically, what metric are you proposing?

A15. I propose (and have implemented, as an illustration) a measure of return on total capital equal to the ratio of total ordinary return to long-term capital (including debt and preferred equity), less tax shields generated by the use of debt, divided by total long-term capital. The numerator of this fraction is therefore the sum of two items: earnings on equity before non-recurring items and pre-tax interest expense on long-

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[4] R.C. 4928.143(F).

term debt multiplied by one minus the effective tax rate for each individual company.[5] The denominator is the sum of average shareholders' equity (including preferred equity) and average long-term debt for the year under analysis:

$$R = \frac{(NI - Nonrec) + (1-t)LT\ Int}{Average\ Total\ Capital}$$

where:

- NI = Net Income (including dividends paid to preferred stock, if any)
- *Nonrec* = Nonrecurring gains/losses
- t = Effective marginal tax rate
- *LT Int* = Interest expense on long-term debt
- *Average Total Capital* = the sum of common equity, preferred equity and long-term debt, computed as an average of the beginning-of-year and end-of-year values.[6]

Q16. Why do you add the interest expense multiplied by (1-*t*)?

A16. I add the interest expense because it is the return obtained by debt holders. I multiply by (1-*t*) in order to eliminate the effect of tax shields created by the use of debt in the capital structure. The effect of adding this term is to account for differences in capital structure between companies, as indicated by the statute language requiring "adjustments for capital structure as may be appropriate."[7] Simply comparing the return on equity between companies with very different equity ratios is not meaningful. Companies with very little equity should earn a higher return on equity reflecting higher financial risk, while companies with comparable business risk, but much higher equity ratios should earn a lower return on equity. In order to arrive at a figure that can be meaningfully compared, I compute the surplus that would accrue to shareholders if each company were financed entirely by equity. This entails adding

[5] The tax rate information is from *Value Line* and relies on the effective tax rate.

[6] Appendix B contains a detailed discussion of the exact *Value Line* items used to compute the earnings metric.

[7] R.C. 4928.143(F).

the interest expense, but subtracting the income tax that would be payable in that case, since interest expense is tax deductible, but earnings are not.

Q17. Can you provide an example of why it is necessary to consider differences in capital structure to insure consistency between sample companies of comparable business risk?

A17. Yes. Consider two companies that are identical in every way except for their capital structures, such as the two hypothetical companies shown in Table 1 below.

Table 1. *Effect of the Capital Structure Adjustment.*

	Company 1 100% Equity Ratio	Company 2 50% Equity Ratio	Formulas
[1] Total Capital	10,000	10,000	
[2] Debt	0	5000	
[3] Equity	10,000	5,000	[1]-[2]
[4] Cost of Debt	6%	6%	
[5] EBIT	1,500	1,500	
[6] Interest Expense	0	300	[2]x[4]
[7] Pretax income	1500	1200	[5]-[6]
[8] Tax Rate	40%	40%	
[9] Total Tax	600	480	[7]x[8]
[10] Net Income	900	720	[7]-[9]
[11] Return on Equity (without capital structure adjustment)	9.00%	14.40%	[10]/[3]
[12] Return on Total Capital (without tax shield adjustment)	9.00%	10.20%	([10]+[6]) / [1]
[13] Return on Total Capital (with tax shield adjustment)	9.00%	9.00%	([10] + (1-[8]) x [6]) / [1]

Assume that both have Earnings before Interest and Taxes ("EBIT") of $1500, but that one is financed entirely with equity while the other has interest expense of $300. After-tax net income for the all equity financed company is $900 assuming a 40 percent income tax rate, but after-tax net income for the debt financed company is $720 (($1500 EBIT - $300 interest) x (1 – 40% tax rate)). As shown is row [11] of Table 1, simply computing the return on equity would suggest that Company 2 is more profitable, since its ROE is 14.4 percent compared to the 9 percent of Company

1. However, the difference in ROEs is simply a reflection of the different capital structures, not of the underlying profitability of the company. Adjusting for these differences is the reason why I rely on a measure of return on total capital instead of simply realized return on equity, following the requirement of the statute that such an adjustment is necessary.[8]

However, as shown in row [12] of Table 1 if the full amount of interest were used in computing the return on total capital, the result would be $1020 ($720 net income + $300 interest expense) compared to the $900 for the all-equity financed firm. Therefore, the measure of return on total capital would suggest that the debt-financed firm also had a greater rate of return on total capital but that also would be incorrect. The after-tax interest expense would be $180 ($300 x (1- tax rate of 40%)) for a total of $900 ($720 net income + $180 after-tax interest expense). As shown in row [13] of Table 1, the use of the after-tax interest expense instead of the full interest expense results in an identical return on total capital for both companies identical in all ways except capital structure.

Q18. Why do you use the average total capital for the year, instead of the end-of-year balances?

A18. The average of the beginning-of-year and end-of-year balances for capital items gives a better measure of the company's capital during the entire year over which earnings have been earned. Using the average reduces the impact of issuing or retiring debt or equity during the year, which could bias the rate of return calculation.

Q19. Why do you eliminate nonrecurring gains and losses from net income?

A19. I eliminate these items because the purpose of using a sample of comparable companies is to obtain a measure of normal, or usual, earned returns – in other words, a measure of ordinary, recurring, returns that have been earned by companies similar to the utility under analysis. Simply put, eliminating non-recurring items from the comparable companies' earnings measure ensures a higher degree of comparability.

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[8] R.C. 4928.143(F).

Q20. Should these items also be excluded from the measure of return computed for the utility under analysis?

A20. It depends. The purpose of the test is to identify significantly excessive, windfall profits. If such profits would be classified by accounting rules as extraordinary or nonrecurring items, or are otherwise non-representative of the utility's operations, then they should also be excluded from the measure for the utility in order to maintain comparability with the sample. An example may be a large gain or loss caused by non-regulatory actions such as the gain on the sale of non-regulated assets. Because these assets are not part of the rate base, they have not been financed by ratepayers, but by shareholders. Any gains or losses should then accrue to the shareholders, whether they are large or small. On the other hand, an extraordinary gain or loss that was an unintended consequence of some regulatory action should be included in the analysis.

Q21. Is it likely that any of the Ohio EDUs may have some non-recurring expenses in the future?

A21. Yes. The testimony of Mr. Harvey L. Wagner discusses the possibility that the Ohio EDUs may write off a substantial amount of goodwill as a result of applying the asset impairment provisions of applicable financial accounting standards.

Q22. If the utility were to write off a large amount of equity from its balance sheet, how might the write-off affect the test for significantly excessive earnings?

A22. A write-off would reduce the size of the denominator in the return on total assets metric which would increase the likelihood of a determination of significantly excessive earning even though nothing has changed in the amount that the utility has earned.

Q23. What do you recommend to mitigate the possibility of an incorrect determination of significantly excessive earnings in a situation such as this?

A23. I recommend that the amount of the write-off be added back to the denominator for purposes of the test. In this way, the possibility of a false positive in the test is reduced to the situation existing before the write-off.

C. Comparable Companies

Q24. How did you select the sample of companies of comparable business and financial risk?

A24. I select the sample based only on business risk similarities, and then take capital structure differences into account by adjusting the measure of return on capital, as discussed above. Differences in financial risk result from differences in capital structure. By using a measure of returns that attempts to control for such differences, there is less need to restrict the sample based on capital structure. This is an enormous advantage, because imposing a restriction that all companies in the sample have approximately the same capital structure as the target utility would reduce the number of sample companies substantially, making the resulting estimate much less precise.

Q25. How did you select companies of comparable business risk?

A25. The law does not restrict the universe of comparable companies to regulated utilities. Indeed, the statute appears to suggest that a larger universe should be considered, "including utilities."[9] Therefore I considered the following important characteristics of an electric distribution industry: sample companies should operate in industries that (1) rely on a network of assets to provide services to a customer mix that includes residential, commercial and industrial customers, and (2) that exhibit high capital intensity. Capital intensity means that the capital investment required for each dollar of revenue is high. Based on the first of these two characteristics, I started with a universe of ten industries as classified by *Value Line*: Electric Utilities[10], Natural Gas Utilities, Oil and Gas Distribution, Water Utilities, Environmental Services[11], Railroads, Air Transportation, Trucking, Cable TV, and Telecommunication Services.

Q26. How did you narrow the number of industries in your final sample?

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[9] R.C. 4928.143(F).

[10] Electric Utilities are divided by *Value Line* into three groups based on geographical area of operation: East, Central, and West.

[11] The Environmental Services industry contains primarily waste management companies.

A26. I computed an industry average measure of capital intensity[12], based on the previous three years of data (fiscal years 2005-2007), and eliminated industries exhibiting low values for this metric. The remaining group of industries includes Electric Utilities, Natural Gas Utilities, Oil and Gas Distribution, Water Utilities, Environmental Services, Railroads, and Telecommunication Services. Appendix B contains additional details about the sample selection procedure, as well as industry statistics for the industries includes in the final sample.

Q27. Did you apply additional criteria to eliminate some companies from the industries remaining in the sample?

A27. Yes. Before calculating the capital intensity measure, I eliminated companies with a credit rating below investment grade, foreign companies, as well as companies for which the information necessary to compute the asset turnover measure was not available. The data were extracted from the *Value Line Investment Analyzer*.[13] The sample contains 80 companies.

Q28. Is this the same sample you used to compute the threshold for significantly excessive earnings?

A28. Not exactly. In order to arrive at the measure of asset turnover, I had to use additional data fields not required for the return on total capital calculation. As a result, there are minor differences between the sample used to select the capital intensive industries, and that used to compute the earnings metric. Table 2 below lists all the industries considered, as well as the number of companies in each industry that was included in either calculation. Table B-4 in Appendix B lists the individual companies that were included in each calculation.

[12] The measure I used was asset turnover, equal to the ratio of revenues to total assets. The resulting value gives a measure of how much revenue is generated by each dollar of assets. Larger values indicate lower capital intensity.

[13] The last update before the data were extracted was performed on June 6, 2008.

Table 2. Sample Industries

Industry	Number of Companies in Capital Intensity Calculation	Number of Companies in Earnings Threshold Calculation
Electric Utilities		
ELECTRIC UTIL.- CEN	19	19
ELECTRIC UTIL.- EAST	17	17
ELECTRIC UTIL.- WEST	11	11
Electric Utilities	***47***	***47***
Other Regulated Utilities		
NATURAL GAS UTILITY	8	8
WATER UTILITIES	2	2
OIL/GAS DISTRIB	6	7
All Regulated Utilities	***63***	***64***
Other Capital Intensive Industries		
RAILROAD	4	4
TELECOM. SERVICES	2	3
ENVIRONMENTAL	3	3
All Capital Intensive Industries	***72***	***74***
Other Industries		
AIR TRANSPORT	3	3
TRUCK'G/TRANSP LEASE	4	3
CABLE TV	1	0
All Industries	***80***	***80***

Q29. Do you have any additional comments about the sample?

A29. Yes. Both the sample containing the initial range of industries and the subset of more capital intensive industries are dominated by electric utilities (47 companies out of 80 and respectively 74 companies). Moreover, 64 companies operate in regulated industries. The large fraction of regulated companies and electric utilities in particular gives a high degree of confidence in the sample being of comparable business risk with an electric utility. At the same time, including some unregulated companies in comparable industries is not only consistent with the language used in the statute but also provides that a larger number of estimates is considered. A larger sample will smooth out fluctuations from an industry group or subset of companies with unusual returns in a particular year.

Q30. Have you considered the effect of including in your sample electric utilities that derive a large part of their earnings from unregulated generation?

A30. Yes. Including companies with unregulated segments is not in itself a reason for concern, since the statute itself envisions looking beyond regulated utilities for a comprehensive sample of comparable companies. However, there could be a legitimate concern that the volatility of generation revenues is higher than that of regulated electric distribution companies, and therefore that the returns of companies that invest heavily in electric generation may not be comparable. In order to gauge whether this is in fact the case, I also computed rate of return thresholds for a subsample of companies that excludes those electric utilities classified by the *Edison Electric Institute* as "Diversified" or "Mostly Regulated."[14] Companies in these two categories have more unregulated assets that companies classified as "Regulated." As a result, eliminating these two categories will eliminate the electric companies with a substantial investment in unregulated generation.

Q31. Are the results obtained by excluding electric utilities with substantial unregulated operations materially different?

A31. No. The thresholds I obtained by excluding the Diversified and Mostly Regulated electric utilities are virtually identical to those obtained for the full sample. The numerical results are discussed in the next subsection. It should also be pointed out that focusing on a particular group of companies that have a high rate of return in a given year is not an appropriate basis for excluding them from the sample as being insufficiently comparable to the utility under analysis. Earned returns vary from year to year which is, in part, the rationale for the significantly excessive earnings test in the first place. Companies or industries that may have had a particularly good year recently may under-perform in the future. It is much more advisable to select sample companies based on characteristics of an operational and business risk nature, which remain unchanged over time as long as the company does not change its primary business.

[14] The EEI classifies utilities as "Diversified" if they have less than 50 percent of their assets in unregulated operations. The "Mostly Regulated" category includes utilities with between 50 and 80 percent regulated assets. The classifications for each company upon which I rely is provided in the Business Segmentation section of the 2008 *Q1 Financial Update* published by EEI, and available at http://www.eei.org/industry_issues/finance_and_accounting/finance/research_and_analysis/quarterly_financial_updates/index.htm. The EEI uses information as of December 31, 2007 to classify companies according to this criterion.

Q32. What data source are you using?

A32. All data are taken from *Value Line* except for the information on the corporate credit ratings, which can be extracted from the Mergent Bond Record, Standard & Poor's, Bloomberg or other sources. I used the *Value Line Investment Analyzer*, which provides electronic access to the historical data reported in the *Value Line* sheets. The analysis could be performed using only the printed *Value Line* sheets, but doing so would require manually collecting the necessary data. In addition, the data items reported in the printed sheets are not identical to the ones available in the historical database, so care should be taken that the correct information is used.

Q33. Are there any issues related to data availability that are important to discuss?

A33. Yes. *Value Line,* as do other reliable data providers, report data based on the fiscal year according to which each company operates. An important reason for this is that for most companies, only annual (fiscal year) financial statements are audited. In addition, there is a lag of up to three months between the end of the fiscal year and the time audited results become available. As a result, the test cannot be performed immediately after the end of each calendar year. This issue is explained in greater detail in Appendix B.

D. Significantly Excessive Earnings

Q34. After you have calculated the return on total capital for the sample companies, how do you propose to test for significantly excessive earnings?

A34. After calculating the return on total capital for the sample companies for the year, I calculate the sample mean and standard deviation of the data. I then propose a one-sided statistical test of significantly excessive earnings. If the earned rate of return on total capital of the utility exceeds the sample mean earned return on total capital by more than 1.28 standard deviations, then significantly excessive earnings may be indicated by the test.

Q35. Can the return threshold be expressed in terms of ROE, rather than return on total capital?

A35. Yes. Using the threshold return on total capital derived from the sample, a threshold ROE level can be determined using information about the utility's capital structure and its tax rate, interest expense, and preferred dividends. An example of how this transformation can be performed is provided in Appendix B.

Q36. Why did you select 1.28 standard deviations above the mean as the cutoff for determining significantly excessive earnings?

A36. For a normal distribution, 90 percent of the observations lie below 1.28 standard deviations above the mean. In other words, if a number were drawn at random from a normal distribution, only 10 percent of the time would the number be expected to be higher than 1.28 standard deviations above the mean. The 90 percent figure is typically referred to in the statistics literature as the confidence level used in hypothesis testing. Other commonly used confidence levels are 95 percent and 99 percent, but in most cases levels below 90 percent are not considered sufficiently reliable. The chosen confidence level determines how conservative the test is: a higher level ensures that fewer false positives are generated but also makes it more likely that the test does not identify significantly excessive earnings. Keeping in mind that 90 percent is the least acceptable level, and also that serious consequences result from an incorrect determination of significantly excessive earnings, I believe that a 90 percent confidence level is the smallest cutoff point that is appropriate to use in this test. This implies setting the threshold at a minimum of 1.28 standard deviations above the average sample returns.

Q37. What standard deviation cutoffs do these alternative confidence levels yield?

A37. Using a higher confidence level means that the return threshold is set farther above the sample average return. For example, using a 95 percent confidence level implies setting the threshold at 1.64 standard deviations above the average. Other common cutoffs are shown in Table 3 below.

Table 3. Standard Deviation Cutoffs at Different Confidence Levels

Confidence Level	90%	95%	97.5%	99%
Number of Standard Deviations for One-Sided Threshold	1.28	1.64	1.96	2.33

Q38. Under what conditions would you recommend using a higher confidence level?

A38. The lowest confidence level was chosen in recognition that the proposed sample contains companies from industries other than the electric utility industry. The 90 percent confidence level is the most conservative statistical test normally applied and has the effect of allowing more false positives than a higher confidence level.[15] I would use a higher confidence level if the sample were restricted to only regulated utilities because the distribution of returns for the sample would likely be less variable. In other words, if the sample companies were more comparable to an electric utility, it is likely that variations in earnings caused by factors not related specifically to the electric utility industry would be reduced. As a result, it is necessary to use a higher confidence level in order to determine that earnings in excess of that threshold could be significantly excessive. For example, if the sample were restricted to only electric utilities, the possibility of a false positive would be higher when using a lower confidence level. The variance of the sample returns would likely be smaller for a sample restricted to electric utilities which would substantially reduce the threshold for a determination of significantly excess profits. In that case, a higher confidence level such as 95 percent, 97.5 percent or even higher would be necessary in order to avoid deeming "significantly excessive" a return that is simply at the high end of the normal variation in returns that characterizes the operations of an electric utility.

Q39. But would it not then be better to use a sample that is as comparable as possible to an electric utility?

[15] I use the term "conservative" within the context of this proceeding. In the case of statistical hypothesis testing, a conservative confidence level would be one that is at the higher end of acceptable levels, such as 99 percent.

A39. Not necessarily. First, the statute refers to a sample of comparable companies "including regulated utilities." This language suggests that not only should the sample include utilities other than electric utilities, but also companies with unregulated operations. Second, it is impossible to select a sample of companies that is perfectly comparable to the utility under analysis. Differences will always exist even if attention is restricted to the same industry. As more industries are included in the sample, the sample may become less comparable to the specific company, but it may also be a better sample for the determination of significantly excessive earnings. However, there is no clear line that determines what an acceptable range of industries to consider may be. It is important however to be aware that changing the breadth of the sample needs to be taken into account when selecting an appropriate statistical confidence level. It would be inappropriate to change one without adjusting the other to reflect the different level of comparability between the sample companies.

Q40. Why is it important to guard against a false positive?

A40. A false positive means that the test incorrectly identifies the utility's earnings as significantly excessive. Although it is important to protect customers from paying rates that result in significantly excessive profits, it is also important to avoid a determination of significantly excessive profits when none were earned. Reducing the probability of false positives mitigates the problem of asymmetric risk, which is an important concern that needs to be addressed when implementing a test of significantly excessive earnings. In addition, incorrect determinations of significantly excessive earnings negatively affect the utility's incentives to operate efficiently.

Q41. Please describe what you mean by the term "asymmetric risk".

A41. Asymmetric risk is the situation in which the possibility of a bad outcome is not offset by the possibility of an equally good outcome. In general, a utility's earned ROE will deviate somewhat from the allowed ROE each year due to random fluctuations in costs and revenues: sometimes the earned ROE will be greater than allowed and sometimes it will be less. For an electric utility, a key reason for under or over-earning the allowed ROE is frequently due to fluctuating power prices or to differences between actual and forecast costs. If high power prices are reflected in rates with a delay, the result will often be that a utility's ROE is low in the current year, but higher than normal next year – simply because the costs of power are recovered with a delay. Under normal economic circumstances, these fluctuations offset each other over time, allowing the utility to earn its cost of capital on average. However, if the utility is erroneously determined to have significantly excessive earnings that must be refunded, the offsetting of high and low earnings over time no longer happens, and the utility will fail to earn its cost of capital on average. This situation would impose asymmetric risk on the utility because the utility receives no extra income in years of very low earnings, but must refund income when earnings are determined to be significantly excessive. If a utility faces asymmetric risk, its allowed return must be set above the estimated cost of capital by an amount that offsets the asymmetric risk so that the utility will again be able to expect to earn its cost of capital.

Imposing asymmetric risk on the utilities is an inappropriate regulatory outcome, and therefore not likely to be what the legislators had in mind. Instead, a determination of significantly excessive earnings, or windfall profits, should be reserved for the situation in which earnings exceed the allowed return by an amount so great as to not likely be the result of random fluctuations of a magnitude to be expected under normal situations. If such excessively high profits were not corrected, then the utility would be likely to earn a rate of return above its cost of capital. Such an outcome could be unfair to ratepayers, and it is this situation that the test should attempt to prevent.

Q42. Are there other problems with erroneously determining that significantly excessive earnings have occurred?

A42. Yes. Too many determinations of significantly excessive earnings can result in inefficient decision-making by the utility. All businesses have an incentive to reduce costs and to operate efficiently through the promise of higher profits. If the expectation of higher earnings disappears, so does the incentive to seek efficiencies that will ultimately benefit rate payers. An inefficient business means that obtainable gains are not realized, either by the shareholders or by the ratepayers. This is a "lose-lose" situation, which has no desirable features for any party.

Q43. You have assumed that the distribution of earned returns for the sample companies can be approximated by a normal distribution. What is the effect on the test if the earned returns were not normally distributed?

A43. If the returns were not normally distributed, the test would not have a precisely 90 percent confidence level. The area in the tails of the distribution could be somewhat more or less than expected for a normal distribution. In fact, a plot of the sample returns shows that the distribution is slightly skewed to the right (toward higher returns), implying that most likely the confidence level is somewhat lower than 90 percent. In other words, if the sample is not exactly normally distributed, then imposing the normal distribution is a conservative assumption in the sense that earnings are found to be excessive more often.

Q44. How would this threshold be used to determine the actual amount of significantly excessive earnings that must be returned to ratepayers?

A44. If the utility is determined to have earned significantly excessive earnings, then the amount of significantly excessive earnings would simply be computed by multiplying the total average capital by the difference between the threshold and the earned rate of return on total capital. Alternatively, if an ROE threshold has been computed using the utility's capital structure information, this can be used as well in similar fashion: the excess earnings would equal the amount of equity multiplied by the difference between the earned ROE and the threshold ROE.

Q45. Assuming that the utility's earnings fall above the threshold, are there any additional factors that need to be considered?

A45. If application of the formula outlined above suggests the utility's earnings may be significantly excessive, the Commission should scrutinize the utility's earnings for any unusual items. If the utility's earnings have fallen above the threshold, then the cause of the excessive earnings should be visible – i.e. the extra earnings should be attributable to a particular event experienced by the company during the year being tested, or to a particular earnings source. If no such item can be identified, the possibility that the determination of significantly excessive earnings is incorrect should be seriously contemplated. I note also that the language of the statute states that "Consideration shall also be given to the capital requirements of future committed investments in this state."[16] From the perspective of an expert in financial and regulatory economics, I believe these are appropriate factors to include in the consideration of whether significantly excessive earnings have been realized.

E. SAMPLE RESULTS

Q46. Based on the sample of comparable companies you selected, what values for the test did you obtain?

A46. Using data for the 2007 fiscal year, I obtained an average return on total capital equal to 8.60 percent with a standard deviation of 2.39 percent. If electric utilities classified as Diversified by the EEI are excluded, then the average return becomes 8.56 percent, with a standard deviation of 2.45 percent. Further excluding Mostly Regulated electric utilities yields an average return on total capital of 8.49 percent, and a standard deviation of 2.53 percent. The results are detailed in Table 4 below.

Q47. What thresholds do these numbers imply?

A47. If the determination is performed based on the full sample of capital intensive industries, then significantly excessive earnings may be found if the return on total capital were greater than or equal to 11.67 percent. Restricting the sample in the two ways described above imply thresholds of 11.70 percent and 11.73 percent respectively.

Q48. What ROE thresholds do these numbers imply?

A48. In order to determine a threshold in terms of ROE, one needs to use information about the utility's capital structure, tax rate, cost of debt and preferred equity. Assuming a 49 percent equity ratio, no preferred stock, a tax rate of 37.1 percent, and a cost of debt of 6.1 percent, I computed the implied ROE threshold at 19.88 percent for the

[16] R.C. 4928.143(F).

full sample of capital intensive industries, and 19.95 percent and 20.02 percent respectively for the two subsamples restricted using the EEI classification.

Q49. Which of these three thresholds do you find most reasonable?

A49. I believe that the result based on the full sample of capital intensive industries is more reliable. While eliminating electric utilities with more unregulated assets does not influence the results, using a larger sample provides a more reliable result, and is a better methodology to use going forward.

Table 4. Thresholds for Significantly Excessive Earnings.

Hypothetical Capital Structure Information		
Ohio EDUs Equity Ratio	0.49	[a]
Ohio EDUs Debt Ratio	0.51	[b]
Ohio EDUs Cost of Debt	6.00%	[c]
Ohio EDUs Tax Rate	37.1%	[d]
Statistical Significance Threshold	**90.0%**	[e]

Calculation of ROE Threshold		Capital Intensive *Industries*	Excluding Electric Utilities Classified "D" by EEI	Excluding Electric Utilities Classified "D" or "MR" by EEI
Sample Average Return on Total Capital	[1]	8.60%	8.56%	8.49%
Sample Standard Deviation	[2]	2.39%	2.45%	2.53%
Return on Total Capital Threshold	[3]	11.67%	11.70%	11.73%
Ohio EDUs D/E Ratio	[4]	1.04	1.04	1.04
ROE Threshold	[5]	**19.88%**	**19.95%**	**20.02%**

Sources and Notes:
[1]: Sample average of return on total capital for the corresponding sample.
[2]: Sample standard deviation of return on total capital for the corresponding sample.
[3] = [1] + 1.282 x [2].
[4] = [a] / [b].
[5] = [1] x (1 + [4]) - (1 - [d]) x [c] x [4].

Q50. How does the resulting ROE threshold depend on the utility's capital structure?

A50. While the return on total capital threshold is based only on the sample of comparable companies, and therefore not affected by the utility's capital structure, the ROE threshold depends on it. In general, a higher equity thickness lowers the ROE threshold, while a lower equity thickness tends to raise it. As an example, if the capital structure assumed for the utility were 55 percent instead of 49 percent, the implied ROE threshold based on the capital intensive sample would be 18.13 percent, or 175 basis points lower than the implied threshold at 49 percent equity. The thresholds that result at several other equity ratios are presented below in Table 5:

Table 5. Implied ROE Thresholds at Different Equity Ratios

Ohio EDUs Cost of Debt	6.00%				[1]
Ohio EDUs Tax Rate	37.1%				[2]
Equity	0.45	0.49	0.50	0.55	[3]
Debt-to-Equity ratio	1.22	1.04	1.00	0.82	[4] = (1-[3])/[3]
Return on Total Capital Threshold	11.67%	11.67%	11.67%	11.67%	[5]
Implied Return on Equity Threshold	21.31%	19.88%	19.56%	18.13%	[6] = [5]x(1+[4]) - (1-[2])x[4]x[1]

Q51. Does this conclude your testimony?

A51. Yes.

APPENDIX A

RESUME

MICHAEL J. VILBERT **PRINCIPAL**

Michael Vilbert is an expert in cost of capital, financial planning and valuation who has advised clients on these matters in the context of a wide variety of investment and regulatory decisions. He received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania, an MBA from the University of Utah, an M.S. from the Fletcher School of Law and Diplomacy, Tufts University, and a B.S. degree from the United States Air Force Academy. He joined The Brattle Group in 1994 after a career as an Air Force officer, where he served as a fighter pilot, intelligence officer, and professor of finance at the Air Force Academy.

REPRESENTATIVE CONSULTING EXPERIENCE

- In a securities fraud case, Dr. Vilbert designed and created a model to value the private placement stock of a drug store chain as if there had been full disclosure of the actual financial condition of the firm. He analyzed key financial data and security analysts' reports regarding the future of the industry in order to recreate pro forma balance sheet and income statements under a variety of scenarios designed to establish the value of the firm.

- For pharmaceutical companies rebutting price-fixing claims in antitrust litigation, Dr. Vilbert was a member of a team that prepared a comprehensive analysis of industry profitability. The analysis replicated, tested and critiqued the major recent analyses of drug costs, risks and returns. The analyses helped develop expert witness testimony to rebut allegations of excess profits.

- For an independent electric power producer, Dr. Vilbert created a model that analyzed the reasonableness of rates and costs filed by a natural gas pipeline. The model not only duplicated the pipeline's rates, but it also allowed simulation of a variety of "what if" scenarios associated with cost recovery under alternative time patterns and joint cost allocations. Results of the analysis were adopted by the intervenor group for negotiation with the pipeline.

- For the CFO of an electric utility, Dr. Vilbert developed the valuation model used to support a stranded cost estimation filing. The case involved a conflict between two utilities over the responsibility for out-of-market costs associated with a power purchase contract between them. In addition, he advised and analyzed cost recovery mechanisms that would allow full recovery of the stranded costs while providing a rate reduction for the company's rate payers.

- Dr. Vilbert has testified as well as assisted in the preparation of testimony and the development of estimation models in numerous cost of capital cases for natural gas pipeline, water utility and electric utility clients before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions. These have spanned standard estimation techniques (e.g., Discounted Cash Flow and Risk Positioning models). He has also developed and applied more advanced models specific to the industries or lines of business in question, e.g., based on the structure and risk characteristics of cash flows, or based on multi-factor models that better characterize regulated industries.

- Dr. Vilbert has valued several large, residual oil-fired generating stations to evaluate the possible conversion to natural gas or other fuels. In these analyses, the expected pre- and post-conversion station values were computed using a range of market electricity and fuel cost conditions.

- For a major western electric utility, Dr. Vilbert helped prepare testimony that analyzed the prudence of QF contract enforcement. The testimony demonstrated that the utility had not been compensated in its allowed cost of capital for major disallowances stemming from QF contract management.

- Dr. Vilbert analyzed the economic need for a major natural gas pipeline expansion to the Midwest. This involved evaluating forecasts of natural gas use in various regions of the United States and the effect of additional supplies on the pattern of natural gas pipeline use. The analysis was used to justify the expansion before the FERC and the National Energy Board of Canada.

- For a Public Utility Commission in the Northeast, Dr. Vilbert analyzed the auction of an electric utility's purchase power agreements to determine whether the outcome of the auction was in the ratepayers' interest. The work involved the analysis of the auction procedures as well as the benefits to ratepayers of transferring risk of the PPA payments to the buyer.

- Dr. Vilbert led a team tasked to determine whether bridge tolls were "just and reasonable" for a non-profit port authority. Determination of the cost of service for the authority required estimation of the value of the authority's assets using the trended original cost methodology as well as evaluation of the operations and maintenance budgets. Investment costs, bridge traffic information and inflation indices covering a 75 year period were utilized to estimate the value of four bridges and a passenger transit line valued in excess of $1 billion.

- Dr. Vilbert helped a recently privatized railroad in Brazil develop an estimate of its revenue requirements, including a determination of the railroad's cost of capital. He also helped evaluate alternative rate structures designed to provide economic incentives to shippers as well as to the railroad for improved service. This involved the explanation and analysis of the contribution margin of numerous shipper products, improved cost analysis and evaluation of bottlenecks in the system.

- For a utility in the Southeast, Dr. Vilbert quantified the company's stranded costs under several legislative electric restructuring scenarios. This involved the evaluation of all of the company's fossil and nuclear generating units, its contracts with Qualifying Facilities and the prudence of those QF contracts. He provided analysis concerning the impact of securitizing the company's stranded costs as a means of reducing the cost to the ratepayers and several alternative designs for recovering stranded costs.

- For a recently privatized electric utility in Australia, Dr. Vilbert evaluated the proposed regulatory scheme of the Australian Competition and Consumer Commission for the company's electric transmission system. The evaluation highlighted the elements of the proposed regulation which would impose uncompensated asymmetric risks on the company and the need to either eliminate the asymmetry in risk or provide additional compensation so that the company could expect to earn its cost of capital.

- For an electric utility in the Southwest, Dr. Vilbert helped design and create a model to estimate the stranded costs of the company's portfolio of Qualifying Facilities and Power Purchase contracts. This exercise was complicated by the many variations in the provisions of the contracts that required modeling in order to capture the effect of changes in either the performance of the plants or in the estimated market price of electricity.

- Dr. Vilbert helped prepare the testimony responding to a FERC request for further comments on the appropriate return on equity for electric transmission facilities. In addition, Dr. Vilbert was a member of the team that made a presentation to the FERC staff on the expected risks of the unbundled electric transmission line of business.

- Dr. Vilbert and Mr. Frank C. Graves, also of The Brattle Group, prepared testimony evaluating an innovative Canadian stranded cost recovery procedure involving the auctioning of the output of the province's electric generation plants instead of the plants themselves. The evaluation required the analysis of the terms and conditions of the long-term contracts specifying the revenue requirements of the plants for their entire forecasted remaining economic life and required an estimate of the cost of capital for the plant owners under this new stranded cost recovery concept.

- Dr. Vilbert served as the neutral arbitrator for the valuation of a petroleum products tanker. The valuation required analysis of the Jones Act tanker market and the supply and demand balance of the available U.S. constructed tanker fleet.

PRESENTATIONS

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Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER07-46-000, on behalf of Northwestern Corporation on the Cost of Capital for Transmission Assets, October 2006.

Direct and rebuttal testimony before the Tennessee Regulatory Authority, Case No. 06-00290, on behalf of Tennessee American Water Company, on the Cost of Capital, November, 2006 and April 2007.

Direct and rebuttal testimony before the Public Service Commission of Wisconsin, Docket No. 5-UR-103, on behalf of Wisconsin Energy Corporation, on the Cost of Capital for Wisconsin Electric Power Company and Wisconsin Gas LLC, May 2007 and October 2007.

Rebuttal testimony before the California Public Utilities Commission, Docket No. A. 07-01-036-39, on behalf of California-American Water Company, on the Cost of Capital, May 2007.

Direct testimony before the Public Utilities Commission of the State of South Dakota, Docket No. NG-07-013, on behalf of NorthWestern Corporation, on the Cost of Capital for NorthWestern Energy Company's natural gas operations in South Dakota, June 2007.

Direct, supplemental and rebuttal testimony before the Public Utilities Commission of Ohio, Case No. 07-551-EL-AIR, Case No. 07-552-EL-ATA, Case No. 07-553-EL-AAM, and Case No. 07-554-EL-UNC, on behalf of Ohio Edison Company, The Toledo Edison Company, and The Cleveland Electric Illuminating Company, on the cost of capital for the FirstEnergy Company's Ohio electric distribution utilities, June 2007, January 2008 and February 2008.

Direct testimony before the Public Service Commission of West Virginia, Case No. 07-0998-W-42T, on behalf of West Virginia American Water Company on cost of capital, July 2007.

Direct and rebuttal testimony before the State Corporation Commission of Virginia, Case No. PUE-2007-00066, on behalf of Virginia Electric and Power Company on the cost of capital for its southwest Virginia coal plant, July 2007 and December 2007.

Direct testimony before the Public Utilities Commission of Ohio, Case No. 07-829-GA-AIR, Case No. 07-830-GA-ALT, and Case No. 07-831-GA-AAM, on behalf of Dominion East Ohio Company, on the rate of return for Dominion East Ohio's natural gas distribution operations, September 2007.

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Companies for Determining Gas and Oil Pipeline Return on Equity, Docket No. PL07-2-000, December, 2007.

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Direct testimony before the Federal Energy Regulatory Commission, Docket No. RP08-___-000, on behalf of El Paso Natural Gas Company, on the Cost of Capital for Natural Gas Transmission Assets, June 2008.

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER08-1207-000, on behalf of Virginia Electric and Power Company, on the incentive Cost of Capital for investment in New Electric Transmission Assets, June 2008

Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER08-1233-000, on behalf of Public Service Electric and Gas Company, on the Cost of Capital for Electric Transmission Assets, July 2008.

APPENDIX B

EMPIRICAL IMPLEMENTATION AND TECHNICAL DETAILS

I. Sample Selection.

Q1. Please describe the universe of companies that you believe have business risk comparable to the Ohio EDUs.

A1. I started by selecting industries that share several essential business characteristics with an electric distribution utility, without restricting the potential sample to regulated companies. The initial criteria I used were: (1) companies that operate in industries relying on a network of assets to provide services to a customer mix that includes residential, commercial and industrial customers, and (2) that exhibit high capital intensity. Capital intensity means that the capital investment required for each dollar of revenue is high. I started with the universe of 100 industries and 1700 companies covered by the *Value Line Standard Edition.* The following ten industries satisfy the first criterion outlined above: Electric Utilities,[1] Natural Gas Utilities, Oil and Gas Distribution, Water Utilities, Air Transportation, Cable TV, Environmental, Railroads, Telecommunication Services, Trucking. The total number of companies covered by the *Value Line Standard Edition* in these ten industries is 143.

Q2. What additional criteria did you use?

A2. I further limited the sample to companies with an investment-grade credit rating, using Standard & Poor's credit ratings provided by Compustat and Bloomberg.[2] I also eliminated foreign companies.

Q3. How did you apply the capital intensity screen?

A3. The electric utility industry is a relatively capital intensive industry, so I eliminated industries whose average capital intensity was substantially below that of an electric

[1] *Value Line* breaks the electric utilities down into three categories, based on geographical location: East, Central, and West.

[2] Not all companies are covered by both databases. The Compustat credit ratings were reported as of 12/31/2007, and Bloomberg reports current ratings as of 6/5/2008.

utility. There are several possible measures of capital intensity. I used asset turnover, which is defined as the ratio of revenues to total assets. In order to account for asset disposals or purchases during the year, I used an average of the beginning and end of year total asset figures for the denominator of the fraction. This ratio provides an indicator of the amount of capital that needs to be invested in order to generate a dollar of revenue. Using this measure and eliminating industries with an average asset turnover in excess of 1 for the 2005-2007 (three-year) period results in six industries: Electric Utilities, Natural Gas Utilities, Water Utilities, Environmental, Railroads, and Telecommunication Services.[3] I also include in the final list of industries Oil and Gas Distribution companies, because their asset turnover statistics are biased by the high natural gas and oil prices in the last few years. These regulated companies pass through the cost of fuel purchases to their customers, and therefore an increase in revenues due to large cost increases does not reflect the true capital intensity of the industry. In fact, considering an alternative measure of capital intensity such as the ratio of earnings before interest and taxes to total assets confirms that this industry has a level of capital intensity comparable to the other industries in the sample.

Q4. Do you recommend that this procedure be repeated yearly, or could the Commission just use this list of industries every year?

A4. No, the list of industries would not require updating every year. In order to ensure I obtained an accurate measure of capital intensity, I used three-year averages for the asset turnover ratio, using data for the 2005-2007 fiscal years. I recommend that the test be performed starting with the companies listed by *Value Line* as operating primarily in one of these ten industries, and then restricting the sample to the companies that for the period of the year being tested have an investment-grade credit rating.

[3] After applying the credit rating criterion, only one Cable TV company remained in the sample (Comcast Cable Inc.). However, *Value Line* did not report a total assets figure for 2007, so I could not perform the capital intensity calculation. As a result, I do not include the Cable TV industry in the list of capital intensive industries.

Q5. How many companies were included in the sample used to compute capital intensity?

A5. The sample consisted of 80 companies. The companies in the sample, by industry classification, are presented in Table B 1 below, which shows the average asset turnover by industry, as well as the average industry beta and equity thickness. The individual companies are in Table B 4 at the end of this Appendix.

Table B 1. Industry Statistics

Industry	Number of Companies	Average Asset Turnover	Common Equity Percentage	Beta as of 2007
Electric Utilities				
ELECTRIC UTIL.- CEN	19	0.49	49%	0.92
ELECTRIC UTIL.- EAST	17	0.47	47%	0.96
ELECTRIC UTIL.- WEST	11	0.41	55%	0.95
Electric Utilities	***47***	***0.46***	***49.5%***	***0.94***
Other Regulated Utilities				
NATURAL GAS UTILITY	8	0.90	55%	0.86
WATER UTILITIES	2	0.31	55%	0.93
OIL/GAS DISTRIB	7	1.38	48%	0.88
All Regulated Utilities	***64***	***0.61***	***50.2%***	***0.92***
Other Capital Intensive Industries				
RAILROAD	4	0.41	61%	1.01
TELECOM. SERVICES	3	0.38	58%	1.07
ENVIRONMENTAL	3	0.60	46%	0.85
All Capital Intensive Industries	***74***	***0.59***	***50.9%***	***0.93***
Other Industries				
AIR TRANSPORT	3	1.16	75%	0.92
TRUCK'G/TRANSP LEASE	3	1.91	60%	1.10
CABLE TV	0	-	-	-
All Industries	***80***	***0.66***	***52.2%***	***0.94***

Q6. Is this the same sample that you used to compute the earnings metric?

A6. Approximately. Several differences arise due to data availability. In order to compute the capital intensity metric, I used all investment-grade companies that had revenue and total assets information provided by *Value Line*, while when computing the return on total capital, I restricted the sample to the companies that had that information available. The data availability criterion generated some differences between the list of companies used to choose the list of industries, and the one used to compute the return metrics. However, most companies appear in both calculations. The list of all companies is provided in Table B 1, which also indicates whether a particular company was not included in one of the sample calculations. The final sample used to derive the earnings threshold, consisting of the more capital intensive companies, contains 72 companies.

Q7. Do you think a sample of 80 companies is sufficient to provide a reliable estimate of industry average capital intensities?

A7. In general, yes, but for some industries, the number of companies with available data is relatively small. In order to verify the reliability of the estimates, I performed the analysis using the measure of sales turnover available from Compustat. This resulted in a larger sample of 84 companies, and provided results that confirmed the analysis restricted to *Value Line* data. Therefore, I believe the selection of industries I include in the final sample is reliable.

Q8. Are there any other data availability issues that you think are important to raise?

A8. Yes. *Value Line* reports accounting information using fiscal year data, as reported by the company. Because not all companies' fiscal years coincide with the calendar year, there are timing differences between the data reported for different companies in the sample. If a company's fiscal year ends in the first four months of the calendar year, then *Value Line* will assign the previous year's label to the data. As a result, if the test of significantly excessive earnings is conducted early in the year, before all companies have reported their fiscal year data, the sample size may be reduced by a substantial amount.

II. Measuring the Return on Total Capital

Q9. Please describe the metric that you propose to determine significantly excessive earnings.

A9. For each sample company, I compute an adjusted annual return on total capital, using the following formula:

$$R = \frac{(NI - Nonrec) + (1-t)LT\ Int}{Average\ Total\ Capital}$$

Where:

- NI = Net Income
- $Nonrec$ = Nonrecurring gains/losses
- t = Company's effective tax rate
- $LT\ Int$ = Interest expense on long-term debt
- $Average\ Total\ Capital$ = the sum of the book values of common equity, preferred equity and long-term debt, measured as the average of beginning-of-year and end-of-year balance sheet values.

Q10. What is the source of the data necessary to perform this calculation?

A10. *Value Line Investment Analyzer* provides an electronic source for historical data collected or computed in *Value Line* reports. This data set, last updated on June 6, 2008, is used in the analysis. I obtained the S&P credit ratings for the sample companies from Compustat and Bloomberg.

Q11. Does *Value Line* report each of the required variables separately?

A11. No, but they can be obtained by straightforward manipulation of the electronic data provided. *Value Line* computes a measure that is very close to the adjusted return on total capital defined above, namely:

$$R_{ValueLine} = \frac{Net\ profit + \frac{1}{2}LT\ Int}{Total\ Capital}$$

Because *Value Line* excludes non-recurring gains and losses from the computation of the Net Profit measure, the only differences from the metric I propose are that *Value Line* multiplies the long-term interest expense by 0.5 instead of the company's effective income tax rate, and that *Value Line* uses the end-of-year balance for total capital instead of the average of beginning and end-of-year values. Net Profit and the components of Total Capital are reported separately so long-term interest can be calculated, and then used to calculate the adjusted return on total capital that I propose.

Q12. Did you make any other adjustment to the return on total capital?

A12. Yes. The components of total capital are reported as of the end of the fiscal year. If the company issues or retires equity or debt during the year, the end-of-year value is different from the average value for the year. Because net profit and interest expense are based on the entire year, it is more accurate to use the average value for common equity, preferred equity, and long-term debt. Therefore, I use an average of the end-of-year total capital values for the current and previous year in the calculation.

Q13. Which data items exactly did you use for the return on total capital calculation?

A13. I used the following data items reported in the *Value Line Investment Analyzer*:

- Net Profit: this item excludes nonrecurring gains and losses, as determined by the *Value Line* analysts, and includes preferred dividends;
- Shareholders Equity: this item includes both common and preferred equity;
- Long-Term Debt;
- Return on Total Capital: this item is defined as the ratio of Net Profit to the sum of end-of-year shareholders' equity and long-term debt;
- Income Tax Rate: this is the effective tax rate, determined as the ratio of taxes to earnings before taxes.

Q14. What were the results of your analysis of sample companies' returns on total capital?

A14. Using only the capital intensive industries, I obtained an average adjusted return on total capital of 8.60 percent, with a standard deviation of 2.39 percent. For the initial universe of companies (which includes additionally the Air Transportation, Cable TV, and Trucking industries), I obtained an average of 9.05 percent, with a standard deviation of 3.45 percent. The results for each sample are provided in Table B 2 below.

Table B 2: Return on Total Capital for Sample Industries

Industry	Number of Companies	Return on Total Capital (2007)
Electric Utilities		
ELECTRIC UTIL.- CEN	19	7.74%
ELECTRIC UTIL.- EAST	17	8.53%
ELECTRIC UTIL.- WEST	11	7.75%
Other Regulated Utilities		
NATURAL GAS UTILITY	8	8.40%
WATER UTILITIES	2	6.65%
OIL/GAS DISTRIB	6	11.26%
Other Capital Intensive Industries		
RAILROAD	4	10.76%
TELECOM. SERVICES	2	9.85%
ENVIRONMENTAL	3	10.39%
All Capital Intensive Industries	***72***	
Mean		***8.60%***
Standard deviation		***2.39%***
Other Industries		
AIR TRANSPORT	3	15.26%
TRUCK'G/TRANSP LEASE	4	13.49%
CABLE TV	1	5.15%
All Industries	***80***	
Mean for All Industries		***9.05%***
S.D. for All Industries		***3.45%***

Q15. Did you consider any subsamples?

A15. Yes. In order to test the sensitivity of the results to including electric utilities that own a large share of unregulated generation assets, I excluded first companies classified as Diversified by the *Edison Electric Institute* (EEI), and then those classified as either Diversified or Mostly Regulated by the EEI. The EEI classifies an electric utility as Diversified if less than 50 percent of its assets are regulated and as Mostly Regulated if between 50 and 80 percent of its assets are regulated. The results of these two subsamples are summarized in Table B 3 below.

III. THE THRESHOLD FOR SIGNIFICANTLY EXCESSIVE EARNINGS

Q16. How did you use the sample information about the adjusted return on total capital to determine a threshold for significantly excessive earnings?

A16. First, I used the sample information to determine a threshold for what could be termed "significantly excessive return on total capital" – a value of the adjusted return on total capital above which only approximately 10 percent of the observations are likely to occur. According to statistical theory, if observations from a normal distribution with mean μ and standard deviation σ are drawn, then 90 percent of them would, on average, fall below a threshold approximately equal to $\mu + 1.28\sigma$.

Of course, it is not possible to know with certainty what statistical distribution characterizes the return on total capital. However, if the sample size is sufficiently large, then the sample average will be approximately described by a normal distribution. I derive a threshold measure of return on total assets of $R_{max} = m + 1.28s$, where m is the sample average adjusted return on total capital, and s is the sample standard deviation of the adjusted return on total capital.

Q17. How do you propose using this threshold to determine significantly excessive earnings?

A17. First, compute the measure of adjusted return on total capital for the utility whose earnings are being examined. Then compare that value to the threshold measure of significantly excessive earnings for the period described above. If the utility's adjusted return on total capital exceeds the threshold R_{max}, then the test would indicate that the utility may have significantly excessive earnings.

Q18. How would the amount of significantly excessive earnings be determined?

A18. Because the return earned by debt holders and preferred shareholders is fixed and known when the allowed rates are set, if returns to total capital are significantly excessive, the excess can only be due to significantly excessive returns to common equity investors. Therefore, it is reasonable to impute any significant excess in the return to total capital to net profit earned on common equity. This amount can be computed simply by multiplying the average total capital by the difference between the utility's return on total capital, and the threshold R_{max} determined above:

$$Excess\ Earnings = (R_{utility} - R_{max}) \times Average\ Total\ Capital$$

Q19. Can you use the return on total capital threshold to compute a corresponding threshold in terms of return on common equity?

A19. Yes. This can be done using the utility's capital structure information, as well as information about its cost of debt and cost of preferred equity for the year under analysis. Specifically, using the $R_{\max}$ threshold, it is straightforward to compute an implied threshold for the amount of net income accruing to common equity holders, taking into account interest expense on long-term debt and preferred dividends paid:

$$Net\ Income\ to\ CE_{\max} = (R_{\max} \times Average Total\ Capital) - (1-t)LT\ Int - PDiv$$

where *PDiv* stands for "preferred dividends," and the other notation is as defined before. The ROE threshold is then simply:

$$ROE_{\max} = \frac{Net\ Income\ to\ CE_{\max}}{Average\ Common\ Equity}$$

Q20. Can you provide an example of how the threshold you determined using 2007 sample information can be used to determine an ROE threshold for the Ohio EDUs?

A20. Yes, but I must make some assumptions about the Ohio EDUs' capital structure and cost of debt. For simplicity, and because the Ohio EDUs do not have preferred equity in the capital structure, I assume the value of preferred to be zero. At a confidence level of 90 percent, and using the results based on the full sample of capital intensive industries, the implied ROE threshold is 19.88 percent. Eliminating electric utilities with Diversified assets yields a threshold of 19.95 percent, while further eliminating Mostly Regulated electric utilities results in a threshold of 20.02 percent. Table B 3 below summarizes the calculations, as well as the assumptions on which I relied to perform the calculation.

Table B 3: Implied ROE Thresholds at 90% Confidence Level.

Hypothetical Capital Structure Information

Ohio EDUs Equity Ratio	0.49	[a]
Ohio EDUs Debt Ratio	0.51	[b]
Ohio EDUs Cost of Debt	6.00%	[c]
Ohio EDUs Tax Rate	37.1%	[d]
Statistical Significance Threshold	**90.0%**	[e]

Calculation of ROE Threshold		Capital Intensive Industries	*Excluding Electric* Utilities Classified "D" by EEI	Excluding Electric Utilities Classified "D" or "MR" by EEI
Sample Average Return on Total Capital	[1]	8.60%	8.56%	8.49%
Sample Standard Deviation	[2]	2.39%	2.45%	2.53%
Return on Total Capital Threshold	[3]	11.67%	11.70%	11.73%
Ohio EDUs D/E Ratio	[4]	1.04	1.04	1.04
ROE Threshold	[5]	**19.88%**	**19.95%**	**20.02%**

Sources and Notes:
[1]: Sample average of return on total capital for the corresponding sample.
[2]: Sample standard deviation of return on total capital for the corresponding sample.
[3] = [1] + 1.282 x [2].
[4] = [a] / [b].
[5] = [1] x (1 + [4]) - (1 - [d]) x [c] x [4].

Table B 4. Sample Companies and Statistics

No.	Company	Ticker	Value Line Industry	EEI Classification	Included in Capital Intensity Calculation	Included in Returns Calculation	Average Asset Turnover 2005-2007	Return on Total Capital 2007
1.	ALLETE	ALE	ELECTRIC UTIL.- CEN	R	x	x	0.52	9.43%
2.	Alliant Energy	LNT	ELECTRIC UTIL.- CEN	MR	x	x	0.45	8.79%
3.	Amer. Elec. Power	AEP	ELECTRIC UTIL.- CEN	R	x	x	0.34	7.32%
4.	Ameren Corp.	AEE	ELECTRIC UTIL.- CEN	R	x	x	0.37	6.77%
5.	CenterPoint Energy	CNP	ELECTRIC UTIL.- CEN	MR	x	x	0.54	8.18%
6.	Cleco Corp.	CNL	ELECTRIC UTIL.- CEN	R	x	x	0.43	6.66%
7.	CMS Energy Corp.	CMS	ELECTRIC UTIL.- CEN	R	x	x	0.42	4.84%
8.	DPL Inc.	DPL	ELECTRIC UTIL.- CEN	R	x	x	0.37	10.97%
9.	DTE Energy	DTE	ELECTRIC UTIL.- CEN	MR	x	x	0.39	6.14%
10.	Empire Dist. Elec.	EDE	ELECTRIC UTIL.- CEN	R	x	x	0.35	5.74%
11.	Entergy Corp.	ETR	ELECTRIC UTIL.- CEN	MR	x	x	0.35	8.57%
12.	G't Plains Energy	GXP	ELECTRIC UTIL.- CEN	R	x	x	0.68	9.37%
13.	MGE Energy	MGEE	ELECTRIC UTIL.- CEN	R	x	x	0.55	8.63%
14.	NiSource Inc.	NI	ELECTRIC UTIL.- CEN	MR	x	x	0.44	5.24%
15.	OGE Energy	OGE	ELECTRIC UTIL.- CEN	MR	x	x	0.93	10.16%
16.	Otter Tail Corp.	OTTR	ELECTRIC UTIL.- CEN	MR	x	x	0.91	8.15%
17.	Vectren Corp.	VVC	ELECTRIC UTIL.- CEN	R	x	x	0.53	7.76%
18.	Westar Energy	WR	ELECTRIC UTIL.- CEN	R	x	x	0.30	6.91%
19.	Wisconsin Energy	WEC	ELECTRIC UTIL.- CEN	R	x	x	0.37	7.51%
20.	Allegheny Energy	AYE	ELECTRIC UTIL.- EAST	D	x	x	0.36	8.78%
21.	CH Energy Group	CHG	ELECTRIC UTIL.- EAST	R	x	x	0.75	6.15%
22.	Consol. Edison	ED	ELECTRIC UTIL.- EAST	R	x	x	0.48	7.55%
23.	Constellation Energy	CEG	ELECTRIC UTIL.- EAST	D	x	x	0.91	10.10%
24.	Dominion Resources	D	ELECTRIC UTIL.- EAST	MR	x	x	0.35	8.31%
25.	Exelon Corp.	EXC	ELECTRIC UTIL.- EAST	MR	x	x	0.38	14.76%
26.	FirstEnergy Corp.	FE	ELECTRIC UTIL.- EAST	MR	x	x	0.38	9.44%
27.	FPL Group	FPL	ELECTRIC UTIL.- EAST	MR	x	x	0.41	8.67%
28.	Northeast Utilities	NU	ELECTRIC UTIL.- EAST	R	x	x	0.51	5.60%
29.	NSTAR	NST	ELECTRIC UTIL.- EAST	R	x	x	0.44	7.79%
30.	Pepco Holdings	POM	ELECTRIC UTIL.- EAST	MR	x	x	0.61	5.71%
31.	PPL Corp.	PPL	ELECTRIC UTIL.- EAST	MR	x	x	0.35	11.08%
32.	Progress Energy	PGN	ELECTRIC UTIL.- EAST	R	x	x	0.37	6.13%
33.	Public Serv. Enterprise	PEG	ELECTRIC UTIL.- EAST	MR	x	x	0.43	10.11%
34.	SCANA Corp.	SCG	ELECTRIC UTIL.- EAST	MR	x	x	0.48	8.00%
35.	Southern Co.	SO	ELECTRIC UTIL.- EAST	R	x	x	0.35	8.86%
36.	TECO Energy	TE	ELECTRIC UTIL.- EAST	R	x	x	0.45	7.87%
37.	Black Hills	BKH	ELECTRIC UTIL.- WEST	D	x	x	0.42	8.69%
38.	Edison Int'l	EIX	ELECTRIC UTIL.- WEST	MR	x	x	0.35	9.14%
39.	El Paso Electric	EE	ELECTRIC UTIL.- WEST	R	x	x	0.49	7.94%
40.	Hawaiian Elec.	HE	ELECTRIC UTIL.- WEST	D	x	x	0.24	5.92%
41.	IDACORP Inc.	IDA	ELECTRIC UTIL.- WEST	R	x	x	0.26	6.06%
42.	MDU Resources	MDU	ELECTRIC UTIL.- WEST	D	x	x	0.84	10.50%
43.	PG&E Corp.	PCG	ELECTRIC UTIL.- WEST	R	x	x	0.36	9.16%
44.	Pinnacle West Capital	PNW	ELECTRIC UTIL.- WEST	R	x	x	0.30	6.30%
45.	PNM Resources	PNM	ELECTRIC UTIL.- WEST	R	x	x	0.41	4.29%
46.	Sempra Energy	SRE	ELECTRIC UTIL.- WEST	D	x	x	0.41	10.29%
47.	Xcel Energy Inc.	XEL	ELECTRIC UTIL.- WEST	R	x	x	0.45	6.93%
48.	Atmos Energy	ATO	NATURAL GAS UTILITY		x	x	1.09	6.58%
49.	Laclede Group	LG	NATURAL GAS UTILITY		x	x	1.27	9.15%
50.	New Jersey Resources	NJR	NATURAL GAS UTILITY		x	x	1.43	8.29%
51.	Nicor Inc.	GAS	NATURAL GAS UTILITY		x	x	0.75	11.80%
52.	Northwest Nat. Gas	NWN	NATURAL GAS UTILITY		x	x	0.50	8.89%
53.	Piedmont Natural Gas	PNY	NATURAL GAS UTILITY		x	x	0.68	8.30%
54.	Southwest Gas	SWX	NATURAL GAS UTILITY		x	x	0.59	6.14%
55.	WGL Holdings Inc.	WGL	NATURAL GAS UTILITY		x	x	0.91	8.07%
56.	Buckeye Partners L.P.	BPL	OIL/GAS DISTRIB		x		0.25	
57.	Kinder Morgan Energy	KMP	OIL/GAS DISTRIB		x	x	0.76	12.53%

No.	Company	Ticker	Value Line Industry	EEI Classification	Included in Capital Intensity Calculation	Included in Returns Calculation	Average Asset Turnover 2005-2007	Return on Total Capital 2007
58.	Magellan Midstream	MMP	OIL/GAS DISTRIB		x	x	0.63	19.27%
59.	Plains All Amer. Pipe.	PAA	OIL/GAS DISTRIB		x	x	4.75	8.82%
60.	Southern Union	SUG	OIL/GAS DISTRIB		x	x	0.38	7.05%
61.	TEPPCO Partners L.P.	TPP	OIL/GAS DISTRIB		x	x	2.42	10.59%
62.	Williams Cos.	WMB	OIL/GAS DISTRIB		x	x	0.44	9.28%
63.	Amer. States Water	AWR	WATER UTILITIES		x	x	0.30	7.06%
64.	California Water	CWT	WATER UTILITIES		x	x	0.32	6.24%
65.	Republic Services	RSG	ENVIRONMENTAL		x	x	0.68	12.56%
66.	Waste Connections	WCN	ENVIRONMENTAL		x	x	0.48	8.36%
67.	Waste Management	WMI	ENVIRONMENTAL		x	x	0.64	10.25%
68.	Burlington Northern	BNI	RAILROAD		x	x	0.47	12.10%
69.	CSX Corp.	CSX	RAILROAD		x	x	0.38	10.13%
70.	Norfolk Southern	NSC	RAILROAD		x	x	0.35	11.14%
71.	Union Pacific	UNP	RAILROAD		x	x	0.42	9.67%
72.	AT&T Inc.	T	TELECOM. SERVICES		x	x	0.36	11.42%
73.	CenturyTel Inc.	CTL	TELECOM. SERVICES		x	x	0.32	8.29%
74.	Sprint Nextel Corp.	S	TELECOM. SERVICES		x		0.46	
75.	FedEx Corp.	FDX	AIR TRANSPORT		x		1.50	15.40%
76.	Southwest Airlines	LUV	AIR TRANSPORT		x		0.63	6.39%
77.	United Parcel Serv.	UPS	AIR TRANSPORT		x		1.34	23.99%
78.	Comcast Corp.	CMCSK	CABLE TV					5.15%
79.	Arkansas Best	ABFS	TRUCK'G/TRANSP LEASE		x		2.03	9.59%
80.	Con-way Inc.	CNW	TRUCK'G/TRANSP LEASE		x		1.70	12.54%
81.	Hunt (J.B.)	JBHT	TRUCK'G/TRANSP LEASE		x		1.99	23.80%
82.	Ryder System	R	TRUCK'G/TRANSP LEASE					8.04%