STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND	**)**	
ELECTRIC COMPANY	**)**	
d/b/a VECTREN ENERGY	**)**	**CAUSE NO. 43839**
DELIVERY OF INDIANA, INC	**)**	
(VECTREN SOUTH – ELECTRIC)	**)**	

DIRECT TESTIMONY

OF

DR. DAVID E. DISMUKES - PUBLIC'S EXHIBIT NO. 2

ON BEHALF OF

THE INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JUNE 25, 2010

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TESTIMONY OF DR. DAVID E. DISMUKES
CAUSE NO. 43839
VECTREN SOUTH - ELECTRIC

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place, Suite 5-F, Baton Rouge, Louisiana.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana, with additional staff in Los Angeles, California, and Fallon, Nevada.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Associate Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University. I am also an Adjunct Professor in the E.J. Ourso College of Business Administration (Department of Economics), and I am a full member of the graduate research faculty at LSU.

Q. HAVE YOU PREPARED ANY ATTACHMENTS TO YOUR TESTIMONY OUTLINING YOUR QUALIFICATIONS IN ENERGY AND REGULATED INDUSTRIES?

A. Yes. Attachment 1 to my testimony provides my academic vita that includes a full listing of my publications, presentations, and pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR TESTIMONY?

A. Yes. I have prepared 29 exhibits in support of my direct testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the Indiana Office of Utility Consumer Counselor ("OUCC") to provide an expert opinion on various policy proposals and the Company's benchmarking analysis that are part of the recent rate case filing by Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South," "Vectren South-Electric," "the Company," or "Petitioner") before the Indiana Utility Regulatory Commission ("IURC" or "the Commission"). My testimony will address: (1) the Company's Sales Reconciliation Adjustment ("SRA" or "revenue decoupling proposal"); (2) its proposed Reliability Cost and Revenue Adjustment ("RCRA") tracker, including its Variable Production Cost ("VPC") recovery component; and (3) components of its proposed Midwestern Independent System Operator ("MISO") Cost and Revenue Adjustment ("MCRA") tracker.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following remaining sections:

- Section II: Overview and Summary of Recommendations
- Section III: Revenue Trackers and the Proposed SRA
- Section IV: Cost Trackers and the Proposed RCRA
- Section V: Alternative Recommendations to the Proposed SRA: Efficiency Incentive Mechanism
- Section VI: Investment Trackers and the Proposed MCRA
- Section VII: Conclusion

II. OVERVIEW AND SUMMARY OF RECOMMENDATIONS

Q. WHAT ARE YOUR GENERAL RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED REVENUE AND COST RECOVERY ADJUSTMENT MECHANISMS?

A. I recommend that the Commission reject Petitioner's revenue decoupling proposal, its variable production cost ("VPC") tracker component in its RCRA tracker proposal, and its proposal to exclude all transmission-related revenues from its MCRA. These proposals should be rejected, particularly the revenue decoupling and VPC proposals since they are based upon a number of faulty premises that are unsupported by any credible evidence, are inconsistent with sound regulatory principles, and contrary to the public interest. As I will outline later, the Commission should instead, consider regulatory mechanisms that provide positive incentives for both demand-side and supply-side efficiencies that "re-couple" rates, earnings, and performance.

Q. WHAT ARE THESE FAULTY PREMISES?

A. The Petitioner's proposed tracker mechanisms are based upon three faulty premises that are common with similar tracker proposals made by utilities in other jurisdictions over the past several years:

1) The premise that the traditional form of electric utility regulation is deficient and in need of complete overhaul, by significantly changing the historic risk/reward relationships between utilities and ratepayers.[1]
2) The premise that cost recovery (fixed and/or variable) should be flexible and discretionary between rate cases.[2]

[1] Direct Testimony of Petitt, 18:33, 19:1-4.
[2] Ibid., 19:7-8.

3) The premise that revenue trackers, like revenue decoupling, will better align the incentives of electric utilities and customers.[3]

Q. COULD YOU EXPLAIN THE FALLACY OF THE FIRST PREMISE UPON WHICH THE COMPANY HAS BASED ITS TRACKER PROPOSALS?

A. Yes. Vectren South's first faulty premise is that traditional regulation has a number of inherent flaws that challenge its ability to recover its revenue requirement, particularly in challenging times. The Company highlights a number of factors that include the current recession, a number of changes in environmental regulations that have spanned at least a decade if not more, low fossil fuel prices, low wholesale power prices, and speculative policy changes related to greenhouse gas ("GHG") regulation.[4]

Q. HOW DO THE PETITIONER'S TRACKER PROPOSALS DIFFER FROM TRADITIONAL REGULATION?

A. Traditional regulation is based upon a principle, developed over the past century, commonly referred to as the "regulatory compact" that defines the relationship and expectations between regulated companies and their regulators. This relationship gives regulated utilities a guaranteed service territory and an opportunity, but not a guarantee, to earn a reasonable rate of return on, and recovery of, its prudently incurred investments. In return, the utility is obligated to provide safe, reliable, and economic service to its ratepayers. Vectren South's collective proposals, however, would turn this regulatory compact on its head by creating a guaranteed revenue requirement and little market incentives or discipline for efficient service.

Q. HOW WILL REVENUE RECOVERY CHANGE IF THE ENTIRE SET OF THE PETITIONER'S TRACKER MECHANISMS IS APPROVED BY THE COMMISSION?

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[3] Direct Testimony of Ulrey, p 24.

[4] Direct Testimony of Carl L. Chapman (Revised), 9:23-33 and 13:19-29; and Direct Testimony of Ronald G. Jochum, 3:13-18 and 19:15-17.

A. Currently, Vectren South receives about $223 million, or 38 percent, of its total revenues through a tracker-type of mechanism. If all of the Company's proposed trackers are approved in this proceeding, $238 million, or 40 percent, of its total revenues will be recovered through a tracker mechanism of one type or another. Excluding fuel, the Company currently collects 10% of its revenue through trackers compared to its proposal of 14% in this case.[5]

Q. HOW IS VECTREN SOUTH'S SECOND PREMISE FOR ITS PROPOSED COST RECOVERY TRACKERS FLAWED?

A. The Petitioner is proposing to modify its existing generation cost tracker mechanism to allow it to automatically recover a wide range of variable production costs, normally included in base rates. This proposal rests upon a premise that there are a wide range of variable costs, and external factors influencing these costs, that are beyond the Company's control. While it may be true that there are many external factors that influence electric power generation costs, the Company, like most electric utilities and power generators, are in the best position to manage these risks, not ratepayers. Completely insuring the Company against these types of production cost risks runs counter to traditional regulation and leads to opportunities for operating inefficiencies that, in turn, can lead to unnecessary rate increases.

Q. DO YOU AGREE WITH THE VECTREN SOUTH'S THIRD PREMISE THAT ITS PROPOSED SRA WILL BETTER ALIGN ITS INCENTIVES WITH THOSE OF ALL REGULATORY STAKEHOLDERS?

A. No, since this premise tends to significantly overstate the impacts that the promotion of utility-sponsored energy efficiency is likely to have on revenue recovery and earnings. Lost base revenues associated with energy efficiency tend to be exceptionally small relative to other factors influencing total electricity use. These factors include, but are not entirely limited to price, weather, and income. As I will discuss later, revenue decoupling has a very strong tendency to

[5] Response to OUCC DR 17 Q-9; Direct Testimony of Susan Hardwick, Exhibit MSH-2.

lead to bill surcharges for revenue changes that have nothing to do with utility-sponsored energy efficiency. This is a real-world observed issue that has become an increasing concern for regulators that have already adopted some form of revenue decoupling. For instance, Virginia, Washington, and Idaho are examples of some of the states that were early-adopters of revenue decoupling but have raised a number of questions and concerns about the unintended consequences of their various programs. Current experience in Indiana would suggest this is equally problematic.

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS REGARDING VECTREN SOUTH'S SRA PROPOSAL?

A. The Petitioner's proposed revenue decoupling proposal should be rejected since:

- The proposed mechanism would shift revenue recovery risk associated with changes in the economy, price, and other factors away from the Company and its shareholders and onto ratepayers. Such a shifting of risk, without any corresponding mitigation measure, will result in rates that are not fair, just, and reasonable.
- The mechanism has been offered on a permanent basis and has no review or analysis period to assess its effectiveness or the emergence of any unanticipated consequences.
- The mechanism is not accompanied or tied to any verifiable, performance-based energy efficiency goals and outcomes, and as such, is incompatible with state alternative regulation policies and performance.
- The mechanism is highly likely to make the Company whole for changes in sales that have nothing at all to do with its energy efficiency efforts. This has been a growing concern for many states, including those states that were early adopters of revenue decoupling policies.

- The need for revenue decoupling for a vertically-integrated electric utility is not as apparent as the stated rationales for unbundled (non-integrated) natural gas local distribution companies ("LDCs"). The Company's cost structure, like most vertically-integrated electric utilities, includes production, transmission, and distribution-related costs that are heavily influenced by its operational decisions. LDCs, being distribution-only, do not face the same type of vertically-integrated cost structure, thus face differing incentives.

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS REGARDING VECTREN SOUTH'S PROPOSED COST ADJUSTMENT MECHANISMS?

A. The Commission should reject the VPC tracker component of its proposed Reliability Cost and Revenue Adjustment ("RCRA") tracker. This proposal should be rejected since:

- Petitioner has provided no evidence of any ratepayer benefits from the mechanism.
- The proposal is inconsistent with economic theory and regulatory practice and likely to lead to cost inefficiencies.
- It creates incentives for inefficiency by reducing the Company's incentive to control operating costs between rate cases.
- It is primarily an asymmetrical mechanism that is more likely to result in rate increases than decreases for ratepayers. The mechanism provides clear and meaningful benefits to the Company and its shareholders but none to ratepayers.
- It is likely to raise challenges for ratepayers and other regulatory stakeholders in their ability to question and review the reasonableness of the Company's operating costs.
- Automatic cost adjustment mechanisms like the VPC component proposal of the RCRA are selective, non-remedial, unfair, and contrary to the public interest and if approved, would result in rates that are not fair, just, and reasonable.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS?

A. Yes. I have proposed an incentive-based mechanism that would actively encourage both supply- and demand-side incentives, recognize the vertically-integrated nature of Vectren South's operations, and create an active incentive for efficiency in both production, through increased off-system sales, and electricity use, through meeting the Commission's annual energy efficiency goals. Under my alternative recommendation, greater levels of both supply-side and demand-side efficiency would be met with greater financial rewards, while lower levels of both forms of efficiency would be met with lower financial rewards. Such an approach is more proactive than the Petitioner's proposal, would address many of the recently-identified concerns by currently decoupled states' regulators, and would be consistent with the performance-based standards of Indiana alternative regulation policies.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING VECTREN SOUTH'S MCRA PROPOSAL?

A. I recommend that the Commission reject Petitioner's proposal to remove MISO-related revenues from the tracker and place such revenues into base rates at a fixed level that is likely to understate potential gains in the future. Mr. Michael Eckert, an additional expert testifying for the OUCC, is offering an expert opinion on this issue including the need to track transmission revenue along with MISO costs or, alternatively, terminate the MCRA. I agree that Mr. Eckert's recommendation is in the public interest and should be adopted.

III. REVENUE TRACKERS AND THE PROPOSED SRA

Q. CAN REVENUE AND COST TRACKER MECHANISMS, LIKE THE ONES PROPOSED BY VECTREN SOUTH IN THIS PROCEEDING, LEAD TO ANY REGULATORY PROBLEMS OR DISINCENTIVES?

A. Yes. Trackers of all types will ultimately lead to higher utility costs compared to traditional regulation because they eliminate the positive incentives attendant to the regulatory process until a utility's next base rate case with regard to a utility's ongoing operational costs. It is a basic economic fact that rational utility management has little incentive to control costs (operational and capital) if it has no effect on the utility's profits.[6] This is precisely the situation that can arise when a utility is able to pass higher costs through to ratepayers with minimal consequences on sales and profits. Such an approach is completely at odds with traditional regulatory principles and ratemaking practices, and because the Petitioner's proposals also exclude any type of benchmarks or standards, they are also contrary to most alternative or performance-based regulatory approaches.

Q. SHOULD UTILITIES BE GIVEN A REASONABLE OPPORTUNITY TO EARN A RETURN ON AND OF THEIR INVESTMENTS AS WELL AS THEIR PRUDENTLY INCURRED COSTS?

A. Yes, but it is a well-recognized fact in utility regulation that in any given year, allowed and achieved returns are not likely to be exactly the same. In fact, such an event usually only occurs by coincidence. While utilities are given a reasonable <u>opportunity</u> to earn a return on and of their investments, these opportunities are not synonymous with an <u>entitlement</u> (or guarantee). Regulatory practice and the academic literature of utility regulation recognize that achieved rates of return can be higher or lower than allowed returns. The positive incentives associated with the

[6]See Alfred Kahn. (1988) *The Economics of Regulation: Principles and Institutions*. Cambridge, MA: MIT Press: Vol. 2 (Institutional Issues), 48.

regulatory process quite often inure to the utility and its shareholders because efficiency improvements that occur between rate cases can increase earnings, thus benefiting shareholders.[7] Such a process can be an important policy tool in controlling utility costs which ultimately can lead to lower rates.[8]

Q. ARE THE USE OF REVENUE TRACKERS, LIKE ELECTRIC REVENUE DECOUPLING, BASED UPON ANY WELL-RECOGNIZED ECONOMIC PRINCIPLES OR ACADEMIC THOUGHT?

A. No. Unlike the better part of utility regulation, electric revenue decoupling has virtually no support or basis in the academic and theoretic economic literature.[9] The entire premise of electric revenue decoupling is that firms (utilities) are revenue maximizers instead of profit maximizers. This is entirely inconsistent with the fundamental principles found in a basic economics textbook. In fact Professor Harry Trebing, the long-recognized and respected professor, utility economist, and former director of the Institute of Public Utilities[10] at the Michigan State University, characterized revenue decoupling as a "scholarly abomination."[11]

Q. HOW DO TRACKERS, LIKE REVENUE DECOUPLING, CONTRADICT TRADITIONAL REGULATORY THINKING?

A. In the early 1960s, a seminal article was published that dramatically influenced the theory and practice of utility regulation. This article, authored by Professors H. Averch and L. Johnson, and published in the *American Economic Review* in 1962,[12] posited that rate of return regulation

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[7]W.K. Viscusi, J.M. Vernon, J.R. Harrington, Jr. (1997) *Economics of Regulation and Antitrust*, Second Edition. Cambridge: MA: MIT Press, 380.

[8]J.C. Bonbright. (1961). Principles of Public Utility Rates. New York: Columbia University Press, 53.

[9]Brennan, Timothy J. (2008). "'Night of the Living Dead' or 'Back to the Future'? Electric Decoupling, Reviving Rate-of-Return Regulation and Energy Efficiency." Washington, DC: Resources for the Future Discussion Paper No. 08-27.

[10]See http://ipu.msu.edu/. The Institute of Public Utilities at the Michigan State University has a decades-long tradition of training regulatory commission staff and new regulatory commissioners through their annual two-week training sessions at MSU commonly referred to as "Camp NARUC" by those who have attended the event.

[11]Brennan, Timothy J. (2008). "Decoupling." Presented to the Institute of Public Utilities, Michigan State University, 40th Annual Regulatory Policy Conference.

[12]H. Averch and L. Johnson. (1962) "Behavior of the Firm under Regulatory Constraint." *American Economic Review*. 52:1052-1069.

creates an incentive for regulated utilities to overcapitalize, resulting in an inefficient utilization of resources and higher than optimal rates. This article was met with a flurry of scholarly research attempting to empirically verify what became known as the "A-J effect," as well as examining the conditions under which the effect would, or would not, be sustained. Later rejoinders to the research noted that two characteristics of the regulatory process tended to temper the likelihood and prevalence of the A-J effect: (1) the possibility of disallowances through the prudence review process,[13] and (2) the positive resource efficiency incentives created by "regulatory lag."[14]

Q. HOW DO TRACKERS UNDO THESE EFFICIENCY-CREATING INCENTIVES?

A. Trackers reduce these resource efficiency incentives in two ways. First, if trackers do in fact reduce the tendency for rate cases, as many of its proponents would suggest, then the mechanism would reduce the potential use of disallowances in tempering bad expenditure and investment decisions. Second, if utilities are given the ability to change, and generally increase their rates, then the discipline typically imposed by the regulatory process until a utility's next base rate case ("regulatory lag") is removed. As noted earlier, the theory and practice of public utility regulation is based upon the well-recognized observation that regulatory lag gives utilities an incentive to reduce costs between rate cases and become more efficient since the benefits of those efficiencies will typically inure to shareholders.[15]

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[13] A.K. Klevorick. (1973). "The Behavior of a Firm Subject to Stochastic Regulatory Review," *Bell Journal of Economics and Management Science* 4 (Spring): 82. P. Joskow. (1974). "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Regulation." *Journal of Law and Economics,* Vol. 17: 291-327. R.J. Gilbert and D.M Newbery. (1988). "Regulation Games." Working Paper 8879, University of California Berkeley, June 16. T.P. Lyons. (1991.) "Regulation with 20-20 Hindsight: 'Heads I Win, Tails You Lose'? *Rand Journal of Economics.* Vol. 22 (Winter): 581-595.

[14]Elizabeth E. Bailey and Roger D. Coleman. (1971). "The Effect of Lagged Regulation in an Averch-Johnson Model. *Bell Journal of Economics and Management Sciences*. 2 (Spring): 278-292.

[15] Again, see Kahn, *The Economics of Regulation*, 48.

Q. HASN'T THE IURC APPROVED A NUMBER OF REVENUE AND COST TRACKING MECHANISMS FOR INDIANA ELECTRIC UTILITIES, INCLUDING SOME FOR VECTREN SOUTH?

A. Yes. I have been informed that the IURC has approved trackers in circumstances where it found the costs at issue are material, volatile, and outside the control of the utility. As many jurisdictions are reassessing tracking mechanisms, I believe that other factors should be considered such as whether the tracker will contribute to operating cost inefficiencies and/or overcapitalization. With rising energy prices, it is an appropriate time to reconsider the efficacy of trackers.

Q. ARE THE USE OF TRACKERS, LIKE THE SRA, CONSISTENT WITH SOME OF THE MORE RECENT DEVELOPMENTS IN REGULATORY ECONOMICS AND PRACTICE?

A. No. One of the more recent contributions to the literature and practice of public utility regulation is a recognition of the importance and role of information in conditioning effective regulatory policy outcomes. Theoretical developments in regulatory economics over the past twenty years recognize that the effectiveness of the traditional regulatory process can be limited by the presence of asymmetric information between regulators and regulated companies. Quite often regulators have less information about costs and other variables important in determining the cost of service than their regulated utilities. When such conditions exist, incentive or performance-based forms of regulation, which tie rewards to observable performance measures, tend to lead to more efficient outcomes benefiting ratepayers and shareholders alike. Decoupling costs and revenues from performance (output), therefore, runs counter to not only traditional regulatory thinking, but also to the more recent developments and innovations to this body of literature and understanding over the past two decades.

Q. ARE THERE ANY OTHER DISINCENTIVES THAT CAN ARISE FROM THE EXCLUSIVE USE OF TRACKERS?

A. Yes, an important disincentive that may arise with revenue tracker mechanisms like decoupling is that utilities may be less likely to take steps that reduce price volatility for their customers through reasonable risk management practices in fuel supply procurement. While fuel costs are a pass-through item through the Fuel Adjustment Clause ("FAC"), they can impact overall average electricity rates paid by households, businesses, and industries. Exhibit DED-2 shows that it is not entirely coincidental that utilities, particularly natural gas utilities, started rapidly requesting revenue decoupling mechanisms in the back-draft of Hurricane Katrina and the volatile fossil fuel price period after 2005. Decoupling sales and utility revenues, therefore, can reduce a utility's incentive to manage its fuel price risk (volatility) since base revenue collections are likely to be less impacted by fuel price variations impacting overall electricity usage.

Q. WHY IS VECTREN SOUTH ASKING FOR ALL OF THESE TRACKERS AT ONE TIME?

A. The Petitioner bases its proposals on a number of investment, regulatory, and operational challenges, many of which are primarily in the past (economic downturn), or have uncertain outcomes (such as greenhouse gas ("GHG") regulation). The challenges the Petitioner enumerates include:

- Deteriorating economic conditions threatening dramatic changes in the Company's customer mix and sales levels.[16]
- Changes in financial markets.[17]
- Continued capital investments necessary to purportedly mitigate emissions, meet changing environmental regulations, and increase operational efficiencies.[18]

[16] Direct Testimony of Carl L. Chapman (Revised), 10:4-8.
[17] Direct Testimony of William E. Avera, 12:16-20.
[18] Direct Testimony of Carl L Chapman (Revised), 9:10-13.

- Volatile fossil fuel markets.[19]
- Volatile wholesale power markets.[20]
- Changes in environmental regulation such as the Clean Air Interstate Act ("CAIR").[21]
- Changes in reliability, energy efficiency, and renewable energy initiatives.[22]
- Potential policy changes associated with GHG regulation.[23]

Q. DO YOU AGREE THAT THE LAST SEVERAL YEARS REFLECT A CHALLENGED BUSINESS ENVIRONMENT FOR ENERGY COMPANIES?

A. Yes. Clearly the last several years have created challenges for larger capital-intensive industries like energy and regulated gas and electric utilities. The recent recession has created challenges for all Americans. But these economic challenges are part of the business cycle, and other similarly-situated utilities and energy companies have adapted, mitigated risk, generated efficiencies, and preserved shareholder value without the expansive set of revenue and cost guarantees being requested by Vectren South in this proceeding. The defense for the Petitioner's proposals lacks a certain degree of perspective and is better observed within the context of how operational challenges have recently changed, if at all, relative to other coal-fired utilities facing similar challenges. A close examination of the Company's investment and operating performance suggests some persistent challenges relative to its peers, particularly in its production plant operations. If this is in fact the case, the Commission should consider alternatives to the Company's proposal which, in their current form, are likely to increase the Company's already higher-than-average retail rates.

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[19] Direct Testimony of Ronald G. Jochum, 11: 9-15; and Direct Testimony of Carl L. Chapman (Revised), 10:4-8.

[20] Direct Testimony of Carl L. Chapman (Revised), 9:30-32; and Direct Testimony of Ronald G. Jochum, 6:19-30.

[21] Direct Testimony of Angila M. Retherford, 5:30-33; and Direct Testimony of Robert L. Goocher, 9:13-17.

[22] Direct Testimony of Carl L. Chapman (Revised), 11:10-11; and Direct Testimony of Robert L. Goocher, 9:13-17.

[23] Direct Testimony of Carl L. Chapman (Revised), 10:4-8.

Q. HAVE YOU EXAMINED VECTREN SOUTH'S PLANT INVESTMENT TRENDS OVER THE PAST SEVERAL YEARS?

A. Yes. My testimony includes a number of plant investment, costs, and operational efficiency comparisons between the Company and a peer group of coal-fired, vertically-integrated electric utilities operating in the Midwest, Mid-Continent, and Appalachian regions. Exhibit DED-3 presents a list of the peer utilities I used in my analyses and their respective descriptive statistics. The data for these analyses come from the Federal Energy Regulatory Commission's ("FERC") Form 1 database. All the utilities included in this sample are significant coal-fired power generators. No utility in the sample, for instance, generates less than 72 percent of its electricity from coal-fired generation. Most of these utilities, in fact, generate 80 percent to 90 percent of their electricity from coal-fired facilities. Thus, most of the utilities in the sample are facing some of the same fuel market, operational, wholesale power market, environmental, economic, and regulatory challenges as the Company.

Q. HOW WERE YOUR ANALYSES DEVELOPED?

A. Each analysis examines a different cost or performance metric. Unless otherwise noted, each analysis is comprised of three pages. The first page includes two tables comparing either investment or operating costs per unit of electricity generated (per megawatt-hour or "MWh") for each of the comparison utilities. The top row provides the Petitioner's statistics, the last row presents the peer-group average, and the middle rows provide the individual costs for each of the peer utilities across time (1994-2009). The bottom table provides the rank order for each metric for each utility. A high rank number in each of these tables indicates a higher investment per MWh, or cost per MWh, relative to other firms in the sample. The second page also has two tables. The top table lists the coefficient of variation, or measure of cost variation or volatility, for each of the sampled utilities. The second table at the bottom of each second page provides

the rank order for this statistic. The last page on every analysis charts the Company's individual investment or cost metric against the composite peer group.

Q. WHAT HAVE BEEN THE RECENT TRENDS IN THE COMPANY'S PRODUCTION PLANT INVESTMENTS?

A. Those investment trends have been provided in Exhibit DED-4. As the Company notes, its production plant investments have virtually doubled from $124/MWh in 1994 to over $242/MWh in 2009. But this is not an unusual trend for coal-fired generators in the region. Like the Petitioner, six of the 17 utilities have seen their production investments in plant increase by over 80 percent, and nine have seen those investments increase by over 50 percent. One company (Kentucky Power) actually saw plant investments increase by an amount greater than the Petitioner. Thus, while the Company's argument that its level of generation plant investment has been considerable, this is equally true for a large number of other comparable coal-fired utilities.

Q. WHAT ABOUT THE ABSOLUTE CHANGE IN ITS OVERALL PLANT INVESTMENTS?

A. The Petitioner has made considerable production plant investments on a per MWh basis relative to its peers. Its investment in production plant per MWh in 2009 ($242.11) was some 91 percent higher than the peer group composite investment of $127.05/MWh. As seen in the lower table, Vectren South ranks 18th (or the highest) of all 18 utilities analyzed. However, this is not a new trend on a relative basis. The Company has consistently had the highest production plant investment per MWh, ranking between 16 and 18 (the highest) for the past 15 years. Thus, while the Company is correct that its per unit generation investment is high, this is not a new trend relative to its peers over time. The exception, as highlighted by the graph on page 3, would be the period between 2003 and 2007 when the Petitioner's production plant investment rates did increase more rapidly relative to the composite peer average. This relative investment

differential has started to diminish in 2008 and 2009 as the industry composite begins to move in the same relative direction as the Company.

Q. ARE THESE PRODUCTION PLANT INVESTMENTS MORE VARIABLE THAN OTHER UTILITIES?

A. In some years, particularly between 2004 to 2007, these investment variations have been significantly greater than average. Page 2 of Exhibit DED-4 shows the coefficient of variation for each company's production plant investments. The coefficient of variation ("CV") measures the spread of a set of data as a proportion of its mean. It can be a useful statistic for comparing the degree of variation from one data series to another, even if the means are drastically different from each other. A series of data with a large CV, therefore, is one that can be said to have a relatively wide dispersion (variation) of data relative to its mean. As shown in the bottom portion of the table on page 2, the Company, while ranking toward the upper end of the peer group, has seen investment variation levels relatively close to the peer group average. This trend changes during the 2004 to 2007 period where the investment levels are high relative to the peers and the average for the peer group. But since 2008, those trends have started to subside. While the Company's rank is still relatively high, its investment variation is trending much closer to the industry average.

Q. DO THESE INVESTMENTS APPEAR TO HAVE BEEN PRODUCTIVE IN REDUCING GENERATION-ASSOCIATED AIR EMISSIONS?

A. Yes, on average these investments appear to have brought the Company's emissions reductions for most major pollutants in line with the peer group. The Company notes that a large portion, if not the overwhelming portion, of its continual production plant investments over the past decade or more are associated with the installation of air emissions mitigation

equipment.[24] However, as seen on Exhibit DED-5, the Petitioner's emissions per generation have not fallen in proportion to the increased rate of investment in production plant raising some questions about the environmental return per dollar invested relative to peer utilities.

Q. HAVE THESE CAPITAL IMPROVEMENTS RESULTED IN GREATER GENERATION OPERATIONAL EFFICIENCIES?

A. Not really. Exhibit DED-6 shows the Petitioner's thermal generation efficiency, which is measured as the ratio of fuel inputs used (MMBTUs of coal burned) to output created (generation in MWhs). This measure is often called a power plant's "heat rate" since it serves as a measure of how efficiently a plant is burning fuel to make electricity. The graph shows that the Petitioner's generation efficiency was quite good relative to its peers prior to 2007. Since that time, the Company's performance is more in line with the peer average and has been relatively stable.

Q. WHAT ABOUT VECTREN SOUTH'S TRENDS IN TRANSMISSION PLANT?

A. Exhibit DED-7 provides the Petitioner's transmission plant investment trends. Overall, Vectren South spent the better part of the analysis period with lower-than-average transmission plant investments per every MWh generated. From 1994 to 2005, the Company's average transmission investment per MWh ranged from between $23/MWh to $28/MWh; whereas, the peer group trend was some 25 percent higher at $28/MWh to $32/MWh. In 2006, the Company appears to have begun a process of transmission investment "catch-up" with its peers and has recently surpassed the peer group average. However, even with this recent increase, Vectren South still only ranks 10th of the 14[25] utilities in the sample with some facing considerably higher transmission plant investments including Kentucky Power ($62.07), Appalachian Power ($59.57)

[24] Direct Testimony of Carl L. Chapman (Revised), 18:27-34.

[25] From 2001 to 2006, data was available for 15 utilities in the sample. From 2007 to 2009, data was available for 14 utilities in the sample.

and Westar ($59.26).

Q. ARE THE PETITIONER'S TRANSMISSION INVESTMENTS MORE VARIABLE THAN OTHER COMPARABLE UTILITIES?

A. Not over the broader time period, but the last few years have seen increases in investments that have clearly been higher than other similarly-situated utilities. Page 2 of Exhibit DED-7 provides the coefficient of variation and shows that since 2004 the Petitioner's investments in transmission have become more variable than in previous years, but variation should not be confused with volatility since the movements have been consistently in one direction and not randomly up and down with little predictability.

Q. WHAT ABOUT VECTREN SOUTH'S RECENT DISTRIBUTION INVESTMENT TRENDS?

A. A comparison of the Petitioner's distribution plant investment relative to its peer group has been provided on Exhibit DED-8. The analysis shows that the Company's investment per MWh is relatively low compared to the other coal-fired utilities. The tables, as well as the graph on the third page of the exhibit, indicate that the historically below-average distribution investment per unit of generation is starting to change. For instance, the Company's overall distribution investment levels have been increasing over the last two years and are moving in directions closer to the peer average.

Q. DO ANY OF THE PEER UTILITIES IN YOUR SAMPLE HAVE THE SAME TYPES OF REVENUE AND COST TRACKERS AS THOSE PROPOSED BY THE PETITIONER?

A. Generally, no. Only one utility in the group, Wisconsin Power, has revenue decoupling at the current time. None of the utilities in the group have any major capital cost trackers, and none have a variable production cost component in a tracker along the lines of the proposal offered by the Petitioner in this proceeding.

Q. WHAT ARE YOUR CONCLUSIONS IN EXAMINING VECTREN SOUTH'S HISTORIC INVESTMENT TRENDS?

A. There are a number of conclusions that can be reached from these comparisons:

- While the Petitioner's generation plant has doubled over the past 15 years, other utilities have had similar investment trends.
- The Petitioner's generation plant investments, while increasing, do not change in a fashion that could be characterized as overly volatile particularly in more recent years where the Company's overall generation investment trend have been moving into line with the peer average.
- The Petitioner's generation plant investments have not resulted in any significant improvements in capacity or operating efficiency, nor have these investments resulted in any disproportionate reductions in air emissions.
- None of the utilities in the peer group have tracker mechanisms proposed by the Petitioner despite the fact that many have investment trends similar to the Petitioner's.

Q. DO YOU AGREE WITH VECTREN SOUTH'S OBSERVATION THAT IT FACES THE POSSIBILITY OF SIGNIFICANT CHALLENGES IF GHG REGULATIONS WERE TO ARISE?

A. Yes, in part. However, many coal-fired utilities are faced with the same potential regulatory challenges as the Petitioner. Power generation accounts for 41 percent of total CO2 emissions in the U.S.[26] While coal-fired utilities and their ratepayers are likely to bear a disproportionate burden relative to other utilities, the entire power sector and all of its customers (i.e., ratepayers) will be impacted by these changes if they come to fruition. The Company is correct in noting that the costs for these proposed regulatory changes will be considerable. However, in my research and the economic impact modeling that I have reviewed and

[26] U.S. Environmental Protection Agency. Human-Related Sources and Sinks of Carbon Dioxide. Internet website: http://www.epa.gov/climatechange/emissions/co2_human.html#fossil.

conducted, ratepayers, not the utilities, are anticipated to bear the brunt of these regulatory changes. The negative economic impacts that were referenced by the Petitioner, as well as just about every other estimate on the topic, are entirely predicated on retail rate increases and the decreased economic activity created by those rate increases, not decreases in utility earnings.

If GHG regulation comes to pass, utilities will be required to comply in a variety of ways that may include investment in renewables, investment in carbon capture and sequestration ("CCS"), investment in other emerging technologies, investments in energy efficiency, and purchases of carbon credits and offsets. Each of these investments and expenditures are anticipated to be recovered entirely through rates. Thus, while the impacts of GHG regulation do pose a significant challenge to near-term energy costs, those are challenges likely to be borne by ratepayers, and not by regulated utilities.

Q. VECTREN SOUTH HAS ALSO NOTED THAT IT FACES CONSIDERABLE PRESSURE DUE TO THE RECENT ECONOMIC RECESSION. ARE INDIANA HOUSEHOLDS AND BUSINESSES FEELING SOME OF THE SAME EFFECTS?

A. Yes. Exhibit DED-9 provides two charts examining recent changes in Indiana economic trends. Page 1, for instance, shows unemployment trends for the state. It illustrates that while Indiana's unemployment rates are below the national levels, they have increased considerably relative to recent historical trends. More importantly, page 2 provides an estimate of the increasing share of income the Petitioner's ratepayers are dedicating to their electricity bills. Estimated electricity expenditures as a share of household income have increased as much as 20 percent from levels experienced as recently as five years ago.

Q. DOES VECTREN SOUTH OFFER ITS RATEPAYERS COMPETITIVE RATES RELATIVE TO ITS PEERS?

A. No, it does not. Over time, the Petitioner's rate competitiveness has deteriorated from being one of the better-priced utilities among its peers, to one of the worst. Exhibit DED-10

shows the trends in the Company's non-fuel system average revenues as a proxy for its non-fuel average rates. From 1994 to 2003, the Petitioner's rates were in the lower two quartiles for coal-fired utilities. Since 2003, its rates have become increasingly more uncompetitive relative to other coal fired utilities as it started to move into the second highest quartile among coal-fired utilities. Over the past two years, Petitioner rates have climbed into the upper quartile. In fact, Vectren South would have the second highest rates in the sample group of coal utilities were it not for the three higher-priced Wisconsin utilities. Wisconsin is the only utility in the sample that has electric revenue decoupling.

Q. DO THESE RATE COMPARISONS GET ANY BETTER IF FUEL IS INCLUDED?

A. No. Exhibit DED-11 provides the same analysis on a total revenue basis. The analysis shows that system average rates are still uncompetitive relative to other coal-fired utilities. In fact, when fuel is included, the deterioration in the Petitioner's rate competitiveness begins as early as 2003.

Q. HAS VECTREN SOUTH RECOGNIZED ITS LACK OF RATE COMPETITIVENESS?

A. Yes. The Petitioner provided a confidential analysis, prepared for the Vectren's Board of Directors in June 2009, outlining its lack of rate competitiveness relative to other peer utilities.[27] The Petitioner's analysis noted:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[27]Response to OUCC Data Request 24-Q-1(b).

[redacted]

Q. DID VECTREN SOUTH IDENTIFY WHAT IT BELIEVED WAS THE SOURCE OF ITS RATE UN-COMPETITIVENESS?

A. Yes. The Petitioner identified three sources for its rate un-competitiveness: [redacted] A replica of a chart provided in this Board of Director's briefing has been provided as a confidential exhibit (Exhibit DED-12). The chart notes that fuel costs account for [redacted] percent of Petitioner's overall retail rates, return and depreciation account for [redacted] percent (combined), and O&M accounts for [redacted] percent of their overall rate structure.

Q. DO YOU AGREE WITH VECTREN SOUTH'S PRESENTATION THAT CAPITAL INVESTMENTS ARE THE PRIMARY DRIVER OF THIS RATE UN-COMPETITIVENESS?

A. Not entirely because return and depreciation, or the Company's "fixed costs," only account for [redacted] percent of their total rate structure at best. Fuel and O&M account for [redacted] percent of the Petitioner's total rate structure, are "variable costs," and are likely the primary drivers of its rate un-competitiveness. In addition, variable production costs is a cost component in which the Petitioner would like to move from base rates, into a tracker mechanism that will encourage more cost inefficiency, not less. This should be a simple and straightforward basis to reject the Petitioner's expanded cost tracker proposals.

Q. HAVE YOU COMPARED THE CHANGES IN TOTAL RETAIL SALES FOR EACH OF THE UTILITIES IN THIS SAMPLE?

A. Yes. All of the utilities in the sample have recently seen a decrease in retail sales, largely as a result of the severe economic recession in effect over the past 30 months. Exhibit DED-13 is comprised of two pages and compares the changes in the Company's retail sales relative to the peer utilities discussed earlier. The graph is indexed to 1994 to put all the utilities on a

comparable scale. Thus the line shows the change in sales for each group relative to its level in 1994. Vectren South's sales increased relative to 1994 for every year and at a rate that was slightly higher than its peers from 1998-2005. After 2005 the Petitioner matched peer group sales trends, and for the past two years, has seen sales growth trends that are slightly lower than the peer average. Thus, the sales growth changes that are presented by Vectren South are a relatively recent phenomenon and are only marginally worse than what other utilities have experienced during comparable time periods.

Q. WHAT ABOUT RETAIL CUSTOMER GROWTH?

A. Page 2 of Exhibit DED-13 provides a similarly-indexed comparison of Vectren South's changes in total customer growth relative to its peers. The customer growth trends are similar to those found in the sales chart. The Petitioner's customer growth was comparable to its peers through the better part of the historic period. In 2005, the peer group and the Petitioner saw relatively flat relative customer growth.

Q. ARE RECENT SALES DECREASES LIKELY TO CONTINUE IN THE FUTURE?

A. No. The State Utility Forecasting Group ("SUFG") anticipates overall Indiana electricity loads to grow by 0.9 percent for 2010, 2.2 percent for 2011, and 2.3 percent for 2012. A graph of the SUFG's current load forecast for the state has been provided in Exhibit DED-14.

Q. HOW DO THE VARIOUS OBSERVATIONS AND ANALYSES YOU JUST DISCUSSED RELATE TO THE PETITIONER'S REVENUE AND COST TRACKER PROPOSALS IN THIS PROCEEDING?

A. In general, each of these analyses and observations were offered to create some context for the investment and operating challenges facing the Petitioner that serve as the justification for the proposed implementation of its wide range of cost and tracker mechanisms. Vectren South, like many other energy companies, has experienced a number of economic challenges over the

past several years. As seen from the comparative charts I presented earlier, some regional utilities have done a better job at reacting to those changes than others. The Company's recent investment cost performance, particularly as it relates to generation plant investment, is certainly high when compared to its peers. The optimal regulatory solution to Vectren South's problems, however, is not to provide a series of revenue and cost trackers, but to promote a ratemaking framework that is based upon performance and accountability, not guarantees. Adopting an expanded range of revenue and cost tracker mechanisms at the current time, for a company that has the highest rates among its peers, only invites turning an already bad situation into one much worse. The remainder of my testimony will explain in greater detail how a worse situation could easily evolve by the adoption of the Petitioner's revenue and cost tracker proposals.

A. OVERVIEW OF THE PETITIONER'S SRA PROPOSAL

Q. WOULD YOU BRIEFLY DESCRIBE THE PETITIONER'S REVENUE DECOUPLING PROPOSAL?

A. Yes. Vectren South proposes to implement electric revenue decoupling through a sales reconciliation process which will adjust rates of all classes other than the DGS-3 class, for differences between fixed costs approved for recovery in this proceeding and actual fixed cost revenues collected by customers in the reconciliation period. These differences will also be adjusted for the change in the number of customers. The Petitioner proposes that these revenue differences be deferred on a monthly basis for subsequent inclusion in an annual SRA filing that would surcharge or credit deferred decoupling amounts. Vectren South's proposed SRA is the same mechanism that it proposed in Cause No. 43427.

B. RATIONALE FOR DECOUPLING

Q. WHAT ARE THE PURPORTED DISINCENTIVES TO UTILITIES TO PROMOTE ENERGY EFFICIENCY?

A. Some energy efficiency advocates, as well as many (but not all) utilities, often argue that current regulatory pricing practices discourage utility-sponsored energy efficiency programs. These advocates claim that energy efficiency reduces sales thereby reducing a utility's ability to recover its fixed costs. One of the primary rationales for the Petitioner's revenue decoupling proposal has been to address what it claims is a mismatch between the financial interests of its customers and its shareholders regarding energy efficiency.

Q. HOW DOES REVENUE DECOUPLING ADDRESS THIS PURPORTED DISINCENTIVE?

A. Revenue decoupling removes the relationship between the collection of a utility's revenue requirement and its sales. Under Vectren South's revenue decoupling approach, changes in sales revenues would be compared with benchmark revenue amounts. The purported public policy goal of revenue decoupling is to make a utility indifferent between making an incremental sale and creating incremental end-use efficiencies.

Q. ARE SALES DECREASES DUE TO ENERGY EFFICIENCY THE ONLY CAUSE OF DIFFERENCES BETWEEN TEST YEAR (ALLOWED) AND ACTUAL REVENUES?

A. No. In fact, utility lost base revenues associated with energy efficiency programs are typically quite small. There are a variety of other reasons why retail sales and revenues in any given year can differ from the test year amount. These impacts are usually considerably larger than sales losses created by energy efficiency programs. Consider that test year retail sales and revenues in a rate case are usually based upon a "typical" year and as such, are based upon typical factors such as the weather, the economy, and prices, among other things. In any given year, the actual performance of the economy may differ from the test year. Weather may be colder or warmer than the historical normal weather trends included in the test year, and other factors may occur in any given year that impact sales differently than what was anticipated in the

test year determination. The differences in sales created by weather, the economy, commodity prices, and other factors usually account for greater changes in revenue than those resulting from utility-sponsored energy efficiency programs.

Q. HOW DO THE MOTIVATIONS FOR REVENUE DECOUPLING DIFFER BETWEEN ELECTRIC AND NATURAL GAS UTILITIES?

A. Revenue decoupling has attained a new level of interest in recent years for natural gas and electric utilities due to (1) recent increases in natural gas prices, particularly after 2005, which has impacted overall usage[28] and (2) the significant acceleration of state-driven energy efficiency ("EE") goals and targets. Exhibit DED-15 presents a map that shows EE goals that many states have recently adopted hoping to attain demand reduction levels by as much as 15 to 20 percent by 2015.

Q. ARE NATURAL GAS AND ELECTRIC UTILITIES FACING SIMILAR USAGE TRENDS?

A. No. Natural gas utilities have claimed an additional motivation for promoting revenue decoupling that is associated with changing trends in overall use per customer ("UPC"), particularly declining trends in residential UPC over the past several years. Electric utilities have not been facing similar decreasing UPC trends. In fact, electric utilities have seen UPC trends move in opposite directions from those seen in the natural gas industry. The chart in Exhibit DED-16 compares overall U.S. electric and natural gas UPC trends over the past 18 years. While electric UPC has been generally increasing, over this same period natural gas UPC has been generally decreasing.

Q. HAVE ELECTRIC COMPANIES EXPERIENCED CONSIDERABLE LOST REVENUES AS A RESULT OF PAST ENERGY EFFICIENCY EFFORTS?

[28]Natural gas price increases are also important in power markets since natural gas typically determines the price of energy at the margin in many hours of the day in most regional wholesale power markets.

A. Typically, no. Most electric utility energy efficiency efforts have represented relatively small shares of their overall retail sales, resulting in relatively small levels of revenue losses. Schedule DED-17 provides a table of electric energy efficiency program savings and spending for those programs at the state level. As seen from the table, savings from EE programs, while large in the absolute, are small relative to total usage and overall revenues. In addition, the table also shows that historic energy efficiency savings in Indiana have amounted to about 1.0 percent of total electricity sales. California, long considered a leading state in electric energy efficiency, has only seen energy efficiency savings of 10.3 percent of total electricity sales.

Q. WHAT LEVEL OF LOST BASE REVENUE CAN BE EXPECTED FOR VECTREN SOUTH AS A RESULT OF THE COMMISSION'S ENERGY EFFICIENCY GOALS?

A. Lost base revenues are anticipated to be very small shares of the Company's overall sales. Exhibit DED-18 shows the Petitioner's forecasted annual lost base revenues that are created by the annual Commission energy efficiency goals. These goals do not exceed 0.55 percent of forecasted base revenues in any given year.

Q. WHAT FACTORS ARE INFLUENCING CHANGES IN UPC IF ENERGY EFFICIENCY SAVINGS DO NOT ACCOUNT FOR CONSIDERABLE SHARES OF UTILITY REVENUE CHANGES?

A. A number of factors influence sales including weather, income, commodity prices, as well as structural usage changes created by new and more efficient appliance standards. More recently, the recession and its consequences of unemployment and belt tightening have contributed to a reduction in usage by customers. As I noted earlier, natural gas commodity prices have changed dramatically over the past eight years starting during the winter of 2000-2001 and particularly in the aftermath of Hurricanes Katrina and Rita in 2005. These collective changes have had considerable impacts on recent changes in total residential UPC.

Q. WHAT CONTROL DOES AN ELECTRIC UTILITY HAVE OVER SUCH FACTORS AS COMMODITY PRICES, THE ECONOMY, WEATHER, AND TECHNOLOGICAL STANDARDS?

A. Utilities have little to no control over these factors. Consider that utilities have no specific influence on the economy or economic growth, they have no ability to change natural gas commodity prices, and they can only change retail service rates with the approval of their regulators. Utilities cannot control the weather, and they have no control over technological trends or innovation.

Q. CAN'T ELECTRIC UTILITIES PROMOTE RATE STRUCTURES THAT EXPAND USE?

A. Yes, but those declining block rate structures are developed in a fashion that tend to reflect the underlying costs as measured by cost of service studies that ultimately have to be approved by regulators. Utilities are regulated because they are (1) imbued with the public interest and (2) have natural monopoly cost characteristics (i.e., declining costs). Rates typically reflect these cost characteristics because efficient use (output) decreases overall average costs for all ratepayers. A contraction of efficient use, therefore, can lead to higher average costs, other things being equal. So, to the extent that rate design promotes use, there is a sound economic and regulatory reason for promoting that use: declining block rate structures are developed for the explicit purpose of creating efficiencies and cost savings for all customers by driving down average costs.

Q. WHAT ABOUT SALES LOSSES ASSOCIATED WITH THE PROMOTION OF MARKET TRANSFORMATION PROGRAMS?

A. Large and rapid decreases in energy use are not likely to arise from any market transformation program thereby causing potential financial harm for the Company. Education is a long-term proposition and the results of these market transformation programs will likely be embedded (and difficult to separate) from the trend in usage per customer.

Q. HOW DO YOU RESPOND TO THE ARGUMENTS THAT LOST REVENUES SIMPLY WILL NOT PROVIDE THE APPROPRIATE SIGNALS FOR ELECTRIC UTILITIES TO ENGAGE IN MARKET TRANSFORMATION?

A. I would disagree. Vectren South, like any other regulated utility in this country, has an obligation to serve its customers in a safe, reliable, and economic fashion. Part of that charge should be informing and educating customers about the appropriate use of utility services that rely heavily upon local, regional, and national natural resources.

Q. WHAT DOES, OR SHOULD, THE PUBLIC INTEREST STANDARD IMPLY ABOUT INEFFICIENT SALES PROMOTION AND THE PROVISION OF UTILITY SERVICE?

A. Utilities operate in the public interest because they (1) provide basic and necessary customer services and (2) extract and utilize valuable natural resources in the provision of these services (energy, air, water, land) to the public. Public utilities are expected to act and perform in a fashion that is consistent with this responsibility. Intentionally wasting these natural resources is inconsistent with this public interest standard. The promotion of inefficient sales for profit is simply inconsistent with the underlying public interest principles of close to 100 years of utility regulation. To act in such a fashion would intentionally jeopardize natural resources, unnecessarily increase costs for ratepayers, and prejudice the public interest. Thus, at least from a regulatory perspective, it is typically not the case that utilities should (or are) promoting inefficient levels of sales.

Q. DO YOU HAVE ANY EXAMPLES OF ELECTRIC UTILITIES THAT RECOGNIZE THIS PUBLIC INTEREST REQUIREMENT RELATIVE TO SALES GROWTH AND DECOUPLING?

A. Yes. Georgia Power Company, which is part of one of the largest electric utilities in the United States, noted in its comments on the Georgia State Energy Strategy:

> <u>Decoupling is typically proposed as a solution to a perceived problem that does not exist</u> … The report assumes that under the current scheme of cost-based regulation…there is an ongoing and significant incentive for electric utilities…to

> grow its sales and a corresponding negative incentive to implement energy efficiency because of lost revenues.
>
> [Our] focus is and has always been on reliable, competitively priced electricity and great service for [our] customers. [Our company] only implements energy sales initiatives where those initiatives can be shown to help reduce the price of electricity to [our] customers.
>
> [We are] also subject to frequent rate proceedings that ensure that there are not long-term incentives to simply increase sales to drive increased profitability…. This has ensured that there is not a long-term benefit to [our] earnings from simply increasing electricity sales, as those additional sales are included when revenues and prices are re-set during the rate proceeding.[29]

More recently, the CEO of Southern Company (Georgia Power's parent company), in his quarterly discussion with equity analysts, stated his continued belief that decoupling is not workable for his company.

> I'm reluctant to answer a [sic] ever consider kind of question, because I think in these times you always have to be willing to consider anything. But fundamentally, we don't think that the decoupling concept works in our regulatory environment. And fundamentally, I've said I don't particularly like the notion. I think there is good reason to keep the cost of the product connected with the use of the product and make sure that our customers are as informed as we can possibly make them about how to use a product and the service efficiently and effectively to control their costs. I like that model a lot better than I like disconnecting what I think ought to go together.[30]

Q. ARE YOU FAMILIAR WITH THE IURC ORDERS APPROVING REVENUE DECOUPLING FOR TWO NATURAL GAS UTILITIES, INCLUDING THE PETITIONER'S OWN GAS AFFILIATES IN INDIANA?

A. Yes. The Commission approved two different decoupling mechanisms: one for the Petitioner's gas operations in 2006 and one for Citizens Gas & Coke Utility ("Citizens") in 2007. In approving the Settlement which included revenue decoupling mechanism, the Commission noted:

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[29] Comments of Georgia Power Company on the State Energy Strategy for Georgia. Comment period June 6, 2006 to July 5, 2006, emphasis added.

[30] Southern Company (SO), Q2 2009 Earnings Call, July 29, 2009 1:00 pm ET; with CEO David Ratcliffe.

> …70% to 80% of the customer's bill being recovered based on usage. It also will allow the customer to retain the savings in gas costs resulting from their conservation efforts…. [T]he long term interests of customers and stakeholders are served by efforts to reduce the 70-80% of their bill representing gas costs. These efforts will be most successful when the serving utility and its customers have the same interests in efficiency, i.e., when service is provided by a utility that can promote energy efficiency without impairing its opportunity to recover its reasonable and authorized operating costs.[31]

Q. WHAT ARE THE DIFFERENCES BETWEEN VERTICALLY-INTEGRATED ELECTRIC UTILITIES AND GAS UTILITIES THAT SHOULD BE CONSIDERED IN EVALUATING A REVENUE DECOUPLING PROPOSAL?

A. One of the more significant differences between gas and electric utilities is the composition of their rate structure. Exhibit DED-19 shows the trend in the cost shares for natural gas utilities relative to coal-fired electric utilities. Over the past several years, fuel costs for gas utilities have averaged about 60 percent of total rates with one year (2005) the share increasing to as high as 68 percent. Coal-fired electric utilities have seen much lower and certainly less volatile changes with fuel comprising only about 17 percent of total rates. As noted earlier, the Commission's approval of the Vectren and Citizens' revenue decoupling plans were premised on the conclusion that the high price of natural gas, coupled with the high proportion of gas commodity cost relative to total rates, were sufficient reasons for moving forward with the mechanism. Those factors are clearly not apparent in this proceeding where the average coal rates included in the Company's rates average around $1.80 per MMBtu, vary significantly less than natural gas prices, and contribute only 25 percent of a customer's overall rate.

Q. HAVE YOU COMPARED THE CHANGES IN FUEL SHARES FOR VECTREN SOUTH'S GAS AND ELECTRIC OPERATIONS?

[31] In re: Petition of the Board of Directors for Utilities of the Department of Public Utilities of the City of Indianapolis, as Successor Trustee of a Public Charitable Trust, d/b/a Citizens Gas & Coke Utility for Authority to Increase its Rates and Charges for Gas Utility Service and for Approval of a New Schedule of Rates and Charges Applicable Thereto, Approval Under IC 8-1-2.5 of an Alternative Regulatory Plan Implementing an Uncollectible Expense Adjustment Mechanism, a Demand Side Management and Rate Decoupling Mechanism and Approval of Other Changes to its General Terms and Conditions for Gas Service, Cause No. 42767, Order Approved August 29, 2007, 21.

A. Yes, as just noted, fuel is only 25 percent of Vectren South's average retail electric rates. This percentage has varied over the past 10 years from a high of 28 percent (2006) to a low of 20 percent (2000). These shares differ considerably for the Company's gas operations where the Commission's decoupling order notes that fuel comprises 70 to 80 percent of total rates.[32]

Q. HOW MUCH OF VECTREN SOUTH'S TOTAL REVENUES WILL BE RECOVERED UNDER SOME TYPE OF TRACKER MECHANISM IF THEIR RATHER EXPANSIVE PROPOSALS ARE APPROVED IN THIS PROCEEDING?

A. Petitioner already has a number of trackers, some of which were approved as a result of the settlement in its last rate case. Under the Petitioner's current rate and regulatory structure, it is allowed to recover some 10 percent of its revenues through one form of tracker or another. If their full complement of trackers are approved in this proceeding, however, some 14 percent of the Company's total revenues will be recovered through a tracker.

C. REVENUE DECOUPLING AND RISK SHIFTING

Q. WHO TRADITIONALLY BEARS THE RISK OF CHANGES IN SALES REVENUE?

A. The utility and its shareholders typically bear the risk of revenue and sales differences from the test year for a number of different reasons. First, it is the utility's responsibility to propose a typical year for rate-making purposes. It would not be in a utility's nor its shareholders' best interests to propose a test year that was unsupportive of what management believed was required to recover costs and earn its allowed return. Second, a utility's allowed rate of return, like that of any other business, includes some premium for the business risk inherent in the industry in which it operates.

Q. HOW ARE ECONOMIC RISKS SHIFTED TO RATEPAYERS?

[32] Verified Petition of Indiana Gas Company, Inc. and Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. for Approval of Conservation Program and Conservation Adjustment through Approval of New Tariff Riders and Associated Terms and Conditions of Service under Ind. Code 8-1-2-41(a). Indiana Utility Regulatory Commission. Cause No. 42943; Cause No. 43046. December 1, 2006.

A. Under decoupling, if revenues fall due to a contraction in the economy, customers will be required to make the utility whole for those revenue shortfalls. Decreases in sales associated with economic downturns have nothing to do with energy efficiency programs offered by the Petitioner. Instead, they are the natural reaction of households trying to reduce their expenditures during difficult economic times or, alternatively, businesses and industries idling or shutting down their operations. Under revenue decoupling, ratepayers would be required to make a utility whole for revenue losses during these economic downturns; whereas, under traditional regulation, utilities bear the risks of these economic contractions, just like many other types of businesses and industries.

Q. HOW IS COMMODITY PRICE RISK SHIFTED TO CUSTOMERS?

A. When natural gas or other fossil fuel prices increase they can have a direct impact on electricity usage. Holding other factors constant, fossil fuel commodity price increases are typically translated into higher overall average electricity prices seen by ratepayers on their total bills. Under Vectren South's decoupling proposal, it will be made whole for any natural gas, or other fossil fuel price-induced reductions in UPC. This impact is still important for coal-fired utilities despite their tendency to procure coal with longer term contracts.

Q. HAVE OTHER REGULATORY COMMISSIONS RECOGNIZED THE RISK SHIFTING NATURE OF REVENUE DECOUPLING?

A. Yes. Notwithstanding recent legislation allowing revenue decoupling, in Connecticut the Department of Public Utility Control ("DPUC") recently rejected, for a second time, a decoupling proposal offered by Connecticut Natural Gas and found:

> Full decoupling compensates the Company for any type of reduction in consumption, such as warmer weather, customer loss, a deteriorating economy as well as permanent and price-induced conservation. Clearly, the very large potential risk of revenue instability is shifted from the Company to customers. If the Company were to purchase an insurance instrument to guarantee [sic] distribution revenues, the insurer would expect compensation and the Company

> would expect to make payment for the transfer of risk. The Company's decoupling proposal thrusts customers into the role of insurer without proffering compensation. By reviewing the level of compensation customers would require to breakeven under decoupling, the Department concluded that the requisite reduction in ROE needed as compensation would prove too draconian and actually impede the Company's ability to attract capital. The Company's own calculation shows that a 10% change in weather (HDDs) alone translates into a $4 million change in revenue. Add to this a continuing loss in UPC as predicted by the Company plus the uncertainty of a faltering economy and customers, conservatively, are at risk for $5 to $7 million of annual revenue shortfall. It will require a 100 basis point reduction in ROE (approximately a $3.8 million reduction in revenue) to provide customers with weather-only compensation, without anything additional. While decoupling can be expected, *a priori*, to reduce the frequency of rate applications and associated expense, the Company has not proffered any stay-out proposal. The enlarged conservation expenditures that the Company points to as the decoupling quid pro quo, will be paid for by ratepayers, who will also experience upward pressure on rates as UPC declines further. The Company's decoupling proposal guarantees a revenue stream free of customer compensation while holding open the freedom to file a rate application at will. The Company's decoupling proposal is denied. [emphasis added][33]

Q. WHAT ABOUT THE FINDINGS IN ARIZONA REGARDING THE RISK-SHIFTING NATURE OF REVENUE DECOUPLING?

A. In 2005, the Arizona Corporation Commission ("ACC"), in evaluating a proposal offered by Southwest Gas Company noted:

> [t]he Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither the law nor public policy requires such a result . . .[34]

In 2008, Southwest proposed another decoupling mechanism and in its decision the ACC found:

> [i]t appears that, first and foremost, revenue decoupling is a means of providing the Company with what is effectively a guaranteed method of recovering

[33] Application of Connecticut Natural Gas Corporation for a Rate Case; Docket No. 08-06-12, Decision, June 30, 2009.

[34] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to its Operations Throughout the State of Arizona, Docket No. G-01551A-04-0876; Decision No. 68487, February 23, 2006.

> authorized revenues, thereby shifting a significant portion of the Company's risk to ratepayers.[35]

Q. WHAT DID THE NEW HAMPSHIRE COMMISSION CONCLUDE REGARDING REVENUE DECOUPLING AND RISK SHIFTING?

A. The New Hampshire Commission determined that decoupling could inappropriately shift risks onto customers.

> Regardless of the model used, it would be appropriate to propose revenue decoupling in the context of a rate case in order to avoid single-issue ratemaking. Further, depending on the specific company proposal, there could be a potential to inappropriately shift risks. That is, revenue decoupling could enhance the utility's revenue stability and reduce earnings volatility; hence, revenue decoupling may result in a shift of risk away from the utility and toward the customer. Therefore, any revenue decoupling model proposed should be in the context of a rate case so that a utility's return on equity (ROE) can be thoroughly analyzed.[36]

Q. DOES THE POSSIBILITY OF RATE DECREASES THAT ARE CREATED BY REVENUE DECOUPLING CREATE A POTENTIAL BENEFIT FOR RATEPAYERS?

A. Not necessarily, particularly for relatively risk-averse ratepayers. While revenue decoupling holds out the purported opportunity for rate decreases, this opportunity comes at a cost. Revenue decoupling puts ratepayers in the position where they have traded base rate certainty for base rate uncertainty. By definition, risk averse agents like ratepayers will be worse off under decoupling (even with rate decrease opportunities) since certainty is always higher valued (greater expected utility) relative to risk.[37]

D. REVENUE DECOUPLING AND PUBLIC POLICY

Q. IS REVENUE DECOUPLING A NEW METHOD FOR DEALING WITH CHANGES IN REVENUES RESULTING FROM UTILITY-SPONSORED ENERGY EFFICIENCY PROGRAMS?

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[35] In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona, Docket No. G-01551A-07-0504; Decision No. 70665, Arizona Corporation Commission, December 24, 2008.

[36] Energy Efficiency Rate Mechanisms Order Resolving Investigation, New Hampshire Public Utilities Commission, DE 07-064; Order No. 24,934, January 16, 2009.

[37] P.R.G. Layard and A.A. Walters. (1978). *Microeconomic Theory*. New York: McGraw-Hill Book Company, 357.

A. No. Revenue decoupling is a policy proposal that dates back to the late 1980s and early 1990s, and was included as a regulatory review requirement in the Energy Policy Act of 1992 ("EPAct 1992"). Past revenue decoupling initiatives were driven primarily by the electric utility industry and many of the same energy efficiency and environmental advocates promoting the mechanism today. Most decoupling mechanisms created during this period were eliminated during the electric restructuring process that also began in the early 1990s and accelerated through the better part of the decade.

Q. ARE THERE ANY REAL-WORLD EXAMPLES OF HOW REVENUE DECOUPLING CAN LEAD TO SERIOUS PROBLEMS DURING AN ECONOMIC CONTRACTION?

A. Yes, one of the more widely-recognized failures of revenue decoupling occurred in Maine during the early 1990s. The program, known as "ERAM" ("Electric Revenue Adjustment Mechanism"), was put into place for a three-year trial period to encourage Central Maine Power ("CMP") to promote energy efficiency. The ERAM, like the proposed SRA, had no adjustments for changes in regional activity. The adoption of the ERAM coincided with a recession that resulted in lower sales levels and substantial revenue deferrals. CMP was entitled to recover these deferrals under the provisions of the ERAM mechanism, which by the end of 1992 reached $52 million. Only a very small portion of this amount was attributed to CMP's conservation efforts as most of the deferral resulted from the economic recession. The ERAM was viewed by many as a mechanism that shielded CMP from the economic impact of the recession rather than furthering the intended energy efficiency and conservation incentives. CMP's ERAM was terminated on November 30, 1993.[38]

Q. CAN YOU EXPLAIN THE RELATIONSHIP BETWEEN THE EISA AND REVENUE DECOUPLING?

[38]Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability, Maine Public Utilities Commission, Presented to the Utilities and Energy Committee, February 1, 2004.

A. The Energy Independence and Security Act ("EISA") of 2007 included a number of provisions designed to increase energy efficiency across a wide range of end-use sectors.[39] The rate design provisions of this bill were included in Section 17 and designed to update the Section 111(d) provisions of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"), the first major piece of energy efficiency legislation passed in the U.S. during the period of the first energy crisis of the 1970s. The EISA outlined six different rate design and rate recovery provisions that state regulatory commissions were required to consider. While revenue decoupling was identified as a potential rate design mechanism, it was not the only mechanism outlined in the legislation. Further state commissions were required to consider, not adopt, these mechanisms. Such a "consideration" is not unusual, and harkens back to the Energy Policy Act of 1992, which also had similar "consideration" requirements for both revenue decoupling and integrated resource planning ("IRP").

Q. CAN YOU EXPLAIN THE RELATIONSHIP BETWEEN THE AMERICAN RECOVERY AND REINVESTMENT ACT OF 2009 ("ARRA") AND REVENUE DECOUPLING?

A. Yes. The ARRA was passed by Congress and signed into law in early 2009. A large portion of the ARRA was dedicated to promoting energy efficiency and renewable energy. In order to qualify for funds distributed from the ARRA, each state was required to certify that its regulatory policies supported the development of energy efficiency. Specifically, the ARRA required states adopt:

> . . . in appropriate proceedings for each electric and gas utility, with respect to which the State regulatory authority has ratemaking authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provide timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable

[39] H.R. 6 [110th]: Energy Independence and Security Act of 2007, http://www.govtrack.us/congress/billtext.xpd?bill=h110-6.

and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently.[40]

Q. DO YOU THINK THE ARRA REQUIRES THE ADOPTION OF REVENUE DECOUPLING FOR AN ELECTRIC UTILITY?

A. No, not from a policy perspective. On its face, and within the four corners of the policy statements, there are no explicit requirements for revenue decoupling, straight-fixed variable rate design, revenue stabilization plans, performance-based regulation, or any other regulatory policy measure often attributed to either piece of legislation. Furthermore, the ARRA gives state commissions considerable latitude to examine the issue of utility incentives, regulatory structure, and energy efficiency. Assertions that the ARRA requires revenue decoupling, or even suggests that this policy is preferred to traditional regulation, is a misinterpretation of the legislation. In fact, the original language in the House version of the ARRA specifically included requirements and provisions for revenue decoupling, but the National Association of Regulatory Utility Commissioners ("NARUC"), as well as other ratepayer and consumer groups like NASUCA and

[40] American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5 § 410(a), 123 Stat. 147 (2009).

ELCON, recommended that these requirements be removed from the bill.[41]

Q. DOES TRADITIONAL REGULATION ADDRESS THE KEY COMPONENTS OF THE ARRA?

A. Yes. Traditional regulation addresses each of the three components including the provision that suggests:

1) Regulators should have a "general" policy that aligns utility incentives with helping customers use energy more efficiently.
2) Regulators should have a "general" policy that allows utilities the timely recovery of their energy efficiency investments.
3) Regulators should have a "general" policy that allows for the timely recovery of earnings associated with cost effective energy efficiency savings.

Q. LET'S TALK ABOUT THE FIRST ARRA REQUIREMENT. DOES CURRENT REGULATION ALIGN ELECTRIC UTILITY INCENTIVES WITH HELPING CUSTOMERS USE ENERGY MORE EFFICIENTLY?

A. Yes. Utilities are regulated in the public interest. The goal of current regulation is to develop fair, just, and reasonable rates. Utilities are given an opportunity to recover their prudently-incurred costs, and a return on and of their prudently-incurred investments if they are found to be providing reliable and economic service. This "regulatory compact" has aligned customer and utility interests in the provision of service for over a century. This general policy is not restricted to just one type of service alone and includes gas procurement, distribution services, electric utility services, and energy efficiency services.

[41]In Re: Economic stimulus legislation and state utility ratemaking policies. Letter to Congressional Leaders from The National Association of State Utility Consumer Advocates (NASUCA) and The Electricity Consumers Resource Council (ELCON). January 23, 2009. Also see: Testimony of the Honorable Richard E. Morgan, Commissioner, District of Columbia Public Service Commission on Behalf of the National Association of Regulatory Utility Commissioners on "Allocation Policies to Assist Consumers". Before the United States House of Representatives Committee on Energy and Commerce, Subcommittee on Energy and the Environment. April 23, 2009.

Q. CAN REVENUE DECOUPLING UNDERMINE THE ALIGNMENT OF THESE INTERESTS?

A. Yes. Revenue decoupling would undermine this positive set of incentives (i.e., profit in return for economic and reliable service) and the alignment of utility and ratepayer interests. Revenue decoupling provides guaranteed revenues, creating incentives for inefficiency and poor service. If a utility's rates are not competitive, and it loses loads to bypass or fuel switching, a decoupled utility will be made whole for the inefficiency. If opportunities to add new loads arise through business relocations or expansions, revenue decoupling potentially discourages active pursuit of those loads since a utility will be made whole with or without the new customers. Thus, while revenue decoupling may reduce the throughput incentive, it may be equally likely to reduce the customer incentive as well.

Q LET'S TURN TO THE SECOND ARRA REQUIREMENT. DOES CURRENT REGULATION PROVIDE A GENERAL POLICY THAT ALLOWS FOR THE TIMELY RECOVERY OF ENERGY EFFICIENCY COSTS FOR ELECTRIC UTILITIES?

A. Yes. Rate cases and other cost recovery mechanism give utilities opportunities to recover their energy efficiency expenditures. Some utility commissions require energy efficiency program costs to be recovered in base rates, while others allow energy efficiency cost recovery tracker mechanisms like the Company's Demand Side Management Adjustment ("DSMA"). Regardless, either mechanism, both currently available under traditional regulation, gives the utility the opportunity for timely recovery of energy efficiency costs without the need for revenue decoupling.

Q. LET'S TURN TO THE THIRD ARRA REQUIREMENT. DOES CURRENT REGULATION PROVIDE A GENERAL POLICY THAT ALLOWS FOR THE TIMELY RECOVERY OF EARNINGS ASSOCIATED WITH ENERGY EFFICIENCY SAVINGS?

A. Yes, as I noted before, current regulation has provided utilities with an opportunity to earn a return on and of their prudently-incurred investments for well over a century. This

allowance is not set on an asset-specific basis, nor is it restricted to certain types of assets. Utilities get an allowed rate of return that is uniform for all types of capital investments such as distribution mains, transmission mains, compression, regulation, service lines, meters, general plant, and other types of capital investments. The current process does not exclude energy efficiency to the extent that the nature of the investment is capitalized. Further, if earnings were to fall due to energy efficiency investments, utilities are typically allowed to come before a regulatory commission to seek an increase in rates in order to cover those earnings losses.[42]

Q. ARE THERE RULES AND REGULATIONS OF THE COMMISSION THAT ARE DESIGNED TO PROMOTE DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY?

A. Yes. The Indiana Administrative Code addresses guidelines for cost recovery of demand-side management costs. 170 IAC 4-8-5 explains the methods for recovering the planning and implementation costs associated with demand-side management programs. Specifically, a utility can recover these costs by:

(1) including them in base rates during a rate case using a balancing account;

(2) periodic recovery of the costs incurred in excess of the cost included in base rates;

(3) inclusion of the capital cost in rate base, amortized over a period set by the Commission;

(4) accumulation for possible future recovery of costs not recovered under 1 through 3; or

(5) a cost recovery mechanism proposed by the utility, other parties, or the Commission.

[42]This assumes that a utility is not under some type of performance, incentive, or formula-based rate plan that includes a "stay-out" provision.

170 IAC 4-8-6 addresses the ability of utilities to recover lost revenue from the implementation of a DSM program. Specifically, it states that the Commission may allow the utility to recover its lost revenue due to DSM programs. The rule requires that the calculation of lost revenue must account for the impact of free-riders and the change in the number of DSM program participants between base rate cases and on the revised estimate of a program-specific load impact resulting from measurement and evaluation activities.

DSM incentives are also addressed in this Rule (170 IAC 4-8-7), stating that when appropriate the Commission may provide the utility with a shareholder incentive to encourage participation in and promotion of demand-side management programs. However, granting such an incentive, according to the rule, is not a determination of the merits of the incentive, which may be debated in future proceedings before the Commission.

Q. HAS THE COMMISSION ISSUED ANY RECENT ORDERS ON DSM?

A. Yes. The Commission recently issued an order in Cause No. 42693 ("Phase II Order") on December 9, 2009. In this Phase II Order, the Commission set forth a set of DSM policy objectives to support efforts to create reductions in statewide energy usage. The Commission established four overarching objectives with respect to demand side management:

> First, the Order establishes an overall annual energy savings goal of 2% to be achieved within 10 years, with interim savings goals to be achieved in years one through nine. Second, this Order establishes certain initial Core DSM Programs that must be offered throughout the State of Indiana. Third, this Order requires the formation and participation in a DSM Coordination Committee by the entities described in this Order. An initial objective of the DSM Coordination Committee is the issuance of two RFPs. The first RFP is to be issued for the selection of an Independent Third Party Administrator to oversee and coordinate the Core Programs established in this Order. The second RFP is to be issued for the selection and utilization of an administrator(s) to undertake Evaluation, Measurement & Verification of DSM program offerings. Fourth and finally, this Order requires the submission of compliance filings including, but not limited to,

three year DSM Plans with annual supplemental updates, with the Commission to confirm that the objectives of this Order are being fully satisfied.[43]

Q. DO YOU AGREE WITH VECTREN SOUTH'S ASSERTION THAT REVENUE DECOUPLING WILL ALIGN THE INTERESTS OF THE COMPANY AND ITS CUSTOMERS?[44]

A. No. The Petitioner's suggestion that revenue decoupling will align the interests of the Company and its customers is not correct.[45] Revenue decoupling is being actively debated before various state legislatures and state regulatory commissions and is seen as a divisive issue by some important stakeholder groups. For some groups, like energy efficiency advocates and some utilities, revenue neutrality is seen as a positive regulatory outcome. Other groups, particularly consumer groups, are very concerned about the adoption of revenue decoupling and the implications it may have for customer bills. Two prominent consumer groups have opposed revenue decoupling mechanisms including the Electric Consumers Resource Council ("ELCON") and the National Association of State Utility Consumer Advocates ("NASUCA").

Q. WHAT POSITION HAS ELCON TAKEN ON REVENUE DECOUPLING?

A. ELCON, a large trade association comprised of major industrial customers of natural gas and electricity, issued both a position statement and White Paper strongly opposed to revenue decoupling: a position similar to that taken by most industrial customers in the early 1990s when revenue neutrality mechanisms were initially debated. The White Paper issued by ELCON noted many flaws with revenue decoupling including:

(1) Decoupling promotes mediocrity in the management of a utility;

(2) Decoupling shifts significant business risk from shareholders to consumers with only limited opportunities for net increases in consumer benefits;

(3) Decoupling eliminates a utility's financial incentive to support economic development within its franchise area;

[43] Order, Cause No. 42693, p. 52.
[44] Revised Direct Testimony of Ulrey, p. 24.
[45] Direct Testimony of Steve Lindsey, p 6.

(4) Decoupling tends to address "lost revenues" and not the real issue which is "lost profits;"

(5) Sending appropriate price signals is the most important step in promoting energy efficiency; and

(6) Third party, independent delivery of energy efficiency services is a more effective means of addressing incentives.[46]

Q. WHO DOES NASUCA REPRESENT?

A. NASUCA represents the various state-funded Attorneys General, consumer counsels, and consumer advocate agencies charged with representing the interests of all ratepayers in state utility regulatory proceedings.

Q. HAS NASUCA ISSUED A FORMAL POSITION STATEMENT OR RESOLUTION ON REVENUE DECOUPLING?

A. Yes. In 2007, NASUCA passed a resolution stating that it would "continue its long tradition of support for the adoption of effective energy efficiency programs" and "oppose decoupling mechanisms that would guarantee utilities the recovery of a predetermined level of revenue without regard to the number of energy units sold and the cause of lost revenue between rate cases."[47]

Q. HAVE YOU PROVIDED AN ANALYSIS ON THE CURRENT PROGRESS OF REVENUE DECOUPLING ADOPTION AND REJECTION?

A. Yes, Exhibit DED-20 shows the recent activity on revenue decoupling for natural gas and electric utilities across the U.S. Currently, there are 20 states that have adopted revenue decoupling as either a permanent or pilot mechanism for natural gas utilities. These states are Arkansas, California, Colorado, Illinois, Indiana, Massachusetts, Maryland, Minnesota, Nevada, New Jersey, New York, North Carolina, Ohio, Oregon, Tennessee, Utah, Virginia, Washington,

[46] Revenue Decoupling, A Policy Brief of the Electricity Consumers Resource Council. The Electricity Consumers Resource Council, January 2007.

[47] National Association of State Utility Consumer Advocates, NASUCA Energy Conservation and Decoupling Resolution, Resolution 2007-01, June 12, 2007.

Wisconsin and Wyoming. In addition, Rhode Island has enacted legislation that requires decoupling, but no mechanisms have been adopted. Kansas is currently considering revenue decoupling proposals. On the electric side, just nine states have adopted decoupling: Connecticut, Idaho, Massachusetts, Maryland, Michigan, New York, Oregon, Vermont and Wisconsin.

Q. HAVE ANY STATES REJECTED REVENUE DECOUPLING PROPOSALS?

A. Yes. Some states have rejected decoupling. In 2009, Rhode Island rejected National Grid's revenue decoupling proposal stating that it "is not persuaded that experimenting with full revenue decoupling is appropriate at this time."[48] Similarly, the Arizona, Iowa and Nebraska commissions have not been convinced that decoupling is necessary. In a generic docket considering decoupling, the Iowa Utilities Board concluded that "Iowa utilities have not been unable to engage in meaningful energy efficiency programs because of concern about their earnings."[49] In 2007, the Nebraska Commission recognized the possibilities of increased rates and risk shifting from decoupling:

> Automatic rate mechanisms raise concerns of piecemeal rate making by adjusting for only one element of cost without accounting for other increases and decreases in costs incurred by the utility. Such automatic mechanisms can lead to excessive rates, an inappropriate shifting of risks from stockholders to ratepayers, and decreased incentives to operate efficiently. Therefore, their use should be limited.[50]

Q. HAVE SOME STATES CHANGED THEIR POSITIONS ON REVENUE DECOUPLING?

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[48]Application for a rate change pursuant to R.I.G.L. §§ 39-3-10 AND 39-3-11 of Narragansett Electric d/b/a National Grid. Rhode Island Public Utilities Commission. Docket No. 3943. January 29, 2009.

[49]In re: Inquiry into the effect of reduced usage on rate-regulated natural gas utilities. Iowa Utilities Board. Docket No. NOI-06-1, December 18, 2006.

[50]In the matter of Aquila, Inc. d/b/a Aquila Networks (Aquila) Omaha, seeking individual rate increases for Aquila's Rate Area One, Rate Area Two, and Rate Area Three. Before the Nebraska Public Service Commission. Application No. NG-0041. July 24, 2007.

A. Yes. In New York, the Commission initially rejected a decoupling proposal for Consolidated Edison, but in 2007 it issued an order requiring electric and gas utilities to file proposals for true-up based decoupling mechanisms in ongoing and new rate cases.

Q. HAS REVENUE DECOUPLING LEGISLATION REQUIRED OTHER COMMISSIONS TO CHANGE THEIR PRECEDENT?

A. Yes. In 2006, the Connecticut Department of Public Utility Control ("DPUC") originally ruled strongly against revenue decoupling for its electric and gas utilities and took issue with: (1) the position that decoupling creates incentives for EE; and (2) the degree to which decoupling shifts business risk from a utility to consumers. The DPUC found that:

> …decoupling by itself does not provide an incentive to energy DCs to promote conservation. Rather, in helping to ensure fixed cost recovery, it removes a disincentive for companies to promote conservation. However, it may also shift to ratepayers such normal business risks as lower sales due to economic downturns, weather, new energy efficiency technology, and demand response to price increases. This report discusses mechanisms for various degrees of decoupling ranging from partial to full decoupling. <u>In general, the more complete the decoupling, the more business risks are shifted from the energy DCs to the ratepayers</u>. [emphasis added][51]

Q. DID THE CONNECTICUT LEGISLATURE ADOPT DECOUPLING?

A. Yes. In 2007, the Connecticut Legislature enacted the Electricity and Energy Efficiency Act which established very specific requirements for decoupling and required the DPUC to order the state's electric and natural gas distribution companies to decouple their distribution revenues. While the DPUC approved decoupling for United Illuminating soon after the legislation passed, it recently rejected a comparable proposal for Connecticut Natural Gas.

Q. HAVE ANY STATES RAISED ISSUES IN THEIR POST-PILOT PERIOD EVALUATIONS OF REVENUE DECOUPLING?

[51]DPUC Investigation into Decoupling Energy Distribution Company Earnings from Sales, Decision, Connecticut Department of Public Utilities, Docket No. 05-05-09, January 18, 2006, *emphasis added*.

A. Yes. Three states (Virginia, Washington, and Idaho) have recently conducted post pilot-period or ongoing annual evaluations for utilities that have implemented revenue decoupling and comprehensive energy efficiency plans. Two of the states (Virginia and Washington) evaluated revenue decoupling plans of natural gas distribution utilities, while Idaho evaluated revenue decoupling for a vertically-integrated electric utility. The Virginia evaluation was a first-year evaluation of revenue decoupling for its natural gas utilities that was reported to its state legislature. Outside of the report, no other immediate action was taken to change revenue decoupling for any of the state's gas utilities. Both Washington and Idaho, however, evaluated revenue decoupling after a three-year pilot period. Both states continued revenue decoupling, but expressed significant reservations about the results and effectiveness of an unadjusted revenue decoupling mechanism.

Q. CAN YOU PLEASE DISCUSS THE VIRGINIA EVALUATION?

A. Yes. The Virginia State Corporation Commission ("VSCC" or "Corporation Commission") raised a number of concerns about the impact decoupling could have on customers not participating in energy efficiency programs, as well as raising issues about these programs' cost effectiveness in the face of a decoupling mechanism. The Corporation Commission recently issued and submitted a report to the Virginia legislature summarizing its recent experience with energy efficiency and revenue decoupling as required under the "Natural Gas Conservation and Ratemaking Efficiency Act" (hereafter "Efficiency Act").[52] While the Corporation Commission did acknowledge that provisions of the Efficiency Act did, or will,

[52]Commonwealth of Virginia, State Corporation Commission. Report to the Governor of the Commonwealth of Virginia, the Speaker of the House of Delegates, the President Pro Tempore of the Senate, and the Chairs of the House and Senate Committees on Commerce and Labor. Report: Implementation of the Natural Gas Conservation and Ratemaking Efficiency Act. December 1, 2009.

encourage energy efficiency investment, it expressed the following concerns regarding program cost effectiveness and ratepayer impacts:

> Sufficient evidence does not yet, however, exist to conclude that these investments are cost-effective under either the RIM or TRC tests. Initial estimates generally indicate that these investments will be beneficial from some perspectives. However, these same estimates indicate that the natural gas utility efficiency plans may negatively impact the non-gas rates paid by natural gas consumers and that non-participations in the programs offered pursuant to these plans will be negatively impacted. Additionally, the cost benefit results do not consider any revenue impact that might be attributable to the implementation of decoupling mechanism. Such revenue changes could significantly impact the costs and benefits of a utility's overall conservation plan when viewed from a utility customer's perspective. [emphasis added][53]

Q. WHAT CONCERNS DID THE VSCC EXPRESS ABOUT REVENUE DECOUPLING'S TENDENCY TO OVER-COMPENSATE UTILITIES FOR NON-ENERGY EFFICIENCY-RELATED CHANGES IN SALES?

A. The Corporation Commission, while finding that revenue decoupling has, or will stimulate energy efficiency investments, expressed considerable frustration with the performance of its leading natural gas utility's (Virginia Natural Gas or "VNG") energy efficiency results and revenue decoupling by noting:

> VNG's revenue decoupling mechanism will compensate the Company for energy reductions of approximately 10 million Ccfs while VNG's own estimates indicate that its programs have generated reductions of less than 116,000 Ccfs. As such, use of the specified non-gas revenue required by the Natural Gas Conservation Act [i.e., revenue decoupling] provides significant additional revenue to VNG over and above compensation needed to offset lost revenues attributable solely to VNG's efficiency efforts. [emphasis added][54]

Q. CAN YOU DISCUSS THE WASHINGTON REVIEW OF AVISTA'S REVENUE DECOUPLING PROGRAM?

A. Yes, last year, the Washington Utilities and Transportation Commission ("WUTC") conducted an independent third party analysis of Avista's revenue decoupling plan as part of its

[53]Ibid, emphasis added.
[54]Ibid, 18, emphasis added.

rate case filing. Interestingly, this is the first independent decoupling review that has been done by an outside consulting firm not commonly associated with a public utility client base or utility regulation. The outside consultant was not allowed to "draw conclusions, make recommendations, or otherwise determine whether conservation increased as a result of implementing decoupling."[55] All parties were given the opportunity to file testimony and offer expert opinions on the decoupling experiment's results, as well as the findings of the outside consultant. On December 22, 2009, the WUTC issued its decision in Avista matter and made a number of important changes to its revenue decoupling mechanism.

Q. WHAT DID THE WUTC FIND?

A. The WUTC found that decoupling appeared to stimulate energy efficiency investments but noted, much like the VSCC, that the mechanism made the utility considerably more than whole from lost margins associated with energy efficiency. Most of the parties to the proceeding agreed that decoupling created greater than necessary revenue recoveries for the utility. Even Avista, the utility, requested lowering the recovery amounts from 90 percent of the deferrals to 70 percent. The WUTC, in its ruling, capped decoupling recoveries to 45 percent of the deferrals (down from the prior allowed amount of 90 percent), and set a sliding scale for recovery based on achieved energy efficiency savings.

Q. SHOULDN'T REVENUE DECOUPLING MAKE A UTILITY WHOLE FOR ALL REVENUE LOSSES?

A. No. While many utilities have attempted to make this argument, including the Petitioner in this proceeding, under the rubric of "new traditional regulation" or some other euphemism, such policies tend to be entirely contrary to the approaches of most regulatory commissions have

[55]Docket 090134 and UG 090135, consolidated. *Washington Utilities and Transportation Commission v. Avista Corporation, d./b./a. Avista Utilities*. Order 10: Final Order Rejecting Tariff Filling; Approving and Adopting Multi-Party Partial Settlement Stimulation; Deferring Lancaster Costs; Extending Decoupling Mechanism; Authorizing Tariff Filing; and Requiring Compliance Filing, December 22, 2009. Final Order at 261.

taken that have adopted revenue decoupling to promote energy efficiency, not utility revenue stability. The WUTC was very clear in noting this in its recent order when the subject arose:

> The Company argues that its decoupling mechanism is necessary to allow the recovery of fixed costs approved in the most recent general rate case. We disagree that decoupling's purpose is so broad. The regulatory construct for decoupling in Washington has centered on the utility's performance relative to consideration….We seek to avoid guaranteed recovery of lost margin that would occur should lost margin from other causes be included in the mechanism. [emphasis added][56]

Q. DID THE WUTC ORDER END ON A POSITIVE NOTE FOR REVENUE DECOUPLING?

A. Not entirely. While the WUTC clearly acknowledged the increase in energy efficiency spending that resulted from revenue decoupling, it expressed, what appears to be, some frustration with decoupling's complexity:

> We note that decoupling is but one method of supporting conservation, and we encourage the Company and parties to consider alternatives that avoid the mechanism's inherent complications while accomplishing the objectives we set forth herein.[57]

Q. WHAT ABOUT IDAHO?

A. The Idaho Commission also expressed concerns about the mismatch between the level of revenues recovered under its Fixed Cost Adjustment ("FCA") factor and the level of base revenues associated with reduced use from Idaho Power Company's energy efficiency programs. Under the second year of the program for instance, Idaho Power was allowed to recover revenues associated with sales losses amounting to some 156.1 million kWhs when energy efficiency-related savings were only 22 million kWhs. As a result, the Idaho Commission decided to reject the Company's request to make revenue decoupling permanent and continued the program on an additional two-year basis. The Idaho Commission noted:

[56]Ibid., p. 291.
[57]Ibid., p. 309.

> The FCA pilot was approved as a three-year program to create a record to evaluate the efficacy of a program to separate recovery of certain fixed costs from Idaho Power's energy sales revenue. The record demonstrates that program results are mixed. Residential and small commercial customers received a small rate decrease during the first year and a rate increase after the second year. The third year of the pilot program resulted in a request by Idaho power for another FCA rate increase.

> According to the comments in this case, the program results are also mixed as to whether the objectives of an FCA are being met. Clearly Idaho Power increased its DSM program expenditures in the past several years, but it is not enough, as Idaho power's reply comments imply, that the Company's investment in efficiency programs increased during the FCA pilot process. <u>There must be a demonstrable nexus between the FCA and the Company's investment in efficiency programs and, as noted in several comments, the Company did not provide evidence that such nexus exists.</u> It is undisputed the Company's increased effort was promoted by several factors, including the Commission's approval of a significant increase in the energy efficiency rider that funds the Company's efficiency programs. Evidence suggests the FCA may have done little to spur Idaho Power's increased investment, at least for residential customers. [emphasis added][58]

Q. DO YOU THINK THESE CONCERNS REGISTERED BY OTHER STATES SHOULD BE OF INTEREST TO THE IURC?

A. Yes. While the Commission has set increasing energy efficiency goals for the Petitioner over the next several years, there are considerable opportunities for revenue recoveries under revenue decoupling to exceed those goals. Current experience with the Petitioner's gas operations would suggest a strong possibility for such an outcome as would a backcast analysis conducted by the Company for its electric operations.

Q. HAVE YOU COMPARED THE ESTIMATED LOST BASE REVENUES FROM THE PETITIONER'S GAS OPERATIONS TO ITS COLLECTIONS UNDER ITS GAS REVENUE DECOUPLING MECHANISM?

A. Yes. Lost base revenue attributable to gas DSM programs has been a very small share of gas revenue the Petitioner has collected for its gas operations through the gas decoupling mechanism. OUCC witness April M. Paronish examined Petitioner's annual lost base revenues

[58]Idaho Public Service Commission. In the Matter of the Application of Idaho Power Company for Authority to Convert Schedule 54 – Fixed Cost Adjustment – From a Pilot Schedule to a Permanent Schedule. Case No. IPC-E-09-28, Order No. 31063, 8.

that were created by its achieved natural gas energy savings. Under the Commission-approved decoupling program, lost base revenues totaled less than 8 percent of the revenues collected.[59]

Q. HAS THE PETITIONER BEEN MEETING ITS NATURAL GAS ENERGY EFFICIENCY GOALS?

A. Not in every year. Exhibit DED-21 reflects the natural gas energy efficiency goals established by the Commission compared to the Petitioner's achievements. As shown, for the first three years of the program, on a net savings basis, Vectren South-Gas has under-achieved program savings by 614,093 therms, or 18 percent. If the Company's achievements are compared on a gross basis, for the total period, the Company exceeded the Commission's goals by 572,984 therms, or 17 percent.

Q. HAVE YOU EXAMINED THE REVENUE DECOUPLING BACK-CAST ESTIMATES FROM VECTREN'S ELECTRIC OPERATIONS HAD DECOUPLING BEEN IN PLACE OVER THE TEST YEAR?

A. Yes. Exhibit DED-22 is a recast of the amounts that would have been collected or refunded if decoupling had been implemented in August 2007 through December 2009. This information was supplied by Vectren in response to OUCC Data Request 21 Q-3. The Petitioner's decoupling request in Cause No. 43427 is the same as requested in this case with the exception that it has not proposed to decouple the largest 250 customers in Rate DGS (the DGS-3 customers). The back-cast shows the amount of revenue Petitioner would have collected from standard residential service is $8.9 million, with $1.3 million from the home heating service, $0.016 million from the water heating service, $0.511 million from the small general service class, $4.8 million from the demand general service class, and $0.119 million from the off season service customers. In total, the Petitioner would have collected $4.7 million. On a per-customer

[59] This figure was derived from the information contained in OUCC Witness Ms. Paronish's Exhibits AMP-1 and AMP-2.

basis, it would have collected $95.81 per residential customer over the back-cast period in total.[60] In contrast, the DGS class would have received a refund of $647.78 per customer for the back-cast period.

Q. HAS THE PETITIONER BEEN MEETING ITS ELECTRIC ENERGY EFFICIENCY GOALS?

A. The Commission's energy efficiency goals become effective in 2010. Specifically, in its Phase II Order, the Commission established electric energy efficiency goals for 2010 through 2019 which ramp from 0.3 percent incremental savings in 2010 to 2.0 percent in 2019. Exhibit DED-18 sets forth the Commission savings goals Petitioner needs to attain. Ms. April Paronish, another OUCC expert in this proceeding, will be addressing the Company's energy efficiency programs.

E. REVENUE DECOUPLING RECOMMENDATIONS

Q. WHAT IS YOUR PRIMARY REVENUE DECOUPLING RECOMMENDATION?

A. I recommend that the Commission reject Vectren South's revenue decoupling proposal. The proposal, as it has been currently offered, will result in considerable risk being shifted from Vectren and its shareholders to its customers. Had the decoupling mechanism been in place during the test year, ratepayers would have seen rate increases of some $4.1 million without any hearing or investigation regarding whether or not Petitioner's costs had changed during the same time period. Furthermore, it is highly likely that Petitioner's proposed decoupling mechanism will compensate it for changes in revenue that have nothing to do with its energy efficiency efforts and are more likely associated with the recent economic recession. The overcompensation problem has been a growing concern with regulators in states that have

[60] Annual residential per customer amounts include: ($23.22) for 2007, $44.98 for 2008, and $74.05 for 2009

adopted revenue decoupling to date. No revenue decoupling mechanism should be adopted that does not take this realization into account.

Q. DO YOU HAVE ANY ALTERNATIVE REVENUE DECOUPLING RECOMMENDATIONS?

A. Yes, but I will discuss those in a later section of my testimony after I discuss the Petitioner's proposal to recover variable production costs in its RCRA tracker.

IV. COST TRACKERS AND THE PROPOSED RCRA

A. COMPANY'S PROPOSED RCRA

Q. CAN YOU EXPLAIN THE RCRA, WHICH THE PETITIONER PROPOSES TO MODIFY IN THIS CASE?

A. The RCRA is a cost tracker designed to adjust Petitioner's rates, semi-annually, for the following items: 1) Non-Firm Wholesale Power Margins ("WPM"); 2) Municipal Wholesale Margins; 3) Environmental Emission Allowance ("EEA") Credits; 4) Interruptible Sales Billing Credits; and 5) Purchased Power Non-Fuel Costs. The RCRA was originally called the Generation Cost and Revenue Adjustment ("GCRA"), but the name was changed as part of the settlement in Vectren South's last rate proceeding, Cause No. 43111.

Q. WOULD YOU PLEASE DISCUSS THE PETITIONER'S RCRA PROPOSAL?

A. Yes. Vectren South is proposing three changes to the RCRA. First, it proposes to change "Generation" Costs and Revenues to "Reliability" Costs and Revenues in the description section of the tariff.[61] Second, the Petitioner proposes to modify the Environmental Emission Allowances portion of the tracker. Specifically, it is proposing to track environmental emission allowance ("EA") costs and move those for future recovery through the RCRA. Third, the

[61] Direct Testimony of Scott E. Albertson (Revised), p. 16.

Petitioner proposes to track differences between the actual level of variable production cost ("VPC") expenses incurred and the actual level of VPC recoveries. Ms. Cynthia Armstrong, another OUCC expert witness, will be testifying about the Petitioner's environmental emissions allowance cost proposals. My discussion will focus on the regulatory, economic, and policy issues associated with the VPC component of the Petitioner's RCRA proposal. Mr. Wes Blakely on behalf of the OUCC will also be offering expert opinions on this matter as well.

B. COST TRACKERS AND TRADITIONAL REGULATION

Q. DO YOU THINK VECTREN SOUTH'S PROPOSAL TO ADD THE VPC COMPONENT TO THE RCRA CAN RESULT IN EFFICIENT REGULATION?

A. No. The Petitioner's proposal runs counter to sound regulatory principles and, if adopted, would create a host of disincentives that are contrary to regulatory efficiency and the public interest. The VPC component of the Petitioner's RCRA would:

- Create considerable disincentives for cost efficiency since rates would be allowed to increase semi-annually through expedited proceedings.
- Lead to an expedited regulatory oversight process that would challenge most regulatory stakeholders.

Q. ARE VECTREN SOUTH'S PROPOSALS CONSISTENT WITH WHAT IS COMMONLY REFERRED TO AS THE "REGULATORY COMPACT"?

A. No. The Petitioner's proposal would effectively turn the regulatory compact on its head by shifting the burden of proof regarding the prudence of its operating costs away from itself and onto the Commission and other stakeholders in an expedited time frame. Equally important is the fact that tracker mechanisms, like the RCRA, invite operating inefficiencies.

Q. HOW DO COMPETITIVE MARKETS EXAMINE THE REASONABLENESS OF CAPITAL INVESTMENTS AND OPERATING COSTS?

A. In competitive markets, inefficient and useless investments and expenses are typically rejected by the market, and firm management is usually held accountable for any earnings ramifications of these imprudent decisions. Rate cases serve a similar function in vetting the reasonableness and usefulness of utility operating costs and investments. The Petitioner's proposal, however, inverts the burden of this review process by creating a venue for increasing rates that places intervener groups and other interested parties in a difficult position.

Q. DO RETROSPECTIVE REVIEWS PLAY AN IMPORTANT ROLE IN TRADITIONAL UTILITY REGULATION?

A. Yes. The regulatory process, as well as the academic and theoretic literature on utility regulation, has long recognized the importance of retrospective reviews in motivating a utility to perform in a manner consistent with regulatory expectations and to avoid cost disallowances from grossly subpar performance.[62] Forcing utilities to be accountable, diligent, and careful in their planning, procurement, and operations is necessary because regulatory theory and practice recognize the asymmetric level of information that exists between regulator and regulated company. This asymmetry arises because utilities know more about their own operations and market conditions than regulatory commissions. Removing this oversight process, or significantly reducing its efficacy, cannot result in efficient regulatory outcomes since it invites inefficient cost escalation, and over-capitalization.

Q. WOULD DENYING APPROVAL TO TRACK VPCs BE TANTAMOUNT TO DEPRIVING THE COMPANY OF ITS REASONABLE OPPORTUNITY TO EARN A RETURN ON AND OF ITS INVESTMENTS AND PRUDENTLY-INCURRED COSTS?

A. No. As I noted earlier in my testimony regarding revenue decoupling, utility regulation provides <u>opportunities</u> to utilities, not <u>guarantees</u>. Contrary to common utility hyperbole, the positive incentives associated with the regulatory process or "regulatory lag" quite often inure to

[62] National Regulatory Research Institute, *The Prudent Investment Test in the 1980s* (Columbus, Ohio: National Research Regulatory Institute, 1985), p. 2.

the utility and its shareholders because efficiency improvements that occur between rate cases can increase earnings, benefiting shareholders. Importantly, regulatory lag can be an important policy tool in controlling utility costs which ultimately can lead to lower rates.[63]

Q. WOULD INCLUSION OF THE VPC COMPONENT TO THE RCRA RESULT IN THE NEED FOR FEWER RATE CASES?

A. No. While this is a common utility assertion it is usually unsubstantiated and unsupported particularly as it relates to trackers, as opposed to other regulatory methods such as performance-based regulation ("PBR"). Unlike PBRs, where "stay-out provisions," are typically a component part of the process, pure cost tracker approaches rarely include any form of "stay-out" provision that would explicitly limit a utility's ability to seek a future rate case. In fact, as a cost-plus approach, trackers are likely to expend considerable administrative review resources. How those compare to traditional rate case efforts, however, is unknown.

Q. CAN THE EXCLUSIVE USE OF PRODUCTION COST TRACKERS, LIKE THE ONES PROPOSED BY THE COMPANY, LEAD TO ANY OTHER REGULATORY PROBLEMS?

A. Yes. The use of production cost trackers could potentially lead to what is referred to as a "moral hazard" problem in regulation. Moral hazard is said to occur in instances where an economic agent facing a certain degree of risk behaves differently when it is insulated from that risk than it would if the risk were not insured.[64] Moral hazard is, in effect, the behavioral difference that results from the presence or introduction of insurance. Moral hazard results in a "market failure," or inefficiency, because the agent receiving the insurance does not have to bear the full responsibility for its actions. As Bonbright, et al. notes:

> A moral hazard is involved when someone other than the purchaser pays for the purchase and hence the purchaser acts, unconstrained by ethics or other

[63] W.K. Viscusi, J.M. Vernon, J.R. Harrington, Jr. (1997) *Economics of Regulation and Antitrust*, Second Edition. Cambridge: MA: MIT Press, 380.

[64] W. Nicholson. *Intermediate Microeconomics and Its Applications.* 5th Edition. (1990) Chicago: Dryden Press, 695.

> institutions, as if there is no resource cost on society from his or her purchases. In other words, moral hazard increases the risk of an event turning out favorably because there may be positive rewards or at least insufficient penalties for opportunistic behavior.[65]

Q. ARE THERE ANY RECENT EXAMPLES OF MORAL HAZARD PROBLEMS ARISING IN PUBLIC POLICY AND REGULATION?

A. Yes. One good example is the recent banking and financial crisis that led to policies bailing out banks and other financial institutions that were considered "too big to fail." Many financial institutions were given billions of dollars in bail-outs and other forms of financial support to buttress their financial positions devastated by past risky lending actions. Some analysts have argued that these policy actions have done nothing to correct the underlying problem leading to the 2009 financial crisis and in fact, in the long run, may exacerbate these problems since in the future, banks may use this policy precedent as support for future rescue actions from continued risky practices.[66]

Q. HOW DOES MORAL HAZARD RELATE TO THE PETITIONER'S PROPOSAL OF RECOVERING VARIABLE PRODUCTION COSTS (AND REVENUES) THROUGH A TRACKER MECHANISM OF ONE SORT OR ANOTHER?

A. The Petitioner's collective proposals, if adopted, could lead to an opportunity for moral hazard because it would establish a regulatory precedent that insulates it from risk, and the cost-disciplining actions that risk can impose on utilities actions. If regulated utilities know that they will be insulated from changes in risk, they are less likely to defend against those risks and pass them along to the party carrying the insurance, which in this case is ratepayers.

Q. HAVE THESE TYPES OF TRACKER DEFICIENCIES BEEN RECOGNIZED IN THE PAST?

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[65] J. Bonbright, A. Danielsen, and D. Kamerschen. (1988) *Principles of Public Utility Rates*. Arlington, VA: Public Utility Reports, 138.

[66] Wilson, L. and Wu, Y. Common (stock) Sense About Risk-Shifting and Bank Bailouts. *Financial Markets and Portfolio Management*, Forthcoming; Hakenes, H. and Schnabel, I. Banks Without Parachutes: Competitive Effects of Government Bail-Out Policies. *Journal of Financial Stability*. May 21, 2009; and Helwege, J. Financial Firm Bankruptcy and Systemic Risk. *Journal of International Financial Markets, Institutions & Money*. November 14, 2009.

A. Yes. The applied and academic literature on FACs has recognized many of the deficiencies associated with trackers.[67] A recent survey report on cost trackers by the National Regulatory Research Institute ("NRRI"), the research arm for the National Association for Regulatory Utility Commissioners ("NARUC") notes:

> Cost trackers, in various ways, can result in higher utility costs. First, they mitigate the positive effects of regulatory lag on a utility's costs. Regulatory lag refers to the time gap between when a utility undergoes a change in cost or sales levels, and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs. The reason is that when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important tool for motivating utilities to act efficiently. As economist and regulator Alfred Kahn once remarked:
>
> > Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.
>
> Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits. This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences on sales. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment. The difficult problem for the regulator is to detect when management is lax. Regulators should concern themselves with this problem: lax management translates into higher cost

[67]The recent NRRI report cited in the subsequent sentence outlines the theoretical and empirical studies that provide evidence of the incentive problems associated with FACs. *See*, for example, David P. Baron and Raymond R. DeBondt, "Fuel Adjustment Mechanisms and Economic Efficiency," *Journal of Industrial Economics*, Vol. 27 (1979): 243-69; David P. Baron and Raymond R. DeBondt, "On the Design of Regulatory Price Adjustment Mechanisms," *Journal of Economic Theory*, Vol. 24 (1981): 70-94; David L. Kaserman and Richard C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," *Southern Economics Journal*, Vol. 48 (1982): 687-700; and Frank A. Scott, Jr., "The Effect of a Fuel Adjustment Clause on a Regulated Firm's Selection of Inputs," *The Energy Journal*, Vol. 6 (1985): 117-126. The first two studies applied a general model to show that FACs tend to cause a utility to overuse fuel relative to other inputs, pay more for fuel prices, and choose non-optimal, fuel-intensive generation technologies. The third study provided empirical support for this prediction. The fourth study showed that some types of FACs cause biasness in fuel use and that FACs in general weaken the incentive of a utility to search for lower-priced fuel. It provided empirical evidence that electric utilities with an FAC pay higher fuel prices than utilities without an FAC. See footnote 29 for additional detail and source.

> of service and, if undetected, higher rates to the utility's customers. Regulators should closely monitor and scrutinize costs like those subject to cost trackers that utilities have little incentive to control.[68]

C. COST COMPARISONS

Q. WOULD YOU CHARACTERIZE VECTREN SOUTH AS "SUPERIOR" IN ITS COST PERFORMANCE COMPARED TO PEERS?

A No, particularly as it relates to the Petitioner's production costs. Exhibits DED-23 through Exhibit DED-25 present a number of analyses that compares the Petitioner's historic operating cost performance relative to the same peer group identified earlier in my testimony on plant investment trends. Like the earlier analyses, each cost analysis is composed of three pages. The first page compares each major operation and maintenance ("O&M) cost category (generation, transmission, distribution) on a per unit (MWh) basis. The top table provides the cost per MWh in absolute terms while the lower table provides a rank of the utilities that have been examined. Vectren South's statistics are highlighted at the top of each table and the peer average is at the bottom. The second page compares each functional O&M cost/MWh on a variability basis (top panel) and rank orders each utility's cost variability (bottom panel). The last page provides a graph of the Petitioner's performance relative to the composite peer group.

Q. WHAT DOES YOUR ANALYSIS OF THE PETITIONER'S GENERATION O&M REVEAL?

A. A comparison of Petitioner's annual non-fuel O&M expenditures per MWh have been provided on Exhibit DED-23. Page 1 shows relatively high O&M costs per MWh for the Petitioner relative to its peers. The bottom table shows the Petitioner's rank and reveals that it is consistently ranked last or close to last each year since 1994. The top table of page 2 of the exhibit provides a measure of the variability of non-fuel O&M with the rank at the bottom.

[68] K. Costello. "How Should Regulators View Cost Trackers?" Washington, DC: National Regulatory Research Institute: 4, footnotes excluded.

Vectren South's non-fuel O&M variability ranks relatively low in the peer group comparison having much lower O&M cost variability than other coal-fired utilities.

Q. WHAT DOES YOUR ANALYSIS OF VECTREN SOUTH'S TRANSMISSION O&M REVEAL?

A. Exhibit DED-24 provides a comparison of the Petitioner's transmission O&M per MWh relative to the peer group utilities. While overall transmission O&M costs for the utility sample have increased significantly over the evaluation period, those increases have been relatively stable in the sense that the increase has been somewhat uniform and not sporadic. Page 3 of this exhibit provides a clearer picture of the longer run trends in transmission O&M costs for the Petitioner versus its peer group. Unlike the other utilities in the sample, the Petitioner's transmission operations costs remained relatively low until 2005 when they began to steadily increase with larger increases in the last two years of the evaluation period. Overall, the Petitioner's transmission O&M costs per MWh are still much lower than its peers although that differential has been contracting over the last two years.

Q. WHAT DOES YOUR ANALYSIS OF VECTREN SOUTH'S DISTRIBUTION O&M REVEAL?

A. Exhibit DED-25 provides a comparison of the Petitioner's distribution O&M expense per MWh relative to its peers. Like transmission, the Petitioner's cost trend, relative to its peers, is relatively favorable for the period 1994 to 2006. In 2007 those costs began to rise and have come close to eliminating the distribution cost advantage Vectren South had historically displayed relative to its peers.

Q. WHAT CONCLUSIONS DO YOU REACH FROM THE ANALYSIS OF VECTREN SOUTH'S O&M COSTS?

A. The Company's cost performance record is somewhat mixed. From a production perspective, its O&M costs are entirely out of line with other comparable coal-fired utilities.

Their costs have been, and continue to be, exceptionally high relative to its peers. These costs have not improved, nor have they become more volatile over time: they are steadily and consistently higher than most similarly-situated utilities. Thus, any tracker proposing to recover Variable Production Cost changes is unwarranted. While the Petitioner's O&M cost performance on the lines portions of its business have historically shown much more favorable numbers, the last three years have shown a considerable deterioration of its relative advantages. Again, the Petitioner's poor performance coupled with trends that do not reflect anything even close to volatile (like natural gas commodity prices) should be basis enough to reject Vectren South's VPC cost tracking proposal. Adopting a tracker mechanism allowing VPC recovery would likely lead to cost increases beyond those already apparent in base rates.

Q. HAS VECTREN SOUTH DONE A COMPARABLE BENCHMARKING ANALYSIS?

A. Yes. In OUCC Data Request 24-Q-1, the OUCC asked for all benchmarking studies that Vectren had conducted on a wide range of its costs components and rates. It provided two summary presentations associated with benchmarking analyses that were conducted for the Board of Directors in 2008 and 2009. The 2009 analysis focused on rate competitiveness which I discussed earlier in my testimony. The 2008 study, however, was relatively more comprehensive and based upon what appears to be a survey of [redacted] coal-fired power generation units in what is defined as the large power plant sample and [redacted] coal-fired power plants in the small generator sample. The study appears to compare the Petitioner's operating and cost performance relative to each of these peer groups.

Q. WERE YOU ABLE TO REVIEW AND CORROBORATE THE ESTIMATES AND FINDINGS OF THE VECTREN 2008 COST AND PERFORMANCE BENCHMARKING STUDY?

A. In part. Although the OUCC request asked for all "information in electronic spreadsheet format with all links and formulas intact, source data identified and provided, and all assumptions and calculations clearly identified and explained," the Company did not provide this information in its original response. While the OUCC recently received a supplemental response that appears to have included this data, it was provided very late in my review process. The data includes a number of relatively-involved comparisons, using a private commercial source of data that is not easily verifiable without some effort. I would like to reserve the right to supplement my testimony once I have had an opportunity to review those responses in greater detail.

Q. BASED UPON YOUR LIMITED REVIEW OF THE STUDY SUMMARY, DO YOU THINK THIS 2008 BENCHMARKING STUDY YIELDS RESULTS COMPARABLE TO THE ANALYSES INCLUDED IN YOUR TESTIMONY?

A. Yes. The study results clearly support a conclusion that [redacted] This suggests a performance-based approach to regulation would be more suitable than an expansion of revenue and cost trackers as proposed by the Petitioner.

D. RCRA RECOMMENDATIONS

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS REGARDING VECTREN SOUTH'S PROPOSAL TO INCLUDE THE VPC COMPONENT IN THE RCRA?

A. The Commission should reject the VPC tracker component of its proposed RCRA. This proposal should be rejected since:

- The Petitioner has provided no evidence of any ratepayer benefits from the mechanism.
- The proposal is inconsistent with economic theory and regulatory practice and likely to lead to cost inefficiencies.
- It creates incentives for inefficiency by reducing the Petitioner's incentive to control operating costs between rate cases.
- It is primarily an asymmetrical mechanism that is more likely to result in rate increases than decreases for ratepayers. The mechanism provides clear and meaningful benefits to the Petitioner and its shareholders but none to ratepayers.
- It will raise challenges for ratepayers and other regulatory stakeholders in their ability to question and review the reasonableness of the Petitioner's operating costs.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS THAT THE COMMISSION SHOULD CONSIDER IN EVALUATING VECTREN SOUTH'S VARIABLE PRODUCTION COST ("VPC") TRACKER PROPOSAL?

A. Yes. Petitioner's historic generation and performance statistics suggest that it would be a poor candidate for a VPC tracker. While the Company has relatively good generation availability statistics and moderate operating efficiencies (from a heat rate perspective), it has had a very hard time getting its overall non-fuel production costs into line. Adopting a VPC tracker mechanism for a utility in this position just invites continued inefficiencies. The Petitioners expanded revenue and cost tracker proposals simply take ideas from other jurisdictions and other regulated utilities (i.e., natural gas LDCs), and applies them to its operations in Indiana. The proposals, collectively, are like fitting a square peg in a round hole:

they do not fit and are likely to lead to greater total energy inefficiencies than any demand-side efficiency measures the Commission could adopt.

Q. WHY DO YOU THINK THESE PROPOSALS DO NOT FIT VECTREN SOUTH'S OPERATING PROFILE?

A. It would appear that Petitioner has two opportunities for cost performance improvement: (1) greater generation utilization and (2) cost containment. Revenue decoupling and cost trackers, since they "decouple" performance from rates, do not encourage operating efficiencies and ultimately could lead to greater overall energy inefficiency rather than energy efficiency. Consider that a 500 BTU improvement in the Company's average system heat rate would lead to some 2.9 million MMBtus of annual energy savings. If these savings were valued at Petitioner's current average fuel cost ($1.83 per MMBtu), these scale-created efficiencies could result in some $5.2 million in annual efficiency savings, some 360 percent higher than the five-year average of the Commission's annual electric demand-side energy efficiency goals. Put another way, a 500 BTU improvement in Vectren South's system average heat rate would equal 3 years worth of natural gas savings projected for its gas retail operations.

Q. WHAT REGULATORY MECHANISMS SHOULD THE COMMISSION CONSIDER THAT WOULD ENCOURAGE THE PURSUIT OF THESE STRATEGIES WHILE STILL PRESERVING A COMMITMENT TO DEMAND-SIDE EFFICIENCIES?

A. The Commission needs a performance-based mechanism that ties demand and supply-side goals to financial rewards. I recommend that the Commission explore developing a mechanism that would encourage Petitioner to promote demand-side energy efficiency for its native load customers, and take the bulk power capacity that is "freed-up" from these efficiency efforts, and put them out to the wholesale market for resale. The gains from these off-system sales could then be used to mitigate the potentially-stranded costs associated with the downstream retail efficiency efforts. In fact, it is highly likely that the gains from these off-

system activities would more than compensate for any purported retail cost recovery losses, thereby creating a win-win opportunity for the Company and its ratepayers.

V. ALTERNATIVE RECOMMENDATIONS TO THE PROPOSED SRA: EFFICIENCY INCENTIVE MECHANISM

A. ALTERNATIVE RECOMMENDATIONS OVERVIEW

Q. CAN YOU PLEASE EXPLAIN YOUR ALTERNATIVE RECOMMENDATION?

A. Yes. One of the problems with revenue decoupling and other types of tracker mechanisms is that by decoupling revenues and costs from sales, these tracker mechanisms also decouple a primary determinant of performance from rates. If left unchecked, rates will start to reflect accumulated inefficiencies and over-capitalization that utility regulation has spent the past 40 years trying to avoid. This is particularly problematic for vertically-integrated electric utilities (as opposed to unbundled gas utilities), since a large portion of their costs do include the production component. The revenue decoupling formula adopted for gas utilities is simply inappropriate to apply to electric utilities. Instead, I recommend that the Commission adopt an "Efficiency Incentive Mechanism" ("EIM") that re-couples performance and rates by tying energy efficiency performance, generation efficiency performance, lost base revenues, and incentives. This type of mechanism would be more consistent with the best practices of traditional as well as performance-based regulation and would provide the Company with incentives to promote both supply-side and demand-side efficiencies. As I noted earlier, the opportunities for supply-side energy efficiencies are just as large and just as important as those acquired at the demand-side. A broader energy efficiency incentive mechanism of this nature would truly put demand-side and supply-side efficiencies on equal footing and create a

sustainable energy policy that creates win-win outcomes for all stakeholders, not just the utility and its shareholders.

Q. CAN YOU EXPLAIN HOW THIS EIM MAY WORK?

A. Yes. In a general fashion, the EIM would tie the Company's performance in both its energy efficiency efforts (demand-side efficiencies) and its off-system sales (supply-side efficiencies). If Petitioner's proposition is correct, that the deployment of cost-effective energy efficiency results in stranding its fixed costs (and capacity), there will be opportunities to resell this bulk power capacity (production, transmission) in wholesale markets provided the Petitioner is able to operate its "freed-up" generation capacity efficiently. The gains from these off-system sales can, therefore, be used to offset the purported stranded costs created by energy efficiency. Under my proposal, the Company would attain greater rewards from the utilization of this freed-up capacity as its efforts at both demand-side and supply-side efficiency improved. In addition, it would be allowed to receive lost base revenues from the distribution-related losses that may be attributable to energy efficiency. Under my proposal, Petitioner's ability to meet the Commission's energy efficiency goals would be measured on a gross basis; however, the incentives are paid-out on a net basis.

B. EIM IMPLEMENTATION EXAMPLE

Q. HAVE YOU PROVIDED AN EXAMPLE OF HOW THIS EIM WOULD WORK?

A. Yes. Exhibit DED-26 provides an illustration of how my proposed EIM would work. The exhibit is composed of three different scenarios that depend upon the Petitioner (1) meeting the Commission's demand-side goals, (2) exceeding the Commission's demand-side goals, and (3) falling short of the Commission's demand-side goals. A three-year period has been utilized in each example. The critical data needed to develop this EIM includes (1) the Company's

annual off-system sales, (2) its annual achieved energy efficiency savings, and (3) a comparison of its achieved savings to the Commission's energy efficiency goals. Lost distribution margins would be subtracted from total off-system sales in order to develop a "net bulk power" margin reflecting the Petitioner's supply-side efficiencies.[69] This margin, in turn, would be shared between Vectren South and ratepayers based upon the Company's demand-side energy efficiency performance. If the Petitioner reaches 90 to 100 percent of the Commission's energy efficiency goals, it will share the net off-system sales margin with ratepayers on a 50-50 basis. If the Company exceeds 100 percent of the Commission's energy efficiency goals, it will share its off-system sales margin on a 75-25 percent basis. If the Company attains less than 90 but greater than 80 percent of the Commission's energy efficiency goals, it will only receive 25 percent of the net off-system sales margin, with the remaining 75 percent going to ratepayers. If it achieves less than 80 percent of the Commission's goals, 100 percent of the gains from offsystem sales would be credited to ratepayers and it receives no distribution credit.

Q. HOW IS THE TOTAL EFFICIENCY CREDIT FOR THE PETITIONER AND RATEPAYERS DETERMINED?

A. Columns (l) and (m) of Exhibit DED-26 provide the total efficiency credits that accrue to the Petitioner and ratepayers, respectively. For the Company, its total efficiency credit is based upon the net margin, as well as the implied lost distribution margin associated with the achieved energy efficiency savings. Ratepayers, however, receive only their respective share of the net margin, which is determined by the Petitioner's energy efficiency performance.

Q. CAN YOU WALK THROUGH A SPECIFIC EXAMPLE UNDER SCENARIO 1 WHERE THE PETITIONER IS ASSUMED TO MEET ITS ANNUAL ENERGY EFFICIENCY TARGETS?

[69] Lost distribution margins would be calculated as the allowed distribution component of the Company's revenue requirement. The example provided in Exhibit DED-26 is based upon the Company's proposed revenue requirement and return, and would need to be modified for any changes made by the Commission in this proceeding.

A. Yes. Assume for this example that in the first year of the program the Petitioner makes 1.5 million MWhs of off-system sales and reaches the Commission's annual demand-side energy efficiency target of 16,005 MWhs in savings. Also assume that the annual average revenues the Company receives for its off-system sales is $12.50 per MWh and that the lost distribution margin associated with its DSM savings is $17.92 per MWh. The total net margin for the first year is about $18.5 million. Since the Company reached its demand-side energy efficiency goals, it split the net margins with ratepayers on 50-50 basis, with a $9.25 million credit for each party. Since the Company would be allowed to recover the distribution portion associated with its energy efficiency savings, the total efficiency credit that accrues to the Company is about $9.5 million, while the amount returning to ratepayers is $9.25 million.

Q. WHAT WOULD HAPPEN UNDER YOUR PROPOSAL IF THE PETITIONER EXCEEDED THE COMMISSION'S ENERGY EFFICIENCY TARGETS?

A. Petitioner's sharing percentage associated with the net margin would increase to 75 percent. Scenario 2 provides this example using the same assumptions for the value of off-system sales and lost distribution margins. In year 2, the Company is assumed to exceed the Commission's energy efficiency target by eight percent. In this example the Petitioner's lost distribution margin recovery would increase to meet the increased achieved energy efficiency savings. The net margin percentage would also increase Petitioner's take to over $14.2 million; up from the $9.5 million under the example in Scenario 1. Ratepayers would still attain considerable benefits through a $4.6 million efficiency credit and the increased opportunities to reduce bills created by the Company's increased energy efficiency efforts.

Q. ARE THERE ANY ADDITIONAL OPPORTUNITIES FOR INCREASED EFFICIENCY SAVINGS THAT MAY NOT BE READILY APPARENT IN THIS EXAMPLE?

A. Yes. Because I am recommending a three year pilot program, as addressed below,

Petitioner can independently increase its incentive credits through greater supply-side efficiencies provided it reaches the minimum energy efficiency threshold for sharing. Consider that under the example provided in Exhibit DED-26, the Company increases the potential for off-system gains by about $2.00 per MWh for every 500 BTU increase in generation thermal efficiency. Thus even in scenario 3 where the Company fails to meet the Commission's demand-side energy efficiency targets, it can still benefit (as can ratepayers) through increased supply-side margins created by power plant efficiency gains, provided, of course, that it meets its 80 percent energy efficiency target.

C. EIM BENEFITS

Q. WHAT DO YOU SEE AS THE BENEFITS OF YOUR EIM PROPOSAL RELATIVE TO THE COMPANY'S PANOPLY OF REVENUE AND COST TRACKERS?

A. I believe that my proposal offers a number of improvements over the relatively blunt and inefficient set of revenue and cost trackers offered by the Petitioner. My proposed EIM, for instance, would:

- Re-couple performance, cost, and revenue recovery in a fashion consistent with the best practices and traditions of utility regulation.
- Preserve traditional risk relationships in utility regulation with the Company bearing risks associated with both its costs and the overall business environment in which it operates.
- Remove disincentives for energy efficiency by creating positive (not neutral) incentives.
- Create a "win-win" outcome for ratepayers and utilities. Consider that under the EIM, the Company always has some opportunity for financial benefit, regardless of outcome, in each scenario. Even with mediocre demand-side energy efficiency efforts, the Petitioner can benefit from supply-side efficiencies to increase rewards to shareholders. However,

the best outcome for the utility under this mechanism is to excel in both its demand and supply-side efficiency efforts.

- Create "win-win" outcomes for all ratepayers, which include those participating in energy efficiency programs and those not participating in energy efficiency programs yet supporting these programs through rate contributions. Thus, customers that may have been early-adopters of energy efficiency measures prior to the creation of utility-supported programs can still participate in overall system efficiency improving benefits.
- Remove the increasingly-recognized deficiency created by revenue decoupling that allows utilities to collect revenue deficiencies that far exceed their energy efficiency efforts (i.e., the problems recognized by the Washington, Idaho, and Virginia regulatory commissions).
- Only penalize the Company if it fails in both its demand-side and supply-side efficiency efforts, which is an outcome consistent with the best practices of regulation and, not surprisingly, competitive market outcomes.

Q. IS YOUR PROPOSAL CONSISTENT WITH ANY OTHER JURISDICTIONS' REVENUE NEUTRALITY MECHANISMS?

A. Yes. My proposal is very similar to New Jersey's Conservation Incentive Program ("CIP"). The program was originally adopted as the result of a settlement in 2006 for South Jersey Gas Company ("SJG") and New Jersey Natural Gas Company ("NJNG"). The program was recently extended for an additional three year period ending 2013.[70] The program is unique since it ties weather-adjusted margin recovery to upstream natural gas savings attained in the purchased gas adjustment ("PGA") clause. Here, upstream savings are those associated with: (a) capacity release; (b) reductions in capacity purchases; and (c) reductions in the average cost of

[70]New Jersey Board of Public Utilities. Docket Nos. GR0512019 and GR0512020. Final Order. January 21, 2010.

purchased gas. The program effectively ties downstream (downstream of the city gate) natural gas savings to those attained upstream in wholesale gas markets much like the EIM proposal I am making in this proceeding. The CIP, like my EIM, makes difficult-to-prove assertions about "lost fixed distribution cost recovery" become more easily verifiable since a loss of capacity upstream is highly unlikely without some type of liberated capacity downstream. The program effectively "re-couples" performance and revenue by tying utility margin deferrals to verifiable savings.

Q. HOW DOES YOUR INCENTIVE PROPOSAL COMPARE TO THE NEW JERSEY CIP?

A. The overall purpose of the New Jersey CIP was to capture the realization that there were off-system opportunities for capacity freed-up from energy efficiency activities. There are significant policy reasons for sending utilities strong signals to maximize this under/un-utilized capacity. For instance, tying downstream capacity losses to upstream capacity gains creates a matching mechanism that verifies the claims made by revenue decoupling advocates. If fixed cost recovery is a genuine risk, sales losses "stranding" downstream capacity should match those upstream. If a natural gas utility has truly lost 1 billion cubic feet ("BCF") of capacity at the distribution level, then 1 BCF less of storage, firm transportation, and commodity capacity premiums will be required upstream. If these capacity offsets do not occur in reality, it raises serious questions about the efficacy of the underlying principles supporting of revenue decoupling that fixed cost and capacity are being effectively stranded.

Q. ARE THERE ANY BROADER EFFICIENCY REASONS FOR UTILIZING A METHOD LIKE YOU HAVE PROPOSED?

A. Yes. Approaches that maximize the use of system resources, including capacity, result in greater overall resource efficiency and lower costs for all parties. Reselling unused capacity to other parties that have the need for this capacity creates gains from trade and great asset

maximization for society and not just the Company and its ratepayers. This reduces land use, water, high cost energy commodity purchases, and offsets expensive capital investments for any one party by sharing, through trade, the capacity resources of another. If that capacity has no market value, then its continued use is put into question since no transaction is significant enough to cover its average variable cost, the traditionally-recognized break-even point for a viable business operation.

Q. DO YOU THINK YOUR PROPOSED EIM ADDRESSES MANY OF THE CONCERNS EXPRESSED BY THE VIRGINIA, WASHINGTON, AND IDAHO COMMISSIONS?

A. Yes. As I noted earlier in my testimony, these Commissions collectively reported two important and fundamental concerns with decoupling mechanisms. The first is that the mechanism allowed utilities to recover margins in excess of those associated with its energy efficiency efforts. The second was that energy efficiency programs had the unattractive feature of creating very little or questionable savings for non-participating customers. My proposed EIM approach solves both of those problems since the program ensures that a utility is not made whole for revenues greater than the energy efficiency savings associated with its efforts. Second, and more importantly, non-participating customers attain benefits of funding energy efficiency programs through the potential to share in expanded wholesale power margins (WPM). Such an approach is clearly more beneficial and more consistent with traditional regulation than the revenue tracker approach proposed by the Company as well as many other regulated utilities around the country.

D. OFF-SYSTEM SALES ISSUES

Q. YOUR EIM IS PREDICATED ON A RELATIVELY SIGNIFICANT OFF-SYSTEM SALES OPPORTUNITY. DO YOU THINK THESE OFF-SYSTEM SALES OPPORTUNITIES WILL MATERIALIZE IN THE NEAR AND INTERMEDIATE FUTURE?

A. Yes. Vectren South has gone to great lengths to present a relatively bleak picture about its future wholesale market opportunities.[71] But despite state and national energy efficiency goals, most credible load forecasts and energy use forecasts continue to predict an increase in the demand for electricity into the foreseeable future. This will translate into the continued needs for cost-effective supplies of power. Petitioner has a portfolio of potentially-attractive solid fuel generators that potentially have low dispatch order, and even with relatively uncompetitive variable costs, have the opportunity to garner significant wholesale power margins. Exhibit DED-27, for instance, shows the Company's past wholesale power trends in annual revenue and margins.

Q. THE MOST RECENT YEAR HAS SEEN A RELATIVELY DRAMATIC DECREASE IN VECTREN SOUTH'S OFF-SYSTEM SALES. DO YOU THINK THIS IS REFLECTIVE OF NORMAL OR FUTURE TRENDS?

A. No. Over the past year, wholesale power markets have been impacted by two relatively significant and somewhat anomalous events. The first has been the very significant economic contraction that has reduced electricity sales across the country. Wholesale markets are a function of retail markets: if there is no end-use demand for electricity, there is likely to be a decrease in the number of wholesale power transactions. The second has been the rapid decrease in natural gas commodity prices starting in about mid-2008. Natural gas influences wholesale power prices since gas-fired generation tends to be the last incrementally-dispatched unit, setting the price at the margin for the entire market. Solid fuel generators (nuclear, coal) can garner significant returns in high-gas price markets which has been the case since roughly 2004 until very recently. While both factors have dampened market prices and the margins, companies like

[71] Direct Testimony of Carl L. Chapman (Revised), 9:3-5; Direct Testimony of Michael W. Chambliss, 11:9-11; Direct Testimony of M. Susan Hardwick, 13:14-18; and Direct Testimony of Ronald G. Jochum, 6:20-30, 8:9-21, and 9:26-29.

Vectren South will continue to have the opportunity to earn meaningful margins from off-system sales.

Q. CAN YOU PROVIDE THE COMMISSION WITH AN EXAMPLE OF HOW THOSE GAINS MAY MATERIALIZE?

A. Yes. Exhibit DED-28 has been provided as an illustration of how future wholesale prices could easily rebound and increase wholesale power margins well above the recent levels the Petitioner has emphasized. This analysis is not offered as a specific forecast or outlook for power prices, but as an example of how off-system sales gains could materialize based on current market efficiency trends, a range of gas price outlooks, and a return to more normal levels of off-system transactions. The exhibit providing this illustration is comprised of four pages. The first page provides a relatively generic forecast of power prices for the Cinergy Hub assuming constant natural gas prices of $5.00/MMBtu and a market clearing heat rate that randomly varies around a mean of 8,200 Btus/kWh. Daily random variations are bounded by two standard deviations as measured over the past five years. With these assumptions, power prices are anticipated to have a daily range from $20 to $80 per MWh depending upon the season.

Q. WHAT KIND OF MARGINS COULD BE GENERATED FROM THIS PARTICULAR ILLUSTRATIVE FORECAST?

A. Page 2 of Exhibit DED-28 provides the same information but restricted for the forecast period alone rather than the historic and forecasted period presented on page 1. As noted earlier, market clearing prices are estimated to range from $20/MWh and $80/MWh with potential margins for one MWh noted in the table in the upper corner of the chart. On average over the three year period 2006-2008 (inclusive), Vectren South sold 1.5 million MWh per year, so the implied total margins for 12 months under this forecast would be $18.5 million.

Q. HAVE YOU EXAMINED ANY SENSITIVITIES TO THIS FORECAST?

A. Yes. Page 3 and 4 of the exhibit provide essentially the same forecast, but assume higher gas prices of $6/MMBtu and $7/MMBtu, respectively. Under the $6/MMBtu scenario, total forecasted year margins based on a forecast of potential 2010 off-system sales volumes, would be around $30 million, while the $7/MMBtu scenario would yield potential margins of $43 million.

Q. HOW DOES THIS WHOLESALE POWER FORECAST INFLUENCE YOUR ALTERNATIVE RECOMMENDATIONS?

A. The forecast influences my recommendation in two ways. First, it shows that even under relatively modest assumptions regarding fuel prices and resource availability, Vectren South clearly has the ability to make some relatively attractive margins in regional wholesale power markets in the near future. This opportunity only increases if regional capacity availability tightens (driving up market clearing heat rates), or natural gas prices spike. Second, these significant opportunities could create the opportunity for potential incentive windfalls if a few minor adjustments are not made to on my recommended EIM.

Q. WHAT DO YOU MEAN BY INCENTIVE WINDFALLS?

A. The forecast I provided shows the potential wholesale power margin opportunities for the Company under a business as usual environment. It does not assume any efficiency improvements, aggressive wholesale marketing, or cost containment. Basing incentives on this level without any adjustment would give Petitioner an incentive for operating in the same fashion it has historically. The only inherent reason for the Company's gain in my earlier illustrative forecast is through a return to normal market conditions and various natural gas price increases above $5/MMBtu. These potential gains would arise for reasons that have nothing to do with the Petitioner's performance. Thus, it seems reasonable that some amount of the initial gain come "off the top" of the reported margins as reimbursement to ratepayers for the assets they help

support through retail rates. The net amount after this adjustment would be the amount used for the EIM as I discussed earlier. I recommend a $10 million dollar credit to base rates that would account for the base level of WPM gains. I have provided an example (Exhibit DED-29) of how this adjustment would work in the context of the EIM.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS REGARDING THE EIM?

A. Yes. The EIM should be adopted on a pilot basis and evaluated after a three-year period in order to assess its effectiveness in stimulating incentives for supply-side efficiency and removing disincentives for demand-side efficiency.

VI. THE PROPOSED MCRA

A. OVERVIEW AND THE COMPANY'S PROPOSAL

Q. WOULD YOU PLEASE DISCUSS VECTREN SOUTH'S PROPOSED MODIFICATIONS TO THE MCRA?

A. Yes. The MCRA is a tracker mechanism that allows Petitioner to recover certain non-fuel transmission costs which are offset by MISO transmission revenue. The MCRA is calculated semi-annually for each of the Petitioner's rate schedules. The Company is proposing to remove transmission revenue from the MCRA which in the past has offset the investment costs included in the MCRA.

Q. WHAT IS THE RATIONALE FOR THE PETITIONER'S PROPOSAL TO SEPARATE REVENUES FROM THE MISO TRACKER?

A. The Petitioner provides two reasons. First, it asserts that certain transmission investments are "federally-mandated" by the Federal Energy Regulatory Commission ("FERC").[72] Second,

[72] Direct Testimony of Ronald G. Jochum (Revised), 38:16-18.

the Company claims that while transmission-related investments are highly variable,[73] transmission-related revenues (i.e., wheeling revenues) are not. The Company notes that the MCRA is still needed to recover MISO-related investments since they are "unpredictable and volatile."[74]

Q. HAS VECTREN SOUTH PROVIDED ANY EVIDENCE THAT THE MISO COSTS ARE UNPREDICTABLE AND VOLATILE?

A. No, it has not, and a review of Exhibit DED-7 would suggest otherwise. Over the past six years, transmission investments have certainly increased and become more variable, particularly over the last two years. Nevertheless, those increases are not "volatile" in the sense that they have unpredictable random movements up and down making cost management entirely unpredictable. It is also typically the case that transmission investments are made in within the context of a long term resource plan. These investments are not like certain types of spot fuel purchases that have to be made at the spur of the moment in order to dispatch a plant.

Q. DO YOU AGREE THAT BECAUSE COSTS ARE FEDERALLY-MANDATED THEY NECESSITATE A SPECIAL COST RIDER?

A. No. Many costs are required by federal regulations and laws and are not recovered through special tracking mechanisms. These costs include income taxes, insurance requirements, pollution control, and unemployment compensation to name a few. Including costs in a tracker because they are caused by or related to some type of federal mandate sets a bad regulatory precedent and opens the door for the inclusion of a wide range of current and future costs into a tracker-type of mechanism.

Q. DO YOU AGREE WITH VECTREN SOUTH'S PROPOSAL TO EMBED A FIXED AMOUNT OF TRANSMISSION REVENUE IN BASE RATES WITH NO TRACKING OF REVENUE CHANGES IN THE MCRA?

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[73] Direct Testimony of Ronald G. Jochum (Revised), p. 38.
[74] Direct Testimony of Scott E. Albertson (Revised), p. 15.

A. No. The Company's proposals are likely to allow them to garner significant upside transmission revenues with little downside risk. The Petitioner's proposal fix these transmission revenues in base rates provides considerable opportunities for it to potentially acquire revenue windfalls over time as regional investments made by all MISO participants expand the scope and opportunities for wholesale power trade and overall power markets recover from the current recession. Setting a transmission revenue credit in base rates today, on recession year observations, clearly stacks the deck in favor of the Company. The Commission should reject this proposal out of hand.

B. RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE COMPANY'S MCRA PROPOSAL GIVEN WHAT WAS AGREED TO IN THE LAST SETTLEMENT AND COMMISSION ORDER?

A. I recommend that the Commission reject Vectren South's proposal to remove transmission revenues from the tracker. Mr. Eckert, an additional expert testifying for the OUCC, is offering an expert opinion on this issue including the need to track transmission revenue along with MISO costs or, alternatively, terminate the MCRA. I agree that Mr. Eckert's recommendation is in the public interest and should be adopted.

Q. DOES THIS CONCLUDE YOUR TESTIMONY FILED ON JUNE 25, 2010?

A. Yes it does.

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola Junior College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-Current	Associate Executive Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1999-2000	Managing Director, Distributed Energy Resources Initiative
1995-2000	Assistant Professor

E.J. Ourso College of Business Administration, Department of Economics

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida
College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-2000	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

2000-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

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21. "Is There a Role for the TVA in Post-Restructured Electric Markets?" (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 433-454.

22. "The Role of Alaska North Slope Gas in the Southcentral Alaska Regional Energy Balance." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Natural Gas Journal*. 19: 10-15.

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24. "Do Economic Activities Create Different Economic Impacts to Communities Surrounding the Gulf OCS?" (2002). With Williams O. Olatubi. *IAEE Newsletter*. Second Quarter: 16-20.

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26. "An Assessment of the Role and Importance of Power Marketers." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly. 50: 713-731.*

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28. "Energy Policy by Crisis: Proposed Federal Changes for the Electric Power Industry." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50:235-249.

29. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49:947-973.

30. "California Dreaming: Are Competitive Markets Achievable?" (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 743-759.

31. "Distributed Energy Must Be Watched As Opportunity for Gas Companies." (2001). With Martin Collette, and Ritchie D. Priddy. *Natural Gas Journal*. January: 9-16.

32. "Clean Air, Kyoto, and the Boy Who Cried Wolf." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. December: 529-540.

33. "Energy Conservation Programs and Electric Restructuring: Is There a Conflict?" (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. September: 211-224.

34. "The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry." (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 751-765.

35. "Issues and Opportunities for Small Scale Electricity Production in the Oil Patch." (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter*. 49: 78-82.

36. "Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry." (2000). With K.E. Hughes II *Oil, Gas and Energy Quarterly*. 48:593-602.

37. "Coming to a Neighborhood Near You: The Merchant Electric Power Plant." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48:433-441.

38. "Slow as Molasses: The Political Economy of Electric Restructuring in the South." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48: 163-183.

39. "Stranded Investment and Non-Utility Generation." (1999). With Michael T. Maloney. *Electricity Journal* 12: 50-61.

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1. *The Benefits of Continued and Expanded Investments in the Port of Venice*. (2009). With Christopher Peters and Kathryn Perry. Baton Rouge, LA: LSU Center for Energy Studies. 83 pp.

2. *Examination of the Development of Liquefied Natural Gas on the Gulf of Mexico*. (2008). U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA OCS Study MMS 2008-017. 106 pp.

3. *Gulf of Mexico OCS Oil and Gas Scenario Examination: Onshore Waste Disposal*. (2007). With Michelle Barnett, Derek Vitrano, and Kristen Strellec. OCS Report, MMS 2007-051. New Orleans, LA: U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico Region.

4. *Economic Impact Analysis of the Proposed Lake Charles Gasification Project*. (2007). Report Prepared on Behalf of Leucadia Corporation.

5. *The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard.* (2005) Report Prepared on Behalf of the New Jersey Division of Ratepayer Advocate.

6. *The Importance of Energy Production and Infrastructure in Plaquemines Parish*. (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.

7. *Louisiana's Oil and Gas Industry: A Study of the Recent Deterioration in State Drilling Activity*. (2005). With Kristi A.R. Darby, Jeffrey M. Burke, and Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources.

8. *Comparison of Methods for Estimating the NO_x Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study*. (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.

9. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.

10. *Economic Opportunities for LNG Development in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.

11. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production*. (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department

of Natural Resources, Office of Mineral Resources.

12. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book.* (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.

13. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana.* With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.

14. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application.* (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.

15. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases*. (2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

16. *Alaska In-State Natural Gas Demand Study*. (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.

17. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana*. (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

18. *The Economic Impacts of Merchant Power Plant Development in Mississippi.* (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.

19. *Energy Conservation and Electric Restructuring In Louisiana*. (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

20. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS.* (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

21. *Restructuring the Electric Utility Industry: Implications for Louisiana.* (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

GRANT RESEARCH

1. *Principal Investigator*. "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

2. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $49,500. Status: Completed.

3. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: In Progress.

4. *Principal Investigator*. "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Awarded, In Progress.

5. *Principal Investigator*. "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Awarded, In Progress.

6. *Principal Investigator*. "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Awarded, In Progress.

7. *Principal Investigator*. "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, In Progress.

8. *Principal Investigator*. "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

9. *Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, In Progress.

10. *Principal Investigator*. "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: In Progress.

11. *Principal Investigator*. "Ultra Deepwater Road Mapping Process." (2005). With Kristi A. R.

Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

12. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

13. *Principal Investigator*. " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

14. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

15. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

16. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

17. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

18. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

19. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

20. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

21. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997).

Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

22. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

23. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7, 2009.

2. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

3. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

4. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7, 2008.

5. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19, 2007.

6. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16, 2007.

7. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

8. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

9. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

10. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

11. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

12. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

13. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

14. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

15. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

16. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

17. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

18. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

19. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

20. “Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring.” (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

21. “Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach.” (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

22. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

23. “Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation.” (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

24. “Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry.” (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

25. “Modeling Regional Power Markets and Market Power.” (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

26. “Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana” (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

27. “Empirical Issues in Electric Power Transmission and Distribution Cost Modeling.” (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

28. “Modeling Electric Power Markets in a Restructured Environment.” (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

29. “Benchmarking Electric Utility Distribution Performance.” (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

30. “Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry.” (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

31. “Benchmarking Electric Utility Transmission Performance.” (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

32. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

33. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

34. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

35. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

36. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

37. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

38. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

39. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

40. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

41. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

42. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

43. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

2. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

3. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

4. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

5. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

6. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

7. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

8. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

9. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

2. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January

28, 2010, New Orleans, LA.

3. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

4. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

5. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

6. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

7. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

8. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

9. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

10. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

11. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

12. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

13. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

14. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economists (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

15. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

16. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

17. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

18. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

19. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

20. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

21. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

22. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

23. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

24. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

25. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

26. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

27. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

28. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

29. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

30. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

31. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

32. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

33. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

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36. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

37. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

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39. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

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the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

41. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

42. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

43. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

44. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

45. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

46. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

47. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

48. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

49. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

50. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

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52. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

53. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

54. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

55. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

56. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

57. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

58. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

59. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

60. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

61. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

62. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

63. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

64. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

65. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

66. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

67. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

68. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

69. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

70. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

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72. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

73. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

74. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

75. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

76. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

77. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

78. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

79. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

80. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

81. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

82. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

83. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

84. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

85. "Power Plant Siting Issues in Louisiana." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.

86. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

87. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

88. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

89. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

90. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

91. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

92. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

93. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

94. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

95. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

96. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

97. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

98. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

99. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

100. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

101. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

102. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

103. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

104. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

105. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

106. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

107. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

108. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

109. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

110. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

111. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

112. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

113. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

114. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

115. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

116. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

117. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

118. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

119. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

120. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

121. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

122. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

123. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

124. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

125. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

126. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

2. Expert Testimony. Docket 09-00183. Before the Tennessee Regulatory Authority. (2010). In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program

review and cost effectiveness analysis.

3. Expert Testimony and Exhibits. Docket No. 10-240. Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

4. Expert Testimony. Docket No. 09505-EI. Before the Florida Public Service Commission. (2010). In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

5. Expert Testimony. Docket 09-00104. Before the Tennessee Regulatory Authority. (2009). In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

6. Expert Testimony. Before the Nebraska Public Service Commission. Docket Number NG-0060. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

7. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

8. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

9. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

10. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public

Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

11. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

12. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

13. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

14. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

15. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

16. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

17. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

18. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate

Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

19. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

20. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

21. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

22. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

23. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

24. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

25. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

26. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

27. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to

determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

28. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

29. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

30. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

31. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

32. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

33. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

34. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

35. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

36. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

37. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

38. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

39. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

40. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

41. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

42. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

43. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

44. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745;

491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

45. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

46. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

47. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

48. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

49. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

50. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

51. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

52. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

53. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

54. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

55. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

56. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

57. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

58. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

59. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

60. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

61. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

62. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

63. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States

Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

64. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

65. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

66. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

67. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Referee, 1995-Current, *Energy Journal*
Contributing Editor, 2000-Current, *Oil, Gas and Energy Quarterly*
Referee, 2005, *Energy Policy*
Referee, 2004, *Southern Economic Journal*
Referee, 2002, *Resource & Energy Economics*
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Econometric Society, Southern Economic Association, Western Economic Association, and the International Association of Energy Economists.

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current)

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Principles of Microeconomic Theory
Principles of Macroeconomic Theory
Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.
Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept of Environmental Studies).
Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

THESIS/DISSERTATIONS COMMITTEES

5 Thesis Committee Memberships (Environmental Studies, Geography)
3 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics).
1 Doctoral Examination Committee Membership (Information Systems & Decision Sciences)

1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Steering Committee Member, LSU Coastal Marine Institute (2009-Current).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-Current)

LSU Faculty Senate (2003-2006)

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture &

Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

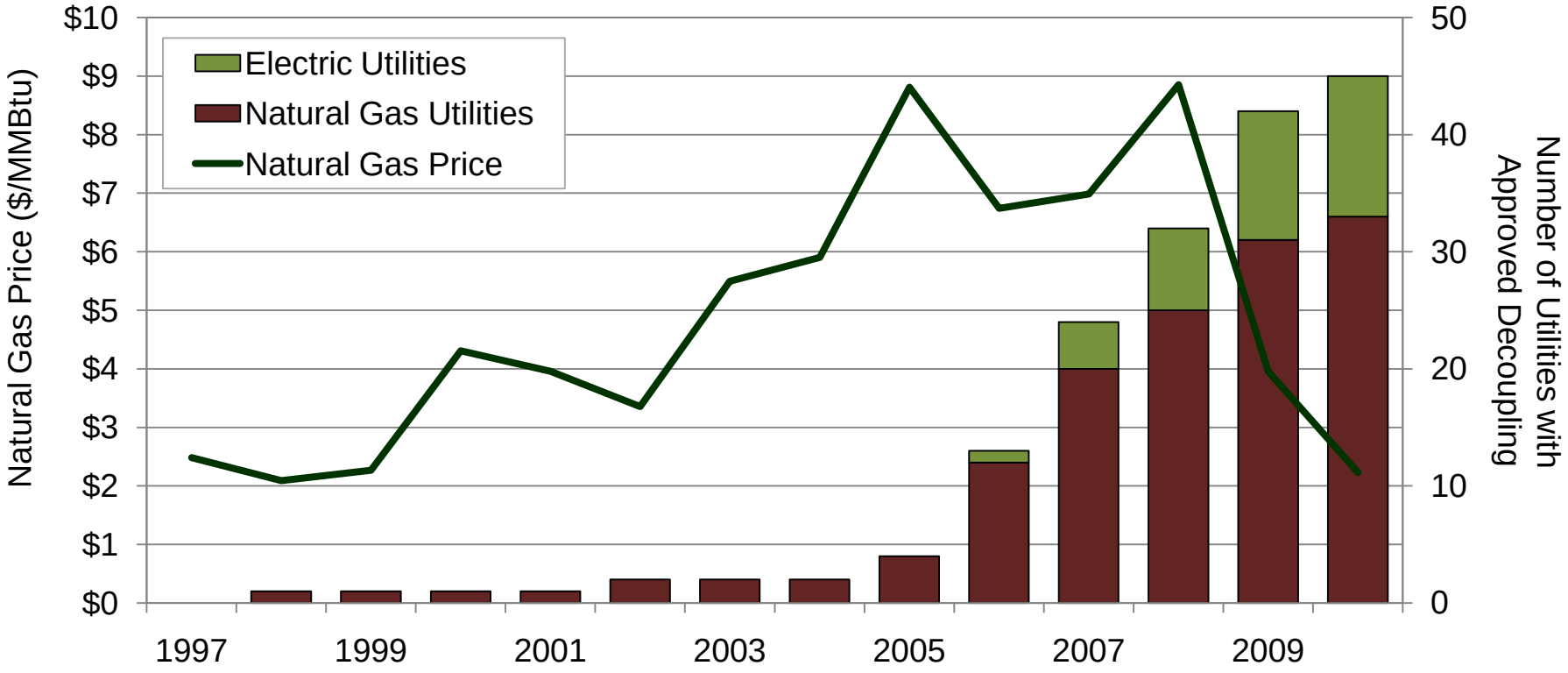
Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Natural Gas Price and Approved Decoupling



Source: Federal Reserve Bank of St. Louis.

Comparison Group Companies

Utility	State	Number of Customers	Sales (MWh)	2009 Fuel Mix Coal	Natural Gas	Nuclear	Other
				---------- (%) ----------			
Vectren-South	**IN**	**145,945**	**5,039,673**	**98%**	**2%**	**0%**	**0%**
Appalachian Power	WV	959,814	30,414,469	99%	0%	0%	0%
Duke Energy Indiana	IN	776,145	26,215,892	98%	1%	0%	1%
Indiana Michigan Power	IN	582,214	17,642,645	72%	0%	28%	0%
Indianapolis Power & Light	IN	467,683	14,085,842	100%	0%	0%	0%
Interstate Power and Light	IA	526,023	14,876,474	91%	8%	0%	1%
Kansas City Power & Light	KS/MO	510,296	14,680,690	97%	1%	0%	2%
Kentucky Power	KY	174,994	7,068,456	100%	0%	0%	0%
Kentucky Utilities	KY	540,618	18,412,507	99%	1%	0%	0%
Louisville Gas & Electric	KY	390,825	11,405,157	99%	1%	0%	0%
MidAmerican Energy	IA	723,271	20,186,482	87%	1%	0%	11%
Monongahela Power	WV	383,621	10,022,115	99%	0%	0%	0%
Northern Indiana Pub Serv	IN	455,645	14,925,097	94%	6%	0%	0%
Union Electric	MO	1,187,613	35,098,274	76%	1%	21%	2%
Westar Energy	KS	367,696	9,433,354	95%	4%	0%	2%
Wisconsin Electric Power	WI	1,115,500	25,817,717	85%	13%	0%	2%
Wisconsin Power & Light	WI	455,794	9,858,145	96%	0%	0%	3%
Wisconsin Public Service	WI	435,630	10,402,358	99%	1%	0%	0%

Source: U.S. Department of Energy, Energy Information Administration.

Plant in Service – Power Production (Steam) per MWh

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	($/MWh)															
Vectren-South	**$ 123.82**	**$ 145.41**	**$ 140.79**	**$ 146.60**	**$ 141.99**	**$ 134.78**	**$ 133.75**	**$ 133.66**	**$ 127.13**	**$ 150.08**	**$ 162.38**	**$ 183.97**	**$ 187.37**	**$ 193.42**	**$ 207.36**	**$ 242.11**
Appalachian Power	67.37	64.76	64.54	65.35	65.46	65.35	65.71	67.60	71.06	73.48	78.39	82.86	78.78	95.15	96.37	127.22
Duke Energy Indiana	88.60	85.31	85.59	85.29	83.04	78.54	80.10	82.42	88.75	95.11	95.70	100.50	111.15	118.81	146.59	162.27
Indiana Michigan Power	60.44	58.93	56.84	56.52	55.50	53.97	54.72	55.30	53.30	56.16	57.11	55.86	62.64	63.62	66.44	77.22
Indianapolis Power & Light	104.16	102.89	114.93	117.30	115.67	112.11	111.40	113.76	113.24	115.79	125.91	124.67	132.77	140.13	145.14	157.73
Interstate Power and Light	69.55	67.38	68.02	67.37	66.36	65.27	65.97	71.54	56.09	59.57	62.83	62.40	64.44	67.56	67.31	85.85
Kansas City Power & Light	66.66	64.79	63.42	63.93	60.89	56.86	59.03	87.37	88.06	88.19	89.86	85.89	88.77	89.44	93.74	128.64
Kentucky Power	37.37	36.21	37.84	37.94	39.80	40.03	38.97	39.11	38.39	68.00	65.23	63.67	66.23	66.88	72.80	76.41
Kentucky Utilities	83.40	81.93	80.34	79.95	76.68	75.68	72.64	74.89	70.84	72.43	81.86	80.42	81.74	85.69	105.28	121.63
Louisville Gas & Electric	142.10	136.02	139.36	142.85	137.71	138.60	138.95	142.49	141.04	149.19	163.19	157.70	162.58	154.63	163.36	166.93
MidAmerican Energy	n.a.	101.08	100.32	97.75	95.64	97.86	95.45	93.07	87.68	88.97	91.82	90.49	89.71	118.19	120.00	132.00
Monongahela Power	91.71	89.12	91.08	91.29	89.55	88.30	84.70	73.11	73.26	77.24	77.54	77.71	93.72	105.16	111.27	168.84
Northern Indiana Pub Srvc	147.60	147.75	153.24	156.09	155.58	150.89	149.35	155.42	154.44	159.77	164.35	160.32	159.73	160.51	183.04	207.02
Union Electric	55.21	55.79	58.51	59.47	57.54	60.45	59.87	65.48	67.80	71.23	73.54	72.43	75.24	73.58	77.96	85.06
Westar Energy	116.96	118.58	115.99	114.64	110.92	115.87	114.76	119.99	118.46	122.47	125.91	125.79	127.39	125.96	149.39	179.80
Wisconsin Electric Power	68.49	67.21	67.57	67.18	65.13	65.95	64.06	66.62	66.58	70.04	64.51	65.45	75.73	76.36	79.07	86.09
Wisconsin Power & Light	68.75	68.20	65.28	63.54	62.22	61.04	61.36	62.73	65.08	68.00	68.01	69.61	70.59	69.69	73.17	76.15
Wisconsin Public Service	65.42	62.68	62.19	60.65	59.74	58.43	58.26	60.69	60.14	59.95	59.96	61.02	63.14	65.03	113.24	121.08
Peer Group Average	**$ 83.36**	**$ 82.86**	**$ 83.83**	**$ 83.95**	**$ 82.20**	**$ 81.48**	**$ 80.90**	**$ 84.21**	**$ 83.19**	**$ 87.98**	**$ 90.92**	**$ 90.40**	**$ 94.37**	**$ 98.61**	**$ 109.66**	**$ 127.05**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**15**	**17**	**17**	**17**	**17**	**16**	**16**	**16**	**16**	**17**	**16**	**18**	**18**	**18**	**18**	**18**
Appalachian Power	6	5	6	7	8	8	8	7	9	9	9	10	8	10	8	9
Duke Energy Indiana	11	11	11	11	11	11	11	11	13	13	13	13	13	13	14	13
Indiana Michigan Power	3	3	2	2	2	2	2	2	2	1	1	1	1	1	1	3
Indianapolis Power & Light	13	14	14	15	15	14	14	14	14	14	15	14	15	15	13	12
Interstate Power and Light	9	8	9	9	9	7	9	8	3	2	3	3	3	4	2	5
Kansas City Power & Light	5	6	5	6	5	3	4	12	12	11	11	11	10	9	7	10
Kentucky Power	1	1	1	1	1	1	1	1	1	5	5	4	4	3	3	2
Kentucky Utilities	10	10	10	10	10	10	10	10	8	8	10	9	9	8	9	8
Louisville Gas & Electric	16	16	16	16	16	17	17	17	17	16	17	16	17	16	16	14
MidAmerican Energy	n.a.	13	13	13	13	13	13	13	11	12	12	12	11	12	12	11
Monongahela Power	12	12	12	12	12	12	12	9	10	10	8	8	12	11	10	15
Northern Indiana Pub Srvc	17	18	18	18	18	18	18	18	18	18	18	17	16	17	17	17
Union Electric	2	2	3	3	3	5	5	5	7	7	7	7	6	6	5	4
Westar Energy	14	15	15	14	14	15	15	15	15	15	14	15	14	14	15	16
Wisconsin Electric Power	7	7	8	8	7	9	7	6	6	6	4	5	7	7	6	6
Wisconsin Power & Light	8	9	7	5	6	6	6	4	5	4	6	6	5	5	4	1
Wisconsin Public Service	4	4	4	4	4	4	3	3	4	3	2	2	2	2	11	7

Source: FERC Form 1.

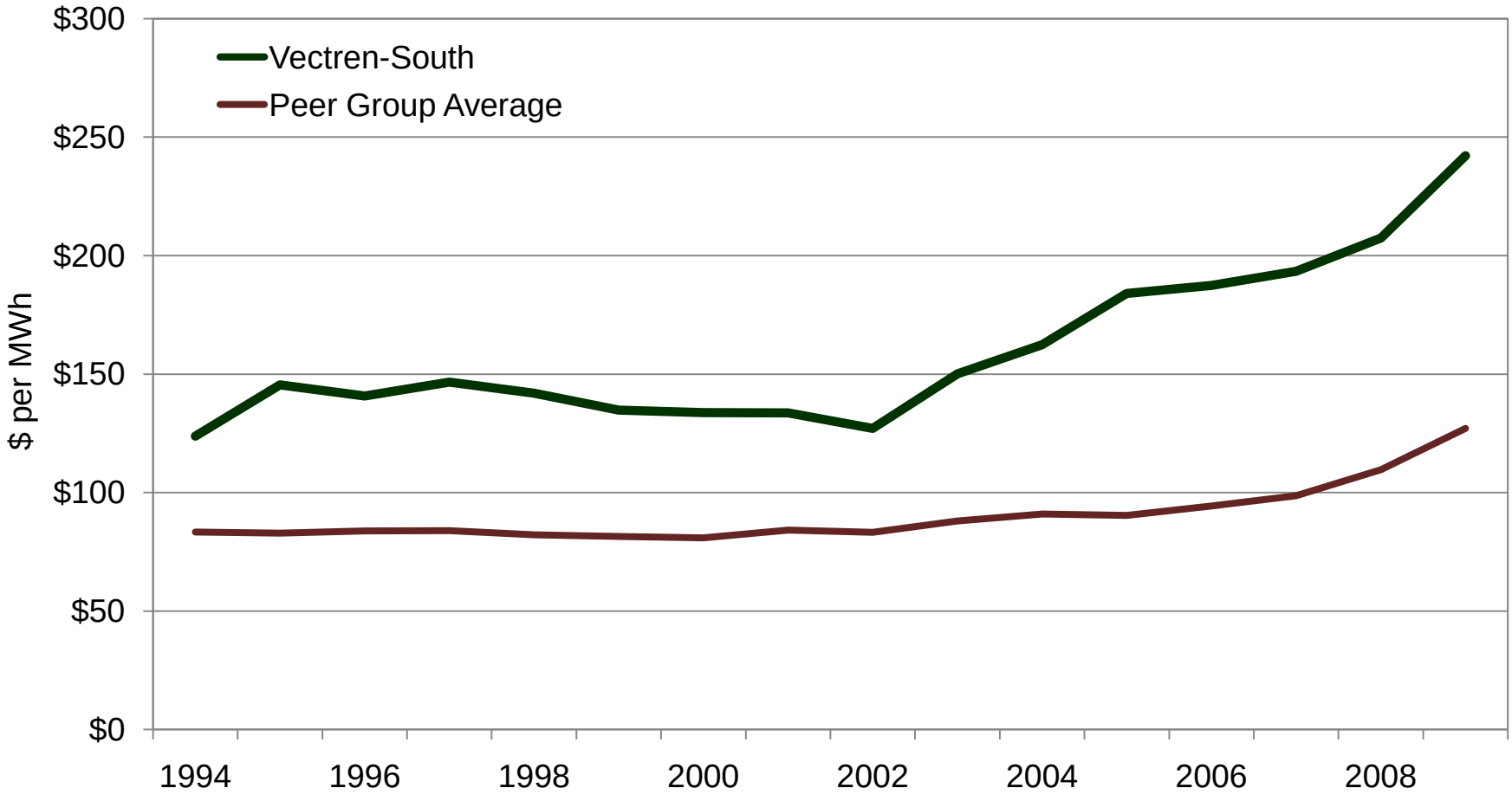
Plant in Service – Power Production (Steam) per MWh Coefficient of Variation

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Coefficient of Variation)															
Vectren-South	**-**	**0.052**	**0.017**	**0.025**	**0.007**	**0.012**	**0.012**	**0.010**	**0.024**	**0.026**	**0.041**	**0.063**	**0.060**	**0.059**	**0.066**	**0.085**
Appalachian Power	-	0.014	0.009	0.001	0.000	0.001	0.001	0.010	0.022	0.028	0.040	0.047	0.031	0.065	0.061	0.099
Duke Energy Indiana	-	0.014	0.006	0.005	0.014	0.030	0.017	0.005	0.017	0.033	0.030	0.038	0.055	0.062	0.091	0.097
Indiana Michigan Power	-	0.009	0.019	0.015	0.017	0.023	0.014	0.008	0.018	0.000	0.005	0.002	0.026	0.027	0.033	0.059
Indianapolis Power & Light	-	0.004	0.038	0.032	0.018	0.003	0.001	0.007	0.004	0.010	0.030	0.024	0.036	0.043	0.046	0.057
Interstate Power and Light	-	0.011	0.003	0.005	0.009	0.013	0.007	0.019	0.061	0.033	0.013	0.013	0.003	0.009	0.007	0.056
Kansas City Power & Light	-	0.010	0.014	0.006	0.022	0.042	0.021	0.089	0.076	0.066	0.061	0.044	0.046	0.042	0.048	0.095
Kentucky Power	-	0.011	0.011	0.008	0.022	0.019	0.006	0.006	0.000	0.124	0.100	0.084	0.081	0.074	0.081	0.081
Kentucky Utilities	-	0.006	0.011	0.009	0.022	0.021	0.031	0.016	0.031	0.019	0.017	0.010	0.013	0.023	0.061	0.080
Louisville Gas & Electric	-	0.016	0.001	0.010	0.006	0.002	0.001	0.007	0.003	0.018	0.038	0.025	0.029	0.015	0.025	0.028
MidAmerican Energy	-	-	0.002	0.010	0.014	0.003	0.010	0.016	0.032	0.023	0.010	0.013	0.014	0.050	0.048	0.061
Monongahela Power	-	0.010	0.003	0.003	0.005	0.009	0.021	0.069	0.057	0.032	0.026	0.022	0.027	0.049	0.055	0.113
Northern Indiana Pub Srvc	-	0.000	0.014	0.016	0.010	0.003	0.005	0.008	0.005	0.013	0.019	0.010	0.008	0.009	0.036	0.056
Union Electric	-	0.004	0.020	0.019	0.002	0.018	0.011	0.035	0.038	0.045	0.046	0.037	0.041	0.032	0.041	0.054
Westar Energy	-	0.005	0.006	0.008	0.018	0.001	0.002	0.012	0.006	0.014	0.020	0.017	0.018	0.014	0.048	0.076
Wisconsin Electric Power	-	0.007	0.002	0.003	0.014	0.006	0.014	0.000	0.000	0.014	0.010	0.005	0.031	0.030	0.034	0.047
Wisconsin Power & Light	-	0.003	0.019	0.023	0.024	0.025	0.018	0.008	0.004	0.016	0.014	0.018	0.019	0.014	0.024	0.030
Wisconsin Public Service	-	0.015	0.011	0.017	0.018	0.022	0.018	0.002	0.004	0.005	0.004	0.001	0.010	0.016	0.111	0.109
Peer Group Average	**-**	**0.008**	**0.011**	**0.011**	**0.014**	**0.014**	**0.012**	**0.019**	**0.022**	**0.029**	**0.028**	**0.024**	**0.029**	**0.034**	**0.050**	**0.070**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**-**	**18**	**14**	**17**	**5**	**9**	**10**	**11**	**12**	**11**	**15**	**17**	**17**	**15**	**15**	**13**
Appalachian Power	-	15	8	1	1	1	3	10	11	12	14	16	11	17	13	16
Duke Energy Indiana	-	14	7	5	8	17	13	3	9	15	11	14	16	16	17	15
Indiana Michigan Power	-	9	16	12	11	15	11	8	10	1	2	2	8	8	4	8
Indianapolis Power & Light	-	5	18	18	13	6	1	6	6	3	12	11	13	12	8	7
Interstate Power and Light	-	13	4	4	6	10	7	15	17	14	5	6	1	2	1	5
Kansas City Power & Light	-	10	13	6	17	18	16	18	18	17	17	15	15	11	9	14
Kentucky Power	-	12	9	7	16	12	6	4	1	18	18	18	18	18	16	12
Kentucky Utilities	-	7	10	9	15	13	18	13	13	9	7	4	4	7	14	11
Louisville Gas & Electric	-	17	1	10	4	3	2	5	3	8	13	12	10	5	3	1
MidAmerican Energy	-	n.a.	3	11	10	5	8	14	14	10	4	7	5	14	10	9
Monongahela Power	-	11	5	2	3	8	17	17	16	13	10	10	9	13	12	18
Northern Indiana Pub Srvc	-	2	12	13	7	4	5	7	7	4	8	5	2	1	6	6
Union Electric	-	4	17	15	2	11	9	16	15	16	16	13	14	10	7	4
Westar Energy	-	6	6	8	14	2	4	12	8	6	9	8	6	3	11	10
Wisconsin Electric Power	-	8	2	3	9	7	12	1	2	5	3	3	12	9	5	3
Wisconsin Power & Light	-	3	15	16	18	16	15	9	4	7	6	9	7	4	2	2
Wisconsin Public Service	-	16	11	14	12	14	14	2	5	2	1	1	3	6	18	17

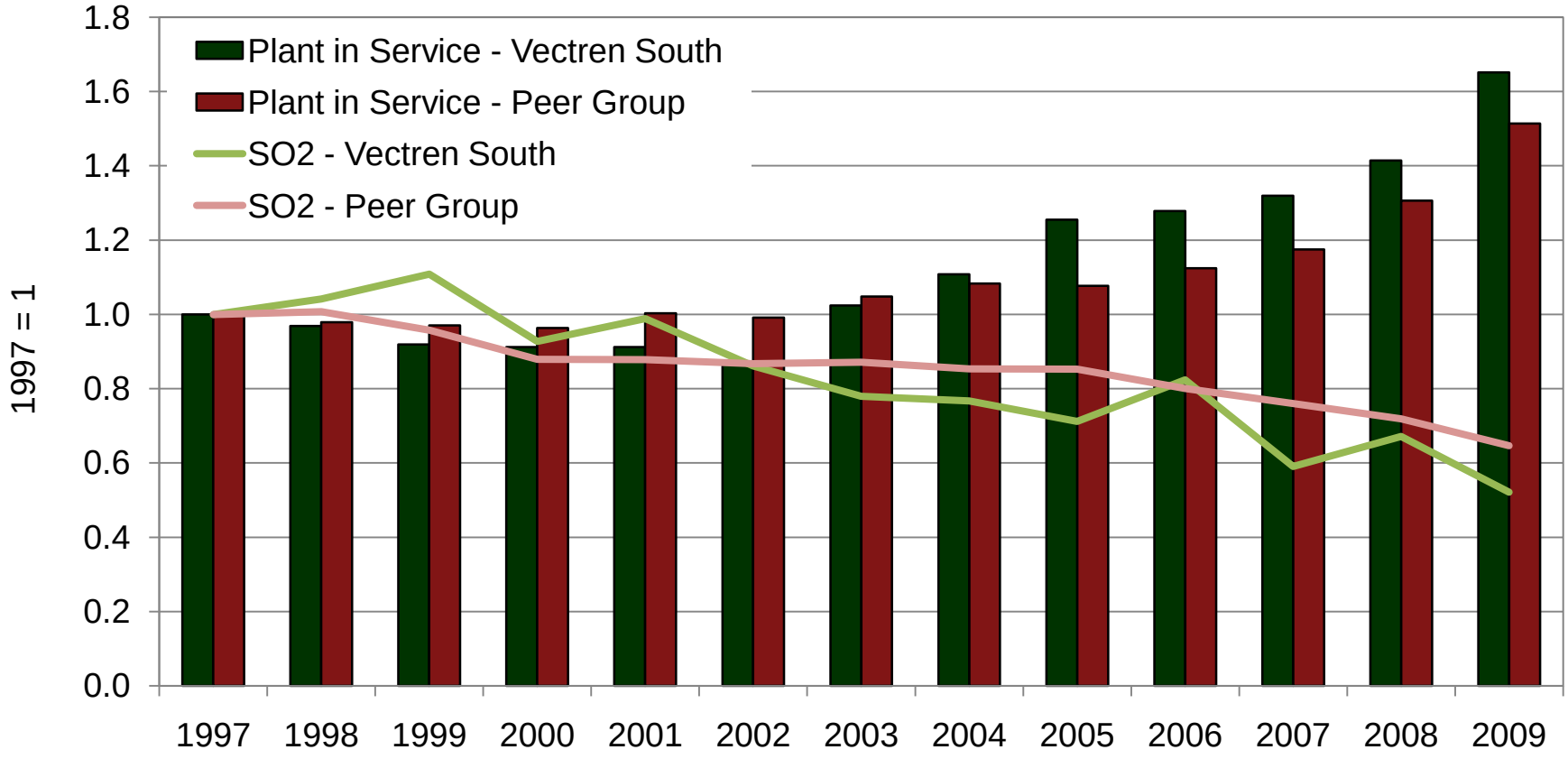
Source: FERC Form 1.

Plant in Service – Power Production (Steam) per MWh



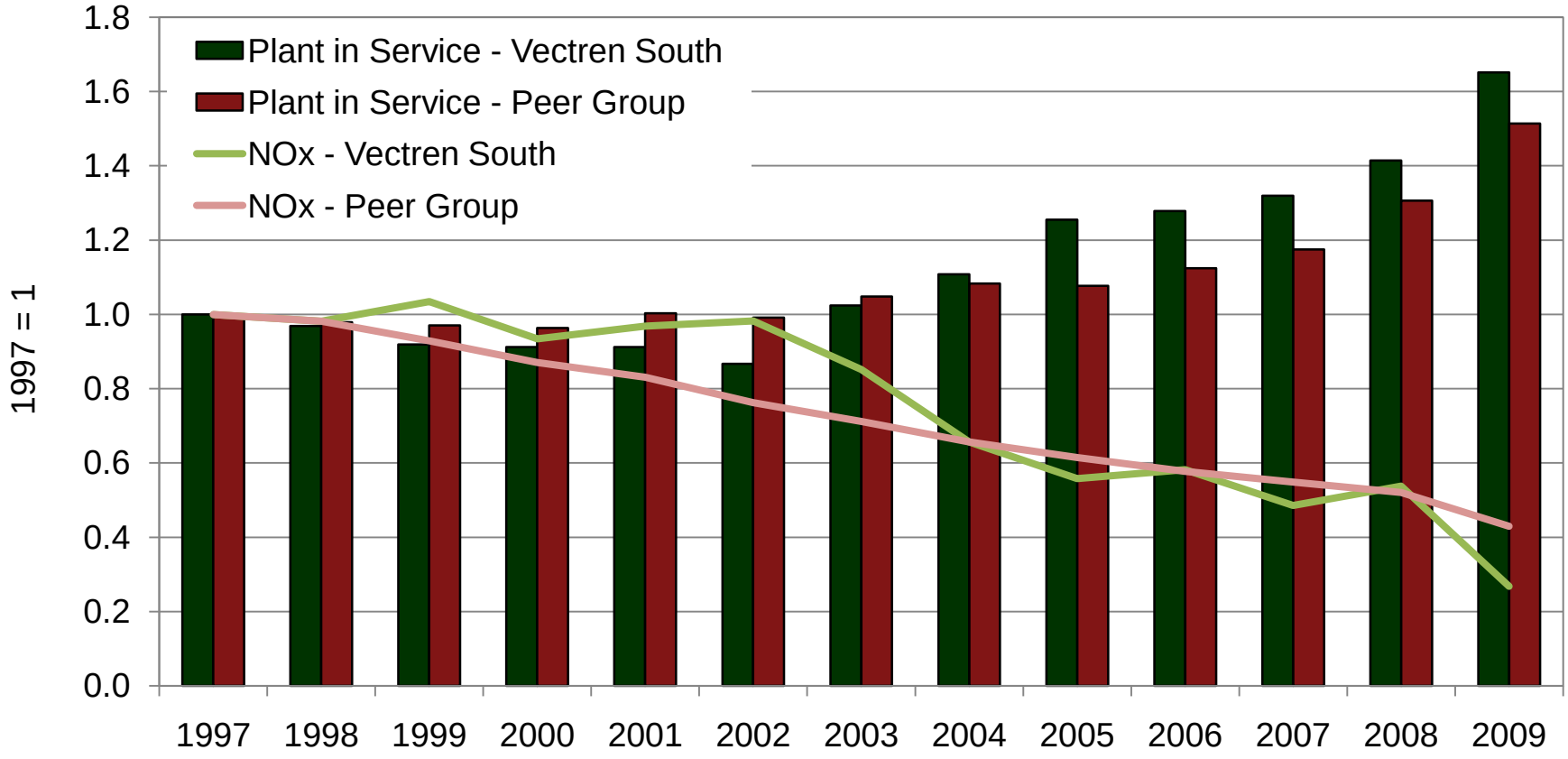
Source: FERC Form 1.

Vectren South
Emissions per MWh, SO_2



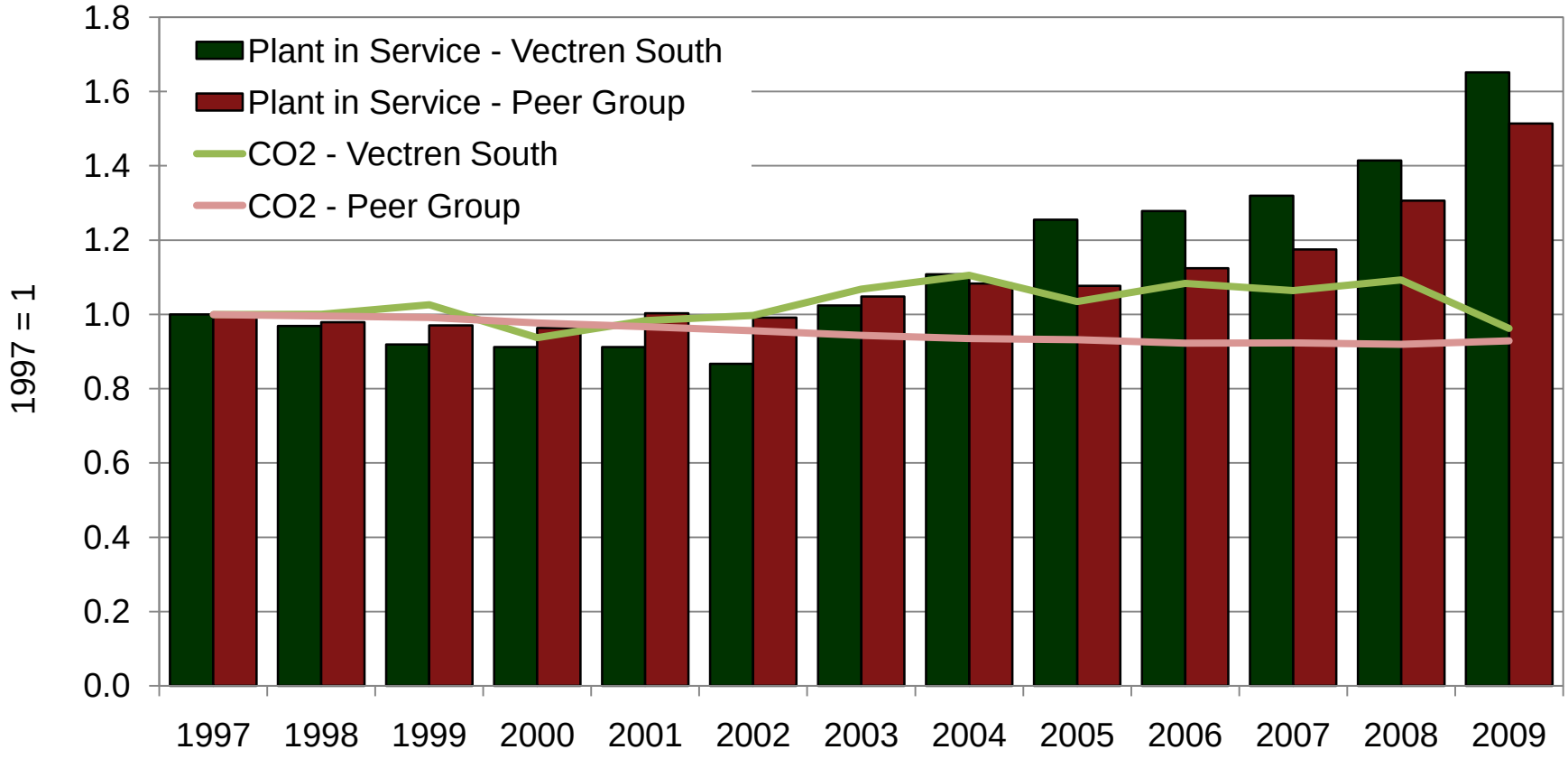
Source: U.S. Environmental Protection Agency; and FERC Form 1.

Vectren South
Emissions per MWh, NOx



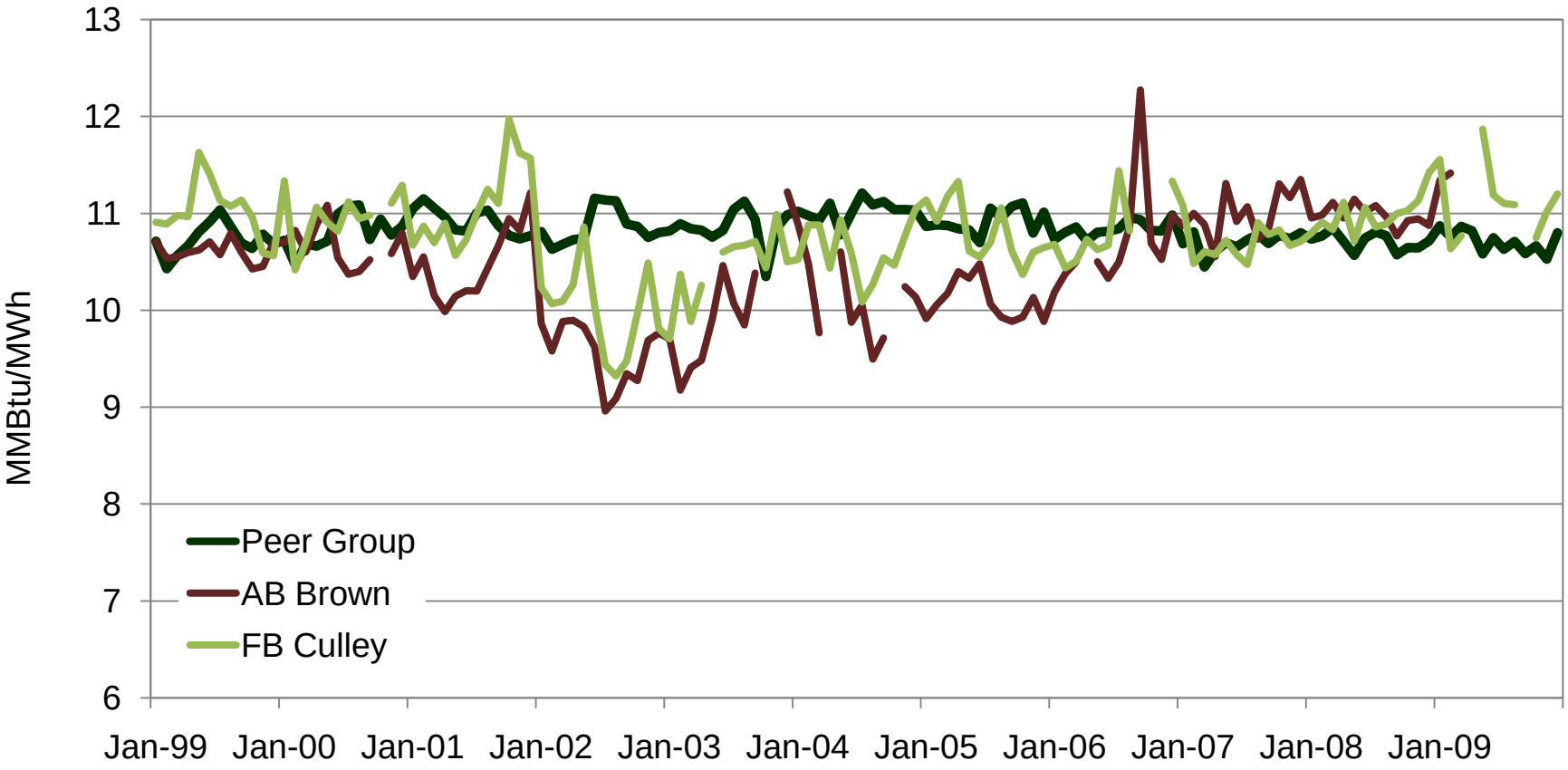
Source: U.S. Environmental Protection Agency; and FERC Form 1.

Vectren South
Emissions per MWh, CO_2



Source: U.S. Environmental Protection Agency; and FERC Form 1.

Heat Rate Comparison



Source: U.S. Department of Energy, Energy Information Administration.

Plant in Service – Transmission per MWh

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	($/MWh)															
Vectren-South	**$ 22.68**	**$ 22.55**	**$ 22.11**	**$ 24.41**	**$ 24.31**	**$ 23.24**	**$ 23.70**	**$ 23.86**	**$ 22.99**	**$ 24.33**	**$ 25.34**	**$ 28.07**	**$ 37.07**	**$ 42.94**	**$ 47.34**	**$ 56.49**
Appalachian Power	40.35	39.80	39.60	39.92	40.81	41.14	41.30	43.17	42.01	43.42	42.59	41.70	49.87	49.39	51.23	59.57
Duke Energy Indiana	26.23	26.25	26.12	26.15	25.73	24.76	25.04	26.32	26.02	27.67	27.80	27.60	29.12	29.93	31.85	36.55
Indiana Michigan Power	54.41	53.81	52.32	53.31	52.14	50.63	51.88	52.60	51.24	54.95	54.23	53.42	55.16	55.15	58.89	65.40
Indianapolis Power & Light	18.02	17.72	17.65	18.11	17.85	17.33	17.09	17.29	17.54	17.83	17.62	17.17	17.76	13.89	13.87	14.84
Interstate Power and Light	36.53	35.89	36.86	37.01	37.84	37.88	38.41	41.67	36.36	38.91	41.28	40.57	42.81	n.a.	n.a.	n.a.
Kansas City Power & Light	16.94	17.39	17.42	17.17	16.45	16.83	16.40	17.82	20.01	21.67	22.27	22.04	24.05	24.41	26.37	25.14
Kentucky Power	43.20	41.42	41.16	46.58	50.36	54.75	53.50	55.59	53.66	57.69	55.27	52.93	55.37	56.54	59.63	62.07
Kentucky Utilities	27.11	26.67	26.47	26.65	26.18	25.92	25.82	26.83	25.61	27.28	26.89	26.48	27.09	26.57	27.53	28.74
Louisville Gas & Electric	17.79	17.14	17.25	17.66	17.39	17.15	17.46	17.87	18.11	19.32	19.27	19.48	20.06	20.11	21.32	21.30
MidAmerican Energy	n.a.	32.95	33.93	35.07	35.15	35.97	21.19	20.32	19.21	19.72	21.18	22.56	25.70	26.65	28.31	31.84
Monongahela Power	24.82	25.49	26.03	26.21	26.32	25.99	24.17	24.51	23.91	23.95	24.05	22.89	27.38	27.32	28.89	31.97
Northern Indiana Pub Srvc	40.33	40.35	41.63	42.66	43.01	41.72	41.87	45.24	45.31	45.81	45.76	45.27	45.79	46.54	43.26	51.10
Union Electric	13.55	13.21	13.05	13.08	12.76	13.79	13.87	13.73	13.86	15.19	15.44	13.33	15.12	14.60	16.51	18.22
Westar Energy	36.51	35.92	35.90	35.59	34.28	35.02	33.92	35.74	35.44	34.82	36.71	35.94	38.52	39.47	48.32	59.26
Wisconsin Electric Power	12.83	12.39	13.06	13.72	13.70	14.89	15.21	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wisconsin Power & Light	27.76	28.23	28.93	28.96	29.49	29.99	31.33	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wisconsin Public Service	14.51	14.26	14.43	14.52	14.23	14.94	15.34	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Peer Group Average	**$ 28.18**	**$ 28.17**	**$ 28.34**	**$ 28.96**	**$ 29.04**	**$ 29.33**	**$ 28.46**	**$ 31.33**	**$ 30.59**	**$ 32.02**	**$ 32.17**	**$ 31.53**	**$ 33.84**	**$ 33.12**	**$ 35.08**	**$ 38.92**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**7**	**7**	**7**	**7**	**7**	**7**	**8**	**6**	**6**	**7**	**7**	**9**	**9**	**10**	**10**	**10**
Appalachian Power	15	15	15	15	15	15	15	12	12	12	12	12	13	12	12	12
Duke Energy Indiana	9	9	9	8	8	8	10	8	9	9	9	8	8	8	8	8
Indiana Michigan Power	17	18	18	18	18	17	17	14	14	14	14	15	14	13	13	14
Indianapolis Power & Light	6	6	6	6	6	6	5	2	2	2	2	2	2	1	1	1
Interstate Power and Light	13	13	14	14	14	14	14	11	11	11	11	11	11	n.a.	n.a.	n.a.
Kansas City Power & Light	4	5	5	4	4	4	4	3	5	5	5	4	4	4	4	4
Kentucky Power	16	17	16	17	17	18	18	15	15	15	15	14	15	14	14	13
Kentucky Utilities	10	10	10	10	9	9	11	9	8	8	8	7	6	5	5	5
Louisville Gas & Electric	5	4	4	5	5	5	6	4	3	3	3	3	3	3	3	3
MidAmerican Energy	n.a.	12	12	12	13	13	7	5	4	4	4	5	5	6	6	6
Monongahela Power	8	8	8	9	10	10	9	7	7	6	6	6	7	7	7	7
Northern Indiana Pub Srvc	14	16	17	16	16	16	16	13	13	13	13	13	12	11	9	9
Union Electric	2	2	1	1	1	1	1	1	1	1	1	1	1	2	2	2
Westar Energy	12	14	13	13	12	12	13	10	10	10	10	10	10	9	11	11
Wisconsin Electric Power	1	1	2	2	2	2	2	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wisconsin Power & Light	11	11	11	11	11	11	12	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wisconsin Public Service	3	3	3	3	3	3	3	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

Source: FERC Form 1.

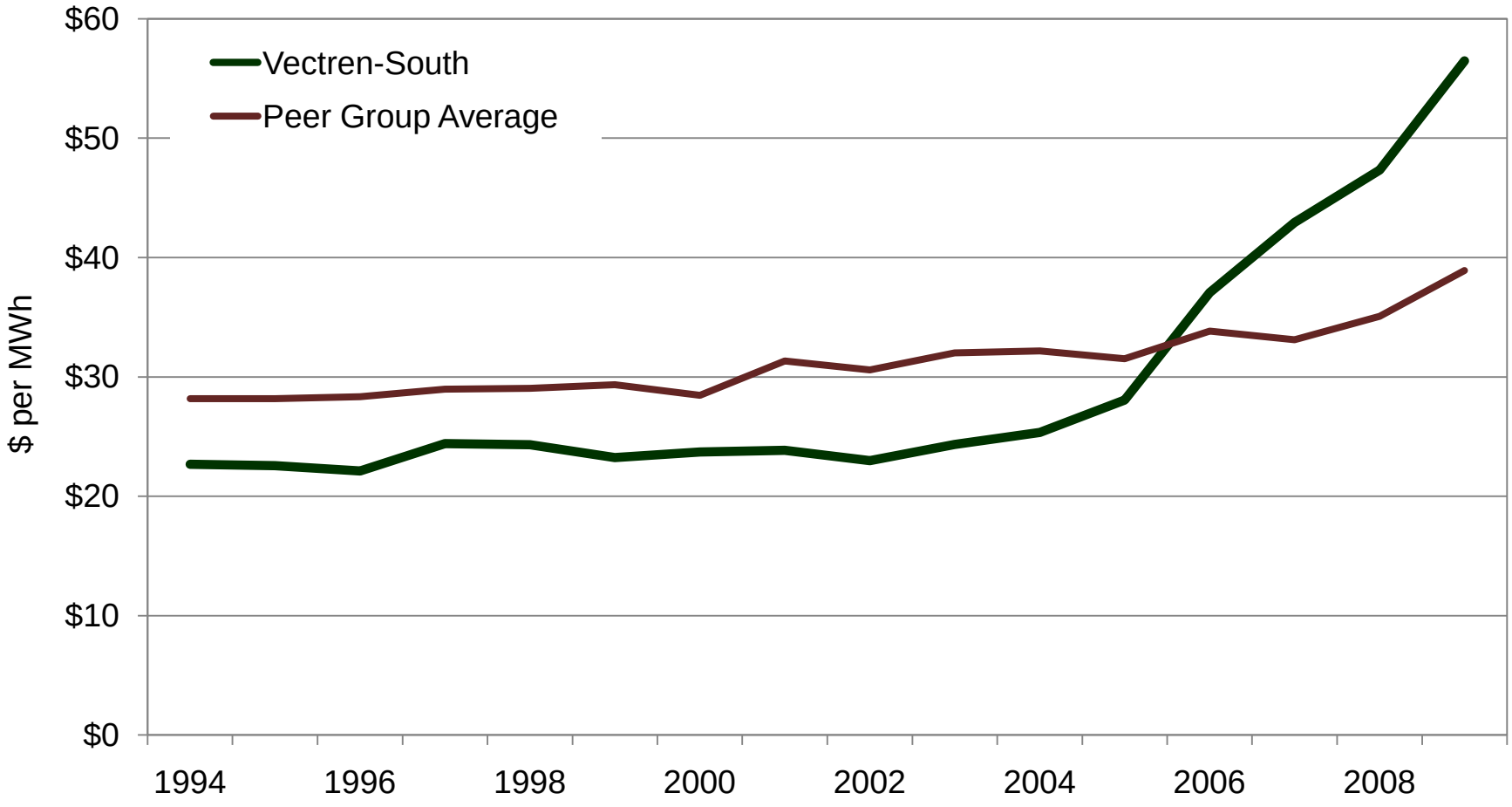
Plant in Service – Transmission per MWh Coefficient of Variation

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Coefficient of Variation)															
Vectren-South	**-**	**0.002**	**0.009**	**0.030**	**0.020**	**0.000**	**0.007**	**0.007**	**0.005**	**0.012**	**0.021**	**0.042**	**0.091**	**0.104**	**0.107**	**0.120**
Appalachian Power	-	0.005	0.005	0.000	0.008	0.009	0.008	0.020	0.009	0.017	0.009	0.003	0.044	0.037	0.041	0.065
Duke Energy Indiana	-	0.000	0.002	0.001	0.006	0.018	0.011	0.007	0.002	0.019	0.017	0.014	0.025	0.028	0.038	0.061
Indiana Michigan Power	-	0.004	0.013	0.001	0.009	0.017	0.006	0.000	0.008	0.013	0.008	0.003	0.010	0.009	0.023	0.042
Indianapolis Power & Light	-	0.006	0.005	0.006	0.000	0.011	0.013	0.007	0.002	0.003	0.000	0.007	0.002	0.066	0.060	0.036
Interstate Power and Light	-	0.006	0.007	0.006	0.012	0.009	0.012	0.033	0.011	0.010	0.024	0.016	0.027	n.a.	n.a.	n.a.
Kansas City Power & Light	-	0.009	0.006	0.002	0.017	0.005	0.013	0.015	0.044	0.056	0.055	0.046	0.059	0.055	0.064	0.050
Kentucky Power	-	0.015	0.011	0.037	0.052	0.063	0.044	0.046	0.030	0.043	0.027	0.013	0.022	0.025	0.034	0.039
Kentucky Utilities	-	0.006	0.006	0.001	0.007	0.009	0.009	0.005	0.010	0.010	0.004	0.000	0.006	0.000	0.009	0.017
Louisville Gas & Electric	-	0.013	0.005	0.005	0.002	0.006	0.001	0.008	0.011	0.026	0.022	0.022	0.026	0.024	0.034	0.031
MidAmerican Energy	-	-	0.008	0.015	0.011	0.015	0.199	0.180	0.174	0.135	0.090	0.057	0.013	0.002	0.012	0.035
Monongahela Power	-	0.009	0.013	0.011	0.009	0.003	0.022	0.013	0.019	0.016	0.012	0.025	0.024	0.021	0.031	0.048
Northern Indiana Pub Srvc	-	0.000	0.012	0.017	0.015	0.001	0.002	0.025	0.021	0.021	0.018	0.013	0.014	0.017	0.002	0.034
Union Electric	-	0.009	0.010	0.005	0.013	0.016	0.015	0.009	0.010	0.033	0.033	0.009	0.023	0.013	0.038	0.053
Westar Energy	-	0.006	0.003	0.005	0.018	0.006	0.015	0.004	0.001	0.005	0.010	0.004	0.020	0.024	0.062	0.089
Wisconsin Electric Power	-	0.012	0.013	0.026	0.018	0.040	0.038	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wisconsin Power & Light	-	0.006	0.012	0.009	0.012	0.015	0.025	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wisconsin Public Service	-	0.006	0.001	0.003	0.005	0.012	0.018	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Peer Group Average	**-**	**0.007**	**0.008**	**0.009**	**0.013**	**0.015**	**0.026**	**0.027**	**0.025**	**0.029**	**0.024**	**0.017**	**0.023**	**0.025**	**0.034**	**0.046**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**-**	**4**	**11**	**17**	**17**	**1**	**4**	**6**	**4**	**5**	**9**	**13**	**15**	**14**	**14**	**14**
Appalachian Power	-	6	4	1	6	7	5	11	6	8	4	2	13	11	10	12
Duke Energy Indiana	-	2	2	2	4	16	7	4	3	9	7	9	10	10	9	11
Indiana Michigan Power	-	5	17	4	7	15	3	1	5	6	3	3	3	3	4	7
Indianapolis Power & Light	-	7	5	11	1	10	10	5	2	1	1	5	1	13	11	5
Interstate Power and Light	-	12	9	10	10	9	8	13	10	3	11	10	12	n.a.	n.a.	n.a.
Kansas City Power & Light	-	14	7	5	14	4	9	10	14	14	14	14	14	12	13	9
Kentucky Power	-	18	13	18	18	18	17	14	13	13	12	8	7	9	6	6
Kentucky Utilities	-	9	8	3	5	8	6	3	7	4	2	1	2	1	2	1
Louisville Gas & Electric	-	17	6	8	2	5	1	7	9	11	10	11	11	8	7	2
MidAmerican Energy	-	n.a.	10	14	9	13	18	15	15	15	15	15	4	2	3	4
Monongahela Power	-	15	16	13	8	3	14	9	11	7	6	12	9	6	5	8
Northern Indiana Pub Srvc	-	3	14	15	13	2	2	12	12	10	8	7	5	5	1	3
Union Electric	-	13	12	7	12	14	11	8	8	12	13	6	8	4	8	10
Westar Energy	-	8	3	9	15	6	12	2	1	2	5	4	6	7	12	13
Wisconsin Electric Power	-	16	18	16	16	17	16	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wisconsin Power & Light	-	10	15	12	11	12	15	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Wisconsin Public Service	-	11	1	6	3	11	13	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

Source: FERC Form 1.

Plant in Service – Transmission per MWh



Source: FERC Form 1.

Plant in Service – Distribution per MWh

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	($/MWh)															
Vectren-South	**$ 42.41**	**$ 44.25**	**$ 44.44**	**$ 48.05**	**$ 47.17**	**$ 47.23**	**$ 48.23**	**$ 49.93**	**$ 50.68**	**$ 55.81**	**$ 55.93**	**$ 59.92**	**$ 67.93**	**$ 70.30**	**$ 80.18**	**$ 94.93**
Appalachian Power	52.61	53.84	56.15	58.50	59.92	62.34	63.85	66.85	67.43	70.33	70.37	70.60	68.96	70.04	73.06	86.80
Duke Energy Indiana	49.83	50.69	53.01	56.14	56.96	55.27	58.86	60.85	61.18	63.60	64.70	64.62	66.72	67.91	73.50	83.53
Indiana Michigan Power	40.33	40.45	40.45	42.43	43.06	43.84	46.58	48.75	47.85	51.85	52.45	52.72	57.28	60.44	67.72	77.10
Indianapolis Power & Light	47.44	48.33	49.92	53.01	53.44	54.32	55.55	56.28	60.86	63.01	64.37	63.80	67.58	71.14	75.30	82.35
Interstate Power and Light	43.23	43.27	45.97	47.76	49.86	52.26	55.77	63.28	76.08	84.28	90.59	91.31	97.35	101.36	107.40	121.82
Kansas City Power & Light	76.49	77.33	78.41	76.21	75.38	80.48	78.38	85.89	87.30	89.46	93.98	92.29	97.38	98.95	107.38	116.24
Kentucky Power	49.82	49.67	51.22	53.85	54.13	57.43	57.50	59.82	59.51	64.41	62.89	62.40	67.54	70.63	73.01	80.46
Kentucky Utilities	42.48	43.38	44.56	46.30	46.75	47.78	47.94	51.74	50.84	53.76	53.26	51.98	54.23	53.01	64.07	70.71
Louisville Gas & Electric	45.29	45.95	47.44	50.12	49.17	50.22	52.58	54.92	55.52	60.00	60.75	60.02	62.98	60.18	68.03	78.27
MidAmerican Energy	n.a.	72.06	73.26	73.10	73.72	76.52	90.23	92.51	90.48	94.02	100.83	101.54	101.95	103.01	109.42	115.75
Monongahela Power	60.82	61.66	64.93	66.74	67.36	67.48	71.02	74.18	74.09	76.22	77.98	75.80	93.54	92.80	99.11	111.40
Northern Indiana Pub Srvc	47.73	48.31	52.01	55.16	56.98	56.87	58.57	63.70	65.03	66.98	67.27	67.84	70.14	72.84	82.81	94.71
Union Electric	74.98	75.67	77.20	80.69	80.52	83.92	82.96	85.52	87.05	91.90	93.79	88.89	95.48	95.11	103.23	119.90
Westar Energy	60.50	63.31	64.12	65.47	64.06	67.97	67.09	71.94	73.39	73.93	78.66	78.52	83.18	84.14	90.74	97.82
Wisconsin Electric Power	64.27	64.53	67.39	70.81	72.19	75.98	78.94	84.15	87.75	93.14	96.73	98.73	106.67	109.20	116.26	131.28
Wisconsin Power & Light	65.93	68.02	72.01	73.92	75.21	78.73	81.65	85.64	88.27	95.24	102.75	108.47	114.04	119.55	133.04	154.22
Wisconsin Public Service	51.63	51.03	52.02	52.23	53.25	55.19	58.64	63.72	64.80	67.86	72.08	73.50	77.19	78.94	83.49	89.20
Peer Group Average	**$ 54.59**	**$ 56.32**	**$ 58.24**	**$ 60.14**	**$ 60.70**	**$ 62.74**	**$ 65.06**	**$ 68.81**	**$ 70.44**	**$ 74.12**	**$ 76.67**	**$ 76.65**	**$ 81.31**	**$ 82.90**	**$ 89.86**	**$ 100.68**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**2**	**4**	**2**	**4**	**3**	**2**	**3**	**2**	**2**	**3**	**3**	**3**	**7**	**6**	**8**	**10**
Appalachian Power	11	11	11	11	11	11	11	11	10	10	9	9	8	5	5	7
Duke Energy Indiana	9	9	10	10	9	8	10	7	7	6	7	7	4	4	6	6
Indiana Michigan Power	1	1	1	1	1	1	1	1	1	1	1	2	2	3	2	2
Indianapolis Power & Light	6	7	6	7	7	6	5	5	6	5	6	6	6	8	7	5
Interstate Power and Light	4	2	4	3	5	5	6	8	13	13	13	14	14	15	15	16
Kansas City Power & Light	17	18	18	17	17	17	14	17	15	14	15	15	15	14	14	14
Kentucky Power	8	8	7	8	8	10	7	6	5	7	5	5	5	7	4	4
Kentucky Utilities	3	3	3	2	2	3	2	3	3	2	2	1	1	1	1	1
Louisville Gas & Electric	5	5	5	5	4	4	4	4	4	4	4	4	3	2	3	3
MidAmerican Energy	n.a.	16	16	15	15	15	18	18	18	17	17	17	16	16	16	13
Monongahela Power	13	12	13	13	13	12	13	13	12	12	11	11	12	12	12	12
Northern Indiana Pub Srvc	7	6	8	9	10	9	8	9	9	8	8	8	9	9	9	9
Union Electric	16	17	17	18	18	18	17	15	14	15	14	13	13	13	13	15
Westar Energy	12	13	12	12	12	13	12	12	11	11	12	12	11	11	11	11
Wisconsin Electric Power	14	14	14	14	14	14	15	14	16	16	16	16	17	17	17	17
Wisconsin Power & Light	15	15	15	16	16	16	16	16	17	18	18	18	18	18	18	18
Wisconsin Public Service	10	10	9	6	6	7	9	10	8	9	10	10	10	10	10	8

Source: FERC Form 1.

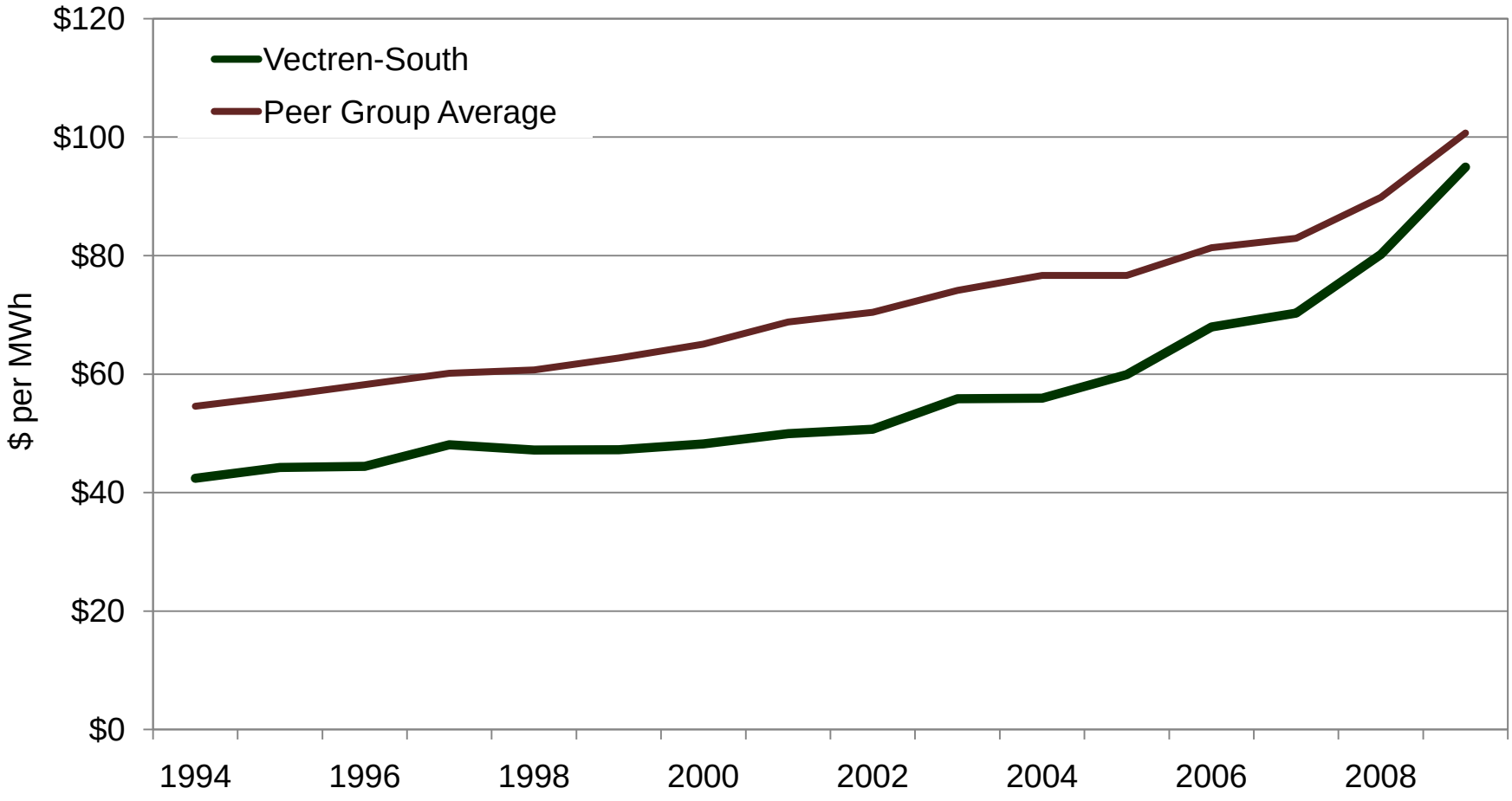
Plant in Service – Distribution per MWh Coefficient of Variation

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Coefficient of Variation)															
Vectren-South	**-**	**0.015**	**0.010**	**0.034**	**0.018**	**0.014**	**0.018**	**0.025**	**0.025**	**0.045**	**0.040**	**0.050**	**0.069**	**0.068**	**0.084**	**0.101**
Appalachian Power	-	0.008	0.020	0.028	0.028	0.033	0.034	0.040	0.036	0.041	0.036	0.032	0.023	0.024	0.031	0.061
Duke Energy Indiana	-	0.006	0.020	0.033	0.029	0.012	0.029	0.033	0.029	0.035	0.034	0.030	0.034	0.034	0.047	0.065
Indiana Michigan Power	-	0.001	0.001	0.018	0.018	0.019	0.034	0.040	0.029	0.044	0.041	0.037	0.051	0.056	0.071	0.085
Indianapolis Power & Light	-	0.007	0.016	0.031	0.025	0.024	0.026	0.025	0.042	0.044	0.043	0.036	0.044	0.050	0.056	0.067
Interstate Power and Light	-	0.000	0.023	0.028	0.034	0.041	0.051	0.073	0.101	0.105	0.104	0.093	0.093	0.090	0.090	0.100
Kansas City Power & Light	-	0.004	0.007	0.006	0.008	0.016	0.004	0.030	0.030	0.032	0.039	0.030	0.039	0.038	0.051	0.060
Kentucky Power	-	0.001	0.011	0.025	0.020	0.034	0.027	0.033	0.027	0.043	0.031	0.025	0.040	0.045	0.047	0.061
Kentucky Utilities	-	0.007	0.014	0.023	0.020	0.022	0.018	0.037	0.026	0.037	0.029	0.020	0.028	0.020	0.056	0.068
Louisville Gas & Electric	-	0.005	0.015	0.029	0.014	0.018	0.028	0.035	0.032	0.047	0.043	0.035	0.042	0.028	0.050	0.070
MidAmerican Energy	-	-	0.005	0.002	0.004	0.015	0.058	0.053	0.038	0.041	0.051	0.046	0.042	0.039	0.047	0.053
Monongahela Power	-	0.005	0.022	0.024	0.020	0.016	0.028	0.035	0.029	0.032	0.033	0.023	0.065	0.056	0.063	0.077
Northern Indiana Pub Srvc	-	0.004	0.030	0.040	0.039	0.029	0.032	0.049	0.046	0.046	0.041	0.038	0.041	0.045	0.064	0.081
Union Electric	-	0.003	0.009	0.022	0.015	0.025	0.016	0.022	0.023	0.034	0.034	0.017	0.032	0.028	0.042	0.065
Westar Energy	-	0.016	0.013	0.016	0.004	0.022	0.014	0.031	0.032	0.029	0.040	0.035	0.043	0.041	0.052	0.061
Wisconsin Electric Power	-	0.001	0.017	0.029	0.027	0.036	0.040	0.050	0.052	0.058	0.059	0.056	0.065	0.063	0.068	0.081
Wisconsin Power & Light	-	0.011	0.027	0.027	0.025	0.033	0.037	0.043	0.044	0.056	0.065	0.068	0.070	0.071	0.082	0.096
Wisconsin Public Service	-	0.004	0.005	0.005	0.010	0.019	0.034	0.050	0.046	0.050	0.057	0.054	0.058	0.056	0.061	0.067
Peer Group Average	**-**	**0.005**	**0.015**	**0.023**	**0.020**	**0.024**	**0.030**	**0.040**	**0.039**	**0.046**	**0.046**	**0.040**	**0.048**	**0.046**	**0.058**	**0.072**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**-**	**17**	**6**	**17**	**8**	**2**	**4**	**2**	**2**	**12**	**8**	**14**	**16**	**16**	**17**	**18**
Appalachian Power	-	15	14	11	15	15	14	12	11	7	6	7	1	2	1	3
Duke Energy Indiana	-	12	13	16	16	1	10	6	6	5	4	5	4	5	3	6
Indiana Michigan Power	-	3	1	5	7	7	12	11	5	11	10	11	12	12	15	15
Indianapolis Power & Light	-	13	11	15	13	11	6	3	13	10	12	10	11	11	9	8
Interstate Power and Light	-	2	16	12	17	18	17	18	18	18	18	18	18	18	18	17
Kansas City Power & Light	-	7	4	3	3	4	1	4	8	2	7	6	5	6	7	2
Kentucky Power	-	4	7	9	10	16	7	7	4	9	2	4	6	10	5	5
Kentucky Utilities	-	14	9	7	9	9	5	10	3	6	1	2	2	1	10	10
Louisville Gas & Electric	-	11	10	14	5	6	8	8	10	14	13	9	9	4	6	11
MidAmerican Energy	-	n.a.	2	1	2	3	18	17	12	8	14	13	8	7	4	1
Monongahela Power	-	10	15	8	11	5	9	9	7	3	3	3	14	14	12	12
Northern Indiana Pub Srvc	-	9	18	18	18	13	11	14	15	13	11	12	7	9	13	13
Union Electric	-	6	5	6	6	12	3	1	1	4	5	1	3	3	2	7
Westar Energy	-	18	8	4	1	10	2	5	9	1	9	8	10	8	8	4
Wisconsin Electric Power	-	5	12	13	14	17	16	15	17	17	16	16	15	15	14	14
Wisconsin Power & Light	-	16	17	10	12	14	15	13	14	16	17	17	17	17	16	16
Wisconsin Public Service	-	8	3	2	4	8	13	16	16	15	15	15	13	13	11	9

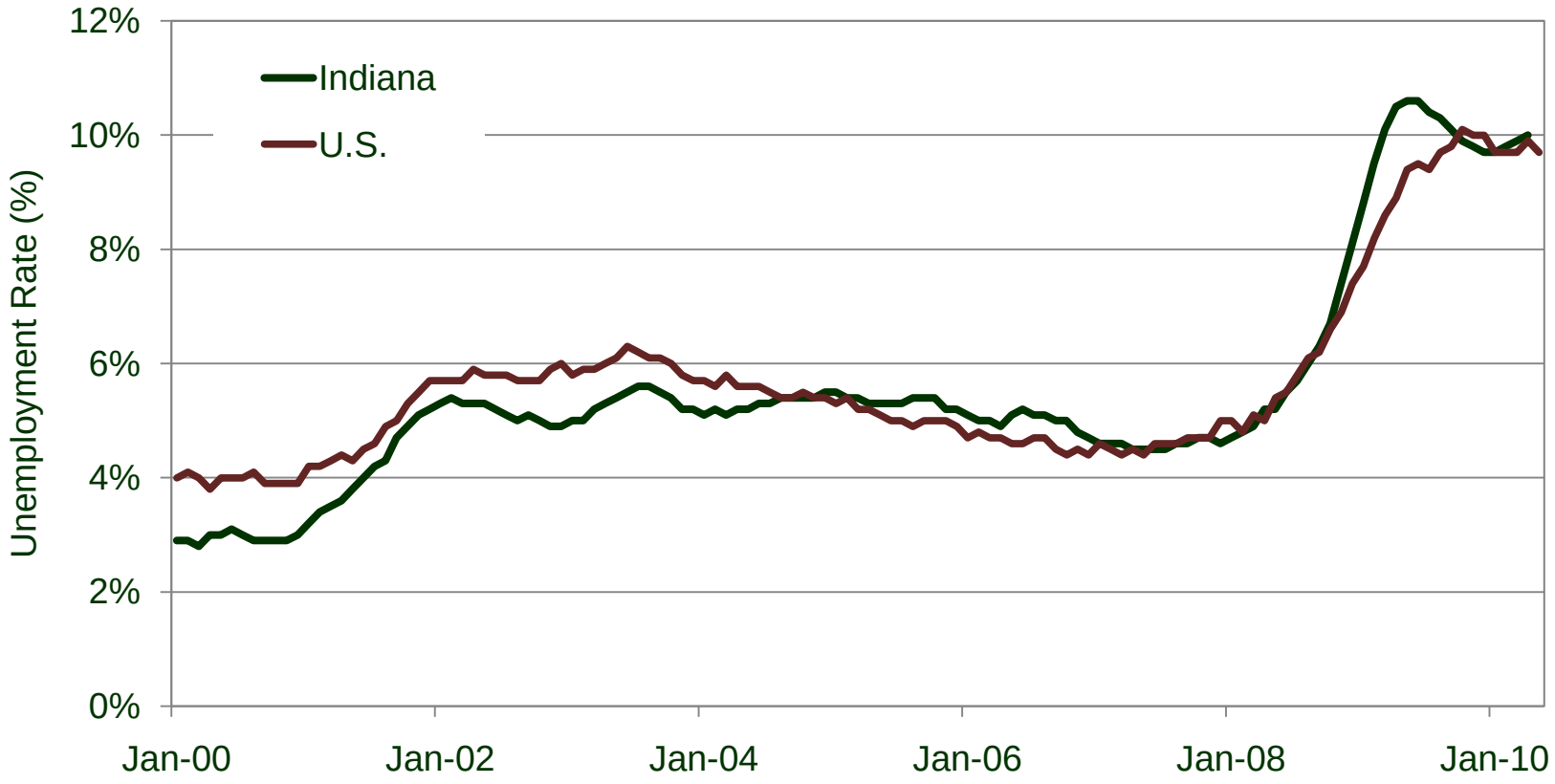
Source: FERC Form 1.

Plant in Service – Distribution per MWh



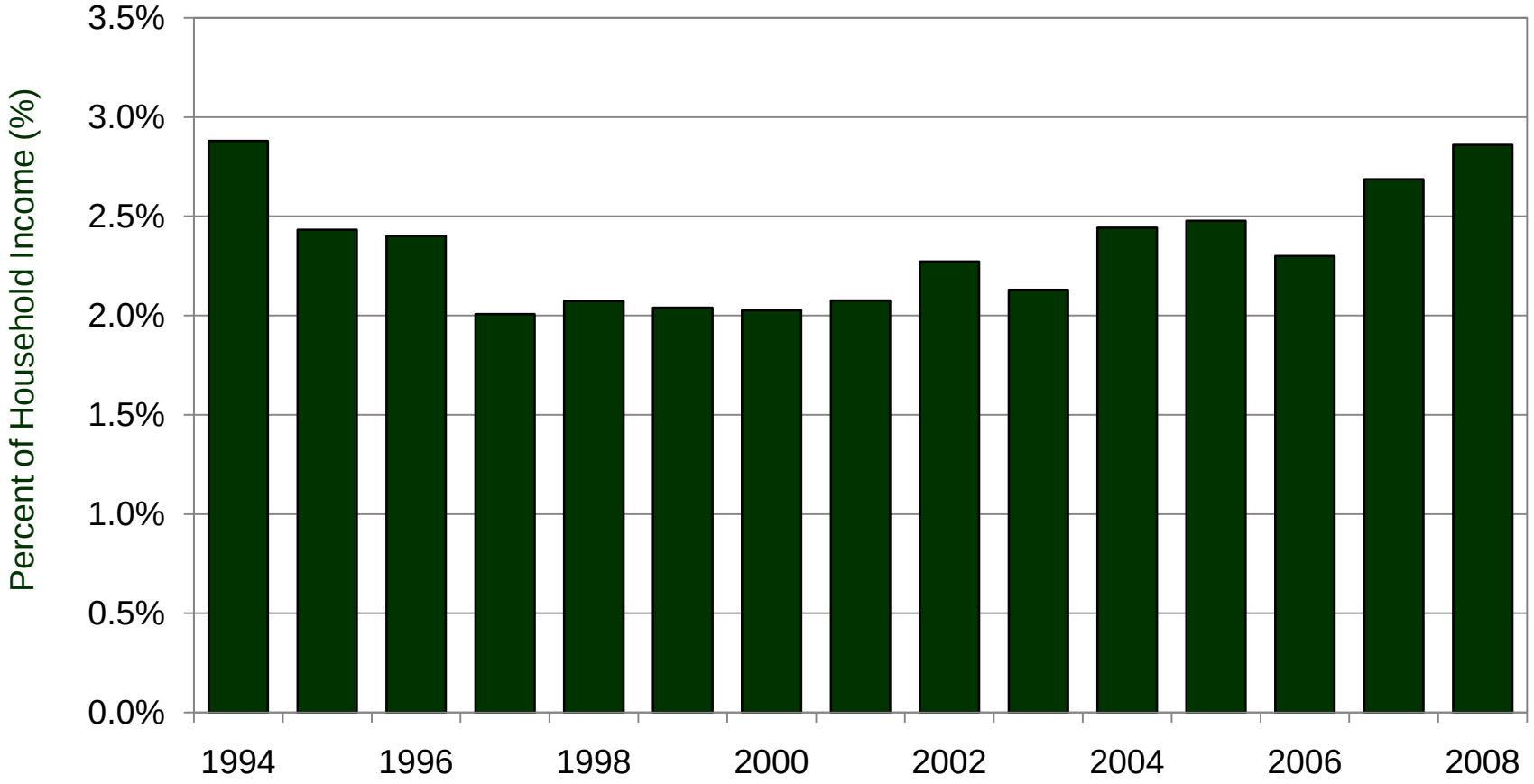
Source: FERC Form 1.

Indiana Economic Trends - Unemployment Rate
Indiana and U.S.



Source: U.S. Department of Labor, Bureau of Labor Statistics.

Indiana Economic Trends – Electricity Bill as a Percent of Household Income



Source: U.S. Census Bureau; and FERC Form 1.

Non-Fuel Average Rate per MWh

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	($/MWh)															
Vectren-South	**$ 32.85**	**$ 31.51**	**$ 33.67**	**$ 34.50**	**$ 33.70**	**$ 33.29**	**$ 33.55**	**$ 34.51**	**$ 36.03**	**$ 37.36**	**$ 42.15**	**$ 38.73**	**$ 42.14**	**$ 49.73**	**$ 55.14**	**$ 65.47**
Appalachian Power	33.13	34.65	33.42	31.66	30.02	30.34	32.84	33.06	30.96	30.63	31.64	28.73	29.05	31.86	37.72	54.49
Duke Energy Indiana	25.45	28.23	30.65	31.66	31.85	32.44	29.63	30.83	33.34	32.62	34.88	34.93	44.67	40.91	45.81	52.33
Indiana Michigan Power	43.46	42.61	40.40	42.49	49.62	46.59	40.63	38.63	39.49	37.95	38.94	38.06	36.18	38.22	37.03	44.34
Indianapolis Power & Light	37.36	38.06	40.84	41.60	41.12	42.02	40.99	41.19	41.31	41.75	42.87	46.28	46.16	47.52	48.93	51.38
Interstate Power and Light	36.86	38.62	39.07	40.20	42.28	38.28	39.38	45.03	49.33	50.83	55.61	61.40	68.32	61.93	61.03	72.00
Kansas City Power & Light	55.84	55.78	55.05	54.30	52.86	53.22	52.20	51.62	52.21	51.24	49.40	48.00	46.91	51.14	55.90	60.12
Kentucky Power	31.51	29.02	29.61	28.10	27.20	28.11	28.87	28.96	31.22	31.81	30.94	29.74	34.27	36.82	42.71	43.17
Kentucky Utilities	28.33	28.63	27.87	28.35	26.74	25.70	23.52	24.38	25.96	26.90	28.16	29.67	31.77	33.92	36.08	43.11
Louisville Gas & Electric	36.87	37.12	36.12	36.44	36.51	35.76	33.03	32.88	33.24	33.37	35.63	33.39	34.20	35.42	34.68	38.31
MidAmerican Energy	n.a.	53.06	51.71	62.32	53.03	54.22	52.30	51.53	50.66	49.86	49.58	48.58	47.83	45.35	42.50	45.13
Monongahela Power	38.15	41.56	40.04	37.66	37.95	38.53	38.64	39.74	40.44	39.93	41.81	41.09	38.56	31.48	28.52	45.27
Northern Indiana Pub Serv	47.81	47.19	48.37	48.55	48.44	48.07	47.59	49.79	50.85	47.73	48.83	52.13	57.81	57.47	54.93	54.95
Union Electric	50.97	51.20	50.06	49.62	49.73	50.56	50.10	50.55	51.84	48.54	46.26	43.50	42.80	41.00	39.92	43.32
Westar Energy Inc	36.58	36.89	34.38	33.58	35.95	34.93	32.32	32.01	34.29	33.58	34.03	32.71	40.48	39.12	37.73	45.98
Wisconsin Electric Power	42.31	41.84	40.40	40.20	45.97	46.48	46.65	51.62	53.90	56.04	56.61	59.24	64.96	64.76	68.32	74.99
Wisconsin Power & Light	38.00	38.02	38.41	37.63	37.44	40.37	44.01	47.45	49.61	57.18	61.54	66.28	72.39	72.20	73.05	76.81
Wisconsin Public Service	36.83	36.59	36.26	33.83	33.00	35.27	36.15	39.66	44.98	46.16	51.63	52.99	61.69	66.70	68.79	72.70
Peer Group Average	**$ 38.72**	**$ 39.94**	**$ 39.57**	**$ 39.89**	**$ 39.98**	**$ 40.05**	**$ 39.34**	**$ 40.52**	**$ 41.98**	**$ 42.13**	**$ 43.43**	**$ 43.92**	**$ 46.94**	**$ 46.81**	**$ 47.86**	**$ 54.02**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**14**	**15**	**14**	**12**	**13**	**14**	**12**	**12**	**12**	**12**	**10**	**11**	**11**	**7**	**6**	**5**
Appalachian Power	13	14	15	16	16	16	14	13	17	17	16	18	18	17	14	8
Duke Energy Indiana	17	18	16	15	15	15	16	16	14	15	14	13	9	11	9	9
Indiana Michigan Power	4	5	6	5	4	5	8	11	11	11	12	12	14	13	15	14
Indianapolis Power & Light	8	9	5	6	8	7	7	8	9	9	9	8	8	8	8	10
Interstate Power and Light	10	8	9	7	7	10	9	7	7	4	3	2	2	4	4	4
Kansas City Power & Light	1	1	1	2	2	2	2	2	2	3	6	7	7	6	5	6
Kentucky Power	15	16	17	18	17	17	17	17	16	16	17	16	15	14	10	16
Kentucky Utilities	16	17	18	17	18	18	18	18	18	18	18	17	17	16	16	17
Louisville Gas & Electric	9	11	12	11	11	11	13	14	15	14	13	14	16	15	17	18
MidAmerican Energy	n.a.	2	2	1	1	1	1	3	5	5	5	6	6	9	11	13
Monongahela Power	6	7	8	9	9	9	10	9	10	10	11	10	13	18	18	12
Northern Indiana Pub Serv	3	4	4	4	5	4	4	5	4	7	7	5	5	5	7	7
Union Electric	2	3	3	3	3	3	3	4	3	6	8	9	10	10	12	15
Westar Energy Inc	12	12	13	14	12	13	15	15	13	13	15	15	12	12	13	11
Wisconsin Electric Power	5	6	7	8	6	6	5	1	1	2	2	3	3	3	3	2
Wisconsin Power & Light	7	10	10	10	10	8	6	6	6	1	1	1	1	1	1	1
Wisconsin Public Service	11	13	11	13	14	12	11	10	8	8	4	4	4	2	2	3

Source: FERC Form 1.

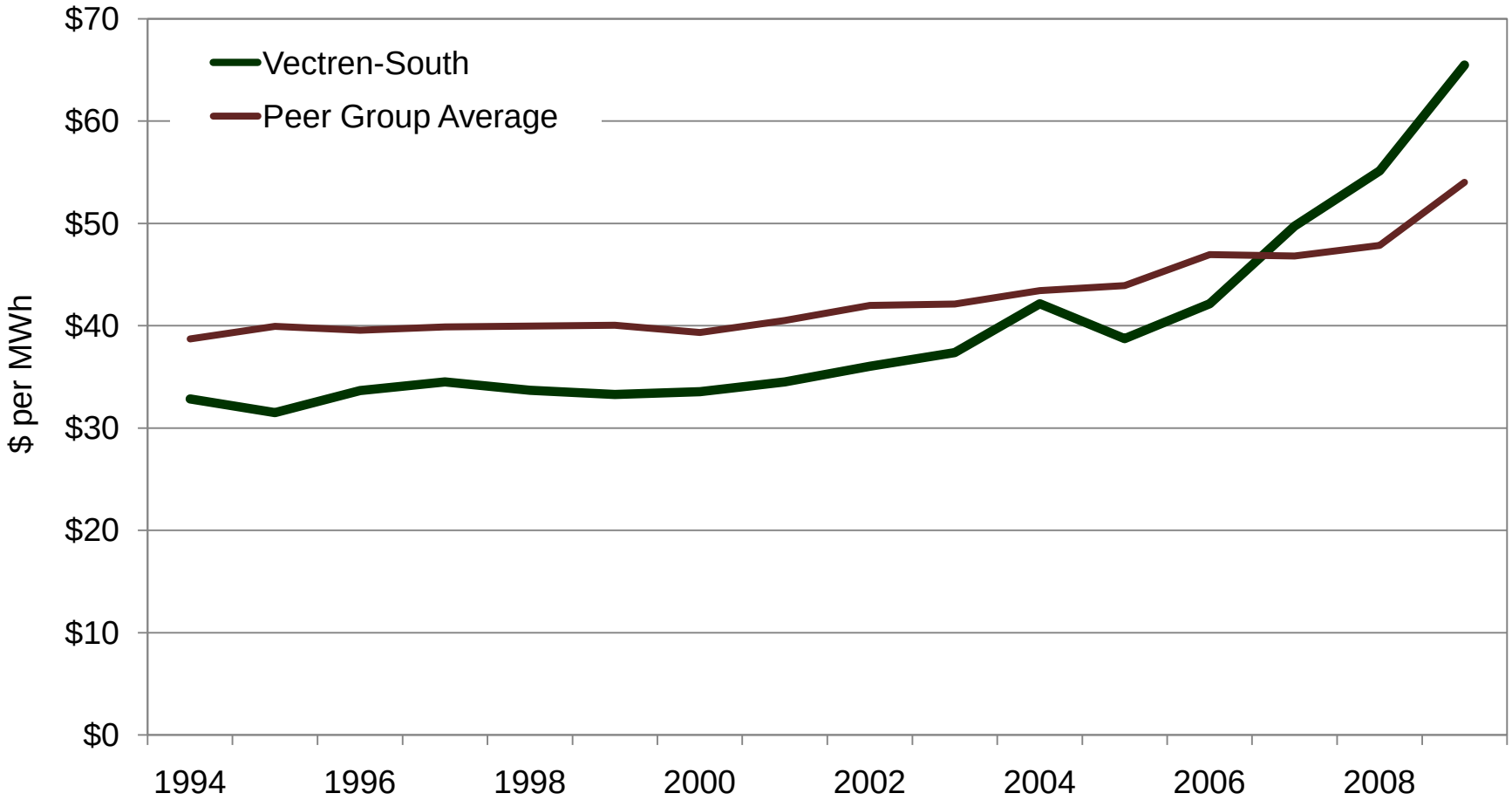
Non-Fuel Average Rate per MWh Coefficient of Variation

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
							(Coefficient of Variation)									
Vectren-South	**-**	**0.018**	**0.017**	**0.017**	**0.009**	**0.002**	**0.006**	**0.011**	**0.014**	**0.015**	**0.019**	**0.014**	**0.017**	**0.019**	**0.019**	**0.019**
Appalachian Power	-	0.018	0.010	0.020	0.024	0.018	0.009	0.009	0.012	0.012	0.006	0.017	0.015	0.004	0.016	0.021
Duke Energy Indiana	-	0.030	0.030	0.026	0.021	0.019	0.008	0.010	0.017	0.014	0.017	0.016	0.022	0.018	0.019	0.020
Indiana Michigan Power	-	0.011	0.019	0.006	0.022	0.014	0.016	0.019	0.015	0.017	0.013	0.014	0.017	0.012	0.013	0.010
Indianapolis Power & Light	-	0.011	0.020	0.018	0.012	0.013	0.008	0.008	0.007	0.008	0.010	0.014	0.013	0.013	0.013	0.014
Interstate Power and Light	-	0.017	0.014	0.015	0.018	0.010	0.004	0.018	0.019	0.019	0.019	0.019	0.019	0.016	0.015	0.016
Kansas City Power & Light	-	0.002	0.007	0.009	0.012	0.009	0.010	0.010	0.008	0.009	0.012	0.013	0.014	0.005	0.009	0.011
Kentucky Power	-	0.027	0.013	0.022	0.023	0.013	0.003	0.002	0.015	0.015	0.011	0.004	0.017	0.018	0.020	0.019
Kentucky Utilities	-	0.010	0.013	0.004	0.019	0.022	0.030	0.022	0.010	0.006	0.013	0.016	0.018	0.019	0.020	0.022
Louisville Gas & Electric	-	0.007	0.012	0.006	0.004	0.010	0.020	0.018	0.014	0.013	0.006	0.011	0.007	0.005	0.004	0.012
MidAmerican Energy	n.a.	-	0.011	0.024	0.013	0.007	0.011	0.012	0.012	0.012	0.011	0.012	0.012	0.015	0.018	0.013
Monongahela Power	-	0.022	0.005	0.017	0.012	0.007	0.005	0.007	0.009	0.006	0.011	0.008	0.007	0.023	0.028	0.014
Northern Indiana Pub Serv	-	0.008	0.009	0.008	0.006	0.000	0.005	0.009	0.010	0.006	0.004	0.010	0.014	0.013	0.010	0.009
Union Electric	-	0.005	0.010	0.009	0.007	0.004	0.004	0.003	0.007	0.009	0.013	0.016	0.016	0.018	0.018	0.012
Westar Energy Inc	-	0.008	0.021	0.020	0.009	0.008	0.019	0.018	0.005	0.009	0.006	0.011	0.016	0.014	0.011	0.017
Wisconsin Electric Power	-	0.008	0.015	0.012	0.019	0.017	0.015	0.018	0.018	0.017	0.016	0.016	0.017	0.015	0.015	0.015
Wisconsin Power & Light	-	0.001	0.008	0.008	0.008	0.015	0.019	0.020	0.019	0.021	0.020	0.019	0.019	0.017	0.016	0.016
Wisconsin Public Service	-	0.007	0.009	0.021	0.021	0.002	0.009	0.017	0.021	0.020	0.021	0.019	0.020	0.019	0.018	0.017
Peer Group Average	**-**	**0.011**	**0.013**	**0.014**	**0.015**	**0.011**	**0.011**	**0.013**	**0.013**	**0.012**	**0.012**	**0.014**	**0.015**	**0.014**	**0.016**	**0.015**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
							(Rank)									
Vectren-South	**-**	**4**	**5**	**9**	**13**	**16**	**13**	**10**	**9**	**7**	**3**	**10**	**8**	**3**	**5**	**4**
Appalachian Power	-	5	12	6	1	3	10	14	10	10	15	4	12	18	9	2
Duke Energy Indiana	-	1	1	1	4	2	12	12	5	8	5	8	1	5	4	3
Indiana Michigan Power	-	8	4	17	3	6	5	3	7	5	7	9	6	15	14	17
Indianapolis Power & Light	-	7	3	7	10	7	11	15	17	15	14	11	15	13	13	12
Interstate Power and Light	-	6	7	10	8	9	16	7	2	3	4	3	3	9	12	8
Kansas City Power & Light	-	16	17	13	12	11	8	11	15	12	10	12	14	16	17	16
Kentucky Power	-	2	9	3	2	8	18	18	6	6	12	18	7	6	2	5
Kentucky Utilities	-	9	8	18	7	1	1	1	12	17	8	7	5	2	3	1
Louisville Gas & Electric	-	13	10	16	18	10	2	5	8	9	16	14	18	17	18	15
MidAmerican Energy	-	n.a.	11	2	9	14	7	9	11	11	11	13	16	11	6	13
Monongahela Power	-	3	18	8	11	13	14	16	14	16	13	17	17	1	1	11
Northern Indiana Pub Serv	-	10	14	15	17	18	15	13	13	18	18	16	13	14	16	18
Union Electric	-	15	13	12	16	15	17	17	16	14	9	5	11	7	8	14
Westar Energy Inc	-	12	2	5	14	12	4	6	18	13	17	15	10	12	15	7
Wisconsin Electric Power	-	11	6	11	6	4	6	4	4	4	6	6	9	10	11	10
Wisconsin Power & Light	-	17	16	14	15	5	3	2	3	1	2	1	4	8	10	9
Wisconsin Public Service	-	14	15	4	5	17	9	8	1	2	1	2	2	4	7	6

Source: FERC Form 1.

Non-Fuel Average Rate per MWh



Source: FERC Form 1.

Total Average Rate per MWh

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	($/MWh)															
Vectren-South	**$ 52.10**	**$ 49.93**	**$ 49.99**	**$ 48.32**	**$ 47.91**	**$ 47.41**	**$ 48.03**	**$ 48.71**	**$ 50.68**	**$ 53.71**	**$ 59.46**	**$ 61.58**	**$ 67.59**	**$ 76.51**	**$ 84.91**	**$ 95.43**
Appalachian Power	48.77	47.98	47.23	46.58	46.01	46.26	45.82	45.52	45.85	46.58	45.92	46.49	48.34	52.12	57.70	71.78
Duke Energy Indiana	44.15	45.59	46.33	48.63	48.07	47.94	46.58	47.85	49.85	50.56	52.94	55.79	64.32	61.81	71.25	76.39
Indiana Michigan Power	56.38	56.44	54.42	55.77	59.48	56.70	52.20	52.38	52.12	52.22	53.95	54.60	55.28	56.99	61.71	64.69
Indianapolis Power & Light	50.09	50.34	52.60	53.60	54.07	54.05	54.12	54.15	53.29	54.17	56.01	58.17	64.48	62.99	66.86	71.00
Interstate Power and Light	49.67	50.50	50.59	50.93	53.78	49.29	50.43	56.41	58.66	61.01	65.35	71.12	78.83	74.10	74.84	83.47
Kansas City Power & Light	67.53	67.45	66.32	64.81	63.45	62.86	62.96	63.55	63.65	62.61	62.17	61.93	62.16	66.89	72.50	77.23
Kentucky Power	41.89	41.74	40.15	39.93	40.03	41.11	39.95	39.46	40.56	43.03	45.20	48.64	55.03	57.08	65.76	69.04
Kentucky Utilities	40.68	41.73	41.16	40.73	40.42	39.18	36.48	38.62	40.14	42.02	44.20	49.86	54.39	57.42	62.74	66.66
Louisville Gas & Electric	51.29	50.31	50.32	50.92	50.71	49.96	47.11	46.88	49.75	50.50	53.30	56.24	58.66	60.49	63.20	67.09
MidAmerican Energy	n.a.	64.39	62.78	62.32	63.54	64.01	62.56	61.91	60.25	59.75	60.55	61.42	60.62	59.75	59.03	59.95
Monongahela Power	53.97	55.34	53.80	51.79	51.81	51.99	51.64	51.63	51.64	51.60	51.94	53.55	55.57	54.88	54.75	66.32
Northern Indiana Pub Serv	64.31	62.98	63.85	64.66	65.14	64.01	62.77	65.09	64.21	61.92	62.87	68.71	74.67	76.18	76.24	80.34
Union Electric	62.17	62.04	60.63	60.15	60.46	60.68	60.18	60.18	60.95	58.31	57.16	56.91	57.29	57.23	57.18	62.44
Westar Energy Inc	52.84	52.91	52.68	51.57	51.55	51.84	51.69	53.04	55.37	55.29	55.21	55.83	62.71	61.34	69.16	78.17
Wisconsin Electric Power	54.21	54.02	52.13	52.29	57.49	57.69	58.47	63.04	64.06	66.89	68.64	74.29	82.40	84.71	88.78	95.24
Wisconsin Power & Light	53.29	51.86	51.69	50.70	50.55	52.03	55.68	59.74	63.02	72.14	74.77	80.63	86.54	87.67	89.55	92.84
Wisconsin Public Service	50.00	48.43	47.97	45.40	44.60	46.76	48.88	51.80	57.17	58.83	64.54	70.09	74.74	81.46	87.68	90.82
Peer Group Average	**$ 52.58**	**$ 53.18**	**$ 52.63**	**$ 52.40**	**$ 53.01**	**$ 52.73**	**$ 52.21**	**$ 53.60**	**$ 54.74**	**$ 55.73**	**$ 57.34**	**$ 60.25**	**$ 64.47**	**$ 65.48**	**$ 69.35**	**$ 74.91**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**9**	**13**	**13**	**14**	**14**	**14**	**13**	**13**	**13**	**11**	**8**	**7**	**6**	**4**	**4**	**1**
Appalachian Power	14	15	15	15	15	16	16	16	16	16	16	18	18	18	16	10
Duke Energy Indiana	15	16	16	13	13	13	15	14	14	14	14	13	8	9	8	9
Indiana Michigan Power	4	5	5	5	5	6	8	10	11	12	12	14	15	16	14	16
Indianapolis Power & Light	11	11	8	6	7	7	7	8	10	10	10	9	7	8	10	11
Interstate Power and Light	13	10	11	10	8	12	11	7	7	5	3	3	3	6	6	5
Kansas City Power & Light	1	1	1	1	3	3	1	2	3	3	6	6	10	7	7	8
Kentucky Power	16	17	18	18	18	17	17	17	17	17	17	17	16	15	11	12
Kentucky Utilities	17	18	17	17	17	18	18	18	18	18	18	16	17	13	13	14
Louisville Gas & Electric	10	12	12	11	11	11	14	15	15	15	13	11	12	11	12	13
MidAmerican Energy	n.a.	2	3	3	2	2	3	4	6	6	7	8	11	12	15	18
Monongahela Power	6	6	6	8	9	9	10	12	12	13	15	15	14	17	18	15
Northern Indiana Pub Serv	2	3	2	2	1	1	2	1	1	4	5	5	5	5	5	6
Union Electric	3	4	4	4	4	4	4	5	5	8	9	10	13	14	17	17
Westar Energy Inc	8	8	7	9	10	10	9	9	9	9	11	12	9	10	9	7
Wisconsin Electric Power	5	7	9	7	6	5	5	3	2	2	2	2	2	2	2	2
Wisconsin Power & Light	7	9	10	12	12	8	6	6	4	1	1	1	1	1	1	3
Wisconsin Public Service	12	14	14	16	16	15	12	11	8	7	4	4	4	3	3	4

Source: FERC Form 1.

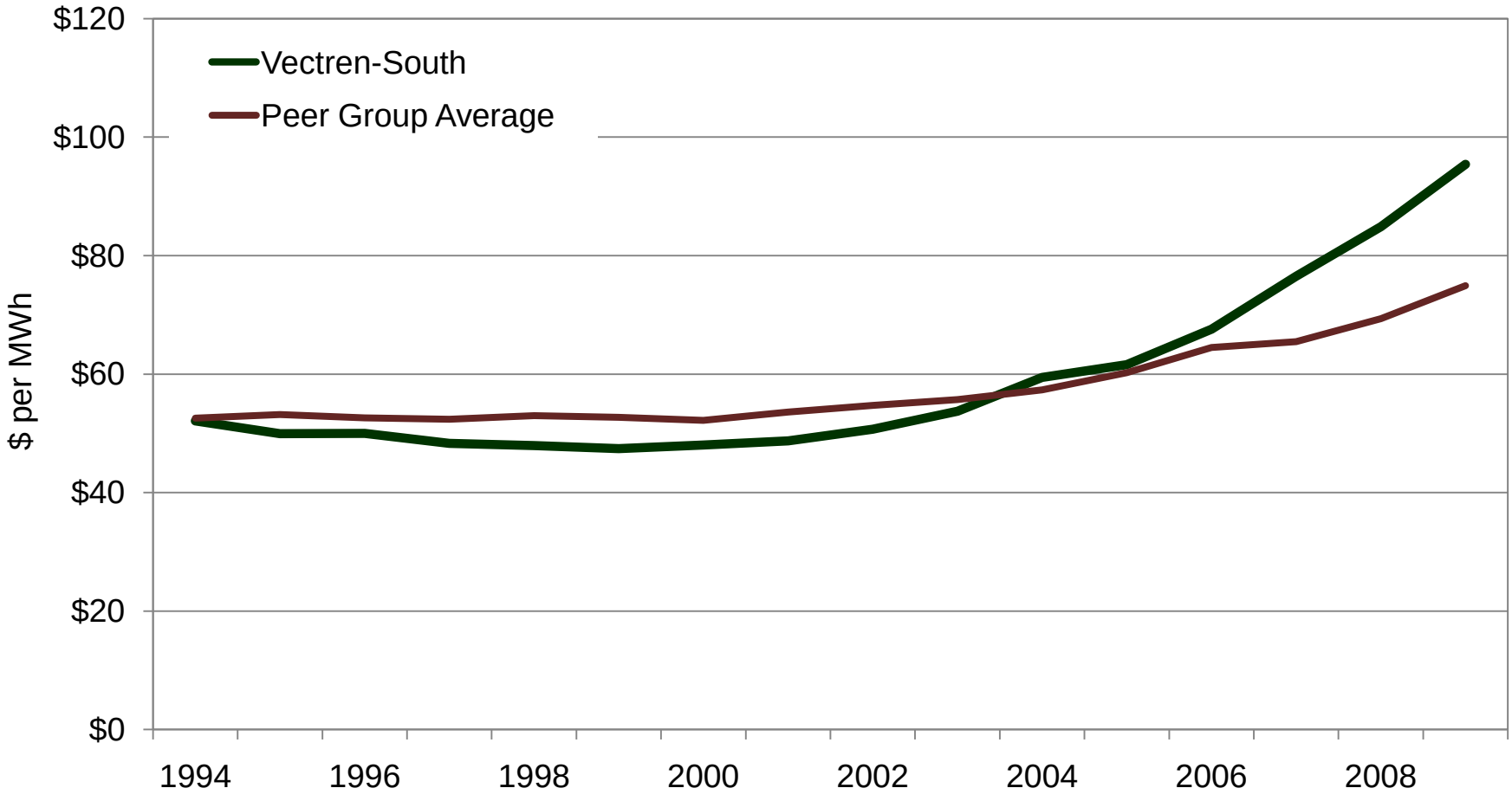
Total Average Rate per MWh Coefficient of Variation

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Coefficient of Variation)															
Vectren-South	**-**	**0.015**	**0.010**	**0.014**	**0.012**	**0.012**	**0.008**	**0.004**	**0.008**	**0.012**	**0.015**	**0.015**	**0.016**	**0.016**	**0.016**	**0.016**
Appalachian Power	-	0.009	0.011	0.011	0.011	0.008	0.009	0.009	0.007	0.002	0.005	0.002	0.007	0.011	0.014	0.017
Duke Energy Indiana	-	0.013	0.012	0.016	0.011	0.009	0.003	0.007	0.011	0.011	0.013	0.014	0.016	0.014	0.016	0.016
Indiana Michigan Power	-	0.002	0.012	0.001	0.013	0.003	0.014	0.012	0.011	0.010	0.005	0.002	0.004	0.007	0.011	0.011
Indianapolis Power & Light	-	0.005	0.014	0.013	0.011	0.010	0.008	0.007	0.004	0.006	0.009	0.010	0.014	0.012	0.013	0.013
Interstate Power and Light	-	0.009	0.007	0.007	0.014	0.010	0.004	0.014	0.014	0.015	0.015	0.016	0.016	0.014	0.013	0.014
Kansas City Power & Light	-	0.002	0.008	0.010	0.011	0.010	0.009	0.006	0.005	0.007	0.007	0.007	0.006	0.007	0.010	0.011
Kentucky Power	-	0.005	0.015	0.013	0.009	0.005	0.008	0.009	0.001	0.011	0.013	0.016	0.018	0.017	0.018	0.017
Kentucky Utilities	-	0.012	0.002	0.007	0.008	0.013	0.020	0.010	0.004	0.010	0.013	0.017	0.018	0.017	0.018	0.017
Louisville Gas & Electric	-	0.010	0.006	0.005	0.001	0.006	0.014	0.013	0.002	0.005	0.010	0.012	0.013	0.013	0.013	0.014
MidAmerican Energy	n.a.	-	0.010	0.009	0.004	0.005	0.005	0.007	0.009	0.009	0.007	0.004	0.006	0.007	0.007	0.005
Monongahela Power	-	0.011	0.008	0.013	0.011	0.008	0.008	0.007	0.006	0.006	0.004	0.005	0.008	0.007	0.006	0.013
Northern Indiana Pub Serv	-	0.009	0.003	0.007	0.007	0.002	0.007	0.005	0.002	0.007	0.005	0.009	0.012	0.011	0.011	0.011
Union Electric	-	0.003	0.009	0.009	0.006	0.004	0.005	0.005	0.002	0.008	0.009	0.009	0.008	0.007	0.007	0.007
Westar Energy Inc	-	0.002	0.004	0.009	0.008	0.005	0.005	0.006	0.010	0.009	0.008	0.008	0.013	0.011	0.014	0.015
Wisconsin Electric Power	-	0.004	0.013	0.009	0.014	0.012	0.012	0.015	0.014	0.014	0.014	0.015	0.015	0.014	0.014	0.014
Wisconsin Power & Light	-	0.012	0.009	0.011	0.009	0.005	0.013	0.015	0.016	0.018	0.017	0.016	0.016	0.015	0.014	0.014
Wisconsin Public Service	-	0.013	0.011	0.018	0.016	0.006	0.009	0.013	0.017	0.016	0.017	0.017	0.017	0.016	0.016	0.015
Peer Group Average	**-**	**0.007**	**0.009**	**0.010**	**0.010**	**0.007**	**0.009**	**0.009**	**0.008**	**0.010**	**0.010**	**0.011**	**0.012**	**0.012**	**0.013**	**0.013**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**-**	**1**	**9**	**3**	**5**	**3**	**11**	**18**	**9**	**5**	**4**	**6**	**7**	**3**	**3**	**4**
Appalachian Power	-	8	7	7	8	9	7	9	10	18	15	17	15	11	8	3
Duke Energy Indiana	-	2	4	2	7	7	18	12	6	7	8	8	4	7	5	5
Indiana Michigan Power	-	16	5	18	4	17	2	6	5	9	16	18	18	16	14	14
Indianapolis Power & Light	-	11	2	5	6	6	9	10	14	15	11	10	9	10	12	13
Interstate Power and Light	-	10	14	15	3	5	17	3	3	3	3	4	5	8	10	8
Kansas City Power & Light	-	17	13	9	9	4	8	14	12	14	13	14	16	18	15	16
Kentucky Power	-	12	1	6	11	12	12	8	18	6	6	5	2	2	1	1
Kentucky Utilities	-	4	18	14	13	1	1	7	13	8	7	2	1	1	2	2
Louisville Gas & Electric	-	7	15	17	18	10	3	5	17	17	9	9	11	9	11	10
MidAmerican Energy	-	n.a.	8	13	17	13	14	13	8	10	14	16	17	17	16	18
Monongahela Power	-	6	12	4	10	8	10	11	11	16	18	15	13	15	18	12
Northern Indiana Pub Serv	-	9	17	16	15	18	13	16	16	13	17	11	12	13	13	15
Union Electric	-	14	10	12	16	16	15	17	15	12	10	12	14	14	17	17
Westar Energy Inc	-	15	16	10	14	14	16	15	7	11	12	13	10	12	9	7
Wisconsin Electric Power	-	13	3	11	2	2	5	2	4	4	5	7	8	6	7	9
Wisconsin Power & Light	-	5	11	8	12	15	4	1	2	1	2	3	6	5	6	11
Wisconsin Public Service	-	3	6	1	1	11	6	4	1	2	1	1	3	4	4	6

Source: FERC Form 1.

Total Average Rate per MWh



Source: FERC Form 1.

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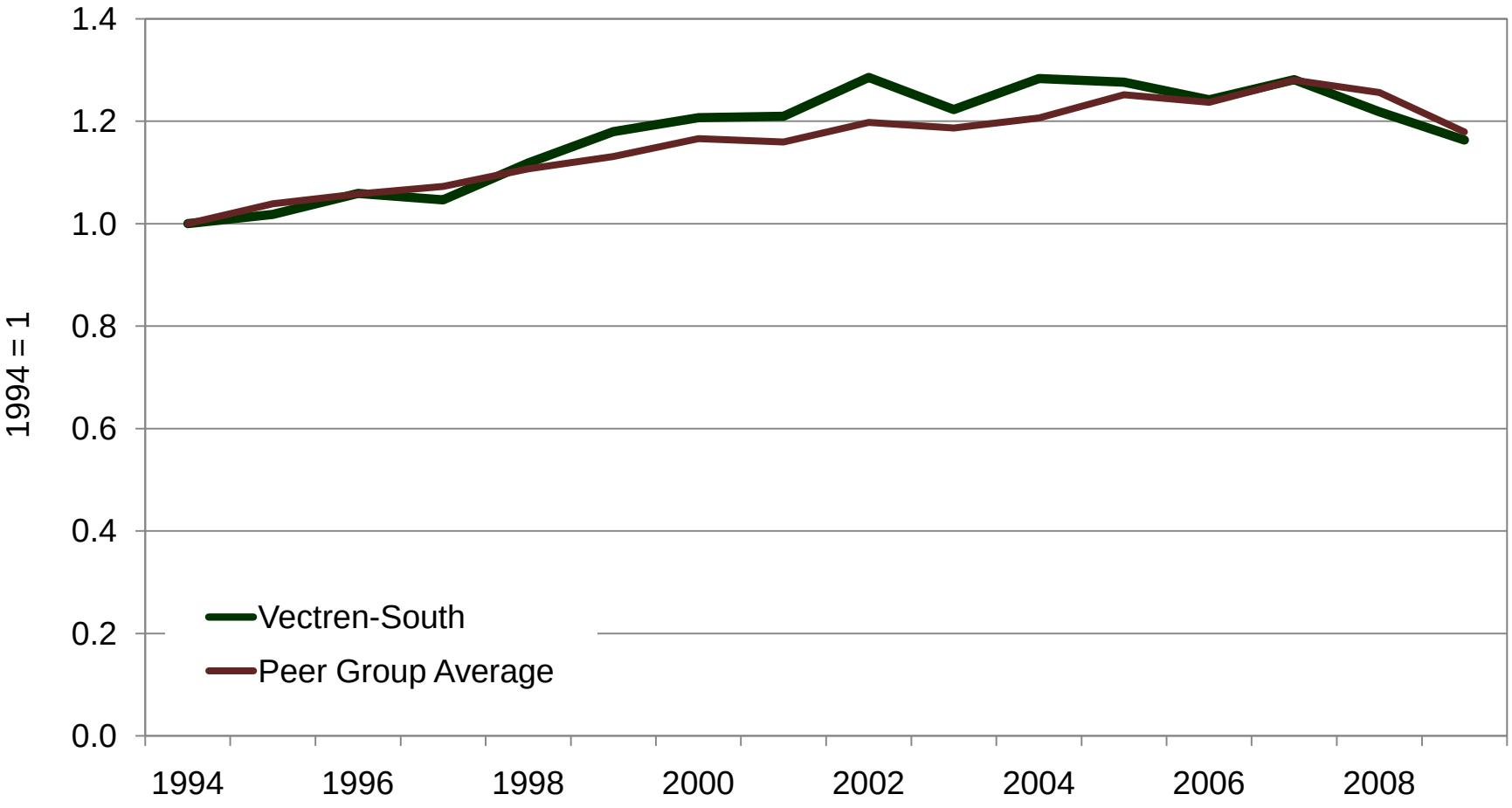
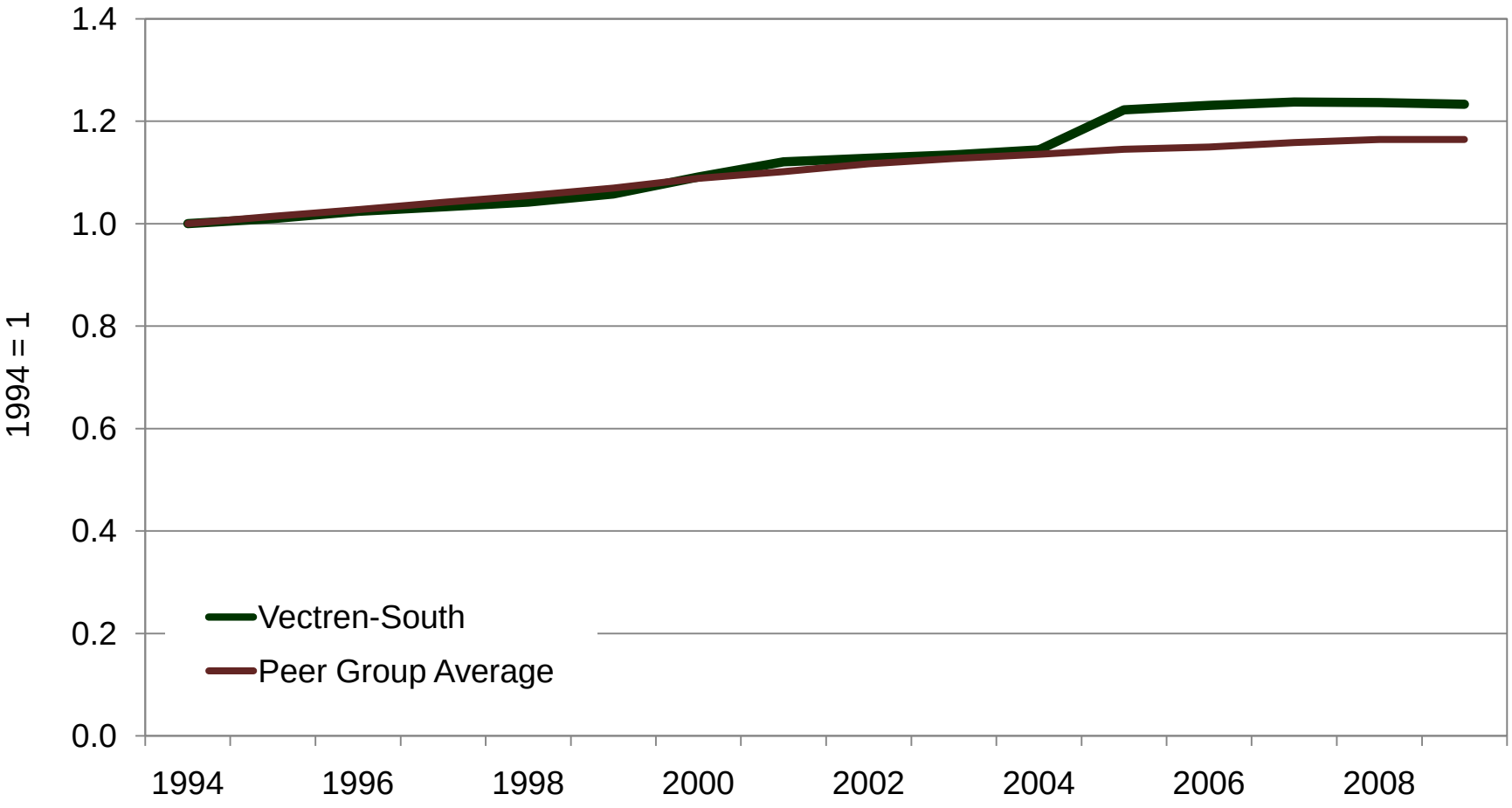
Source: Response to OUCC Data Request 24-Q-1(b).

Sales to Ultimate Customers



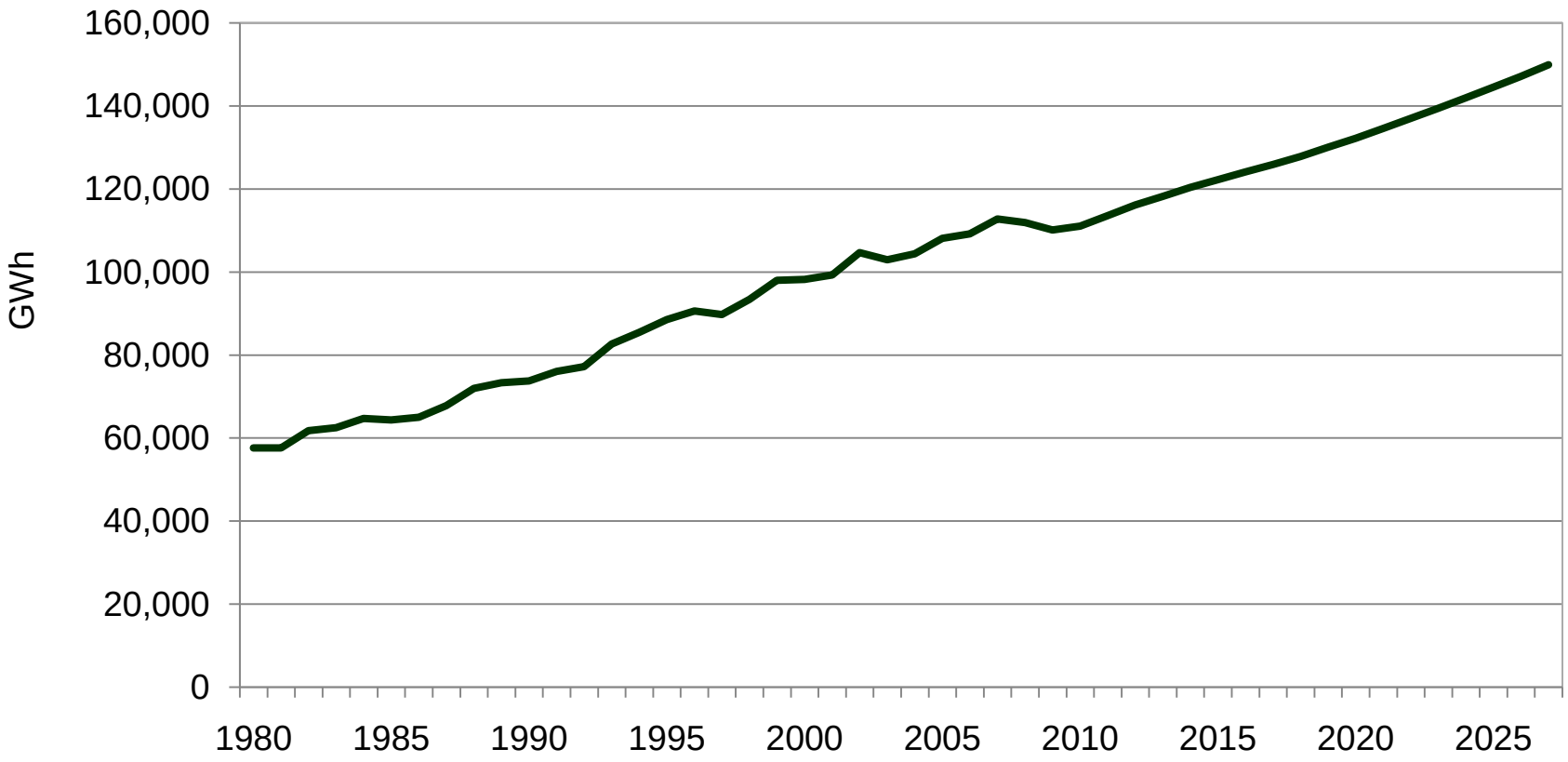
Source: FERC Form 1.

Number of Retail Customers



Source: FERC Form 1.

State Utility Forecasting Group
Base Energy Requirements for Indiana



Source: State Utility Forecasting Group; Indiana Electricity Projections: The 2009 Forecast.

Energy Efficiency Resource Standards

ID: Energy Plan sets conservation – DR and EE as priority resources

WA: pursue all cost effective conservation: ~10% by 2025

OR: IOU 2008 goals 34 MW; administered by Energy Trust OR

CA: 8% energy savings; 4,885 MW peak reduction by 2013 (from '04)

NV: EE up to 25% of RPS: ~5% electric reduction by 2015

UT: EE earns incentive credits in RE goal

CO:11.5% energy savings by 2020 ~ 3,669 GWh (from '08)

NM: 10% retail electric sales savings by 2020 (from '05)

NE: Interim Energy Plan stresses multi-sector EE improvements

KS: Voluntary utility programs

OK: PSC approved quick-start DR utility EE and DR programs

TX: 20% of load growth by 2010, using average growth rate of prior 5 years

HI: 30% electricity reduction: ~4,300 GWh by 2030 (from '09)

MI: 1% annual energy savings from prior year's sales

MN: 1.5% annual savings based on prior 3-years average, to 2015

IA: 5.4% energy savings by 2020 ~ 1.5% annual

IL: reduce energy use 2% by 2015 and peak 0.1% from prior year

IN: 2% energy savings by 2019

OH: 22% energy savings by 2025 (from '09); reduce peak 8% by 2018

KY: proposed RPS-EE to offset 18% of projected 2025 demand

ME: 30% energy savings; 100 MW peak electric reduction by 2020

VT: 11% energy reductions by 2011 (2% annual) administered by Efficiency VT

MA: 25% of electric load from DSR, EE by 2020: capacity and energy

NY: reduce electric use 15% by 2015 from levels projected in 2008

CT:4% energy savings (1.5% annual) and 10% peak reduction by 2010 (from '07)

RI: reduce 10% of 2006 sales by 2022

NJ: BPU proceeding to reduce consumption, peak

DE: Sustainable Energy Utility charged with 30% energy reduction by 2015

PA: reduce use 3%; peak 4.5% by 2013 as % of 2009-10 sales

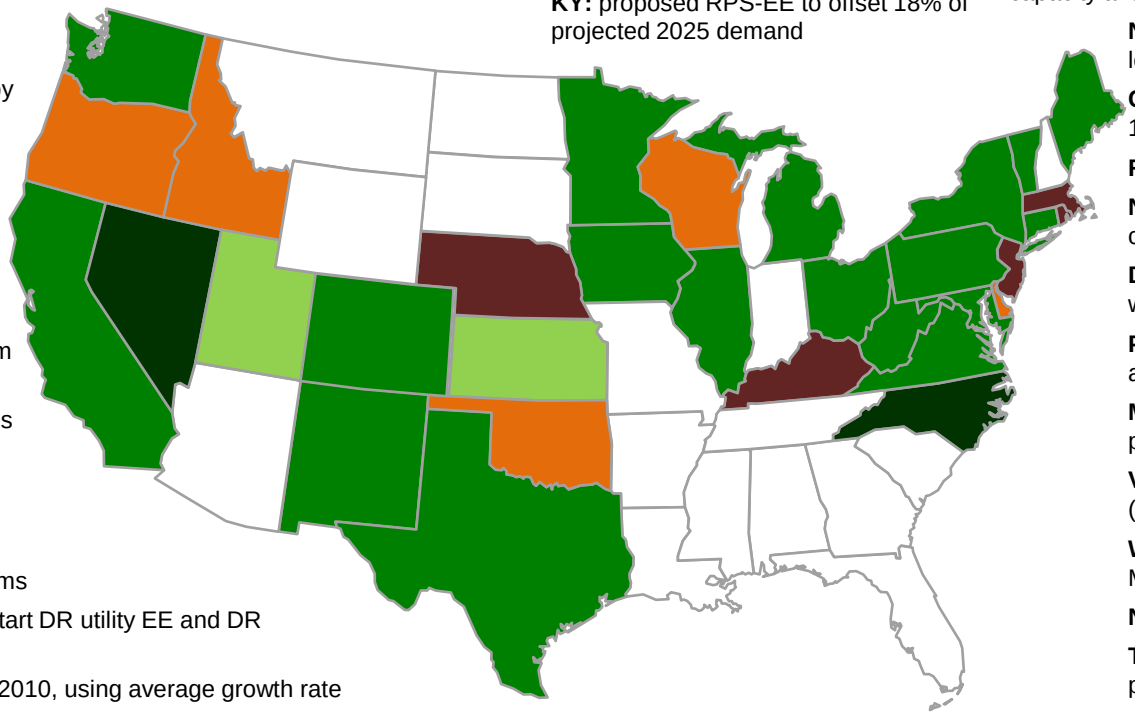
MD: reduce per capita electricity use and peak 15% by 2015 (from '07)

VA: reduce electric use 10% by 2022 (from '06)

WV: EE & DR earn one credit for each MWh conserved in the 25% by 2025

NC: EE to meet up to 25% of RPS by 2011

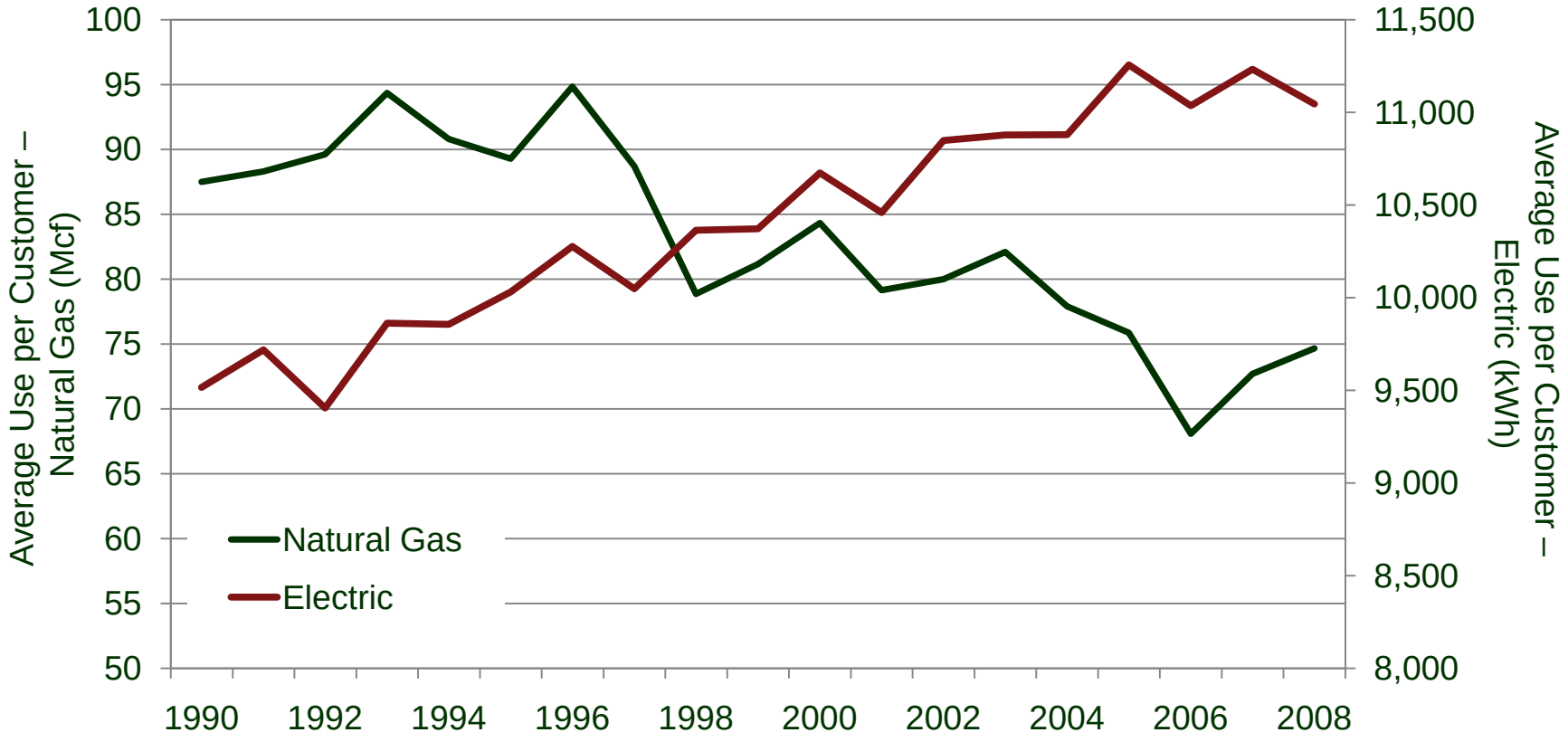
TVA: reduce energy use 25% and cut peak 1,400 MW by 2012 (from '08)



- EE as part of an RPS law or rule
- EERS by regulation or law (stand-alone)
- Voluntary standards (in or out of RPS)
- EE pending regulations, proposed or studied
- Other EE entity, rule or procurement order

Note: As of July 8, 2009
Source: Federal Energy Regulatory Commission.

U.S. Residential Natural Gas and Electric Use Per Customer



Source: U.S. Department of Energy, Energy Information Administration.

Electric DSM

	Average Rate to Retail Customers		Total EE Spending		Total EE Spending as a Percent of Total Revenue*		Total State Annual EE Savings		Total State EE Savings as a Percent of Total Sales	
	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007
	(cents/kWh)		--- (thousand $) ---		--- (%) ---		--- (MWh) ---		--- (%) ---	
Connecticut	18.46	16.45	$ 121,576	$ 115,110	3.0%	0.2%	3,184,325	5,922,914	14.4%	1.8%
Massachusetts	16.80	15.16	$ 62,269	$ 62,856	2.1%	0.3%	2,302,377	5,545,262	12.8%	5.1%
California	12.45	12.80	$ 1,255,099	$ 971,720	4.3%	2.1%	24,176,432	41,513,504	10.3%	11.1%
Florida	10.74	10.33	$ 296,489	$ 261,164	1.2%	0.8%	17,913,221	13,737,098	7.9%	4.8%
Rhode Island	16.55	13.12	$ 15,257	$ 17,981	1.4%	1.6%	527,522	1,350,110	7.9%	19.6%
Hawaii	29.20	21.29	$ 32,215	$ 22,143	1.1%	0.7%	669,546	1,072,462	6.4%	10.1%
New Hampshire	14.59	13.98	$ 21,616	$ 20,082	1.4%	1.2%	625,539	1,137,462	5.7%	10.1%
Wisconsin	9.00	8.48	$ 152,728	$ 123,609	1.4%	0.7%	6,388,231	13,420,154	5.3%	7.2%
Washington	6.55	6.37	$ 117,013	$ 82,547	1.7%	0.9%	4,942,437	8,353,842	4.8%	6.1%
Minnesota	7.79	7.44	$ 42,490	$ 35,757	1.0%	0.3%	2,399,774	4,593,246	4.3%	3.3%
Iowa	6.89	6.83	$ 94,599	$ 89,111	1.8%	1.6%	2,665,699	4,803,380	3.4%	5.8%
Indiana	**7.09**	**6.50**	**$ 10,147**	**$ 11,759**	**0.2%**	**0.1%**	**829,799**	**1,654,300**	**1.0%**	**1.2%**
Illinois	10.26	8.46	$ 205,891	$ 11,957	3.4%	0.1%	128,580	213,342	0.2%	0.2%
Kentucky	6.26	5.84	$ 10,189	$ 10,497	0.3%	0.2%	104,464	132,888	0.2%	0.1%
Missouri	6.84	6.56	$ 382,229	$ 12,938	4.4%	0.1%	73,490	95,446	0.1%	0.1%
Kansas	7.45	6.84	$ 2,874	$ 2,405	0.1%	0.1%	3,928	6,694	0.0%	0.0%

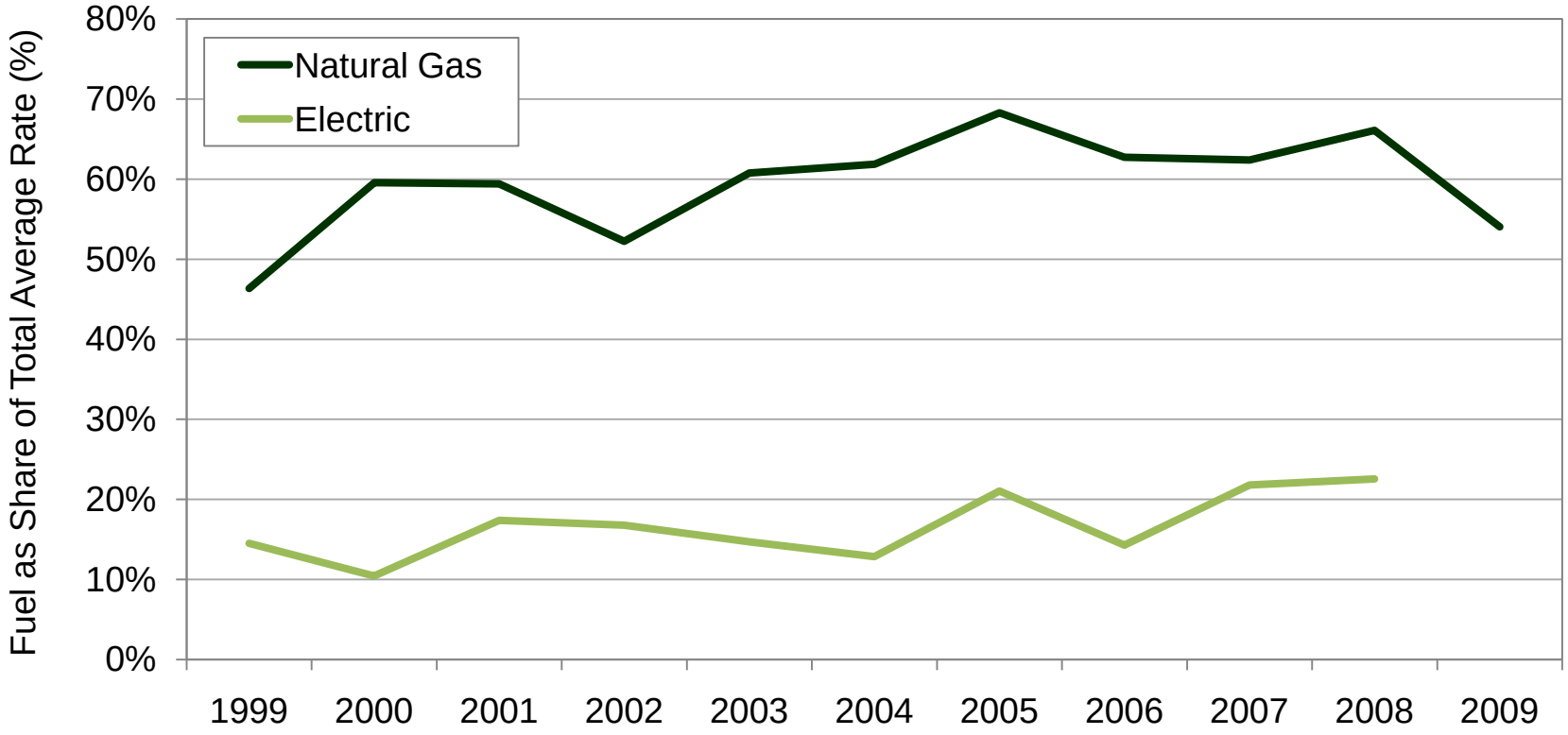
Source: U.S. Department of Energy, Energy Information Administration.

Projected Lost Revenues

	Target (%)	Target MWh Savings Goal (MWh)	DSM Program Costs	Lost Margin	Cumulative Lost Margin	Forecasted Base Revenue	Lost Margin as a Percent of Base Revenue (%)
			---------- (thousand $) ----------				
2010	0.30%	16,005	$ 4,001	$ 644	$ 644	$ 381,314	0.17%
2011	0.50%	25,715	$ 6,429	$ 1,035	$ 1,678	$ 410,140	0.25%
2012	0.70%	35,717	$ 8,929	$ 1,437	$ 3,115	$ 441,146	0.33%
2013	0.90%	45,957	$ 11,489	$ 1,849	$ 4,964	$ 474,495	0.39%
2014	1.10%	56,428	$ 14,107	$ 2,270	$ 7,234	$ 510,366	0.44%
2015	1.30%	66,276	$ 16,569	$ 2,666	$ 9,900	$ 548,948	0.49%
2016	1.50%	75,843	$ 18,961	$ 3,051	$ 12,952	$ 590,447	0.52%
2017	1.70%	85,176	$ 21,294	$ 3,427	$ 16,378	$ 635,084	0.54%
2018	1.90%	94,195	$ 23,549	$ 3,789	$ 20,168	$ 683,094	0.55%
2019	2.00%	97,998	$ 24,499	$ 3,942	$ 24,110	$ 734,734	0.54%

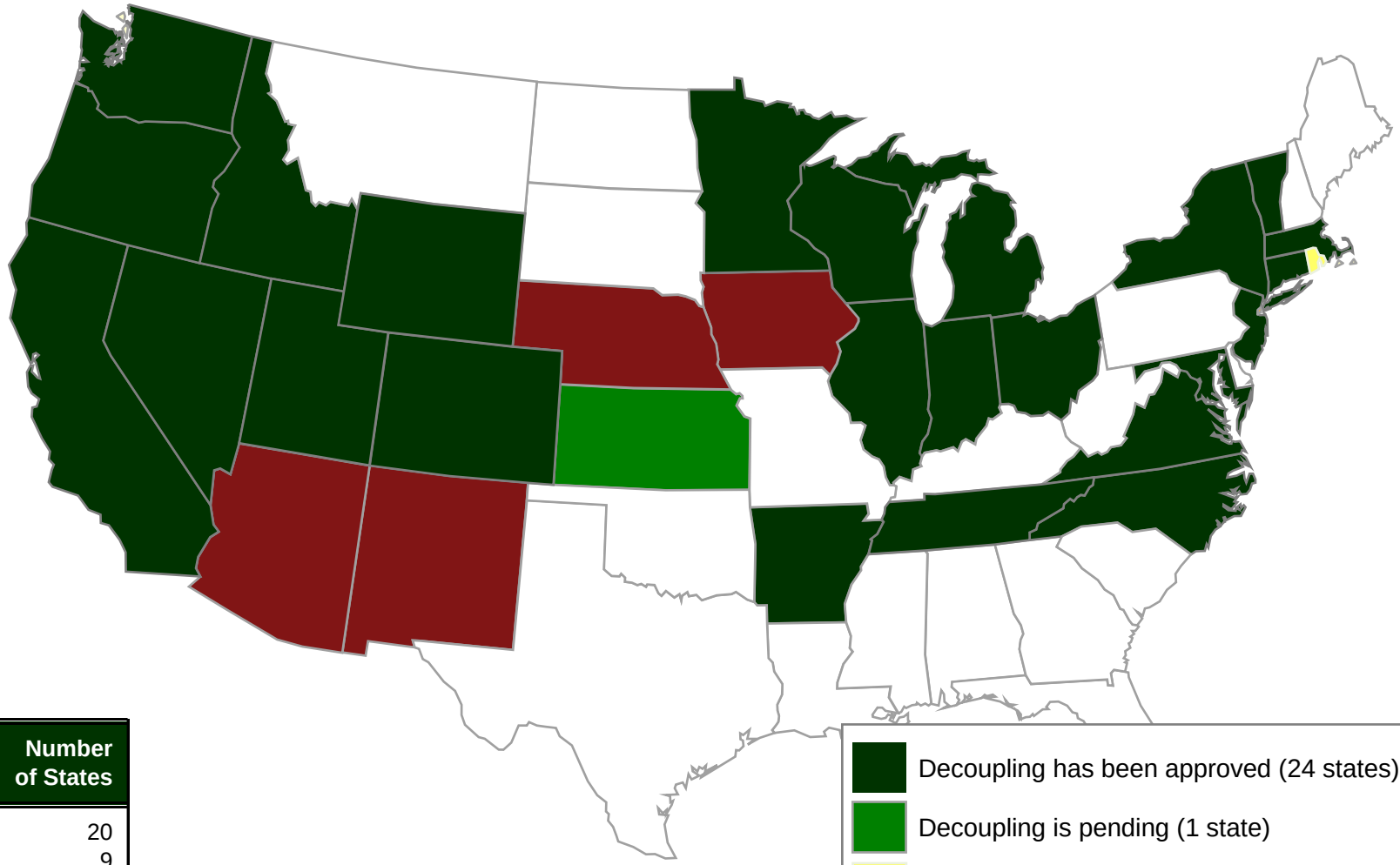
Note: Forecasted Base Revenues are estimated to increase based on 5-year average of non-fuel revenues.
Source: Response to DR 21 Q-29; and FERC Form 1.

Electric and Gas Cost Shares



Source: U.S. Department of Energy, Energy Information Administration.

Status of Natural Gas and Electric Decoupling



Adopted Decoupling	Number of States
Natural Gas	20
Electric	9

- Decoupling has been approved (24 states)
- Decoupling is pending (1 state)
- Decoupling is mandated by legislature, but not yet approved by Commission. (1 states)
- Decoupling has been rejected (4 states)
- No decoupling in place (21 states)

Notes:
Arizona has rejected proposals for decoupling. However, it is currently considering decoupling in a generic docket. The **Connecticut** and **Rhode Island** legislatures have required decoupling, but all natural gas proposals have been rejected thus far.

Achieved Natural Gas Energy Savings Compared to Annual Planning Goals

Program Year (Dec 1 - Nov 30)	Savings Goal	Actual Gross Savings	Actual Net Savings	Gross versus Goal	Net versus Goal
	----------	----------	(therms)	----------	----------
2006-07	850,000	783,322	515,488	(66,678)	(334,512)
2007-08	1,000,000	989,242	683,715	(10,758)	(316,285)
2008-09	1,500,000	2,150,420	1,536,704	650,420	36,704
Total	**3,350,000**	**3,922,984**	**2,735,907**	**572,984**	**(614,093)**

Source: Response to OUCC DR 21, Vectren Natural Gas DSM Final Report Program Year 3, p.6.

Back-Cast of Proposed Decoupling Mechanism

	Rate A Residential Service	Rate EH Home Heating Service	Rate B Water Heating Service	Rate SGS Small General Service	Rate DGS Demand General Service[1]	Rate OSS Off-Season Service
4 months December 2007						
Current period SRA	$ (2,162,776)	$ (30,568)	$ (5,027)	$ (322,015)	$ (1,203,912)	$ (25,918)
Estimated Volumes	335,720,545	158,900,906	4,123,499	21,268,460	386,593,511	33,581,307
SRA Rates	$ (0.00644)	$ (0.00019)	$ (0.00122)	$ (0.01514)	$ (0.00311)	$ (0.00077)
kWh per Customer	3,604	5,459	826	2,118	51,757	41,175
SRA Impact	**$ (23.22)**	**$ (1.05)**	**$ (1.01)**	**$ (32.07)**	**$ (161.18)**	**$ (31.78)**
12 months December 2008						
Current period SRA	$ 4,189,547	$ 213,169	$ 563	$ 30,368	$ (2,607,932)	$ (68,091)
Estimated Volumes	1,007,161,636	476,702,719	12,370,498	63,805,381	1,159,780,532	100,743,921
SRA Rates	$ 0.00416	$ 0.00045	$ 0.00005	$ 0.00048	$ (0.00225)	$ (0.00068)
kWh per Customer	10,813	16,377	2,478	6,354	155,271	123,524
SRA Impact	**$ 44.98**	**$ 7.32**	**$ 0.11**	**$ 3.02**	**$ (349.15)**	**$ (83.49)**
12 months December 2009						
Current period SRA	$ 6,897,359	$ 1,086,631	$ 20,472	$ (219,103)	$ (1,026,663)	$ (25,424)
Estimated Volumes	1,007,161,636	476,702,719	12,370,498	63,805,381	1,159,780,532	100,743,921
SRA Rates	$ 0.00685	$ 0.00228	$ 0.00165	$ (0.00343)	$ (0.00089)	$ (0.00025)
kWh per Customer	10,813	16,377	2,478	6,354	155,271	123,524
SRA Impact	**$ 74.05**	**$ 37.33**	**$ 4.10**	**$ (21.82)**	**$ (137.45)**	**$ (31.17)**
Total September 2007 through December 2009						
Total period SRA	$ 8,924,130	$ 1,269,233	$ 16,008	$ (510,750)	$ (4,838,507)	$ (119,434)
Total Estimated Volume:	2,350,043,817	1,112,306,344	28,864,495	148,879,222	2,706,154,575	235,069,149
SRA Rates	$ 0.00380	$ 0.00114	$ 0.00055	$ (0.00343)	$ (0.00179)	$ (0.00051)
kWh per Customer	25,230	38,213	5,782	14,827	362,298	288,222
SRA Impact	**$ 95.81**	**$ 43.60**	**$ 3.21**	**$ (50.86)**	**$ (647.78)**	**$ (146.44)**

Note: [1] All DGS customers are included here. In 43839 DGS has been split into three customer Groups. The largest 250+ DGS customers belong in Group III and are being excluded from the 43839 SRA.
Source: Response to OUCC DR 21 Q-3.

O&M – Power Production (Steam) per MWh

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	($/MWh)															
Vectren-South	**$ 6.99**	**$ 7.69**	**$ 7.39**	**$ 7.77**	**$ 8.96**	**$ 8.03**	**$ 7.94**	**$ 7.93**	**$ 6.89**	**$ 7.85**	**$ 8.72**	**$ 9.36**	**$ 10.53**	**$ 10.89**	**$ 13.90**	**$ 11.51**
Appalachian Power	3.13	3.01	3.32	3.16	3.53	2.91	3.37	3.69	3.49	3.42	4.93	5.25	4.87	6.02	5.24	6.13
Duke Energy Indiana	4.18	4.23	4.33	4.05	4.48	4.49	4.69	4.73	4.35	4.92	6.39	7.06	8.21	7.37	7.46	7.03
Indiana Michigan Power	7.42	6.88	6.74	6.87	7.00	6.00	6.47	6.49	6.17	6.62	6.55	7.23	6.82	8.37	7.25	9.06
Indianapolis Power & Light	4.84	4.55	5.06	5.58	5.28	5.22	5.50	6.24	4.35	5.64	5.52	6.22	7.68	6.59	7.61	8.66
Interstate Power and Light	2.59	2.37	2.48	2.63	2.88	3.00	3.34	3.80	3.02	2.76	2.92	2.52	2.31	2.58	1.61	3.97
Kansas City Power & Light	4.83	5.14	4.42	4.16	3.79	3.20	3.83	4.05	4.57	4.97	4.97	4.91	4.68	4.85	5.35	5.58
Kentucky Power	3.67	3.13	4.04	2.75	3.19	2.26	3.87	3.37	4.63	3.11	3.55	3.42	3.60	4.42	5.83	3.86
Kentucky Utilities	3.56	3.69	3.71	3.64	3.50	3.20	3.40	3.09	3.26	3.06	3.26	3.40	3.45	4.00	4.20	5.16
Louisville Gas & Electric	6.52	6.52	6.87	6.93	7.45	7.32	6.80	6.37	6.40	6.79	6.69	6.50	7.48	6.96	8.63	9.38
MidAmerican Energy	n.a.	3.08	2.81	12.82	3.02	3.29	3.61	4.11	3.92	4.83	6.23	4.88	4.93	5.28	5.42	5.73
Monongahela Power	5.30	5.30	5.46	4.57	4.17	3.93	3.97	4.76	9.23	6.94	6.82	5.14	4.82	7.48	7.06	4.38
Northern Indiana Pub Serv	6.55	6.67	6.26	6.39	5.92	5.63	5.79	5.63	5.43	5.39	5.53	5.72	6.27	6.86	7.11	8.75
Union Electric	4.07	4.23	4.18	4.53	3.93	4.60	4.63	4.47	4.64	4.20	4.16	3.87	3.84	3.70	4.66	4.44
Westar Energy Inc	5.14	4.80	3.60	5.12	4.72	5.21	5.29	6.34	4.53	4.35	5.90	5.79	6.02	7.26	7.81	8.26
Wisconsin Electric Power	3.59	3.36	3.01	3.07	3.33	3.38	3.90	3.81	3.99	3.99	3.81	3.56	7.90	7.72	13.18	13.77
Wisconsin Power & Light	3.04	3.30	3.23	3.69	3.46	3.09	3.00	2.69	3.51	3.24	2.88	2.93	3.02	3.08	3.57	3.72
Wisconsin Public Service	5.00	5.16	4.53	3.41	3.56	4.15	4.34	3.88	4.16	4.14	4.66	4.49	4.79	6.13	5.46	6.62
Peer Group Average	**4.59**	**4.44**	**4.36**	**4.90**	**4.31**	**4.17**	**4.46**	**4.56**	**4.69**	**4.61**	**4.99**	**4.88**	**5.33**	**5.80**	**6.32**	**6.74**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**16**	**18**	**18**	**17**	**18**	**18**	**18**	**18**	**17**	**18**	**18**	**18**	**18**	**18**	**18**	**17**
Appalachian Power	3	2	5	4	7	2	3	4	3	5	8	11	9	8	5	9
Duke Energy Indiana	8	8	10	8	12	11	12	11	8	11	14	16	17	14	13	11
Indiana Michigan Power	17	17	16	15	16	16	16	17	15	15	15	17	13	17	12	15
Indianapolis Power & Light	10	10	13	13	14	14	14	14	9	14	10	14	15	10	14	13
Interstate Power and Light	1	1	1	1	1	3	2	5	1	1	2	1	1	1	1	3
Kansas City Power & Light	9	12	11	9	9	6	6	8	11	12	9	9	6	6	6	7
Kentucky Power	6	4	8	2	3	1	7	3	12	3	4	4	4	5	9	2
Kentucky Utilities	4	7	7	6	6	5	4	2	2	2	3	3	3	4	3	6
Louisville Gas & Electric	14	15	17	16	17	17	17	16	16	16	16	15	14	12	16	16
MidAmerican Energy	n.a.	3	2	18	2	7	5	9	5	10	13	8	10	7	7	8
Monongahela Power	13	14	14	11	11	9	9	12	18	17	17	10	8	15	10	4
Northern Indiana Pub Serv	15	16	15	14	15	15	15	13	14	13	11	12	12	11	11	14
Union Electric	7	9	9	10	10	12	11	10	13	8	6	6	5	3	4	5
Westar Energy Inc	12	11	6	12	13	13	13	15	10	9	12	13	11	13	15	12
Wisconsin Electric Power	5	6	3	3	4	8	8	6	6	6	5	5	16	16	17	18
Wisconsin Power & Light	2	5	4	7	5	4	1	1	4	4	1	2	2	2	2	1
Wisconsin Public Service	11	13	12	5	8	10	10	7	7	7	7	7	7	9	8	10

Source: FERC Form 1.

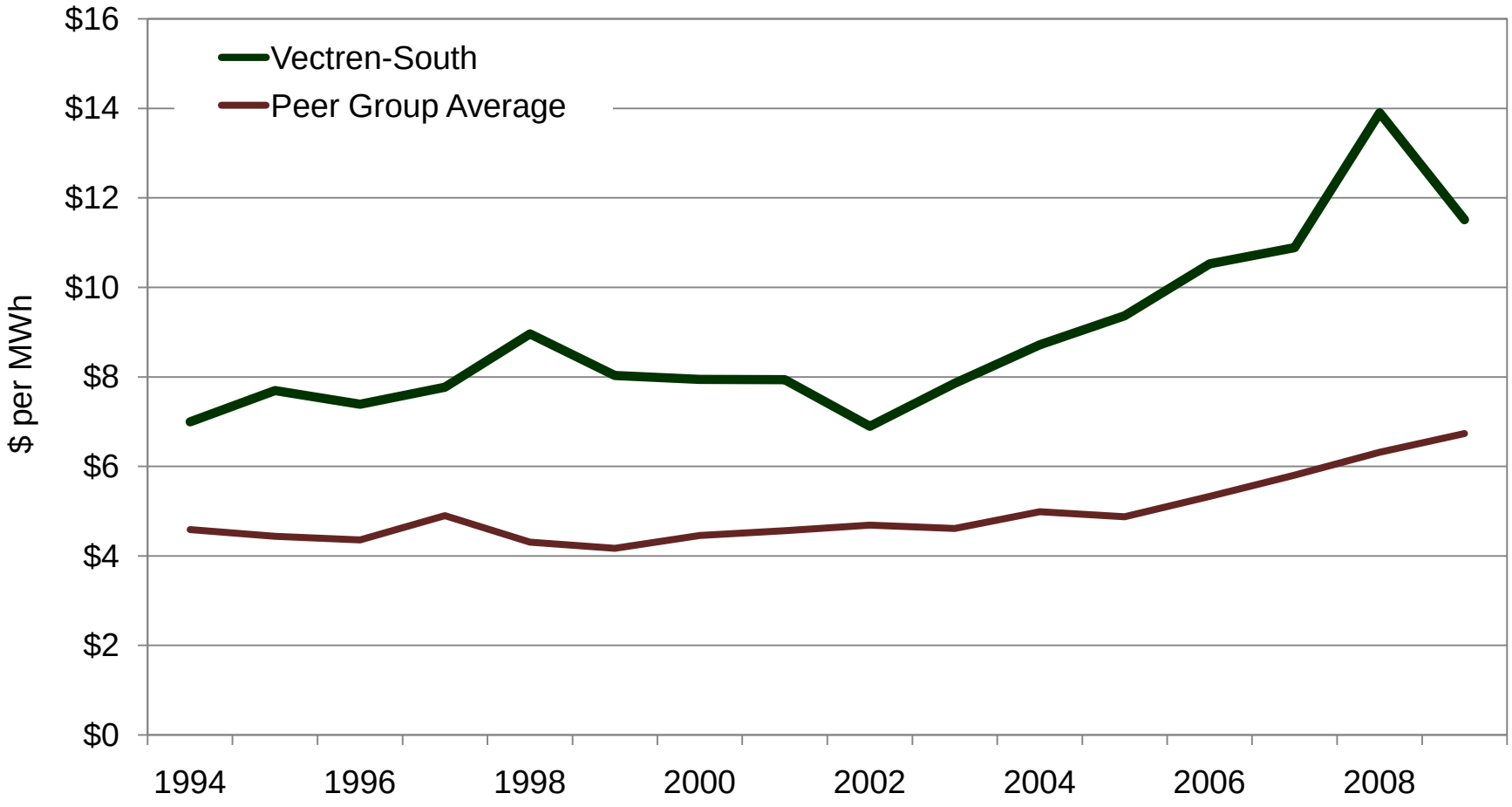
O&M – Power Production (Steam) per MWh Coefficient of Variation

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Coefficient of Variation)															
Vectren-South	**-**	**0.054**	**0.013**	**0.036**	**0.055**	**0.024**	**0.016**	**0.014**	**0.044**	**0.013**	**0.033**	**0.037**	**0.041**	**0.039**	**0.042**	**0.035**
Appalachian Power	-	0.056	0.071	0.012	0.069	0.072	0.046	0.063	0.043	0.031	0.074	0.071	0.062	0.065	0.056	0.058
Duke Energy Indiana	-	0.028	0.039	0.048	0.048	0.041	0.047	0.043	0.015	0.044	0.063	0.061	0.060	0.053	0.050	0.044
Indiana Michigan Power	-	0.054	0.045	0.024	0.008	0.061	0.032	0.027	0.038	0.011	0.015	0.029	0.013	0.040	0.022	0.040
Indianapolis Power & Light	-	0.059	0.056	0.068	0.039	0.028	0.041	0.055	0.070	0.036	0.028	0.044	0.053	0.040	0.047	0.048
Interstate Power and Light	-	0.098	0.007	0.063	0.083	0.080	0.086	0.089	0.038	0.040	0.017	0.067	0.085	0.049	0.169	0.068
Kansas City Power & Light	-	0.054	0.081	0.083	0.097	0.131	0.059	0.031	0.043	0.052	0.047	0.042	0.030	0.035	0.044	0.045
Kentucky Power	-	0.117	0.093	0.147	0.058	0.173	0.075	0.031	0.079	0.055	0.031	0.007	0.032	0.058	0.065	0.028
Kentucky Utilities	-	0.047	0.037	0.014	0.045	0.076	0.040	0.071	0.044	0.061	0.034	0.003	0.018	0.050	0.052	0.061
Louisville Gas & Electric	-	0.005	0.041	0.034	0.046	0.035	0.019	0.038	0.033	0.004	0.014	0.023	0.030	0.014	0.039	0.040
MidAmerican Energy	n.a.	-	0.092	0.116	0.257	0.178	0.122	0.069	0.074	0.032	0.061	0.019	0.021	0.035	0.037	0.040
Monongahela Power	-	0.007	0.035	0.084	0.095	0.096	0.080	0.020	0.073	0.057	0.051	0.032	0.045	0.049	0.043	0.062
Northern Indiana Pub Serv	-	0.026	0.044	0.021	0.050	0.057	0.040	0.043	0.047	0.044	0.034	0.022	0.026	0.036	0.037	0.045
Union Electric	-	0.048	0.018	0.058	0.057	0.052	0.046	0.029	0.038	0.029	0.030	0.049	0.047	0.052	0.036	0.024
Westar Energy Inc	-	0.061	0.153	0.066	0.020	0.052	0.048	0.064	0.049	0.054	0.048	0.043	0.043	0.052	0.051	0.049
Wisconsin Electric Power	-	0.072	0.107	0.071	0.033	0.036	0.070	0.057	0.059	0.053	0.039	0.004	0.070	0.065	0.057	0.053
Wisconsin Power & Light	-	0.077	0.038	0.083	0.044	0.061	0.064	0.092	0.051	0.013	0.059	0.048	0.035	0.024	0.045	0.048
Wisconsin Public Service	-	0.039	0.077	0.155	0.110	0.039	0.016	0.055	0.023	0.023	0.040	0.029	0.039	0.056	0.046	0.053
Peer Group Average	**-**	**0.050**	**0.061**	**0.067**	**0.068**	**0.074**	**0.055**	**0.052**	**0.048**	**0.038**	**0.040**	**0.035**	**0.042**	**0.045**	**0.053**	**0.047**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**-**	**11**	**2**	**6**	**10**	**1**	**2**	**1**	**9**	**4**	**7**	**10**	**10**	**6**	**6**	**3**
Appalachian Power	-	12	12	1	13	12	8	13	7	7	18	18	16	17	15	15
Duke Energy Indiana	-	5	7	7	8	6	10	8	1	12	17	16	15	14	12	7
Indiana Michigan Power	-	9	10	4	1	11	4	3	6	2	2	8	1	7	1	4
Indianapolis Power & Light	-	13	11	11	4	2	7	11	15	9	4	13	14	8	11	11
Interstate Power and Light	-	17	1	9	14	14	17	17	4	10	3	17	18	9	18	18
Kansas City Power & Light	-	10	14	14	16	16	12	5	8	13	12	11	5	3	8	8
Kentucky Power	-	18	16	17	12	17	15	6	18	16	6	3	7	16	17	2
Kentucky Utilities	-	7	5	2	6	13	5	16	10	18	9	1	2	11	14	16
Louisville Gas & Electric	-	2	8	5	7	3	3	7	3	1	1	6	6	1	5	5
MidAmerican Energy	-	n.a.	15	16	18	18	18	15	17	8	16	4	3	4	3	6
Monongahela Power	-	3	4	15	15	15	16	2	16	17	14	9	12	10	7	17
Northern Indiana Pub Serv	-	4	9	3	9	9	6	9	11	11	8	5	4	5	4	9
Union Electric	-	8	3	8	11	7	9	4	5	6	5	15	13	13	2	1
Westar Energy Inc	-	14	18	10	2	8	11	14	12	15	13	12	11	12	13	12
Wisconsin Electric Power	-	15	17	12	3	4	14	12	14	14	10	2	17	18	16	13
Wisconsin Power & Light	-	16	6	13	5	10	13	18	13	3	15	14	8	2	9	10
Wisconsin Public Service	-	6	13	18	17	5	1	10	2	5	11	7	9	15	10	14

Source: FERC Form 1.

O&M – Power Production (Steam) per MWh



Source: FERC Form 1.

O&M – Transmission per MWh

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	($/MWh)															
Vectren-South	**$ 0.33**	**$ 0.28**	**$ 0.29**	**$ 0.30**	**$ 0.23**	**$ 0.31**	**$ 0.38**	**$ 0.32**	**$ 0.24**	**$ 0.29**	**$ 0.25**	**$ 0.46**	**$ 0.50**	**$ 0.68**	**$ 1.72**	**$ 2.06**
Appalachian Power	1.38	1.22	1.24	1.24	1.05	0.53	0.95	0.95	0.28	0.70	0.72	1.03	0.52	0.45	0.35	n.a.
Duke Energy Indiana	0.58	0.54	0.83	0.75	1.34	1.15	1.53	0.90	1.24	0.82	1.01	1.00	1.13	1.10	1.26	1.18
Indiana Michigan Power	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Indianapolis Power & Light	0.48	0.44	0.45	0.50	0.49	0.48	0.39	0.40	0.44	0.60	0.55	0.38	0.69	0.66	0.74	0.77
Interstate Power and Light	1.26	1.19	1.16	1.36	1.49	1.31	1.71	2.16	1.68	1.53	1.37	1.60	1.37	1.62	5.78	9.03
Kansas City Power & Light	0.56	0.54	0.63	0.74	0.70	0.75	0.75	0.82	0.85	1.08	1.47	1.06	1.33	1.56	1.62	1.72
Kentucky Power	0.02	0.13	0.27	0.31	n.a.	n.a.	0.04	0.29	n.a.	n.a.	n.a.	0.36	0.97	1.17	0.93	n.a.
Kentucky Utilities	0.61	0.62	0.59	0.61	0.63	0.57	0.57	0.63	0.98	1.07	1.00	1.10	0.67	0.95	1.04	1.17
Louisville Gas & Electric	0.44	0.42	0.50	0.44	0.63	0.71	0.74	0.72	1.82	2.10	2.10	1.17	0.33	0.95	1.24	0.95
MidAmerican Energy	n.a.	0.64	0.65	0.88	0.85	0.82	0.75	0.53	0.59	0.49	0.72	0.85	1.78	1.72	2.24	2.59
Monongahela Power	0.65	0.67	0.58	0.65	0.48	0.60	0.67	0.83	1.29	1.71	1.36	1.28	1.31	1.50	1.35	1.73
Northern Indiana Pub Serv	0.76	0.69	0.66	0.68	0.60	0.56	0.61	0.57	0.57	0.85	1.42	1.60	1.22	0.87	0.99	1.17
Union Electric	0.36	0.41	0.37	0.46	0.38	0.58	0.99	0.55	1.17	1.02	1.24	1.07	0.69	0.55	1.02	1.14
Westar Energy Inc	0.99	0.98	1.05	1.19	1.31	1.34	1.24	1.73	4.65	4.85	5.26	4.78	5.41	6.05	5.45	7.10
Wisconsin Electric Power	0.44	0.34	0.28	0.59	0.60	0.70	0.57	2.23	2.59	3.87	3.87	4.02	6.07	6.03	8.86	9.98
Wisconsin Power & Light	0.62	0.67	1.41	2.33	2.67	1.75	1.70	4.52	4.69	5.94	5.67	6.13	6.83	7.69	9.08	9.79
Wisconsin Public Service	0.89	0.82	0.91	0.88	0.87	0.89	1.02	2.73	3.51	3.93	5.14	5.61	6.14	7.33	8.64	9.26
Peer Group Average	**0.67**	**0.65**	**0.72**	**0.85**	**0.94**	**0.85**	**0.89**	**1.28**	**1.76**	**2.04**	**2.19**	**2.07**	**2.28**	**2.51**	**3.16**	**4.11**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**2**	**2**	**3**	**1**	**1**	**1**	**2**	**2**	**1**	**1**	**1**	**3**	**2**	**4**	**11**	**9**
Appalachian Power	16	17	16	15	12	3	11	12	2	4	4	6	3	1	1	n.a.
Duke Energy Indiana	8	7	12	11	14	13	15	11	9	5	6	5	8	8	8	6
Indiana Michigan Power	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Indianapolis Power & Light	6	6	5	5	4	2	3	3	3	3	2	2	5	3	2	1
Interstate Power and Light	15	16	15	16	15	14	17	14	11	10	9	12	12	12	14	12
Kansas City Power & Light	7	8	9	10	9	10	9	9	6	9	11	7	11	11	10	7
Kentucky Power	1	1	1	2	n.a.	n.a.	1	1	n.a.	n.a.	n.a.	1	7	9	3	n.a.
Kentucky Utilities	9	9	8	7	7	5	5	7	7	8	5	9	4	6	6	4
Louisville Gas & Electric	4	5	6	3	8	9	8	8	12	12	12	10	1	7	7	2
MidAmerican Energy	n.a.	10	10	12	10	11	10	4	5	2	3	4	13	13	12	10
Monongahela Power	11	11	7	8	3	7	7	10	10	11	8	11	10	10	9	8
Northern Indiana Pub Serv	12	13	11	9	5	4	6	6	4	6	10	13	9	5	4	5
Union Electric	3	4	4	4	2	6	12	5	8	7	7	8	6	2	5	3
Westar Energy Inc	14	15	14	14	13	15	14	13	15	15	15	15	14	15	13	11
Wisconsin Electric Power	5	3	2	6	6	8	4	15	13	13	13	14	15	14	16	15
Wisconsin Power & Light	10	12	17	17	16	16	16	17	16	16	16	17	17	17	17	14
Wisconsin Public Service	13	14	13	13	11	12	13	16	14	14	14	16	16	16	15	13

Source: FERC Form 1.

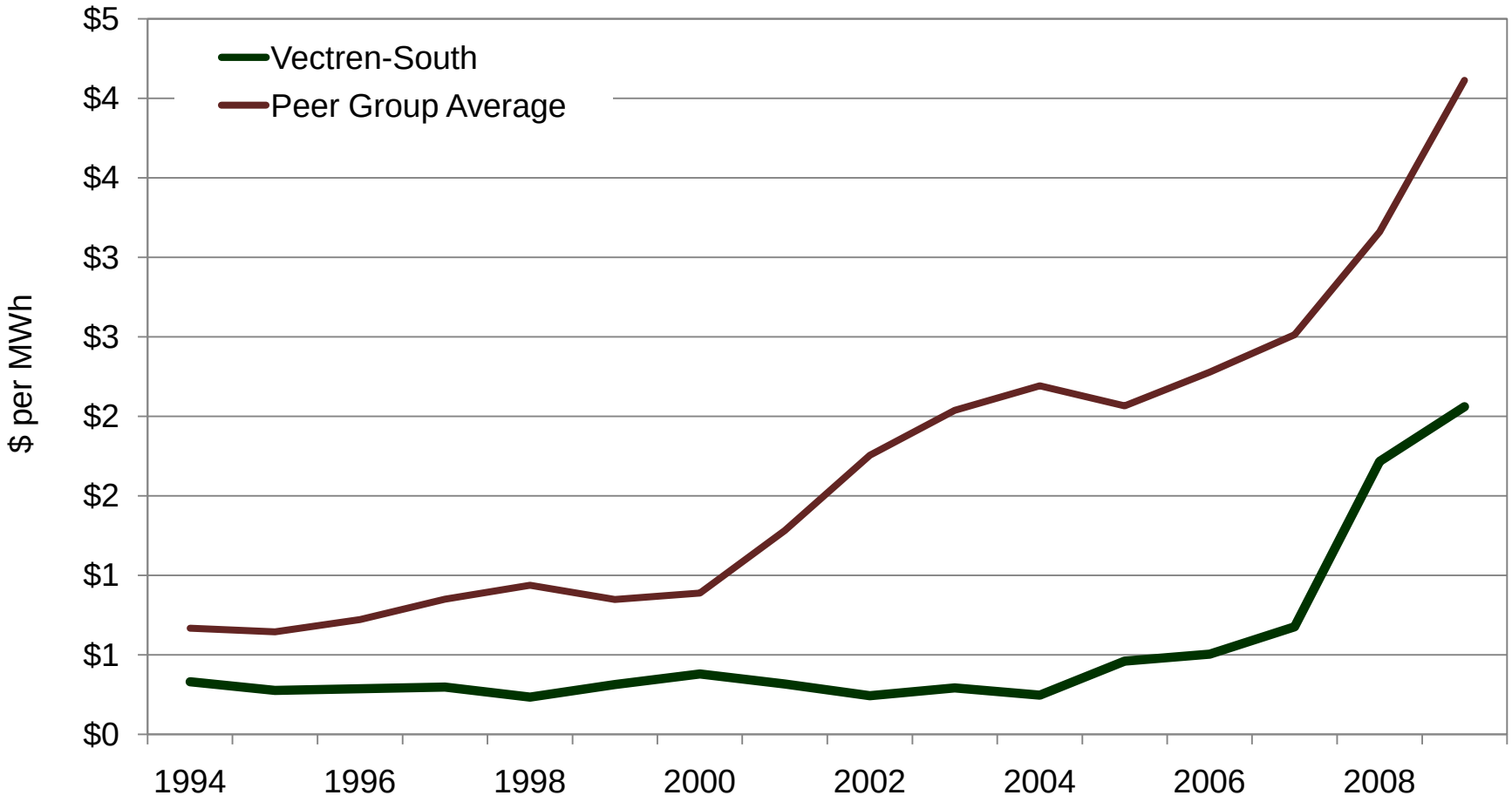
O&M – Transmission per MWh Coefficient of Variation

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Coefficient of Variation)															
Vectren-South	**-**	**0.422**	**0.206**	**0.007**	**0.432**	**0.198**	**0.276**	**0.123**	**0.320**	**0.079**	**0.263**	**0.246**	**0.235**	**0.227**	**0.170**	**0.150**
Appalachian Power	-	0.162	0.098	0.071	0.180	0.579	0.145	0.132	1.015	0.224	0.194	0.085	0.336	0.383	0.515	(1.387)
Duke Energy Indiana	-	0.173	0.296	0.186	0.243	0.190	0.187	0.090	0.136	0.147	0.056	0.048	0.092	0.078	0.102	0.083
Indiana Michigan Power	-	(0.132)	(0.126)	(0.096)	(0.168)	(0.134)	(0.191)	(0.217)	(0.150)	(0.041)	(0.043)	(0.055)	(0.182)	(0.500)	(0.323)	(0.263)
Indianapolis Power & Light	-	0.217	0.109	0.178	0.118	0.058	0.263	0.211	0.078	0.191	0.147	0.228	0.183	0.164	0.166	0.160
Interstate Power and Light	-	0.107	0.106	0.126	0.134	0.035	0.132	0.137	0.089	0.045	0.073	0.061	0.067	0.060	0.089	0.072
Kansas City Power & Light	-	0.107	0.210	0.239	0.166	0.170	0.146	0.157	0.149	0.170	0.167	0.130	0.142	0.137	0.129	0.122
Kentucky Power	-	1.274	0.770	0.576	(2.087)	(4.618)	2.015	0.509	(1.998)	(1.025)	(0.767)	0.429	0.261	0.223	0.227	(1.283)
Kentucky Utilities	-	0.088	0.124	0.060	0.086	0.129	0.113	0.087	0.197	0.183	0.160	0.156	0.111	0.123	0.127	0.130
Louisville Gas & Electric	-	0.159	0.257	0.090	0.269	0.249	0.219	0.186	0.193	0.168	0.153	0.107	0.651	0.035	0.111	0.005
MidAmerican Energy	n.a.	-	0.054	0.261	0.180	0.122	0.053	0.322	0.205	0.309	0.072	0.134	0.161	0.149	0.135	0.123
Monongahela Power	-	0.093	0.234	0.098	0.332	0.059	0.135	0.185	0.197	0.175	0.157	0.140	0.131	0.130	0.114	0.120
Northern Indiana Pub Serv	-	0.178	0.176	0.100	0.215	0.229	0.131	0.171	0.146	0.165	0.177	0.162	0.142	0.062	0.099	0.118
Union Electric	-	0.264	0.170	0.267	0.125	0.278	0.266	0.124	0.218	0.194	0.181	0.161	0.055	0.186	0.138	0.137
Westar Energy Inc	-	0.058	0.110	0.155	0.155	0.135	0.090	0.145	0.125	0.111	0.100	0.092	0.085	0.078	0.073	0.068
Wisconsin Electric Power	-	0.487	0.556	0.358	0.288	0.266	0.170	0.195	0.166	0.133	0.121	0.110	0.092	0.086	0.072	0.065
Wisconsin Power & Light	-	0.170	0.292	0.222	0.178	0.098	0.072	0.125	0.111	0.097	0.088	0.081	0.075	0.069	0.063	0.059
Wisconsin Public Service	-	0.155	0.119	0.051	0.044	0.046	0.129	0.164	0.138	0.122	0.105	0.094	0.085	0.077	0.069	0.064
Peer Group Average	**-**	**0.209**	**0.209**	**0.173**	**0.027**	**(0.124)**	**0.240**	**0.160**	**0.060**	**0.080**	**0.067**	**0.127**	**0.146**	**0.091**	**0.112**	**(0.094)**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**-**	**16**	**11**	**2**	**18**	**13**	**17**	**4**	**17**	**4**	**18**	**17**	**15**	**17**	**16**	**17**
Appalachian Power	-	10	3	5	11	18	10	7	18	17	17	5	17	18	18	n.a.
Duke Energy Indiana	-	12	16	12	14	12	13	3	7	9	3	2	8	7	8	10
Indiana Michigan Power	-	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Indianapolis Power & Light	-	14	5	11	5	5	15	16	3	15	10	16	14	14	15	18
Interstate Power and Light	-	6	4	9	7	3	8	8	4	3	5	3	3	3	6	9
Kansas City Power & Light	-	7	12	14	9	11	11	10	10	12	14	10	11	12	12	13
Kentucky Power	-	18	18	18	n.a.	n.a.	18	18	n.a.	n.a.	n.a.	18	16	16	17	n.a.
Kentucky Utilities	-	4	8	4	4	9	5	2	14	14	13	13	9	10	11	15
Louisville Gas & Electric	-	9	14	6	15	15	14	14	12	11	11	8	18	2	9	4
MidAmerican Energy	-	n.a.	2	15	12	8	2	17	15	18	4	11	13	13	13	14
Monongahela Power	-	5	13	7	17	6	9	13	13	13	12	12	10	11	10	12
Northern Indiana Pub Serv	-	13	10	8	13	14	7	12	9	10	15	15	12	4	7	11
Union Electric	-	15	9	16	6	17	16	5	16	16	16	14	2	15	14	16
Westar Energy Inc	-	3	6	10	8	10	4	9	6	6	7	6	5	8	5	8
Wisconsin Electric Power	-	17	17	17	16	16	12	15	11	8	9	9	7	9	4	7
Wisconsin Power & Light	-	11	15	13	10	7	3	6	5	5	6	4	4	5	2	5
Wisconsin Public Service	-	8	7	3	3	4	6	11	8	7	8	7	6	6	3	6

Source: FERC Form 1.

O&M – Transmission per MWh



Source: FERC Form 1.

O&M – Distribution per MWh

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	($/MWh)															
Vectren-South	**$ 1.77**	**$ 1.96**	**$ 1.74**	**$ 1.58**	**$ 1.64**	**$ 1.41**	**$ 1.37**	**$ 1.50**	**$ 1.39**	**$ 1.72**	**$ 1.60**	**$ 1.57**	**$ 1.81**	**$ 1.73**	**$ 3.00**	**$ 3.25**
Appalachian Power	3.73	3.76	3.01	2.81	3.41	3.11	2.91	2.94	2.81	3.18	3.19	3.16	3.03	2.85	3.44	5.15
Duke Energy Indiana	1.75	1.58	1.71	1.49	1.55	1.35	1.42	1.48	1.39	1.60	1.54	1.58	1.60	1.54	2.99	3.40
Indiana Michigan Power	2.60	2.54	2.25	2.45	2.58	2.26	2.42	3.00	2.35	2.51	2.81	3.71	3.14	3.10	3.74	3.79
Indianapolis Power & Light	2.10	2.07	2.11	2.11	2.22	2.16	2.21	2.06	2.46	2.72	2.28	2.35	2.40	2.06	2.64	2.52
Interstate Power and Light	2.35	1.95	2.12	2.17	2.54	1.92	1.89	2.36	2.29	1.96	1.75	1.53	1.37	1.98	1.73	1.55
Kansas City Power & Light	3.20	2.90	2.72	2.76	2.67	2.80	3.29	3.47	4.26	3.32	3.38	3.61	2.93	2.67	2.80	3.18
Kentucky Power	3.40	2.96	2.56	2.74	3.33	3.51	2.53	2.56	2.85	3.14	3.25	3.00	3.25	3.45	3.67	4.20
Kentucky Utilities	2.61	2.06	2.04	1.93	1.88	1.71	1.66	1.39	1.40	2.05	1.77	1.99	2.09	1.92	2.25	2.63
Louisville Gas & Electric	2.33	2.14	2.32	2.31	2.44	2.08	2.11	1.99	2.04	2.20	3.36	2.10	2.67	2.33	2.72	2.72
MidAmerican Energy	n.a.	2.88	2.87	3.17	3.37	3.32	3.58	4.05	3.46	3.67	4.07	4.27	4.21	5.09	5.34	4.37
Monongahela Power	3.66	3.77	3.60	3.77	3.49	2.91	2.96	3.00	2.84	3.14	3.03	3.41	3.35	2.96	3.66	4.67
Northern Indiana Pub Serv	1.59	1.55	1.57	1.72	1.51	1.41	1.60	1.57	1.61	1.54	1.77	1.77	1.78	2.28	2.47	2.36
Union Electric	2.86	2.56	2.51	2.52	2.59	2.89	3.00	3.28	3.34	3.12	2.97	3.10	4.09	4.69	3.88	5.45
Westar Energy Inc	2.11	2.28	2.08	2.23	2.49	2.72	2.67	3.13	2.77	2.68	3.17	3.62	4.16	4.04	4.25	4.95
Wisconsin Electric Power	2.97	2.33	2.25	2.09	2.42	2.33	2.60	2.64	2.63	2.61	2.32	2.32	2.49	2.54	3.25	3.17
Wisconsin Power & Light	2.54	2.37	2.44	2.31	2.29	1.94	2.13	2.17	2.33	2.62	2.47	2.29	2.48	2.35	2.10	1.97
Wisconsin Public Service	3.01	2.95	3.21	2.87	3.04	3.57	3.55	3.45	3.60	3.42	3.65	3.82	3.89	4.04	3.98	4.11
Peer Group Average	**2.68**	**2.51**	**2.43**	**2.44**	**2.58**	**2.47**	**2.50**	**2.62**	**2.61**	**2.67**	**2.75**	**2.80**	**2.88**	**2.94**	**3.23**	**3.54**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**3**	**4**	**3**	**2**	**3**	**2**	**1**	**3**	**1**	**3**	**2**	**2**	**4**	**2**	**9**	**9**
Appalachian Power	17	17	16	15	17	15	13	11	12	15	13	12	11	11	11	17
Duke Energy Indiana	2	2	2	1	2	1	2	2	2	2	1	3	2	1	8	10
Indiana Michigan Power	9	11	9	11	11	9	9	13	8	7	9	16	12	13	14	11
Indianapolis Power & Light	4	6	6	6	5	8	8	6	9	11	6	9	6	5	5	4
Interstate Power and Light	7	3	7	7	10	5	5	8	6	4	3	1	1	4	1	1
Kansas City Power & Light	14	14	14	14	13	12	16	17	18	16	16	14	10	10	7	8
Kentucky Power	15	16	13	13	15	17	10	9	14	14	14	10	13	14	13	13
Kentucky Utilities	10	5	4	4	4	4	4	1	3	5	5	5	5	3	3	5
Louisville Gas & Electric	6	7	10	10	8	7	6	5	5	6	15	6	9	7	6	6
MidAmerican Energy	n.a.	13	15	17	16	16	18	18	16	18	18	18	18	18	18	14
Monongahela Power	16	18	18	18	18	14	14	12	13	13	11	13	14	12	12	15
Northern Indiana Pub Serv	1	1	1	3	1	3	3	4	4	1	4	4	3	6	4	3
Union Electric	11	12	12	12	12	13	15	15	15	12	10	11	16	17	15	18
Westar Energy Inc	5	8	5	8	9	11	12	14	11	10	12	15	17	16	17	16
Wisconsin Electric Power	12	9	8	5	7	10	11	10	10	8	7	8	8	9	10	7
Wisconsin Power & Light	8	10	11	9	6	6	7	7	7	9	8	7	7	8	2	2
Wisconsin Public Service	13	15	17	16	14	18	17	16	17	17	17	17	15	15	16	12

Source: FERC Form 1.

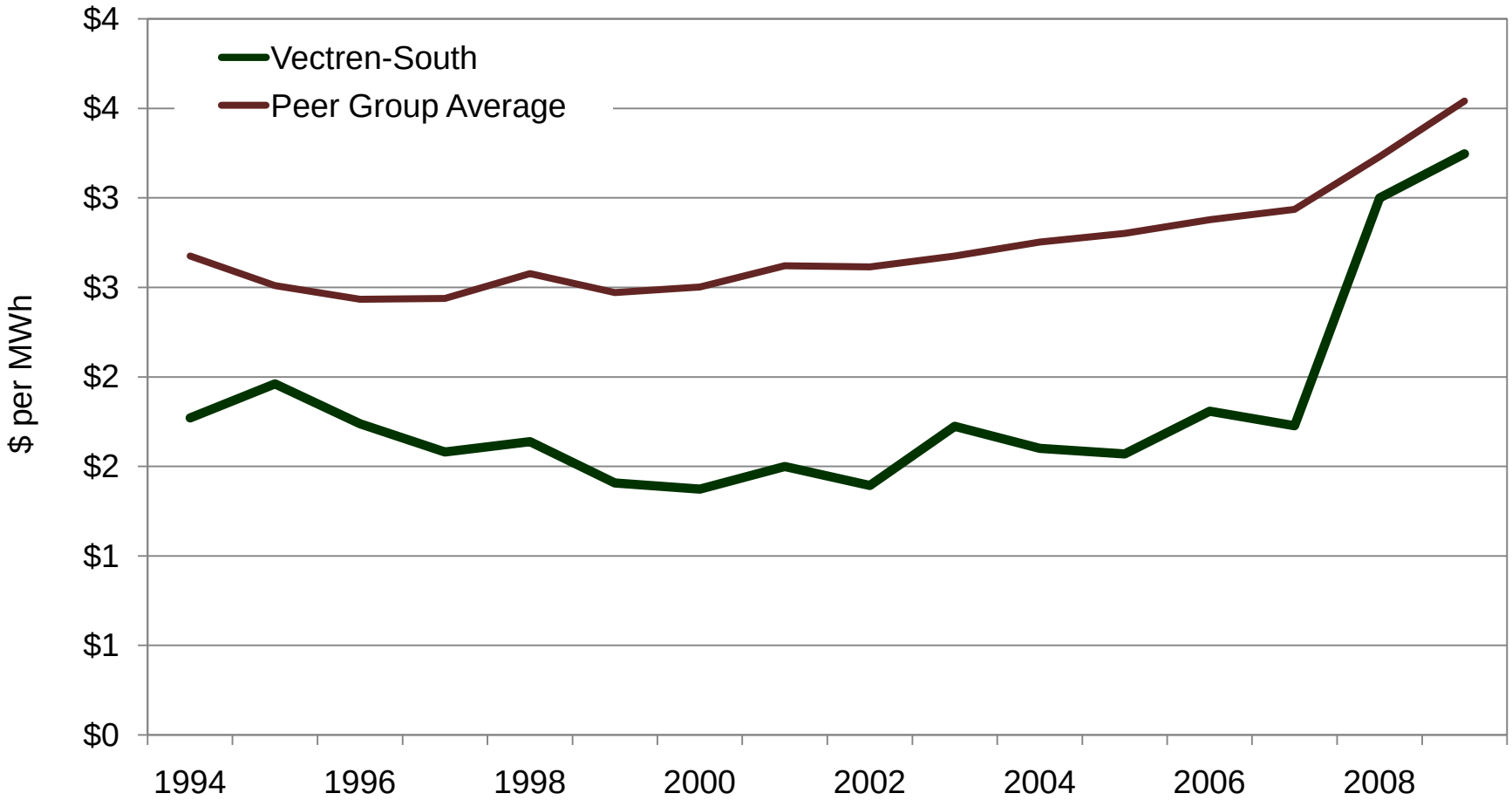
O&M – Distribution per MWh Coefficient of Variation

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Coefficient of Variation)															
Vectren-South	**-**	**0.111**	**0.097**	**0.135**	**0.086**	**0.152**	**0.142**	**0.082**	**0.108**	**0.062**	**0.016**	**0.034**	**0.066**	**0.049**	**0.097**	**0.092**
Appalachian Power	-	0.023	0.134	0.128	0.033	0.059	0.075	0.063	0.070	0.011	0.014	0.009	0.033	0.050	0.040	0.066
Duke Energy Indiana	-	0.133	0.055	0.126	0.075	0.143	0.095	0.057	0.087	0.053	0.010	0.040	0.040	0.012	0.100	0.095
Indiana Michigan Power	-	0.048	0.118	0.021	0.052	0.078	0.025	0.082	0.055	0.013	0.058	0.081	0.061	0.055	0.068	0.065
Indianapolis Power & Light	-	0.035	0.032	0.024	0.063	0.034	0.047	0.044	0.073	0.082	0.030	0.042	0.045	0.054	0.060	0.049
Interstate Power and Light	-	0.163	0.039	0.036	0.099	0.107	0.099	0.067	0.049	0.072	0.104	0.139	0.162	0.025	0.076	0.104
Kansas City Power & Light	-	0.094	0.100	0.068	0.072	0.029	0.071	0.072	0.084	0.040	0.042	0.051	0.047	0.069	0.052	0.019
Kentucky Power	-	0.112	0.145	0.077	0.078	0.076	0.103	0.086	0.034	0.043	0.048	0.011	0.042	0.050	0.054	0.061
Kentucky Utilities	-	0.180	0.125	0.124	0.113	0.137	0.130	0.184	0.159	0.065	0.051	0.049	0.059	0.024	0.066	0.078
Louisville Gas & Electric	-	0.102	0.060	0.041	0.067	0.085	0.067	0.084	0.064	0.011	0.092	0.059	0.062	0.011	0.058	0.054
MidAmerican Energy	n.a.	-	0.011	0.081	0.081	0.060	0.070	0.080	0.036	0.049	0.062	0.061	0.055	0.064	0.062	0.043
Monongahela Power	-	0.044	0.044	0.035	0.052	0.110	0.090	0.074	0.082	0.043	0.051	0.028	0.019	0.051	0.042	0.061
Northern Indiana Pub Serv	-	0.063	0.016	0.098	0.084	0.109	0.044	0.009	0.040	0.032	0.073	0.068	0.064	0.092	0.091	0.082
Union Electric	-	0.106	0.083	0.060	0.025	0.068	0.069	0.076	0.071	0.051	0.030	0.042	0.071	0.072	0.056	0.067
Westar Energy Inc	-	0.089	0.077	0.055	0.091	0.095	0.078	0.092	0.063	0.048	0.073	0.078	0.078	0.072	0.069	0.069
Wisconsin Electric Power	-	0.171	0.133	0.135	0.013	0.046	0.060	0.058	0.051	0.042	0.051	0.047	0.018	0.029	0.068	0.062
Wisconsin Power & Light	-	0.087	0.025	0.070	0.062	0.128	0.071	0.052	0.033	0.067	0.046	0.023	0.042	0.014	0.058	0.073
Wisconsin Public Service	-	0.041	0.070	0.066	0.021	0.078	0.066	0.051	0.055	0.036	0.049	0.052	0.051	0.051	0.046	0.047
Peer Group Average	**-**	**0.088**	**0.075**	**0.073**	**0.063**	**0.085**	**0.074**	**0.072**	**0.065**	**0.045**	**0.052**	**0.052**	**0.056**	**0.047**	**0.063**	**0.064**

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	(Rank)															
Vectren-South	**-**	**13**	**12**	**18**	**15**	**18**	**18**	**13**	**17**	**14**	**3**	**5**	**15**	**7**	**17**	**16**
Appalachian Power	-	2	17	16	4	4	11	7	11	2	2	1	3	8	1	10
Duke Energy Indiana	-	15	7	15	11	17	14	5	16	13	1	6	4	2	18	17
Indiana Michigan Power	-	6	14	1	6	9	1	14	8	3	13	17	12	13	13	9
Indianapolis Power & Light	-	3	4	2	8	2	3	2	13	18	4	7	7	12	9	4
Interstate Power and Light	-	16	5	4	17	12	15	8	5	17	18	18	18	5	15	18
Kansas City Power & Light	-	10	13	9	10	1	10	9	15	6	6	11	8	15	4	1
Kentucky Power	-	14	18	11	12	7	16	16	2	9	8	2	6	9	5	7
Kentucky Utilities	-	18	15	14	18	16	17	18	18	15	10	10	11	4	11	14
Louisville Gas & Electric	-	11	8	5	9	10	6	15	10	1	17	13	13	1	8	5
MidAmerican Energy	-	n.a.	1	12	13	5	8	12	3	11	14	14	10	14	10	2
Monongahela Power	-	5	6	3	5	14	13	10	14	8	12	4	2	10	2	6
Northern Indiana Pub Serv	-	7	2	13	14	13	2	1	4	4	15	15	14	18	16	15
Union Electric	-	12	11	7	3	6	7	11	12	12	5	8	16	16	6	11
Westar Energy Inc	-	9	10	6	16	11	12	17	9	10	16	16	17	17	14	12
Wisconsin Electric Power	-	17	16	17	1	3	4	6	6	7	11	9	1	6	12	8
Wisconsin Power & Light	-	8	3	10	7	15	9	4	1	16	7	3	5	3	7	13
Wisconsin Public Service	-	4	9	8	2	8	5	3	7	5	9	12	9	11	3	3

Source: FERC Form 1.

O&M – Distribution per MWh



Source: FERC Form 1.

Example: EIM Estimation

	(a)	(b)	(c)	(d) (b) - (c)	(e)	(f)	(g) (a) * $12.5	(h) (b) * $17.92	(i) (g) - (h)	(j) Sharing Mechanism	(k)	(l) (j) + (k)	(m) (h) + (j)	(n) (k)	(o) (m) + (n)
										Efficiency Share			Efficiency Credit		
	Offsystem Sales	Achieved EE (Gross Savings)	Commission Annual EE Goal	Achieved v. Target EE Goals	Percent of EE Goals Met (%)	Net Achieved EE Goals* (MWh)	Offsystem Margin @ $12.50	Lost Distribution Margin @ $17.92	Net Margin	Utility	Ratepayer	Total	Utility	Ratepayer	Total
	(MWh)						(million $)								
Scenario 1: Vectren South Meets Energy Efficiency Goals															
Year 1	1,500,000	16,005	16,005	-	100%	12,804	$ 18.8	$ 0.2	$ 18.5	$ 9.3	$ 9.3	$ 18.5	$ 9.5	$ 9.3	$ 18.8
Year 2	1,500,000	25,715	25,715	-	100%	20,572	$ 18.8	$ 0.4	$ 18.4	$ 9.2	$ 9.2	$ 18.4	$ 9.6	$ 9.2	$ 18.8
Year 3	1,500,000	35,717	35,717	-	100%	28,574	$ 18.8	$ 0.5	$ 18.2	$ 9.1	$ 9.1	$ 18.2	$ 9.6	$ 9.1	$ 18.8
							$ 56.3	**$ 1.110**	**$ 55.1**	**$ 27.6**	**$ 27.6**	**$ 55.1**	**$ 28.7**	**$ 27.6**	**$ 56.3**
Scenario 2: Vectren South Exceeds Energy Efficiency Goals															
Year 1	1,500,000	16,135	16,005	130	101%	12,908	$ 18.8	$ 0.2	$ 18.5	$ 13.9	$ 4.6	$ 18.5	$ 14.1	$ 4.6	$ 18.8
Year 2	1,500,000	27,775	25,715	2,060	108%	22,220	$ 18.8	$ 0.4	$ 18.4	$ 13.8	$ 4.6	$ 18.4	$ 14.2	$ 4.6	$ 18.8
Year 3	1,500,000	40,000	35,717	4,283	112%	32,000	$ 18.8	$ 0.6	$ 18.2	$ 13.6	$ 4.5	$ 18.2	$ 14.2	$ 4.5	$ 18.8
							$ 56.3	**$ 1.203**	**$ 55.0**	**$ 41.3**	**$ 13.8**	**$ 55.0**	**$ 42.5**	**$ 13.8**	**$ 56.3**
Scenario 3: Vectren South Does Not Meet Energy Efficiency Goals															
Year 1	1,500,000	14,250	16,005	(1,755)	89%	11,400	$ 18.8	$ 0.2	$ 18.5	$ 4.6	$ 13.9	$ 18.5	$ 4.8	$ 13.9	$ 18.8
Year 2	1,500,000	21,125	25,715	(4,590)	82%	16,900	$ 18.8	$ 0.3	$ 18.4	$ 4.6	$ 13.8	$ 18.4	$ 4.9	$ 13.8	$ 18.8
Year 3	1,500,000	30,120	35,717	(5,597)	84%	24,096	$ 18.8	$ 0.4	$ 18.3	$ 4.6	$ 13.7	$ 18.3	$ 5.0	$ 13.7	$ 18.8
							$ 56.3	**$ 0.939**	**$ 55.3**	**$ 13.8**	**$ 41.5**	**$ 55.3**	**$ 14.8**	**$ 41.5**	**$ 56.3**

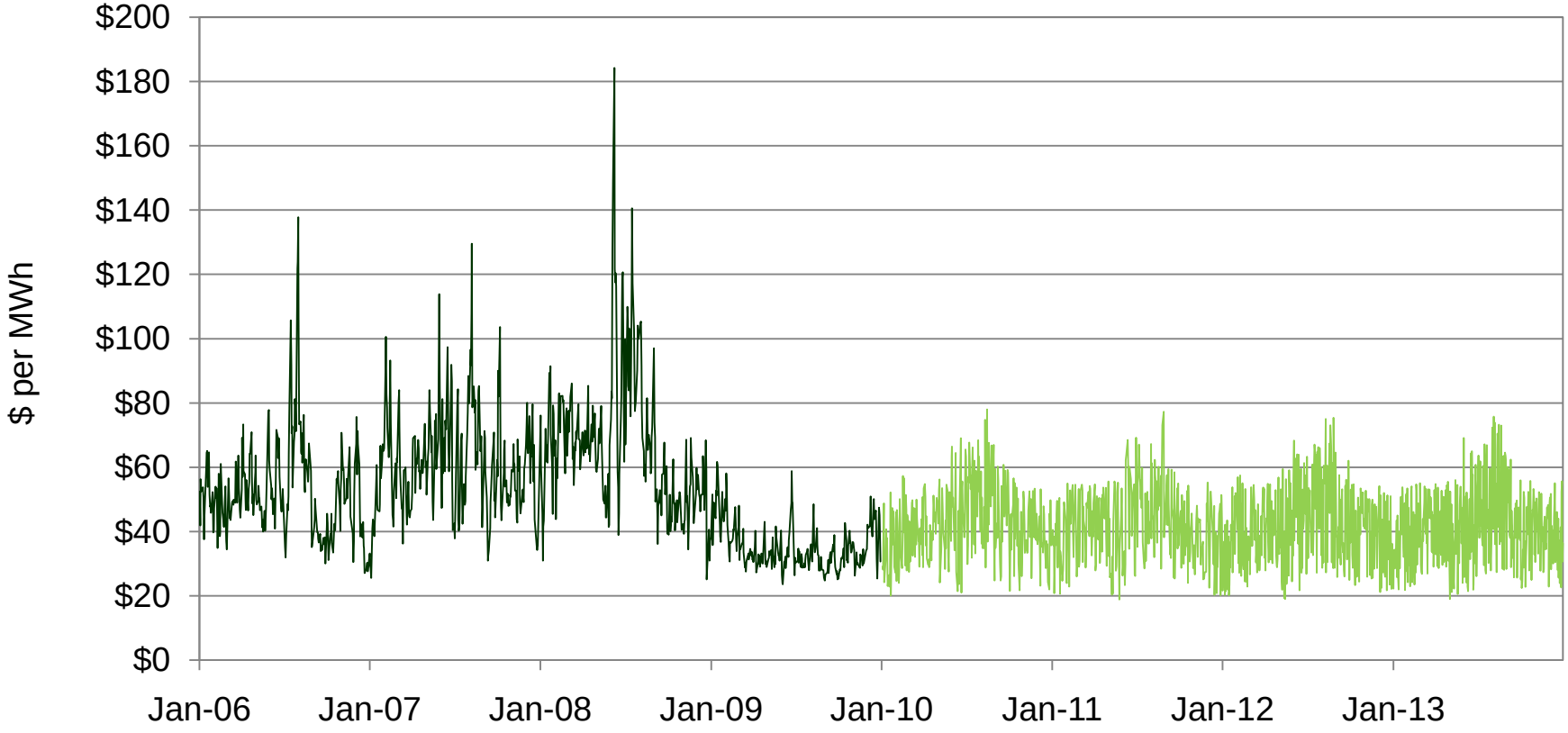
Note: *Assumes a net-to-gross ratio of 0.80.

Wholesale Margins

	Operating Revenues			MWH Sold			Average Revenue		
	Sales for Resale	Total Charges Requirements Customers	Sales for Resale - Wholesale	Sales for Resale	Total Charges Requirements Customers	Sales for Resale - Wholesale	Sales for Resale	Total Charges Requirements Customers	Sales for Resale - Wholesale
	------- (thousand $) -------			--------- (MWh) ---------			------- ($/MWh) -------		
1990	50,823	-	50,823	1,605,723	-	1,605,723	$ 31.65	$ -	$ 31.65
1991	49,620	-	49,620	1,647,796	-	1,647,796	$ 30.11	$ -	$ 30.11
1992	40,916	12,573	28,343	1,265,296	272,194	993,102	$ 32.34	$ 46.19	$ 28.54
1993	39,424	13,400	26,024	1,200,116	289,614	910,502	$ 32.85	$ 46.27	$ 28.58
1994	37,669	13,577	24,092	1,234,804	295,144	939,660	$ 30.51	$ 46.00	$ 25.64
1995	43,471	14,233	29,238	1,570,416	332,350	1,238,066	$ 27.68	$ 42.83	$ 23.62
1996	41,212	13,641	27,571	1,497,481	316,760	1,180,721	$ 27.52	$ 43.06	$ 23.35
1997	47,300	12,863	34,437	1,752,641	319,442	1,433,199	$ 26.99	$ 40.27	$ 24.03
1998	60,687	13,089	47,598	2,013,557	351,002	1,662,555	$ 30.14	$ 37.29	$ 28.63
1999	60,191	14,381	45,810	1,829,770	390,454	1,439,316	$ 32.90	$ 36.83	$ 31.83
2000	78,682	13,442	65,240	2,296,050	371,305	1,924,745	$ 34.27	$ 36.20	$ 33.90
2001	121,416	10,953	110,463	3,898,231	311,901	3,586,330	$ 31.15	$ 35.12	$ 30.80
2002	317,886	11,501	306,385	11,329,300	329,091	11,000,209	$ 28.06	$ 34.95	$ 27.85
2003	38,574	21,534	17,040	4,906,114	600,924	4,305,190	$ 7.86	$ 35.83	$ 3.96
2004	44,699	23,561	21,138	4,151,930	625,925	3,526,005	$ 10.77	$ 37.64	$ 5.99
2005	60,073	25,786	34,287	3,719,565	670,337	3,049,228	$ 16.15	$ 38.47	$ 11.24
2006	55,479	26,069	29,410	1,522,623	624,347	898,276	$ 36.44	$ 41.75	$ 32.74
2007	60,617	26,361	34,256	1,537,498	616,178	921,320	$ 39.43	$ 42.78	$ 37.18
2008	58,520	2,044	56,476	1,557,192	44,291	1,512,901	$ 37.58	$ 46.15	$ 37.33

Source: Response to OUCC DR24 Q-2c.

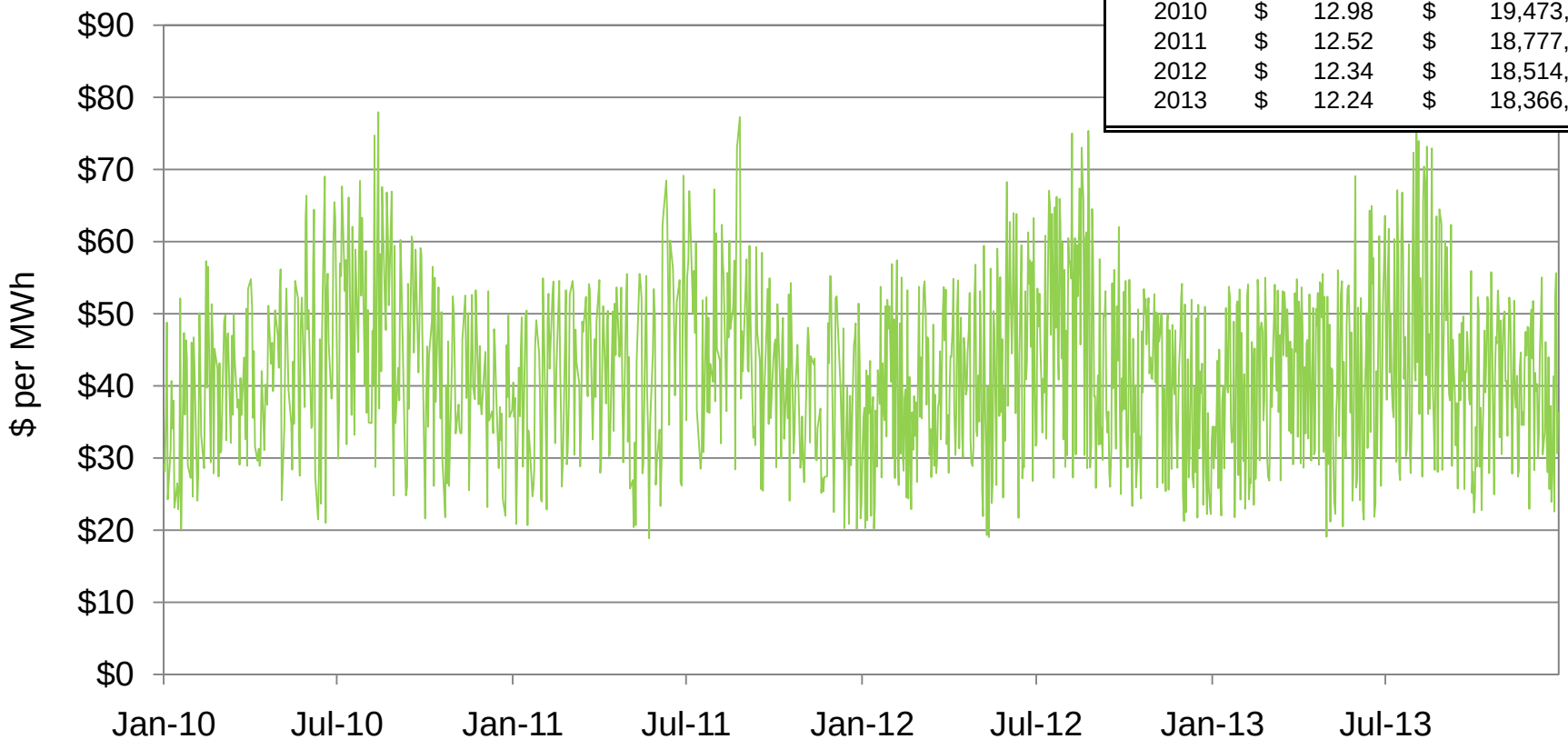
Illustrative Wholesale Market Price Forecast



Source: The Intercontinental Exchange.

Illustrative Wholesale Market Price Forecast
Power Prices at $5 Gas

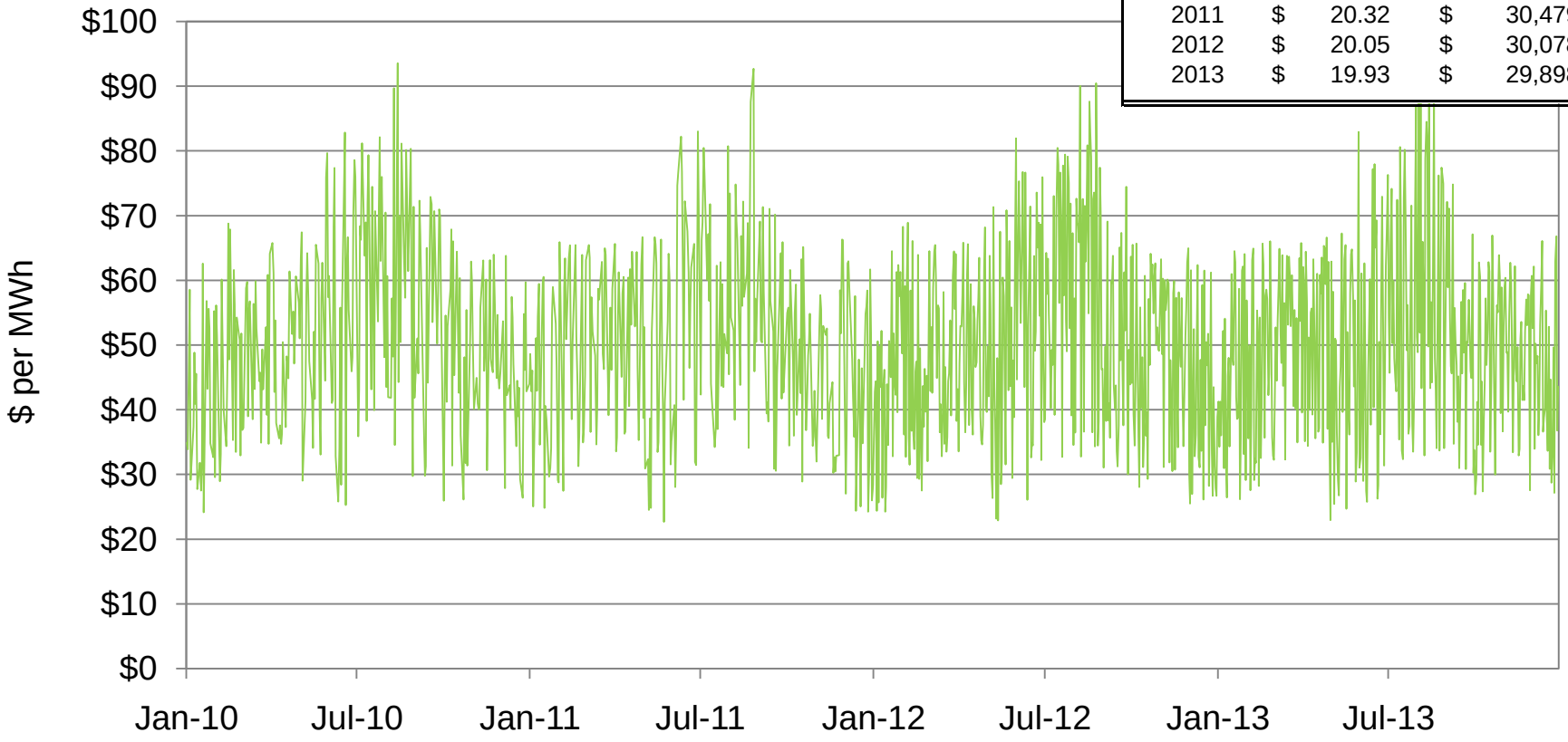
	Margin	
	1 MWh	1.5 Million MWh
	---------- ($) ----------	
2010	$ 12.98	$ 19,473,635
2011	$ 12.52	$ 18,777,126
2012	$ 12.34	$ 18,514,139
2013	$ 12.24	$ 18,366,658



Source: The Intercontinental Exchange.

Illustrative Wholesale Market Price Forecast
Power Prices at $6 Gas

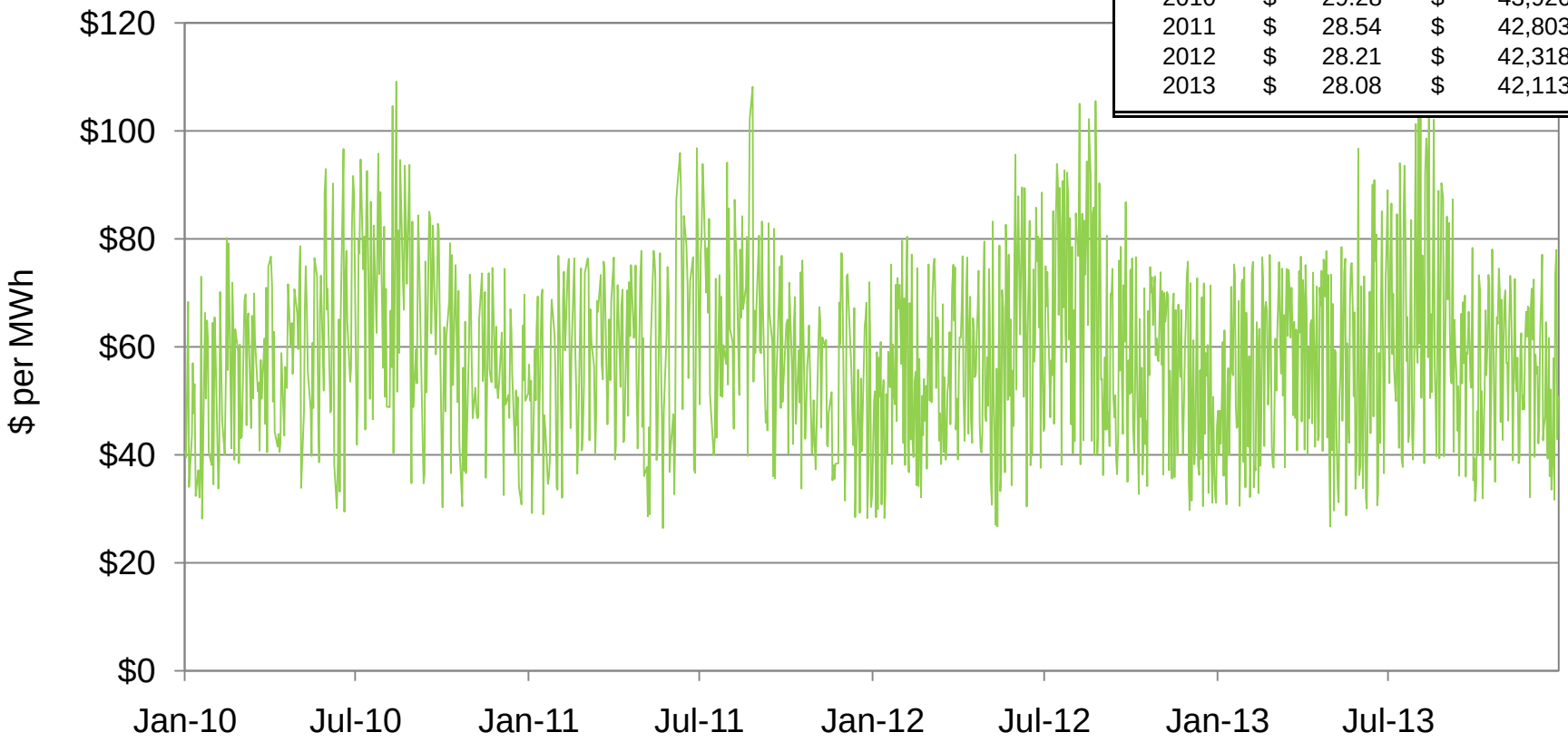
	Margin	
	1 MWh	1.5 Million MWh
	---------- ($) ----------	
2010	$ 20.94	$ 31,406,296
2011	$ 20.32	$ 30,479,161
2012	$ 20.05	$ 30,078,213
2013	$ 19.93	$ 29,898,534



Source: The Intercontinental Exchange.

Illustrative Wholesale Market Price Forecast
Power Prices at $7 Gas

	Margin	
	1 MWh	1.5 Million MWh
	---------- ($) ----------	
2010	$ 29.28	$ 43,926,785
2011	$ 28.54	$ 42,803,856
2012	$ 28.21	$ 42,318,922
2013	$ 28.08	$ 42,113,955



Source: The Intercontinental Exchange.

EIM Recommendation

	(a)	(b)	(c)	(d) (b) - (c)	(e)	(f)	(g) (a) * $12.5	(h)	(i) (g)-(h)	(j) (b) * $17.92	(k) (i) - (j)	(l) Sharing Mechanism		(m)	(n) (l) + (m)	(o) (i) + (k)	(p) (l)	(q) (o) + (p)
												Efficiency Share				Efficiency Credit		
	Offsystem Sales	Achieved EE (Gross Savings)	Commission Annual EE Goal	Achieved v. Target EE Goals	Percent of EE Goals Met (%)	Net Achieved EE Goals* (MWh)	Offsystem Margin @ $12.50	Base Rate Credit Amount $10 MM	Net Offsystem Margin	Lost Distribution Margin @ $17.92	Net Margin	Utility	Ratepayer	Total		Utility	Ratepayer	Total
	----------	----------	(MWh)	----------			----------	----------	----------	----------	----------	(million $)	----------	----------	----------	----------	----------	----------
Scenario 1: Vectren South Meets Energy Efficiency Goals																		
Year 1	1,500,000	16,005	16,005	-	100%	12,804	$ 18.8	$ 10.0	$ 8.8	$ 0.229	$ 8.5	$ 4.3	$ 4.3	$ 8.5		$ 4.5	$ 4.3	$ 8.8
Year 2	1,500,000	25,715	25,715	-	100%	20,572	$ 18.8	$ 10.0	$ 8.8	$ 0.369	$ 8.4	$ 4.2	$ 4.2	$ 8.4		$ 4.6	$ 4.2	$ 8.8
Year 3	1,500,000	35,717	35,717	-	100%	28,574	$ 18.8	$ 10.0	$ 8.8	$ 0.512	$ 8.2	$ 4.1	$ 4.1	$ 8.2		$ 4.6	$ 4.1	$ 8.8
							$ 56.3	**$ 30.0**	**$ 26.3**	**$ 1.110**	**$ 25.1**	**$ 12.6**	**$ 12.6**	**$ 25.1**		**$ 13.7**	**$ 12.6**	**$ 26.3**
Scenario 2: Vectren South Exceeds Energy Efficiency Goals																		
Year 1	1,500,000	11,507	11,507	-	100%	12,804	$ 18.8	$ 10.0	$ 8.8	$ 0.229	$ 8.5	$ 6.4	$ 2.1	$ 8.5		$ 6.6	$ 2.1	$ 8.8
Year 2	1,500,000	21,500	19,442	2,058	111%	22,220	$ 18.8	$ 10.0	$ 8.8	$ 0.398	$ 8.4	$ 6.3	$ 2.1	$ 8.4		$ 6.7	$ 2.1	$ 8.8
Year 3	1,500,000	29,000	26,276	2,724	110%	32,000	$ 18.8	$ 10.0	$ 8.8	$ 0.573	$ 8.2	$ 6.1	$ 2.0	$ 8.2		$ 6.7	$ 2.0	$ 8.8
							$ 56.3	**$ 30.0**	**$ 26.3**	**$ 1.201**	**$ 25.0**	**$ 18.8**	**$ 6.3**	**$ 25.0**		**$ 20.0**	**$ 6.3**	**$ 26.3**
Scenario 3: Vectren South Does Not Meet Energy Efficiency Goals																		
Year 1	1,500,000	11,000	11,507	(507)	96%	11,400	$ 18.8	$ 10.0	$ 8.8	$ 0.204	$ 8.5	$ 2.1	$ 6.4	$ 8.5		$ 2.3	$ 6.4	$ 8.8
Year 2	1,500,000	17,000	19,442	(2,442)	87%	16,900	$ 18.8	$ 10.0	$ 8.8	$ 0.303	$ 8.4	$ 2.1	$ 6.3	$ 8.4		$ 2.4	$ 6.3	$ 8.8
Year 3	1,500,000	22,000	26,276	(4,276)	84%	24,096	$ 18.8	$ 10.0	$ 8.8	$ 0.432	$ 8.3	$ 2.1	$ 6.2	$ 8.3		$ 2.5	$ 6.2	$ 8.8
							$ 56.3	**$ 30.0**	**$ 26.3**	**$ 0.939**	**$ 25.3**	**$ 6.3**	**$ 19.0**	**$ 25.3**		**$ 7.3**	**$ 19.0**	**$ 26.3**

Note: *Assumes a net-to-gross ratio of 0.80.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

By: David E. Dismukes
Consultant for:
Indiana Office of
Utility Consumer Counselor

June 25, 2010
Date

Cause No. 43839