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REGULATORY FLEXIBILITY COMMITTEE

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Authority: IC 8-1-2.5-9

MEETING MINUTES[1]

Meeting Date:	**September 18, 2013**
Meeting Time:	**1:30 P.M.**
Meeting Place:	**State House, 200 W. Washington St., Senate Chamber**
Meeting City:	**Indianapolis, Indiana**
Meeting Number:	**2**

Members Present: **Sen. James Merritt, Co-Chairperson; Sen. Rodric Bray; Sen. Michael Crider; Sen. Jean Leising; Sen. James Tomes; Sen. Jean Breaux; Sen. John Broden; Rep. Eric Koch, Co-Chairperson; Rep. Heath VanNatter; Rep. Robert Behning; Rep. David Frizzell; Rep. Jack Lutz; Rep. Alan Morrison; Rep. Edmond Soliday; Rep. Christina Hale; Rep. Matthew Pierce.**

Members Absent: **Sen. Dennis Kruse; Sen. Carlin Yoder; Sen. Lonnie Randolph; Rep. Dale DeVon; Rep. Timothy Neese; Rep. Kreg Battles; Rep. Shelli VanDenburgh.**

Representative Eric Koch and Senator James Merritt, Co-Chairmen of the Regulatory

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[1] These minutes, exhibits, and other materials referenced in the minutes can be viewed electronically at http://www.in.gov/legislative Hard copies can be obtained in the Legislative Information Center in Room 230 of the State House in Indianapolis, Indiana. Requests for hard copies may be mailed to the Legislative Information Center, Legislative Services Agency, West Washington Street, Indianapolis, IN 46204-2789. A fee of $0.15 per page and mailing costs will be charged for hard copies.

Flexibility Committee (Committee), convened the meeting at 1:30 p.m..

(1) Update from the Office of Utility Consumer Counselor (OUCC):

A. David Stippler, Indiana's Utility Consumer Counselor, discussed the OUCC's recent activities in the context of the agency's three-part mission to represent all Indiana consumers in utility matters through "dedicated advocacy, consumer education, and creative problem solving."[2] Mr. Stippler highlighted the following with respect to each element of the mission:

• Dedicated advocacy: On December 27, 2012, the Indiana Utility Regulatory Commission (IURC) approved a settlement concerning cost overruns at Duke Energy's coal gasification plant in Edwardsport, Indiana. The agreement was reached by Duke Energy, the OUCC, Nucor Steel, and a group of Duke Energy's large industrial customers. The agreement caps the project's costs and shields ratepayers from having to pay for over $900 million in cost overruns.

• Creative problem solving: The OUCC participated in a settlement agreement between Citizens Gas and LNG Indy, LLC, under which Citizens Gas will sell liquefied natural gas to LNG Indy, LLC, for use as a transportation fuel. According to Mr. Stippler, the use of liquefied natural gas in vehicles has both environmental and economic benefits.

The OUCC is also a party in a settlement agreement that is currently pending before the IURC and involves a request by Indiana Michigan Power Company (I&M) for approval to install new pollution control equipment at its generating facility in Rockport, Indiana, as required under a federal consent decree. I&M estimates the project will cost $284.7 million and seeks to incrementally recover the project's costs through utility rates. In a previous case, I&M had sought approval of a $1.4 billion project at Rockport. However, I&M filed a motion to dismiss that case after the OUCC recommended that the IURC reject that request.

• Consumer education: On July 31, 2013, southern Indiana was assigned "930" as a new area code when the IURC adopted an area code overlay to resolve the "812" numbering shortage. The OUCC has been involved in educating consumers on the different options for resolving the numbering shortage, and will continue to educate consumers on the upcoming changes during the 13-month transition period before the overlay takes effect.

Mr. Stippler also described the OUCC's activities involving the authority given to electric and gas utilities under SEA 560-2013 to petition the IURC to recover certain costs for transmission and distribution projects through a "transmission, distribution, and storage system improvement charge," or "TDSIC." Mr. Stippler reported that the first petition for cost recovery through a TDSIC was filed by the Northern Indiana Public Service Company (NIPSCO) on July 19, 2013. As required by the new law, NIPSCO submitted to the OUCC a copy of the petition filed with the IURC. The OUCC has formed a team to handle the case and has so far expended 500 staff hours and $30,000 on this single petition. The OUCC will continue to assess the impact of SEA 560-2013 on the OUCC's resources. Mr.

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[2]See Exhibit 1.

Stippler noted that the new law authorizes the OUCC to submit to the Budget Agency a request for funds sufficient to carry out the OUCC's new duties under the law.

After Mr. Stippler concluded his testimony, Representative Matt Pierce asked about an appeal of the settlement agreement reached in the case of Duke Energy's coal gasification plant in Edwardsport. Mr. Stippler answered that the appeal was filed in early September by environmental and consumer groups and is currently pending before the Indiana Court of Appeals. The groups contend that ratepayers should not have to pay for the project's cost overruns. Mr. Stippler stated that the OUCC carefully considered the appropriate level of cost recovery before entering into the settlement agreement and continues to maintain that the agreement is reasonable.

(2) Electric Grid Security:

Commissioner Carolene Mays of the IURC testified about protecting the electric grid and other critical infrastructure from cyberattacks.[3] She reported that cyberattacks are a threat not only to the electric grid and energy utilities, but also to a host of critical infrastructure industries, including the communications, water and wastewater, chemical, defense, financial, agricultural, government, healthcare, information technology, and transportation sectors. Still, energy facilities were the target of 40% of reported cyberattack attempts in 2012.

Commissioner Mays emphasized that states, the federal government, regulators, utilities, and vulnerable industries must collaborate and share best practices for preventing and preparing for cyberattacks. Recognizing the importance of such collaboration, the National Association of Regulatory Utility Commissioners (NARUC) provides a forum for state regulators to analyze solutions to infrastructure security concerns through its Critical Infrastructure Committee, which Commissioner Mays currently chairs.

Commissioner Mays assured the Committee that Indiana has been proactive in addressing cybersecurity issues, with various state and local agencies engaging in ongoing discussions with the FBI, the Department of Homeland Security, and cybersecurity experts. Utilities and transmission organizations (RTOs) have also had meetings to address preparedness. Commissioner Mays stressed that the threat of cyberattacks is dynamic and may never be mastered. However, the threat can be managed with careful planning.

(3) Electric Feed-in Tariffs:

Tim Caister and John Haselden:

Tim Caister, Director of Electric Regulatory Policy for NIPSCO, and John Haselden, Principal Engineer in the Regulatory Affairs Division of Indianapolis Power & Light (IPL), discussed their respective companies' feed-in tariff (FIT) pilot programs for customers who generate electricity through their own renewable energy facilities.[4]

In contrast to a traditional utility tariff, which sets forth a rate at which a customer may purchase electricity from a utility, a FIT specifies the price at which the utility will purchase energy produced by qualified, customer-owned facilities. Unlike in a net metering

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[3]See Exhibit 2.

[4]See Exhibit 3.

program, in which customers receive a credit on their electric bill for any excess energy they generate and return to the grid, in a FIT program, customers receive actual payments from the utility for the electricity they supply to the grid. The utility pays the customer an above-market rate that makes the customer's investment in the renewable energy facility economically viable.

Mr. Caister described various program elements under the companies' respective FITs:

- Both programs specify a minimum capacity for participating customer-owned facilities, a maximum aggregate capacity for all customer-owned facilities under the tariff, and a maximum contract term of 15 years.

- Both programs allow facilities using wind, solar, or biomass technologies to participate. NIPSCO also allows small hydroelectric facilities under its tariff.

- The price paid by the utilities for customer-generated electricity varies by the technology used, but ranges from 10.6¢-30¢/kWh under NIPSCO's tariff, and from 10¢-24¢/kWh under IPL's tariff.

Mr. Caister noted that there is an ongoing, national policy discussion about FITs. The debate includes the following considerations that utilities must weigh in deciding whether and how to implement FITs:

- Utilities can usually acquire renewable energy from producers at lower costs than through net metering and FITs.

- Utilities have to balance supporting the use of renewable energy technologies by some of their customers with having to shift the costs of that use to non-participating customers.

- Utilities must consider how to design programs with protections for non-participating customers, such as program caps on aggregate capacity and fixed charges for participating customers.

Mr. Haselden offered the following observations about the two companies' pilot programs:

- Large developers seeking federal tax incentives and subsidies dominate the customer base under both programs. In many cases, large developers own the project and the utilities' customers serve as hosts for the project.

- All of IPL's FIT customers use solar technology. The majority of NIPSCO's FIT customers use solar technology, although there are three each using wind and biomass. While NIPSCO's program allows small wind projects to participate, all of the wind capacity under the program comes from large wind projects.

- If utilities want to be able to buy and sell renewable energy credits (RECs), utilities and project owners must be careful how they characterize renewable energy projects participating in a TIF. As tradeable commodities regulated by the Federal Trade Commission, RECs can be voided if utilities take credit for the renewable energy attributes of projects under a TIF. Both IPL and NIPSCO can sell RECs.

• Phase I of IPL's solar panel installation at the Indianapolis International Airport is scheduled to begin operations by the end of September 2013. Phase I cost $30 million, represents 9.8 MW of capacity, covers 60 acres, and will generate 18.3 million kWh of electricity annually.

After Mr. Caister and Mr. Haselden concluded their presentation, Representative Alan Morrison asked for further explanation of the purpose of RECs. Mr. Caister explained that RECs can be traded among utilities. In states with a renewable portfolio standard (RPS), for example, utilities can purchase RECs to meet the required percentage of their electricity that must come from renewables. RECs have to be certified and are more valuable in states with an RPS. NIPSCO received approval for its "green power" tariff in 2013 and is still evaluating who may be interested in purchasing RECs.

Representative Pierce asked whether FITs could prove to be economically sound policy by making investments in renewable energy initially more economically attractive to customers and developers. This initial investment would in turn spark production of renewable energy components, such as solar panels, and further drive down the cost of these technologies, making renewable energy more cost competitive with fossil fuels. Mr. Caister suggested that the recent decrease in the cost of solar energy may be the result of a decline in the price of solar panels imported from China. He expressed reluctance to speculate that renewable energy incentives have created a market for these technologies and driven the price down.

Senator Jean Breaux asked whether the IPL and NIPSCO pilot programs would be extended. Mr. Caister replied that both pilot programs are for three years. NIPSCO's FIT will expire on December 31, 2013. NIPSCO is currently in discussions with interested parties about whether to continue its program. Mr. Haselden indicated that IPL's FIT expired on March 30, 2013. The company will not be accepting new projects, although construction of approved projects is continuing.

Laura Arnold:

Laura Arnold, President of the Indiana Distributed Energy Alliance ("IndianaDG"), testified on behalf of customers and developers who have participated in the FIT programs offered by NIPSCO and IPL.[5] She explained that her association's members include renewable energy and distributed generation businesses that are developing, or interested in developing, projects in Indiana. The IndianaDG membership also includes manufacturers of renewable energy systems.

Ms. Arnold reported that Indiana's two pilot FIT programs require all of the energy generated by a participating customer to be sold to the utility, with the customer continuing to buy electric service from the utility to serve the customer's own demand. She also noted that the minimum system capacity for participating facilities is 5 kW under NIPSCO's FIT and 20 kW under IPL's FIT. Because of the larger system size required under IPL's FIT, residential customers have not participated in that program. Ms. Arnold encouraged IPL to consider making any future FIT program more accessible to residential customers.

Ms. Arnold argued that the following are elements of a properly designed FIT:

• FIT pricing should reflect a utility's costs, including the avoided costs of new generation, and allow the utility to recover those costs, plus a

[5]See Exhibit 4.

reasonable rate of return that is fair to both investors and ratepayers.

• Programs should be available to a wide range of renewable energy and distributed generation technologies.

• Programs should include a contract length of 25-30 years for solar photovoltaic technologies, with a fixed price paid over the contract term.

• Programs should allow for third-party financing.

• Programs should not limit a project size to customer usage.

Ms. Arnold also noted that NIPSCO filed a petition with the IURC on September 11, 2013, to explore offering another FIT after its current pilot program expires at the end of the year. In addition, under a settlement agreement reached in August 2013 in a case involving Duke Energy's air permit for the utility's Edwardsport plant, Duke is required to either generate (or enter into long-term contracts for the purchase of) energy from wind or solar resources, or implement a solar energy FIT modeled after the current NIPSCO FIT.

Ms. Arnold stated that she was not seeking state legislation to create mandatory FITs. Rather, she urged lawmakers to consider offering incentives to encourage more voluntary FIT programs, like those offered by NIPSCO and IPL.

Representative Pierce asked Ms. Arnold to discuss how businesses other than utilities can benefit from FIT programs. Ms. Arnold observed that FITs have increased the demand for renewable energy technologies in Germany and other European countries, which in turn has benefitted manufacturers of renewable systems and components. Ms. Arnold suggested that Indiana's strong manufacturing sector could similarly take advantage of the new business opportunities that FIT programs could spur.

Representative Morrison asked about cost-shifting to non-participating customers when a utility offers a FIT program. Ms. Arnold acknowledged that in the case of a customer with a solar facility, for example, the price paid by the utility for electricity sold by the customer may be higher than the market price for electricity at the beginning of the 15 year contract with the customer. However, the rate paid by the utility will be level throughout the term of the contract, while the market price for electricity will likely rise, which means that, at some point during the contract, the utility would potentially pay less for the customer's electricity than it would otherwise pay for purchased power.

Senator Breaux asked about IPL's decision to discontinue its pilot FIT program. Ms. Arnold replied that it was reasonable for IPL to put its program on hold and wait for renewable energy projects to be developed and come online before offering another FIT. However, Ms. Arnold noted that there are many customers interested in participating in a FIT and encouraged IPL to consider making a FIT available to residential installations in the future.

(4) Customer Choice, Deregulation, and Competitive Procurement in the Energy Industry:

Kenneth Rose, Ph.D.:

Kenneth Rose, Ph.D., a power industry consultant and Senior Fellow with the Institute of Public Utilities at Michigan State University, discussed the status of states that have restructured the regulation of retail electric service, versus states that continue to regulate

retail electric service under a traditional model.[6] Dr. Rose explained that 13 states, plus the District of Columbia, have restructured retail service regulation to allow alternative suppliers to compete with incumbent electric utilities, while in the majority of states, regulators continue to grant utilities exclusive service territories in exchange for certain obligations by the utilities to provide reliable service to customers.

Dr. Rose made the following observations about national price trends for energy:

- In general, all regions of the country have experienced higher retail electric prices since the early 2000s.

- In states with restructured rate regulation, retail electric prices increased rapidly from 2002-2008 when initial government-imposed price caps came to an end. Retail prices have since leveled off in these states, due in part to the lower price of natural gas, which is used as a fuel source in electricity production.

- In states with traditional rate regulation, retail electric prices continue to increase, but are still below the prices in states that have restructured.

Dr. Rose noted that operational efficiencies are often cited as a benefit to restructuring. Proponents of restructuring have cited the lower operating costs that result when power plants are dispatched over an RTO's entire territory, rather than just for a monopoly utility's individual service area. However, Dr. Rose suggested that much of this benefit is realized at the wholesale level. He pointed out the following costs of restructuring that must be weighed against any potential efficiencies:

- Under the traditional regulatory model, vertically integrated utilities own and operate generation and transmission and distribution facilities that provide retail electric service to customers. This structure encourages capital investment in generation and transmission capacity. A restructured regulatory scheme may result in insufficient capital investment in needed infrastructure.

- "Deregulating" at the state level transfers jurisdictional authority from the state to federal regulatory authorities, primarily the Federal Energy Regulatory Commission (FERC).

- Retail competition replaces a complex and expensive regulatory system with a complex and expensive "deregulatory" system that is a composite of different markets that are highly regulated at the federal level.

Dr. Rose concluded that there appears to be no clear benefit to customers from retail rate restructuring at this time. The recent price decreases in restructured states could quickly reverse if natural gas prices increase again. He also cautioned legislators that once states restructure their regulation of retail service, it is difficult to return to a traditionally regulated structure if the new regulatory scheme does not work.

Senator Rodric Bray noted that several of the graphs included in Dr. Rose's presentation showed that Kentucky's electric retail rates are the lowest among neighboring states. He asked if Kentucy's lower prices are due to that state's reliance on coal as a generating

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[6]See Exhibit 5.

source. Dr. Rose indicated that the use of coal, along with low operating costs in general, contributed to Kentucky's relatively inexpensive electricity.

Senator Jean Leising asked whether Dr. Rose had performed an analysis comparing industrial retail rates among the states. Dr. Rose explained that industrial and residential rates generally follow the same trajectory. While the rates themselves are different between the two customer classes, the patterns in price increases and decreases are generally the same.

Senator Breaux asked whether Dr. Rose's various price graphs reflect automatic rate "trackers" that allow utilities to recover costs on an ongoing basis. Dr. Rose responded that the graphs show aggregate prices for the states represented, based on data from the U.S. Energy Information Administration (EIA). Trackers are not separated out from the EIA data and would be reflected over time.

Jennifer Terry:

Jennifer Terry, Director of Indiana Industrial Energy Consumers, Inc. (INDIEC), testified that significant regulatory reform is needed in Indiana to address the problem of rising energy costs for industrial energy consumers and other retail customers.[7] Ms. Terry made the following observations and suggestions to address the problem:

- Indiana has gone from having the fifth lowest industrial electricity prices in the nation in 2003 to being tied with New York for the 27th lowest prices in 2013.

- Because of Indiana's heavy reliance on aging coal-fired power plants and other factors, retail electric rates in Indiana will continue to rise, resulting in lost economic development opportunities for the state.

- Restructuring in other states provides a baseline of experience and data in considering retail competition.

- A one-year study period in Indiana would provide an opportunity for careful analysis of the available options to address rising retail rates.

- Indiana law should encourage non-utilities to develop private energy projects, such as co-generation facilities, waste-to-energy facilities, and renewable energy projects. Private generation projects can provide cost relief to industrial energy consumers and relieve the rate burden on all customers that results when utilities have to construct new generation facilities.

- Indiana's "alternative utility regulation act" ("AUR") should be amended to allow consumers to propose alternative regulatory plans. Under the existing statute, only energy utilities can propose alternative regulatory plans to the IURC and can veto any modifications to such plans suggested by the IURC.[8]

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[7]See Exhibit 6.

[8]IC 8-1-2.5 allows an energy utility to petition the IURC for approval of alternative regulation of the utility's energy services or rates. IC 8-1-2.5-6(c) provides that an energy utility

Representative Pierce commented that while industrial customers may benefit from retail rate restructuring, residential customers wouldn't necessarily see the same rate relief under a restructured system. Ms. Terry remarked that because of the complexity surrounding rate restructuring, INDIEC is recommending that the IURC conduct a thorough study of the issue. However, she expressed hope that increased competition at the retail level, in whatever form it takes, would benefit all ratepayers.

Philip O'Connor, Ph.D.:

Philip O'Connor, Ph.D., President of PROactive Strategies, Inc., maintained that Indiana should conduct a study to examine the possibility of allowing retail electric choice in the state.[9] He made the following arguments in support of such a study:

- Indiana is losing its retail electric price advantage and the accompanying economic benefits.

- Market conditions and federal regulatory policies warrant a re-evaluation of the traditional regulatory model's allocation of risk to customers.

- A study would be based on the actual experience of 13 states with broad-based customer choice programs.

Dr. O'Connor further discussed risk allocation in both traditional and restructured regulatory schemes, making the following observations:

- The traditional regulatory standard that requires utilities to exercise "prudence" in making investments places the burden of business and investment risk on customers, rather than on investors and a utility's management.

- States that have restructured retail electric service and given customers choice have compensated utilities for investments already made, ensuring that utilities are not burdened with stranded costs. Future investments are then made by investors on the basis of ability to compete with others to control costs and attract customers.

- Indiana policymakers should consider how the business risk should be allocated with respect to the significant upcoming investments that will be needed to replace older power plants and comply with federal environmental rules.

Finally, Dr. O'Connor stressed that service reliability is as good in states with retail choice

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that seeks alternative regulation of its services or rates shall file with the IURC "an alternative regulatory plan proposing how the [IURC] will approve retail energy services or just and reasonable rates and charges for the energy utility's retail energy service." Under IC 8-1-2.5-6(e), the IURC "may approve, reject, or modify the energy utility's proposed plan." However, the IURC may not order material modifications to the plan "without the agreement of the energy utility." An energy utility has 20 days after the date of an IURC order modifying a proposed plan to "accept or reject the [IURC's] order."

[9]See Exhibit 7.

as in states with the traditional, monopoly system. According to Dr. O'Connor, independent experts have not found customer choice to be a factor in outages or other power disruptions.

Chris Olsen:

Chris Olsen, Vice President for Community and Government Affairs at Tate & Lyle, urged legislators to consider restructuring retail electric service regulation to allow customers to choose their service supplier.[10] Mr. Olsen described Tate & Lyle as a leading global provider of specialty foods and industrial ingredients, with 30 production facilities around the world, including two plants in Lafayette, Indiana. While Tate & Lyle employs 600 people in Indiana and sees opportunities for growth in the state, the company views rising electricity costs as the single largest deterrent to expanding its Indiana operations. Mr. Olsen displayed a graph showing a comparison of electricity costs in Indiana versus those in Ohio and Illinois, both of which have restructured retail rate regulation. The graph showed that since January 2011, electricity prices in Illinois and Ohio have declined relative to those in Indiana.

Joe Clark:

Joe Clark, Manager of Government and Regulatory Affairs for Direct Energy Services, LLC, also encouraged lawmakers to consider restructuring Indiana's retail electric service market.[11] As a company that provides gas and electricity to residential, commercial, and industrial customers across the United States and Canada, Direct Energy has experience as a competitive service provider in states with restructured retail regulation. Mr. Clark showed the Committee a video featuring a small business owner who described how he was able to save money on electricity costs by purchasing his electricity from Direct Energy. Mr. Clark then described the energy plans that Direct Energy is able to offer its retail energy customers, including fixed rate, variable rate, and pre-paid plans, along with "time of use" rates that give customers more control over how they use electricity.

Mr. Clark offered the following reasons for Indiana to consider restructuring its retail electric service market:

- Seventeen states, plus the District of Columbia, have adopted some form of retail electric choice for customers.

- Restructuring has occurred in other industries, including the airline, telephone, and cable industries.

- Indiana law already recognizes that "competition is increasing in the provision of energy services in Indiana and the United States" and that traditional regulation is "not adequately designed to deal with an increasingly competitive environment for energy services." (See IC 8-1-2.5-1.)

- Customer choices at the retail level result in customer engagement and the development of innovative products.

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[10]See Exhibit 8.

[11]See Exhibit 9.

• Customers are more satisfied with services from competitive suppliers than those offered by their local utility.

Mr. Clark stressed that restructuring Indiana's retail electric service does not have to involve deregulation. Under a restructured system in Indiana, the IURC could license competitive suppliers and maintain jurisdiction over marketing practices and certain customer interactions.

Representative Morrison commented that it was difficult to draw conclusions about whether electricity prices are higher or lower in states with restructured regulatory schemes. He noted that different speakers had made different assertions in that regard. Mr. Clark responded that customers can save money in states that allow retail choice. He claimed that residential customers in Illinois and Ohio are saving money with retail choice.

Senator Breaux asked about how competitive suppliers get access to the infrastructure needed to deliver their services. She asked whether suppliers enter into leases with the incumbent electric utilities that own the infrastructure. Mr. Clark replied that Direct Energy pays "open access charges" in order to get power to its customers. He assured the Committee that the company pays its fair share.

Jason Minalga:

Jason Minalga, Manager of Commercial Analytics and Regulatory Affairs for Invenergy, LLC, proposed a competitive procurement process that would eliminate some of the existing disincentives that keep utilities from purchasing needed energy and capacity from competitive suppliers.[12] Mr. Minalga explained that in states with traditional regulation, energy utilities develop integrated resource plans that address the supply needs of customers. Generally, the utilities fulfill any identified shortfall in supply by issuing requests for proposals (RFPs) for the capacity needed. According to Mr. Minalga, despite the RFP process, utilities often end up building new generating facilities themselves, instead of entering into power purchase agreements (PPAs) with independent power producers (IPPs). Because utilities receive no rate of return on PPAs under a traditional regulatory scheme, they choose the "self-build" option to avoid potentially forfeiting profits for shareholders.

In addition, if a utility chooses the self-build option and encounters cost overruns in the construction process, it has the ability to recover these costs from ratepayers. IPPs, on the other hand, bear the entire risk if a project is completed over budget, shielding ratepayers from cost overruns. As a result, PPAs result in lower costs for ratepayers. To prevent the cost-shifting to ratepayers that can occur when utilities opt to build new generation, and to reduce the existing disincentives that discourage utilities from entering into PPAs, Mr. Minalga proposed a procurement process that would allow utilities to earn a rate of return on PPAs. Mr. Minalga argued that such a process would do the following:

• Allow utilities to balance shareholder interests with ratepayer's desires for low-cost energy.

• Reduce ratepayers' exposure to cost overrun risk.

• Allow utilities to leverage third parties to provide the capital needed to maintain supply adequacy, especially those utilities facing capital

[12]See Exhibit 10.

constraints because of generation fleet retrofit and retirement costs, transmission expansion costs, and other system improvement costs.

After Mr. Minalga presented his proposal, Senator Leising asked about the role the IURC would play in such a system. Mr. Minalga responded that the IURC would review a utility's proposal for obtaining capacity and then solicit responses from IPPs.

Representative Edmond Soliday asked why IPPs couldn't just intervene in a utility's rate case if they were unsatisfied with the decisions made by the utility. Mr. Minalga indicated that Invenergy has intervened in cases, but that it is costly for the company to intervene and results in an adversarial relationship with utilities. Representative Soliday then questioned why Mr. Minalga's proposal also wouldn't lead to adversarial dealings with utilities. Mr. Minalga suggested that by having the IURC involved in the bidding process, the proposal would allow for arm's-length dealings between utilities and IPPs.

Joe Kerecman:

Joe Kerecman, Director of Government and Regulatory Affairs for Calpine Corporation, discussed the benefits of a competitive procurement process in the provision of retail electric service.[13] He first described his company as the largest IPP in the nation in terms of megawatt hours produced. He testified that in North America, Calpine has more than 28,000 MW of generating capacity from 91 plants, which are primarily natural gas-fired. The company's generating fleet includes cogeneration plants and combined cycle plants.

Mr. Kerecman then made the following observations and arguments in support of a competitive procurement process in the retail electric industry:

- Electricity generation is capital-intensive, with a new 1,000 MW generating facility requiring a capital investment of approximately $1.2 billion.

- Under the traditional cost-of-service regulatory model, ratepayers are exposed to the financial risks associated with both the construction and operation of new, capital-intensive power plants.

- IPPs, whose core business is power generation, often have more experience in constructing new power plants than do electric utilities that have only infrequent experience with construction.

- Competitive bidding for new projects by IPPs ensures that additions are built and operated at the lowest possible cost, shifting significant financial risks away from ratepayers.

- RFPs for competitive generating capacity ensure that a utility's self-build proposal is fairly evaluated against the best alternatives the market has to offer.

Mr. Kerecman noted that NARUC has recommended that the following features be included in a competitive procurement process in order to ensure fairness and efficiency:

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[13]See Exhibit 11.

• Involvement of an independent, third-party monitor to evaluate proposals.

• Measures to ensure transparency of the procurement process to market participants and the public.

• Measures to ensure that utilities provide potential bidders with detailed project requirements, including capacity needed, generation type sought, timing, and any locational, operational, or environmental criteria.

Jodi Perras:

Jodi Perras of the Sierra Club Hoosier Chapter addressed the rising cost of electricity in Indiana and made the following observations and recommendations:[14]

• Under Indiana's existing regulatory structure, utilities must consider, but are not required to implement, the least-cost options for electricity generation.

• Volatile fuel prices and automatic rate adjustment mechanisms, or trackers, expose ratepayers to the risk of price increases.

• The use of distributed renewable generation can provide competitive business opportunities that expand economic opportunity in the state and can be implemented with ratepayer protections.

• Natural gas plants may be necessary in the near-term to help Indiana transition away from coal-fired plants. However, the use of distributed generation and efficiency measures can help Indiana eventually transition away from natural gas, further protecting ratepayers from fuel-price volatility.

Kerwin Olson:

Kerwin Olson, Executive Director of the Citizens Action Coalition, argued against customer choice for retail electric and natural gas service.[15] Mr. Olson pointed to Indiana's experience with retail competition through NIPSCO's residential choice program for natural gas service. Mr. Olson noted that all of the competitive providers available through the program offered gas service at prices significantly higher than NIPSCO's price. Mr. Olson also cited studies of customer choice programs in Illinois and New York that found participating customers paid more for natural gas and electric service than they would have paid by purchasing the services from the utility. Higher costs for consumers have also been reported for choice programs in Pennsylvania, Ohio, and Canada. Mr. Olson emphasized that the percentage increase in costs are typically higher for low-income customers. Mr. Olson concluded that retail competition in energy markets presents significant risks for consumers, including the possibility of higher prices, predatory or deceptive market practices, poor customer service from suppliers, and hidden costs associated with the transition to a restructured market.

The Co-Chairmen adjourned the meeting at 5:20 p.m..

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[14]See Exhibit 12.

[15]See Exhibit 13.

Exhibit 1
Regulatory Flexibility Committee
9/18/13

Indiana Office of Utility Consumer Counselor

Testimony to the Regulatory Flexibility Committee
September 18, 2013

Utility Consumer Counselor
www.in.gov/oucc

Overview

- OUCC's Mission Effectiveness
  - Dedicated Advocacy
  - Creative Problem Solving
  - Consumer Education
- SB 560
  - OUCC Activities to Date
  - Associated Costs

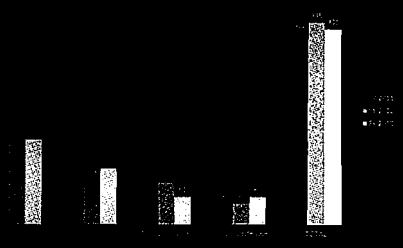
Utility Consumer Counselor
www.in.gov/oucc

OUCC Mission

- "To represent all Indiana Consumers to ensure quality, reliable utility services at the most reasonable prices possible through:
  - dedicated advocacy,
  - consumer education, and
  - creative problem solving."
- Demonstrating value for all Indiana ratepayers: Over $1B in savings in FY'13.

Utility Consumer Counselor
www.in.gov/oucc

Number of Cases With OUCC Activity During FY 2011, 2012 and 2013



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Dedicated Advocacy

- Duke Energy (IGCC Edwardsport) (Cause No. 43114 IGCC4 S1)
  - Over $900M in ratepayer savings from settlement agreement
  - Capped cost savings of over $2B over next 30 years

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Creative Problem Solving

- Citizens Gas / LNG Indy, Inc. (Cause No. 44277)
  - Approval of Liquefied Natural Gas Settlement Agreement
  - Sale of natural gas as a transportation fuel; economic and environmental benefits

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Creative Problem Solving

- Indiana Michigan Power Company (I&M) (Cause No. 44331)
  - Settlement Agreement to cost effectively meet federal consent decree requirements for the Rockport generating station

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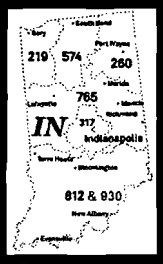
Consumer Education

- 812 Telephone Area Code Relief (Cause No. 44233)
  - Educating consumers on:
    - Options available for adding a new area code
    - Economic transition
    - www.in.gov/oucc/2718.htm
- IURC's adoption of the "930" Area Code Overlay (7/31/2013)



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SB 560
IC 8-1-1.1-6.1(h)

- "(h) The consumer counselor may submit to the budget agency a request for funds sufficient to carry out any new duties or responsibilities created under IC 8-1-39-12(b). The consumer counselor shall include in its annual report to the regulatory flexibility committee:
  (1) a description of its activities under IC 8-1-39-12(b)
  (2) a summary of the costs associated with those activities."

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TDSIC Filings

- NIPSCO: First utility filing for TDSIC relief (July 19, 2013)
- NIPSCO's "Electric Infrastructure Modernization Plan"
  - 7 year plan, 210 day IURC proceeding (Cause No. 44370)
- NIPSCO concurrently filed a 90-day "shell" petition without specific proposed rate schedules (Cause No. 44371)
- NIPSCO has waived its right to receive an IURC Order in 90 days, asking for schedule to run concurrently with 210-day proceeding

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TDSIC Filings

- NIPSCO's approach recognizes this is its initial filing under the new law
- It further recognizes that the IURC must determine the appropriate cost allocation methodology before approving rate schedules
- NIPSCO's 7-year Plan projects the expenditures of about $1B over the term

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TDSIC Filings

- OUCC activities to date
  - Formulation of initial case team
  - Review and analysis of NIPSCO filings underway
  - OUCC's testimony due on Oct. 11, 2013
  - Keeping track of costs related to activities
  - Ongoing assessment of new law's impact on OUCC resources

Utility Consumer Counselor
www.in.gov/oucc

Contact Information

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Toll Free: 1.888.441.2494

Exhibit 2
Regulatory Flexibility Committee
9/18/13

Protecting the Grid

Energy & Cybersecurity

9.18.2013

Carolene Mays

Commissioner

Indiana Utility Regulatory Commission

Celebrating a century of service to the Hoosier state.

Indiana Utility Regulatory Commission

IURC

Cyber Attacks Threaten:

privacy

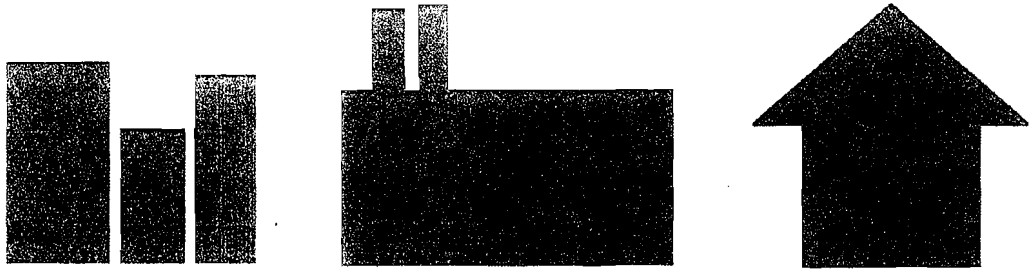
reliability

safety

resiliency

Critical Infrastructure Sectors

1. Chemicals
2. Commercial Facilities
3. Communications
4. Critical Manufacturing
5. Dams
6. Defense Industrial Base
7. Emergency Services
8. Energy
9. Financial Services
10. Food and Agriculture
11. Government Facilities
12. Healthcare and Public Health
13. Information Technology
14. Nuclear Reactors, Materials, and Waste
15. Transportation
16. Water and Wastewater



85% of critical infrastructure is privately held

Cyberattacks Against U.S. Corporations are on the Rise

-David E. Sanger & Nicole Perlroth, The New York Times, May 12, 2013

Should Companies Be Required to Meet Certain Minimum Cybersecurity Protections?

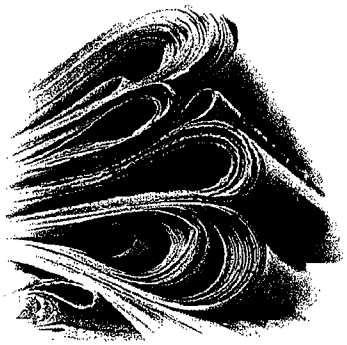
-Siobhan Gorman, Wall Street Journal, May 10, 2013

Power Hacking - Electric utilities are a growing target for international cyberattacks

-Daniel James Devine, World Magazine, June 29, 2013

NSA Chief Says U.S. Highly Vulnerable to Cyber Attack

- Deborah Charles, Reuters, June 12, 2013



Syrian Hackers Try to Attack Haifa's Water Supply

- Peak Water.org

Cybersecurity Global Tensions on the Rise

-Mickley McCarter, Judi Hasson & Dan Verton, Homeland Security Today, April 2013

Significant Cyber Attacks

Homeland Security Today Magazine, April 2013

April 2012 - Internal computer attack on Iranian oil facilities

May 2012 - Cyberespionage malware discovered on Iranian Oil Ministry computers

July 2012 - 800 critical infrastructure engineering firms, government agencies, financial houses and academia attacked by virus

Aug. 2012 - 30,000 Aramco computers attacked by virus

Sept. 2012 - Hackers attack banks (Bank of America, Chase, NYSE, etc.)

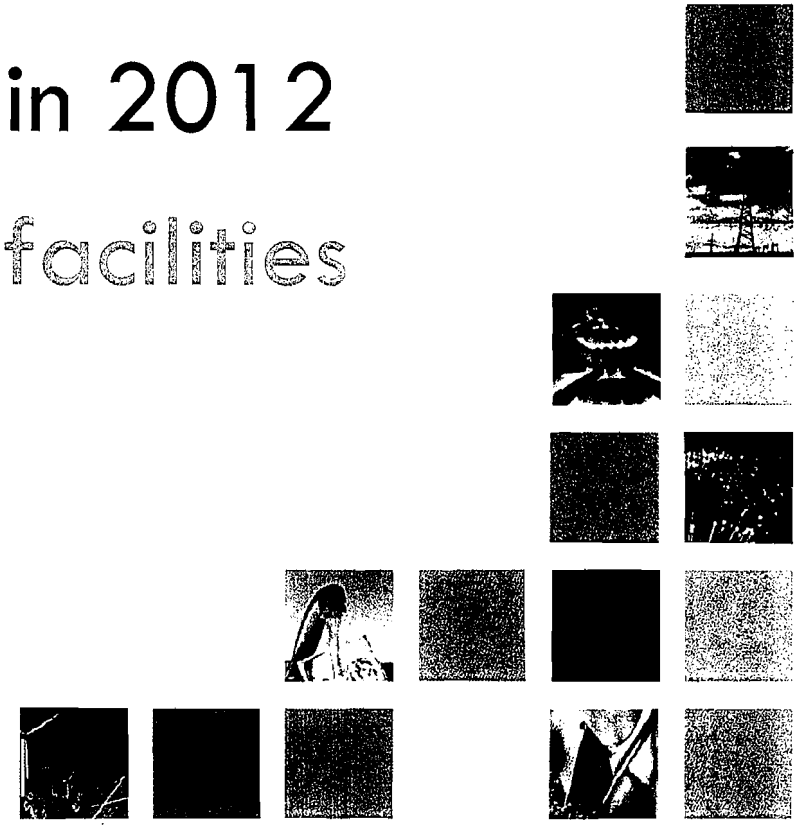
Dec. 2012 - Two power plants in the U.S. attacked by malware

Jan. 2013 – U.S. banks attacked again, including Ally, Capital One and PNC

Feb. 2013 - DHS reports that cyber criminals targeted 23 gas pipeline companies and stole information, potentially to be used for sabotage

The Numbers

40% of reported cyber attack attempts in 2012 were on energy facilities



Cyber Attacks Can Be Devastating

We Must Be Vigilant

- States
- Federal Government
- Regulators
- Utilities/Industry

. . . we all have a role

What Should We Be Doing?

- Communicating
- Collaborating
- Building on lessons learned
- Sharing
  - Best practices
  - Concerns

NARUC's Efforts

- Educational opportunities
- Cybersecurity for state regulators primer
- Critical Infrastructure Committee

Themes = Ask Questions & Be Proactive

It is our duty as regulators

What's Indiana Doing?

- We have been proactive
  - Cyber training
  - Continued discussion with FBI, DHS, and cybersecurity experts
  - Meetings with utilities and RTOs
- We have encouraged dialogue
  - State law allows confidential executive sessions under IC 5-14-1.5-6.1(b)(13)

The Threat is Real

It is *dynamic*.

We may never *master* it.

But, we can *manage* it.

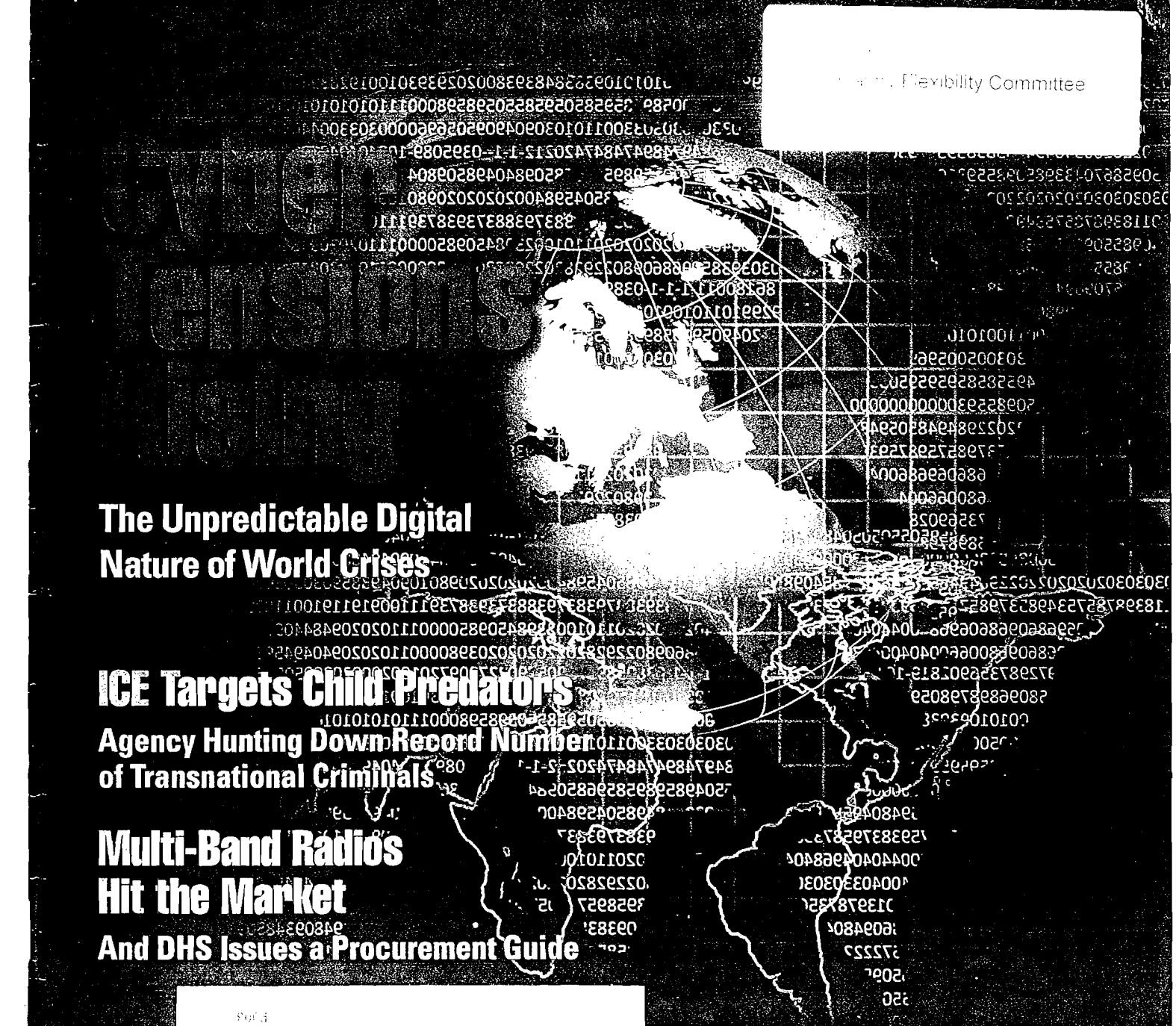
Questions?

The Rising 10 of 2013: The Innovators Edition

HOMELAND SECURITY TODAY™

April 2013 Vol. 10, No.3 $5.95 USD

INSIGHT & ANALYSIS FOR GOVERNMENT DECISION MAKERS



The Unpredictable Digital Nature of World Crises

ICE Targets Child Predators

Agency Hunting Down Record Number of Transnational Criminals

Multi-Band Radios Hit the Market

And DHS Issues a Procurement Guide

Flexibility Committee

HS117 1350B
FIRM: CARRT LOT: C-017

WWW.HSTODAY.US

United States and its allies in similar ways. Meanwhile, Russia and China, two nations with strong cybercapabilities but maintaining normal diplomatic relations with much of the Western world, would be more likely to explore cyberespionage to gather intelligence.

"Iran is the world's largest state sponsor of terrorism and continues to pursue nuclear weapons to 'wipe Israel off the map.' In that sense, I believe we are dealing with a potentially irrational actor, which makes the Iranian cyber threat even more dangerous," said Rep. Patrick Meehan, (R-Pa.), chairman of the House Homeland Security Committee's Subcommittee on Cybersecurity, Infrastructure Protection, and Security.

"The U.S. government must make clear to the Iranians our 'red lines' and make clear to them that if they escalate any cyberattacks against US critical infrastructure, we will respond appropriately," he added.

Ilan Berman, vice president of the American Foreign Policy Council, told the hearing the threat is real and growing more intense as Iran moves toward developing a nuclear bomb. International experts say Iran is about a year away from completing its first nuclear weapon.

The past year has seen the Iranian regime evolve significantly in its exploitation of cyberspace as a tool of internal repression, Berman told the hearing.

April 2012
Iran is forced to disconnect key oil facilities after a cyber attack against internal computer systems.

May 2012
Malware code-named "Flame" is discovered in computers in the Iranian Oil Ministry, as well as in other Middle Eastern countries, including Israel, Syria, and Sudan, and other nations around the world. Flame is later determined to be a sophisticated cyberespionage tool.

July 2012
A Trojan nicknamed "Mahdi" is discovered gathering data from approximately 800 critical infrastructure engineering firms, government agencies, financial houses, and academia throughout the Middle East and beyond, predominantly in Israel and Iran. The virus contains Persian language strings.

August 2012
A group called "Cutting Sword of Justice" linked to Iran claimed it has used the "Shamoon" virus to attack Aramco, a major Saudi oil supplier, deleting data on 30,000 computers and infecting control systems. The attack also affected the Qatar company RasGas, a major LNG supplier. Other oil companies may have also been infected.

September 2012
Izz ad Din al-Qassam, a hacker group linked to Iran, launched "Operation Ababil" targeting bank websites for sustained denial-of-service attacks. Targets include Bank of America, New York Stock Exchange, Chase Bank, Capital One, SunTrust, and Regions Bank.

December 2012
The U.S. Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) reported that two power plants in the U.S. suffered sophisticated malware infections using unprotected USB drives as an attack vector.

January 2013
Izz ad-Din al-Qassam claims responsibility for another series of distributed denial-of-service attacks against US Bank websites, as part of "Operation Ababil," phase two. Targets include: Ally Financial, BB&T, Capital One, Fifth Third Bank, HSBC, PNC, Wells Fargo, SunTrust, and Zions Bank. US officials speculate that the group is a front for a state-sponsored campaign attributed to Iran.

February 2013
The Department of Homeland Security issued a restricted report, revealing that from December 2011 through June 2012, cyber criminals targeted 23 gas pipeline companies and stole information that could be used for sabotage purposes. The report does not mention China, but experts trace the digital signatures of the attacks to a Chinese cyber espionage group.

Source: Excerpted from Significant Cyber Events, Center For Strategic and International Studies.

Discussion of Feed-in Tariff Pilot Programs

September 18, 2013

Presentation to the Regulatory Flexibility Committee of the Indiana General Assembly

Indiana ENERGY Association

1

Outline of Discussion

- Purpose & Variables of a Feed-in Tariff
  - Purpose and Design of Feed-in Tariffs (FIT)
  - Comparison of Pilot Programs
  - Pricing Considerations
  - National Policy Discussion
- Observations of the Programs
  - IPL & NIPSCO
  - General Observations
  - Renewable Energy Certificates (RECs)
- IND Solar Farm (Indianapolis Airport) Update

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PURPOSE & VARIABLES OF A FIT

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Design of a Feed-in Tariff (FIT)

- Purpose of the Pilot FIT Programs:
  - Determine the types of technologies that work within the framework
  - Determine customer interest in FIT, and provide a defined program for FIT customers
  - Identify contract issues that arise
  - Identify other market drivers
  - Determine how these projects interact within our distribution systems
- Program design considerations:
  - Contain rate impacts on all other customers
  - Differing unit output and capital costs
  - Significant tax subsidies
  - Renewable generation costs more than conventional resources
  - Utility-specific reasons to explore biomass

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Differences between Feed-in Tariffs and Net Metering

	NIPSCO FIT	IPL FIT	Net Metering
Summary	Each program provides: opportunity for customers to participate in renewable generation, above-market incentive / subsidy to support development of such facilities and defined terms and conditions for participation		
Payment	Payment check sent to customer for production	Payment check sent to customer for production	No exchange of money; simply a billing credit mechanism
Program Cap	30 MW with small facility carve-outs	Approx. 1% of sales = Approx. 100 MW	1% of System peak load
Contract	15 years, monthly payments, fixed prices	15 years, monthly payments, fixed prices	Indefinite term, Excess kWh credited to next month's bill
Project Size	5 kW - 5 MW	20 kW - 10 MW	Up to 1 MW
Technologies	Wind, Solar PV, Biomass, New Hydro	Wind, Solar PV, Biomass	Wind, Solar PV, New Hydro
Purchase Rate	Varies by Technology: $0.10 - $0.30/kWh	Varies by Technology: $0.075 - $0.24/kWh	Bill credit at full retail rate
Environmental Attributes	Included in purchase price, retained by utility	Included in purchase price, retained by utility	Retained by Customer

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Feed-in Tariff Pricing Variables

- Estimated energy outputs for representative project(s) for each technology
- Contract term
- Capital cost of installation
- Operations and maintenance costs
- Discount rate for purposes of financing
- Federal investment tax credit
- Tax effect of accelerated depreciation
- Inflation

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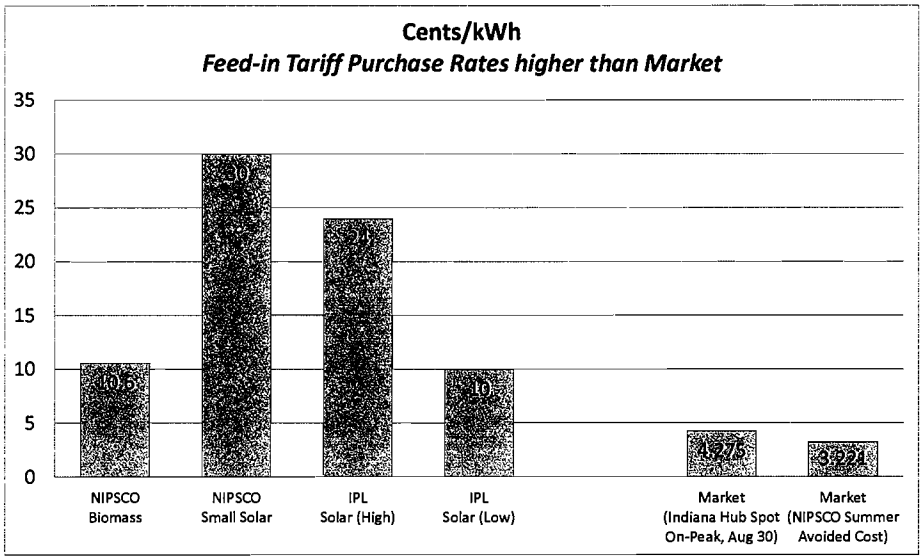
Relative Power Prices



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National Policy Discussion

- Debate Continues
  - Typically renewable energy can be acquired by the utility from producers at lower costs than through net metering and feed in tariffs
  - Balance between support of renewable energy growth and cost-shifting to non-participating customers
  - Protections for other customers such as program caps / fixed charges
- Fitch Bond Rating Agency (July 2013)
  - "Integrating renewable and energy efficiency policies into an equitable customer rate design remains among the largest challenges facing the U.S. utility industry."

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National Policy Discussion (cont.)

- Federal Energy Regulatory Commission
  - Chairman Jon Wellinghoff (July 23, 2013)
    - He recently said that solar generation should not continue to receive subsidies after the initial set of incentives and should instead compete on a market basis with other technologies.
    - *Yes, it's good to jump-start these technologies initially with some types of subsidies…[b]ut I personally believe that subsidies should be reduced and then eventually eliminated so that we can all compete on a market basis and so consumers can see prices in those markets and then respond to those prices and make decisions based upon that.*

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OBSERVATIONS OF THE PROGRAMS

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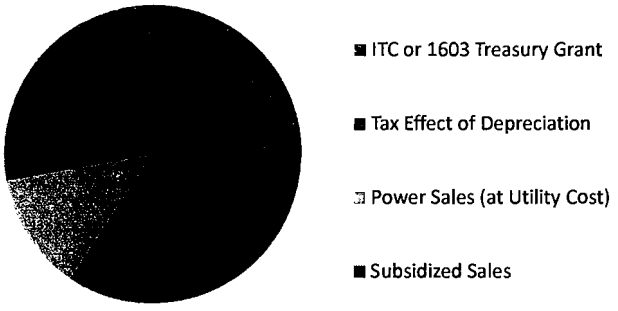
Incentives and Subsidies

- Federal government offers incentives such as you might find in European FITs, but these are not national mandates
- Tax incentives and subsidy are drivers to any renewable development
- Large developers dominate the marketplace due to tax incentives

Typical Solar Project Revenue Sources



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Observations - IPL

- Customers are not interested in large projects except as a host
- Some customers are interested in owning small scale projects

IPL Projects	Count	KW
Customer Owned	9	2,817
Third Party Owned	31	96,321

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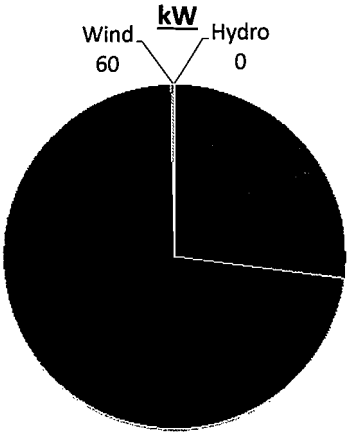
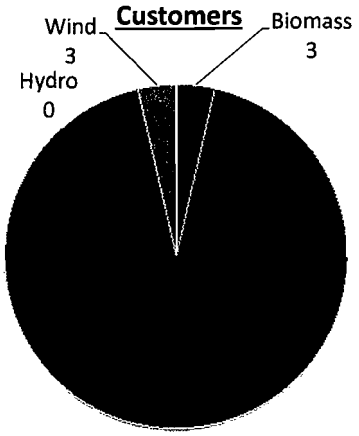
Observations – NIPSCO in-Service (as of September 3, 2013)





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Customer Impacts - NIPSCO

- Developers' use of the Queue
- Developers cooperate with customers
  - Use of the assignment clause in contracts
- 16 large projects connected in the FIT
  - 15 have completed or have a pending assignment
- Waivers of 12 month requirement

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General Observations

- Development of larger projects may be better suited in the context of Integrated Resource Planning (IRP)
  - Integrated planning for the entire system
  - Compliance with mandates
  - Optimal siting
  - Project quality, control of operations
  - Assurance projects will be completed
- Technology costs and tax incentives change quickly
- Jurisdictional factors
- Safety and power quality

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Renewable Energy Credits (RECs)

- 1 MWH = 1 REC
- Tradable commodity
  - Regulated by the Federal Trade Commission
- Oversight
  - Utilities, producers and owners must be careful how they characterize the projects
  - Taking credit for the renewable energy attributes can void the RECs
- RECs can be sold by IPL and NIPSCO

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IND SOLAR FARM

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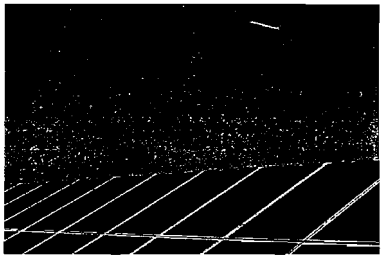
IND Solar Farm Update - Characteristics

- Over 41,000 PV panels
- Annual generation = 18,300,000 kWh
- Covers 60 Acres
- Phase I Cost = Approx. $30 million
- Owned by ET Energy Solutions
- Phase I = 9.8 MW



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IND Solar Farm Update – 9.8 MW

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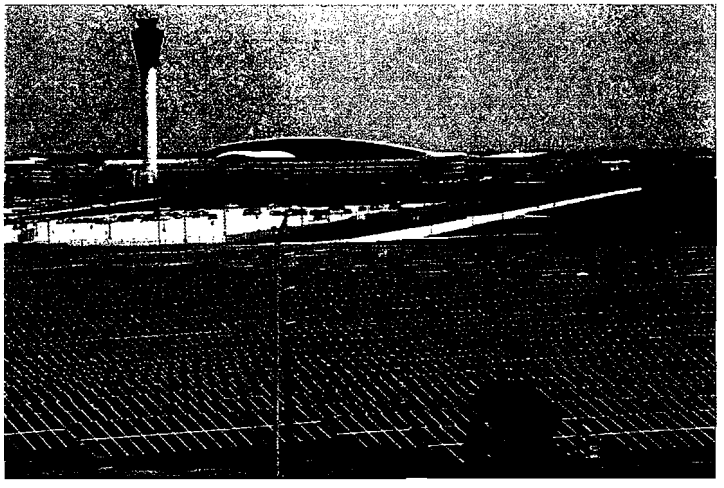
IND Solar Farm Update



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QUESTIONS?

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Presentation on 9/18/13 to the
Regulatory Flexibility Committee

by Laura Ann Arnold, President
Indiana Distributed Energy Alliance
(Presentation available at IndianaDG.net)

Rationale for Indiana Voluntary Feed-in Tariffs (VFITs)

Our Mission Statement

- To be the voice of the renewable energy (RE) and distributed generation (DG) business, educational and public sectors in Indiana to advocate public policies and to foster economic growth which fosters this business sector, creates jobs, promotes national security, provides stabilized energy resources and improves the quality of the environment.

IndianaDG Members

- Renewable energy and distributed generation (RE&DG) developers both located in Indiana doing projects here and elsewhere across the country, as well as developers located outside the state either doing business or wanting to do business in Indiana
- Manufacturers of RE systems
- Supporting non-profits and individuals wanting to develop a project

Properly designed VFIT #1

- The key element of a feed-in tariff is to set a price that reflects the cost of generating the energy, including a reasonable rate of return that is fair and equitable to both investors and ratepayers.
- A Properly Designed Feed-in Tariff Can Lower the Cost of Capital and Keep Electric Rates Down

Properly designed VFIT #2

- Properly designed FIT pricing is generally designed the same way that regulators set electricity rates, by looking at a utility's costs – including investments in new generation – and setting rates at a level to recover those costs plus a reasonable rate of return to their investors.

Properly designed VFIT #3

- The rate of return is critical, because there is evidence that the necessary rate of return under a feed-in tariff program can be lower than the typical rate of return that utilities require. This means that renewable energy is cheaper with a feed-in tariff than without a feed-in tariff.

VFIT Golden Rule

- Golden Rule: Do onto others as you would have them do unto you.
- VFIT Golden Rule: Treat VFITs like electric utilities treat themselves, i.e. VFIT contracts should reflect the cost of generation including a reasonable rate of return that is fair and equitable to both investors and ratepayers.

What's a good Indiana VFIT?

- Collaborative process to establish terms and conditions as well as rates
- Broad range of renewable energy and distributed generation technologies
- Contract length of 25-30 years for solar PV
- Allows third party financing
- Does not limit project to customer usage
- Transparent selection process
- Reasonable milestones

Advanced Renewable Tariffs

- Tariffs based on cost of generation
- Differentiation by technology, project size, application and density
- For example, solar PV tariff could depend on:
  - Solar PV integrated into building design;
  - Solar PV panels installed on the roof; or
  - Solar PV ground mounted.

FITs not just for IOUs

- FIT programs of US municipalities include:
  - Gainsville Regional Utilities (FL)
  - Sacramento Municipal Utility District (SMUD)
  - Long Island Power Authority (LIPA)
  - Los Angeles Department of Water and Power (LADWP)
  - Palo Alto (CA) Municipal Utility

Cogeneration & Alternate Energy Production Rates

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
IPL peak	$0.0299	$7.42	$0.0282	$7.30
IPL off-peak	$0.0257		$0.0246	
Duke	$0.02851	$7.05	$0.033687	$9.85
I&M TOD peak	$0.0234	$8.56	$0.0274	$8.70
I&M off-peak	$0.0223		$0.0241	
NIPSCO peak	.03221-.0399	$5.45	.03533-.03990	$5.49
NIPSCO off-peak	.02377-.02847		.02196-.02631	
Vectren peak	$0.03882	$4.81	$0.04077	$5.03
Vectren off-peak	$0.03428		$0.03603	

170 IAC 4.1. Cogen & Alternate Energy Production Facilities

- **170 IAC 4-4.1-4 Filing of rate data—annually**
  170 IAC 4-4.1-5 Obligation to purchase and sell
  170 IAC 4-4.1-8 Rates for energy purchase
  170 IAC 4-4.1-9 Rates for capacity purchase

History of Indiana VFITs

Indianapolis Power and Light (IPL) Rate REP & Northern Indiana Public Service Company (NIPSCO) Experimental Rate 665 Renewable FIT

IPL Rate REP History

- Cause No. 43623
  - Petition filed 12/29/08
  - Order issued 2/10/10
- Cause No. 43960
  - Petition filed 10/13/10
  - Motion to temporarily suspend Rate REP 2/7/11
  - Order issued 11/22/11

IPL Rate REP History con't

- Cause No. 44018
  - Petition filed 4/11/11
  - Order issued 03/07/2012
  - Tariff expired 3/30/2013
  - All projects with IURC approved contracts must be commissioned by ???

NIPSCO VFIT 1.0 History

- Cause No. 43922 filed 7/16/10
- Technical conference held 10/04/10
- Settlement Agreement filed 4/18/11
  IURC order issued: 7/11/2011
- Two stakeholder annual meetings held in
  - Goshen on 7/18/12; and
  - Munster on 8/1/13

NIPSCO VFIT 1.0 expires 12/31/13

NIPSCO VFIT 2.0

NIPSCO filed petition with IURC 9/11/13 in Cause No. 44393 to explore another VFIT

- Prehearing conference TBA
- Technical conference TBA
- IndianaDG filed petition to intervene 9/15/13

Duke Air Permit Settlement

- Duke Energy Indiana (DEI) enters into Settlement Agreement on Edwardsport air permit on 8/28/13 requiring DEI to either:
  - Implement a feed-in tariff for Solar PV modeled on the current NIPSCO FIT; <u>or</u>
  - Construct/install, and/or execute a long term contract with one or more independent producers for energy and capacity from wind and/or solar with a combined nameplate capacity of no less than 15 MWs (minimum shall be 5 MW solar).

Possible Duke VFIT

- Duke Energy Indiana (DEI) VFIT:
  - Implemented in DEI service territory;
  - Total program cap no fewer than 30 MW;
  - No fewer than 5 MW to be reserved for small systems (no larger than 10 kW in size); and
  - Be requested in a filing not later than 6/1/14.

Settlement not to preclude DEI and Petitioners from collaborating on other or additional VFITs.

IPL vs. NIPSCO VFIT Rates

IPL RATE REP

- Wind 50-100 KW: $0.14/kWh
- Wind 100 kW-1 MW: $0.105
- Wind > 1 MW:$0.075/kWh
- Solar 20-100 kW: $0.24/kWh
- Solar >100 kW: $0.20/kWh
- Biomass 50 kW- 1 MW: $.085

NIPSCO RATE 665

- Wind ≤ 100kW: $0.17/kWh
- Wind 101kW-2MW: $0.10/kWh
- Solar ≤ 10kW: $0.30/kWh
- Solar 11kW-2MW: $0.26/kWh
- Biomass ≤ 5MW: $0.106/kWh
- New Hydro ≤ 1MW: $0.12/kWh

Conclusion, Next Steps?

What steps or actions can be taken to encourage more electric utilities to offer VFITs in Indiana?

What happens at the end of current 15 year VFIT contracts?

- To give VFIT customers option to net meter, net metering rule needs to be revised to:
  - Allow net metering > 1 MW; and
  - Allow third party net metering.

References and resources

- Provided upon request

Contact information

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  Indianapolis, IN 46202
  (317) 635-1701
  (317) 502-5123 cell
  Laura.Arnold@IndianaDG.net or
  Laura.Arnold@thearnoldgroup.biz

IndianaDG Social Media

- Subscribe to website
- Follow IndianaDG on Twitter
  Like our Facebook Page
  Join IndianaDG LinkedIn Group

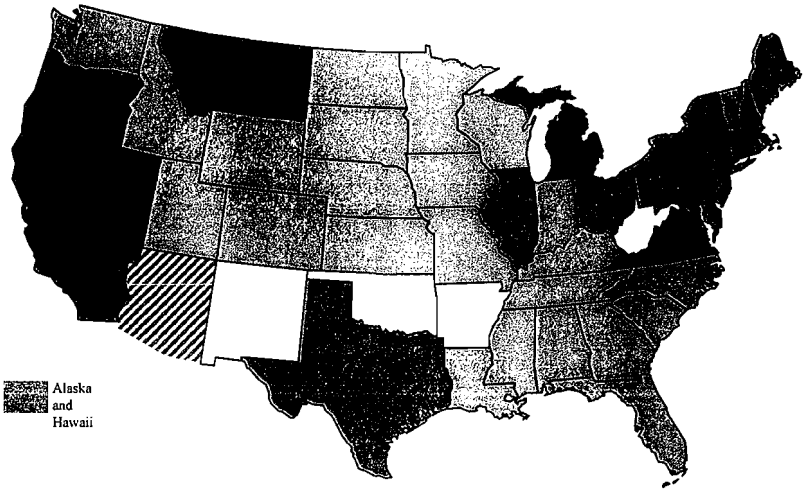
Exhibit 5
Regulatory Flexibility Committee
9/18/13

Comparing re[illegible] in [illegible] States

REGULATORY FLEXIBILITY COMMITTEE
INDIANA GENERAL ASSEMBLY
INDIANAPOLIS, INDIANA
SEPTEMBER 18, 2013

Ken Rose
Independent Consultant and
Senior Fellow with the Institute of Public Utilities
WWW.IPU.MSU.EDU

Status of State Restructuring



Allow retail access (13+DC)

Limited access (5) – see summary at right;

Not considering restructuring at this time (26)

Retail access suspended (CA)

Restructuring law repealed or delayed (4)

Retail access with generation price control (AZ)

MI: alternative suppliers limited to maximum of 10% of electric utility's retail sales

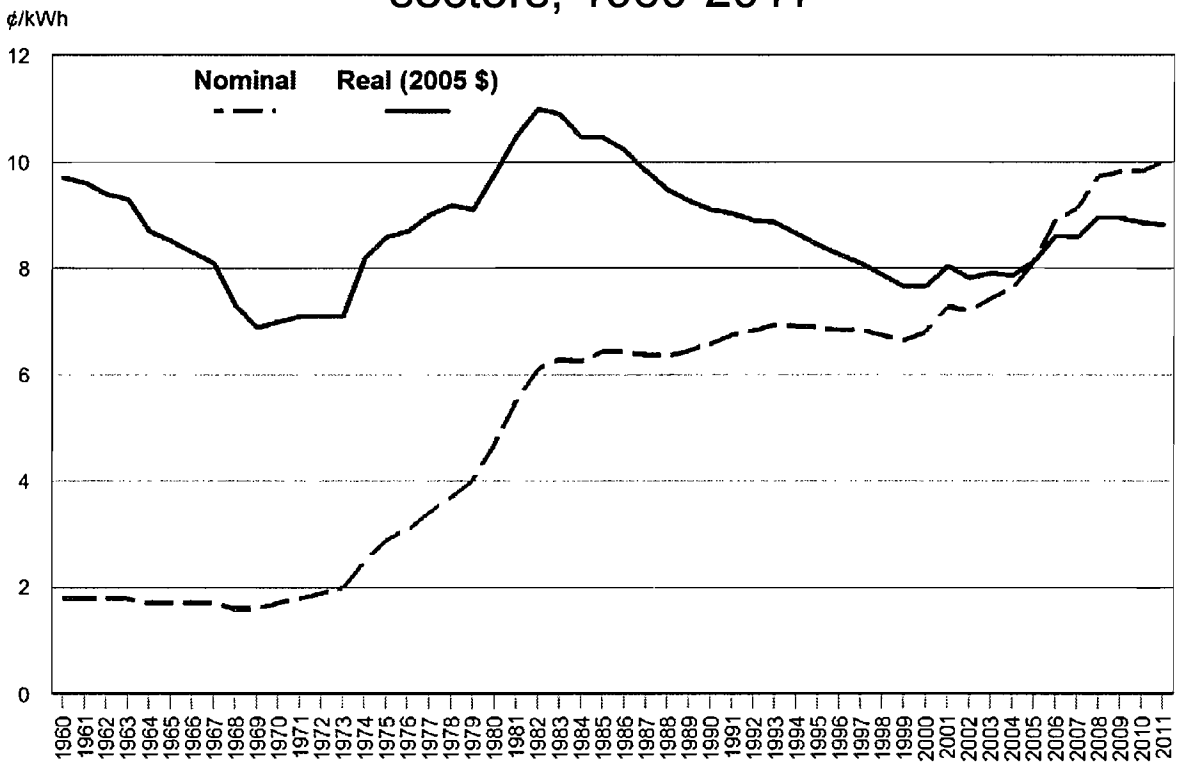
MT: Retail access repealed for customers < 5 MW and for all customers that choose utility service

NV: retail access limited to large customers > or = 1 MW, with permission of the PUC

OR: nonresidential consumers of PGE and Pacific Power have option to buy electricity from an alternative provider

VA: Retail access ended for most customers -- except those >5 MW (w/conditions for return)

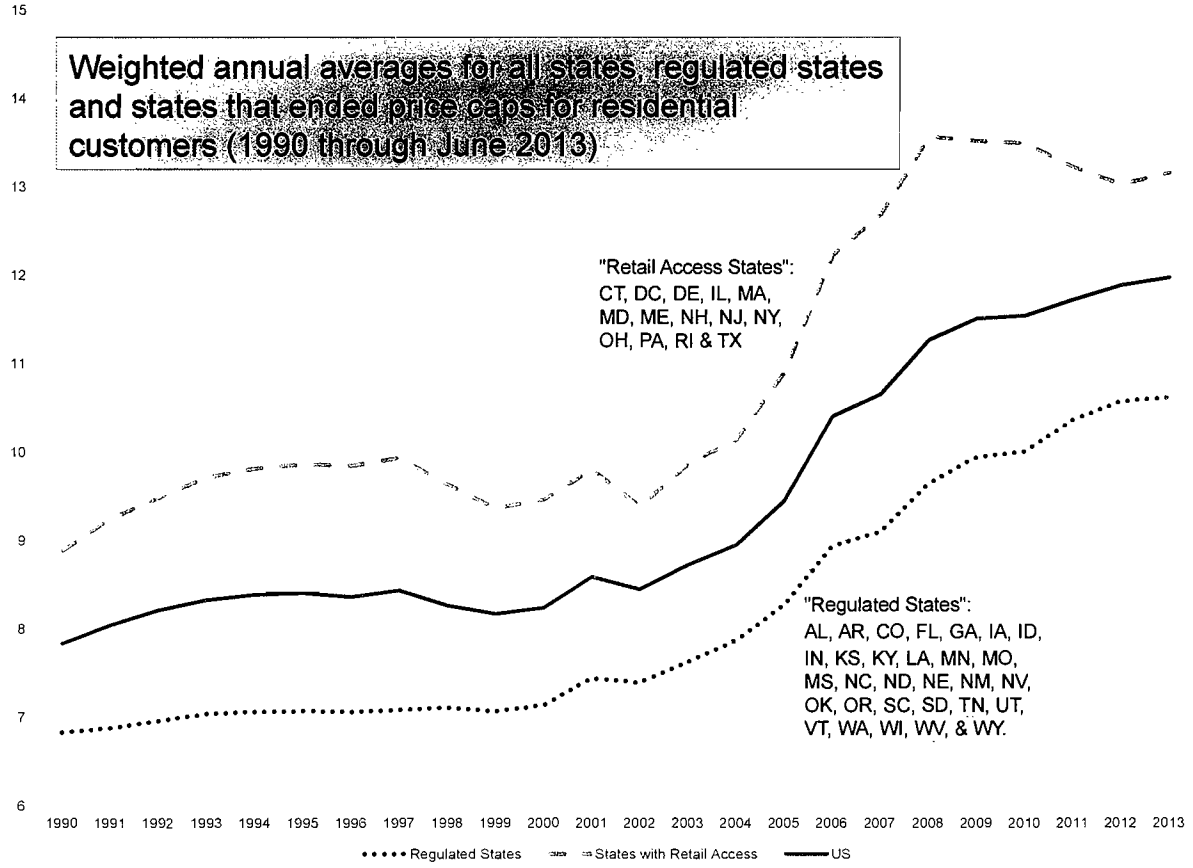
Average retail price of electricity, all sectors, 1960-2011



Data source: DOE/EIA.

Some National Price Trends

- Generally, all regions of the country are seeing higher prices since early 2000s
- Wholesale prices have fallen since 2008, and been roughly steady since
- Restructured state prices increased rapidly from 2002 until 2008, and have since leveled off (small decrease)
- For states that still regulate, prices continue to increase, but are still below states that restructured
- Can discern no clear and consistent pattern of benefit to consumers from retail access at this time



5

Data source: DOE/EIA.

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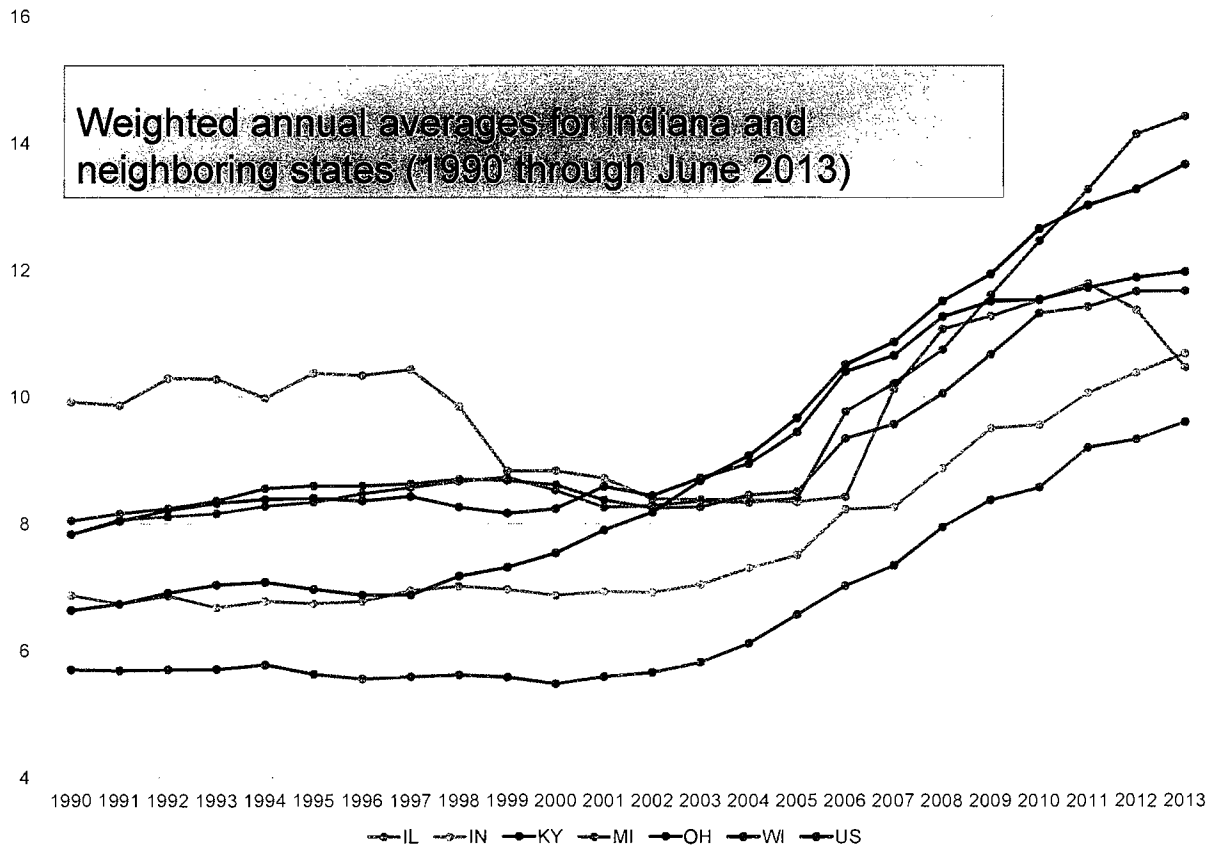
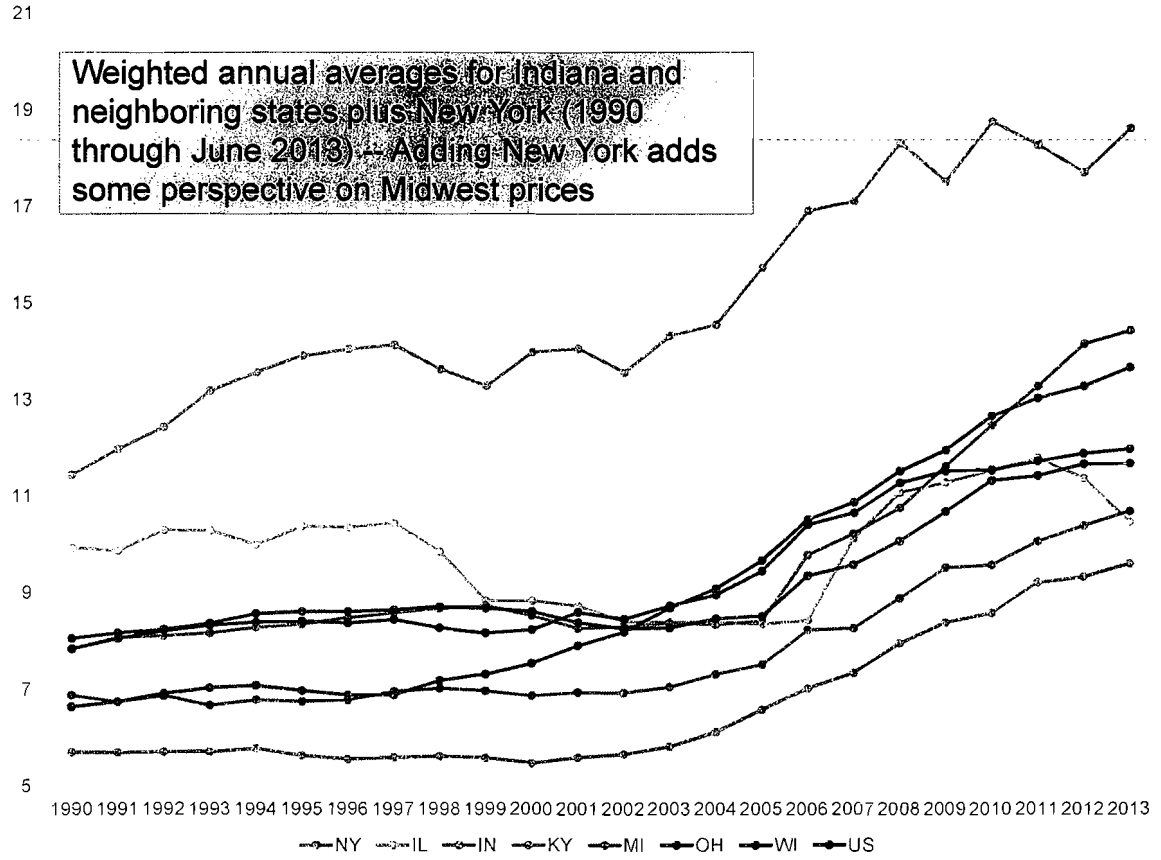
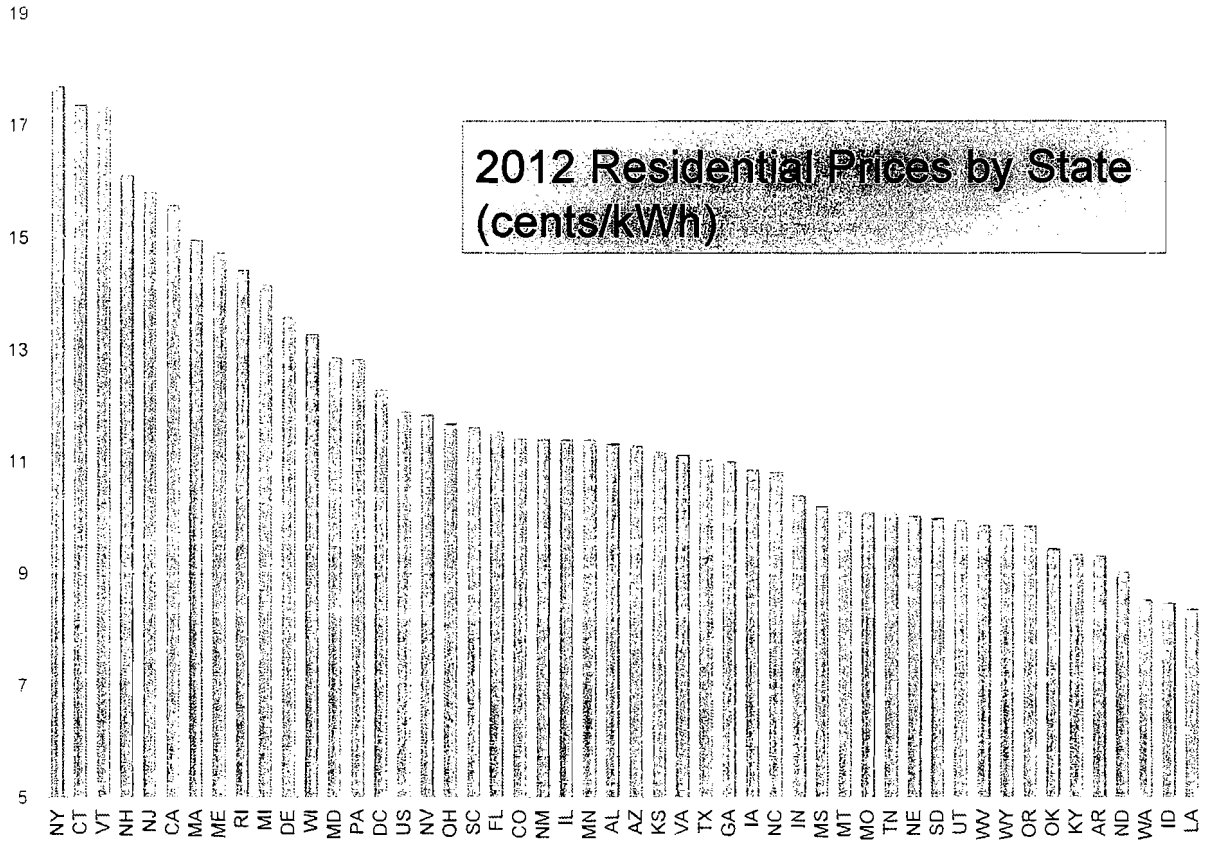


6

Data source: DOE/EIA.

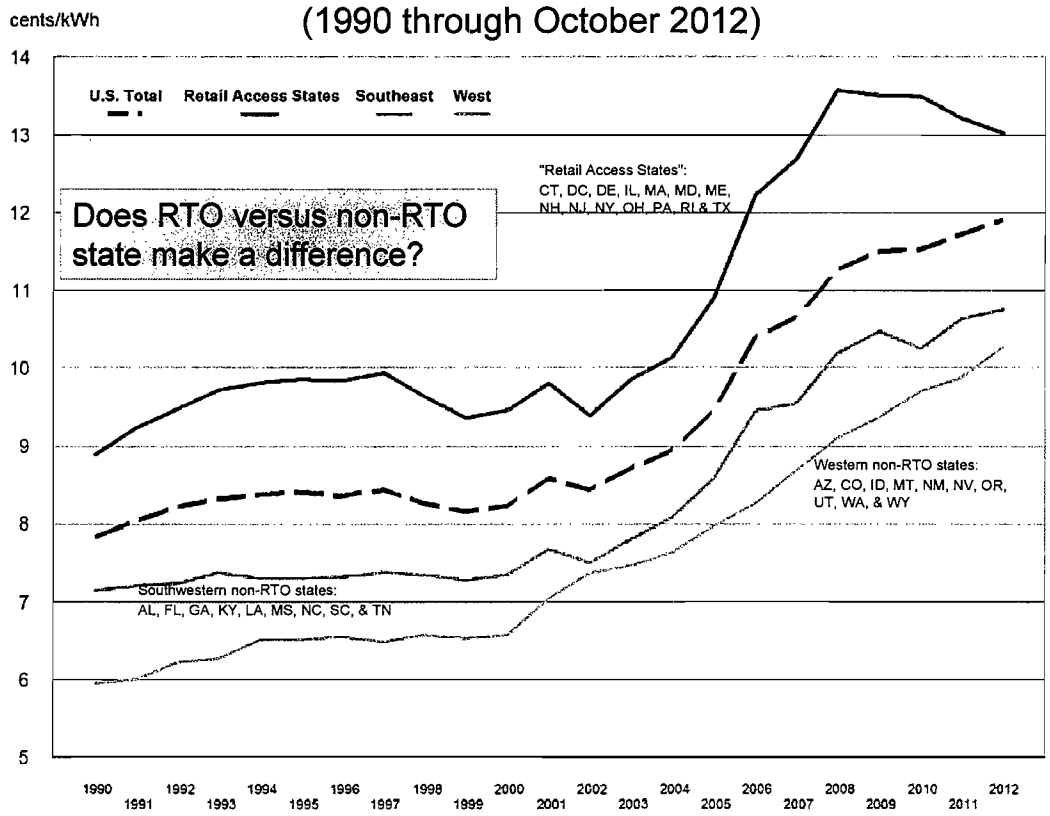
Ken Rose -- Sept. 18, 2013





Data source: DOE/EIA.

Weighted annual averages for all states, non-RTO states and states that ended price caps for residential customers (1990 through October 2012)

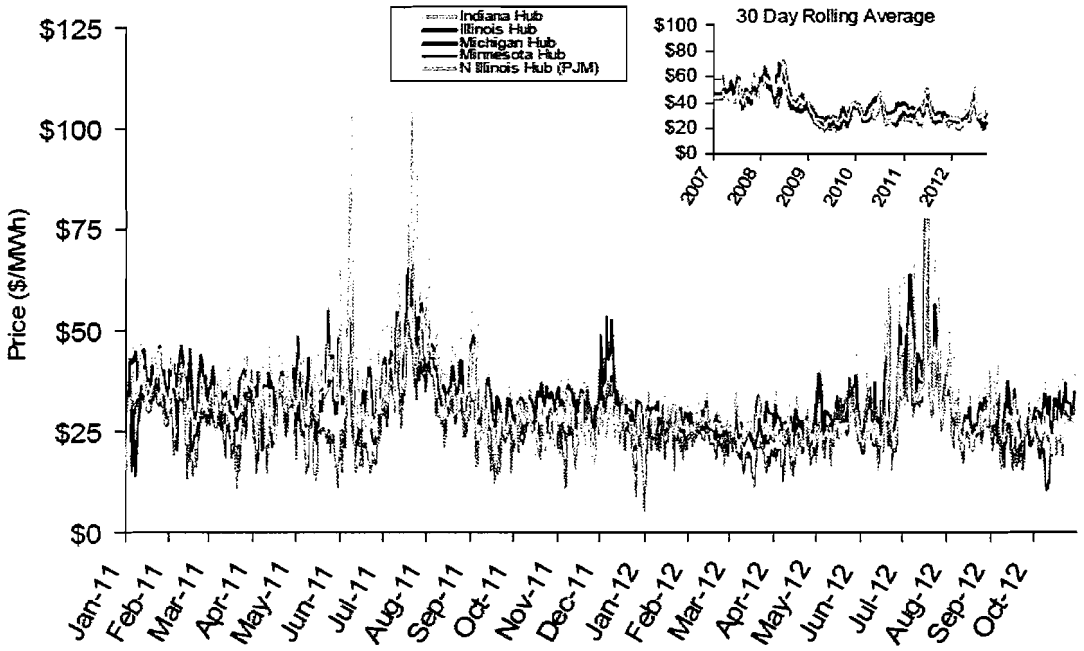


Data source: DOE/EIA.

Why are most states seeing higher prices (even though fuel prices have been falling)?

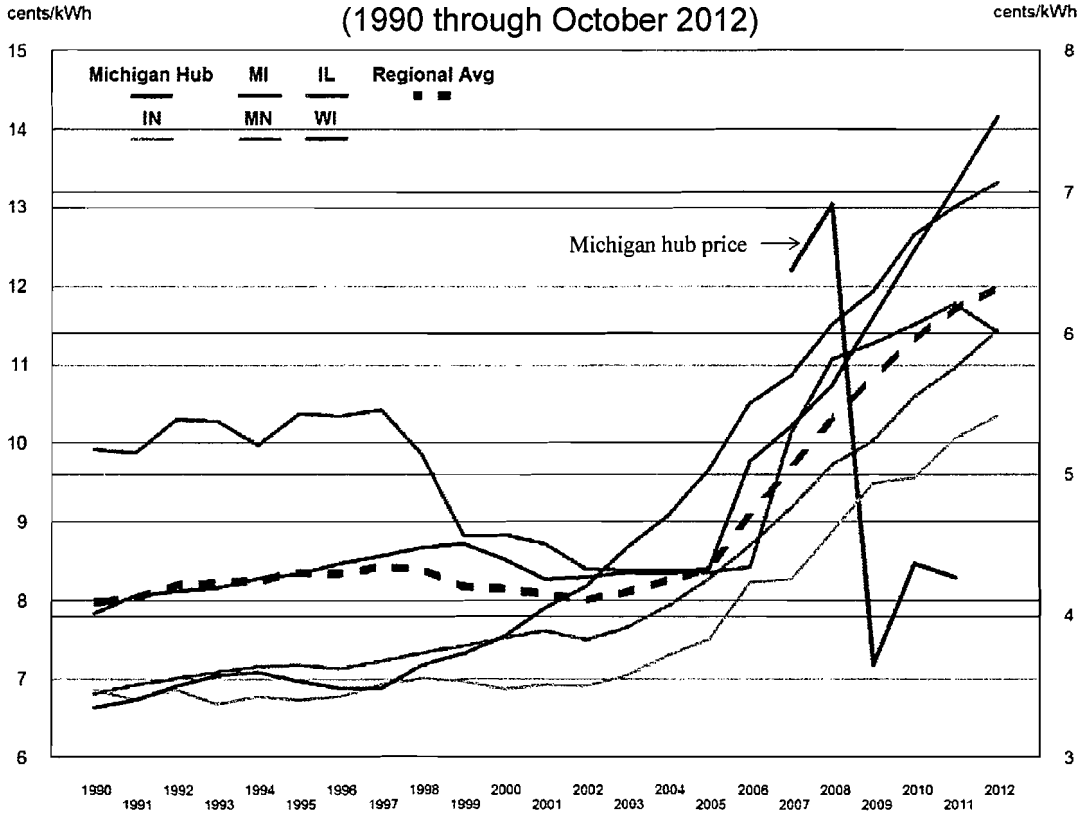
- Some of the usual suspects . . .
  - Wholesale market prices?
  - Declining sales (MWh sold)?
  - EPA compliance costs?
  - Fuel costs?

Daily Average of MISO Day-Ahead Prices - All Hours



Source: FERC, November 2012, Derived from *Bloomberg data.*

Figure 6. Weighted annual averages for Michigan, neighboring states, regional weighted average, and MISO annual average bilateral price.
(1990 through October 2012)



Data source: DOE/EIA.

Why are most states seeing higher prices (continued)?

- These factors contribute to higher prices, but don't seem to explain all the variation
  - Wholesale market prices from 2002 to 2008 may explain the run-up in retail price; but retail prices have not matched the recent decline in energy prices
  - Declining sales (MWh sold)? -- after steady growth in the 1990s, sales have been essentially flat or slight declines since 2007 in most of the country, but not sufficient to explain the difference
  - EPA compliance costs? – more of a coming attraction at this point
- Even though natural gas prices have been falling, coal is going in the opposite direction – that may explain some of the price increases
- What about new capacity costs?
  - Not by itself, EIA data shows Indiana increased total capacity by 14.5% between 2000 and 2011; Wisconsin increased total generating capacity by 34.6% during that time; and the US by 29.5%

Costs/Benefits of restructuring versus traditional regulation

- We know the predicted benefits from restructuring, including operational efficiencies
  - lower operating costs that result from dispatching power plants over the RTO's region (rather than for each individual utilities' area)
  - much of this benefit may be realized in the wholesale market, where power suppliers in Indiana compete in two RTOs now
  - these markets may not be ideally designed (perhaps they're *over* designed), but this is beyond the control of the states to deal with – this lack of state control will be discussed later

Costs/Benefits of restructuring versus traditional regulation *(continued)*

- On the other side of the ledger, additional costs from restructuring may equal or exceed any benefit, additional costs include:
  - insufficient capital investment in generation and transmission capacity – costly either if we fall short (i.e., loss of reliability) or have to pay for additional incentive structures to attract more investment
    - a regulated/vertically integrated structure encourages investment
  - de-integration costs, from loss of vertical economies (from when one decentralized entity supplied all products and services)
  - additional administrative costs that are passed on to customers
  - costs all market participants incur to deal with increasing market complexity

State Costs From Restructuring

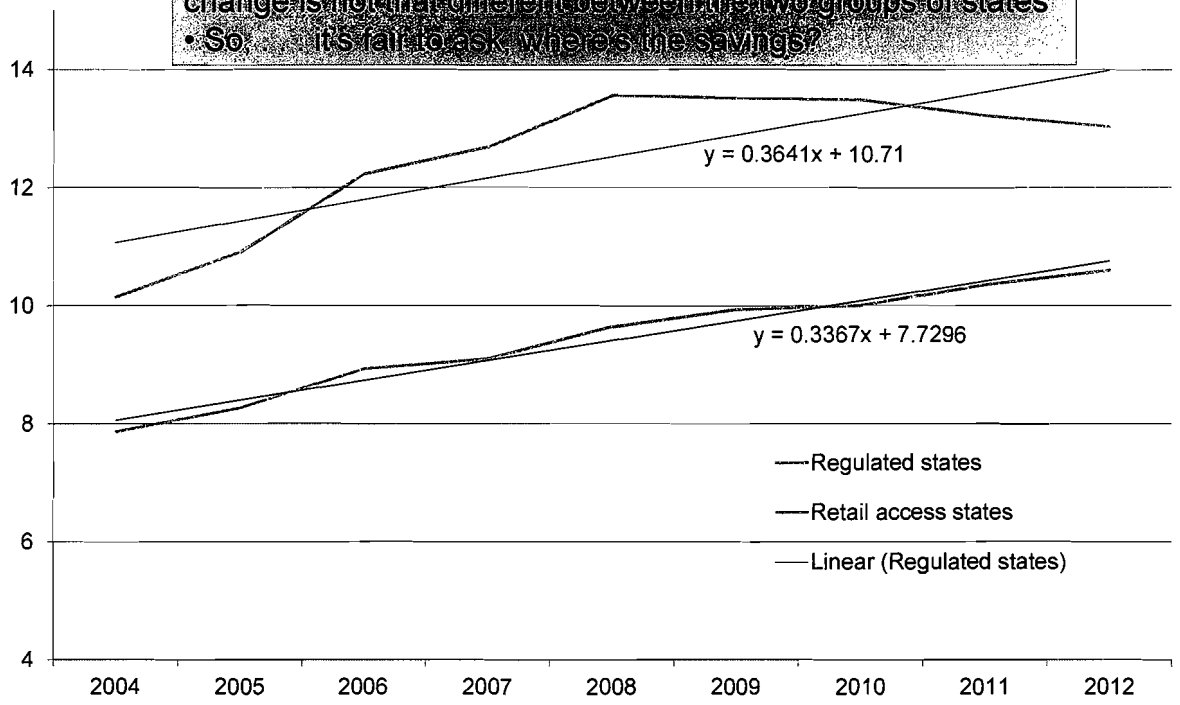
- States that restructured found (to their surprise), that when things go wrong (that is, prices increase rapidly – such as in California, Maryland, New Jersey, etc.), their options are very limited
- "Deregulating" at the state level actually transfer jurisdictional authority from the state to the federal regulatory authorities – primarily the Federal Energy Regulatory Commission (FERC)
- Unfortunately, when things go wrong within a state or region, customers and other market participants are wholly dependent on the federal government to fix it

Wrapping up . . .

- Not saying that one option is clearly worse or better than the other – retail access versus regulation, but
  - . . . there appears to be no clear benefit for retail customers, unless you look at just the last couple years, with retail choice – and that could quickly change if natural gas prices increase again (as they have in the not too distant past)
  - cost-based regulation is not perfect, but if the "restructured" model can't beat it, then something's wrong
- Not always sure what "competition" has to do with what we have been doing the past 20 years
  - replaced a complex, cumbersome, and expensive regulatory system with a complex, cumbersome, and expensive "deregulatory" system
  - the current RTO (wholesale markets, such as PJM's and MISO's) and retail access-based model (states that have it) is a composite of different markets, that are highly regulated at the federal level and frequently adjusted by FERC and the states
- Most of the country is facing the same cost pressures (environmental impact constraints, capacity, flat demand, renewable costs)

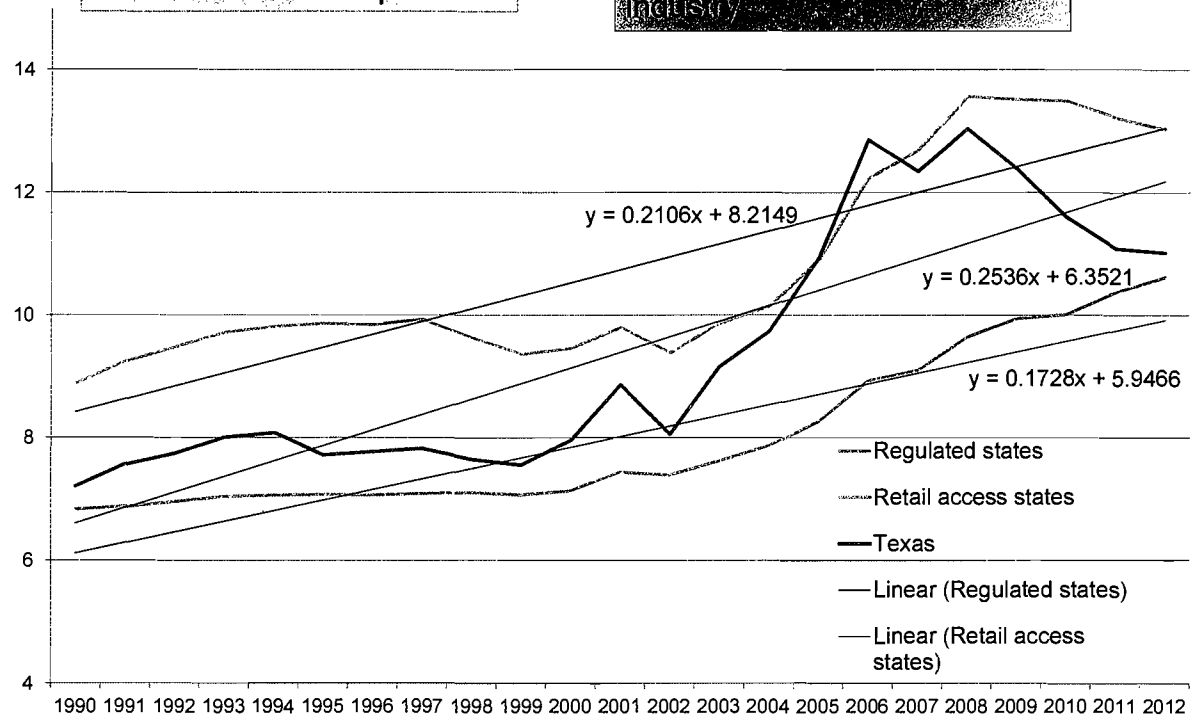
Another perspective . . .

- Just looking from 2004 through 2012, the average rate of change is not that different between the two groups of states
- So, it's fair to ask, where's the savings?



Even Texas (yes, Texas) follows the same trend line over the entire time period

Maybe it doesn't matter what we do ... because of the underlying economics of the industry



INDIEC
Indiana Industrial Energy Consumers, Inc.

Industrial Members:

1. Air Liquide
2. Air Products and Chemicals, Inc.
3. Allison Transmission, Inc.
4. ALCOA
5. ArcelorMittal
6. BP
7. Chrysler LLC
8. Eli Lilly and Company
9. General Motors
10. Haynes International, Inc.
11. Honda of America Mfg., Inc.
12. Ingredion (formerly National Starch/Corn Products)
13. Lehigh Hanson
14. Linde Group
15. Marathon Petroleum Company LLC
16. NLMK Indiana
17. Novelis Corporation
18. Praxair, Inc.
19. Rolls-Royce Corporation
20. Saint-Gobain Containers
21. Subaru of Indiana Automotive, Inc.
22. Tate & Lyle
23. Toyota Motor Manufacturing Indiana
24. U.S. Gypsum
25. Vertellus Specialties, Inc.

Affiliate Members:

- 1. Indiana Cast Metals Association
- 2. BP Canada Energy Marketing Corp
- 2. Shell Energy North America
- 3. CenterPoint Energy
- 4. EDF Energy Services

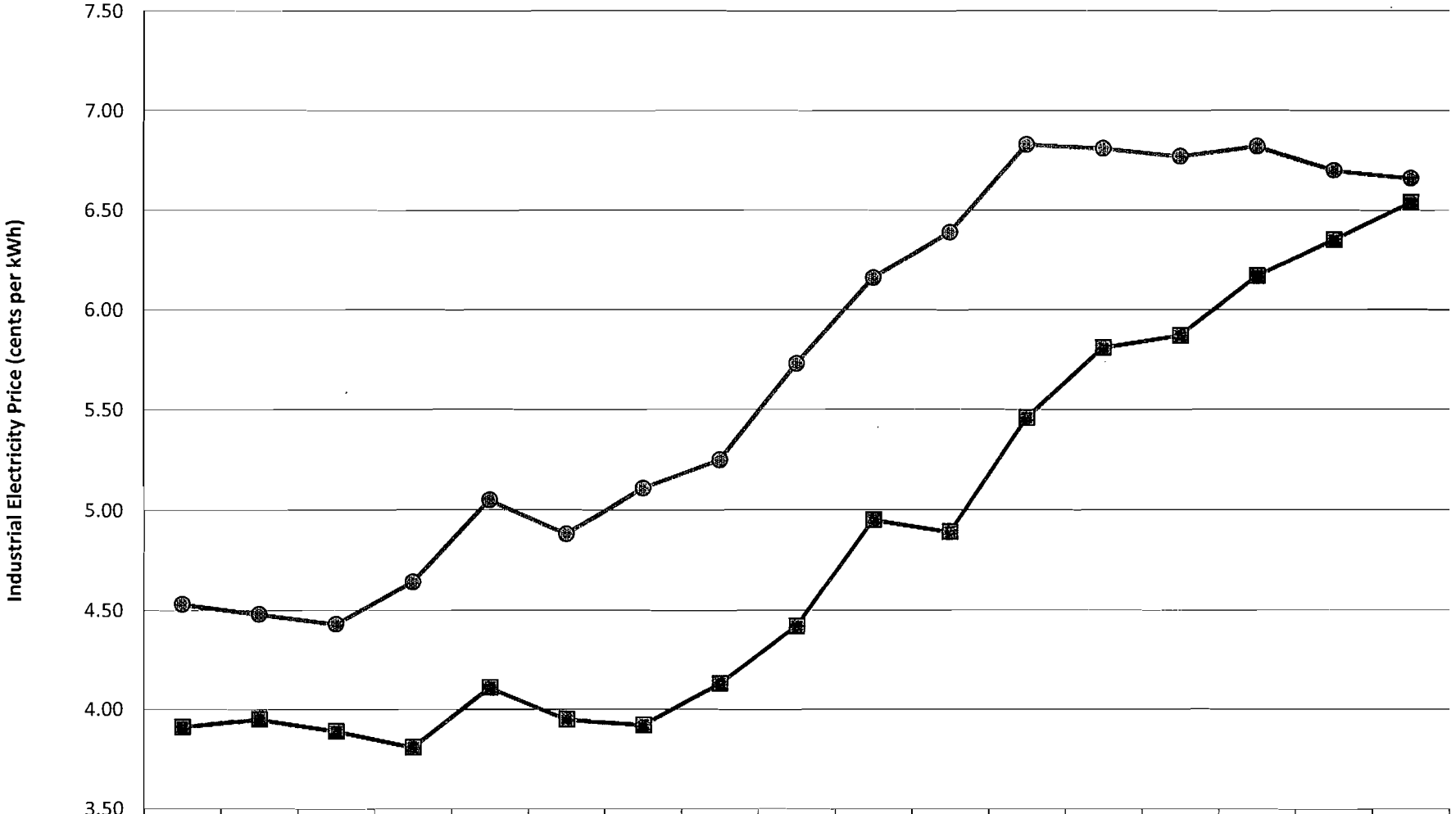
Exhibit 6
Regulatory Flexibility Committee
9/18/13

Average Industrial Electricity Prices by State

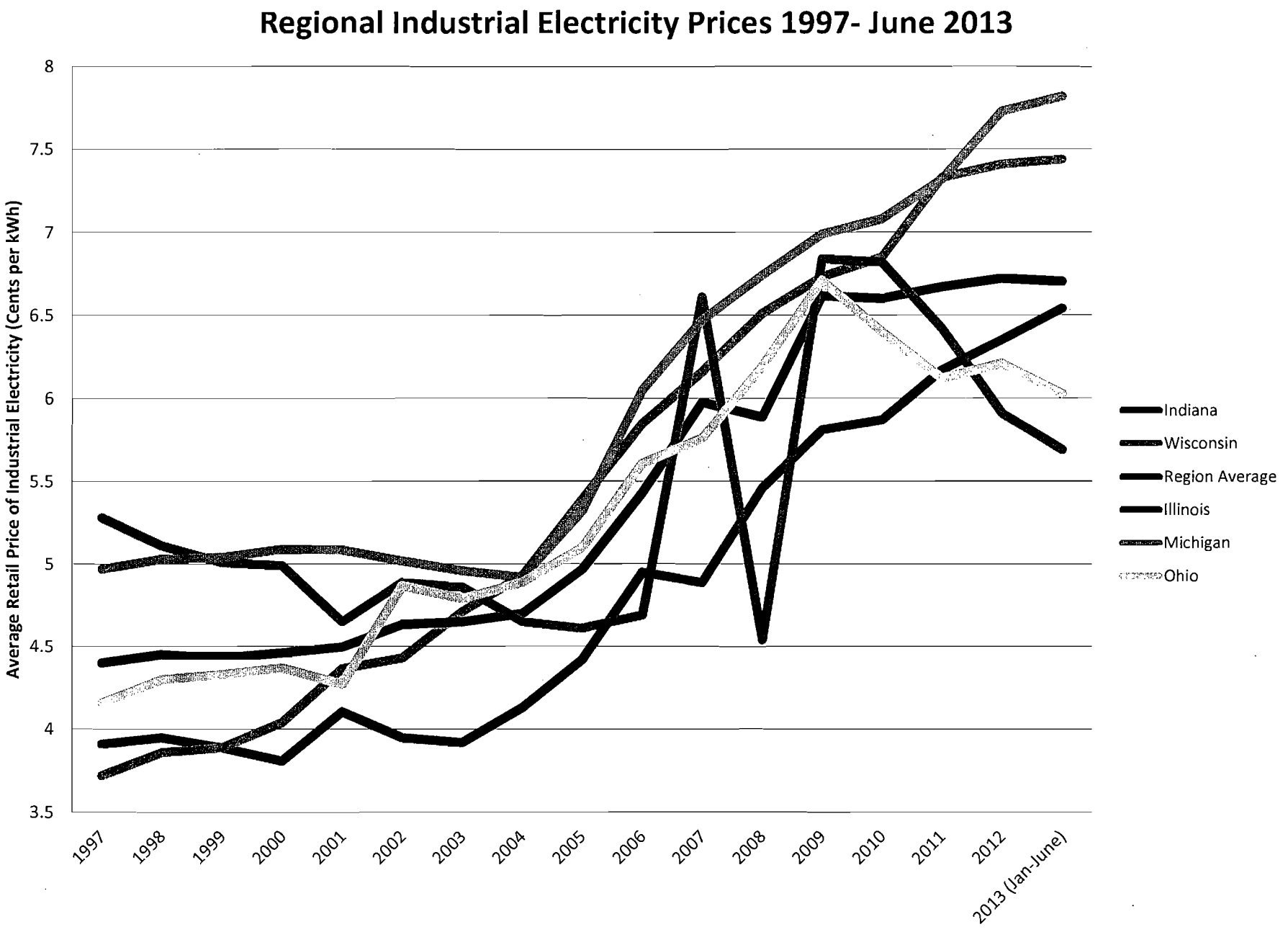
State	State Rank - Lowest to Highest			Industrial Price - Cents per kwh		
	YTD June 2013	2012	2003	YTD June 2013	2012	2003
Washington	1	1	25	4.08	4.11	4.76
Oklahoma	2	3	21	5.21	5.03	4.59
Montana	3	4	9	5.24	5.04	4.01
Kentucky	3	6	1	5.24	5.35	3.21
Iowa	5	5	12	5.47	5.33	4.16
Nevada	6	25	42	5.66	6.46	7.3
Illinois	7	16	29	5.69	5.91	4.91
Oregon	8	9	23	5.72	5.61	4.63
South Carolina	9	17	8	5.74	5.96	4
Arkansas	9	11	11	5.74	5.65	4.04
Utah	9	10	3	5.74	5.62	3.79
Idaho	12	8	12	5.76	5.55	4.16
Texas	13	12	34	5.80	5.73	5.27
Louisiana	14	2	37	5.83	4.75	5.57
Alabama	15	20	7	5.87	6.2	3.98
Missouri	16	14	19	5.94	5.85	4.49
Georgia	17	15	10	5.95	5.89	4.02
Ohio	18	21	26	6.03	6.21	4.79
District of Columbia	19	7	38	6.07	5.43	5.61
North Carolina	20	23	26	6.12	6.34	4.79
New Mexico	21	13	30	6.22	5.83	4.95
Mississippi	22	19	18	6.24	6.16	4.48
West Virginia	23	22	4	6.26	6.33	3.81
Tennessee	24	35	16	6.27	7.12	4.29
Wyoming	25	18	2	6.37	6.03	3.65
Arizona	26	26	35	6.40	6.53	5.38
New York	27	30	41	6.54	6.67	7.14
Indiana	27	24	5	6.54	6.35	3.92
Virginia	29	31	15	6.61	6.72	4.23
South Dakota	30	27	20	6.80	6.57	4.51

Industrial Electricity Prices for Indiana and U.S. Total

(1997-June 2013)

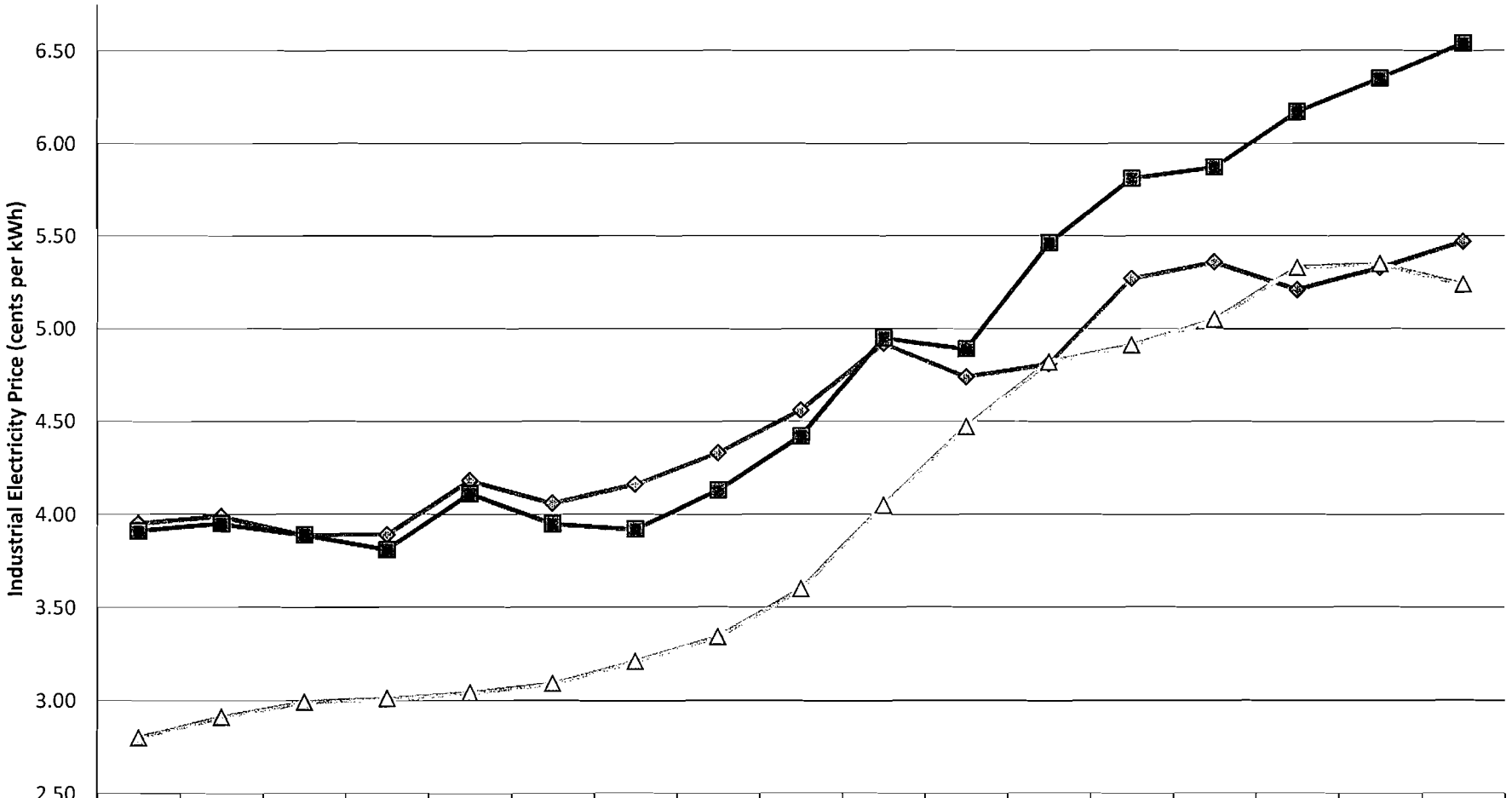


	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 (Jan-June)
IN	3.91	3.95	3.89	3.81	4.11	3.95	3.92	4.13	4.42	4.95	4.89	5.46	5.81	5.87	6.17	6.35	6.54
US Total	4.53	4.48	4.43	4.64	5.05	4.88	5.11	5.25	5.73	6.16	6.39	6.83	6.81	6.77	6.82	6.70	6.66


Regional Industrial Electricity Prices 1997- June 2013
Average Retail Price of Industrial Electricity (Cents per kWh)
8
7.5
7
6.5
6
5.5
5
4.5
4
3.5
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013 (Jan-June)
Indiana
Wisconsin
Region Average
Illinois
Michigan
Ohio

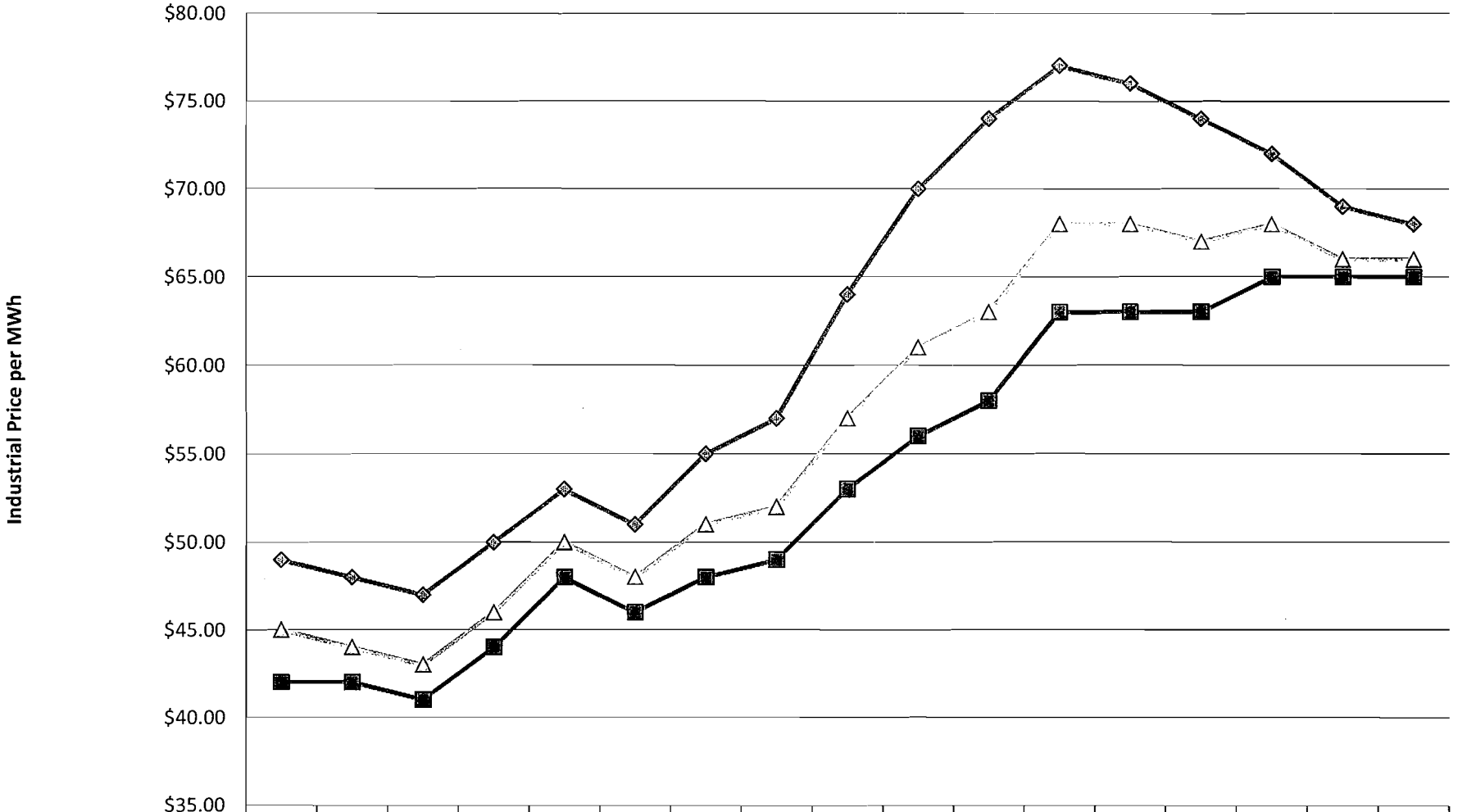
Industrial Electricity Prices for Iowa, Indiana, & Kentucky

(1997-June 2013)



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 (Jan-June)
IA	3.95	3.99	3.89	3.89	4.18	4.06	4.16	4.33	4.56	4.92	4.74	4.81	5.27	5.36	5.21	5.33	5.47
IN	3.91	3.95	3.89	3.81	4.11	3.95	3.92	4.13	4.42	4.95	4.89	5.46	5.81	5.87	6.17	6.35	6.54
KY	2.80	2.91	2.99	3.01	3.04	3.09	3.21	3.34	3.60	4.05	4.47	4.82	4.91	5.05	5.33	5.35	5.24

Industrial Electricity Prices in Restructured and Regulated Markets



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 (Jan-June)
Restructured States	$49.00	$48.00	$47.00	$50.00	$53.00	$51.00	$55.00	$57.00	$64.00	$70.00	$74.00	$77.00	$76.00	$74.00	$72.00	$69.00	$68.00
Regulated States	$42.00	$42.00	$41.00	$44.00	$48.00	$46.00	$48.00	$49.00	$53.00	$56.00	$58.00	$63.00	$63.00	$63.00	$65.00	$65.00	$65.00
US Total	$45.00	$44.00	$43.00	$46.00	$50.00	$48.00	$51.00	$52.00	$57.00	$61.00	$63.00	$68.00	$68.00	$67.00	$68.00	$66.00	$66.00

Response to Rising Industrial Electricity Costs

- Major Regulatory Reform is Needed
- Indiana Law should Support Development of Private Energy Projects
- AUR Act Should be Amended to Make it Available to Consumers

Exhibit 6
Regulatory Flexibility Committee
9/18/13

Indiana Industrial Energy Consumers, Inc.

The Voice of Industrial Energy in Indiana
2013 Members List

Industrial Members:

1. *Air Liquide*
2. *Air Products and Chemicals, Inc.*
3. *Allison Transmission, Inc.*
4. *ALCOA*
5. *ArcelorMittal*
6. *BP*
7. *Chrysler LLC*
8. *Eli Lilly and Company*
9. *General Motors*
10. *Haynes International, Inc.*
11. *Honda of America Mfg., Inc.*
12. *Ingredion (formerly National Starch/Corn Products)*
13. *Lehigh Hanson*
14. *Linde Group*
15. *Marathon Petroleum Company LLC*
16. *NLMK Indiana*
17. *Novelis Corporation*
18. *Praxair, Inc.*
19. *Rolls-Royce Corporation*
20. *Saint-Gobain Containers*
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Arkansas	9	11	11	5.74	5.65	4.04
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Louisiana	14	2	37	5.83	4.75	5.57
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Virginia	29	31	15	6.61	6.72	4.23
South Dakota	30	27	20	6.80	6.57	4.51
Minnesota	31	28	17	6.94	6.59	4.36
Pennsylvania	32	36	39	6.99	7.24	6.14
North Dakota	33	29	6	7.03	6.66	3.96
Kansas	34	33	22	7.04	6.88	4.61
Colorado	35	34	32	7.07	6.94	5.1
Nebraska	36	32	14	7.12	6.81	4.18
Wisconsin	37	37	24	7.44	7.41	4.71
Florida	38	40	36	7.66	8.04	5.41
Michigan	39	38	31	7.82	7.73	4.96
Maryland	40	41	28	8.34	8.12	4.89
Delaware	41	42	33	8.47	8.34	5.15
Maine	42	39	40	8.58	7.87	6.35
Vermont	43	43	46	10.22	9.96	8.05
New Jersey	44	44	43	10.39	10.54	7.47
California	45	45	50	10.51	10.73	9.85
New Hampshire	46	47	49	11.57	11.82	9.39
Rhode Island	47	46	47	12.17	10.86	9.06
Connecticut	48	48	45	12.71	12.76	7.92
Massachusetts	49	49	48	12.97	12.91	9.11
Alaska	50	50	44	16.06	16.75	7.86
Hawaii	51	51	51	30.13	30.77	12.2

Rank lowest electricity price to highest electricity price

Sources: US Energy Information Administration - Electric Power Monthly, Table 5.6B, August 2013, February 2013 and March 2005

INDUSTRIAL CONSUMERS POSITION PAPER
EXECUTIVE SUMMARY

RISING POWER COSTS ARE A SERIOUS PROBLEM FOR INDUSTRIALS IN INDIANA

- In the past decade, Indiana has gone from having the 6th lowest industrial electricity prices in the nation to being tied for 27th
- Energy is one of the top costs faced by large industrial consumers
- Indiana has lost the economic development tool of low energy costs and has begun to lose jobs to surrounding states
- Due to heavy reliance on aging coal-fired generation and other factors, rates in Indiana will continue to rise

MAJOR REGULATORY REFORM IS NEEDED

- Restructuring in other states provides a baseline of experience and comparative data for consideration of retail competition
- Revisions to regulatory standards and procedures offer additional options to address the problem of rising energy costs
- A one-year study period would provide an opportunity for careful analysis of the complex issues before proceeding with comprehensive legislation

INDIANA LAW SHOULD SUPPORT GROWTH OF INDUSTRY AND MANUFACTURING IN INDIANA THROUGH DEVELOPMENT OF PRIVATE ENERGY PROJECTS

- Public policy can encourage non-utilities to construct private generation resources, such as cogeneration, waste-to-energy and renewables
- Existing regulations nevertheless hinder the development of private energy projects
- Private generation can provide energy cost relief for industrials, relieve the rate burdens of utility construction, and create new in-state resources

THE ALTERNATIVE UTILITY REGULATION ACT SHOULD BE AMENDED TO MAKE IT AVAILABLE TO ALL CONSUMERS

- The AUR Act authorizes flexible regulation, but under current law only an energy utility can propose an alternative regulatory plan and the utility can veto any changes
- Amending the AUR Act to permit consumers to propose alternative regulatory plans would provide balance and a mechanism for innovative and efficient energy solutions

Exhibit 6
Regulatory Flexibility Committee
9/18/13

POSITION PAPER OF INDUSTRIAL CONSUMERS ON ELECTRIC REFORM

Indiana Industrial Energy Consumers, Inc.
Indiana Industrial Group

September 2013

For questions and further information, please contact:

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(317) 639-1210

Miriam Dant
Dant Advocacy, Inc.
54 Monument Circle, Suite 300
Indianapolis, Indiana 46204
(317) 450-6182

POSITION PAPER OF INDUSTRIAL CONSUMERS
ON ELECTRIC REFORM

September 2013

This paper has been prepared on behalf of the Indiana Industrial Energy Consumers, Inc. ("INDIEC") and the Indiana Industrial Group, an ad hoc group consisting of INDIEC members and other large electric users operating industrial facilities in Indiana (collectively the "Industrial Consumers"). In light of the serious problems arising from rapidly escalating energy prices, the Industrial Consumers support reform of Indiana's retail electric market in order to provide greater flexibility and better options to manage energy costs. Specific proposals are set forth in Section D below.

A. Rising Energy Costs Are a Serious Problem for Industrial Consumers in Indiana

For many years, Indiana offered industrial operations a favorable business location arising from economical energy rates, in comparison to the region and the nation, arising largely from the availability of low cost Indiana coal. Because of economical natural gas supplies across the nation and rising rates in Indiana in recent years, Indiana can no longer be considered a low-cost energy state. Ten years ago, Indiana ranked sixth lowest in the nation in average electricity prices for industrial customers.[1] As of 2012, Indiana's national ranking had dropped to 24th in that respect.[2] In other words, over the past decade, Indiana has gone from being one of the lowest cost energy locations for industrial facilities in the United States to being average at best.

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[1] *See* U.S. Energy Information Administration, *Electric Power Monthly March 2004* (with data through December 2003), Table 5.6.B.

[2] *See* U.S. Energy Information Administration, *Electric Power Monthly February 2013* (with data through December 2012), Table 5.6.B. Through the first half of the current year (the most recent data available), Indiana's ranking dropped further from 24th to tied for 27th. *See* U.S. Energy Information Administration, *Electric Power Monthly August 2013* (with data through June 2013), Table 5.6.B.

That unfavorable trend is expected to continue to get worse into the future, due to factors largely outside the control of Indiana.

Attached as Exhibit A is a chart showing the direction of average industrial electricity prices over the past fifteen years in Indiana as compared to the average throughout the United States. Up until the past five years, Indiana maintained a consistent cost advantage, but since that time the spread has been essentially erased and the trend is in the wrong direction.[3] Exhibit B shows the same comparison in the region that includes Indiana, Illinois, Michigan, Ohio and Wisconsin. For the initial part of that period, Indiana was consistently at or near the bottom in energy rates in comparison to other states in the region, providing Indiana with a distinct advantage as a location of choice for industrial operations. The steep rise in energy prices, however, is apparent in the most recent decade. The unfavorable status of industrial electric rates in Indiana is further apparent in comparison to other Midwestern states that have retained traditional regulation. Exhibit C shows the rise in Indiana prices in comparison to averages in Kentucky and Iowa. As of 2012, Indiana's average electricity prices for industrial consumers were higher than those of Illinois and Ohio (restructured states), as well as Kentucky and Iowa (regulated states).

For several reasons, the problem of rapidly escalating energy costs can be expected to continue to get worse in Indiana. In the first place, Indiana is highly dependent on coal-fired generation, which continues to face very expensive environmental compliance challenges. Over

[3] Based on year-to-date data through June of this year, the average industrial electricity price in Indiana for 2013 was 6.54¢ per kWh and the average for the total United States was 6.66¢. *See* U.S. Energy Information Administration, *Electric Power Monthly August 2013* (with data through June 2013), Table 5.6.B.

80% of the electricity production in Indiana in 2011 was generated by coal plants.[4] The impact of federal environmental regulations were analyzed in a January 2012 report by the State Utility Forecasting Group, which concluded: "Due to the state's heavy reliance on coal as a fuel source for electricity generation, Indiana is expected to experience larger price increases than those projected on a regional or national level. Similar studies by other entities have shown projected electricity price increases at the regional or national level of roughly half those indicated in this study."[5] In other words, the impact of environmental compliance on electric prices in Indiana is expected to be on the order of twice as severe as the impact in the broader region and nationally.

Compounding the heavy reliance on coal-fired generation facilities, the State's generation resources are aging, with many units nearing the end of their useful production. Coal units are typically retired between forty and sixty years. Over 30% of the coal-fired generation in Indiana is greater than forty years old, and about 75% is over thirty years old.[6] "For the electric industry, an aging generation fleet is particularly concerning due to the potential risk to system reliability and the rising costs associated with the construction of new power plants."[7] In light of the high costs of environmental compliance for coal-fired generators, Indiana utilities are being forced to consider the retirement of coal units earlier than would otherwise be the case. As a result, Indiana is facing a period of very expensive construction projects to replace the capacity of aging coal plants as they are being retired.

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[4] *See* Indiana Utility Regulatory Commission, *2012 Annual Report to the Regulatory Flexibility Committee, 2012 Electricity Report*, pp. 23-24 & Chart 3.
[5] *See* State Utility Forecasting Group, *The Impacts of Federal Environmental Regulations on Indiana Electricity Prices* (January 2012), p.2.
[6] *See* Indiana Utility Regulatory Commission, *2012 Electricity Report*, *supra*, pp.28-30 & Table 2.
[7] *Id.* at p.28.

A third factor that continues to exacerbate the increasing electricity prices in Indiana is the trend in legislative policy with respect to regulated utilities. While Indiana retains the regulated monopoly model for the provision of electricity and provides designated utilities with exclusive sales territories, energy utilities in Indiana have been provided expanded opportunities to demand greater assurance of cost recovery on an accelerated basis, often based on forecasts and projections, with restricted regulatory oversight and limited opportunity for challenge by affected consumers. In particular, utilities have an array of tracker options at their disposal, by which selected categories of costs are subject to essentially automatic recovery through rates, without regard to the utility's overall financial status or the need for increases to establish reasonable rates. Virtually all major expense categories, from mine to meter, can be recovered by utilities through trackers without regard to the reasonableness of overall rates. This one-sided flexibility has enabled Indiana utilities to restrict regulatory oversight while imposing extensive costs on retail customers.

A particular example of one-sided deregulation is the Alternative Utility Regulation Act ("AUR Act"), by which an energy utility may propose a form of alternative regulation that deviates from traditional utility law.[8] Under the AUR Act, an alternative regulatory plan can only be proposed by an energy utility, not by any other party.[9] If the Indiana Utility Regulatory Commission modifies the utility's proposal in any respect, the utility has the extraordinary option to refuse the change and withdraw the proposal.[10]

The upward spiral in electric prices resulting from the combined effects of such factors has severely and adversely impacted the economics of industrial operations in Indiana. Indiana

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[8] *See* Ind. Code §8-1-2.5-1 *et seq.*
[9] *See* Ind. Code §8-1-2.5-4.
[10] *See* Ind. Code §8-1-2.5-6(e).

has historically enjoyed a strong industrial base, due in significant part to traditionally low energy costs. Industrial processes are typically energy-intensive, and consequently energy costs are a material factor in the cost of production. In 2012, manufacturing operations provided employment to nearly half a million Hoosiers, representing one in six jobs in the State.[11] The percentage employed in Indiana in that sector is the highest of any state in the country.[12] In 2012, furthermore, industrials in Indiana consumed nearly 48 billion kilowatt-hours of electricity, accounting for nearly half the State's entire electric consumption.[13] For the same period, the total revenue paid by Indiana industrial consumers for electricity was more than $3 billion.[14] Energy-intensive, trade exposed (EITE) industrial operations in Indiana are impacted by changes in the overall economics due to the decision of being located in Indiana. Accordingly, EITE industrials will have to review their choice of Indiana as a location for competitive businesses active in global markets.

Unquestionably, energy costs have a substantial impact on the economic vitality of the State's industrial base. Those costs are a significant factor in business decisions involving the location of facilities, where to expand or restrict production, and the potential relocation of operations. The trend in energy prices is costing Indiana in productivity and jobs. As major employers and taxpayers, industrial businesses play a vital role in the Indiana economy.[15]

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[11] *See* Stats Indiana, www.stats.indiana.edu/ces/ces_naics (based on U.S. Bureau of Labor Statistics and Indiana Dept. of Workforce Development data).
[12] *See* Indiana Manufacturers Association, *Indiana Leads the U.S. in Manufacturing Production, Employment and Earnings* (April 4, 2013), www.imaweb.com/press-releases.
[13] *See* U.S. Energy Information Administration, *Electric Power Monthly* (with data for December 2012) (February 2013), p.118, Table 5.4.B.
[14] *Id.* at p.120, Table 5.5.B.
[15] *See* InContext, *Manufacturing's Impact on Household Income and the Middle Class*, www.incontext.indiana.edu/2012/nov-dec/article4.asp ("For every 1 percentage point increase in manufacturing's contribution to Indiana's economy, yearly median household incomes increase by nearly $89.").

Indiana is now falling behind other states such as Illinois, Ohio, Kentucky and Iowa in the provision of affordable energy. As a result, the State's ability to attract and retain industrial operations and maintain productivity in that essential sector has been seriously undermined. There is a compelling need, therefore, to provide industrial consumers in Indiana with effective energy solutions and greater flexibility to secure access to economical sources of electric energy.

B. The Time is Right to Reform Indiana's Retail Electric Market

For a number of decades, there has been a progression in federal law toward the restructuring of regulated industries and the promotion of competition, as in the transportation, telecommunications and natural gas markets. That movement in federal regulatory policy has typically been followed at the state level by restructuring of state-regulated markets. In the 1990s, federal initiatives restructured the wholesale electric market and the interstate transmission system. The federal restructuring was intended to promote competition in the process by which public utilities purchase electricity for resale, and has resulted in the establishment of independent system operators with responsibility for regional transmission systems.

As federal restructuring of the electric industry progressed, virtually every state, including Indiana, considered measures to introduce competition at the retail level in which electricity is purchased by consumers. In 1995, the General Assembly passed the AUR Act, which addressed the increasing competition in energy services by providing a mechanism to implement greater flexibility in traditional regulation in Indiana through deregulatory proposals and alternative regulatory plans. Comprehensive restructuring aimed at the establishment of retail electric competition was proposed in bills introduced in Indiana starting in 1997. That proposed legislation was supported by an array of consumer groups, trade associations and two

of the State's investor-owned electric utilities. The prevailing perspective at the time, however, was that Indiana already had advantageously low energy rates and hence should proceed with caution. In 2000, an energy crisis in California exposed structural flaws in the restructuring model that was implemented in that state, effectively chilling the national trend toward restructuring retail electric markets.

Although Indiana and the majority of states did not proceed with electric restructuring, a number of other states went forward with restructuring. Many of those states were in the northeastern United States, where electric rates tended to be higher. At this point, there are sixteen jurisdictions with active electric competition programs: Illinois, Ohio, Michigan, Texas, Oregon, Pennsylvania, New York, New Jersey, Maryland, District of Columbia, Delaware, Connecticut, Massachusetts, Rhode Island, New Hampshire and Maine.[16] In each of those states, the restructuring process began in the 1990s. None of the other states with retail competition programs have experienced the kind of energy crisis that occurred in California in 2000. In recent years there has been some concern about the adequacy of long-term reserve margins in some regions, in particular with respect to projected capacity deficiencies in Texas.[17]

Attached as Exhibit D is a chart comparing average retail electricity prices to industrial consumers from 1997 to June 2013 in states with currently restructured markets and states that have retained the regulated monopoly model. The prices are weighted by relative consumption across the competitive and regulated states. As indicated in the chart, average industrial prices started out considerably higher in what are now restructured states, and for a period of time, as those markets transitioned to competition, the spread grew wider. Over the most recent five

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[16] *See* U.S. Energy Information Administration, *Status of Electricity Restructuring by State*, www.eia.gov/electricity/policies/restructuring/restructure_elect.html.
[17] *See* North American Electric Reliability Corporation, *2012 Long-Term Reliability Assessment*, November 2012, www.nerc.com/files/2012_ltra_final.pdf.

years, however, while price levels in regulated states have been relatively flat (and while Indiana's rates have continued to rise precipitously), the average in restructured states has dropped steadily. Price trends have been affected by a variety of factors, including the imposition of federal environmental regulations, changes in the natural gas market, shifts in demand and regulatory conditions. Indiana's current regulatory framework does not provide industrial consumers with effective tools to manage those risk factors.

The present circumstances differ in key respects from those at the time that Indiana previously considered electric reform. Most notably, Indiana no longer enjoys the advantage of low energy rates, and to the contrary high electricity prices in Indiana are now a serious impediment to industrial productivity and greatly impair the State's economic development prospects. The problem, moreover, is getting worse. The federal initiatives and restructuring by other states, which were at the beginning stages when Indiana last considered electric competition, have now matured into more established structures that provide a baseline of experience and data for comparative analysis. Two neighboring states with restructured markets, Illinois and Ohio, now have lower cost energy than Indiana. Nearby states that have retained their regulatory models, Kentucky and Iowa, have also achieved an advantage over Indiana in energy costs. For the State to remain competitive as a location for industrial operations, accordingly, Indiana should take immediate steps to provide industrial consumers with more flexible energy options and enhanced capability to manage energy costs.

C. Indiana Should Support the Development of Private Generation Resources

An important element of any potential reform involves the long-range development of generation resources by non-utilities. Under traditional regulation, monopoly suppliers are provided exclusive sales territories subject to an obligation to reliably serve the public demand at

regulated rates. The duty of public utilities to serve the public, in combination with rates imposed on consumers with the force of law, establishes a framework under which utilities can undertake expensive construction projects to build generation facilities with a high degree of assurance that the costs will be recovered from captive customers, which in turn enhances access to favorable financing arrangements. With the introduction of competition and customer choice, on the other hand, the development of generation resources becomes to a greater extent subject to the market dynamics of supply and demand. In that context, adequate measures to support new generation by private enterprises can facilitate a diversity of supply options for consumers.

In a number of contexts, established public policy already favors the construction of private generation projects. Cogeneration facilities producing both electric power and useful thermal output for an industrial host operation,[18] small power production facilities,[19] combined heat and power units,[20] waste-to-energy facilities,[21] wind farms and other renewable sources of energy[22] – all are examples of alternative generation resources that non-utilities can develop, outside the traditional model of public utility regulation, pursuant to existing legislative policy under both federal and Indiana law. The policy favoring private energy projects, notably, is designed substantially to support the development of alternative energy solutions for industrial operations in particular. In the current market, accordingly, the recognized policy favoring the development of alternative energy resources by non-utilities supports supply diversity and provides greater flexibility and options for industrial consumers. Advancing the same policy,

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[18] *See* 16 U.S.C. §824a-3; Ind. Code §8-1-2.4-1 *et seq.*
[19] *See* 16 U.S.C. §796(17)(A)(ii); Ind. Code §8-1-2.4-5(a).
[20] *See* www.epa.gov/chp/index.html; Ind. Code §8-1-37-4(a)(20).
[21] *See* 16 U.S.C. §796(17)(A)(i); Ind. Code § 8-1-37-4(a)(5)(D), (9).
[22] *See* 16 U.S.C. §796(17)(A)(i); Ind. Code § 8-1-2.4-2(b)(1); Ind. Code § 8-1-37-4(a)(1)-(6), (11).

furthermore, facilitates the establishment of a wider array of energy resources better equipped to meet demand with new production.

The important policy supporting the development of private energy facilities by non-utilities, however, faces significant obstacles that undermine the current effectiveness in meeting the needs of industrial consumers and threatens the future establishment of a more diverse supply portfolio in Indiana. Some of the impediments are non-regulatory and not specific to issues under the public utility laws, including challenges relating to siting, permitting, financing and taxation. In addition, however, private energy projects face an array of difficulties arising from the existing framework of public utility regulation. In particular, due to their exclusive service franchises, monopoly utilities typically control access to the electric grid and non-utilities must navigate a regulatory maze to transmit electric power. In many instances, a non-utility must interconnect with a public utility and secure both regulatory compliance as well as contractual rights, impairing the efficiency and adding to the complexity of the arrangement. Under current law, furthermore, industrial consumers encounter resistance and regulatory obstacles in connection with efforts to access off-site energy resources, to join with other consumers or developers on private energy ventures, to aggregate load at different locations for efficient purchasing and private distribution, and to secure the back-up and maintenance services needed for reliable operation of private generation facilities.

Reform of the regulatory framework to remove existing impediments to the development of private energy projects, accordingly, will provide benefits to industrial consumers and the State by promoting efficiency and enhancing the diversity of supply options. Measures to support the construction of energy facilities by industrial consumers and other non-utilities will expand production by Indiana's native energy industry and broaden the availability of in-state

energy alternatives. Such measures could provide immediate relief to consumers seeking greater ability to manage rising energy costs with innovative solutions at their own initiative. In the longer term, the same steps promote the establishment of adequate supply resources as Indiana considers and implements further reforms to its retail electric market.

D. Indiana Should Reform Its Regulatory Framework to Provide Efficient Solutions to Rising Energy Costs

Based on experience in other states, comprehensive restructuring to institute competition in the provision of retail electric service involves a sequence of steps and initiatives over a multi-year transition period. The Industrial Consumers propose, accordingly, that the process of implementing regulatory reform commence with a thorough study of alternative solutions to the many complex issues presented. The purpose of the study would be to determine an optimal form and timeline for any restructuring in Indiana and to evaluate alternative avenues of containing rate increases through revised regulatory standards and procedures. In the meantime, the present challenges to consumers facing rapidly escalating energy costs call for immediate measures to provide relief without delay. Industrial consumers need access to mechanisms to manage energy costs through self-directed procurement.

The Industrial Consumers therefore support the following measures:

1. A thorough study should be conducted, under the oversight of the Indiana Utility Regulatory Commission and the Regulatory Flexibility Committee, to determine the optimal form of comprehensive reform and to assess potential measures to rectify the deficiencies in the existing regulatory structure. The study will be oriented on determining the approach best suited to promote efficiency, reliability, diversity of supply options, the restoration of Indiana's energy advantage and competitiveness with neighboring states, and the equitable allocation of risks and benefits for all consumers in Indiana's retail electric market. In many restructured states, the

process began with an evaluation of approaches by the state agency charged with regulating public utilities. In Indiana, the Commission has the expertise to investigate regulatory reform and the procedural tools to elicit evidence and consider the policy views of all interested stakeholders. An effective process requires adequate opportunity for all affected stakeholders, including consumer groups, to present views and proposals. The Commission reports annually to the Regulatory Flexibility Committee, which, with the determinations presented by the Commission and further information and recommendations presented through the legislative process, can then submit a proposal for consideration by the General Assembly. A one-year period to study potential approaches and determine the best alternative for Indiana would enable the General Assembly to consider comprehensive legislation in the 2015 session.

2. The AUR Act should be amended to permit parties other than energy utilities to propose alternative regulatory plans for approval by the Commission. The AUR Act was established in the mid-1990s as a mechanism to provide flexibility in traditional regulation, in recognition that "competition is increasing in the provision of energy services in Indiana and the United States."[23] Under the existing provisions, however, only an energy utility can propose flexible regulation and, if the utility's plan is modified by the Commission, the utility has the option to reject the modification.[24] Consumers, consequently, have been denied the opportunity to present proposals promoting competition and other energy alternatives, and the Commission's

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[23] *See* Ind. Code §8-1-2.5-1.

[24] *See* Ind. Code §8-1-2.5-4 (provisions authorizing deregulation or alternative regulatory plans "do not apply to an energy utility unless the energy utility voluntarily submits a verified petition to the commission stating the energy utility's election to become subject to such section or sections"); *id.* §8-1-2.5-6(e) ("[T]he commission may not order that material modifications changing the nature, scope or duration of the plan take effect without the agreement of the energy utility. The energy utility shall have twenty (20) days after the date of a commission order modifying the energy utility's proposed plan within which to, in writing, accept or reject the commission's order.").

ability to regulate flexibly in the public interest has been circumscribed. Amending the AUR Act to permit other interested parties to propose alternative regulatory plans,[25] without providing the utility with veto power over any resulting Commission order, would restore balance to the statutory mechanism and would permit the Commission to consider alternative proposals, such as a pilot program for electric choice. The interests of the utility, notably, would remain protected by its ability to present evidence and assert positions in the proceeding, by the statutory criteria that must be satisfied for any proposal to be approved, [26] and by the Commission's authority to make public interest determinations. In short, this change would appropriately shift the focus of regulatory policy from that which is best only for Indiana's utilities to that which is best for jobs and the Indiana economy as a whole.

3. Both through immediate legislative initiatives and as developed and evaluated through the one-year study period, Indiana should implement regulatory reform measures to mitigate rising energy rates. The existing regulatory standards and procedures that permit Indiana utilities to implement rate increases with circumscribed regulatory oversight, based on projections and estimates, should be balanced with protections that mitigate the impact on consumers and restore the Commission's authority to prevent the imposition of unreasonable rates. Revisions to existing regulatory standards and procedures that should be adopted include the following:

(a) The Commission should be directed by statute to review and where appropriate to impose downward adjustments in an energy utility's authorized rate of

[25] The parties with standing to commence a formal complaint proceeding at the Commission against a public utility are defined at Ind. Code §8-1-2-54.
[26] *See* Ind. Code §§8-1-2.5-5(b), 8-1-2.5-6(a).

return to reflect the reduced level of risk when utilities take advantage of rate tracking mechanisms;

(b) An energy utility that implements a non-fuel tracking mechanism, or implements an alternative regulatory plan under the AUR Act, should be required to file a general rate case within two years, in order to enable the Commission to conduct a comprehensive review of rates and to adhere to the standard of just and reasonable rates;

(c) Because increases in a particular category of costs do not necessarily require increased revenue to maintain just and reasonable rates, such as in situations where energy sales increase or where another category of costs decreases, in all instances where an energy utility seeks a tracker for a given expense the Commission should be authorized to deny the request if it determines that the proposed tracker is not necessary to provide the utility with fair opportunity to earn its authorized rate of return;

(d) Any new revenue requirements authorized by the Commission through a tracking mechanism should be allocated among customer classes consistent with the methodology established in the most recent general rate proceeding or otherwise in accordance with cost causation principles;

(e) In all rate proceedings in which an energy utility seeks an increase in revenues to reflect increases in a tracked expense, the utility should bear the burden of proof in establishing that it has made reasonable efforts to manage the costs in order to provide efficient and reliable service as economically as possible, so that even where a tracker is approved the utility retains continuing responsibility and incentive to minimize the rate impact;

(f) In light of the prevalence of tracking mechanisms implemented by energy utilities in Indiana, the earnings test applicable to fuel cost adjustments pursuant to Ind. Code §8-1-2-42(d) should be expanded to reflect the cumulative impact of all trackers affecting rates;

(g) The existing statute that contemplates rate review every four years[27] should be amended to require a general rate proceeding for energy utilities at least once every four years; and

(h) In the event that the Office of Utility Consumer Counselor or affected ratepayers commence a proceeding challenging the rates and charges of an energy utility as excessive or unreasonable, the Commission should be authorized in any order granting relief to include customer refunds dating back to the date the complaint was filed.[28]

4. The Commission should be granted statutory authority to approve, on its own motion or upon petition by any interested party, tariff provisions applicable to particular electric utilities providing for distribution-only service. In connection with natural gas service, the General Assembly enacted a statute in 1987 authorizing the Commission to implement tariff provisions for transportation-only service.[29] Under the oversight of the Commission, large volume consumers now have access to competitively priced natural gas and can, under transportation tariffs, utilize the local utility's distribution system only for the purpose of transporting the gas to the customer's location. While recognizing significant differences between natural gas and electricity markets, the efficiencies and cost savings available under transportation tariffs in the natural gas market remain unavailable to consumers in the electric

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[27] *See* Ind. Code §8-1-2-42.5.
[28] Under federal law, the Federal Energy Regulatory Commission has authority to provide refunds dating back to the filing of a rate complaint. *See* 16 U.S.C. §824e(b).
[29] *See* Ind. Code §8-1-2-87.7.

market. Authorizing the Commission to implement distribution-only tariff provisions for electric customers, in the same manner that transportation-only tariffs are authorized in the gas market under the existing statute, could expand the benefits and options available to consumers across a broader array of energy services. Such distribution tariffs would require Commission approval based on substantial evidence in the context of a specific utility, and would remain subject to the Commission's regulatory oversight.

5. Indiana should adopt measures to support the development of private electric generation and distribution facilities by non-utilities, including industrial consumers. In the long term, such measures could facilitate the construction of adequate energy resources in the context of any future regulatory reform, and in the near term would provide consumers and alternative suppliers with greater ability to fashion innovative and efficient energy solutions. Provisions supporting private energy projects would address issues relating to siting, permitting, financing and taxation, in addition to matters specific to the context of utility regulation. Such regulatory issues include: restrictions imposed by monopoly utilities associated with interconnection with the electric grid; imposition of the utility as a middleman buyer and reseller; prohibitions on aggregation of load and private distribution by consumers with multiple locations; impediments to off-site and joint venture projects by consumers; and restrictions in the availability of reliable back-up and maintenance service in the event of outages affecting private facilities. In all instances, the objective of promoting diversity of in-state supply resources and enhanced economic efficiency could be advanced by measures aimed at reducing the burdens and obstacles faced by industrial operations and other non-utilities seeking to develop energy projects, in particular the imposition of regulatory restrictions that assist monopoly utilities in efforts to inhibit the deployment of alternative energy solutions.

6. The Service Area Assignments Act[30] should be amended consistent with the regulatory reforms as proposed. The Service Area Assignments Act was initially enacted by the General Assembly in 1980 to establish the integrity of service area boundaries served by electric utilities in Indiana and thereby address recurring service disputes between adjacent suppliers.[31] The Act further provides for exclusive service rights by the designated utility within its defined service area.[32] While suited at the time to prevent incursions across boundaries in the context in which the Act was adopted, the statutory establishment of monopoly service rights now serves to inhibit and restrict consumer options in today's increasingly competitive electricity market. In connection with the proposed steps to mitigate rising energy costs, to provide a broader range of alternatives to consumers and to make Indiana more competitive as a location for large employers, the Service Area Assignments Act should therefore be amended to provide that the service rights of electric suppliers within their assigned service territories shall be subject to the following exceptions: (1) services by alternative suppliers in accordance with an alternative regulatory plan approved by the Commission pursuant to the AUR Act, as revised; (2) services to a customer eligible for and receiving service under a distribution-only tariff provision approved by the Commission; (3) electric power generated by facilities owned in whole or in part by the consumer being served, regardless of whether the facilities are located on the consumer's property or are off-site; and (4) electric power produced from a clean energy resource[33] that is connected to the distribution system of the utility in whose assigned service area the consumer is located. In the context of more comprehensive changes to Indiana's retail electric market,

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[30] *See* Ind. Code §8-1-2.3-1 *et seq.*
[31] *See United REMC v. Indiana & Michigan Electric Co.*, 549 N.E.2d 1019, 1021 (Ind. 1990) (describing legislative history).
[32] *See* Ind. Code §8-1-2.3-4.
[33] "Clean energy resource" is defined at Ind. Code §8-1-37-4.

pursuant to further legislation arising from the proposed one-year study period, additional amendments to the Act may well be necessary and appropriate.

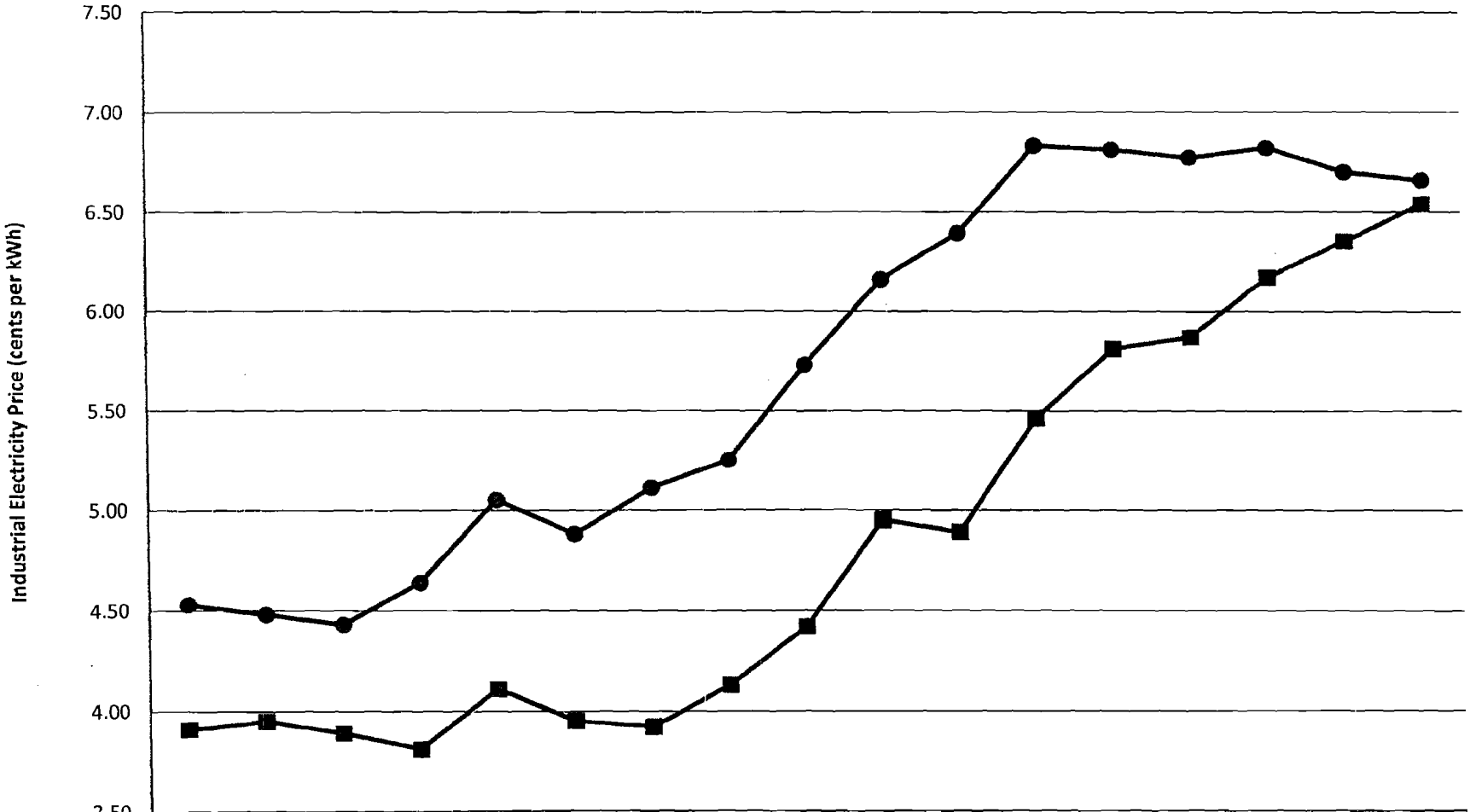
E. Conclusion

Indiana is no longer a low-cost energy state. Rising electric rates are posing increasing problems to the vitality of Indiana's industrial base, to the attraction and retention of large employers, and to the interests of all consumers. Indiana is falling behind other states in addressing high energy costs, and the problem is getting worse. The Industrial Consumers, accordingly, support the institution of a one-year study period to develop comprehensive regulatory reform legislation. The Industrial Consumers further support the prompt adoption of provisions to support energy projects by non-utilities and the immediate amendment of regulatory statutes to authorize greater flexibility to consumers seeking alternative supply options, including a grant of authority to the Commission to establish alternative regulatory mechanisms.

EXHIBIT A

Industrial Electricity Prices for Indiana and U.S. Total

(1997-June 2013)



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 (Jan-June)
IN	3.91	3.95	3.89	3.81	4.11	3.95	3.92	4.13	4.42	4.95	4.89	5.46	5.81	5.87	6.17	6.35	6.54
US Total	4.53	4.48	4.43	4.64	5.05	4.88	5.11	5.25	5.73	6.16	6.39	6.83	6.81	6.77	6.82	6.70	6.66

EXHIBIT B

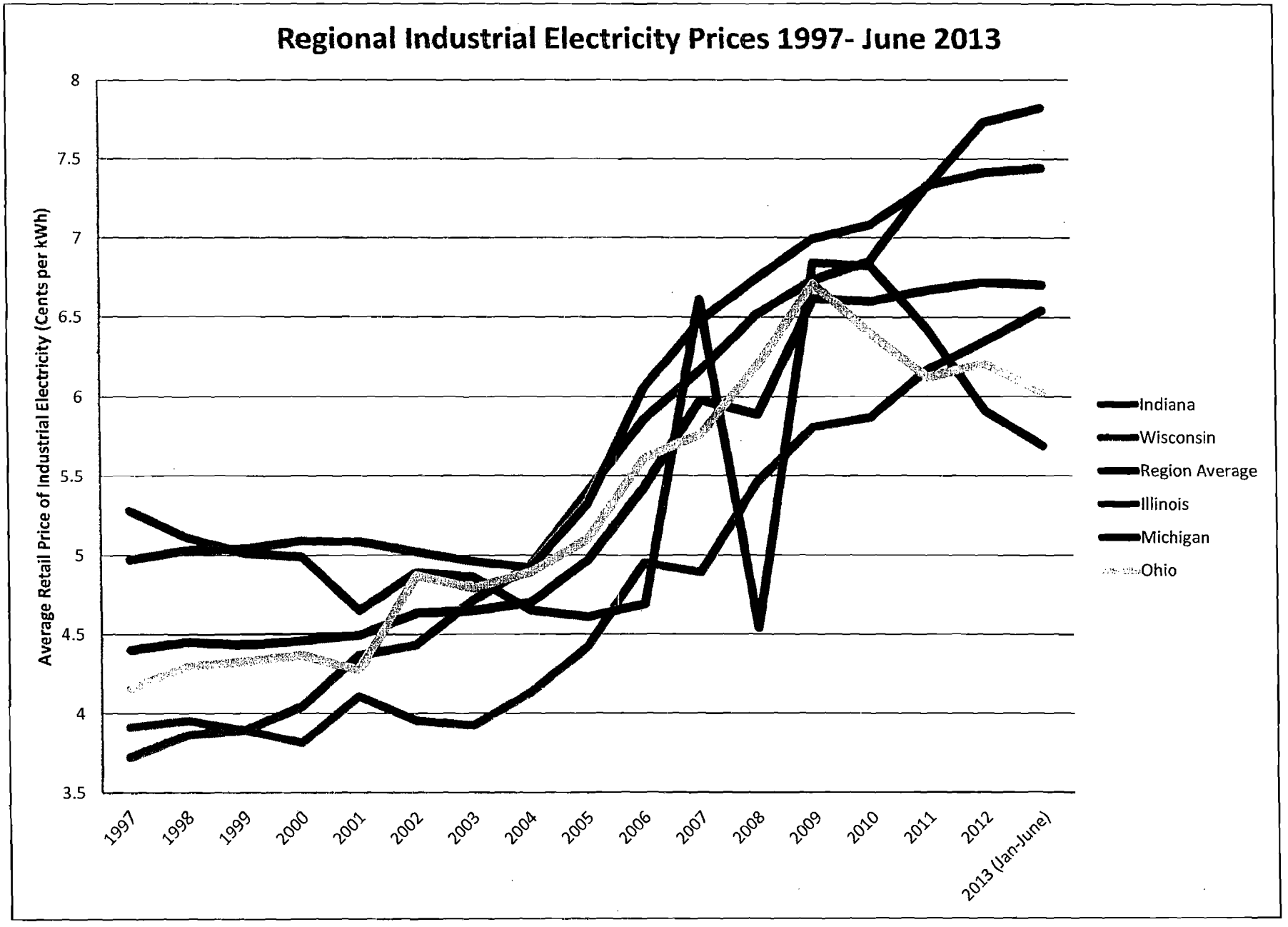
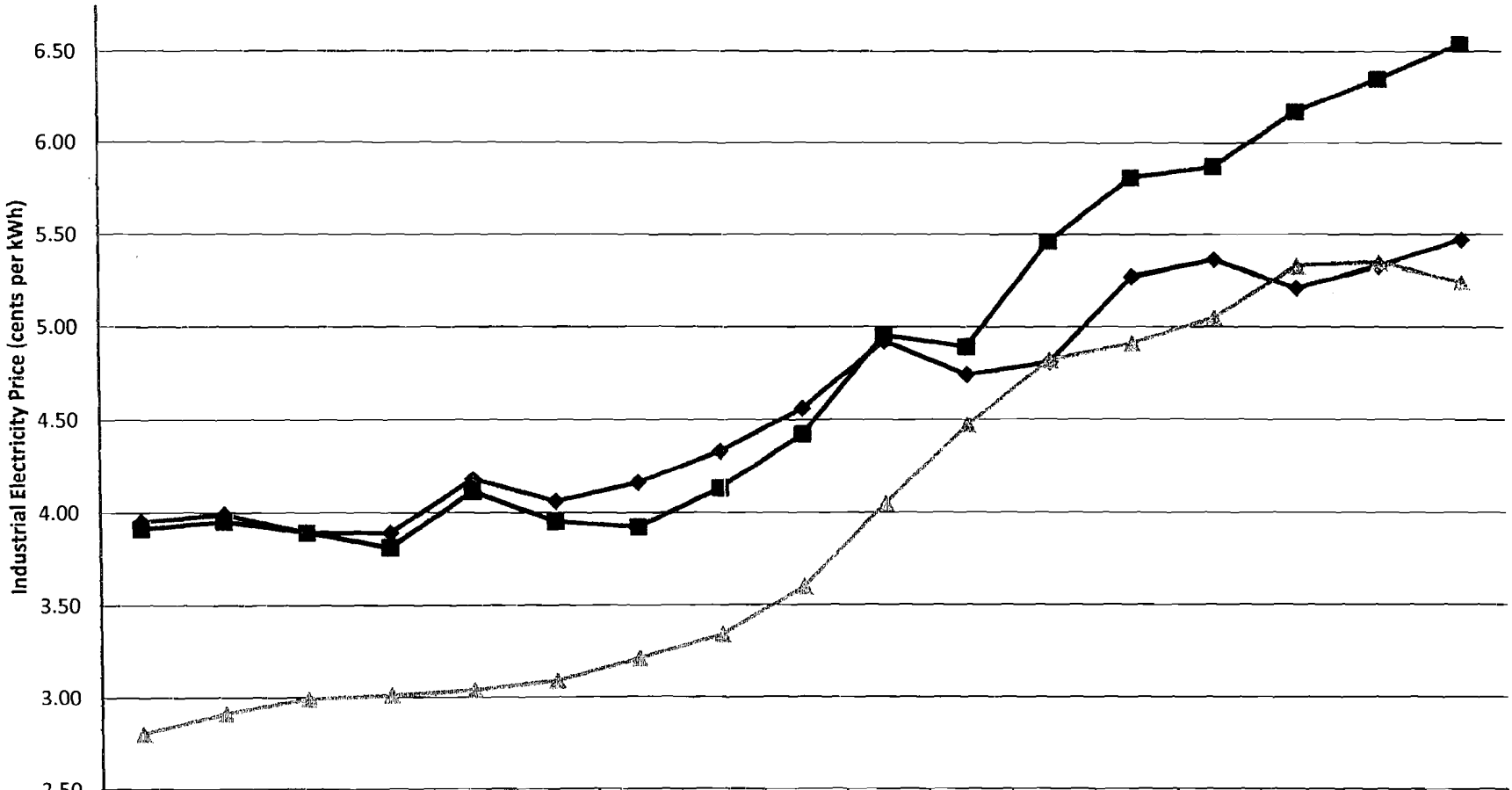

Regional Industrial Electricity Prices 1997- June 2013
Average Retail Price of Industrial Electricity (Cents per kWh)
8
7.5
7
6.5
6
5.5
5
4.5
4
3.5
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013 (Jan-June)
Indiana
Wisconsin
Region Average
Illinois
Michigan
Ohio

EXHIBIT C

Industrial Electricity Prices for Iowa, Indiana, & Kentucky

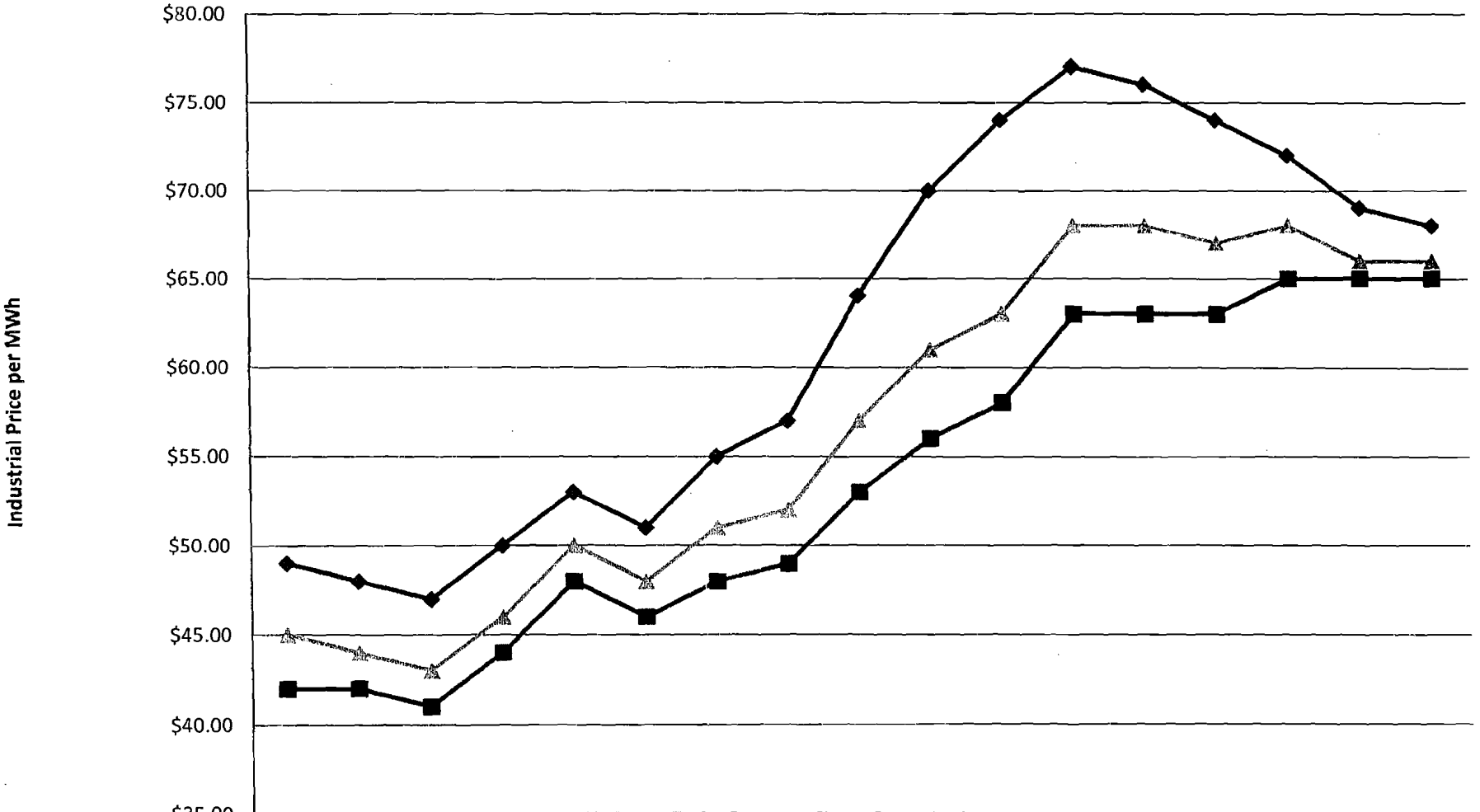
(1997-June 2013)



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 (Jan-June)
IA	3.95	3.99	3.89	3.89	4.18	4.06	4.16	4.33	4.56	4.92	4.74	4.81	5.27	5.36	5.21	5.33	5.47
IN	3.91	3.95	3.89	3.81	4.11	3.95	3.92	4.13	4.42	4.95	4.89	5.46	5.81	5.87	6.17	6.35	6.54
KY	2.80	2.91	2.99	3.01	3.04	3.09	3.21	3.34	3.60	4.05	4.47	4.82	4.91	5.05	5.33	5.35	5.24

EXHIBIT D

Industrial Electricity Prices in Restructured and Regulated Markets



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 (Jan-June)
Restructured States	$49.00	$48.00	$47.00	$50.00	$53.00	$51.00	$55.00	$57.00	$64.00	$70.00	$74.00	$77.00	$76.00	$74.00	$72.00	$69.00	$68.00
Regulated States	$42.00	$42.00	$41.00	$44.00	$48.00	$46.00	$48.00	$49.00	$53.00	$56.00	$58.00	$63.00	$63.00	$63.00	$65.00	$65.00	$65.00
US Total	$45.00	$44.00	$43.00	$46.00	$50.00	$48.00	$51.00	$52.00	$57.00	$61.00	$63.00	$68.00	$68.00	$67.00	$68.00	$66.00	$66.00

Exhibit 7
Regulatory Flexibility Committee
9/18/13

Table 5.6.A. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, June 2013 and 2012 (Cents per Kilowatthour)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	June 2013	June 2012	June 2013	June 2012	June 2013	June 2012	June 2013	June 2012	June 2013	June 2012
New England	16.41	16.00	14.06	13.80	12.18	12.54	12.47	6.48	14.52	14.29
Connecticut	17.77	17.32	14.69	14.60	12.58	12.62	10.24	9.06	15.69	15.42
Maine	14.16	14.27	11.00	10.77	7.59	7.48	--	--	11.30	11.22
Massachusetts	15.86	15.52	14.46	14.39	13.34	13.88	13.53	4.64	14.63	14.57
New Hampshire	16.73	16.53	13.53	13.40	11.25	11.71	--	--	14.34	14.28
Rhode Island	16.90	15.32	13.96	12.30	12.38	11.46	13.35	12.70	14.93	13.34
Vermont	17.77	17.11	14.83	14.41	10.30	10.14	--	--	14.62	14.23
Middle Atlantic	16.16	15.65	13.56	13.52	7.27	7.64	12.28	12.52	13.29	13.21
New Jersey	16.03	15.69	13.77	13.56	11.40	11.03	10.45	10.01	14.44	14.16
New York	19.31	18.32	15.93	15.94	6.42	6.97	14.09	14.36	16.14	15.90
Pennsylvania	13.09	12.95	9.17	9.22	6.89	7.26	7.69	7.70	9.76	9.90
East North Central	12.51	12.11	9.68	9.46	6.67	6.56	5.97	6.66	9.53	9.37
Illinois	10.12	11.23	7.77	7.95	5.72	5.78	5.71	6.53	7.92	8.46
Indiana	11.15	10.40	9.45	9.07	6.58	6.38	10.77	9.77	8.67	8.33
Michigan	15.47	14.14	11.57	11.12	8.26	7.92	9.27	7.21	11.75	11.18
Ohio	12.95	12.15	9.58	9.27	6.10	6.08	6.78	6.99	9.49	9.17
Wisconsin	14.39	13.43	11.17	10.67	7.64	7.57	--	--	10.91	10.54
West North Central	12.22	11.40	9.86	9.17	6.98	6.58	11.08	9.74	9.76	9.19
Iowa	12.03	11.34	8.98	8.44	5.76	5.47	--	--	8.39	8.11
Kansas	12.11	11.62	9.90	9.59	7.32	7.30	--	--	10.01	9.82
Minnesota	12.83	11.81	10.42	9.27	7.37	6.76	10.64	9.17	10.12	9.25
Missouri	12.34	11.44	10.24	9.51	7.37	6.86	11.55	10.23	10.51	9.81
Nebraska	11.69	10.68	9.10	8.72	7.34	6.92	--	--	9.14	8.62
North Dakota	10.94	10.56	9.03	8.65	7.40	6.75	--	--	8.92	8.39
South Dakota	11.29	10.38	8.77	8.17	6.95	6.59	--	--	9.20	8.58
South Atlantic	11.67	11.69	9.48	9.42	6.75	6.72	8.90	8.53	9.96	9.94
Delaware	13.18	13.96	10.20	10.15	8.53	8.88	--	--	10.96	11.32
District of Columbia	12.65	13.17	11.78	12.01	5.59	5.08	9.45	8.31	11.74	11.98
Florida	11.29	11.58	9.36	9.69	7.87	8.29	8.43	8.27	10.25	10.58
Georgia	12.17	11.70	10.26	9.47	6.68	6.36	10.05	8.85	10.25	9.72
Maryland	13.97	13.15	10.93	10.71	8.39	7.96	8.57	8.54	11.97	11.45
North Carolina	11.04	10.90	8.73	8.59	6.49	6.44	7.83	8.14	9.24	9.12
South Carolina	12.02	12.15	10.24	9.90	6.24	6.10	--	--	9.52	9.44
Virginia	11.51	11.88	8.11	8.32	6.68	6.79	8.15	8.77	9.21	9.44
West Virginia	9.74	9.91	8.01	8.00	6.21	6.28	12.56	8.60	7.88	7.99
East South Central	10.83	10.38	9.90	9.95	6.67	6.72	11.75	11.44	9.17	8.96
Alabama	11.66	11.47	10.91	10.69	6.90	7.10	--	--	9.69	9.70
Kentucky	10.04	9.38	8.01	8.83	5.82	5.65	--	--	7.75	7.55
Mississippi	11.14	10.19	10.34	9.22	7.27	6.85	--	--	9.61	8.84
Tennessee	10.46	10.21	10.35	10.45	7.15	7.67	11.75	11.44	9.67	9.55
West South Central	10.96	10.31	8.23	7.96	6.13	5.40	10.36	10.21	8.74	8.24
Arkansas	10.05	9.59	8.21	7.80	6.25	6.08	NM	NM	8.20	7.89
Louisiana	9.65	8.00	8.96	7.24	6.08	4.16	9.55	7.98	8.19	6.48
Oklahoma	10.18	9.43	8.32	7.48	5.92	5.16	--	--	8.42	7.69
Texas	11.45	11.03	8.09	8.18	6.16	5.75	10.49	10.56	8.99	8.79
Mountain	11.84	11.48	9.87	9.44	6.97	6.60	10.96	10.15	9.72	9.34
Arizona	12.18	11.87	10.55	10.10	7.14	7.01	--	--	10.89	10.54
Colorado	12.42	11.93	10.49	9.89	7.70	7.02	11.00	10.01	10.34	9.75
Idaho	10.19	8.84	7.98	7.02	6.97	6.24	--	--	8.00	7.09
Montana	11.06	10.44	9.81	9.12	5.62	4.86	--	--	8.77	8.16
Nevada	11.56	11.80	8.38	8.63	7.15	7.41	8.20	8.82	9.22	9.42
New Mexico	12.48	12.09	10.18	9.78	6.91	6.09	--	--	9.86	9.34
Utah	10.83	10.36	9.20	8.84	6.57	6.35	11.50	10.66	8.82	8.54
Wyoming	10.77	10.23	8.82	8.32	6.38	6.04	--	--	7.47	7.19
Pacific Contiguous	14.82	13.78	14.67	13.54	8.80	8.23	7.49	7.52	13.36	12.41
California	17.50	16.15	16.94	15.44	12.25	11.46	7.44	7.50	16.22	14.92
Oregon	10.16	9.96	8.43	8.38	5.88	5.46	8.93	8.37	8.28	8.10
Washington	8.82	8.70	7.62	7.58	4.04	3.94	8.50	7.72	6.81	6.75
Pacific Noncontiguous	29.68	31.21	25.59	27.13	25.74	28.54	--	--	26.79	28.78
Alaska	18.51	18.05	15.79	14.97	15.23	16.03	--	--	16.46	16.17
Hawaii	37.04	39.99	33.61	37.07	29.58	32.74	--	--	32.98	36.23
U.S. Total	12.54	12.09	10.70	10.42	7.13	6.92	10.70	10.22	10.47	10.15

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.
Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
Notes: - See Glossary for definitions. - Values are preliminary estimates based on a cutoff model sample.
See Technical Notes for a discussion of the sample design for the Form EIA-826.
Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.
Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.
Totals may not equal sum of components because of independent rounding.
Source: U.S. Energy Information Administration, Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report.

Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through June 2013 and 2012 (Cents per Kilowatthour)

	Residential		Commercial		Industrial		Transportation		All Sectors	
Census Division and State	June 2013 YTD	June 2012 YTD	June 2013 YTD	June 2012 YTD	June 2013 YTD	June 2012 YTD	June 2013 YTD	June 2012 YTD	June 2013 YTD	June 2012 YTD
New England	15.88	15.95	14.08	13.83	12.15	11.98	11.01	6.92	14.35	14.19
Connecticut	17.37	17.38	14.76	14.77	12.71	12.77	9.78	10.09	15.65	15.61
Maine	14.37	14.69	11.73	11.71	8.58	7.67	–	–	11.96	11.79
Massachusetts	15.02	15.35	14.33	13.94	12.97	12.88	11.54	4.64	14.16	14.05
New Hampshire	16.51	16.35	13.62	13.52	11.57	11.65	–	–	14.46	14.34
Rhode Island	15.64	14.60	13.39	12.44	12.17	11.01	12.83	13.86	14.15	13.11
Vermont	17.25	16.94	14.69	14.40	10.22	10.02	–	–	14.49	14.23
Middle Atlantic	15.36	15.13	12.77	12.75	7.27	7.51	12.13	11.82	12.65	12.56
New Jersey	15.50	15.94	12.50	12.71	10.39	10.35	10.55	9.31	13.39	13.60
New York	18.48	17.08	14.91	14.72	6.54	6.79	13.64	13.38	15.32	14.76
Pennsylvania	12.56	12.93	9.30	9.41	6.99	7.23	7.89	7.73	9.77	9.94
East North Central	11.91	11.99	9.50	9.52	6.52	6.48	5.80	6.29	9.25	9.20
Illinois	10.46	11.75	7.90	8.30	5.69	5.99	5.56	6.11	8.02	8.62
Indiana	10.69	10.44	9.46	9.20	6.54	6.42	9.94	9.85	8.53	8.27
Michigan	14.37	13.81	11.02	10.80	7.82	7.54	9.38	7.39	11.17	10.76
Ohio	11.66	11.45	9.40	9.49	6.03	5.97	6.44	6.76	9.02	8.85
Wisconsin	13.59	13.18	10.74	10.47	7.44	7.31	–	–	10.54	10.24
West North Central	10.58	10.23	8.78	8.25	6.44	6.06	8.10	7.24	8.74	8.26
Iowa	10.72	10.52	8.18	7.70	5.47	5.09	–	–	7.83	7.43
Kansas	11.44	10.94	9.52	9.04	7.04	6.84	–	–	9.48	9.04
Minnesota	11.64	11.11	9.38	8.62	6.94	6.43	9.62	8.44	9.35	8.70
Missouri	10.16	9.78	8.54	7.97	5.94	5.62	6.87	6.28	8.68	8.18
Nebraska	9.70	9.43	8.41	8.13	7.12	6.71	–	–	8.41	8.04
North Dakota	8.66	8.70	8.09	7.76	7.03	6.56	–	–	7.95	7.65
South Dakota	9.84	9.69	8.22	7.93	6.80	6.43	–	–	8.59	8.28
South Atlantic	11.17	11.27	9.32	9.39	6.37	6.39	8.70	8.20	9.58	9.62
Delaware	13.15	13.59	10.29	9.95	8.47	7.96	–	–	11.02	10.85
District of Columbia	12.26	12.36	11.88	12.22	6.07	5.08	9.68	8.52	11.76	11.98
Florida	11.27	11.45	9.52	9.77	7.66	8.04	8.62	8.48	10.25	10.47
Georgia	10.97	10.71	9.81	9.40	5.95	5.65	7.82	7.59	9.35	9.00
Maryland	12.84	12.80	10.43	10.59	8.34	8.09	8.59	7.93	11.34	11.28
North Carolina	10.64	10.69	8.55	8.50	6.12	6.19	7.90	7.85	8.96	8.92
South Carolina	11.70	11.56	9.74	9.42	5.74	5.87	–	–	8.98	8.84
Virginia	10.63	11.18	7.96	8.30	6.61	6.68	8.15	8.80	8.87	9.17
West Virginia	9.57	9.82	8.33	8.40	6.26	6.30	10.77	8.62	8.01	8.10
East South Central	10.34	10.17	9.85	9.79	5.77	5.95	11.67	11.42	8.54	8.38
Alabama	11.19	11.21	10.52	10.52	5.87	6.03	–	–	8.92	8.94
Kentucky	9.63	9.26	8.68	8.69	5.24	5.32	–	–	7.31	7.10
Mississippi	10.68	10.30	9.98	9.34	6.24	6.07	–	–	8.91	8.50
Tennessee	10.01	9.93	10.05	10.17	6.27	6.79	11.67	11.42	9.14	9.04
West South Central	10.58	10.26	8.13	8.06	5.74	5.36	10.38	10.24	8.32	8.06
Arkansas	9.30	9.00	7.96	7.56	5.74	5.41	NM	NM	7.68	7.29
Louisiana	9.22	8.26	8.93	7.81	5.83	4.74	9.54	8.29	7.85	6.80
Oklahoma	9.50	9.42	7.51	7.17	5.21	5.08	–	–	7.61	7.40
Texas	11.24	11.00	8.10	8.29	5.80	5.60	10.51	10.55	8.64	8.57
Mountain	10.97	10.63	9.15	8.79	6.17	5.91	10.18	9.33	8.86	8.53
Arizona	11.39	11.05	9.71	9.32	6.40	6.20	–	–	9.85	9.50
Colorado	11.55	11.03	9.61	9.06	7.07	6.71	10.54	9.27	9.54	9.03
Idaho	8.80	8.12	7.12	6.65	5.76	5.31	–	–	7.21	6.68
Montana	10.16	9.84	9.46	9.06	5.24	4.93	–	–	8.47	8.14
Nevada	11.70	12.01	8.71	8.86	5.66	5.82	7.62	7.82	8.47	8.64
New Mexico	11.44	11.04	9.40	8.96	6.22	5.69	–	–	8.98	8.54
Utah	10.07	9.63	8.25	8.00	5.74	5.45	10.17	9.72	7.95	7.63
Wyoming	9.88	9.54	8.48	8.12	6.37	5.97	–	–	7.48	7.11
Pacific Contiguous	13.14	12.62	11.86	11.39	7.73	7.49	7.34	7.70	11.43	11.00
California	16.07	15.29	13.39	12.76	10.51	10.16	7.28	7.68	13.77	13.14
Oregon	9.79	9.74	8.36	8.36	5.72	5.49	8.81	8.26	8.30	8.23
Washington	8.56	8.42	7.73	7.66	4.08	4.06	8.29	8.21	7.02	6.94
Pacific Noncontiguous	28.26	28.78	25.24	25.52	26.31	27.25	–	–	26.50	27.07
Alaska	17.82	17.87	15.15	14.87	16.06	17.08	–	–	16.26	16.36
Hawaii	37.18	37.60	34.46	35.29	30.13	31.12	–	–	33.57	34.39
U.S. Total	11.90	11.75	10.13	10.00	6.66	6.55	10.36	9.84	9.87	9.69

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.
Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.
Notes: - See Glossary for definitions. - Values are preliminary estimates based on a cutoff model sample.
See Technical Notes for a discussion of the sample design for the Form EIA-826.
Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.
Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.
Totals may not equal sum of components because of independent rounding.
Source: U.S. Energy Information Administration, Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report.

Exhibit 7
Regulatory Flexibility Committee
9/18/13

INDIANA SHOULD STUDY ELECTRICITY CUSTOMER CHOICE & INDUSTRY RESTRUCTURING

Regulatory Flexibility Committee
Indiana General Assembly

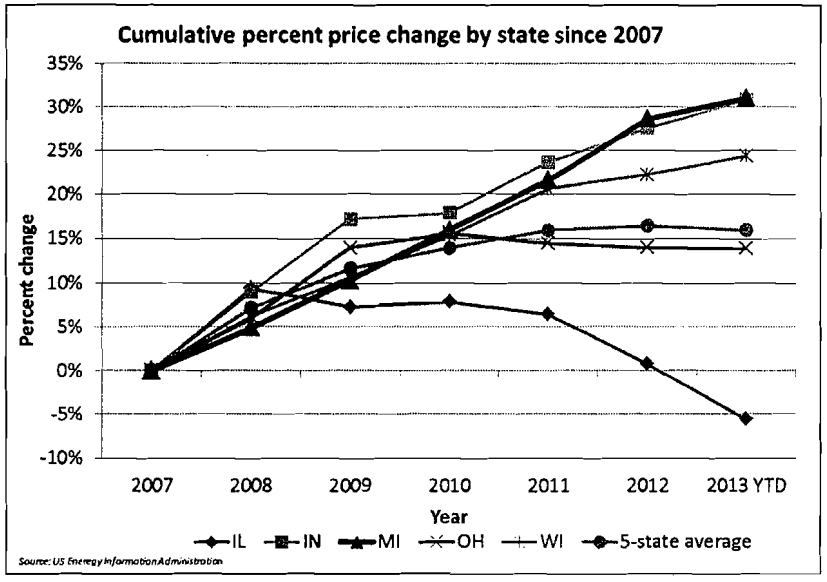
Philip R. O'Connor, Ph.D.
PROactive Strategies, Inc.

September 18, 2013

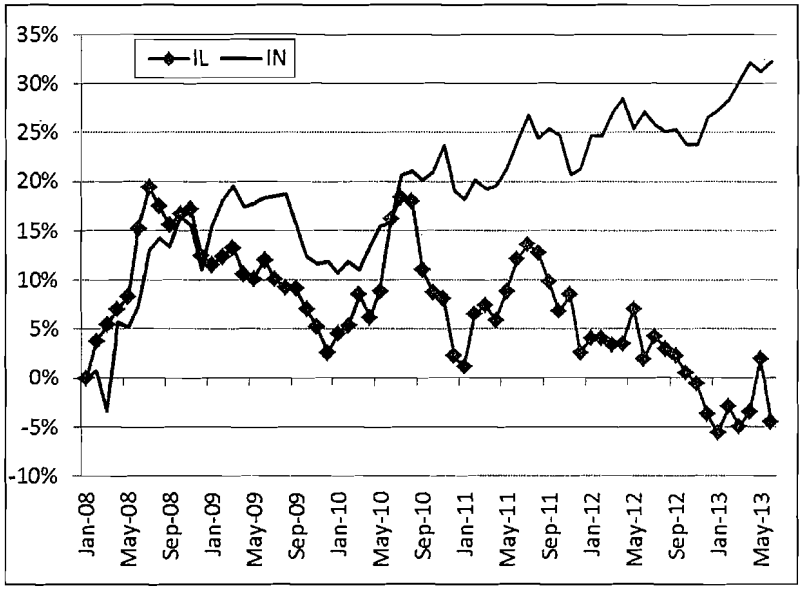
THREE REASONS WHY A STUDY OF ELECTRICITY CHOICE IS TIMELY

1) Indiana is losing its traditional electricity price advantage and the economic benefits. Indiana's continuing price trend is disadvantageous.
2) Market conditions and federal regulatory policies warrant a re-evaluation of traditional regulation's allocation of risk to customers.
3) A study would be based on the actual experience of more than a dozen states with broad-based operating customer choice programs. It would not be speculative.

INDIANA & MICHIGAN RATES RISING FASTEST IN UPPER MIDWEST



INDIANA v ILLINOIS ALL SECTORS % PRICE CHANGE JAN2008-JUN2013



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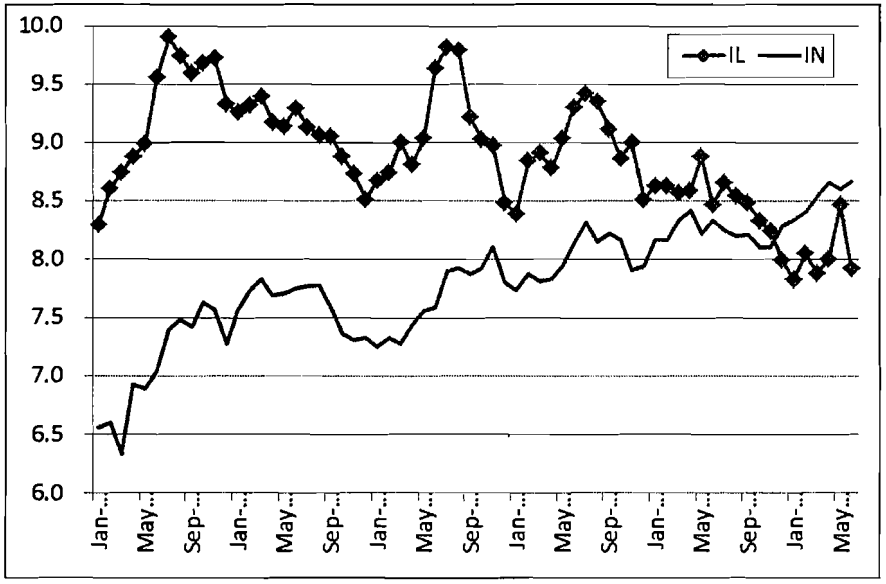
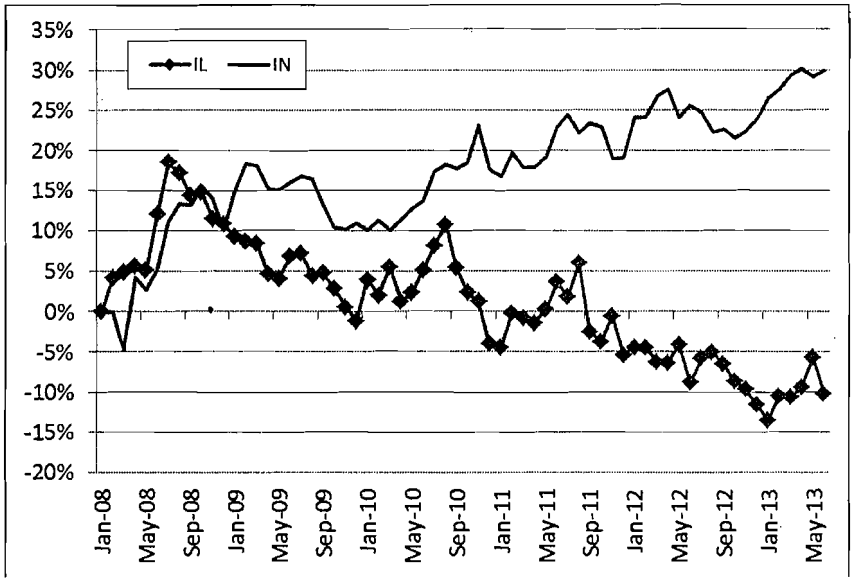


INDIANA v. ILLINOIS C&I PRICES % CHANGE JAN2008–JUN2013



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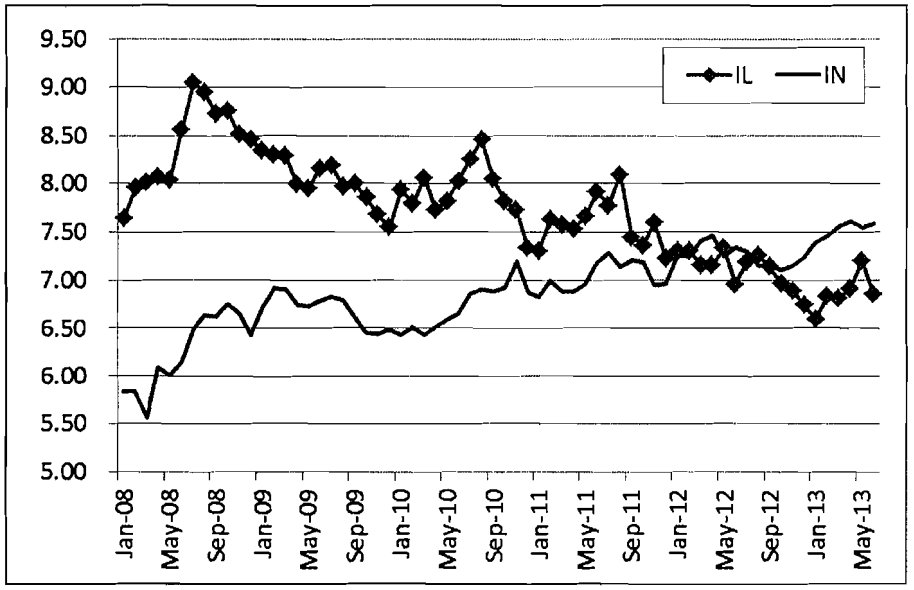
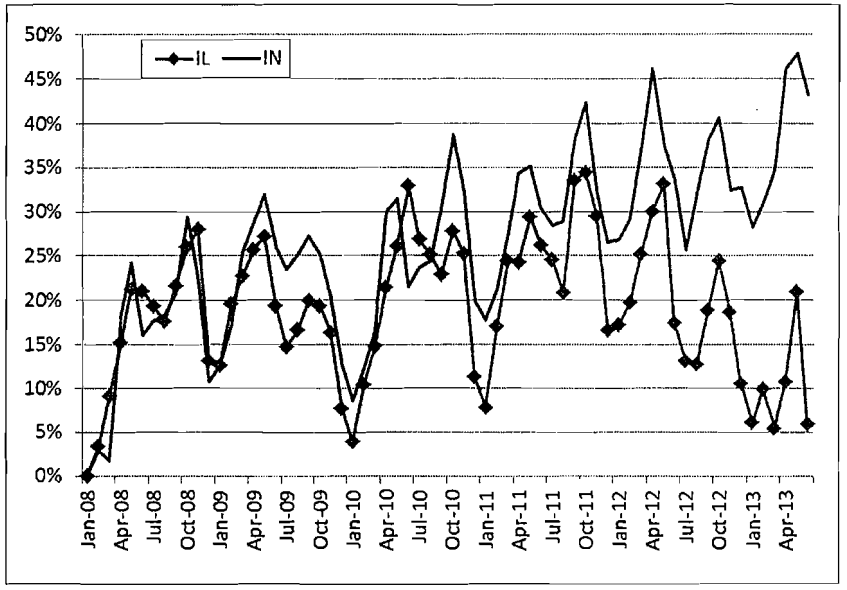
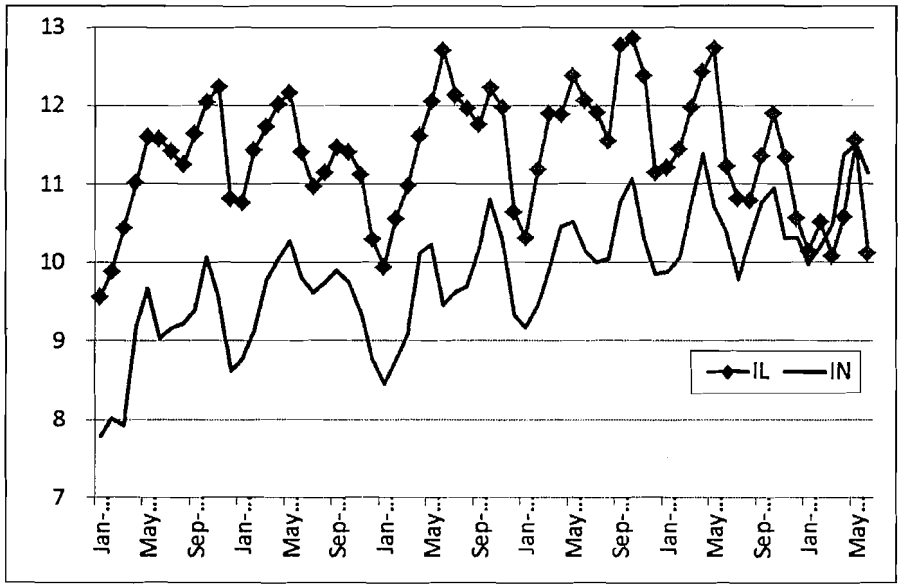


INDIANA v ILLINOIS RESIDENTIAL % PRICE CHANGE JAN2008-JUN2013



INDIANA v ILLINOIS RESIDENTIAL ¢/kWh JAN2008-JUN2013



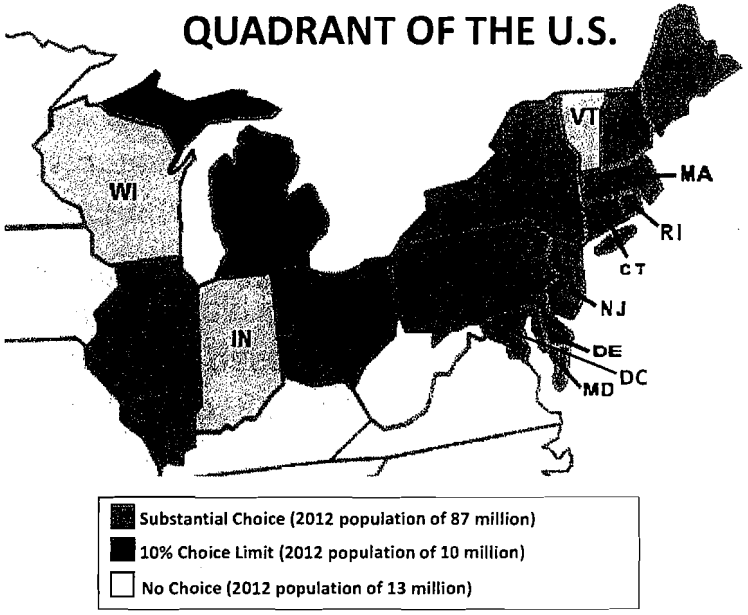
RISK ALLOCATION: WHO PAYS FOR UNECONOMIC INVESTMENTS?

- Traditional utility regulation, devised in the late-1800s & early-1900s, fit well with the technology & economy that prevailed for a century.
- Since 1980s new technologies and fuel markets upheavals have made the generation business intrinsically competitive – not a monopoly.
- The traditional regulatory standard of utility "prudence" places the burden of business and investment risk on customers rather than on investors and generation plant management.

RESTRUCTURING & CUSTOMER CHOICE: RISK IS ALLOCATED IN THE MARKET

- States that have restructured the industry & given customers choice have compensated utilities for above-market investments – "stranded costs."
- With a clean start, future investments are made by investors on the basis of the ability to compete with others to control costs & attract customers .
- In Indiana, where should the business risk lie for billions of dollars in power plant investment to replace older plants and to comply with federal environmental rules?

CHOICE IS THE NORM IN THE NORTHEAST QUADRANT OF THE U.S.



RELIABILITY IS AS GOOD WITH CUSTOMER CHOICE AS UNDER MONOPOLY

- States with customer choice have attracted billions of dollars in generation investment.
- Competitive & monopoly states both belong to the same regional transmission organizations.
- Power industry organizations, federal and state regulators maintain reliability standards.
- Independent experts & bodies have not found customer choice to be a factor in outages or other power disruptions.

ALL RESTRUCTURED STATES HAVE ADDRESSED THE BIG ISSUES

- Stranded cost compensation for utilities
- Devolution of generating plants to market
- Setting cost-based, open access delivery rates
- Financial integrity of regulated wires utilities
- Provider of last resort for small customers
- Attracting investment in generating capacity
- Customer protection rules & supplier licensing
- Mechanisms for facilitating residential choice.
- Inclusion of renewable resources in supply.

Philip R. O'Connor, Ph.D.
PROactive-Strategies, Inc. -- Chicago, Illinois

Dr. Phil O'Connor is President of PROactive Strategies, a Chicago consulting firm providing advice in the energy and insurance industries. For over three decades Phil has been recognized as a leading authority on competitive market solutions for regulated businesses.

Phil is the author of *Customer Choice in Electricity Markets: From Novel to Normal*, published by COMPETE Coalition in November 2010 and co-author with Terrence L. Barnich of "The Grand Experiment: Has Restructuring Succeeded on Either Continent?", published in *Public Utilities Fortnightly*, February 2007. He co-authored with John L. Domagalski "Regulation and Relevancy: Assessing the Impact of Electricity Customer Choice," published in *Electricity Policy*, June 2012.

In addition to a lengthy career in the private sector, Phil has had extensive government and political experience, serving as Illinois' chief utility regulator having chaired the Illinois Commerce Commission serving as Director of the Illinois Department of Insurance and as a member of the Illinois State Board of Elections. Five consecutive Illinois Governors have appointed him to various boards and commissions.

From March 2007 to March 2008, Phil served in the U.S. Embassy in Baghdad, Iraq with the US Army Corps of Engineers and the US State Department as an advisor to the Iraqi Ministry of Electricity. A *magna cum laude* graduate of Loyola University of Chicago, Phil received his Masters and Doctorate in Political Science from Northwestern University.

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Exhibit 7
Regulatory Flexibility Committee
9/18/13

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6 August 2013

Representative Eric Koch, Co-Chair
Senator Jim Merritt, Co-Chair
200 W. Washington Street
Indianapolis, Indiana 46204

Re: September 18, 2013 Regulatory Flexibility Committee meeting and review of electricity customer choice pursuant to Senate Enrolled Act 560

Dear Co-Chairmen Representative Koch and Senator Merritt:

It is my understanding that the Regulatory Flexibility Committee at its September 18 meeting may consider undertaking a study of the merits of electric industry restructuring in order to provide Indiana electric customers with the opportunity to access competitive electricity supply.

I believe that Indiana would be well served by such a study. Given the time frame contemplated in Senate Enrolled Act 560, the study would necessarily be preliminary. Nonetheless, a preliminary review would, I believe, validate that an open and more complete discussion of customer choice is warranted for Indiana.

My perspective is informed by a long career as a utility regulator, a consultant in the energy industry and as a practitioner in competitive electricity markets. My *curriculum vitae* is attached. Since my days as a utility regulator, three decades ago, I have been a strong advocate of placing greater reliance on well-functioning competitive electricity markets rather than on administrative monopoly pricing.

This letter is intended merely to lay out three reasons why the proposed study would be timely. I believe, based on my experience, that an initial study by the Regulatory Flexibility Committee would serve to educate the Legislature and to provide the groundwork for fashioning solutions to genuine challenges faced by Indiana in the electricity sector.

***First*, Indiana is losing ground in the long-running electricity price advantage it has enjoyed.**

For many years, Indiana had the lowest average prices for delivered electricity in the five-state Upper Midwest region – Illinois, Indiana, Michigan, Ohio and Wisconsin.[1] The most pointed example of Indiana's eroding position is the dramatic change in the price relativity between Indiana and Illinois. Further, Illinois' national price ranking has improved relative to Indiana's.

A comparison of average prices and national ranking in average prices for Illinois and Indiana illustrate the point. The figures below are drawn from the U.S. Energy Information Agency (EIA). The data for 2010-2012 are full calendar data while the figures for 2013 are year-to-date through May.[2] It is likely that 2013 full-year data will show a similar ranking as do the data through May.

Year	Illinois		Indiana	
	¢/kWh	Rank above lowest	¢/kWh	Rank above lowest
2010	9.13	28th	7.67	13th
2011	8.97	25th	8.01	13th
2012	8.50	18th	8.23	12th
2013 (YTD May)	8.03	11th	8.50	19th

In the decade prior to the introduction of competitive electricity supply and customer choice in Illinois average prices consistently were lower in Indiana than in Illinois. As customer access to the market expanded with the gradual and measured implementation of Illinois' electricity restructuring law, the price gap has closed. This improvement in Illinois' price position relative to its former position prior to restructuring has been worth tens of billions of dollars to Illinois consumers. For your information, I have included with this letter a copy of an opinion column authored late last year by Vince Persico and Phil Novak, former members of the Illinois House of representatives who were the bi-partisan co-sponsors of Illinois' 1997 electric restructuring law.[3]

The two charts below, based on data from the U.S. Energy Information Administration (EIA) illustrate Indiana's declining price advantage over Illinois in recent years in the critically important arena of commercial and industrial (C&I) electricity pricing. C&I electricity customers, including government, account for about two-thirds of electricity consumption and for the bulk of employment in Indiana. Average non-residential prices in Illinois have fallen below those in Indiana. While Illinois prices were higher than those in Indiana until recently, there have been consistently opposite trends in the two

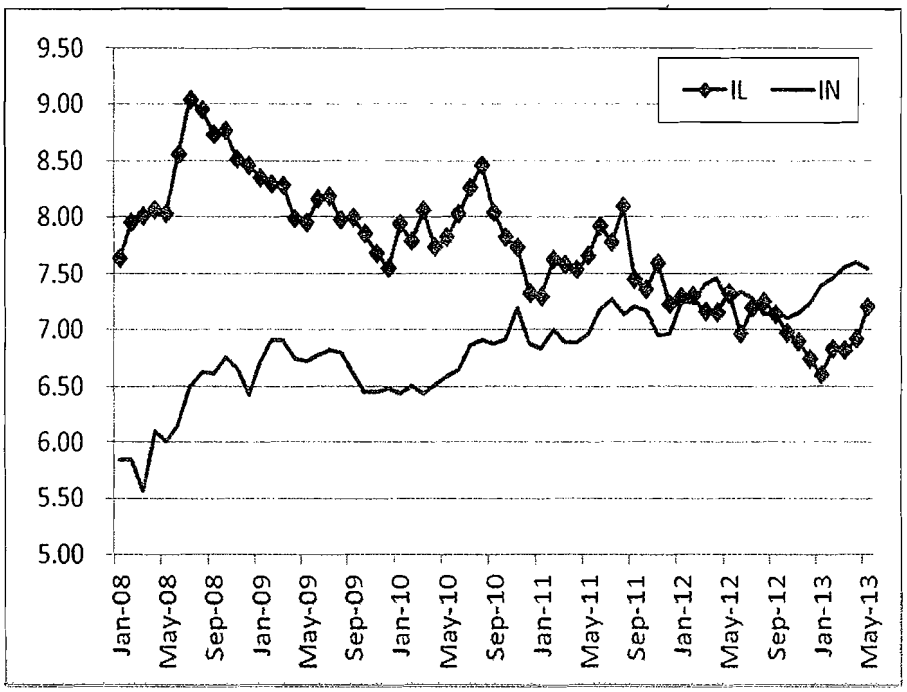
[1] Illinois, Indiana, Michigan, Ohio and Wisconsin have long been grouped by the U.S, Bureau of the Census as the East North Central geographic division for data collection. This geographic unit of analysis is used by other agencies such as the U.S. Energy Information Administration (EIA) http://www.census.gov/econ/census07/www/geography/regions_and_divisions.html.

[2] The EIA issues monthly and annual electricity data. The average price data for the January-May period data for 2010-11 and 2012-13 can be accessed, respectively, in Table 5.6.B at http://www.eia.gov/electricity/monthly/current_year/august2011.pdf and http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_06_b

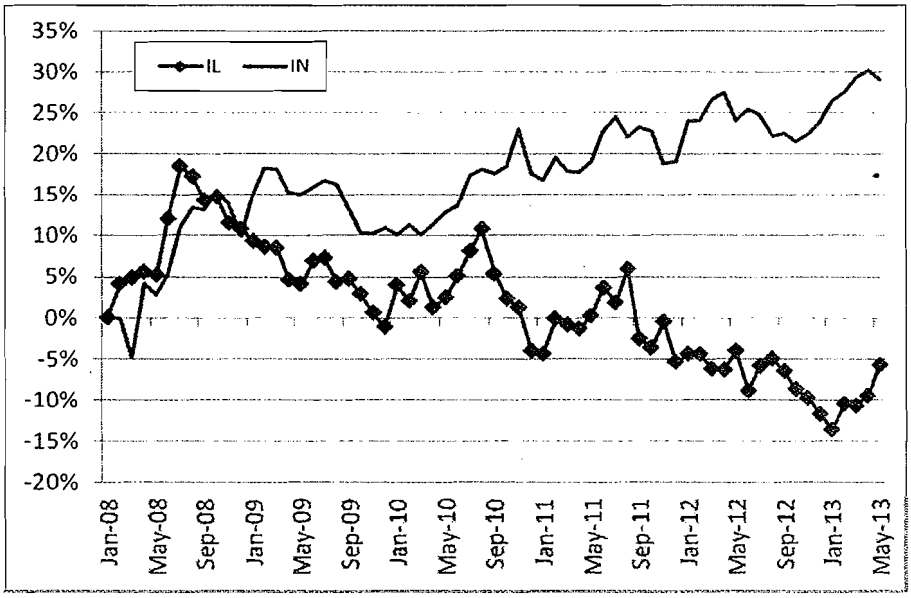
[3] "$31 billion in benefits, and counting" by Vince Persico and Philip Novak, *Daily Herald*, December 27, 2012, http://www.dailyherald.com/article/20121227/discuss/712279988/print/

states, with Indiana prices rising under monopoly regulation and Illinois prices falling as competitive markets reflect a variety of changing conditions. Between January 2008 and May of 2013, Indiana's average C&I prices have experienced a significant upward trend while prices in Illinois have been on a downward trend.

Average C&I ¢/kWh Price 2008-12



Percent 2008-12 Cumulative Change Average C&I kWh Price



The dollar implications are significant. During the first five months of 2013, January through May, the average Indiana price of 8.5 cents per kilowatt hour (delivered) was nearly a half-penny, or nearly 6% higher, than the Illinois average of 8.03 cents per kilowatt hour. Given the total volume of kilowatt hour sales in Indiana of 42.5 billion kilowatt hours during that five month period, Indiana customers paid about $200 million more than if Indiana prices were strictly on par with Illinois average prices. If that nearly half-penny price disparity is maintained over the course of 2013, then the price premium paid by Indiana customers compared to Illinois average prices would approach $480 million ($40 million per month).

There is good reason to believe that unless regulatory policies and practices accommodate changing conditions, Indiana average prices will continue to rise relative to those in Illinois. Various conditions are converging to exert upward pressure on prices in Indiana. This pressure will be magnified by inherent features of traditional regulation. Certainly, some of the more significant conditions are well-known to you and have been analyzed to some extent in the 2011 and 2012 reviews by the State Utility Forecasting Group.[4] As addressed further below, traditional monopoly utility regulations are not well-suited to addressing these conditions. There should be an inquiry into regulatory alternatives that are fair and effective, as proven by experience, in addressing the types of issues now facing Indiana.

Indiana policymakers would benefit from a study that could contribute to an understanding of the reasons for the erosion of Indiana's relative price position.

***Second*, traditional regulation requires customers to bear risks that private investors are better suited to bear.**

One reason for Indiana's eroding price position is that traditional utility regulation tends to shift risks to customers and away from private investors who are better suited to managing such risks. Traditional regulation also is ill-suited to conveying accurate price signals to customers, utility management and investors, resulting in consumption and investment decisions that may well be out of line with prevailing market realities.

This is not a criticism of Indiana's utility regulators or of their professionalism. Rather it is an observation that it is the very structure of traditional monopoly regulation that is incongruent with conditions that are quite different than those that prevailed when current regulatory practices were developed earlier in the 20th century. Professional application of traditional protocols that are mismatched with market realities naturally results in adverse, unintended consequences.

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[4] The State Utility Forecasting Group's (SUFG) most recent price forecast was issued September 2011, *Indiana Electricity Projections: The 2011 Forecast*, http://www.purdue.edu/discoverypark/energy/assets/pdfs/SUFG/publications/2011%20SUFG%20Forecast.pdf. In January 2012 SUFG issued a report on the potential impact of proposed USEPA emissions standards for coal-fired power plants. "The Impacts of Federal Environmental Regulations on Indiana Electricity Prices," January 2012 http://www.purdue.edu/discoverypark/energy/assets/pdfs/SUFG/publications/EPA%20regulations%20impact.pdf

The current difficulty of incorporating the construction costs and operating expenses of the Edwardsport plant into classically regulated rates represents a distillation of the problems inherent in traditional utility regulation in an environment of fast-changing market conditions. The apparent disadvantageous economics of the Edwardsport plant would be apportioned quite differently if Indiana customers could access market-priced power supplies rather than being captive to regulated prices. The responsibility for bearing construction costs and operating expenses in excess of previous estimates would be sorted out in the market rather than through regulatory settlements that distort market signals.

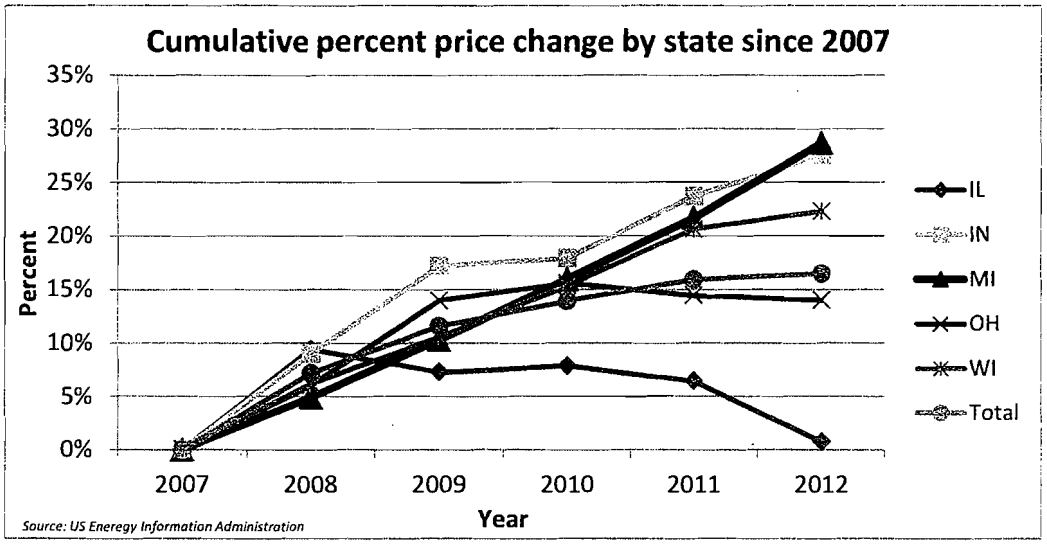
Beyond the question of any individual power plant, there are three systemic issues coming to bear in Indiana that traditional utility regulation will be less capable of addressing than would be a well-functioning competitive market for electric supply and customer choice. To the extent that Indiana utilities retrofit coal-fired units to meet new emissions standards, traditional regulation will tend to pass those costs on to customers even if doing so contributes to a further erosion of Indiana's relative price position. Next, continuing low natural gas prices due to substantial and growing supplies indicate attractive electricity prices in a competitive electricity market to which customers are denied access by traditional monopoly regulation. Finally, competitive market prices for generating capacity have been falling, meaning that captive monopoly customers are paying more for capacity in regulated retail rates than are being paid by customers who have access to competitive market supplies.

***Third*, a study would be based on substantial experience and not speculation or unproven theory.**

In 2013 any study to consider the relative merits of competitive and regulated electricity supply models would not be a speculative or academic undertaking. There is now a wealth of experience and literature available that a legislative review can consider. In 2013, more than a dozen states have broad-based customer choice models in operation. About 20% of all electricity load in the United States is now served under competitively priced retail supply arrangements.[5] In the northeastern quadrant of the United States, from the Atlantic to the Mississippi and from the Mason-Dixon Line to the Canadian border, the majority of electricity consumption is served under competitive wholesale and retail market models.

In the five-state East North Central region to which Indiana belongs, Illinois and Ohio have been demonstrating the value of competitive retail markets and the ways in which such markets can be methodically installed and carefully managed so as to bring benefits to customer and fair treatment to utility investors. Since 2008, Illinois prices have been falling and Ohio prices have remained fairly stable. In contrast, in the three states that rely exclusively or largely on traditional monopoly regulation, prices have been rising noticeably and well above the regional average change in prices. The chart below illustrates these developments.

[5] "Retail Choice: Proven, Growing, Sustainable," by Dr. Phillip R. O'Conner, for the COMPETE Coalition, April 2012, http://www.competecoalition.com/files/COMPETE_Coalition_2012_Report.pdf



The key point is that competitive markets are working well from a pricing standpoint and, further, there have not been adverse results for reliability and investment in electricity generation or delivery infrastructure.

Undertaking a study in Indiana is not a commitment to implement customer choice. Doing so, however, would bring a more in-depth understanding of Indiana's situation and of regulatory alternatives. It is better to make this inquiry now, rather than to wait until the Legislature feels that it is facing urgent circumstances.

I do appreciate the opportunity to write to you and I would be pleased to address any questions that you, other members or legislative staff might have.

Sincerely,

Philip R. O'Connor, Ph.D.

Cc: Governor Mike Pence
Members of the Regulatory Flexibility Committee
Members of the Legislative Council

Exhibit 7
Regulatory Flexibility Committee
9/18/13

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Regulation & Relevancy: Assessing the Impact of Electricity Customer Choice

The price spread between restructured states and traditionally monopoly-regulated states has narrowed in the three years since 2008 as much as it widened in the six-year period. In-depth analysis will be needed to determine whether traditional regulation provides discernible consumer benefits compared to competitive customer choice.

by John L. Domagalski and Philip R. O'Connor

Electricity Policy – the website ElectricityPolicy.com and the newsletter Electricity Daily – together comprise an essential source of information about the forces driving change in the electric power industry.

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The price spread between restructured states and traditionally monopoly-regulated states has narrowed in the three years since 2008 as much as it widened in the six-year period. In-depth analysis will be needed to determine whether traditional regulation provides discernible consumer benefits compared to competitive customer choice.

by John L. Domagalski and Philip R. O'Connor

The June 18, 2012 edition of *ElectricityPolicy.com* featured Dr. Kenneth Rose's views on the relative merits of traditional regulation of monopoly electricity generation supply service and the relatively new alternative of competitive customer choice in power supply.[1]

Dr. Rose's key contribution to the debate is his method of analysis. Dr. Rose reviews a lengthy time period - 1990 through 2011 - and uses weighted average prices for his

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[1] Kenneth Rose, *State Retail Electricity Markets: How Are They Performing So Far? Electricity Policy.com*, http://www.electricitypolicy.com/archives/4455-stateretailelectricitymarkets.

comparison of electricity rates between monopoly and competitive states.[2]

Dr. Rose compares the weighted average prices of electricity of a group of 14 customer choice jurisdictions against a group of 30 states that have maintained traditional regulation of vertical monopolies.[3] He excludes seven states from the analysis; five that have had fitful and partial approaches to customer choice and also Hawaii and Alaska due to their geographic separation from the lower 48 states.

Dr. Rose concludes that the jurisdictions he classifies as competitively restructured have not closed the electricity price gap with the states he classifies as traditionally regulated. However, averages can conceal as well as reveal. When viewed from a different vantage point and looked at more closely, the same twenty-two years of price data analyzed by Dr. Rose tells a story of success for competitive electricity markets.

Four Missing Questions

In his analysis, Dr. Rose explores whether electric competition accomplished the following objective:

> "A principal motivation for retail access legislation was that states with high electricity prices relative to other states and the national average were hoping to lower their prices."[4]

He concludes that this goal has not been achieved. However, there are four key points that are missing from the discussion.

The *first* is that a primary goal of pioneer electric restructuring states was to address various combinations of major challenges they faced in the mid-1990s that motivated industry restructuring. These included high and rising retail rates, excess generating capacity, costly nuclear projects, PURPA QF contracts and angry and migrating industrial customers. For example, circa 1994, the electric utilities with significant power purchases from non-utility generators (NUGs, PURPA-QFs) were mainly located in California, Connecticut, Maine, Massachusetts, Michigan, New Hampshire, New Jersey, Oklahoma, Pennsylvania, Rhode Island, Texas, and Virginia, nearly all of which later pursued retail competition.[5] The electricity crises of the past are now over in the retail competition states and the related stranded cost issues have been resolved. Lack of continued failure ought to be regarded as success.

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[2] Weighted average electricity prices for states are calculated by dividing total statewide electricity revenue reported by the U.S. Energy Information Administration for all providers, including municipal and rural cooperative utilities by total kilowatt hours delivered.

[3] The 14 competitive jurisdictions are Connecticut, District of Columbia, Delaware, Illinois, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island and Texas. Seven states were excluded, Alaska and Hawaii, and five states that have varied histories of recent choice and traditional monopoly regimes, Arizona, California, Michigan, Montana and Virginia. The remaining 30 states were classified as traditionally regulated.

[4] Rose, *supra note 1, at* 2.

[5] U.S. Energy Information Administration, *Financial Impacts of Nonutility Power Purchases on Investor-Owned Electric Utilities*, at 57 (DOE/EIA-0580 June 1994).

The *second* is that while many advocates of customer choice were seeking to blunt ongoing step rate increases, there were opponents of industry restructuring who warned of unregulated, out-of-control increases in supply prices in the absence of traditional rate-of-return regulation of generation. Those concerns proved misplaced.

Within the next several years, competitive supply may well challenge the combined 27% retail market share held by municipal, rural cooperative and federal utilities.

The *third* is that the competitive states are conveying price signals more promptly than the monopoly structured states. The conveyance of price signals to inform customers of supply-demand conditions was a key goal of the earliest advocates of relying on market forces for electricity supply pricing.[6] Dr. Rose notes that residential prices in the competitively restructured states declined by 1.7% between 2008 and 2011 while average residential prices in the traditionally regulated monopoly states increased by 8%.[7] In the several years prior to the economic downturn that commenced in mid-2008, prices in restructured states increased faster than in traditional states as rate freezes ended and fuel prices and demand grew amidst strong economic activity. However, as shown in the tables that follow, the spread between choice states and monopoly states narrowed as much in the three years since 2008 as it grew in the six-year prior period. Others have noted the more rapid increase in rates in traditional states than in jurisdictions participating in competitively restructured wholesale markets.

The *fourth* is the implicit, yet central question of whether traditional regulation of utility monopolies delivers discernible price benefits to customers. If moving from a traditional form of regulation to competitive choice does not negatively impact comparative long-run average electricity prices, then what is the purpose of the elaborate procedures that characterize traditional regulation of monopoly generation supply prices? Is the purpose, as Tevye in *Fiddler on the Roof* might say, "Tradition!"?

The time has come for a more expansive consideration of the nature of competitive electricity models in contrast to the traditional monopoly model. While the average price of electricity is certainly worthy of note, the massive migration of customers to choice in electricity supply is itself an argument that consumers are finding the option attractive for a variety of reasons.

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[6] *See, e.g.*, Philip R. O'Connor, Robert G. Bussa and Wayne P. Olson, *Competition; Financial Innovation and Diversification in the Electric Industry*," by PUBL. UTIL. FORT., Feb. 20, 1986. This article was one of the first in a major industry publication advocating a movement to competition in electricity supply and argued that … "A greater reliance on market forces could correct one of the critical deficiencies of traditional regulation – its inherent inability to match end-user prices with the economic cost of production. Standard regulatory practices attempt to achieve 'equilibrium' by using historical costing techniques to price electricity. However, using traditional regulatory practices, supply only appears to match demand. Regulation, by its very nature, over-prices new capacity and underprices old capacity."

[7] Rose, supra note 1, at 3-4.

Millions of customers, accounting for nearly one-fifth of all kilowatt hours consumed in the United States, purchase from non-utility suppliers at market prices.[8] Within the next several years, competitive supply may well challenge the combined 27% retail market share held by municipal, rural cooperative and federal utilities.[9] Competitive retail supply already has substantially greater market share than do any of the non-investor utility categories. In the 14 competitive jurisdictions included in the Rose analysis, regulators and policymakers have consistently expanded opportunities for customer choice. Customer choice is now a well-established feature of the national electricity landscape.

The traditional monopoly model has not been accommodating to the sorts of innovative features of competitive markets that are proving attractive to customers. Among these are the ability to contract for prices for specific periods to match business plans, pricing demand response at its true value to the system and fully rewarding least-cost operating practices by producers and customers alike.

The debate over choice is no longer one of whether competitive electricity will be a part of the nation's energy picture. Rather, with a decade of customers embracing choice in more than a dozen states, the burden of proof is gradually shifting to those who advocate for maintenance of the vertically integrated, monopoly utility model.

Long-Run Average Price Levels

Dr. Rose notes, correctly, that many factors contribute to differences in electricity prices across states. General factors – such as weather, local and regional economic structure, generation types and fuel mix, degree of urbanization, disparate environmental rules, taxation, labor costs and role of federally produced power allocations – are important determinants of long-run electricity price levels.

Differences in these factors, whether external or internal to the electricity business, tend to be regional in nature rather than merely following state boundaries. For example, one of the recent developments has been the concentration of renewable portfolio standards (RPS) in the competitive states.[10] As a general matter renewable resources exert upward pressure on electricity prices. It is important in this regard to note that the 14 customer choice jurisdictions identified by Dr. Rose are, with the single exception of Texas and its isolated ERCOT system, clustered entirely in the northeast quadrant of the United States, defined in great

[8] For an examination of the growth in customer choice in the post-2008 period of economic stress, *see* Philip R. O'Connor, Retail Electric Choice: Proven Growing Sustainable, April 2012 (prepared for the COMPETE Coalition) at http://www.competecoalition.com/files/COMPETE_Coalition_2012_Report.pdf.

[9] EIA's most recent State Electricity Profiles Report shows that rural cooperatives sold 10.97% of all kilowatt hours, public or municipal utilities sold 14.85% and federal utilities sold 1.16% for a total of 26.98% that http://www.eia.gov/electricity/state/unitedstates/.

[10] The May 2011 FERC update map of RPS in the states shows the great weight of such programs to have been implemented in the 14 competitive jurisdictions. See http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf.

part by the boundaries of the PJM Interconnection.

Table 1: Residential Rate Ratios
Competitive v. Traditional States; Competitive and Traditional States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Competitive v. Traditional	1.30	1.34	1.36	1.38	1.39	1.39	1.39	1.40	1.36	1.32	1.33	1.36
Competitive v. US	1.13	1.15	1.15	1.17	1.17	1.17	1.18	1.18	1.17	1.15	1.15	1.16
Traditional v. US	0.87	0.86	0.85	0.85	0.84	0.84	0.84	0.84	0.86	0.87	0.87	0.85

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2001-2011 Average
Competitive v. Traditional	1.32	1.27	1.29	1.29	1.32	1.37	1.39	1.41	1.36	1.35	1.28	1.33
Competitive v. US	1.14	1.11	1.13	1.13	1.15	1.18	1.19	1.20	1.17	1.17	1.13	1.16
Traditional v. US	0.87	0.88	0.87	0.88	0.88	0.86	0.85	0.86	0.86	0.87	0.88	0.87

Table 2: All-Sectors Rate Ratios
Competitive v. Traditional States; Competitive and Traditional States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Competitive v. Traditional	1.28	1.33	1.35	1.37	1.37	1.38	1.38	1.39	1.35	1.32	1.34	1.35
Competitive v. US	1.11	1.12	1.13	1.14	1.14	1.15	1.15	1.16	1.15	1.13	1.14	1.14
Traditional v. US	0.86	0.84	0.83	0.84	0.83	0.83	0.84	0.83	0.85	0.86	0.85	0.84

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2001-2011 Average
Competitive v. Traditional	1.35	1.30	1.32	1.32	1.37	1.42	1.44	1.45	1.36	1.35	1.28	1.36
Competitive v. US	1.13	1.10	1.12	1.13	1.16	1.18	1.19	1.21	1.16	1.16	1.11	1.15
Traditional v. US	0.84	0.85	0.85	0.85	0.85	0.83	0.83	0.83	0.85	0.86	0.87	0.85

All of this suggests that the impact of the specific regulatory regime on long-run price levels would be but one factor among many. Ultimately, it will require a carefully developed multivariate regression analysis to sort out which factors explain how much of the variance in electricity prices is linked to the regulatory structure.[11]

Consumer Prices: Standardized Ratio Comparison

The analysis here begins with a replication of Dr. Rose's comparison of residential electricity prices in the competitive and traditional monopoly model states, after which the analysis expands to cover industrial and commercial customers and all-sectors taken together.

Using data from the U.S. Energy Information Administration,[12] Dr. Rose compares the weighted average[13] 1990-2011 price of electricity for residential customers (including

[11] The optimal unit of analysis would be utility service territories rather than states. However, there are considerable obstacles to such an analysis, not the least of which would be the data requirements.

[12] The data used by Dr. Rose and in this analysis are available in Excel spreadsheet form at the US EIA website. Sales and revenue data for 1990-2010 are accessible at http://www.eia.gov/electricity/data/state/ and 2011 data are accessible Table 5.5B and 5.6A at http://www.eia.gov/electricity/monthly/.

[13] Weighted average prices are calculated by dividing the sum of all megawatt hours sold in all states in each regulatory category, traditional monopoly and restructured, by the sum of all electricity sales revenue in each group.

delivery charges, taxes, stranded-cost fees, etc.) between 14 competitive choice jurisdiction states and 30 traditionally regulated states. The United States average rates used by Dr. Rose and in this analysis encompass all 51 jurisdictions, including the 7 states excluded from the competitive and traditional groups being examined.

Dr. Rose illustrates his rate comparison with graphs that, while visually interesting, sometimes require the reader to estimate the precise relationship of rates in the competitive states to those in the traditional states. The analysis here presents relative price information in tables and takes out the impact of inflation by converting the raw cents per kilowatt-hour (¢/kWh) into ratios in order to standardize the data over the 22-year period. This allows for more precise comparison.

Table 1 presents yearly weighted average residential rates in the 14 competitive jurisdictions as ratios to prices in the 30 traditional states. Averages for two 11-year equal length periods 1990-2000 and 2001-2011 are also presented. During the earlier period of 1990-2000 all states in the two groupings shared nearly identical traditional regulatory regimes and the classic monopoly utility model. The latter period of 2001-2011 roughly approximates the period during which the 14 retail jurisdictions have operated in a significant way under the competitive construct.

Table 1 also presents ratios comparing prices in the competitive states and the traditional states with overall United States average prices. **Tables 2, 3 and 4** do the same for all-sectors, commercial customers and industrial users, respectively.

Table 3: Commercial Rate Ratios
Competitive v. Traditional States; Competitive and Traditional States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Competitive v. Traditional	1.29	1.34	1.36	1.37	1.39	1.39	1.40	1.42	1.38	1.35	1.39	1.37
Competitive v. US	1.09	1.11	1.11	1.12	1.12	1.13	1.14	1.16	1.14	1.13	1.14	1.13
Traditional v. US	0.85	0.83	0.82	0.82	0.81	0.81	0.82	0.81	0.83	0.83	0.82	0.82

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2001-2011 Average
Competitive v. Traditional	1.43	1.36	1.38	1.36	1.40	1.43	1.46	1.50	1.36	1.35	1.26	1.39
Competitive v. US	1.14	1.09	1.13	1.13	1.16	1.17	1.19	1.22	1.15	1.14	1.10	1.15
Traditional v. US	0.80	0.80	0.82	0.83	0.83	0.82	0.82	0.81	0.84	0.85	0.87	0.83

Table 4: Industrial Rate Ratios
Competitive v. Traditional States; Competitive and Traditional States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Competitive v. Traditional	1.24	1.30	1.31	1.30	1.28	1.25	1.26	1.29	1.25	1.22	1.26	1.27
Competitive v. US	1.08	1.10	1.11	1.12	1.11	1.09	1.10	1.11	1.10	1.08	1.10	1.10
Traditional v. US	0.87	0.85	0.85	0.86	0.87	0.87	0.88	0.86	0.88	0.89	0.87	0.87

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2001-2011 Average
Competitive v. Traditional	1.26	1.24	1.28	1.29	1.34	1.39	1.43	1.36	1.32	1.28	1.21	1.31
Competitive v. US	1.07	1.07	1.10	1.12	1.15	1.18	1.20	1.16	1.14	1.12	1.08	1.13
Traditional v. US	0.85	0.86	0.86	0.86	0.85	0.85	0.84	0.86	0.86	0.88	0.89	0.86

During much of the 1990s, the price levels in the group of 14 jurisdictions that would ultimately undertake industry restructuring were rising as a ratio of the price levels in the 30 states classified as traditional by Dr. Rose. Residential ratios increased from 1.30 in 1990 to 1.40 in both 1997. The all-sector ratios rose from 1.28 in 1990 to 1.39 in 1997. Industrial and commercial ratios rose in a similar pattern during this period.

Following the enactment of restructuring laws around the turn of the millennium, competitive state price ratios declined until the mid-2000s when natural gas prices and electricity demand rose with a growing economy. Ratios then rapidly declined following the 2008 economic downturn. As can be seen in Table 2 above, the all-sectors ratio of competitive price levels to those in traditional jurisdictions fell from a peak of 1.45 to 1.28, a 13-point drop.

More recently, the dramatic reduction in natural gas prices and slow economic growth have contributed to further reductions in competitive states' ratios to prices in traditional monopoly states. EIA data for the first three quarters of 2012 produce price ratios among the lowest in the 22-year analytical period. Customers take the opportunity to capture the value of competitive choice state prices that on average have fallen an additional 6 ratio points compared to 2001.[14]

TABLE 5: High and Low State Average Price Ratio v. US Average Price

	Range	1990	2000	2010
Among 14 Competitive States	High	1.43 (NY)	1.65 (NH)	1.77 (CT)
	Low	.90 (OH&DC)	.89 (DE)	.93 (IL&OH)
Among Traditionally Regulated States	High	1.26 (VT)	1.51 (VT)	1.35 (VT)
	Low	.52 (WV)	.61 (ID&KY)	.63 (WY)

Yearly average ratios, of course, cannot capture the range of individual state price levels that go into making up the averages. **Table 5** provides an indication of the heterogeneity of ratios within the competitive and traditional states, showing the individual states with the highest and lowest ratios against the total United States average price in 1990, 2000 and 2010. The high and low ratios fluctuate as do the states occupying the high and low positions.

Case Study: The Industrial Upper Midwest

Beyond the analyses of high-level aggregate data, there are stories at the regional level that can be instructive. Five states of the industrial Upper Midwest - Illinois, Indiana, Michigan, Ohio and Wisconsin present especially interesting venues to consider the possible price impact of differing regulatory regimes.

[14] EIA state-by-state revenue and sales data through September 2012 allow for the calculation of ratios of competitive to traditional states compared to calendar 2011 levels: at 1.22 v. 1.28 for all-sectors, 1.23 v. 1.28 for residential, 1.19 v. 1.26 for commercial and 1.13 v. 1.21 for industrial.

Table 6: All-Sectors Rate Ratios
Upper Midwest States v. US Average

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
Illinois	1.14	1.13	1.13	1.12	1.07	1.12	1.12	1.12	1.11	1.05	1.02	1.10
Indiana	0.82	0.79	0.78	0.75	0.76	0.76	0.76	0.77	0.79	0.80	0.76	0.78
Michigan	1.08	1.07	1.06	1.03	1.03	1.02	1.04	1.03	1.05	1.07	1.04	1.05
Ohio	0.90	0.91	0.89	0.90	0.90	0.91	0.92	0.91	0.95	0.96	0.94	0.92
Wisconsin	0.82	0.81	0.80	0.80	0.79	0.78	0.77	0.76	0.81	0.83	0.84	0.80

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2001-2011 Average
Illinois	0.95	0.96	0.92	0.89	0.85	0.79	0.93	0.95	0.92	0.93	0.90	0.91
Indiana	0.73	0.74	0.72	0.73	0.72	0.73	0.71	0.73	0.78	0.78	0.81	0.74
Michigan	0.96	0.99	0.92	0.91	0.89	0.91	0.93	0.92	0.96	1.01	1.04	0.95
Ohio	0.91	0.94	0.91	0.91	0.87	0.87	0.87	0.86	0.92	0.93	0.91	0.90
Wisconsin	0.83	0.87	0.89	0.90	0.92	0.91	0.93	0.92	0.95	1.00	1.02	0.92

These states share any number of important social, economic and energy industry characteristics that underlie electricity prices and often see themselves as intra-regional competitors.

Indiana and Wisconsin have consistently adhered to traditional regulation and maintained vertically integrated electric utilities and have not employed customer choice even for the largest users. Yet, those two states have had decidedly different price experiences while sharing a common regulatory style over the past decade.

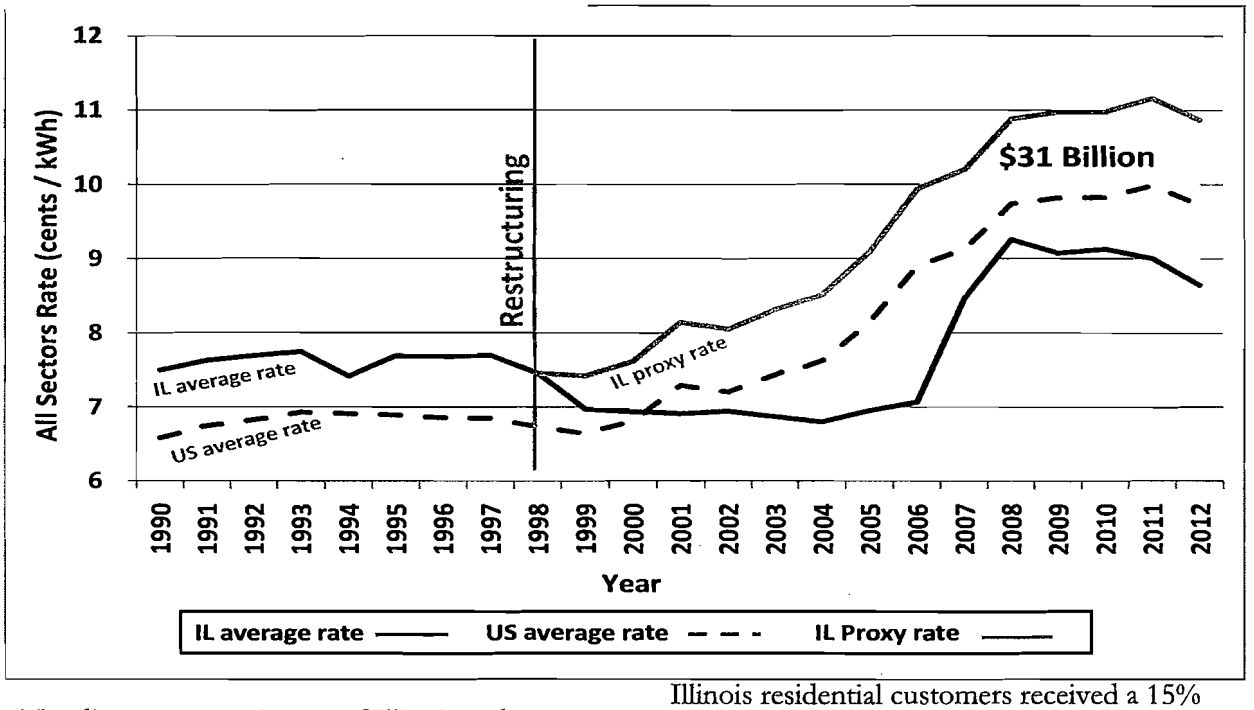
The other three states, Illinois, Michigan and Ohio undertook restructuring, but did so in quite different ways. Illinois started early and has implemented a nearly complete approach to customer choice, with large numbers of residential and small business customers now joining nearly all larger users in choosing alternative suppliers or participating in municipal aggregation. Ohio delayed aggressive restructuring until the past several years but is now moving quickly. A large portion of Ohio's residential load is now being served through municipal aggregation competitive procurement. Dr. Rose excluded Michigan from his analysis because in 2008 it largely re-instituted traditional regulation, with the exception of allowing 10% of total load to be served competitively.

Table 6 presents the yearly all-sectors price ratios for each of the five states against the U.S. averages as well as summary averages for the 1990-2000 and 2001-2011 periods.[15] Indiana has maintained a highly favorable ratio over the entire two decades, due in great part to its reliance on low-cost coal plants, a cost advantage that is under increasing pressure. Wisconsin, in contrast, has seen a deterioration of its initial favorable price ratios such that its price levels now exceed the national average. Wisconsin has tended toward a policy of reliance on relatively expensive new generation and related transmission rather than relying on the wholesale market. Ohio has maintained

[15] It should be noted that the sales and revenue figures for Illinois, Indiana, Michigan, Ohio and Wisconsin are included in the national averages.

favorable ratios during both periods of traditional regulation and of restructuring.

Figure 1 - Illinois Restructuring Savings Estimate



The divergent experiences of Illinois and Michigan are instructive. Illinois consistently pursued the opening of its electricity markets while Michigan, having started the transition to competitive choice, truncated the process and reinstalled monopoly regulation for the most part.

The Case of Illinois

Lying at the western edge of the PJM Interconnect, Illinois is bordered entirely by states that have maintained traditional monopoly regulation, among them Indiana and Wisconsin. Illinois, Indiana and Wisconsin are often in open competition for firms seeking business locations. Indeed, during the 1990s, Indiana and Wisconsin sought to attract employers with the prospect of lower electricity rates than available in much of Illinois.[16]

On August 1, 1998, the vast majority of Illinois residential customers received a 15% rate reduction mandated under the 1997 industry restructuring law while most of the remainder received 5% reductions. In the fall of 1999, following the finalization of rules and rates for delivery service by the Illinois Commerce Commission, one-third of larger industrial and commercial load became eligible to choose alternative suppliers. Over time, there were small additional residential reductions and all non-residential customers became choice-eligible. Today all customers

[16] Co-author O'Connor recalls during his time as chairman of the Illinois Commerce Commission (1983-85) seeing billboards at the Wisconsin-Illinois line urging Illinois based firms to move north for lower electricity bills. The disparity between Illinois rates, especially in the northern third of the state was an important marker in the path taken by the state to industry restructuring.

served in investor-owned utility areas can choose their supplier.

Illinois's experience, coincident with developing one of the complete transitions to customer choice, has been one of significant reductions in price ratios, going from well above the national average to consistently below the national average. Illinois swung by 19 points from a 1990-2000 average of 1.10 against the U.S. average to .91 in the 2001-2011 period.

premium and the 7% discount to average national all sector prices.

Table 7 presents price ratios for Illinois against prices for each of the other four industrial Upper Midwest states under discussion. Prior to industry restructuring, Illinois all-sectors price ratios for the 1990-2000 period averaged 1.42 against Indiana and 1.38 against Wisconsin. Following restructuring, Illinois' average against Indiana swung downward by 19 points to 1.23 and

Table 7: All-Sectors Rate Ratios
Illinois v. US Average v. Other Upper Midwest States

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1990-2000 Average
US	1.14	1.13	1.13	1.12	1.07	1.12	1.12	1.12	1.11	1.05	1.02	1.10
Indiana	1.40	1.43	1.45	1.50	1.41	1.47	1.47	1.46	1.40	1.32	1.34	1.42
Michigan	1.06	1.06	1.06	1.08	1.05	1.09	1.08	1.09	1.05	0.98	0.98	1.05
Ohio	1.27	1.25	1.27	1.25	1.20	1.23	1.22	1.23	1.17	1.09	1.08	1.21
Wisconsin	1.40	1.40	1.40	1.40	1.36	1.44	1.46	1.47	1.37	1.26	1.22	1.38

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2001-2011 Average
US	0.95	0.96	0.92	0.89	0.85	0.79	0.93	0.95	0.92	0.93	0.90	0.91
Indiana	1.30	1.30	1.28	1.22	1.18	1.09	1.30	1.31	1.19	1.19	1.12	1.23
Michigan	0.99	0.98	1.00	0.98	0.96	0.87	0.99	1.04	0.97	0.92	0.87	0.96
Ohio	1.04	1.03	1.02	0.99	0.98	0.92	1.07	1.10	1.01	1.00	0.99	1.01
Wisconsin	1.14	1.10	1.03	0.99	0.93	0.87	1.00	1.03	0.97	0.93	0.88	0.99

If a more conservative starting point of 1999 is considered, that being July of the previous year (1998) when the initial residential rate reduction in Illinois's choice law was implemented, the average ratio for 1990-1998 of 1.12 is significantly higher than the January 1999-June 2012 average ratio of .93. The difference in electricity spend by Illinois consumers between a 12% premium above the national average if it had persisted and the actual experience of 7% below the national average for the 1999-June 2012 period is $31 billion. The shaded area **in Figure 1** on page 9 shows the delta value between the 12%

downward by 39 points against Wisconsin to 0.99 – which is below Wisconsin's all-sector 2001-2011 average price level. In 2011, the Illinois all-sectors ratio against Wisconsin was just .88, a 12 point discount.

Illinois' progress on electricity prices helps to explain the support that Illinois customers, regulators and policy makers have shown for competitive electricity markets.[17]

[17] For more information on customer choice in Illinois, see the "2012 Office of Retail Market Development Annual Report" of the Illinois Commerce Commission that can be found at

The Case of Michigan

Michigan is another story altogether. In the 1990s, prior to restructuring, Michigan prices were above the national average and then fell below the national average following its initial restructuring. However, with the reinstitution of traditional regulation and vertically integrated monopoly utilities, ratios began to rise again and now once again exceed national averages.

In 2000, Michigan enacted its electricity restructuring law. The Wolverine State, rather than emulating the doggedness of its namesake critter, employed a transition of half-measures that allowed for choice but created difficult conditions for its full implementation. In 2008 Michigan substantially re-monopolized the retail electricity market for 90% of load, while allowing 10% of load to be served under customer choice.

As shown in Table 6, Michigan made considerable progress in closing the price gap with the national average following restructuring legislation in 2000. Michigan's price ratios fell below national averages. However, following the 2008 quasi-re-monopolization, a series of utility rate increases pushed Michigan prices back above national levels and higher than those of other states in the Midwest.

Michigan provides a laboratory situation in which customer choice exists in parallel with traditional regulation, without the confounding problems of cross-state or regional factors being at play.

It is fairly easy to calculate the financial implications for electricity customers of the 10% limit on total load that can be served competitively. As of November 2012, annualized competitive load in Michigan's two major utilities, Consumers Power and Detroit Edison, was nearly 9.25 billion kWh. The state's major utilities are required to maintain waiting lists for non-residential customers that have asked to be allowed to purchase power from alternative suppliers.[18]

In the two utilities, more than 10,300 non-residential customers accounting for nearly 9.4 billion kWh have signed up for the waiting list. As part of the decision making process to be placed on the waiting list, many of these customers received indicative offers from suppliers. With wholesale prices that currently represent about a 2¢/kWh gap compared to higher generation components in Michigan's traditionally regulated bundled rates (5¢ v 7¢), annualized savings that are *unrealized* for business customers on the waiting list are on the order of more than $180 million.[19] If competitive market

http://www.icc.illinois.gov/reports/. Further, one of the important features of the competitive market in Illinois has been the role of major business trade organization in establishing endorsed partnerships with alternative electricity suppliers. The programs of the Illinois Manufacturers Association and of the Illinois Retail Merchants Association are notable in this regard.

[18] Data on the customer choice queues for Michigan's two largest utilities, Consumers Energy and DTE Energy, can be found at http://www.consumersenergy.com/content.aspx?id=2186&sid=107 and http://www.suppliers.detroitedison.com/internet/cap_tracking_system.jsp;jsessionid=QvkDnHpn65XfGRHyvG8vv1FpDX819Zv7rCGYWnnQy9NwNLLD4Ctp!460242865.

[19] This calculation is based on a similar exercise that was performed for a review of the status of

participation levels in Michigan were comparable to those in Illinois and Ohio for business and government customers, additional savings over and above those currently realized by the 11% of total load now served competitively would be on the order a half-billion dollars annually in 2013.

Future Paths

Competition proponents have often pointed out that regulatory lag and reliance on embedded costs serve to suppress prices during shortages and prop prices up during times of surplus. However, with wholesale electricity competition established as national policy, competitive forces will gradually exert increasing influence on retail rates in traditionally regulated states. Current wholesale spot and forward electricity prices are reflecting lower gas costs in rapidly declining retail prices in customer choice states. Further, competitive states are generally not as reliant on coal as are the 30 traditional monopoly states. Thus, the major question at this point is the extent to which traditional regulation and reliance on coal will deflect and defer the benefits of low gas prices. A review of the price data suggests that monopoly states have not benefited as much from low gas prices as competitive states to date, with retail rates in competitive states falling by 5% from 2008 to 2011 and retail rates in monopoly states increasing by 7% over the same time period.

The burden of proof is shifting from those who advocate customer choice to those who advocate maintenance of a regulatory model that now borders on the unique.

With the combination of falling prices and the implementation of regulatory measures that accommodate residential choice, the national share of electricity consumption by retail customers provided by competitive non-utility suppliers has grown dramatically during the 2008-2011 period of economic stress. The number of choice customers nationally increased from nearly 8.7 million in 2008 to more than 13.3 million at the end of 2011. Total electric load served by alternative suppliers increased by 40% from 488 million MWh in 2008 to 685 million MWh or 18% of total load in 2011. Growth in competitive market share has continued during 2012.

There is no serious prospect of a return to the *status quo ante* of uniform traditional regulation of electricity. Even as customer choice grows in importance, there will to be two different regulatory formats operating in parallel with one another. There will be many opportunities for additional research about the relative merits of each mode of regulation.

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competitive retail electricity published in April 2012. *See* Philip R. O'Connor, Retail Electricity Choice: Proven, Growing, Sustainable, (COMPETE Coalition, April 3, 2012) at http://www.competecoalition.com/files/COMPETE_Coalition_2012_Report.pdf.

The conventional framework for public policy debates about electricity regulation is that competition and customer choice should be in the position of presenting a justification for change. That framework is increasingly obsolete and an outlier. The price of natural gas is a function of market forces. Only a small portion of telecommunications services remains subject to traditional regulation. Other network services – airlines, rail and trucking are largely free of government price setting. So far, no affirmative case has been made that traditional regulation and the monopoly model deliver benefits for consumers by controlling prices that could otherwise be set competitively and by enforcing monopoly despite worldwide examples that competitive generation and supply function perfectly well.

With wholesale electricity competition established as national policy, competitive forces will gradually exert increasing influence on retail rates in traditionally regulated states.

The burden of proof is gradually shifting from those who advocate customer choice to those who advocate maintenance of a regulatory model that now borders on the unique.

There are numerous areas of inquiry that could help to determine whether traditional regulation or customer choice in generation supply is superior in contributing to customer welfare and to the efficiency of the industry and the economy it serves.[20] Areas of inquiry might include:

- Whether it is better that price signals evident in wholesale electricity markets be conveyed promptly and transparently to end-use customers or that those price signals be mediated and delayed?
- Whether the administrative procedures that characterize price-setting in traditional regulation yield value for consumers of electricity?
- Which approach to electricity supply pricing better supports energy efficiency investment and demand response as complements to capacity and generation?
- Will renewables be better accommodated in one regulatory regime or the other?
- Which regulatory mode provides better information to business customers making investments in new facilities or energy related-equipment?

These questions and others are all long-term issues that will not be answered in any single, dispositive study but by an accumulation of research, debate and experience.

[20] For a fuller discussion of possible future measures of relative performance of competitive and traditional regulatory regimes, see Terrence L. Barnich and Philip R. O'Connor, *The Grand Experiment: Has Restructuring Succeeded on Either Continent?*" PUB. UTIL. FORT., Feb. 2007.

Exhibit 8
Regulatory Flexibility Committee
9/18/13

TATE & LYLE

Tate & Lyle Reg/Flex

2013

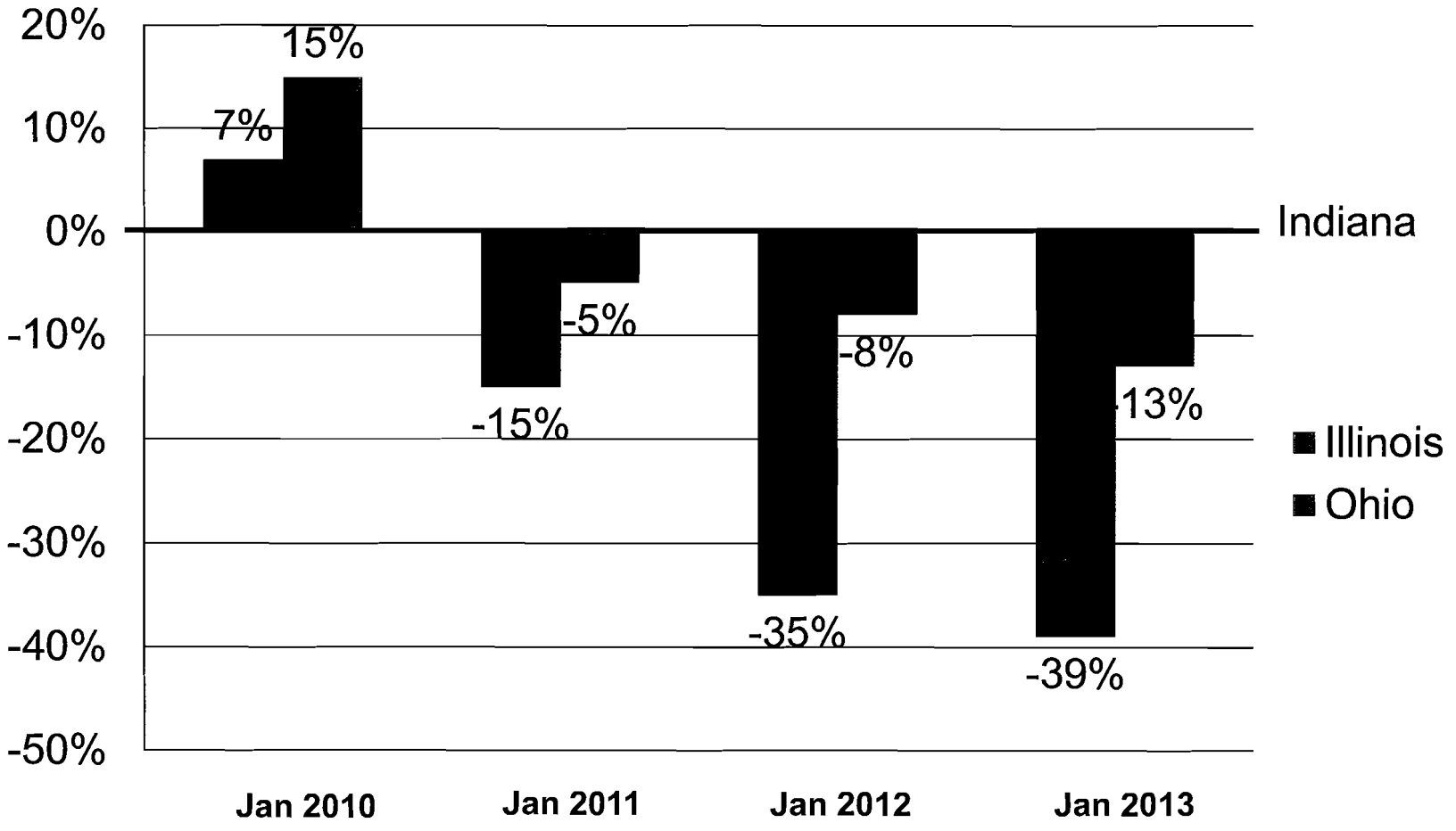
Tate & Lyle - Corporate

- Corporate headquarters in London
- Leading global provider of specialty food and industrial ingredients
- 30 production facilities across the globe

Tate & Lyle – Indiana

- Two plants in Lafayette
- 600 jobs
- Nearly $1 billion in economic impact in Indiana
- Growth opportunities here

Electric Cost Comparison
Electricity Costs Single Largest Deterrent to Growth



Tate & Lyle – Solution

- **Restructuring/Choice**
- **OTHER (?)**
- **Status quo not an option**

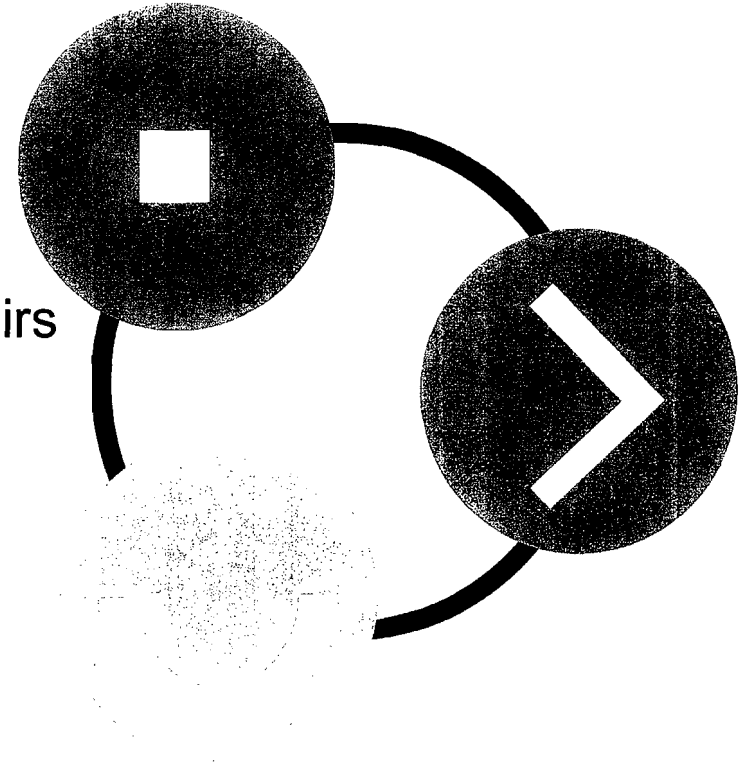
Exhibit 9
Regulatory Flexibility Committee
9/18/13

Regulatory Flexibility Committee
September 18, 2013

Direct Energy

Joe Clark

Manager, Government & Regulatory Affairs



Direct Energy

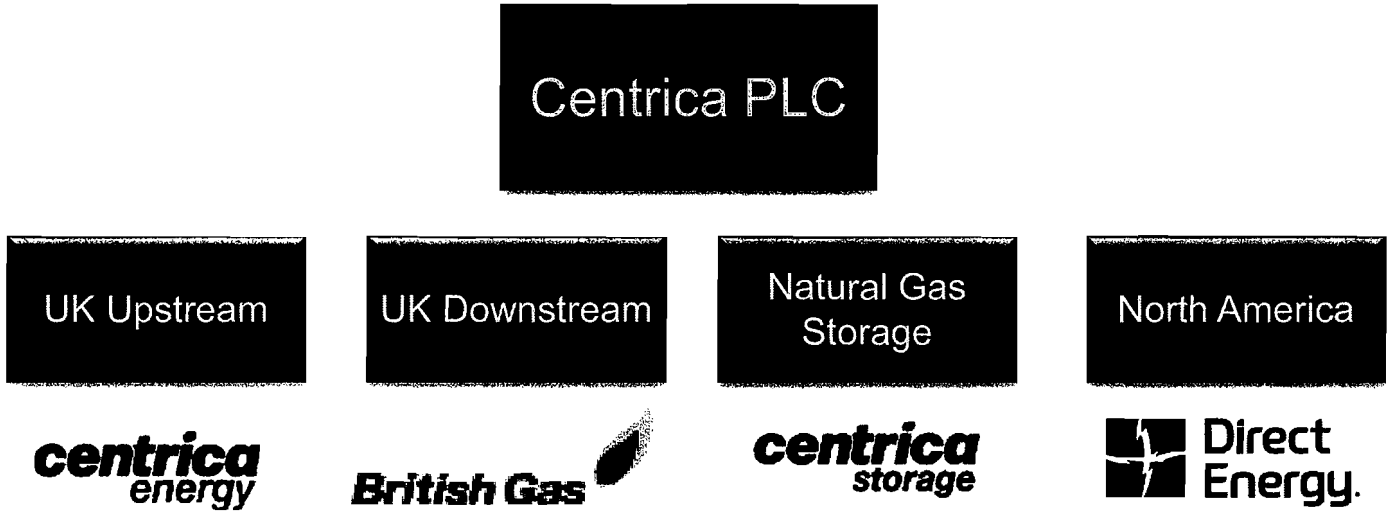
Voice of the Customer

A Dog's Life

http://www.youtube.com/user/TheDirectEnergy

Direct Energy.

Direct Energy's role within Centrica



- **Direct Energy** is a core part of Centrica plc (LSE:CNA)
- Centrica is one of the world's leading integrated energy companies with a market cap. of approx. US$28 billion and a credit rating of A3 (Moodys) and A- (Standard & Poors)
- Over 30 million customers and +39,000 employees worldwide
- A top 30 FTSE100 company, a long-standing member of the Global 500
- Operations in the UK, Canada, USA, Norway, Netherlands, Germany, Egypt & Trinidad

Direct Energy.

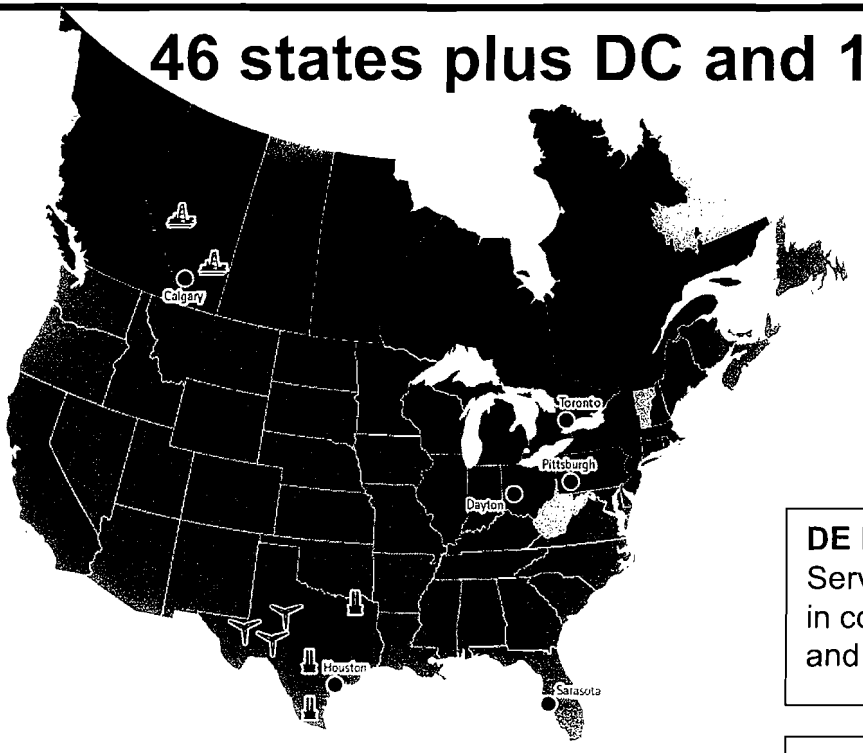
Direct Energy
North American footprint

46 states plus DC and 10 provinces

Supply and Trading

Renewable Energy
Nearly 600 MW of Texas wind power contracts

Power
Three gas-fired power stations 1305 MW in Texas



Main Offices

Upstream
- Power Plants (1305MW)
- Wind Farms (813MW)
- Gas Fields (172MMcfe/d)

Downstream
- Natural Gas/Electricity/Services
- Natural Gas/Services
- Electricity/Services
- Services

Downstream

DE Business
Providing gas and electricity to C&I customers in Canada, Texas, and U.S. North

DE Residential
Serving gas and electricity customers in core markets in Canada, Texas, and U.S. North

DE Services
Serving residential and business services customers across North America

Direct Energy.

What does electric choice look like for customers?

- ***<u>If our customers are not satisfied, we do not exist</u>***
- Products and services are available to every type of energy customer
- Permits customers to take control of their energy budget. Types of products include:
  - Fixed rate – budget certainty; remove supply rate fluctuations
  - Variable rate products to match how a person or business uses electricity
  - Pre-paid product for fixed income families and individuals
  - Low-income products/services to assist people with using energy differently to reduce costs
  - Renewable energy products and services
  - Time of use rates
  - Fully integrated energy management service and tools to assist with overall energy strategies incorporating

Direct Energy

APPENDIX

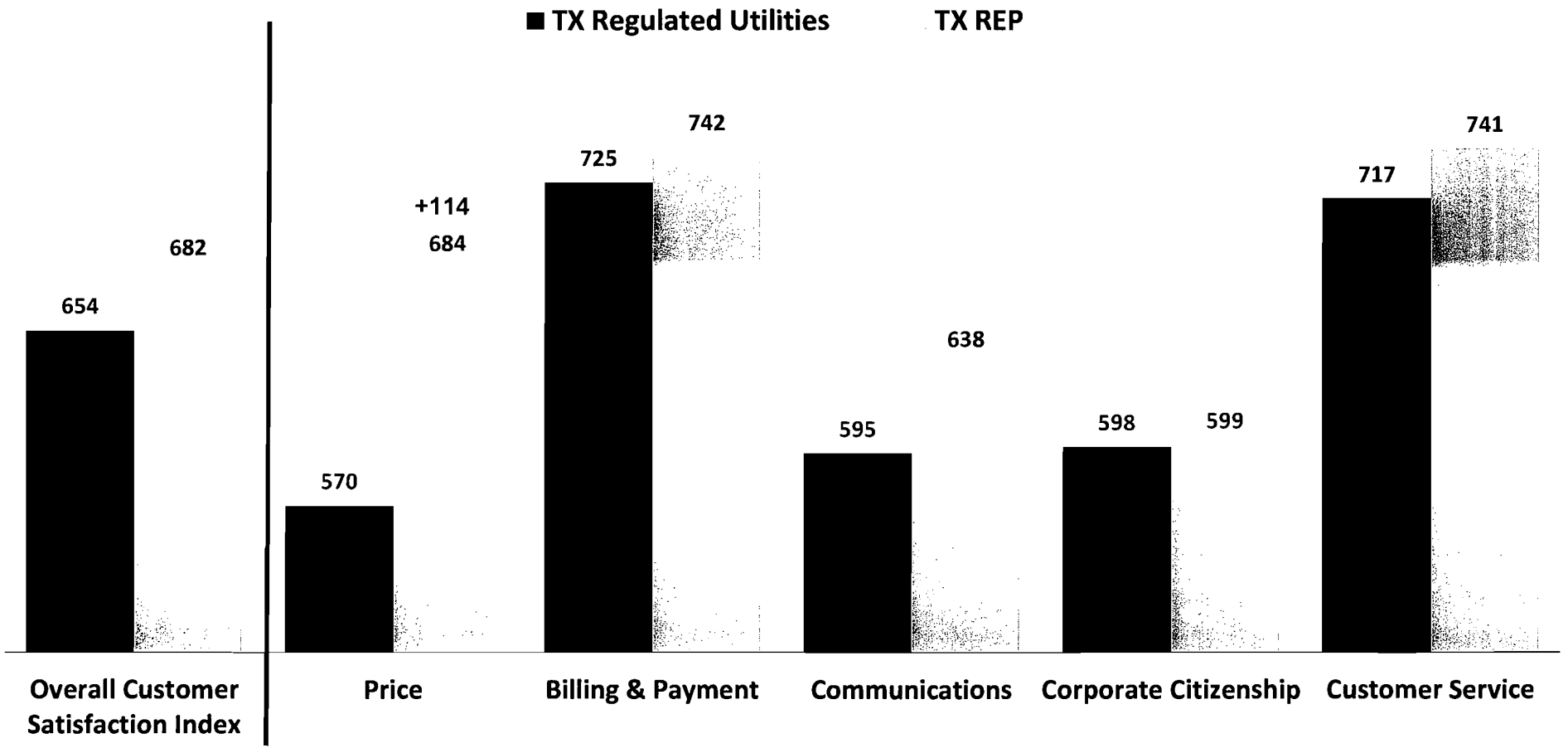
Direct Energy

Why should Indiana consider restructuring its electric market?

*17 states and D.C. have adopted electric choice
* Competition should displace regulation when functioning marketplace exists – pillar of a capitalistic economy and society
* Other industries (airlines, telephone, cable) restructured
* Indiana law already recognizes competition is "increasing in provision of energy services in Indiana and the US" and that traditional regulation is not adequately designed to deal with increasing competitiveness (IC 8-1-2.5-1)
* Customer choices = customer engagement + innovative products
* Customers more satisfied with suppliers than local utility
* *Not* "deregulation" – restructured environment where IURC licenses suppliers and maintains jurisdiction over marketing practices and other aspects of customer interactions

Direct Energy.

REP Customer Satisfaction Scores Higher Than Texas Regulated Electric Utilities



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http://powertochoose.org/ | Power To Choose | Home

POWER TO CHOOSE

HOME | ABOUT SHOPPING

Shop. Compare. Choose.

Welcome to Power to Choose, the official and unbiased electric choice website of the Public Utility Commission of Texas. This website is available to all electric providers to list their offers for free. Compare offers and choose the electric plan that's right for you.

ENTER YOUR ZIPCODE

Need help? Answer 3 simple questions.

NARROW YOUR SEARCH ›

OR

Want to see plans for your area?

VIEW RESULTS ›

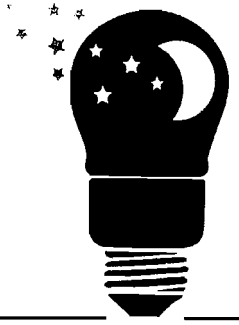
Innovative Products for Customers

FREE-Power Nights

Get Free Power Every Night For A Year.

The savings are up to you. When you switch to the 12-Month FREE-Nights Plan, the possibilities for spending less on electricity are endless. Simply switch activities like cooking, laundry and entertainment to your FREE-Power Nights and there's no charge for your electricity supply.*

- Get FREE electricity supply every night from 7:00 p.m. - 10:59 p.m.
- Switch activities to your FREE time for greater potential savings



Sign up for the 12-Month FREE-Nights Plan and discover how much you could save.

Direct Energy.

Direct Energy.

FREE ELECTRICITY ON SATURDAY EVERY SATURDA

If today was Saturday, what would you be doing?

Imagine what you could do with 24 hours of free electricity every Saturday. You'll save every week by switching activities to your prepaid FREE-Power Saturday plan. The savings are up to you and there's no long-term contract.

SIGN UP HERE

Direct Energy.

Downstream
Our retail brands across North America

Energy

- Direct Energy
- CPL Retail Energy
- WTU
- Gateway Energy Services
- First Choice Power you first
- Vectren Source

Services

- C. A. Woods Air Conditioning • Heating — A Direct Energy Company
- Airtron Heating • Cooling • Plumbing — A Direct Energy Company
- Mister Sparky
- Serving the Houston Area Since 1967 — Hallmark Cooling • Plumbing • Heating — A Direct Energy Company
- Evans Plumbing • Heating • Cooling
- Benjamin Franklin — If there's any delay,
- Masters Heating & Air Conditioning
- Van's Comfortemp Air Conditioning & Refrigeration — A Direct Energy Company
- One Hour Air Conditioning & Heating — Always On Time...Or You Don't Pay A Dime!
- Chilltrol Incorporated — Heating • Air Conditioning • Refrigeration • Generators • Service Contracts — A Direct Energy Company
- HWA Home Warranty of America

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Exhibit 10
Regulatory Flexibility Committee
9/18/13

INDIANA POWER OF WIND COALITION

Regulatory Flexibility Committee

Strategies for Procuring New Generation

September 18, 2013

The Challenge

- There is no "free market" for procurement of energy and resources.
- Utilities in regulated states are vertically integrated monopolies with a franchise agreement that entitles them to serve customers within the franchise area.
- Currently, utilities develop integrated resource plans (IRP) which identify supply needs for customers.
- Generally, utilities fulfill energy/capacity shortfall through request for proposals (RFP) and the utility typically chooses themselves.

Other Challenges

- Self build options don't always take into account all transmission and interconnection costs.
- Risk of construction delay and cost overruns are often not accounted for in self build options.
- Utilities have the ability to recover additional costs from ratepayers.
- Independent power producers (IPP) provide an all-in, binding cost when responding to request for proposals.
- This includes all costs – including transmission and interconnection costs.
- If the project is completed over budget, the risk is borne by the IPP as opposed to the ratepayer.

Example of Utility Share of Supply Resources

- Approx. 95% of all electricity comes from generation owned by the IOUs

Utility	Total Resources (MW)	Owned Resources (MW)	PPA Resources (MW)	% Owned Resources
AEP	5,279	5,012	267	94.9%
Duke	6,830	6,722	108	98.4%
IPL	3,353	3,053	300	91.1%
NIPSCO	3,422	3,322	100	97.1%
Vectren	1,498	1,288	210	86.0%

SOURCE: 2011 Utilities IRPs

Comparison of Self-Build to Third Party Supply

- Utilities receive no rate of return on power purchase agreement (PPA) and as a result forfeit potential returns for shareholders.
- Lower cost to ratepayer for power purchase agreement, however this may not be the successful proposal.

Utility Self-Build – 100 MW Thermal Plant[1] (excludes operating costs)	
$427,488,000	Resource Investment
8%	Rate of Return
$ 34,199,040	**Total Return**

Current structure leads to inefficient outcomes

Power Purchase Agreement – 100 MW Plant[2]	
$336,384,000	Purchase Agreement Cost
0%	Rate of Return
$0	**Total Return**

[1] Lazard Levelized Cost of Energy Analysis Version 6.0, June 2012. Assumes Gas Combined Cycle at 40% capacity factor for 20 years at $61/MWh.

[2] Lazard Levelized Cost of Energy Analysis Version 6.0, June 2012. Assumes Wind at 40% capacity factor for 20 years at $48/MWh.

Example of Competitive Procurement Proposal

- Allowing an earned rate of return still provides a lower cost to ratepayer.

Alternative Procurement – Utilized Wind PPA	
$336,384,000	Resource Investment
8%	Rate of Return
$ 26,910,720	**Total Return**

Ratepayer Savings: $98,392,320

Utility Self-Build – 100 MW Thermal Plant[1] (excludes operating costs)	
$427,488,000	Resource Investment
8%	Rate of Return
$ 34,199,040	**Total Return**

Current structure leads to inefficient outcomes

Power Purchase Agreement – 100 MW Plant[2]	
$336,384,000	Purchase Agreement Cost
0%	Rate of Return
$0	**Total Return**

Benefits

- Ensure ratepayer is served at lowest, efficient cost. Allow utility sector to balance the utility shareholder interests with the ratepayer's desire for low cost energy.
- Reduce ratepayer exposure to cost overrun risk.
- Does not change the regulatory process that currently exists in each state.
- Cooperative working relationships between utilities and independent power producers.
- Alternative for utilities if capital constrained due to generation fleet retirement/retrofit costs, transmission expansion costs, and other system improvement costs. Leverage third parties to provide capital needed to maintain supply adequacy.
- Provide appropriate human resources to support utilities in building new resources. Some utilities no longer have in-house capability for design, project management, and commissioning of new generation resources. The projected utility attrition rate is also a potential concern.

Questions/Follow Up

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President

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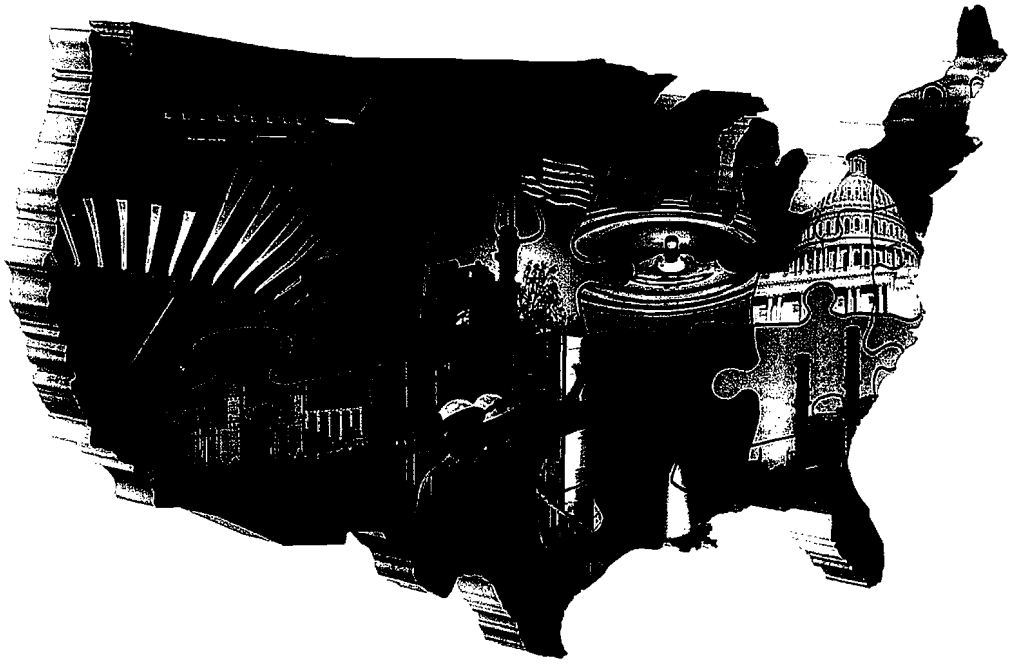
Exhibit 11
Regulatory Flexibility Committee
9/18/13

CALPINE®
NYSE CPN

A GENERATION AHEAD, *today*

Regulatory Flexibility Committee
Competitive Procurement
September 18th

Joe Kerecman
Director Government and
Regulatory Affairs



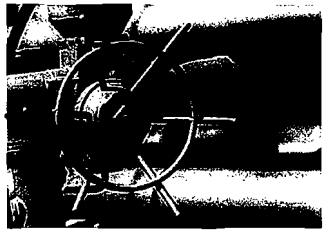
CLEAN MODERN EFFICIENT FLEXIBLE POWER GENERATION

Calpine Overview

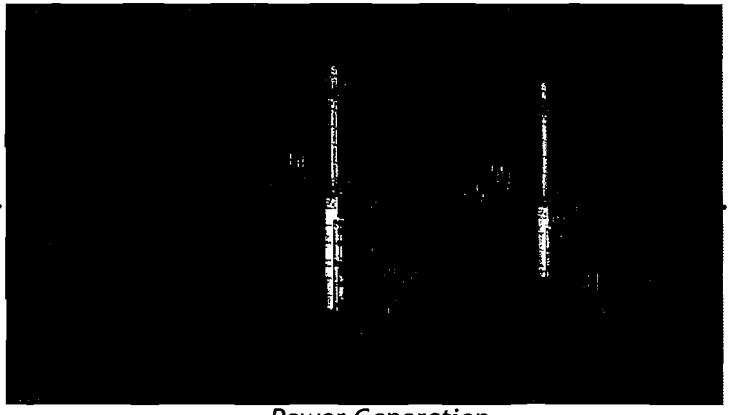
CALPINE

Strategically positioned within U.S. power industry value chain

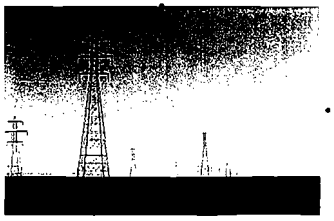
Fuel Supply



Transportation



Power Generation



Transmission & Distribution

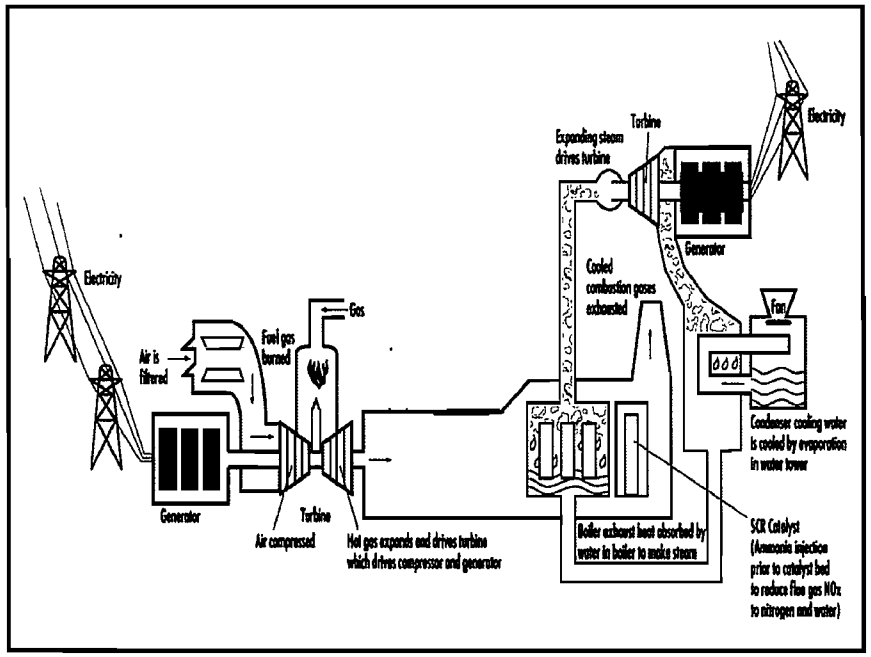
Retail

Calpine: Nationally Focused

- Largest IPP in US by megawatt hours produced
- More than 28,000 MW of capacity from 91 plants in 20 States and Canada
- Primarily natural gas-fired
- Nation's largest fleet of highly efficient CHP (cogeneration) plants
- Approx. 2,300 Employees

www.calpine.com

Combined Cycle Power Generation - Overview



- Combined Cycle Power Generation each combustion turbine (CT) powers a generator. The high temperature exhaust gas from the CT is used to produce steam in a Heat Recovery Steam Generator. That steam is then used to drive a Steam Turbine generator.

- This “Combined Cycle” arrangement ensures the highest efficiency possible from the fuel burned to make electricity.

Introduction to Competitive Procurement

CALPINE

- Electricity generation is capital-intensive. A new 1,000 megawatt generating facility requires a capital investment of approximately $1.2 billion;

- Consumers and taxpayers are always better off when major spending decisions are subject competitive processes. Competitive bidding ensures that those who are paying the bills are getting the best value for their money;

- IPPs - whose core business is power generation - often have significantly more experience in constructing new power plants compared with utilities that have had only infrequent experience is this area.

Key Benefits of Competitive Procurement

CALPINE

It's all about the ratepayer:

- Under the traditional cost-of-service utility model, ratepayers are exposed to the financial risks associated with both the construction and operation of new, capital-intensive power plants;
- The single most important benefit of relying on competitive procurement is the opportunity to shift the allocation of these significant financial risks away from ratepayers;
  - Competitive procurement ensures that resource additions are built and operated at the lowest possible cost.
- Utilities have an inherent incentive to maximize ratebase rather than minimize costs;
- Power Purchase Agreements with IPPs are binding contracts, subject to state regulatory review and approval;
- RFP's for competitive generating capacity ensure that utility proposals are fairly evaluated against the best alternatives the market has to offer.

Key Design Elements for Successful Competitive Procurement "Establishing a Level Playing Field"

According to the National Association of Regulatory Utility Commissioners, In order to ensure fairness, objectivity and a least-cost/best-fit outcome, the competitive procurement process must incorporate the use of standardized criteria:

- Involvement of a third-party independent monitor or independent evaluator;
- Measures to ensure the transparency of the procurement process to market participants and the public;
- Providing potential bidders with detailed information and requirements:
  - criteria such as size, new or existing plant, generation type, timing; and any desirable locational, operational, environmental or other non-price characteristics.

Conclusion

CALPINE

- The process of Competitive procurement is well suited to getting the least supply solution for the ratepayer with the least amount of risk;
- By its very nature competitive procurement shops the market for the best deal.

Follow up questions:

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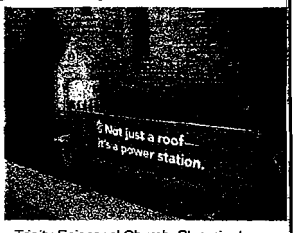
CALPINE®

NYSE CPN

Sustainable Electric Generation Would...

- Be affordable (including the ability to decline in cost over time)
- Be reliable
- Use and consume the least amount of water
- Rely on the least polluting resources and methods
- Effectively reduce greenhouse gases



Trinity Episcopal Church, Bloomington

Affordability

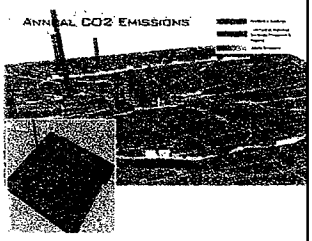
- Certificate of need required by statute in exchange for least-cost service
  - Utilities must review, but not implement, least-cost options
  - No agreed-upon formula
- Health and environmental costs not taken into account
- Automatic rate adjustment mechanisms (trackers), including CWIP, also contribute to rising costs
- Ratepayers exposed to volatile fuel prices

Water Availability/Quantity

- No coordinated policy on water availability
- 65% of Indiana's total water use is for cooling in coal-fired power plants[1]
- Coal-related water quality problems and unsafe mercury levels in fish throughout the state[2]

[1]Indiana Water Resources Research Center: http://www.iwrrc.org/
[2]ISDH: State of the Young Hoosier Child Environmental Health Report

Carbon Pollution



- Federal carbon rules coming
- No state climate policy or plan
- Coal-fired power plants are largest carbon dioxide contributors

Our Clean Energy Future

- Energy efficiency (building efficiency) as the foundation
- Distributed power – including wind and rooftop solar, biomass and less polluting resources
- Demand-response management
- Storage technologies
- The least amount of natural gas achievable, with its eventual phase-out

Opportunities and Choice

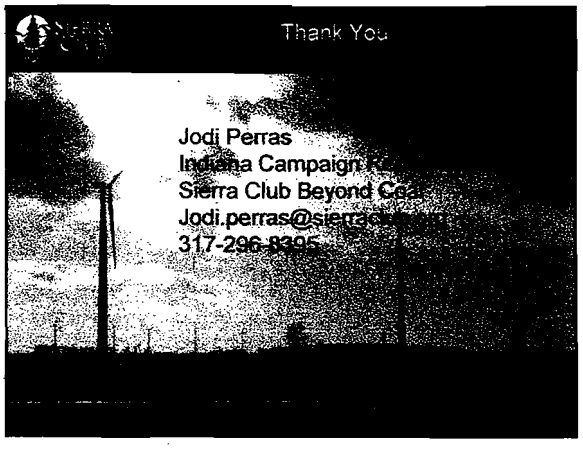
- Distributed renewable generation, storage, end-use energy efficiency and micro-grids
  - Competitive business opportunities that expand economic opportunity
  - Greater potential for customer choice, diversity and competition
  - Can be implemented with protections for ratepayers

Policies that Hold Us Back

- Centralized generation of electricity
- No mandatory renewable energy standard to encourage gradual shift toward carbon-free energy
- Weak standards for protecting consumers in utility rate cases (CPCN, CWIP, trackers)
- No competition or least-cost decision-making required in utility capital decisions
- Restrictions on distributed generation (who can participate, how it's financed)

Policies We Support

- Protect and improve the Commission-imposed energy efficiency requirements
- Improve incentives for renewables and efficiency
- Improve net metering and feed-in tariff opportunities for renewable energy
  - Expand participation
  - Allow creative financing
  - Increase energy savings opportunities for schools, local governments, universities, etc.


Thank You
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RESIDENTIAL & LOW-INCOME CONSUMERS & CUSTOMER CHOICE

September 18, 2013

Presentation to Regulatory Flexibility Committee

CITIZENSACTIONCOALITION
turning on citizen power www.citact.org

"Basic electric and natural gas service are essential to all residential customers and the affordability of those services for low income customers whose energy burden is high in relationship to their income is crucial. **The lack of affordable electricity and natural gas for home heating, refrigeration, and cooling is not the equivalent of the retail market for most other consumer goods and services, for which substitutes exist.** The lack of affordable electricity or natural gas for heating and cooling has dire consequences for residential customer health and safety."

AN ANALYSIS OF RETAIL ELECTRIC AND NATURAL GAS COMPETITION:
RECENT DEVELOPMENTS AND POLICY IMPLICATIONS FOR LOW INCOME CUSTOMERS
June 2013, Barbara Alexander

CITIZENSACTIONCOALITION
turning on citizen power www.citact.org

INDIANA'S EXPERIENCE NIPSCO RESIDENTIAL CHOICE

- NIPSCO Commodity Price (per therm): September 2013 (changes monthly) = $0.293
- Constellation = $0.539
- Just Energy = $0.530 to $0.650
- Direct Energy = $0.629
- Santanna Energy = $0.539
- Spark Energy = $0.525
- Xoom Energy = $0.607

http://www.nipsco.com/en/our-services/NIPSCO-Choice/choice-residential-plans.aspx

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NIPSCO CHOICE (CONT'D)

COMMODITY $ + STORAGE/TRANSPORTATION $ PER THERM

- Constellation: 67.2% higher
- Just Energy: 62.9% - 94.9% higher
- Direct Energy: 86.4% higher
- Santanna: 65.1% higher
- Spark: 64.3% higher
- Xoom: 85.9% higher

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ILLINOIS RESIDENTIAL GAS CHOICE

- Consumers Utility Board (CUB) – Gas Market Monitor
- Analyzed 6,063 plans since 2003
- 94% of consumers who chose alternative supplier lost money
- $1,190.64 average loss over the life of the plan

http://www.citizensutilityboard.org/GasMarketMonitor.php

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NEW YORK: NIAGARA MOHAWK (NATIONAL GRID AFFILIATE)

- Evaluated 8,709,449 residential customer gas and electric bills over 24 months.
- 84% of electric bills and 92% of gas bills of those who switched were higher.
- $500 more for electricity and $260 for gas.
- This represents approximately $130M more for 24 months than they would have paid.
- Low Income – 91.5% of electric and 93.4% of gas bills were higher.

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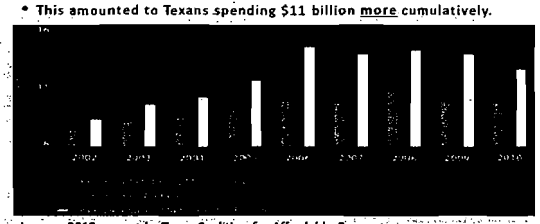
TEXAS

- Customers paid $3,000 in added costs over the last ten years because of deregulation.
- This amounted to Texans spending $11 billion more cumulatively.



January 2012, report by Texas Coalition for Affordable Energy
http://historyofderegulation.tcaptx.com/

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OTHER EXPERIENCES

- Pennsylvania – 70% of PPL Electric low income customers paid more than they otherwise would have if they had stayed with default provider.
- Ohio - Columbia Gas of Ohio indicates that customers who switched providers have paid over $861 million more for natural gas.
- Canada - 2011 Report by the Office of the Auditor General of Ontario showed a customer using 1K kWh/year would pay about $2,000 more for electricity over a 5 year period.

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RISKS TO RESIDENTIAL CUSTOMERS

- Higher prices for essential service;
- Predatory, deceptive market practices;
- Volatile and unaffordable bill impacts;
- Poor customer service from suppliers;
- Hidden fees, additional costs;
- Higher prices for distribution services due to costs associated with the transition to a restructured market

Comments by AARP, AZ Corporation Commission
Generic Docket No. E-00000W-13-0135, July 15, 2013

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THANK YOU!

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ADDITIONAL SOURCES

- **New York**: Direct Testimony of William D. Yates, C.P.A., on behalf of the Public Utility Law Project of New York, Inc., before the NY PSC, Proceeding for Niagara Mohawk Power Co. for Natural Gas and Electric Rates, Case No. 12-G-0202 and Case No. 12-E-0201 (August 31, 2012)
- **Pennsylvania**: Direct Testimony of Stephen Krone, on behalf of Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania, before the PA PUC, Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan, Docket No. P-2012-2302074 (July 20, 2012).
- **Canada**: This Report is available from the Auditor General at http://www.auditor.on.ca/en/reports_en/en11/302en11.pdf

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