Members

Sen. James Merritt, Co-Chairperson
Sen. Jean Leising
Sen. Beverly Gard
Sen. Dennis Kruse
Sen. Scott Schneider
Sen. James Tomes
Sen. Carlin Yoder
Sen. Lonnie Randolph
Sen. Jean Breaux
Sen. Richard Young
Rep. Jack Lutz, Co-Chairperson
Rep. Heath VanNatter
Rep. Robert Behning
Rep. David Frizzell
Rep. Eric Koch
Rep. Timothy Neese
Rep. Edmond Soliday
Rep. David Yarde
Rep. Dan Stevenson
Rep. Kreg Battles
Rep. Ryan Dvorak
Rep. Charles Moseley
Rep. Matthew Pierce

LSA Staff:

Diana Agidi, Fiscal Analyst for the Committee
Sarah Burkman, Attorney for the Committee
Sarah Freeman, Attorney for the Committee

Authority: IC 8-1-2.5-9

REGULATORY FLEXIBILITY COMMITTEE

Legislative Services Agency
200 West Washington Street, Suite 301
Indianapolis, Indiana 46204-2789
Tel: (317) 233-0696 Fax: (317) 232-2554

MEETING MINUTES[1]

Meeting Date:	**September 21, 2011**
Meeting Time:	**10:00 A.M.**
Meeting Place:	**State House, 200 W. Washington St., House Chamber**
Meeting City:	**Indianapolis, Indiana**
Meeting Number:	**1**

Members Present: **Sen. James Merritt, Co-Chairperson; Sen. Jean Leising; Sen. Beverly Gard; Sen. James Tomes; Sen. Lonnie Randolph; Sen. Jean Breaux; Rep. Jack Lutz, Co-Chairperson; Rep. Heath VanNatter; Rep. Robert Behning; Rep. Eric Koch; Rep. Timothy Neese; Rep. Edmond Soliday; Rep. David Yarde; Rep. Dan Stevenson; Rep. Ryan Dvorak; Rep. Matthew Pierce.**

Members Absent: **Sen. Dennis Kruse; Sen. Scott Schneider; Sen. Carlin Yoder; Sen. Richard Young; Rep. David Frizzell; Rep. Kreg Battles; Rep. Charles Moseley.**

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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.

I. Call to Order

Senator Merritt served as Chairman and called the meeting to order at 10:05 a.m. Representative Lutz welcomed members.

II. James Atterholt, Chairman, Indiana Utility Regulatory Commission (IURC)

Chairman Atterholt introduced the IURC commissioners and division heads. He praised the long term and nonpolitical nature of the commissioners and staff. Chairman Atterholt updated the Committee on various changes to the IURC's ethics guidelines, especially with respect to meeting with representatives of the regulated utilities.

Chairman Atterholt provided an overview of the IURC's electricity and natural gas divisions and distributed copies of the IURC's 2011 Report to the Regulatory Flexibility Committee of the Indiana General Assembly. See Exhibit A, pp. 1-22; Exhibit B. 23 electric utilities serving more than 2.6 million customers are under IURC jurisdiction. Chairman Atterholt explained the differences between investor owned utilities, municipally owned utilities, and rural electric membership cooperatives (REMCs). He stated that Indiana's average retail electric prices are competitive nationally and regionally and that 85% of Indiana's energy production comes from coal fired generation. Chairman Atterholt spoke briefly about ongoing proceedings concerning Duke Energy's Edwardsport Integrated Gasification Combined Cycle (IGCC) generating facility. He also discussed the IURC's recent net metering and demand side management initiatives. Following a discussion of the impact of federal environmental regulations on Indiana's electricity providers, he described the IURC's revisions to its tree trimming rules. Next, Chairman Atterholt provided an overview of natural gas pipeline safety in Indiana. He described the transmission and distribution systems that supply natural gas to Indiana customers. Chairman Atterholt closed his presentation by talking about the IURC's role in the Indiana Finance Authority's purchase of synthetic natural gas from Indiana Gasification, LLC, for sale to Indiana customers.

At the invitation of Chairman Merritt, Representative Koch introduced several people from the Ukraine who were visiting Bedford, Indiana, through the Open World program.

Representative Pierce reminded the Committee that former IURC Chairman Hardy testified during the 2010 interim that IURC staffing levels were so low as to permit the IURC only to "check the math" in rate cases. He asked Chairman Atterholt if he found current staffing levels adequate. Chairman Atterholt stated his opinion that former Chairman Hardy probably had been referring to review of automatic trackers and that the Office of Utility Consumer Counselor (OUCC) performs most of the review in rate cases. Representative Pierce inquired about the IURC's authority with respect to the ongoing merger proceedings between Duke and Progress Energy, a North Carolina utility. Chairman Atterholt said that the IURC has no real role in the proceedings because it lacks jurisdiction over mergers and that such jurisdiction can be effective or abusive. Representative Pierce also asked for Chairman Atterholt's impressions of feed-in tariffs (FITs); the chairman replied that FITs are great in concept and that some Indiana electric utilities are voluntarily implementing FITs.

Senator Breaux asked about the IURC's role in the recent merger of Citizens Gas and Indianapolis Water. Chairman Atterholt stated that Commissioner Mays would address that issue in her presentation.

III. Carolene Mays, Commissioner, IURC

Commissioner Mays stated that the IURC exercises jurisdiction over 104 water utilities and 47 wastewater utilities that generate $493 million and $29 million respectively in annual revenue. She said that the water sector is the most capital intensive of all utility industries. Commissioner Mays brought to the Committee's attention possible conflicts between IC 8-1-2-6 and IC 8-1.5-2-6(b) concerning the value of municipal utility assets. She also discussed the process by which water utilities receive rate increases, including the recovery of infrastructure costs through distribution system improvement charges (DSICs). See Exhibit A, pp. 23-29.

Senator Breaux asked if there is a cap on DSICs. Commissioner Mays answered that DSICs are capped at 5% of revenue and may be approved not more than once every 12 months. Representative Pierce referred to the graph on page 92 of the IURC's annual report (see Exhibit B, p.92) and asked what happened in 1983 to cause water utility rates to increase so drastically. Commissioner Mays stated that it was probably due to investments in aging infrastructure and offered to follow up with the author of the study on which the chart is based. Senator Randolph asked about the significance of IURC jurisdiction over water and wastewater utilities and if there is a correlation between the health of the economy and rate cases. Commissioner Mays said that IURC jurisdiction confers the authority to regulate rates; she also said that current rate cases are driven more by infrastructure costs than the economy.

IV. Doug Gotham, Director, State Utility Forecasting Group (SUFG)

Mr. Gotham distributed copies of the SUFG's 2011 Indiana Renewable Energy Resources Study and 2011 Forecast: Indiana Electricity Projections. See Exhibits C and D. He stated that the study addresses renewable energy trends, barriers to renewable energy development, and statistics for various individual renewable energy resources, including percentage shares as part of Indiana's electricity generation. See Exhibit E. Mr. Gotham discussed the use of energy crops as transportation fuels and said that organic waste biomass is the third largest source of renewable electricity generation in Indiana. He stated that photovoltaics are growing rapidly but remain a small contributor overall. He also mentioned that American Municipal Power is constructing a new hydroelectric facility on the Ohio River. With regard to the forecast, Mr. Gotham addressed Indiana's overall electricity requirements, peak demand requirements, resource requirements, and real price projections. He also stated that SUFG is conducting a study of the expected impacts of recent, proposed, and expected federal environmental regulations.

V. David Stippler, Indiana Utility Consumer Counselor, OUCC

Counselor Stippler said that in 2010, OUCC advocacy resulted in $112 million in savings to Indiana rate payers. The OUCC's mission is to represent all Indiana utility consumers while balancing competing interests across customer classes; the OUCC also represents the state in proceedings before the Federal Energy Regulatory Commission. Counselor Stippler discussed the recent collaboration between the OUCC and the IURC intended to reduce duplicated efforts and inconsistent results between the two agencies. He stated that the IURC will handle consumer complaints that require mediation with regulated utilities; the OUCC is in charge of public comments on pending cases. Counselor Stippler said that the OUCC must engage in creative problem solving as utilities must find ways to repair, rebuild, and replace aging infrastructure. He also stressed the OUCC's dedicated advocacy role, especially at the federal level with regard to environmental regulations.

Senator Tomes asked for the United States' ranking among all nations and among regulated countries with respect to industrial emissions. Counselor Stippler said that he only had anecdotal data. Senator Breaux asked if the OUCC considers a utility's profit when representing customer interests in rate cases. Counselor Stippler answered that the OUCC considers revenues but not profits. Senator Breaux also asked if the OUCC encourages utilities to maintain a rainy day fund in anticipation of future infrastructure costs. Counselor Stippler said that utilities are prohibited from recovering future speculative costs under IC 8-1-2-6. Senator Leising asked if the OUCC had performed any mapping that would show the availability of clean drinking water in Indiana's rural counties. Counselor Stippler said he would present this issue to OUCC staff.

Chairman Merritt recessed the Committee for lunch at 12:15 p.m.

VI. Thomas Easterly, Commissioner, Indiana Department of Environmental Management (IDEM)

Chairman Merritt reconvened the Committee at 1:40 p.m. Commissioner Easterly provided an update on federal regulations impacting the electric industry, including the Clean Air Interstate Rule, the Cross State Air Pollution Rule (CSAPR), the National Ambient Air Quality Standards, the Clean Water Act (CWA), and the Resource Conservation and Recovery Act. See Exhibit F. Commissioner Easterly said that, at the end of 2009, Indiana satisfied all health based ambient air quality standards. He displayed several charts and maps showing ozone and particulate matter trends relative to both adult and childhood asthma trends. Commissioner Easterly also spoke specifically about CWA section 316(b) , which is designed to reduce the damage to aquatic organisms from impingement on the intake structures and entrainment in the water passing through certain electric utility facilities. Finally, he addressed proposed rules governing coal combustion residuals (CCRs); he said that IDEM data indicates that CCRs do not exhibit hazardous characteristics and should not be regulated as hazardous wastes.

Senator Leising asked Commissioner Easterly if he knew why coal fired electric plants in Lawrenceburg had closed. He said that it was because the plant's emissions offsets were not adequate to achieve compliance with CSAPR. Representative Behning characterized the proposed federal regulations as frightening and asked if the state or utilities can sue the federal government. Commissioner Easterly answered that Indiana is researching the feasibility of litigation. Senator Leising asked what consequences Indiana would face if it refused to comply with federal regulations. Commissioner Easterly said the Environmental Protection Agency would prohibit IDEM from issuing permits.

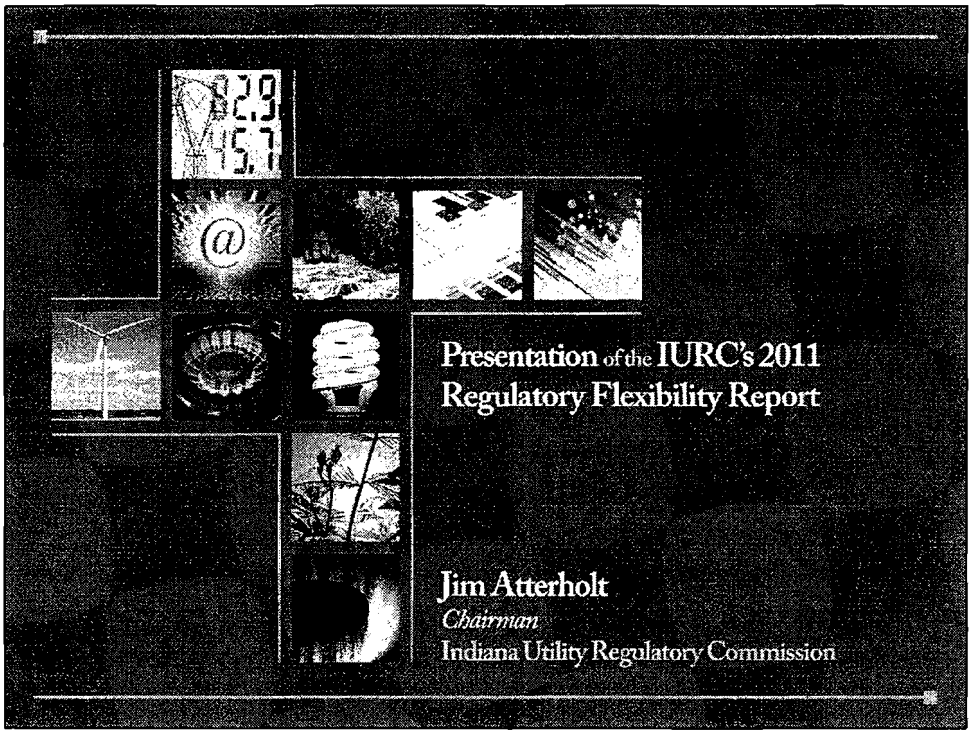
VII. Brandon Seitz, Director, Indiana Office of Energy Development (OED)

Mr. Seitz provided an update on OED, including the state energy program (SEP) and the Hoosier Homegrown Energy Plan. See Exhibit G. Regular annual funding for the SEP averages between $600,000 and $1 million; however, in 2010, SEP received an additional $90 million in federal stimulus funding. OED used $68 million to partner with the Indiana Economic Development Corporation (IEDC) to attract green jobs to Indiana; the remaining $22 million were distributed among the Energy Efficiency Conservation Block Grant, the Indiana HVAC Incentive Program, and Conserving Hoosier Industrial Power (CHIP). OED also administers the Community Energy Plan, distributes Alternative Fuel Vehicle Fleet Grants, and promotes the Energy Action in Schools program. Mr. Seitz also provided highlights of the Hoosier Homegrown Energy Plan, including clean coal development, growth in wind power, recovery in the biofuels sector, development of the Indiana Biomass working group, increased manufacturing of solar components, development of the electric vehicle manufacturing sector, and promotion of energy conservation.

Senator Leising and Mr. Seitz discussed weatherization retrofits performed in Indianapolis and Lafayette that were funded through grants from the U.S. Department of Energy (DOE). Senator Breaux asked where funding for SEP grants comes from; Mr. Seitz said that the DOE provides annual stipends to the OED. Representative Pierce asked what opportunities the OED passed up in order to spend $68 million to attract green jobs to Indiana. Mr. Seitz stated that the money could have been spent elsewhere but that OED determined that the creation of long term green jobs was most important. Representative Pierce asked how the OED will know if the companies that benefitted from the stimulus dollars are creating the jobs they promised. Mr. Seitz said that all the companies are currently complying with their reporting requirements but that the IEDC is responsible for ensuring that the jobs are actually created. Senator Tomes asked how legislators can best inform their constituents about OED programs. Mr. Seitz recommended visiting the OED's website and following its blog.

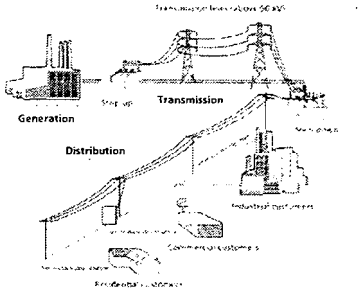
VIII. Other Business & Adjournment

Chairman Merritt reminded members that the second Committee meeting is scheduled for Wednesday, September 28, at 10:00 a.m. He said that Representative Lutz will chair the meeting. Chairman Merritt adjourned the Committee at 2:55 p.m.



Electricity Overview

- The 23 electric utilities under Commission rate jurisdiction generated $8.4 billion in revenue in 2010 and served more than 2.6 million electric customers. [Page 8]



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Ex. A

Investor-Owned Utilities

- Five major IOUs operate in Indiana in exclusive service territories with other portions of the state similarly assigned to municipal utilities and REMCs. IOUs are for-profit enterprises funded by debt (bonds) and equity (stock). Indiana's IOUs are vertically integrated, which means they own facilities for the generation, transmission, and distribution of electricity. These utilities account for more than 90% of the electric power sales of the state's regulated electric utilities to Indiana customers. [Page 9]

IURC 13

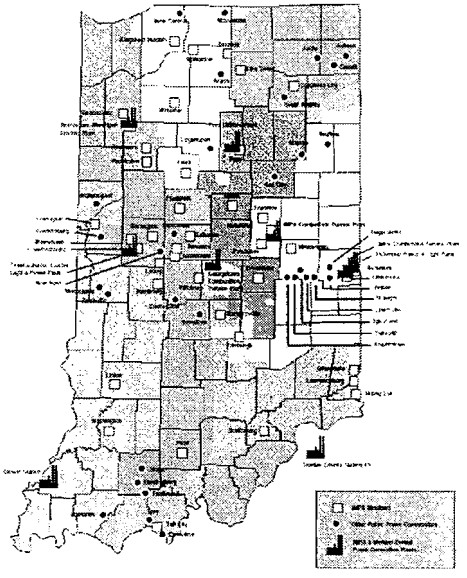
Municipally-Owned Utilities

- State law allows municipal utilities to remove themselves or "opt out" of the Commission's jurisdiction. Under certain circumstances, the Commission may review financing arrangements for individual municipal electric utilities, but this typically occurs through rate cases.
- As of the printing of this report, 12 of the 72 municipally-owned utilities operating in Indiana remained under the Commission's jurisdiction for rate regulation. [Page 10]

IURC 14

IMPA

- A group of municipalities created the Indiana Municipal Power Agency (IMPA) in 1980 to jointly finance and operate generation and transmission facilities. Additionally, IMPA was established to purchase wholesale power and meet members' needs through a combination of member-owned generating facilities, member-dedicated generation, and purchased power. The Commission does not regulate the rates that IMPA charges its members. [Page 10]

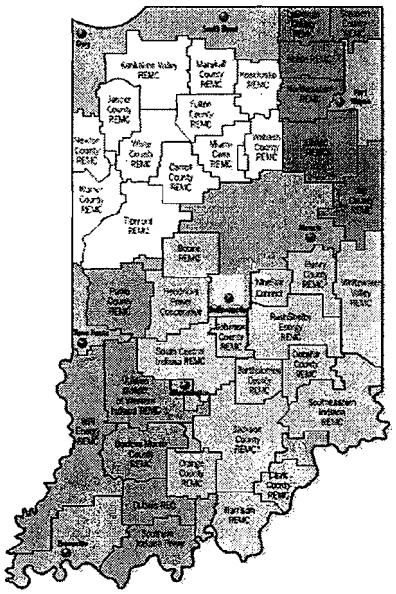


[Page 11]

REMCs

- Rural Electric Membership Cooperatives (REMCs) are customer-owned utilities, all of which are members of either Hoosier Energy Rural Electric Cooperative (Hoosier Energy), located in the southern part of the state, or Wabash Valley Power Association (WVPA), located in the northern part of the state.
- REMCs, like municipalities, have the ability to remove themselves or "opt out" of the Commission's jurisdiction. As of the printing of this report, only 4 of the 40 REMCs operating in Indiana remained under the Commission's jurisdiction for rate regulation. [Page 12]

IURC : 7

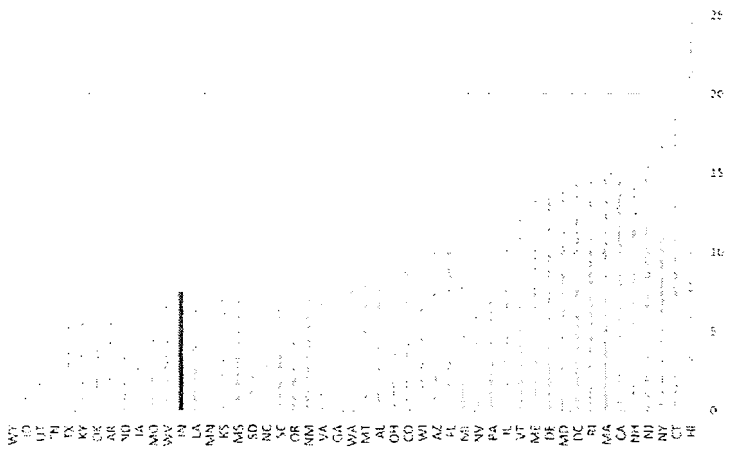


[Page 12]

IURC : 8

How Indiana Compares

- Indiana's average retail prices for electricity have been and are presently competitive both nationally and regionally. Retail prices are the average price for all rate classes, including residential, commercial, and industrial customers.
- For 2010, Indiana's rates were 13th lowest, as shown in Chart 1. Neighboring states' total customer retail rates for 2010 rank as follows, with the first being the lowest: Kentucky 6th, Ohio 28th, Illinois 36th, and Michigan 33rd. [Page 13]

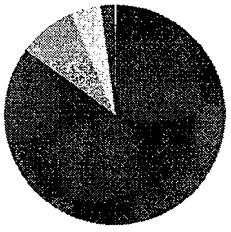


[Page 13]

Existing Generation Portfolio

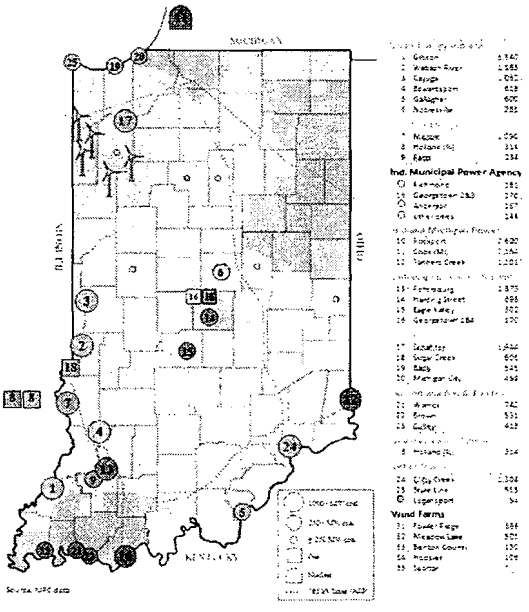
- Coal-fired generation accounts for 85% of actual energy production for Indiana consumers. The second highest is nuclear generation at 8.5%.

Projected 2010 Energy Production for Indiana Consumers by Fuel Type



- Coal (108,312 GWH, 85%)
- Nuclear (10,749 GWH, 8.5%)
- Natural Gas (5,650 GWH, 4.4%)
- Wind , Other Renew. (2,049 GWH, 1.6%)
- Hydro (503 GWH, 0.4%)
- Oil (157 GWH, 0.1%)

[Pages 14-15]



[Page 16]

Energy Generation & Water

- "The largest single consumer of water in the United States, in fact, is virtually invisible. Every day, the nation's power plants use 201 billion gallons of water in the course of generating electricity. That isn't water used by hydroelectric plants – it's the water used by coal, gas, and nuclear power plants for cooling and to make steam. U.S. electric utilities require seven times more water than all U.S. homes. They use 1.5 times the amount of water used by all the farms in the country. In fact, 49 percent of all water use in the United States is for power plants."
  - Fishman, Charles. *The Big Thirst.* New York: Free Press, 2011.

Age Profile

Age Profile of Generating Units Owned by Indiana Utilities
Separated by Coal-Based Units and Gas Generation Units

Years Old	Number of Coal-Based Units	MW of Generation (Summer Rating)	Percent of Total Coal-Based Generation
Over 50	21	1,711	11.3%
40-50	15	2937	19.3%
30-40	13	5904	38.9%
20-30	9	4633	30.5%
Total	58	15,185	100%

[Pages 19-20]

Edwardsport

- In an Order issued on November 20, 2007, the Commission granted a CPCN and approved the construction of Duke Energy's Edwardsport Integrated Gasification Combined Cycle (IGCC) generating facility, which will have a capacity of 618 MW.
- The Commission initially approved a cost estimate of $1.985 billion in its 2007 Order. However, the figure was revised by the company and approved by the Commission at $2.35 billion in January 2009. [Page 23]

Edwardsport

- DEI has since filed a second request with the IURC (Cause No. 43114-IGCC 4-S1) to update the estimated capital cost of the project and to set a "hard cap" for the project at $2.72 billion.
  - This case has since been expanded by the Commission to include two phases.
    - Phase I will address Commission review of the utility's progress reports, the proposed cost estimate increase, and the reasonableness of going forward with the project. Phase II, on the other hand, will address allegations made by intervening parties of fraud, concealment, and/or gross mismanagement associated with the project.
  - Those public hearings are scheduled for October 2011. [Page 24]

Nuclear

- To extend the life of these units, I&M will need to implement a systematic replacement of many parts of the plant, some of which are no longer commercially available, that may not otherwise safely last until the end of the extended period (new life cycle).
  - This Life Cycle Management Project is part of an overall AEP plan to replace older and less efficient coal generation that would be too costly to upgrade to comply with the various anticipated pollution mandates with more cost-effective, less environmentally-challenged units. Projected costs to extend the life cycle of the Cook plant range from $1.5 billion to $2 billion. [Pages 28-29]

Net Metering

- Net metering is a service offering that allows participants to supplement their electric usage and cut costs by installing renewable energy facilities such as wind turbines or solar panels, while relying on the electric utility as a back-up provider.
  - If the amount of electricity the customer receives from the utility is greater than the amount delivered to the utility, the difference is charged to the customer. If the amount the customer received from the utility is less than the amount delivered to the utility, the customer receives a credit on the next bill for the difference. [Pages 31-32]

Net Metering

- *The net metering rulemaking, initiated by the IURC in June 2010, went into effect in July 2011.*
  - *Significant changes stemming from the rulemaking include:*
    - *A **9,900%** increase in the maximum size of an eligible facility from 10 kW to 1 MW;*
    - *Expanded eligibility to **all customer classes** (industrial, commercial, and residential) from just K-12 schools and residential customers; and*
    - *A **900%** increase in the aggregate sales level under each utility's net metering tariff from 0.1% to 1% of annual kWh sales.*
  - *To accomplish these changes, the IURC traveled to public meetings in Indianapolis, Ellettsville, and South Bend. The agency also held numerous meetings with stakeholders to solicit feedback from around the state.* [Page 31]

Demand-Side Management

- Underscoring the urgency to become more energy efficient in Indiana, the Commission's 2009 Phase II Demand-Side Management (DSM) Order instructed Indiana's jurisdictional electric utilities to move forward with a set of Statewide Core Conservation Programs in their respective service territories. Per the Commission's Order, the utilities must achieve an annual energy savings goal of 2.0% within ten years. [Page 34]

Demand-Side Management

- Although the cost of DSM programs will be included in customer retail rates, the impact to rates is anticipated to be less than it would be without DSM efforts. This is because DSM slows the growth in energy consumption and peak demand, thus postponing or reducing the need to build new and expensive generation facilities to meet future demand. [Page 34]

U.S. EPA Regulations

- Decisions made at the federal level have the potential to considerably impact the state of Indiana. In fact, one recently finalized and three currently proposed U.S. EPA rules are expected to impose significant burdens on the Indiana power sector. [Page 38]

U.S. EPA Regulations

- These rules include:
  - The Cross-State Air Pollution Rule (CSAPR or Transport Rule) that implements controls for nitrogen oxides and sulfur dioxide; The electric generating utility Maximum Achievable Control Technology Rule (Utility MACT) for mercury and other air toxics;
  - A new rule for cooling water intake structures (CWIS), potentially requiring cooling towers to be installed at certain facilities; and
  - A proposal for the U.S. EPA to regulate coal combustion residuals (CCR), including coal ash, initiated as a result of the 2008 ash pond failure in Tennessee. [Page 38]

Senate Enrolled Act 251

- Senate Enrolled Act 251 (P.L. 150-2011) provides guidance to the Commission on three major issues in the electricity sector that have received significant attention in recent years:
  - Regulatory treatment for a growing number of federally-mandated costs;
  - Regulatory treatment for nuclear projects; and
  - Implementation of a Voluntary Clean Energy Portfolio Standard. [Page 41]

Tree Trimming

- Vegetation management plans and practices play a key role in helping to reduce the number of service interruptions to Indiana consumers. At the same time, ratepayers have basic rights that need to be protected. In November 2010, the Commission concluded its investigation into tree trimming practices and tariffs for jurisdictional electric utilities and found that Hoosiers would benefit from having consistency with regard to the rules and regulations surrounding tree-trimming practices and procedures. [Pages 42-43]

Tree Trimming Notice

- The Order requires utilities to provide advance notice to customers when trimming is about to occur and allows customers to be present during that time. When contacting customers, the utilities must now provide notice in person or over the phone and provide at least one form of written notice to the customer. The initial notice should be no later than two weeks before the trimming is estimated to occur. In doing so, customers and utilities will have more time to discuss and resolve concerns. [Page 43]

Tree Trimming Rules

- The rules are as follows:
  - Utilities are prohibited from "topping" trees or removing more than 25% of a tree's canopy without the property owner's consent.
  - Utilities are prohibited from trimming outside an easement or right-of-way without the customer's consent. If the property owner does not consent, the utility must offer alternatives. One such alternative is a tree replacement program set up by the Order that allows utilities to compensate for tree removal.
  - Once normal maintenance trimming is complete, the debris should be promptly removed within three calendar days. [Page 43]

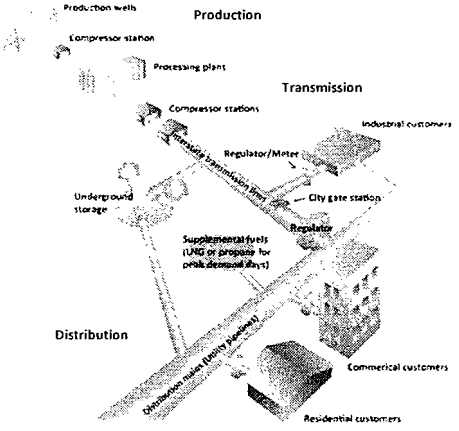
Natural Gas Overview

- The natural gas industry consists of three systems: producers (the gathering system), interstate and intrastate pipelines (the transmission system), and local distribution companies or LDCs (the distribution system).
- Interstate pipelines, regulated by the Federal Energy Regulatory Commission (FERC), carry natural gas across state boundaries; intrastate pipelines, regulated by state commissions, carry natural gas within state boundaries. [Page 48]

Pipeline Safety Overview

- States, including Indiana, that have certified pipeline safety programs are delegated federal authority by the U.S. Department of Transportation to conduct inspections, investigate incidents, and enforce state and federal safety regulations.
- In Indiana, the Indiana Utility Regulatory Commission regulates the rates, charges and terms of service for intrastate pipelines and LDCs. [Page 48]

Process



[Page 48]

Transmission

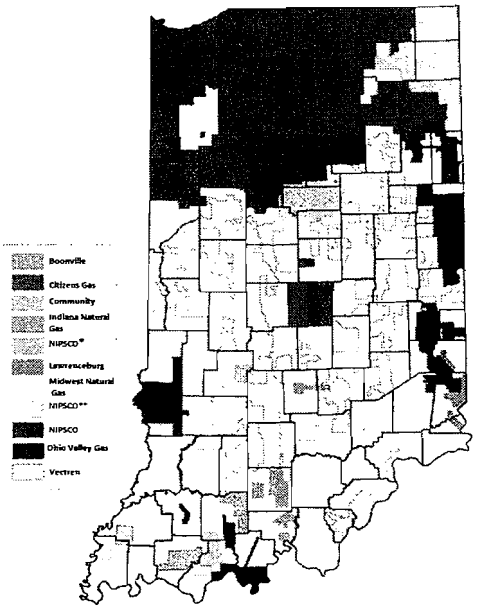
- The transmission system includes interstate and intrastate pipelines that carry gas from producing regions throughout the U.S. to LDCs, industrial consumers, and power generation customers. The vast majority of natural gas consumed in Indiana is from out-of-state production, primarily from the Gulf of Mexico.
  - In 2009, Indiana consumed approximately 507 million dekatherms (Dth) of natural gas, of which roughly 4.9 million Dth, or less than 1%, was produced within the state. This illustrates Indiana's dependence on the transmission system to carry natural gas from the gas producing regions of the country into the state. [Page 49]

U.S. Transmission Lines

[Page 49]

Distribution

- The Commission has regulatory authority over 19 natural gas distribution utilities in Indiana with operating revenues totaling $1.9 billion (Appendix A). These utilities maintain plant in service of approximately $3.6 billion and serve roughly 1.7 million customers. Of the regulated utilities, one is a not-for-profit, two are municipalities, and sixteen are investor-owned utilities (IOUs). Citizens Gas, and three IOUs (NIPSCO, Vectren North and Vectren South) represent the four largest natural gas utilities in Indiana and collectively serve 92% of the gas customers by count in the state. [Page 50]

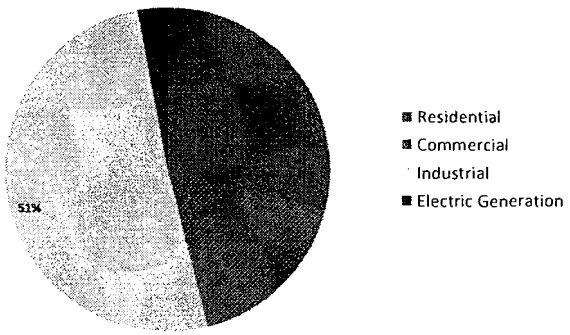


[Page 52]

How Indiana Compares

- Indiana ranked 5th nationally and 2nd in the Midwest region for the lowest 2010 average residential gas prices. The average residential gas price has fallen each of the last two years from $12.65 per thousand cubic feet in 2008 to $8.52 per thousand cubic feet in 2010. These numbers are higher than the commonly referenced commodity cost of approximately $4.50/Mcf, because they are bundled prices. Bundled prices include all utility costs to deliver the product, including pipeline and LDC operator charges. [Page 53]

Indiana Consumption by Sector



[Page 55]

Demand

- In 2010, Indiana's residential customers consumed approximately 140 million Dth of natural gas, which accounts for 29% of the state's total consumption.
- Also in 2010, Indiana's commercial customers consumed approximately 17% of the state's total consumption or 79 million Dth of natural gas.
- Industrial customers accounted for more than half of the state's total consumption with about 245 million Dth, which ranked Indiana fourth highest for industrial natural gas consumption in the U.S. [Page 56]

NIPSCO Rates

- All customer classes in the NIPSCO service territory received a modest reduction in their natural gas rates and charges as a result of the Commission's approval of the settlement agreement in the NIPSCO gas rate case on November 4, 2010, under Cause No. 43894. The residential class, specifically, experienced a decrease in rates of roughly $5 million or 3.3% from existing rates. [Page 66]

Synthetic Natural Gas

- Coal gasification is a process that converts coal into substitute natural gas (SNG). Given Indiana's vast coal reserves, the prospect of using local coal sources for the production of substitute natural gas is another alternative to importing natural gas into our state. SNG that is produced is of pipeline quality and may be used for home heating, manufacturing facilities, or in the generation of electricity. [Page 69]

Senate Enrolled Act 423

- On March 25, 2009, Governor Daniels signed into law Senate Enrolled Act 423, which directs the Indiana Finance Authority (IFA) to enter into contracts for the sale of SNG with 3rd parties, with net proceeds from and the costs of those sales being reflected on natural gas customers' bills.
- On December 16, 2010, the IFA and Indiana Gasification, LLC (IG) petitioned the Commission.
- The Commission began its evidentiary hearing on May 2, 2011. We expect a final decision this fall. [Pages 69-70]

SNG Contract

- The petition requested the following:
  - Approval of an SNG purchase and sales agreement between the IFA and IG;
  - If necessary, for the Commission to order Indiana regulated energy utilities to enter into a management agreement with the IFA; and
  - For the Commission to decline jurisdiction over IG.
- Prior to the evidentiary hearings, the Commission provided the public with an opportunity to voice its opinion on the proposed SNG facility, holding three separate field hearings in Jasper, West Lafayette, and Indianapolis. [Page 71]

SNG Timeline

- The Commission then began its evidentiary hearings on May 2, 2011.
- The case is still pending before the Commission.
- We expect a decision some time this fall. [Page 71]

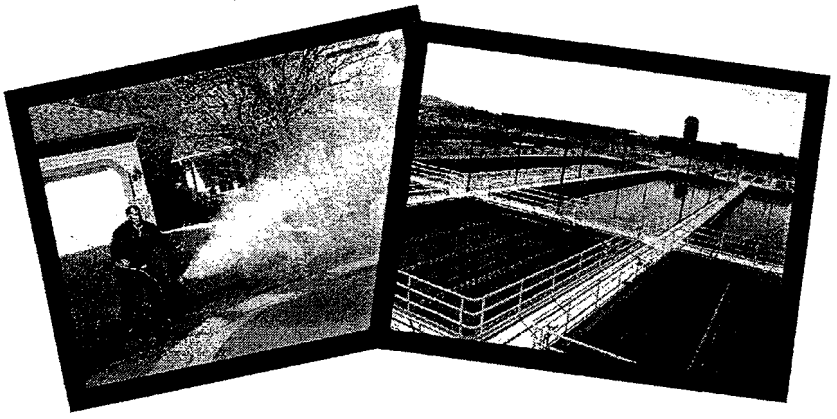
Universal Service Programs

- The Commission's Order in Cause No. 43669 authorized Citizens Gas, NIPSCO, Vectren North, and Vectren South to reinstate their respective bill assistance programs to provide Hoosiers in need with assistance during the winter heating season. [Page 71]
- Particularly with the possibility of federal cutbacks, we continue to work with these companies to make sure we are ready by winter.

San Bruno Incident

- Despite the nation's overall excellent pipeline safety record, recent pipeline incidents in California, Michigan, Pennsylvania, and other locations have elevated the awareness of stakeholders and the public to the potential dangers of natural gas and hazardous liquid pipelines across the country. It has also prompted the IURC's Pipeline Safety Division to closely monitor the findings of the incidents, especially the one in San Bruno, California. [Page 72]

Water/Wastewater Sectors



Water/Wastewater Overview

- Numerous small systems serve a relatively small percentage of the population, while a small number of large systems serve the majority of the population.
- There are 104 water utilities and 47 wastewater utilities under the Commission's jurisdiction. [Page 80]

Commission Jurisdiction

This table details some of the IURC's jurisdiction and shows which utilities the agency generally does not regulate with regard to rates and charges or rules and regulations.

Type of Utility	Rates and Charges	Rules and Regulations	Ability to Withdraw from Jurisdiction	No Jurisdiction	CTA
Investor-Owned Water*	✓	✓	✓		
Investor-Owned Sewer*	✓	✓	✓		✓
Not-for-Profit Water	✓	✓	✓		
Not-for-Profit Sewer	✓	✓	✓		
Municipal Water	✓		✓		
Municipal Sewer				✓	
Regional Water District				✓	
Regional Sewer District				✓	
Conservancy Water District**	✓		✓		
Conservancy Sewer District				✓	

* Investor-owned water and sewer utilities with 200 customers or less can opt out of the IURC's jurisdiction, per IC § 8-1-2.7-1.3.

** Water conservancy districts with fewer than 2,000 customers can opt out of the IURC's jurisdiction, per IC § 8-1-2.7-1.3.

Note: Municipal water and not-for-profit utilities can opt out regardless of the number of customers.

[Page 81]

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Utility Finances

- Regulated water utilities generate $493 million in annual revenue and regulated wastewater utilities generate $29 million.
- The regulated water systems have $3.7 billion of utility plant in service, and the regulated wastewater utilities have $199.1 million of utility plant in service. [Page 80]

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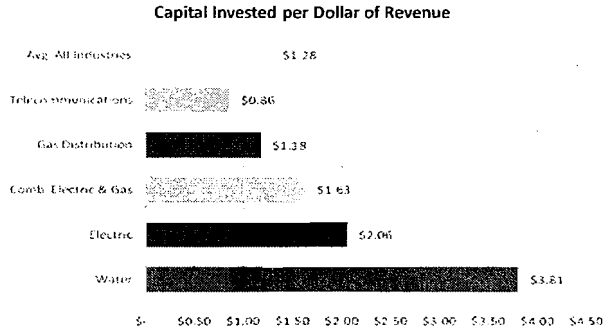
Capital Investments

The water sector is the most capital intensive, investing more capital per dollar of revenue generated than any other industry.



[Page 89]

Acquisitions & Consolidations

- The pace of mergers and acquisitions has slowed; however, transactions continue to take place.
  - In July, the Commission approved a unique transfer of the City of Indianapolis' water and wastewater systems to Citizens Energy Group, after a settlement agreement was reached.
- Recent utility transfers have highlighted several issues of concern. [Pages 83-84]

Issues of Concern

- There may be a conflict between Indiana statutes that explains how the price is determined for the assets and what the Commission sets as the fair value.
  - Under IC § 8-1.5-2-6(b), municipal assets may not be sold for less than their full appraised value; however, the Commission must adhere to IC § 8-1-2-6, which disallows Contributions in Aid of Construction (CIAC) in determining the fair value.
- In some cases, appraisers do not eliminate all utility plant that has been contributed by developers or was funded by a government grant. CIAC is utility plant that was not funded by the utility such as plant contributed by a developer or obtained as part of a government grant. [Pages 83-84]

Small Utilities

- Small water/wastewater utilities are prevalent in Indiana.
- Due to limited resources, many small utilities need technical, financial, and managerial assistance.
- In some instances, the Commission may classify small systems as "troubled."
  - These utilities typically serve fewer than 300 customers. [Page 95]

Troubled Utilities

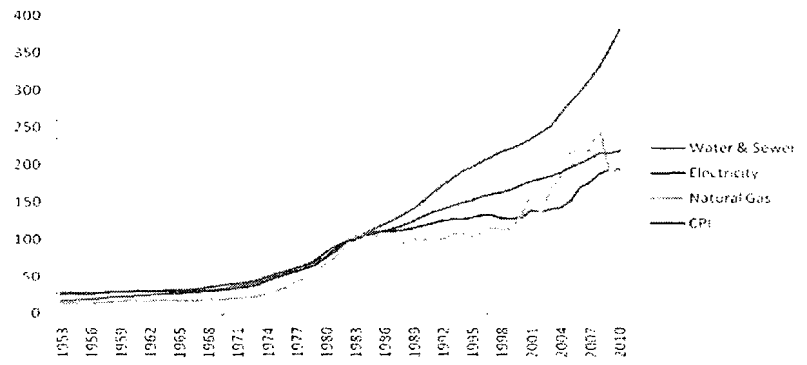
- The Commission's primary goal is to prevent utilities from becoming "troubled" by:
  - Ensuring utilities can provide reliable service prior to serving the customers.
  - Improving the management and operation of small utilities through small utility workshops.
  - Assisting utilities with record keeping through training and development of a small utility accounting manual.
- If the utility has continued violations, the IURC can order the acquisition of the utility by a new owner or appoint a receiver. [Page 96]

Rate Increases

- Rate cases in Indiana reflect the national trend that shows water and wastewater rates outpacing inflation.
- Overall, the number of rate increase requests has been significant, with as many as 23 pending at any one time during the past year.
- In 2010, nine water utilities were approved for general rate increases averaging 25.01%, and twelve wastewater utilities were approved for general rate increases averaging 46.63%. [Pages 92-93]

Rate Increases

Comparison of Utility Prices from 1953 to 2010
Index is set to 100 for 1982-1984



Source: IPU Research Note, February 2011, Janice Beecher, Ph.D., U.S. Bureau of Labor Statistics

[Page 92]

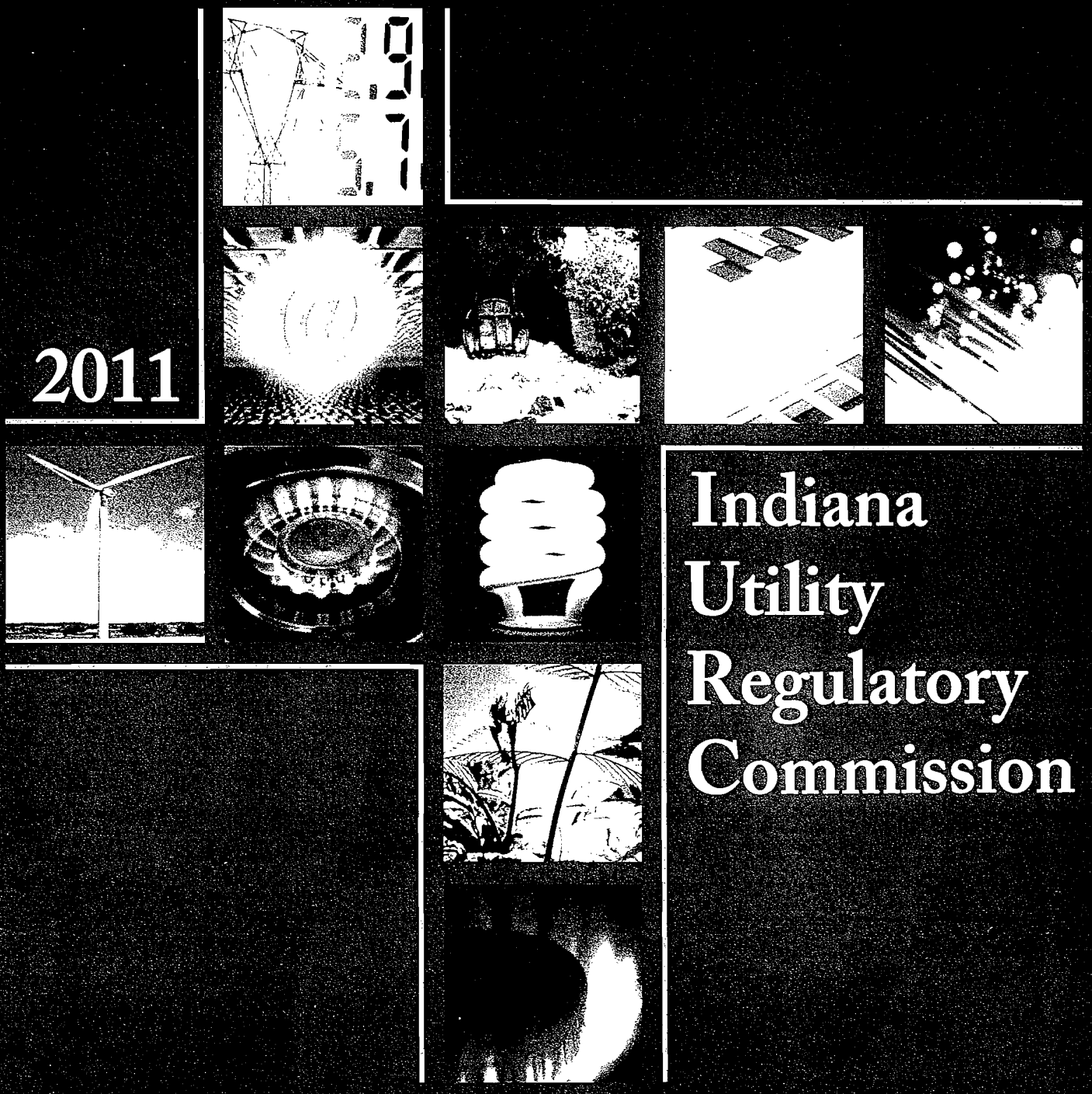
Rate Increases

- Increasing costs are driven by:
  - Increase in expenses
  - Relocation of facilities
  - Compliance with U.S. EPA standards
    - In recent years, Indiana utilities have incurred costs associated with maintaining and improving their systems, and these costs are expected to keep increasing as new rules are approved.
  - Need to replace aging infrastructure
    - Water infrastructure needs have been estimated at $12.4 to $13.9 billion. [Pages 88-89]

Recovery of Infrastructure Costs

- The Commission has several mechanisms that allow utilities to recover costs associated with infrastructure projects the most significant is the Distribution system improvement charge (DSIC).
  - Allows water utilities to recover the costs of improvements to existing distribution systems without a rate case
  - The Indiana General Assembly enacted legislation in 2000
  - As of May 2011, the Commission approved close to $138 million in utility distribution plant placed in service through the DSIC. [Pages 93-94]

Report to the Regulatory Flexibility Committee of the Indiana General Assembly



2011

Indiana Utility Regulatory Commission

EXECUTIVE SUMMARY

The Indiana Utility Regulatory Commission's (Commission or IURC) *Report to the Regulatory Flexibility Committee of the Indiana General Assembly for 2011* highlights key issues addressed by the Commission with respect to the Electric, Natural Gas, Water/Wastewater, and Communications utilities in the state of Indiana. This year's report provides an overview of recent issues; considers the current industry landscape; and discusses the successes, as well as the challenges facing the utility industry.

In order to better serve the Legislature, the agency focused on issues thought to be most relevant based on inquiries received and legislation filed in recent years. Additionally, information was streamlined to make the report more readable and user-friendly; hopefully you will agree. We understand this is an important tool for the General Assembly and are committed to providing information in a manner useful for policymaking and responding to constituent inquiries. If there are any questions about the information contained herein, the Commission welcomes the opportunity to further discuss those matters of concern. For your convenience, a list of acronyms and a glossary are included.

- Electricity -

In 2010, Indiana's retail rates were 13th lowest in the nation, as compared to 15th lowest in 2009. Consequently, Indiana's average retail prices for electricity have been and are presently competitive both nationally and regionally. Retail prices are the average price for all rate classes, including residential, commercial, and industrial customers. Neighboring states' total customer retail rates for 2010 rank as follows, with the first being the lowest: Kentucky 6th, Ohio 28th, Illinois 36th, and Michigan 33rd.

The State Utility Forecasting Group (SUFG) at Purdue University has been tasked by the Legislature to identify and forecast future electric needs in Indiana. According to the SUFG's 2011 forecast, the state will need approximately 2,600 MW of additional resources (all types of generating capacity, demand response, efficiency, and transmission to import power) by 2020 to meet expected demand and maintain a 15.8% reserve margin. A reserve margin is the amount of extra capacity available to serve customer demand in the event of a system contingency, such as

the planned or unplanned outage of a generation plant or a high-capacity transmission line. The forecast also projects that electricity usage will grow at an annual rate of 1.30% over the 20-year forecast and that peak demand will grow at an annual rate of 1.28%.

With the encouragement of the Legislature, the Commission began an informal review in June 2010 of net metering practices in Indiana to determine whether the existing rules within the Indiana Administrative Code should be changed, and if so, to what extent. Net metering is a service offering that allows participants to supplement their electric usage and mitigate a portion of their cost by installing renewable energy facilities such as wind turbines or solar panels, while retaining the electric utility as a back-up provider. If the amount of electricity the customer receives from the utility is greater than the amount delivered to the utility, the difference is charged to the customer. After holding several field hearings throughout the state, the Commission completed the formal rulemaking process and worked with all interested stakeholders to draft a new rule. By dramatically expanding the availability of net metering to all customer classes and the size of the eligible facilities, the Commission believes its new rule will stimulate growth and make it a more attractive option for those who wish to utilize renewable energy in their own backyards.

The Commission also concluded its investigation into the utilities' policies and practices related to tree-trimming. The Commission acted on this investigation in response to customer complaints and has since issued an Order that standardizes the rules for utilities, while protecting basic consumer rights. For example, utilities are now prohibited from "topping" trees or removing more than 25% of a tree's canopy without the property owner's consent. When contacting customers, the utilities must now provide notice in person or over the phone and provide at least one form of written notice to the customer. Further, once normal maintenance trimming is complete, the utility must remove the debris within three calendar days. The Order also required the Commission to initiate a formal rulemaking to further detail the following issues: dispute resolution, notice requirements, customer education, and tree replacement.

With respect to future issues that may affect the electric industry, the Electricity section of this Report focuses on a number of key issues including:

- **Renewables and Conservation** – The use of renewable energy continues to grow in Indiana through purchase power contracts with Indiana wind farms. New demand-side management requirements by the Commission for Indiana utilities, as well as newly approved time-of-use rates for electric vehicles, will continue to help Indiana move forward on the conservation front.

- **Integrated Resource Planning** – By making the integrated resource planning process more transparent, interested parties will have an opportunity to better understand a utility's needs and to weigh in on the long-term goals to meet those needs.

- **U.S. EPA Rulemakings** – Decisions made at the federal level have the potential to considerably impact the state of Indiana. In fact, one recently finalized and three currently proposed U.S. Environmental Protection Agency (U.S. EPA) rules are expected to impose significant burdens and additional costs on the Indiana power sector.

- Natural Gas -

Natural gas commodity pricing continues to create uncertainty in the marketplace. Due to the emergence of unconventional sources such as shale gas, there has been the potential for an increase in supply; however, concern remains about the environmental impacts of fracking, a process by which shale gas is recovered. There is also uncertainty about possible federal regulations, which could limit supply by placing tighter restrictions on the industry. Therefore, Indiana companies are doing their best to hedge against the highs and lows of pricing to protect consumers and ensure rates are "just and reasonable."

The state has also explored ways to mitigate this volatility by passing Senate Enrolled Act 423 (IC ch. 4-4-11.6) in 2009. This bill directed the Indiana Finance Authority (IFA) to enter into contracts for the sale of substitute natural gas (SNG) with third parties, with net proceeds from and the costs of those sales being reflected on natural gas customers' bills. It also established Commission authority over the allocation of the costs and proceeds from the sale, transportation, and delivery of SNG to retail end-use customers. On December 16, 2010, the IFA filed a petition with the Commission seeking approval to enter into a 30-year contract with Indiana Gasification, Inc. Its petition under Cause No. 43976 is pending before the Commission.

The Underground Plant Protection Advisory Committee (Advisory Committee) will soon make recommendations on how violators of the Indiana Damage to Underground Facilities Act should be penalized. A rulemaking that details the process for determining violations of the law, codified under IC ch. 8-1-26, became effective in May 2011. Approximately 1,500 violations have been identified, and responsible parties have started to receive notification letters from the Commission's Pipeline Safety Division. In order to receive a letter, an individual or a business had to allegedly engage in an unsafe digging practice, such as not calling 8-1-1 to have the underground facilities lines marked, causing either a natural gas or hazardous liquid pipeline to sustain damage.

With respect to future issues that may impact the natural gas industry, the Natural Gas section of this Report focuses on a number of key issues including:

- **Regulation of Shale Gas Production** – If restrictions are placed on the natural gas industry, there could be a shift in supply and pricing.
- **Demand** – Depending on the economy, demand could decrease or remain stagnant, which could affect overall market pricing.
- **Rate Cases** – While many utilities have petitioned the Commission in recent years, Northern Indiana Public Service Company (NIPSCO) had not filed a general rate case for more than 20 years. In this instance, the Commission granted a modest decrease in gas rates for NIPSCO customers on November 4, 2010.

- Water/Wastewater -

The water/wastewater industry is extremely capital intensive due to high costs and relatively low revenues; investing more capital per dollar of revenue earned than any other industry. As the costs for water and wastewater services continue to rise, rates are following suit. For example, from 2000 to 2010, water/wastewater rates rose 5.05% per year while the consumer price index only rose 2.47% per year. According to data obtained from the U.S. Bureau of Labor Statistics, water/wastewater rates are increasing at a faster pace than rates in the electricity and natural gas industries.

Costs are increasing for the following reasons: 1) replacement of aging infrastructure; 2) compliance with U.S. Environmental Protection Agency standards such as water quality and wastewater effluent; 3) growing demand; and 4) the relocation of facilities for city and state road projects. For example, from 1984 to 2008 average water and wastewater treatment cost rose 310% while the consumer price index only rose 207%. A 2003 report issued by the Indiana Advisory Commission on Intergovernmental Relations estimates that statewide wastewater and drinking water infrastructure needs will require $12.4 to $13.9 billion in funding from the year 2000 to 2020.

With regard to significant cases, the Commission concluded several this past year. In February 2011, the Commission issued an Order in the Indianapolis Department of Waterworks' rate case, Cause No. 43645. More than 75% of the 25.99% increase was attributable to capital expenditures, specifically investments that will assure the integrity of the system and the quality of the water now and for future generations. In July 2011, the Commission approved the transfer of water and wastewater assets from the City of Indianapolis to Citizens Energy Group. In August 2011, Citizens Energy Group officially took over the water and sewer utilities.

Due to an "opt out" provision in Indiana Code, many utilities have chosen to withdraw from the Commission's jurisdiction. The Commission regulates approximately 116 out of 824 water utilities, and 47 out of 531 wastewater utilities. When a utility opts out, the IURC no longer oversees its rates and charges or rules and regulations. It also eliminates the agency's ability to provide dispute resolution between utility customers and their utilities. The primary complaint with this arrangement has to do with the difference between inside-city and outside-city customer rates. Some municipalities charge outside-city customers higher rates or a surcharge, ranging from modest amounts to those up to 100% greater than rates paid by inside-city customers for the same service.

With respect to future issues that may impact the water and wastewater industries, the Water/ Wastewater section of this Report focuses on a number of key issues including:

- **Infrastructure** – Indiana's water project funding needs over the next 20 years are $5.9 billion. The greatest need, $4.5 billion, is for underground infrastructure.

- **Environmental Regulations** – Depending on the type of regulations handed down by the U.S. Environmental Protection Agency, costs could be substantial, especially if a water or wastewater utility must upgrade its facilities to comply with the mandates. In the Indianapolis Department of Waterworks' rate case, one of out of every four revenue dollars invested was due to environmental mandates.

- **Troubled Utilities** – Small, troubled utilities continue to present regulatory challenges for the Commission, which is actively monitoring select small utilities in an effort to educate owners and prevent utilities from becoming troubled. These are typically small utilities (fewer than 300 customers) that were constructed by a developer as part of a housing development.

- Communications -

In 2011, the availability and advancement of broadband continued to be a priority for the IURC. The Federal Communications Commission (FCC) released its National Broadband Plan (NBP) on March 16, 2010 and subsequently issued Notices of Inquiry (NOIs) and Notices of Proposed Rulemaking (NPRMs) to implement significant changes to portions of the NBP. In response, the IURC issued comments and raised concerns about the NBP's impacts on universal service, intercarrier compensation, and broadband policies.

Of similar importance for the IURC during 2010 and 2011 was universal service or "service for all." The IURC closely monitored and analyzed the actions of the FCC as it discussed possible modifications to the multi-billion dollar federal Universal Service Fund (USF), which could significantly impact the availability and affordability of communications services for Indiana's consumers. The IURC also submitted a final rule for the state's Lifeline Assistance Program, which must receive approval through the state process before it can become effective.

Commission involvement remained necessary in 2011 for the areas of the communications industry where competition alone may not provide solutions. For example, the IURC resolved carrier-to-carrier disputes, managed policies regarding telephone numbering resources, protected consumers from unauthorized changes to their service, ensured that all areas of the state had a

provider of last resort, and ensured continued access to basic telecommunications services in high-cost areas of the state.

With respect to future issues that may impact the communications industry, the Communications section of this Report focuses on a number of key issues including:

- **Universal Service Fund** – The Commission must remain engaged at the federal level to ensure Indiana is well represented.
- **Cost of Content** – Unless this issue is addressed by the FCC, it is likely that some smaller providers of video will cease providing video services, and the video rates of the providers that remain will likely continue to increase.
- **Indiana Universal Service Fund (IUSF)** – The IUSF generates funds that are used to subsidize the rates for services offered by companies in high-cost areas in an effort to keep rates reasonable and affordable.

2011 Electricity Report

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I. ELECTRICITY OVERVIEW

Industry Structure

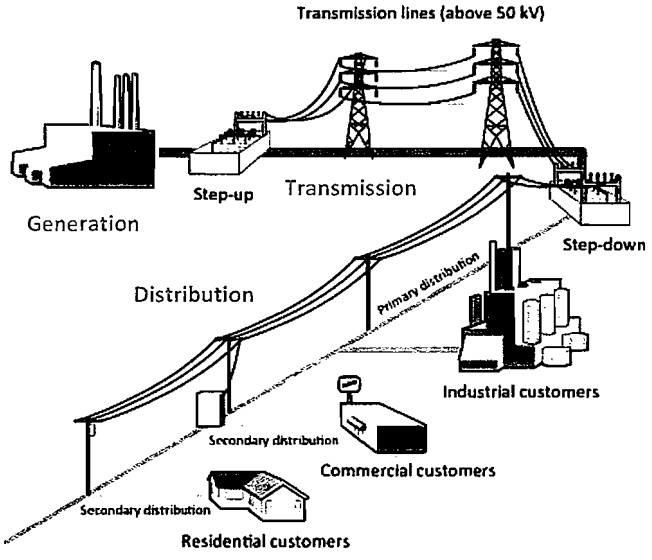
The Indiana Utility Regulatory Commission (Commission or IURC) regulates Indiana's electric utilities due to the monopolistic nature of the industry. This relationship is often described as the "regulatory compact," which means that in return for government regulators granting exclusive service territories and setting rates in a manner that provides an opportunity for a reasonable return on investment, investor-owned utilities (IOUs) operate under traditional Commission regulation. Other types of electric utilities, rural electric membership cooperatives (REMCs), and municipal electric utilities, also have exclusive service territories, but may withdraw from the Commission's jurisdiction. The 23 electric utilities under Commission rate jurisdiction generated $8.4 billion in revenue in 2010 and served more than 2.6 million electric customers.

The Commission has jurisdiction over the electric service provided to approximately 2.6 million customers in Indiana. In 2010, Indiana's average retail rates were the 13th lowest in the nation.

Regulatory Structure

Indiana's electric utilities operate under a traditional regulatory structure overseen by the Commission and own and operate generation, transmission, and/or distribution facilities in order to provide electric retail service to customers in a defined exclusive service territory.

Figure 1



As shown in Figure 1, the electricity generation, transmission, and distribution process goes through a series of steps before it is available for consumption. During this process, the electricity voltage is stepped-up (increased) or stepped-down (decreased) depending on the level of voltage required to provide service. For a detailed list of the

generation facilities serving Indiana, please refer to Map 3 on page 16.

There are two types of electric utility customers: retail and wholesale. Retail customers include residential, commercial, and industrial customers who are billed for service based on a study that analyzes the costs associated with providing service for each class. For IOUs, a reasonable rate of return on investment for the company is added to the cost of service. Wholesale customers include other electric utilities, cooperatives, and municipalities that resell energy to retail consumers.

In addition to setting rates for these retail customer classes, the Commission renews and approves long-term financing for IOUs, the Indiana Municipal Power Agency (IMPA), and Wabash Valley Power Association (WVPA). The Commission also reviews and approves the construction of generation facilities for all of Indiana's electric utilities.

- Investor-Owned Utilities -

Five major IOUs operate in Indiana in exclusive service territories with other portions of the state similarly assigned to municipal utilities and REMCs.[1] IOUs are for-profit enterprises funded by debt (bonds) and equity (stock). Indiana's IOUs are vertically integrated, which means they own facilities for the generation, transmission, and distribution of electricity. These utilities account for more than 90% of the electric power sales of the state's regulated electric utilities to Indiana customers. Map 3 on page 16 shows the IOUs' service territories.

Duke Energy Indiana, Inc. (DEI), a subsidiary of Duke Energy Corporation, is headquartered in Charlotte, NC and based in Plainfield, IN. The utility serves 781,000 customers in areas throughout central and southern Indiana, not including the cities of Indianapolis and Evansville.

Indiana Michigan Power Company (I&M), a subsidiary of American Electric Power Company, Inc. (AEP), is headquartered in Columbus, OH and based in Ft. Wayne, IN. The utility serves 458,000 customers in two, noncontiguous parts of northeast and north central Indiana.

[1]IC § 8-1-2.3-3

Indianapolis Power and Light Company (IPL), a subsidiary of the AES Corporation, is headquartered in Arlington, VA and based in Indianapolis, IN. The utility serves 468,000 customers in the greater Indianapolis area.

Northern Indiana Public Service Company (NIPSCO), a subsidiary of NiSource Inc., is headquartered and based in Merrillville, IN. The electric utility serves 457,000 electric customers in the northern part of Indiana.

Southern Indiana Gas & Electric Company (SIGECO), a subsidiary of Vectren Corporation, is headquartered and based in Evansville, IN. The electric utility serves 146,000 customers in a small part of southwestern Indiana.

- Municipally-Owned Utilities -

State law allows municipal utilities to remove themselves or "opt out" of the Commission's jurisdiction.[2] Under certain circumstances, the Commission may review financing arrangements for individual municipal electric utilities, but this typically occurs through rate cases. As of the printing of this report, 12 of the 72 municipally-owned utilities operating in Indiana remained under the Commission's jurisdiction for rate regulation. For a complete list of the municipal utilities under the Commission's jurisdiction and those that have opted out, please see Appendix B. Of these 72 municipally-owned electric utilities, 51 are members of IMPA, including 10 of the 12 regulated by the Commission.

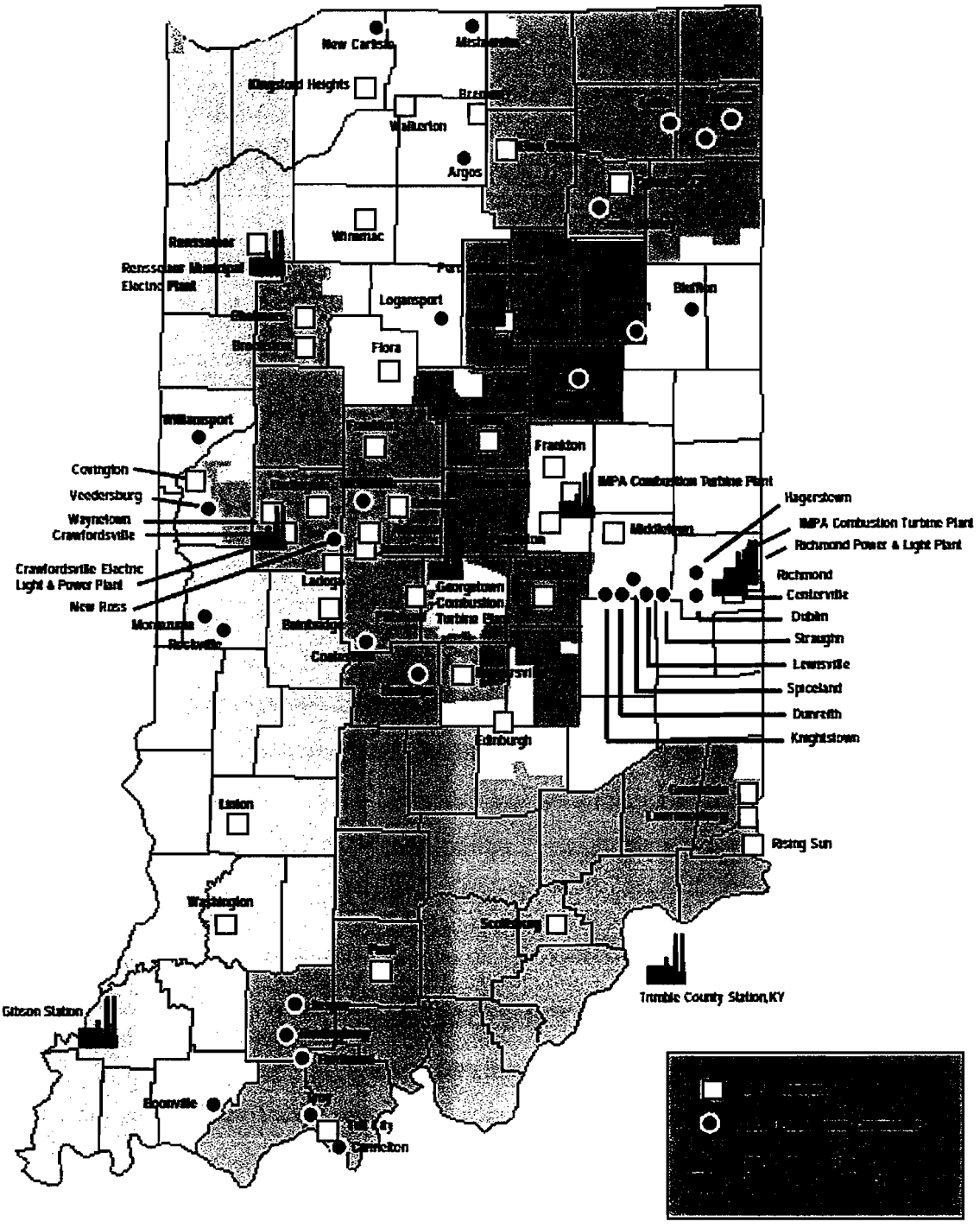
When a utility opts out of the IURC's jurisdiction, the agency no longer oversees its rates and charges or rules and regulations.

A group of municipalities created the Indiana Municipal Power Agency (IMPA) in 1980 to jointly finance and operate generation and transmission facilities. Additionally, IMPA was established to purchase wholesale power and meet members' needs through a combination of member-owned generating facilities, member-dedicated generation, and purchased power. The Commission does not regulate the rates that IMPA charges its members. Map 1 shows the location of these utilities.

[2]IC § 8-1.5-3-9

Map 1

Statewide Map of Indiana Municipal Power Agency Members



Source: Indiana Municipal Power Agency
Note: Colors stand for Congressional districts

- Rural Electric Membership Cooperatives -

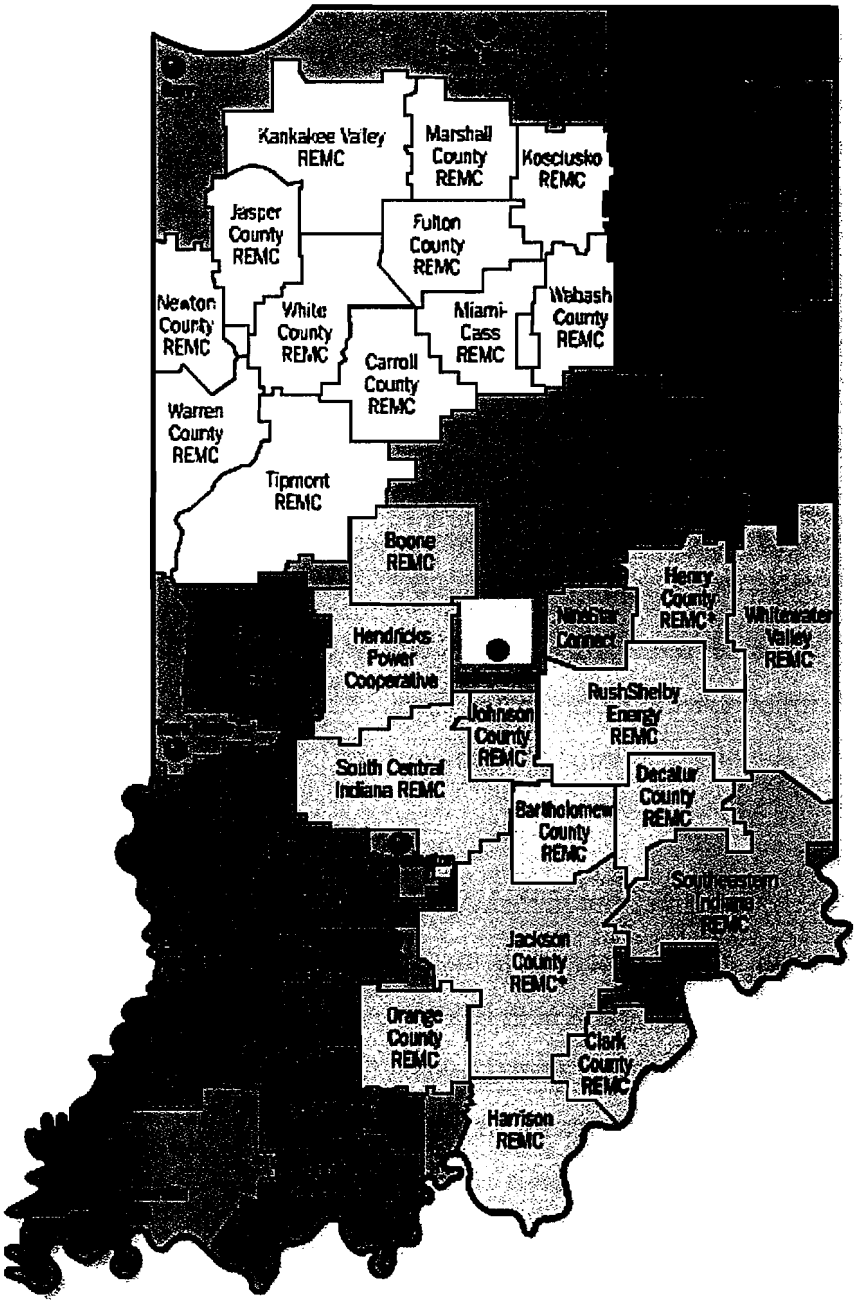
Rural Electric Membership Cooperatives (REMCs) are customer-owned utilities, all of which are members of either Hoosier Energy Rural Electric Cooperative (Hoosier Energy), located in the southern part of the state, or Wabash Valley Power Association (WVPA), located in the northern part of the state. Map 2 shows the location of these member utilities.

Hoosier Energy and WVPA are power generating and transmission cooperatives formed to supply power to the REMCs. The Commission's regulation of Hoosier Energy and WVPA is limited to decisions to purchase, build, or lease generation facilities. In addition, the Commission retains jurisdiction over WVPA's long-term financing.

REMCs, like municipalities, have the ability to remove themselves or "opt out" of the Commission's jurisdiction.[3] As of the printing of this report, only 4 of the 40 REMCs operating in Indiana remained under the

Map 2

Statewide Map of the Association of Rural Electric Cooperatives



Source: Indiana Statewide Association of Rural Electric Cooperatives

[3]IC § 8-1-13-18.5

Commission's jurisdiction for rate regulation. For a complete list of the REMCs under the Commission's jurisdiction and those that have opted out, please see Appendix C.

How Indiana Compares

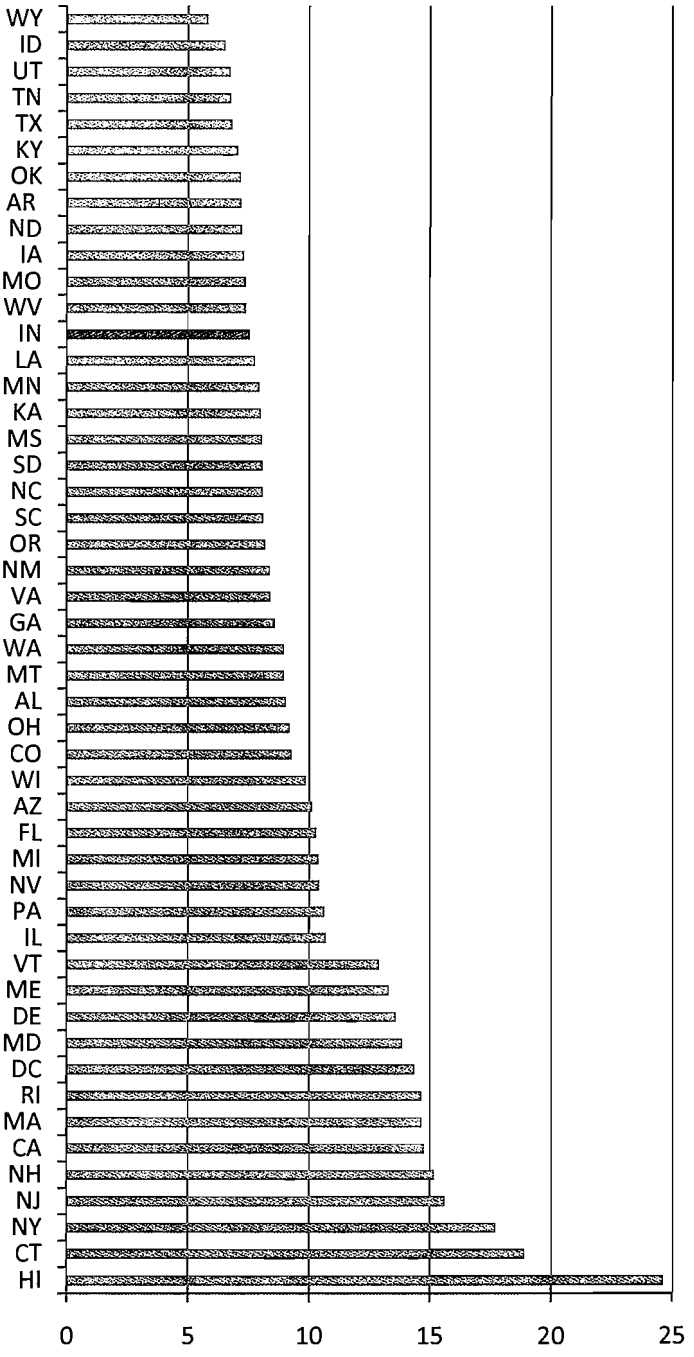
Indiana's average retail prices for electricity have been and are presently competitive both nationally and regionally. Retail prices are the average price for all rate classes, including residential, commercial, and industrial customers.

Indiana's annual ranking for average total customer retail rates from 2000 to 2009 ranged from 9th lowest in 2000 to 4th lowest in 2002 to 15th lowest in 2009. For 2010, Indiana's rates were 13th lowest, as shown in Chart 1. Neighboring states' total customer retail rates for 2010 rank as follows, with the first being the lowest: Kentucky 6th, Ohio 28th, Illinois 36th, and Michigan 33rd.

The variability in ranking is the result of many factors, including the timing of rate cases both in and out of state and fluctuations in the cost of fuel. Chart 2 shows Indiana's national rankings over the past 20 years and how they have fluctuated.

Chart 1

2010 State Average Electricity Prices (cents/kWh)

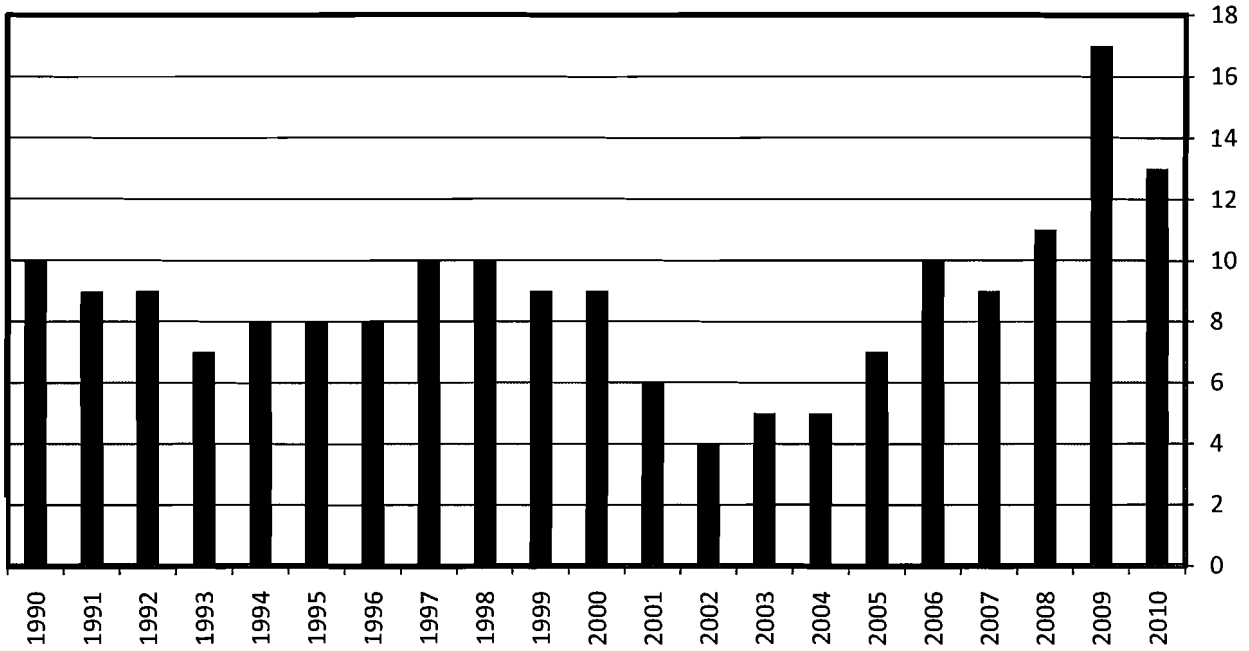


Source: Energy Information Administration

Chart 2

Indiana Total Retail Customer Rate National Ranking

Lowest to Highest



Source: SNL Energy

Historically, Indiana's use of coal as a fuel source for electricity generation has contributed to the state's relatively low-cost electricity. However, the general trend of increased coal prices observed since 2003 has reduced Indiana's relative price advantage. Some of the factors driving the cost increases are as follows: escalating coal mine operating costs due to declining mining productivity, increasingly difficult permitting requirements, the proliferation of regulations being conducted by the U.S. Environmental Protection Agency, and international competition for domestic supply. Therefore, the extensive use of coal in Indiana has led to an increase in utility fuel costs, and subsequently customer rates, in a manner that corresponds with the increase in the cost of coal.

Historically, Indiana's use of coal has contributed to its relatively low-cost electricity; however, costs have increased in recent years due to a number of factors. Coal-fired generation accounts for 85% of actual energy production for Indiana consumers.

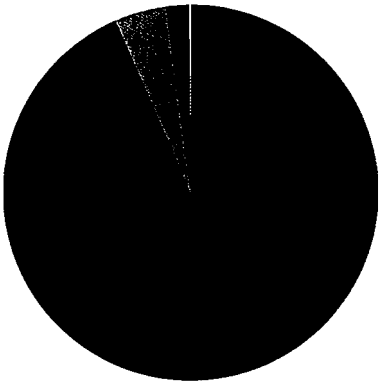
Existing Generation Portfolio

Coal-fired generation accounts for 85% of actual energy production for Indiana consumers, as shown in Chart 3. The second highest is nuclear generation at 8.5%. Although Indiana does

not have a nuclear plant within the state, customers in the northeastern portion of Indiana are served by I&M's Cook Nuclear Generation Station located in Bridgman, Michigan. In order to show a more accurate depiction of energy production within the state, the IURC used the most recent 2009 data from the U.S. Energy Information Administration (EIA). However, the nuclear figure was recalculated based on available 2010 figures.

Chart 3

Projected 2010 Energy Production for Indiana Consumers by Fuel Type



- Coal (108,312 GWH, 85%)
- Nuclear (10,749 GWH, 8.5%)
- Natural Gas (5,650 GWH, 4.4%)
- Wind , Other Renew. (2,049 GWH, 1.6%)
- Hydro (503 GWH, 0.4%)
- Oil (157 GWH, 0.1%)

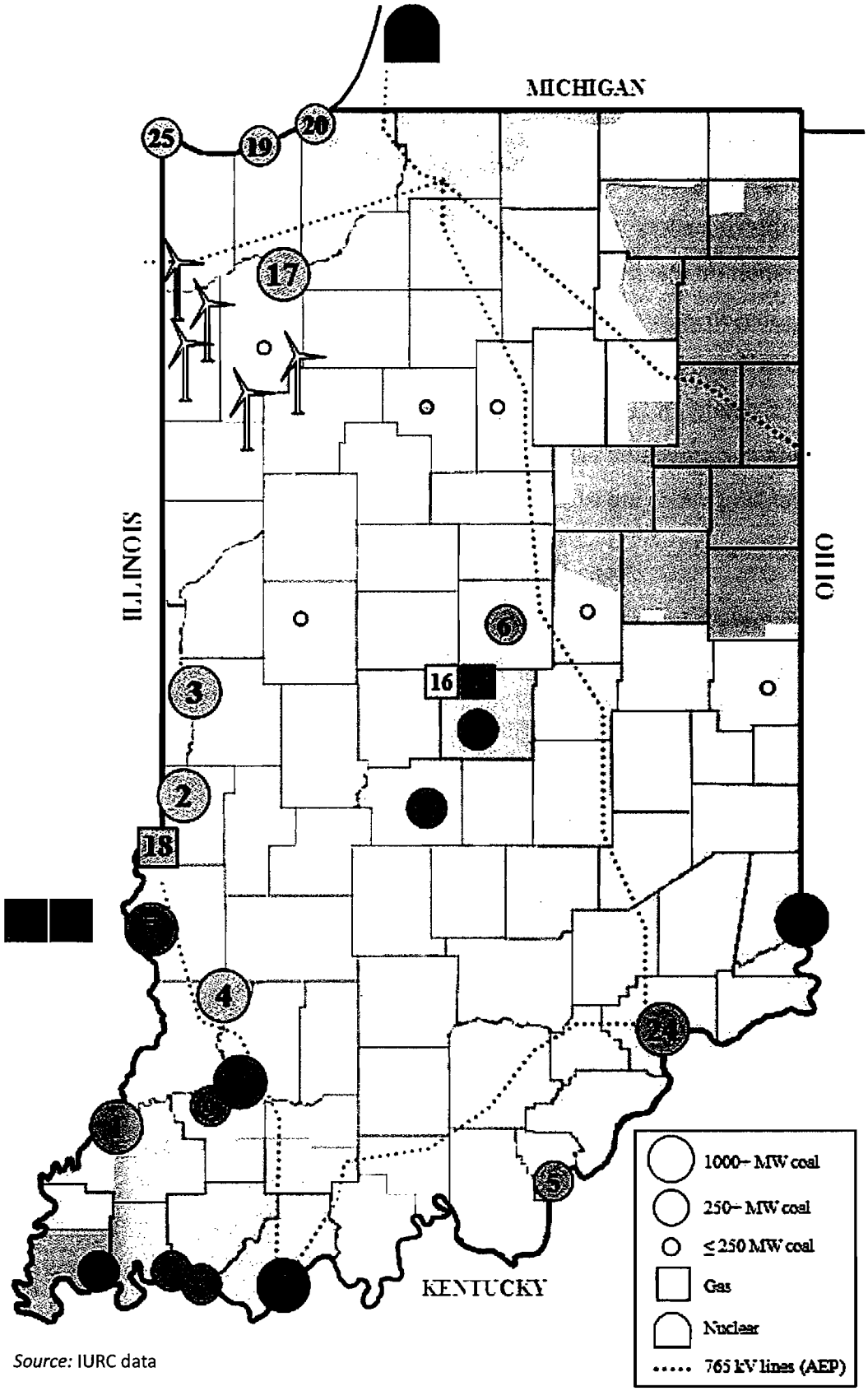
Source: Best available data

EIA data from 2009 has been used to support the assertion that 93% of Indiana's electricity comes from coal. This figure can be misleading due to the fact it does not consider out-of-state generation sources. Therefore, nuclear power is not taken into account, despite it being the second largest source of electric power.

Over a period of time, it is normal for power plants to only produce a percentage of what they could produce if run at full capacity. This ratio of actual energy output to the potential output over a period of time is referred to as a capacity factor. The capacity factors of power plants vary depending on technology, resource, and purpose. Nationally, capacity factors are typically more than 90% of the potential output for nuclear, 70-90% for large coal units, 20-40% for wind, and 10-15% for solar photovoltaics. Capacity factors for gas combined cycle units vary widely depending on a unit's role in the grid system. Gas combustion turbines (peakers) are used sparingly when demand is highest because of their relatively high cost of operation compared with base load coal plants and typically have much lower capacity factors. The following map shows the location, size, and fuel type of the large power plants providing electricity to Indiana customers.

Map 3

Statewide Map of Electric Generation Serving Indiana



Duke Energy Indiana

1	Gibson	3,340
2	Wabash River	1,165
3	Cayuga	1,062
4	Edwardsport	618
5	Gallagher	600
6	Noblesville	285

Hoosier Energy

7	Merom	1,090
8	Holland (IL)	314
9	Ratts	234

Ind. Municipal Power Agency

	Richmond	181
16	Georgetown 2&3	170
	Anderson	167
	other cities	144

Indiana Michigan Power

10	Rockport	2,600
11	Cook (MI)	2,164
12	Tanners Creek	1,101

Indianapolis Power & Light

13	Petersburg	1,873
14	Harding Street	698
15	Eagle Valley	302
16	Georgetown 1&4	170

No. Indiana Public Service

17	Schahfer	1,944
18	Sugar Creek	606
19	Bailly	545
20	Michigan City	469

So. Indiana Gas & Electric

21	Warrick	742
22	Brown	531
23	Culley	415

Wabash Valley Power

8	Holland (IL)	314

Other Plants

24	Clifty Creek	1,304
25	State Line	515
	Logansport	54

Wind Farms

31	Fowler Ridge	686
32	Meadow Lake	501
33	Benton County	130
34	Hoosier	106
35	Spartan	*

Source: IURC data

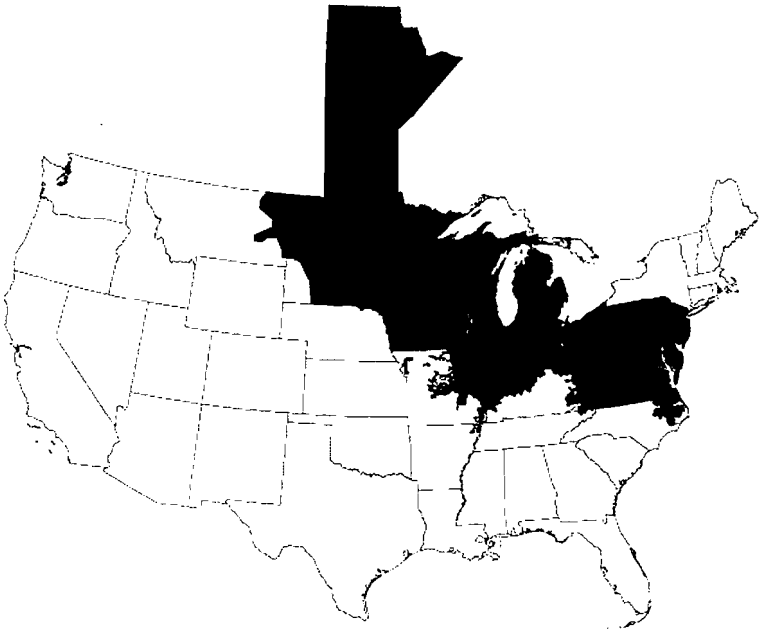
Regional Transmission Organizations

Two regional transmission organizations (RTOs) operate in Indiana: Midwest Independent Transmission System Operator, Inc. (MISO) and PJM Interconnection, LLC (PJM). These organizations are regulated by the Federal Energy Regulatory Commission (FERC). In addition to operating the regional transmission facilities in a reliable and non-discriminatory manner, MISO and PJM direct the operation (in real time) of all generating facilities in their regions to ensure that the lowest-cost combination of generation resources is being used at any given moment. Additionally, RTOs engage in long-term transmission planning in conjunction with their transmission-owner utilities, some of which are under the IURC's jurisdiction.

There are two regional transmission organizations operating in Indiana: the Midwest Independent System Operator and PJM Interconnection, LLC. RTOs dispatch all of the generating facilities in their regions to ensure that the lowest-cost combination of resources is used at any given moment.

Map 4

MISO (red) and PJM (blue) Reliability Coordination Area



Source: http://www.miso-pjm.com

RTO Characteristics	MISO	PJM
Participating Indiana Utilities	DEI, NIPSCO, IPL, SIGECO, Hoosier Energy, WVPA, and IMPA	AEP (including its Indiana subsidiary I&M), IMPA and WVPA
Transmission Lines	53,000 miles	60,800 miles
Capacity	146,000 MW	176,400 MW
Headquarters	Carmel, Indiana (815 employees)	Valley Forge, Pennsylvania

Participation in RTOs provides a number of benefits for Indiana's consumers.[4] In addition to greater reliability, RTOs provide lower costs through more efficient regional planning than is possible when individual utilities act alone. Because of the vast regional scope of the RTOs, Indiana customers should receive the financial and operational benefits of a more diverse resource mix and additional customer diversity of demand (e.g., Indiana might experience peak demand due to hot weather while Montana has much more moderate weather), allowing demand to be satisfied with relatively lower-cost resources.

RTO Benefits

1) Improved reliability;

2) More efficient use of resources; and

3) Substantial savings through greater diversity and higher generator availability

Additionally, because the reliability risk is diversified over the entirety of the RTOs' footprints – from the Rocky Mountains to the Atlantic Ocean – reserve requirements are reduced. A reserve margin is the amount of extra capacity available to serve customer loads in the event of a system contingency, such as the planned or unplanned outage of a generation plant or a high-capacity transmission line. RTOs are able to maintain lower planning and operating reserve margins than Indiana's utilities prior to RTO development.[5]

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[4]The MISO states, "For 2010, the region realized net benefits of between $650 million and $875 million. These benefits resulted from Midwest ISO's improved grid reliability and increased generation efficiencies. During the next 10 years, we anticipate that the region will realize between $6.1 billion and $8.1 billion in benefits on a net present value basis." https://www.midwestiso.org/WhatWeDo/ValueProposition/Pages/ValueProposition.aspx PJM has conducted a similar analysis of net benefits which shows annual net benefits to the region between $1.5 billion to $2.2 billion.

[5]The electric industry has historically maintained planning reserve margins in the 15% to 20% range. With the development of RTOs, reserve margins have fallen to reflect the benefit of more efficient regional coordination. In the Midwest ISO, for example, Indiana utilities have an 11.0% reserve requirement for 2011-12.

While participation in RTOs provides benefits to Indiana's end-use customers, it is challenging to translate the costs and revenues associated with RTO participation into the traditional cost-of-service model used to set rates in Indiana. To better ensure that Indiana customers and utilities receive the benefits of participating in RTOs, the Commission has staff dedicated to participating in the RTOs' processes. Because of the important and pervasive impact of the RTOs on Indiana's utilities and their customers, the Commission's involvement with the FERC has also increased dramatically to ensure that Indiana's utilities are providing safe, reliable energy at reasonable prices.

Age Profile

Aging infrastructure is a concern across all utility sectors. 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 plants. Although generation plants are designed to last decades, it is important for the utilities to monitor their condition, as the last coal-fired generation unit constructed in Indiana was completed in 1989.

In recent years, Indiana's utilities have generally purchased incremental electricity from other sources rather than building their own power plants to maintain required power reserves. Because it takes approximately three years to construct new gas-fired peaking generation, five to ten years to construct new conventional coal-fired generation, and longer to bring new nuclear generation online, long-term planning is critically important. Table 1 shows the age profile for the coal and natural gas-fired fleet of electric generation owned by Indiana's utilities.

Table 1

Age Profile of Generating Units Owned by Indiana Utilities
Separated by Coal-Based Units and Gas Generation Units

Years Old	Number of Coal-Based Units	MW of Generation (Summer Rating)	Percent of Total Coal-Based Generation
Over 50	21	1,711	11.3%
40-50	15	2937	19.3%
30-40	13	5904	38.9%

20 -30	9	4633	30.5%
Total	58	15,185	100%

Years Old	Gas Units (Peaking)	MW of Generation (Summer Rating)	Percent of Total Gas Generation (Peaking)
Over 50	2	59	0.1%
40-50	7	90	4.6%
30-40	3	220	6.9%
20 -30	1	80	2.6%
10-20	36	2229	70.2%
0-10	5	493	15.6%
Total	54	3171	100%

Coal units commonly become candidates for retirement past the age of 40, with most retiring by age 60. More than 30% of the total coal-fired generation is more than 40 years old, and about 70% of the total coal-fired generation is more than 30 years old. Natural gas-fired generation is much newer; only 15% of that fleet is more than 20 years old. However, because gas-fired combustion turbines generally have higher marginal operating costs than coal-fired units, they typically only operate during periods of high peak demand. With regard to nuclear generation, Cook Units 1 and 2 became operational in 1975 and 1978, respectively. Then in 2005, the Nuclear Regulatory Commission re-licensed the units for commercial operation until 2034 for Unit 1 and 2037 for Unit 2.

Legal and Policy Foundations

Because electricity cannot be effectively stored on a large scale, generation resources owned by utilities must be economically dispatched such that generation output meets customer demand. This means the lowest-cost generation resources are used first, with successively more expensive units coming online until total customer demand is met at any given point in time. Consequently, Indiana's utilities are responsible for short-term planning. They are also responsible for long-term resource planning to meet customer demand at the lowest reasonable

cost, while providing safe, adequate, and reliable service. In order to help the utilities meet their charge, policies such as "Allowance for Funds Used During Construction" and "Construction Work in Progress" have been enacted by the General Assembly. These policies provide cost recovery for utilities building new generation.

CWIP and AFUDC provide cost recovery for utilities building new generation. Depending how these mechanisms are applied, costs can vary for consumers.

Allowance for Funds Used During Construction

Allowance for Funds Used During Construction (AFUDC) is an accounting procedure that tracks the estimated composite interest accrued from using borrowed and internal funds during a construction project. AFUDC is charged until the plant is placed in service or otherwise allowed recovery through an approved Construction Work in Progress (CWIP) tracker. Depending on the construction project, the amount of AFUDC can be considerable.

Construction Work in Progress

Construction Work in Progress (CWIP) deals with the timing and cost recovery of capital projects during the construction phase. It provides the funds to pay for capital costs during construction and is funded by the ratepayers through a tracker, which is further discussed on page 29. Often referred to as "pay as you go" financing, CWIP provides a utility with positive cash flows. By allowing construction projects to be tracked periodically, the eventual cost of the plant is less because the AFUDC stops, thereby saving ratepayers from paying for the recovery of these additional costs.

Construction Work in Progress is often referred to as "pay-as-you-go" financing.

Utilities often cite that if CWIP were employed more frequently, consumers would benefit over the long term because the costs of construction would actually be put into rate base as they occur, rather than being delayed until a utility's next rate proceeding. By adding expenditures as they occur, shareholders receive their rate of return sooner, which theoretically reduces the cost of the project over the long term, because a utility would require less revenue to support the project on a going forward basis. Additionally, the use of CWIP spreads the rate impact of a large

construction project over several years so that ratepayers are not exposed to a single large rate increase.

However, one of the concerns associated with CWIP is that ratepayers incur the costs of construction that is not yet "used and useful." This concept became a point of controversy in the 1970s because of the extraordinary costs and timelines involved in major nuclear construction projects. Therefore, in the 1980s, the General Assembly enacted several statutes that permitted the Commission to apply this special regulatory treatment to certain projects. These projects include those deemed to be clean coal, as well as existing nuclear generation facilities that serve Indiana, the latter of which was signed into law during the 2011 legislative session.

II. ELECTRICITY LANDSCAPE

Infrastructure

Large-Scale Projects and Capital Investment Recovery

Large investments in utility infrastructure over long periods expose the investor to risks on two fronts. First, conditions may change during the construction period and call the "used and useful" nature of the project into question. Second, construction financing is not ratepayer sourced, because traditional utility ratemaking does not include the cost of infrastructure in customer rates until construction is complete. However, Indiana and other states have addressed these challenges through a certificate of need process[6] and the allowance of a cash return on financing costs during construction in certain instances (i.e., CWIP).[7]

The certificate of need process provides the Commission and interested parties with an opportunity to evaluate the merits of a project before it is undertaken. If the Commission approves the project, the utility is granted a Certificate of Public Convenience and Necessity (CPCN). As such, the preapproved finding of need and prudency reduces risks for the utility, which results in lower project financing costs, but shifts risks to ratepayers. The allowance of cost recovery while construction costs are incurred is done in lieu of deferring them until construction is complete and then paying both the amount borrowed and the related interest. This

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[6]*See*, IC ch. 8-1-8.5; IC ch. 8-1-8.7; IC § 8-1-2-23
[7]*See*, IC ch. 8-1-8.8

is recognized as a significant credit enhancement by credit rating agencies. Consequently, both of these tools serve to reduce the lifetime costs of the investment, a cost paid by a utility's ratepayers.

To obtain a CPCN, utilities must provide supporting analysis demonstrating that the proposed project is the lowest reasonable cost method of meeting customers' needs. Therefore, the CPCN application must be consistent with lowest reasonable cost resource plans, which utilities are required to submit every two years. These are known as integrated resource plans (IRPs), because they evaluate all supply and demand-side alternatives available to meet a utility's future electricity requirements. These IRPs are required to meet certain requirements imposed by the Commission in the form of what is known as the IRP rule (170 IAC 4-7).

Many electricity industry changes have occurred since the IRP rule was issued in 1995. In 2010, the Commission issued an Order finding that the IRP rule should be updated and instructed staff to commence a rulemaking proceeding. The new rule will be updated in accordance with industry changes, incorporate input from Indiana stakeholders and outside experts, and reflect Commission priorities, such as making the IRP development process transparent.

Edwardsport IGCC

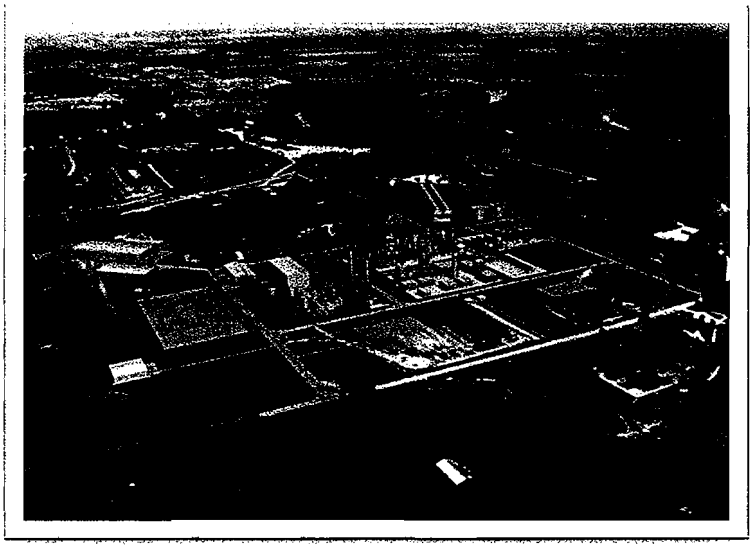
In an Order issued on November 20, 2007, the Commission granted a CPCN and approved the construction of Duke Energy's Edwardsport Integrated Gasification Combined Cycle (IGCC) generating facility, which will have a capacity of 618 MW.[8] Once complete, the Edwardsport IGCC facility will be the first commercial-scale clean coal plant of its kind built in the United States in the last 10 years. The facility is located on approximately 220 acres adjacent to DEI's existing Edwardsport Generating Station in Knox County and has an in-service date of 2012. The Commission initially approved a cost estimate of $1.985 billion in its 2007 Order. However, the figure was revised by the company and approved by the Commission at

The Edwardsport IGCC facility will be the first commercial-scale clean coal plant of its kind built in the United States in the last 10 years and is the first base load power plant built in Indiana in more than 20 years.

[8]The plant will also be able to run on natural gas, though doing so reduces available capacity by approximately 128 MW.

$2.35 billion in January 2009.[9]

DEI has since filed a second request with the IURC (Cause No. 43114-IGCC 4-S1) to update the estimated capital cost of the project and to set a "hard cap" for the project at $2.72 billion.[10] This case has since been expanded by the Commission to include two phases. Phase I will address Commission review of the utility's progress reports, the proposed cost estimate increase, and the reasonableness of going forward with the project. Phase II, on the other hand, will address allegations made by intervening parties of fraud, concealment, and/or gross mismanagement associated with the project. Those public hearings are scheduled for October 2011.



Rendition of the IGCC facility under construction in Edwardsport, Indiana

Under traditional ratemaking, DEI would have constructed the facility and not been allowed recovery of the costs from ratepayers until the plant was determined to be "used and useful." However, by applying Indiana's clean coal technology statutes to the facility, DEI proposed and the Commission approved a "pay-as-you-go" plan, whereby the financing costs of the plant are passed on to ratepayers on a periodic basis as part of an ongoing review process during construction. This process is otherwise known as CWIP, as previously discussed. As of the end of March 2011, the overall project was approximately 85% complete.

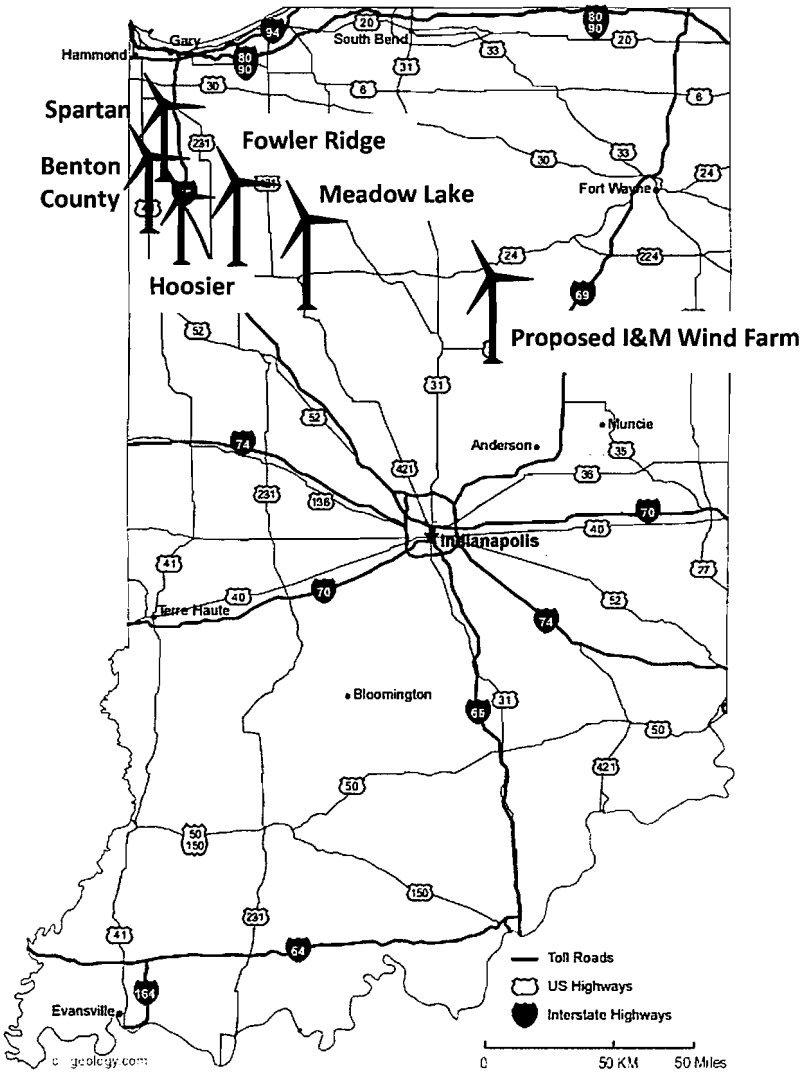
[9]Cause No. 43114-IGCC 1

[10]DEI states it will not ask for recovery of costs above its proposed hard cap. However, the hard cap does not include AFUDC, which DEI requests to recover in addition to the hard cap. DEI's proposal agrees to certain other concessions as well, and it estimates its proposal will increase average retail revenues by approximately 16.3% (at its highest point), when compared to retail revenues billed in 2009.

The IGCC facility will utilize state-of-the-art technology and a gasification process that is designed to convert locally-sourced coal into a combustible gas called synthetic gas or syngas that can then be used to generate electricity. The technology will reduce traditional air emissions by approximately 50% and provide 90% or higher mercury capture at a fraction of the cost of a traditional coal unit. Carbon capture and sequestration (CCS) is also being explored as an option for this plant. The Commission authorized DEI to spend up to $17 million for a carbon capture study to analyze its feasibility. However, before carbon can be stored or sequestered, significant feasibility and cost issues will need to be resolved before it becomes possible to implement. This includes the cost of permanent geologic storage, insurance, legal liability, property rights, and regulatory issues. DEI has a pending proposal in Cause No. 43653 to spend $42 million on the first phase of a study to further evaluate carbon sequestration through site assessment and characterization.

Map 5

Indiana Wind Farms



Wind

Indiana has become one of the fastest growing states for the development of wind farms, which are currently located in Benton, Newton and White counties. Several other wind farms are in the planning stages. The most recently announced wind farm was proposed for Madison, Grant, Howard and Tipton counties. This proposed project (Wildcat-1) stems from I&M adding another 100 MW of wind power to its generation portfolio as part of a 20-year power purchase agreement reached with E.ON Climate and Renewables.

Despite having a capacity factor of 20-40%, far less of wind's capacity can be relied upon at times of peak demand due to the variability of its output. Unlike conventional power resources, wind power is intermittent, because its output is weather-driven. Therefore, to plan for the summer 2011 load, Indiana utilities and the Midwest ISO assumed a 12% capacity credit, shown in Table 2, for wind energy resources available during periods of peak demand.[11]

Using the credit, a 100 MW wind farm would typically have an expected output of 12 MW (12% of its nominal capacity) during the summer peak periods. Consequently, the limited ability of wind to reliably meet power needs at times of highest need puts it at a disadvantage when compared to conventional generation technologies. However, there are means of compensating for the intermittent nature of wind.

Table 2

Specifications of Indiana Wind Farms

Wind Projects	County	Nameplate Capacity (MW)	Estimated Availability at Peak (MW)*	Completion Date
Benton County Wind Farm	Benton	130.5	15.7	2008
Fowler Ridge Wind Farm I	Benton	301.3	36.2	2009
Fowler Ridge Wind Farm II-A	Benton	199.5	23.9	2009
Fowler Ridge Wind Farm II-B	Benton	150.0	0	N/A**
Fowler Ridge Wind Farm III	Benton	99.0	11.9	2009
Hoosier Wind Farm	Benton	106.0	12.7	2009
Meadow Lake Wind Farm I	White	199.7	24.0	2009
Meadow Lake Wind Farm II	White	99.0	11.9	2010
Meadow Lake Wind Farm III	White	103.5	12.4	2010
Meadow Lake Wind Farm IV	White	98.7	11.8	2010
Meadow Lake Wind Farm V	White	100.8	0	N/A**
Spartan Wind Farm	Newton	101.0	0	N/A**
TOTAL		1,689.0	160.5	

*Assumes 12% of nameplate capacity (Midwest ISO wind capacity credit) will be available during summer peak.

**The wind farm has not reported a completion date to the Commission.

[11]This is an increase from the 8% Midwest ISO wind capacity credit for the summer of 2010.

When wind output drops, natural gas units (because they can start up so quickly), are dispatched to fill the void. To better predict these drops, the MISO recently created a centralized wind forecasting system, which has helped it better predict available wind resources on an hour-to-hour basis. Forecasting accuracy is improving significantly and will allow grid operators to more efficiently integrate wind projects onto the grid. Consequently, the MISO's increased use of wind forecasting has enabled dependency on wind during peak times to increase from 8% to 12% in recent years.

The MISO's increased use of wind forecasting has enabled dependency on wind during peak times to increase from 8% to 12% in recent years.

The development of emerging storage technologies, such as batteries that store energy from wind generation for later use, could help alleviate the intermittency problem in the future and shift wind energy dispatch from nighttime to more valuable daytime hours.[12] The potential growth in electric vehicles could also help to serve as a battery storage system for wind, as consumers are more likely to charge their cars at night.

While wind output cannot be dispatched to match increases in demand, it can be dispatched downward very quickly.[13] This function is valuable during times of grid congestion and during minimum demand. The MISO announced in June of 2011 that wind can be designated a "dispatchable intermittent resource" and can, therefore, fully participate in its real-time energy market. This is expected to enhance the MISO's ability to efficiently integrate intermittent resources into its system.

Biomass

Biomass generally consists of: 1) woody residues from forest management activities and the pulp and paper industry; 2) municipal solid waste such as waste paper, cardboard, wood waste and yard cuttings; and 3) agriculture crop residues and animal waste. The decomposition of biomass is what produces fuels, such as landfill gas and coal bed methane.

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[12]Wind resources in Indiana are greatest in the evening, which is when demand is lowest and energy is of least value.

[13]Dispatchability is the ability of a power plant to alter its output quickly to a desired level.

According to the State Utility Forecast Group's 2009 "Indiana Renewable Energy Resources Study," landfill gas is the primary biomass fuel used to generate electricity in Indiana. The current total operating generation capacity from Indiana's landfills is 44 MW.[14] As of the summer of 2011, the IURC had received three new petitions for a CPCN in the past year, one of which involved landfill gas.

Hoosier Energy's petition for a CPCN, which was filed on January 14, 2011, is still under consideration by the Commission. The utility's petition is for authority to construct up to 40 MW of landfill gas generation capacity. The other two projects involve generating electricity from wood biomass. Two companies, Liberty Green Renewables and Bioenergy Power, petitioned the Commission to obtain CPCNs for the sale of electricity generated from biomass in the wholesale power market. Liberty Green's case for a plant in Scott County was dismissed on June 16, 2011,[15] and Bioenergy Power received approval for its 26 MW plant in Clay County on October 20, 2010.[16]

Nuclear

I&M utilizes the Cook Nuclear Generation Station located in Bridgman, Michigan to serve its customers with approximately 65% of the Cook plant costs and power generated being allocated to Indiana retail customers. This facility has two pressurized water reactors: Unit 1, which has a nameplate generation of 1,048 MW and Unit 2, which has a nameplate generation of 1,107 MW. The two units became operational in 1975 and 1978, respectively, and in 2005 the units were re-licensed by the Nuclear Regulatory Commission (NRC) for commercial operation until 2034 for Unit 1 and 2037 for Unit 2. To extend the life of these units, I&M will need to implement a systematic replacement of many parts of the plant, some of which are no longer commercially available, that may not otherwise safely last until the end of the extended period (new life cycle).

This Life Cycle Management Project is part of an overall AEP plan to replace older and less efficient coal generation that would be too costly to upgrade to comply with the various

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[14]IURC Data
[15]Petition of Liberty Green Renewable Indiana, LLC, (IURC, Cause No. 43851)
[16]Petition of Bioenergy Power, LLC, (IURC, Cause No. 43882)

anticipated pollution mandates with more cost-effective, less environmentally-challenged units. Projected costs to extend the life cycle of the Cook plant range from $1.5 billion to $2 billion.

In the aftermath of the recent damage to the Fukushima Daiichi Nuclear Station in Japan, the U.S. Nuclear Regulatory Commission began testing U.S. nuclear facilities to assess their ability to respond to extraordinary events similar to those experienced at the Japanese plant. The Cook plant's inspection was completed on April 29, 2011 by the Nuclear Regulatory Commission, which found no major deficiencies in the plant's ability to respond to extraordinary disaster events.

Pricing and Economics

Adjustable Rate Mechanisms (Trackers)

Indiana's regulatory statutes include adjustable rate mechanisms (trackers) for certain expenses and capital investments. Tracking mechanisms provide for timelier recovery of specifically-defined costs when compared to recovery as the result of a rate case. An expense tracker allows retail rates to be adjusted outside the context of a base rate case to reflect changes in operating expenses but does not include a return on such expenses. Recovery of expenses that are characterized as largely outside the utility's control, variable, and materially significant is the intended goal of such trackers. Examples of expense trackers include fuel adjustment and RTO charges.

Indiana's regulatory statutes include adjustable rate mechanisms (trackers) as an integral part of regulation. Expenses that are characterized as largely outside the utility's control, variable, and materially significant are the intended goals of such trackers.

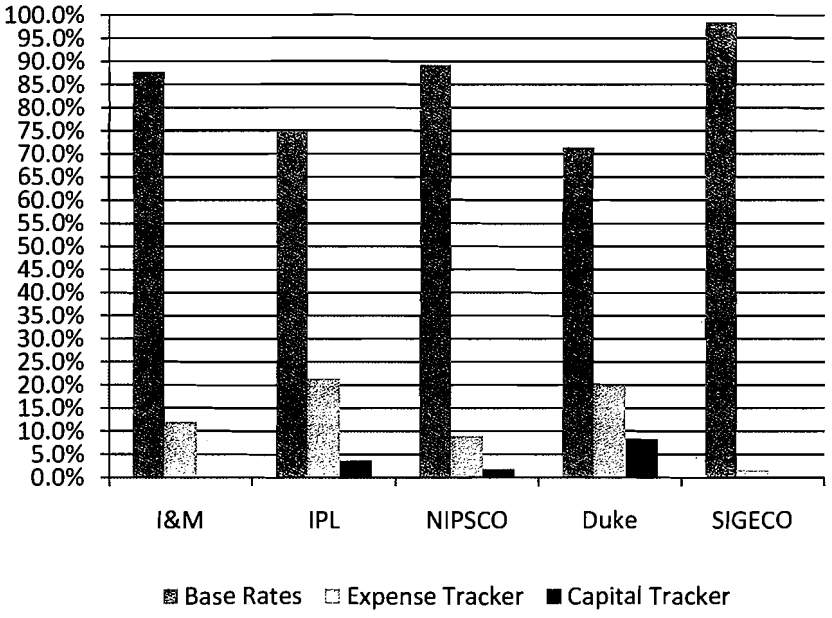
By comparison, a capital investment tracker allows a utility to reflect certain clean coal and energy generation capital costs in its rate base and to reflect the associated return on such investment in retail rates outside a base rate case. A capital investment tracker reduces the lag time between capital expenditures and cost recovery for the utility and is typically viewed favorably by credit rating agencies. Capital trackers have most commonly been utilized by utilities to support major investments in

upgrading coal generation plants to comply with increasingly stringent environmental regulations.

Chart 4 shows a breakdown of how base rates, expense adjustments, and capital adjustments contribute to a residential customer's bill for each of Indiana's electric IOUs. The relative weighting of these elements varies in part due to the magnitude of a company's construction program and how much time has elapsed since its last base rate case.

Chart 4

Residential Bill Components for the Investor-Owned Utilities



The fuel adjustment clause (FAC) has existed in Indiana for more than three decades and tracks a utility's largest variable and unpredictable operating expense: fuel. Other expenses tracked have expanded in recent years to include demand-side management programs, emission allowances, purchased power capacity, clean coal technology operation and maintenance, and MISO/PJM management expenses. Direct pass-through of expense or revenue reflects current conditions in retail rates in a more real-time manner than traditional base rate case regulation. The pass-through of unpredictable revenues and expenses to ratepayers also reduces volatility in the utility's earnings and may enhance the utility's credit rating.

The FAC by statute and most other adjustable rate mechanisms by design are expedited summary proceedings in order to provide more timely cost recovery. However, before these costs are passed along to customers, the Office of Utility Consumer Counselor (OUCC) reviews the underlying support for rate adjustments and provides evidence on that review in those summary proceedings. Yet, as the number of items, dollar values, and utility decision points have increased, there has been a limited increase in oversight resources or time allowed to review and process the matters at hand.[17] Consequently, this can present a challenge for effective regulation.

Modernization and Efficiency

Even though the majority of Indiana's electric needs are met through coal-fired generation owned by the utilities, energy efficiency and demand response programs are also being developed to enhance the value of Indiana's energy services.[18]

Net Metering

Net metering is a service offering that allows participants to supplement their electric usage and cut costs by installing renewable energy facilities such as wind turbines or solar panels, while relying on the electric utility as a back-up provider. If the amount of electricity the customer receives from the utility is greater than the amount delivered to the utility, the difference is charged to the

Net Metering Rulemaking

The net metering rulemaking, initiated by the IURC in June 2010, went into effect in July 2011.

Significant changes stemming from the rulemaking include:

1) A 9,900% increase in the maximum size of an eligible facility from 10 kW to 1 MW;

2) Expanded eligibility to all customer classes (industrial, commercial, and residential) from just K-12 schools and residential customers; and

3) A 900% increase in the aggregate sales level under each utility's net metering tariff from 0.1% to 1% of annual kWh sales.

To accomplish these changes, the IURC traveled to public meetings in Indianapolis, Ellettsville, and South Bend. The agency also held numerous meetings with stakeholders to solicit feedback from around the state.

[17]For 2009, the Indiana electric IOUs reported $1.69 billion of jurisdictional fuel costs. The FAC cost recovery mechanism provided for the collection of $698 million of these costs.
[18]Energy efficiency refers to measures or technologies that reduce the consumption of energy while demand response resources refer to measures, technologies, or incentives and pricing programs that reduce or curtail load during peak periods.

customer. If the amount the customer received from the utility is less than the amount delivered to the utility, the customer receives a credit on the next bill for the difference.

Last year, the Commission solicited input from various parties to better understand the interest in net metering. Several public hearings were conducted across the state to gather feedback on whether to adopt new net metering rules or modify the Commission's existing rules, codified at 170 IAC 4-4.2. With the help of stakeholders, the Commission drafted an amended rule that will significantly increase both customer participation and net metering capacity. By expanding the availability of net metering and the size of the eligible facilities, the Commission believes it will stimulate growth within the industry and make it a more attractive option for those who wish to utilize renewable energy in their own backyards. The rule was approved during the summer of 2011.

Feed-in Tariffs

Some new electric technologies may require subsidies to financially compete with traditional generation resources such as coal or gas. Therefore, many utilities, with the support of their regulators, are seeking to encourage the development of renewable technologies such as solar, wind, or biomass by offering to buy renewable power, which is generated by customer-owned facilities at prices that make the projects economically viable.

Unlike a traditional utility tariff, which specifies the price at which a ratepayer may purchase energy, a feed-in tariff specifies the price at which a utility will purchase energy generated from qualified, customer-owned facilities. Feed-in rates differentiate between technologies and unit size so as to not encourage one renewable technology to the detriment of another. The cost of the energy purchased under a feed-in tariff is recovered from the utility's ratepayers in a manner similar to that by which fuel expenses are recovered. An appropriate purchase price for feed-in technologies will balance the desired supply of renewable energy against the fuel cost increase to customers.

IPL is currently offering a feed-in tariff that limits total renewable energy purchases from its customers to 1% of the utility's annual sales. Although residential customers of IPL paid less than 8¢/kWh in 2010, this experimental tariff permits an owner of a 50 kW wind turbine or solar array to sell energy to IPL for 14¢/kWh and 24¢/kWh, respectively. The Commission has

authorized IPL to enter into contracts of up to 10 years with eligible customers and will review the continued need for the feed-in tariff in 2013. However, IPL has since petitioned the Commission to suspend its feed-in tariff due to unexpected interest from out-of-state developers. Further, IPL did not envision that companies in the renewable energy industry might become a customer for the sole purpose of selling energy back to the utility.

NIPSCO also proposed an experimental feed-in tariff that will pay up to 17¢ and 30¢ per kWh of wind and solar power, respectively, for facilities with capacities less than or equal to 100 kW. The company has agreed to purchase electricity, generated by small facilities powered by renewable energy sources, for up to 15 years from eligible customers. On July 14, 2011, the IURC approved the settlement agreement for NIPSCO's pilot program.[19] The pilot program is set to expire on December 31, 2013.

Plug-in Electric Vehicle Development

Widespread deployment of plug-in electric vehicles[20] (PEVs) can offer significant energy security, environmental, and economic benefits. PEVs pose both potential benefits and challenges to the grid, utilities, and ultimately ratepayers, which will become clearer as nationwide and statewide pilot programs advance. The Commission will continue to examine these issues and serve as a supportive technical resource for parties interested in the regulatory environment as it relates to PEVs.

IPL's time-of-use rate is the first to be approved in Indiana for the purpose of electric vehicles.

Earlier this year, the Commission authorized IPL to implement a new time-of-use rate for customers who wish to charge their PEVs at home. The summer weekday peak rate is five times that of the overnight rate to encourage off-peak charging. IPL will provide the first 150 customers with free home charging equipment to encourage participation.

The Commission also authorized IPL to install public PEV charging stations within the company's service area and to assess customers a $2.50 fee per unlimited charge. IPL will lease

[19] Cause No. 43922
[20] A plug-in electric vehicle refers to plug-in hybrid electric vehicle, as well as a fully-electric vehicle.

space from businesses such as hotels and parking lot operators. NIPSCO also proposed a program earlier this year to promote alternative fuel vehicles. The Commission expects to issue an Order on this petition in late 2011.

Although not necessarily specific to Indiana, Duke Energy will be purchasing PEVs for its own fleet of vehicles and has made a commitment that by 2020 all new vehicle purchases will be PEVs. According to Duke Energy, "this represents a $600 million investment and has the potential to reduce greenhouse gas emissions by more than 125,000 metric tons over the next 10 years."[21]

Demand-Side Management Programs

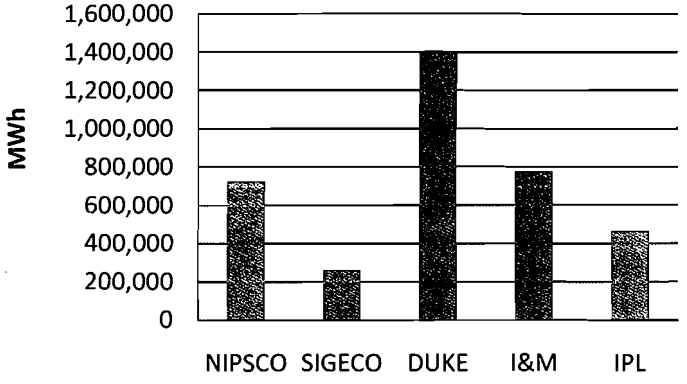
Underscoring the urgency to become more energy efficient in Indiana, the Commission's 2009 Phase II Demand-Side Management (DSM) Order instructed Indiana's jurisdictional electric utilities to move forward with a set of Statewide Core Conservation Programs in their respective service territories. Per the Commission's Order, the utilities must achieve an annual energy savings goal of 2.0% within ten years, with interim savings goals, "annual stepped savings targets," for years one through nine.

Annual Electric Savings Goal
(% of weather-normalized average electric sales for prior three years)

Year	Percentage
2010	0.3%
2011	0.5%
2012	0.7%
2013	0.9%
2014	1.1%
2015	1.3%
2016	1.5%
2017	1.7%
2018	1.9%
2019	2.0%

Although the cost of DSM programs will be included in customer retail rates, the impact to rates is anticipated to be less than it would be without DSM efforts. This is because DSM slows the growth in energy consumption and peak demand, thus postponing or reducing the need to build new and expensive generation

Chart 5
Total MWh Savings Anticipated by 2013
Indiana Utilities' Three-Year DSM Plans



[21] http://www.duke-energy.com/plugin/

facilities to meet future demand in providing reliable electric service.

The Core Programs are offered to all customer classes (residential, commercial, and industrial) and are intended to address what was determined to be nonexistent or inconsistent conservation programs between Indiana's electric utilities. The Core Programs include: a home energy audit program, low-income weatherization program, residential lighting program, energy efficiency schools program, and a commercial and industrial program.

In July of 2010, utilities submitted for approval their three-year DSM plans that proposed Core and Core Plus Programs. Core Plus Programs are additional energy savings programs beyond Core Programs that are intended to better position the utilities to achieve Commission-mandated savings targets. Core Plus Programs are a direct intervention or behavior modifying program designed to help residential customers understand their individual energy usage and/or their usage as it compares to their neighbors' usage. By understanding individual energy usage in the home, the consumer is more likely to modify their energy consumption behavior. It is expected that the Core and Core Plus Programs will both be needed to meet the mandated energy savings goals.

The DSM plans also included the budgets necessary to meet the statewide savings targets and the projected MWh progress in reaching them. Total MWh savings anticipated by 2013 are presented in Chart 5. Although each utility is mandated to have the same percent reduction, Duke shows more MWh reduction because of its larger customer base.

Demand-Side Management (DSM) Programs

As recognized in Governor Daniels' Homegrown Energy Plan, Indiana must become a self-sufficient leader with respect to its energy needs, and such an effort is not limited to building new generation.

Therefore, the IURC initiated an investigation and found that Indiana was a strong candidate for DSM programs.

The IURC also identified the following benefits:

1) If implemented statewide, the DSM programs would create efficiencies and lessen the cost of the programs over the long term;

2) With effective DSM programs, the impact to rates is anticipated to be less than it would be without DSM efforts; and

3) Increased utilization of DSM can mitigate environmental issues and lessen the costs associated with new or increased regulatory requirements regarding energy generation.

In order to implement the programs, the Demand-Side Management Coordination Committee and the utilities undertook the significant task of evaluating and selecting a third-party administrator (TPA) and an evaluation, measurement, and verification administrator (EM&V Administrator). The TPA is responsible for administering the Core Programs; whereas, the EM&V Administrator is responsible for the evaluation of the Core Programs. On July 27, 2011, the IURC approved the recommended administrators – GoodCents, as the TPA and TecMarket Works, as the EM&V Administrator. It is anticipated that implementation of the statewide Core Programs will begin at the start of 2012.

Demand Response Programs

Demand response programs have a long history in the electric industry, and the types of programs available have expanded in recent years. The U.S. Department of Energy defines demand response, in part, as "changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time."

Traditionally, Indiana utilities have relied upon interruptible load contracts with large industrial customers to reduce the need for utility-owned generation capacity. In other words, if the customer agrees to reduce its demand during peak use times, it will get a better overall rate. This arrangement is often called demand response.

Increased use has also been made of appliance demand response programs, with emphasis on the control of air conditioners during times of peak load. Indiana utilities have 1,010 MW of interruptible load and 103 MW of air conditioner load control. Demand response programs emphasize the relationship between customer consumption patterns during peak periods in response to high wholesale market prices or when system reliability is at risk. Indiana is among many states working to increase cost-effective customer participation in demand response programs.

Indiana utilities have 1,010 MW of interruptible load and 103 MW of air conditioner load control. Having these contracts allows them to manage load on peak demand days.

On July 28, 2010, the Commission issued an Order in its investigation, Cause No. 43566, relating to participation by customers in demand response programs offered by the PJM and the MISO. In the Order, the Commission expressed support for efforts to increase demand response

at the wholesale level and stated that RTO demand response programs must work in tandem with, and not in contravention of, Indiana's utility regulatory framework. The benefits of RTO demand response are best captured by permitting retail customers of Indiana utilities to participate in RTO demand response programs through the local utility. The Commission also encouraged utilities to consider the use of aggregators (or third-party service providers) to serve as agents between the utility and the customer for the provision of demand response. In March and April 2011, the Commission approved the initial tariff proposals submitted by the five IOUs permitting customer participation in RTO demand response programs through the utility.

Indiana Electricity Outlook

The State Utility Forecasting Group (SUFG) at Purdue University has been tasked with identifying and forecasting Indiana's resource needs. According to the SUFG's 2011 forecast,[22] the state will need approximately 2,600 MW of additional resources (all types of generating capacity, demand response, efficiency, and transmission to import power) by 2020 to meet expected load growth and maintain a 15.8% reserve margin.[23] The forecast also projects that electricity usage will grow at an annual rate of 1.30% over the 20-year forecast and that peak demand will grow at an annual rate of 1.28%.[24] This means that utilities must start considering how to meet this demand in the short term.

According to the SUFG's 2011 forecast, Indiana will need approximately 2,600 MW of additional resources by 2020 to meet expected load growth and maintain a 15.8% reserve margin.

While the current recession may temporarily slow the growth of energy and demand, the expectation is that the forecasted growth rates will resume over the forecast horizon. These projections provide a reasonable basis for estimating future electricity prices for planning purposes, but they do not ensure resource plans obtained at least cost. These projections also do not yet address the effects of potential U.S. EPA environmental regulations, which are expected

[22] http://www.purdue.edu/discoverypark/energy/pdfs/SUFG/2009SUFGforecast.pdf
[23] SUFG used individual utility reserve margins that reflect the planning reserve requirements of the utility's RTO to determine the reserve requirements in the forecast.
[24] The maximum level of electric demand in a specified period

to require additional environmental controls on some pulverized coal fueled generating stations and the retirement of some others, thereby requiring retrofitting and replacements.

U.S. EPA Rules and Rulemakings

Decisions made at the federal level have the potential to considerably impact the state of Indiana. In fact, one recently finalized and three currently proposed U.S. EPA rules are expected to impose significant burdens on the Indiana power sector. These rules include:

1. The Cross-State Air Pollution Rule (CSAPR or Transport Rule) that implements controls for nitrogen oxides and sulfur dioxide;

2. The electric generating utility Maximum Achievable Control Technology Rule (Utility MACT) for mercury and other air toxics;

3. A new rule for cooling water intake structures (CWIS), potentially requiring cooling towers to be installed at certain facilities; and

4. A proposal for the U.S. EPA to regulate coal combustion residuals (CCR), including coal ash, initiated as a result of the 2008 ash pond failure in Tennessee.

Over the next few years, the U.S. EPA is expected to issue at least six rules directly affecting the electric power sector, which will have a significant fiscal impact on the state of Indiana.

Stricter ambient air quality standards for ozone and particulate matter, which are implemented at the state level, could also result in tighter limits under CSAPR and through compliance enforcement. However, the U.S. EPA has delayed this action until 2013.

Yet to be proposed are New Source Performance Standards (NSPS) for greenhouse gases (GHG), which would allow the U.S. EPA to establish emission limits for new and significantly modified facilities and establish emissions guidelines to be implemented by states for existing sources. Cost impacts will depend primarily on the stringency, flexibility, and timing of the standards. In the long term, performance standards are a higher-cost emissions control policy than cap-and-trade, because utilities have less flexibility to pursue least-cost emissions reduction strategies. However, in the near-term, compliance costs may be comparable. As of January 2011, the U.S. EPA granted state permitting agencies the authority to develop GHG performance

standards for new or modified stationary sources and provided guidance for setting standards. As of summer 2011, the Indiana Department of Environmental Management (IDEM) has two such permitting cases. Because they are in the draft stage, it is not yet clear what substantive form such standards might take.

The suite of U.S. EPA rules is slated to be finalized by mid-2012. In recent decades, it has been common for the power industry to face one or two pending regulations at the same time. Conversely, over the next few years, the U.S. EPA is expected to issue at least six rules directly affecting the electric power sector, as shown in Table 2. As opposed to a staggered timing of rules, this will reduce regulatory uncertainty, enabling utilities to plan power resources and environmental compliance strategies more cost-effectively in the long term. However, the condensed and close timing of compliance schedules will exacerbate retrofit costs and present reliability challenges over the next few years. Extending the duration and increasing the flexibility of compliance schedules would lessen such impacts.

Table 3

Status, Compliance Date, and Key Issues of Recent U.S. EPA Rules Affecting Power Sector

U.S. EPA Rule	Rulemaking Status	Compliance Date (expected)	Key Issues and Implications
CSAPR I **CSAPR II**	Final issued July 2011 Proposal expected in summer 2011 Final expected summer 2012	Different requirements for 2012 and 2014	IDEM is currently reviewing compliance strategies Presents compliance timeline challenges considering combined impact of other rules
Utility MACT	Currently proposed Final expected 11/2011	2014; 2015 if state grants extension	Proposal is relatively flexible, however compliance timeline is challenging
Ambient Air Standards	PM proposal expected fall of 2011 Ozone proposal delayed for fourth time in 7/2011	TBD	Potentially tighter limits under CSAPR and in state implementation plan administered by IDEM

GHG NSPS	Proposal expected Sept. 30, 2011 Final expected 5/2012	TBD	Uniform performance standards for new and modified sources may require efficiency upgrades at plants State issues standards for existing sources with U.S. EPA guidance
CWIS	Currently proposed Final expected 7/2012	2015	Whether site-specific cost-benefit analysis is used in place of uniform standards greatly affects applicability and costs
CCR	Currently proposed No signal on final, possibly late 2011 or early 2012	No sooner than 2014	Whether waste is deemed hazardous greatly affects costs

Quantitative assessments of the cost impact on utilities and the effects on electricity prices will remain very speculative until the rules are finalized. However, Indiana and the industrial Midwest are at risk to bear a larger burden than other states and regions. The bulk of this impact will fall on coal units, as utilities will be forced to either undertake capital-intensive retrofits or retire certain units within a short timeframe. Consequently, Indiana may have numerous coal-fired units that are "at-risk" of retirement; older, smaller coal plants with fewer environmental controls are most likely to be forced to retire prematurely. The decision to retire them will depend on replacement costs, which are largely determined by natural gas prices.

Resource Planning

Over the next 15 years, state electricity demand is forecasted to steadily increase while many aging coal-fired units will be approaching retirement or premature shutdown. This era is expected to have far greater build-out of new generation than the past two decades. At the same time, lifetime cost assessments of new generation units are expected to be increasingly difficult to estimate in large part due to federal regulatory uncertainty and upward pressure on the prices of inputs, such as materials, construction and fuel costs. Thus, the Indiana power sector is entering a period of unprecedented planning difficultly at a time when resource planning is increasingly necessary, especially over the next few years.

By around 2015, Indiana will need to retrofit or retire an unprecedented wave of coal-fired power capacity and replace it with a combination of new resources due to a suite of likely environmental regulations and a large cohort of old coal units that lack sufficient controls. This

will require utilities to make cascading, sequential capital-intensive decisions inside a short window and could result in significant electric rate increases. The primary replacement fuel, based on current information, is expected to be natural gas due to the low price of the fuel, with wind and demand side management also expected to play a key role. Nuclear, IGCC, additional efficiency, and other alternative resources could also play a role in meeting Indiana's resource requirements.

Regulatory Development

Regulatory Changes Stemming from SEA 251

Senate Enrolled Act 251 (P.L. 150-2011) provides guidance to the Commission on three major issues in the electricity sector that have received significant attention in recent years:

1. Regulatory treatment for a growing number of federally-mandated costs;
2. Regulatory treatment for nuclear projects; and
3. Implementation of a Voluntary Clean Energy Portfolio Standard.

As the federal government hands down mandates, utilities across the nation, including those in Indiana, will be required to invest in their systems in order to become compliant with new environmental standards. In order to ensure timely recovery of the costs associated with these projects, the law addresses how the Commission is to handle them from a regulatory standpoint.

In order to recover the costs associated with a federal mandate, the utility must identify the mandate and develop a plan for compliance. The utility must then file an application with the Commission for a CPCN. If the Commission determines that the public convenience and necessity is served by the proposed project, it is to grant approval. Once approved, the Commission is required to grant a tracker mechanism for cost recovery; however, only 80% of the costs are eligible for tracking. The remaining 20% are deferred and recoverable only within the utility's next base rate case.

As for the regulatory treatment of nuclear projects, the law states that: "it is in the public interest for the state to encourage the study, analysis, development, and life cycle management of nuclear energy production or generating facilities . . ." This provides existing nuclear generation facilities the ability to recover costs associated with life cycle management to enhance the safe and reliable operation of the facility throughout the period the facility is licensed to operate by the United States Nuclear Regulatory Commission. Further, the law allows all costs attributable to life cycle management to be treated the same as a qualifying clean coal facility from a regulatory standpoint. This includes CWIP treatment through a tracking mechanism.

Lastly, the law requires the Commission to proceed with an emergency rulemaking regarding the state's Voluntary Clean Energy Portfolio Standard Program. The program is designed to encourage a participating utility to reach a clean energy target of 10% of the total electricity supplied to Indiana retail electric customers from the 2010 base year to December 31, 2025. There are also interim targets to be met and maintained by January 1, 2013 of 4% and January 1, 2019 of 7%. The Commission held workshops during the summer and met with interested stakeholders so that a draft rule could be written. Workshops are also scheduled for the fall.

State Renewable Portfolio Standards

According to the Database of State Incentives for Renewables & Efficiency, 29 states, plus DC and PR have an RPS; whereas, 8 states have goals.

Because the statute requires a rule to be effective by January 1, 2012, the workshop schedule has been expedited. This means that the IURC has been working with interested parties so that a draft rule can be written and circulated for comment by the end of September. To meet the deadline, the IURC will finalize the draft rule by the end of 2011 and adopt it as an emergency rule, as allowed by IC § 8-1-37-10(d). The IURC will then use this emergency rule as the proposed rule to begin the regular rulemaking process.

Tree-Trimming Practices

Vegetation management plans and practices play a key role in helping to reduce the number of service interruptions to Indiana consumers. At the same time, ratepayers have basic rights that

need to be protected. In November 2010, the Commission concluded its investigation into tree trimming practices and tariffs for jurisdictional electric utilities and found that Hoosiers would benefit from having consistency with regard to the rules and regulations surrounding tree-trimming practices and procedures.

For example, the Order requires utilities to provide advance notice to customers when trimming is about to occur and allows customers to be present during that time. When contacting customers, the utilities must now provide notice in person or over the phone and provide at least one form of written notice to the customer. The initial notice should be no later than two weeks before the trimming is estimated to occur. In doing so, customers and utilities will have more time to discuss and resolve concerns.

Changes due to the Tree-Trimming Order

Utilities are now prohibited from "topping" trees or removing more than 25% of a tree's canopy without the property owner's consent. When contacting customers, the utilities must now provide notice in person or over the phone and provide at least one form of written notice to the customer. Further, once normal maintenance trimming is complete, the Commission finds that it is reasonable for the utility to have the debris promptly removed within three calendar days.

Additionally, utilities are prohibited from "topping" trees or removing more than 25% of a tree's canopy without the property owner's consent. Utilities are also prohibited from trimming outside an easement or right-of-way without the customer's consent. This decision stems from consumer complaints raised during the course of the proceeding. If the property owner does not consent, the utility must offer alternatives. One such alternative is a tree replacement program set up by the Order that allows utilities to compensate for tree removal. Once normal maintenance trimming is complete, the Commission finds that it is also reasonable for the utility to have the debris promptly removed within three calendar days.

In its Order, the Commission identified areas where a rulemaking would benefit the relationship between Indiana's electric utilities and its customers. Therefore, it ordered that the following issues be addressed through the rulemaking process: dispute resolution, notice requirements, customer education, and tree replacement. The Commission has since held three technical conferences (in December 2010, February 2011, and August 2011) to receive proposed

language and has drafted a rule based on the proposed language from consumer groups, the public, and the utilities. A final rule is expected by the end of the year.

III. ELECTRICITY APPENDICES

Appendix A – Jurisdictional Electric Utility Revenues

Rank	Utility Name	Operating Revenues*	% of Total Revenue
1	Duke Energy Indiana, Inc.	$ 2,517,375,579	29.98%
2	Indiana Michigan Power Co.	2,157,506,760	25.70%
3	Northern Indiana Public Service Co.	1,387,408,342	16.53%
4	Indianapolis Power & Light Co.	1,144,797,510	13.64%
5	So. Indiana Gas & Electric Co. d/b/a Vectren	608,185,246	7.24%
6	Richmond Municipal	84,923,471	1.01%
7	Northeastern REMC	83,167,789	0.99%
8	Anderson Municipal	71,140,240	0.85%
9	Harrison County REMC	51,402,350	0.61%
10	Mishawaka Municipal	50,366,417	0.60%
11	Jackson County REMC	49,459,736	0.59%
12	Logansport Municipal	35,388,274	0.42%
13	Crawfordsville Municipal	29,712,506	0.35%
14	Frankfort Municipal	25,643,346	0.31%
15	Auburn Municipal	25,583,972	0.30%
16	Peru Municipal	22,596,315	0.27%
17	Lebanon Municipal	16,388,191	0.20%
18	Marshall County REMC	12,819,327	0.15%
19	Tipton Municipal	9,387,426	0.11%
20	Columbia City Municipal	9,368,756	0.11%
21	Knightstown Municipal	2,231,076	0.03%
22	Kingsford Heights Municipal	639,683	0.01%
23	Greenfield Mills, Inc. Power & Light	24,560	0.00%
	Total Revenue	$ 8,395,516,872	100.00%

*Year ending December 31, 2010

Appendix B – Jurisdiction over Municipal Electric Utilities

Municipal Utilities under the IURC's Jurisdiction		
Anderson	Frankfort	Logansport
Auburn	Kingsford-Heights	Mishawaka
Columbia City	Knightstown	Richmond
Crawfordsville	Lebanon	Tipton

Municipal Utilities Withdrawn from the IURC's Jurisdiction (IC § 8-1.5-3-9)		
Advance	Ferdinand	Pendleton
Argos	Flora	Peru
Avilla	Frankton	Pittsboro
Bainbridge	Garrett	Rensselaer
Bargersville	Gas City	Rising Sun
Bluffton	Greendale	Rockville
Boonville	Greenfield	Scottsburg
Bremen	Hagerstown	South Whitley
Brooklyn	Huntingburg	Spiceland
Brookston	Jamestown	Straughn
Cannelton	Jasper	Tell City
Centerville	Ladoga	Thorntown
Chalmers	Lawrenceburg	Troy
Coatesville	Lewisville	Veedersburg
Covington	Linton	Walkerton
Darlington	Middletown	Warren
Dublin	Montezuma	Washington
Dunreith	New Carlisle	Waynetown
Edinburgh	New Ross	Williamsport
Etna Green	Paoli	Winamac

Appendix C – Jurisdiction over Rural Electric Membership Cooperatives

REMCs under the IURC's Jurisdiction		
Harrison County REMC	Jackson County REMC	
Marshall County REMC	Northeastern REMC	

REMCs Withdrawn from the IURC's Jurisdiction (IC § 8-1-13-18.5)		
Bartholomew County REMC	Jay County REMC	Rush Shelby County REMC
Boone County REMC	Johnson County REMC	South Central Indiana REMC
Carroll County REMC	Kankakee Valley REMC	Southeastern Indiana REMC
Ninestar Connect	WIN Energy REMC	Southern Indiana REC
Clark County REMC	Kosciusko County REMC	Steuben County REMC
Daviess-Martin County REMC	Lagrange County REMC	Tipmont REMC
Decatur County REMC	Miami-Cass REMC	United REMC
Dubois REC	Newton County REMC	Utilities District of W. Indiana
Fulton County REMC	Noble County REMC	Wabash County REMC
Hendricks County REMC	Orange Co. REMC	Warren County REMC
Henry County REMC	Parke County REMC	White County REMC
Jasper County REMC	Paulding-Putnam Electric Coop.	Whitewater Valley REMC

2011 Natural Gas Report

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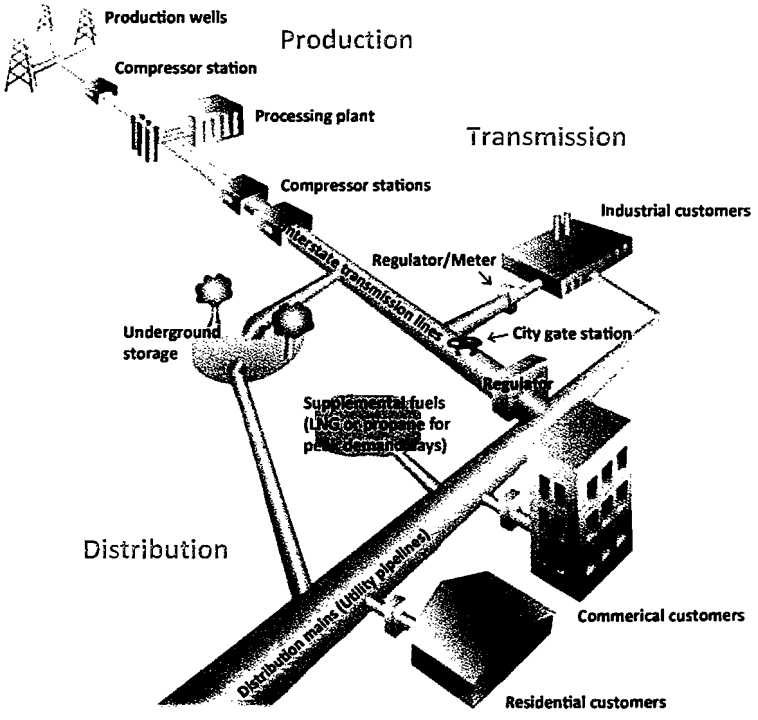
I. NATURAL GAS OVERVIEW

Industry Structure

The natural gas industry consists of three systems: producers (the gathering system), interstate and intrastate pipelines (the transmission system), and local distribution companies or LDCs (the distribution system), all of which are illustrated in Figure 1. Interstate pipelines, regulated by the Federal Energy Regulatory Commission (FERC), carry natural gas across state boundaries; intrastate pipelines, regulated by state commissions, carry natural gas within state boundaries. States, including Indiana, that have certified pipeline safety programs are delegated federal authority by the U.S. Department of Transportation to conduct inspections, investigate incidents, and enforce state and federal safety regulations.

In Indiana, the Indiana Utility Regulatory Commission (Commission or IURC) regulates the rates, charges and terms of service for intrastate pipelines and LDCs. Through its Pipeline Safety Division (Pipeline Safety), the Commission enforces state and federal safety regulations for all intrastate natural gas facilities. Additionally, the Commission reviews gas cost adjustments (GCAs), financial arrangements, service territory requests, and conducts investigatory proceedings. It also analyzes various forms of alternative regulatory proposals, such as rate decoupling, trackers, and customer choice initiatives.

Figure 1



Production Overview

As shown in Figure 1, the production of natural gas begins with raw natural gas extracted at the wellhead, where initial purification occurs before entering the low-pressure, small diameter pipelines of the gathering system. The natural gas is then repurified at a

processing plant. Purified natural gas consists of approximately 90% methane, compared to raw natural gas that is generally 70% methane combined with a variety of other compounds. Quality and safety reasons require natural gas to meet certain standards before it is released into the pipeline system.

Transmission System

The transmission system includes interstate and intrastate pipelines that carry gas from producing regions throughout the U.S. to LDCs, industrial consumers, and power generation customers. The vast majority of natural gas consumed in Indiana is from out-of-state production, primarily from the Gulf of Mexico. In 2009, Indiana consumed approximately 507 million dekatherms (Dth) of natural gas, of which roughly 4.9 million Dth, or less than 1%, was produced within the state. This illustrates Indiana's dependence on the transmission system to carry natural gas from the gas producing regions of the country into the state.[1]

The vast majority of natural gas consumed in Indiana is from out-of-state production, predominantly the Gulf of Mexico. This illustrates Indiana's dependence on the transmission system to carry natural gas from the gas producing regions of the country into the state.

In Indiana, Heartland Pipeline (Heartland) and the Ohio Valley Hub (OVH) Pipeline are the two intrastate pipelines under the Commission's jurisdiction. The Commission governs these pipelines' operations, services, and rates. Heartland is a 25-mile pipeline running west to east connecting the Midwestern Gas Transmission (MGT) interstate pipeline in Sullivan, Indiana to Citizens Gas' underground storage facility in Greene County. OVH is a 9.2-mile pipeline located in Knox County. It provides connections for

Map 1
U.S. Transmission Lines

[1]http://www.eia.gov/state/state-energy-profiles-print.cfm?sid=IN

two interstate pipelines (Texas Gas Transmission and MGT) to the Monroe City Gas Storage Field owned by Vectren Energy Delivery of Indiana.

Distribution System

Gas moves through the transmission system and enters the distribution system, where LDCs deliver gas to their customers on either a bundled basis (i.e., commodity and transportation) or unbundled basis (i.e., the customer buys gas from a producer or marketer and pays the LDC to transport the gas from the city gate[2] to the customer's facilities).

LDCs serve three customer classes: residential, commercial, and industrial. The residential customer class consists of single-family homes and small multi-family dwellings that generally use the LDCs for bundled services. The commercial customer class typically consists of office, retail, and wholesale facilities in addition to larger residential complexes. The industrial customer class consists of large manufacturers and processors who typically use the highest volumes of gas both individually and collectively. Both commercial and industrial customers may receive bundled service from an LDC or they may purchase their gas supplies from independent suppliers and pay the LDCs for transportation service.

The Commission has regulatory authority over 19 natural gas distribution utilities in Indiana with operating revenues totaling $1.9 billion (Appendix A).[3] These utilities maintain plant in service of approximately $3.6 billion and serve roughly 1.7 million customers. Of the regulated utilities, one is a not-for-profit, two are municipalities, and sixteen are investor-owned utilities (IOUs). Citizens Gas (Citizens) and three IOUs, detailed on the following page, represent the four largest natural gas utilities in Indiana and collectively serve 92% of the gas customers by count in the state. Map 2 shows the services territories of these utilities, as well as other jurisdictional natural gas utilities in Indiana.

[2]The city gate is the delivery point where the natural gas is transferred from a transmission pipeline to the LDC.
[3]2010 Annual Reports filed with the Commission

- Investor-Owned Utilities -

The three largest IOUs providing gas service in Indiana are Northern Indiana Public Service Company (NIPSCO), Vectren North, and Vectren South. IOUs are for-profit enterprises funded by debt (bonds) and equity (stock).

NIPSCO, a subsidiary of NiSource Inc., is headquartered and based in Merrillville, IN. The natural gas utility serves 620,000 customers in northern Indiana.

Vectren Corporation is headquartered and based in Evansville, IN. The natural gas utility serves 570,000 customers in central and southern Indiana through Vectren North and an additional 111,000 customers in southwestern Indiana through Vectren South.

- Municipally-Owned Utilities -

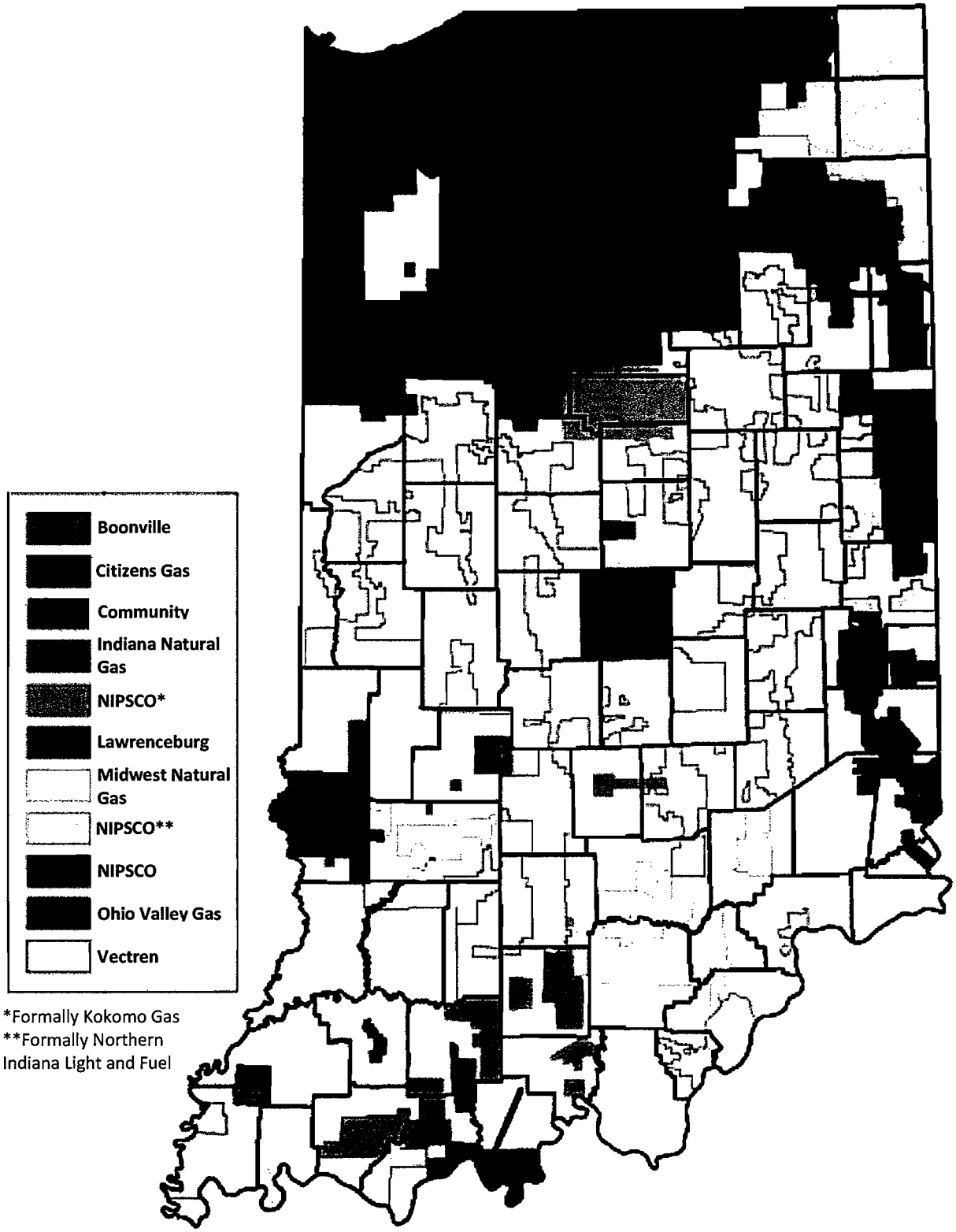
Citizens is a public charitable trust (treated as a municipal utility for regulatory purposes) serving 263,000 customers primarily in the Indianapolis metropolitan area. Pursuant to statute, municipal utilities, excluding Citizens, may elect to "opt out" of the Commission's jurisdiction for rates and charges in favor of local control in determining rates.

However, utilities that choose to opt out still remain under the jurisdiction of the Commission's Pipeline Safety Division.[4] Of the state's 19 municipal gas utilities, 17 have elected to withdraw from the Commission's oversight. To view a list of the withdrawn utilities, please see Appendix B.

[4] *See*, IC § 8-1.5-3-9

Map 2

Natural Gas Service Territories

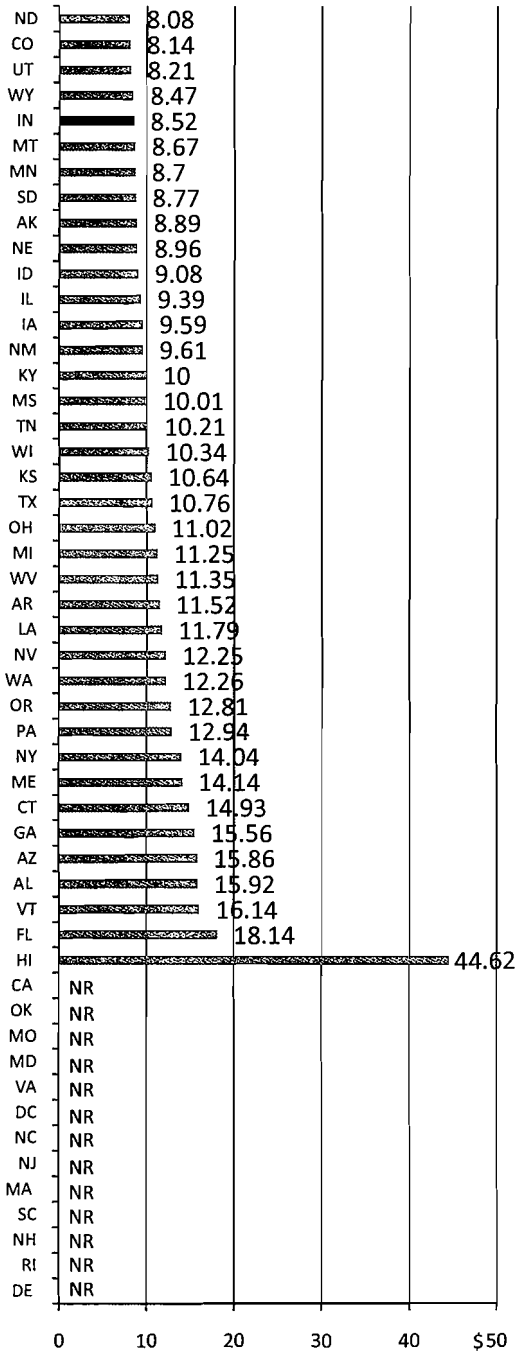


How Indiana Compares with Other States

Over the last 10 years, Indiana has consistently compared well with other states for residential and commercial delivered (bundled) gas prices. Over the last five years, Indiana has also performed well with industrial gas prices. As Chart 1 demonstrates, Indiana's national price rankings for all three customer classes improved dramatically in 2010, as compared with other states. This is due to a variety of factors, including the timing of rate cases both in and out of state.[5]

Indiana ranked 5th nationally and 2nd in the Midwest region[6] for the lowest 2010 average residential gas prices. The average residential gas price has fallen each of the last two years from $12.65 per thousand cubic feet in 2008 to $8.52 per thousand cubic feet in 2010. These numbers are higher than the commonly referenced commodity cost of approximately $4.50/Mcf, because they are bundled prices. Bundled prices include all utility costs to deliver the product, including pipeline and LDC operator charges. Neighboring states' average residential retail rates for 2010 are as follows, with the first being the lowest: Illinois $9.39, Kentucky $10.00, Ohio $11.02, and Michigan $11.25.[7]

Chart 1
2010 State Residential Gas Prices ($/thousand cubic ft)



Source: U.S. Energy Information Administration

[5]Although the majority of states reported, 13 did not. These states are at the bottom of the list and are marked with an "NR," which stands for not reporting.
[6]The Midwest region includes Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, and Wisconsin.
[7]http://www.eia.doe.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_a.htm

Indiana ranked 6th nationally and 3rd in the Midwest for lowest 2010 average commercial gas prices. Indiana's 2010 average commercial price was $7.44 per thousand cubic feet, significantly less than the 2008 average price of $11.14. Neighboring states' average commercial retail rates for 2010 were as follows, with the first being the lowest: Kentucky $8.42, Illinois $8.74, Michigan $8.79, and Ohio $9.23 per thousand cubic feet.[8]

Table 1

Comparison between Indiana and the U.S. Average Price for Delivered Gas

2008 (peak year) vs. 2010

Customer Category	Indiana Price ($/Mcf)**		U.S. Average Price ($/Mcf)	
	2008	2010	2008	2010
Residential	12.65	8.52	13.89	11.20
Commercial	11.14	7.44	12.23	9.15
Industrial	10.48	5.53	9.65	5.40

* Higher ranking denotes lower rates

**Dollars per thousand cubic feet

Indiana ranked 9th lowest nationally and 3rd lowest of the Midwest states for 2010 average industrial gas prices. As the chart to the right demonstrates, the average industrial price fell from $10.48 per thousand cubic feet in 2008 to $5.53 per thousand cubic feet in 2010. The year 2008 was selected because this is when natural gas prices peaked. The chart also shows Indiana industrial customers pay slightly more than the national average of $5.40 per thousand cubic feet. However, of the four neighboring states, only Kentucky had a lower average industrial gas price of $5.30 per thousand cubic feet. The other three states' average industrial retail rates for 2010 are as follows: Ohio (not reporting), Illinois $7.25, and Michigan $9.18 per thousand cubic feet.[9]

Age Profile

Indiana's natural gas infrastructure consists of more than 75,000 miles of intrastate pipelines, which were placed in service over the past 80-plus years. In this total are more than 39,000 miles of distribution mains (i.e., pipes which transport gas within a given service area to points of connection with pipes serving individual customers). More than 60% of the state's distribution mains are at least 30 years old.

Also included in the state's infrastructure is approximately 1,950 miles of transmission mains (i.e., pipelines that transmit gas from a source or sources of supply to one or more distribution

[8]http://www.eia.doe.gov/dnav/ng/ng_pri_sum_a_EPG0_PCS_DMcf_a.htm
[9]http://www.eia.doe.gov/dnav/ng/ng_pri_sum_a_EPG0_PIN_DMcf_a.htm

centers, large volume customers, or other pipelines that interconnect sources of supply). Typically, transmission lines differ from gas mains in that they operate at higher pressures, are longer, and have a greater distance between the connections. Nearly 50% of the state's transmission mains are at least 40 years old.

Table 2

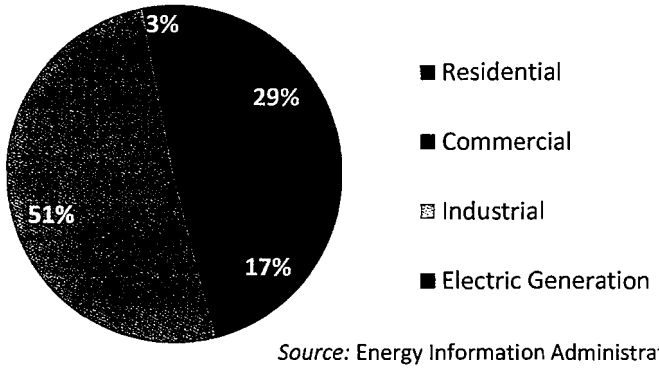
Age Profile of Jurisdictional Transmission and Distribution Mains in Indiana

	Transmission Mains		Distribution Mains	
Years Old	Number of Main Miles	% of Total Main Miles	Number of Main Miles	% of Total Main Miles
80+	-	-	572.6	1.45%
70-80	0.1	0.01%	382.2	0.96%
60-70	2.9	0.15%	2,711.6	6.84%
50-60	284.6	14.59%	9,507.8	24.00%
40-50	685.1	35.13%	4,797.1	12.11%
30-40	246.8	12.66%	6,954.7	17.55%
20-30	175.2	8.98%	8,241.0	20.80%
10-20	257.9	13.22%	5,441.3	13.73%
0-10	179.7	9.21%	224.8	0.57%
Unknown	117.8	6.04%	784.3	1.98%
Total	1,950.1	100.00%	39,617.0	100.00%

Federal guidelines for integrity management require that operators (including LDCs and pipeline companies) make every effort to assess threats to their pipelines.[10] The replacement of aging infrastructure continues to be an ongoing focus as demand for service connections continues to increase.

Chart 2

Consumption by Sector in Indiana (2010)



Source: Energy Information Administration

Demand and Supply

As previously mentioned, Indiana's local distribution companies serve three different types of customers: residential, commercial, and

[10]Integrity management is a risk-based approac
and 2006.

industrial. In 2010, Indiana's residential customers consumed approximately 140 million Dth of natural gas, which accounts for 29% of the state's total consumption.[11]

Also in 2010, Indiana's commercial customers consumed approximately 17% of the state's total consumption or 79 million Dth of natural gas.[12] Industrial customers accounted for more than half of the state's total consumption with about 245 million Dth, which ranked Indiana fourth highest for industrial natural gas consumption in the U.S.[13]

Drivers of Demand

Environmental factors and weather are the primary factors driving demand for natural gas. Because natural gas is a cleaner burning fuel than coal, it is being evaluated as an alternative fuel source for electricity generation. Although the magnitude of the increase has yet to be determined, demand is expected to increase. As for weather, when it is colder-than-normal during the heating season, demand for natural gas increases. Demand also increases, to a lesser extent, when weather is hotter-than-normal during the non-heating season, as natural gas is often used to generate electricity at times of peak demand.

Chart 3

Top 10 States for Industrial Consumption

% of total national industrial consumption

Texas	19.4%
Louisiana	12.3%
California	11.5%
Indiana	4.0%
Illinois	3.8%
Ohio	3.8%
Oklahoma	2.9%
Pennsylvania	2.8%
Iowa	2.7%
Georgia	2.3%

Source: U.S. Energy Information Administration

Because gas consumption is lower in the summer cooling season, gas utilities typically replenish their stored natural gas supplies at this time in preparation for the winter heating season. Due to lower overall demand during the summer, utilities are often able to purchase these supplies at lower, more favorable prices.

As demand increases, new sources of supply are continually needed. New sources are also needed to replace the decline in production of existing wells as they mature. Higher natural gas

[11]http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SIN_a.htm
[12]http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SIN_a.htm
[13]http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_a_EPG0_vin_mmcf_a.htm

prices over the last few years have increased interest in the exploration for unconventional sources, once considered too costly to extract. New technology and lower extraction costs have also led to the increased drilling of non-conventional gas supplies (e.g., coal bed methane, shale gas, and tight sands). As formerly unrecoverable sources of gas are being tapped, this has contributed significantly to the supply of natural gas. The robust supply of natural gas, specifically shale gas, currently overwhelms swings in demand. As demonstrated in 2010, record setting summer heat and winter cold prevailed, yet spot market prices remained stable.

Legal and Policy Foundations

Pipeline Safety Act of 1968

The Pipeline Safety Act of 1968 established the federal pipeline safety program. This federal program[14] establishes a framework and organizational structure for a federal/state partnership regarding pipeline safety. This framework promotes pipeline safety through exclusive federal authority for the regulation of interstate pipeline facilities and federal delegation to the states for all or part of the responsibility for intrastate pipeline facilities.

The federal/state partnership is the cornerstone for ensuring uniform implementation of the pipeline safety program nationwide. It also authorizes federal grants for a state agency's personnel, equipment, and activity costs. Grants are determined primarily on the annual evaluation of the state's program. Indiana's program, as established by statute, has historically received high marks from the federal annual evaluations.[15]

Indiana's Pipeline Safety Program

The Pipeline Safety Division is responsible for enforcing state and federal safety regulations for Indiana's gas intrastate pipeline facilities and is established under IC ch. 8-1-22.5. The division operates in partnership with the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) under a certification agreement.

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[14] 49 U.S.C. Chapter 601
[15] IC ch. 8-1-22.5

The Pipeline Safety Division's mission is to ensure the safe and reliable operation of Indiana's pipeline transportation system. This mission is accomplished largely through inspections, investigations of pipeline accidents, training, outreach programs, and enforcement through injunctions and monetary sanctions. In 2010, the division conducted 835 inspections of 96 operators and 195 associated inspection units, safely resolving 137 probable violations.

In 2010, the IURC's Pipeline Safety Division conducted 835 inspections of 96 operators and 195 associated inspection units, safely resolving 137 probable violations.

The Pipeline Safety Division is also responsible for the prevention of damage to underground facilities and the education of public and emergency officials and responders in knowing how to recognize, report, and respond to gas-related emergencies. In 2009, the General Assembly passed SEA 487, the Underground Plant Protection Law, which imposes requirements designed to ensure compliance with state and federal laws that apply to homeowners, excavators, and operators.[16] The law requires anyone undertaking a digging project to call the Indiana Underground Plant Protection Service Center at the toll-free 811 number before digging. In response to calls received, a trained representative is dispatched to mark the utility lines free of charge to the calling party. Once the lines are marked, individuals may begin their digging project; however, they must hand dig within two feet of the buried utility line to prevent damage to underground facilities.

If there is damage to underground facilities, the Pipeline Safety Division serves as the investigative unit. If a violation is found, the information is then forwarded to the Underground Plant Protection Advisory Committee, which was formed in 2010 as a result of SEA 487. Upon receiving a recommendation from the Advisory Committee, and after notice and opportunity for a public hearing, the Commission must uphold or reverse the finding; approve or disapprove the recommendation(s) of the Advisory Committee; and/or collect any civil penalties and deposit the penalties in the underground plant protection account. Since July 1, 2009, the Pipeline Safety Division has registered more than 1,500 possible violations.

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[16]P.L. 62-2009

II. NATURAL GAS LANDSCAPE

Infrastructure

Although age is one factor in considering whether a pipeline may need to be replaced, the type of material used (bare steel, cast iron, plastic), its location, and relative risk to public safety are also considered. In accordance with pipeline safety standards, utilities perform inspections of their pipeline facilities on a regular basis to help identify areas at risk. Based on the results of these inspections, corrective actions are initiated. In some cases, this may include implementing replacement programs for existing bare steel, cast iron, or wrought iron systems. Many of these pipes need to be replaced because older pipelines of this nature were not coated or cathodically protected when they were installed years ago. Consequently, corrosion and leaks have developed over time. To enhance reliability and safety, many utilities now use plastic pipe for their distribution systems.

Pipeline safety programs nationwide are being asked to develop risk-based methods and approaches to help evaluate a pipeline operator's overall risk. Doing so will help identify riskier pipeline operators, resulting in greater scrutiny and enhanced public safety. In addition to these initiatives at the regulator level, the Commission is also requiring pipeline operators to develop data-driven, risk-based inspection plans of their own, which will enable them to assess risks in their operations and take appropriate action to minimize or eliminate them.

Modernization and Efficiency

Recent advancements in technology have allowed the natural gas industry to modernize itself in terms of natural gas resources and the development of more efficient uses of natural gas. New sources of gas, such as shale, which were not historically commercially viable to pursue, now represent a large percentage of the recent increases in the country's proven or identified natural gas supplies.

Other technological advancements in gas appliances provide consumers with the opportunity to become more efficient and reduce their overall energy consumption. Natural gas furnaces and water heaters now use less gas than ever before, and utilities are promoting these opportunities through their energy efficiency programs. As a result, these combined advancements are having

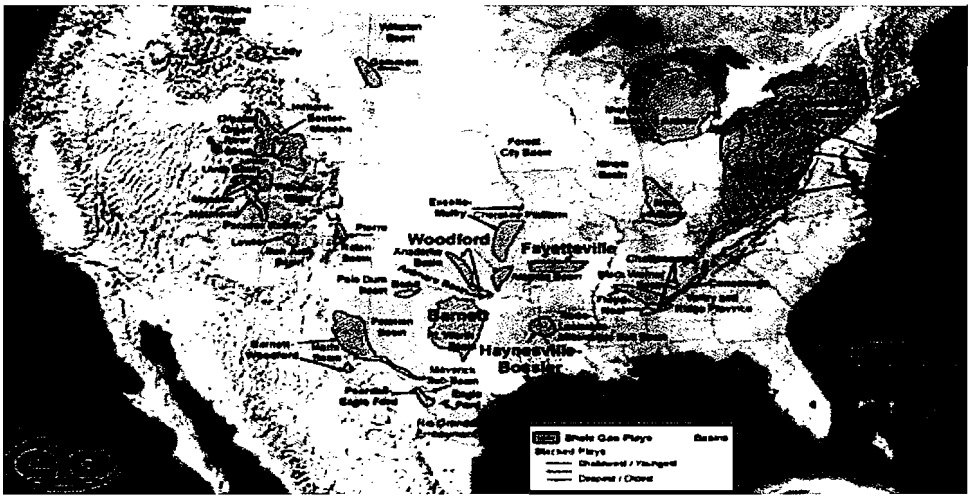
an impact on natural gas supply and demand and have helped result in lower prices and less volatility in the gas market.

Shale Gas

The emergence of unconventional sources of natural gas supply (e.g., shale gas) has affected the overall supply of natural gas in our country. A 2011 report by the Potential Gas Committee[17] indicates the U.S. possesses a total natural gas resource base of 1,898 trillion cubic feet (TCF), an increase of 3.3% or 61 TCF from 2009. This is the highest resource evaluation in the 46-year history of the Committee and arose from the reevaluation of shale gas plays in the Gulf Coast, Mid-Continent, and Rocky Mountain areas.[18] Map 3 shows the locations of shale plays in the U.S.

Map 3

Gas Shale Plays in the Continental U.S.



Source: U.S. Energy Information Administration

Recently, consumer and environmental groups raised concerns about the drilling techniques employed to extract shale gas. Some studies have suggested a correlation linking drilling with environmental harm. Many states where drilling has occurred have experienced air pollution and

[17]The Potential Gas Committee is an incorporated, nonprofit organization consisting of experienced volunteers in the natural gas field working independently in association with the Colorado School of Mines.
[18]"Play" is used in the oil and gas industry to refer to a geographic area which has been targeted for exploration due to favorable geoseismic survey results, well logs or production results.

contaminated drinking wells due to poorly cased wells and the illegal disposal of fluids. As a result, the federal government launched a review of the commonly used drilling technique known as hydraulic fracturing or fracking.[19] The U.S. Environmental Protection Agency (U.S. EPA) expects to release its initial findings on the environmental impacts of fracking in late 2012, which should provide a more accurate estimate of possible future regulation of hydraulic fracking.[20]

In a joint project, the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission created a hydraulic fracturing registry that allows citizens to search for specific wells and determine the chemicals used for fracturing the well.[21] In January 2011, Arkansas' Oil and Gas Committee required drillers to begin reporting the chemicals used in their fracking activities, given contamination concerns in the Fayetteville shale play.[22] In the state of New York, a fracking moratorium was in place until July 2011 to allow time for its Department of Environmental Conservation to determine environmental impacts.[23] The Department of Environmental Conservation has since recommended replacing the moratorium with regulations.[24]

Indiana Gas and Storage Wells

The vast majority of Indiana's gas and gas storage wells are located in the southwestern part of the state.

The largest reported volume of fluid used to hydraulically fracture a single well in Indiana during the period from 2005 to 2010 represents only 1.64% of the total fluid that might be used in a single Marcellus Shale well.

Source: www.in.gov/dnr/dnroil/5715.htm

While it appears the industry is making strides to enhance transparency by publicizing the chemicals used in fracking, some remain skeptical. The results of the U.S. EPA study should give the industry and the public a better understanding of how environmental sanctions could impact the price of shale gas. However, if new federal

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[19]Hydraulic fracturing is a technique used to create fractures that extend from the well bore into rock or coal formations so that the gas may travel more easily from the rock pores to the production well. www.earthworksaction.org/FracingDetails.cfm
[20]http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm
[21]http://fracfocus.org/
[22]SNL Energy, Gas Utility Week. "Arkansas to require reporting of chemicals used in hydraulic fracturing," Vol. 5, Issue 49, pg. 10
[23]www.reuters.com/article/2010/12/12/us-natgas-newyork-idUSTRE6BB00Y20101212
[24]Oil & Gas Law Brief, July 9, 2011

regulations are imposed or if restrictive legislation is passed regarding drilling techniques and practices, the price of natural gas may increase.

Coal Bed Methane (CBM)

Coal bed methane (CBM), which is extracted from coal beds, is another source of natural gas. Generally, CBM is contained in the un-mined coal seams a few hundred feet below the surface. CBM is recovered by drilling into the coal seam using water and sand at high pressure, thus fracturing the seam. This drilling process is similar in nature to shale fracturing. Currently, CBM accounts for approximately 7% of natural gas production in the United States.[25] One CBM project in operation is located in Sullivan County. Jericho, LLC received a Certificate of Public Convenience and Necessity from the IURC in December 2008 to construct, own and operate a coal bed methane gathering system as a public utility. Jericho is producing roughly 1.6 million cubic feet of CBM on a daily basis, with forecasts of up to approximately 2 million cubic feet in the future. All of Jericho's CBM gas production is purchased by ProLiance Energy[26] and transported via the Heartland Pipeline.[27]

Renewables

Interest in agricultural, organic, and human-generated waste may lead to alternatives to conventional fuels, such as natural gas, fuel oil, and coal. Since sustainable sources of natural gas provide economic and environmental benefits, continued success of these types of projects is important to Indiana's energy future. Indiana has several opportunities for using renewable energy options as an alternative.

Since sustainable sources of natural gas provide economic and environmental benefits, continued success of these types of projects is important to Indiana's energy future.

One source is the creation of methane gas or renewable natural gas (RNG) from the anaerobic digestion of waste from livestock. Another is landfill methane gas (LMG). Since landfills are the largest human-generated source of methane emissions in the United States, the ability to capture

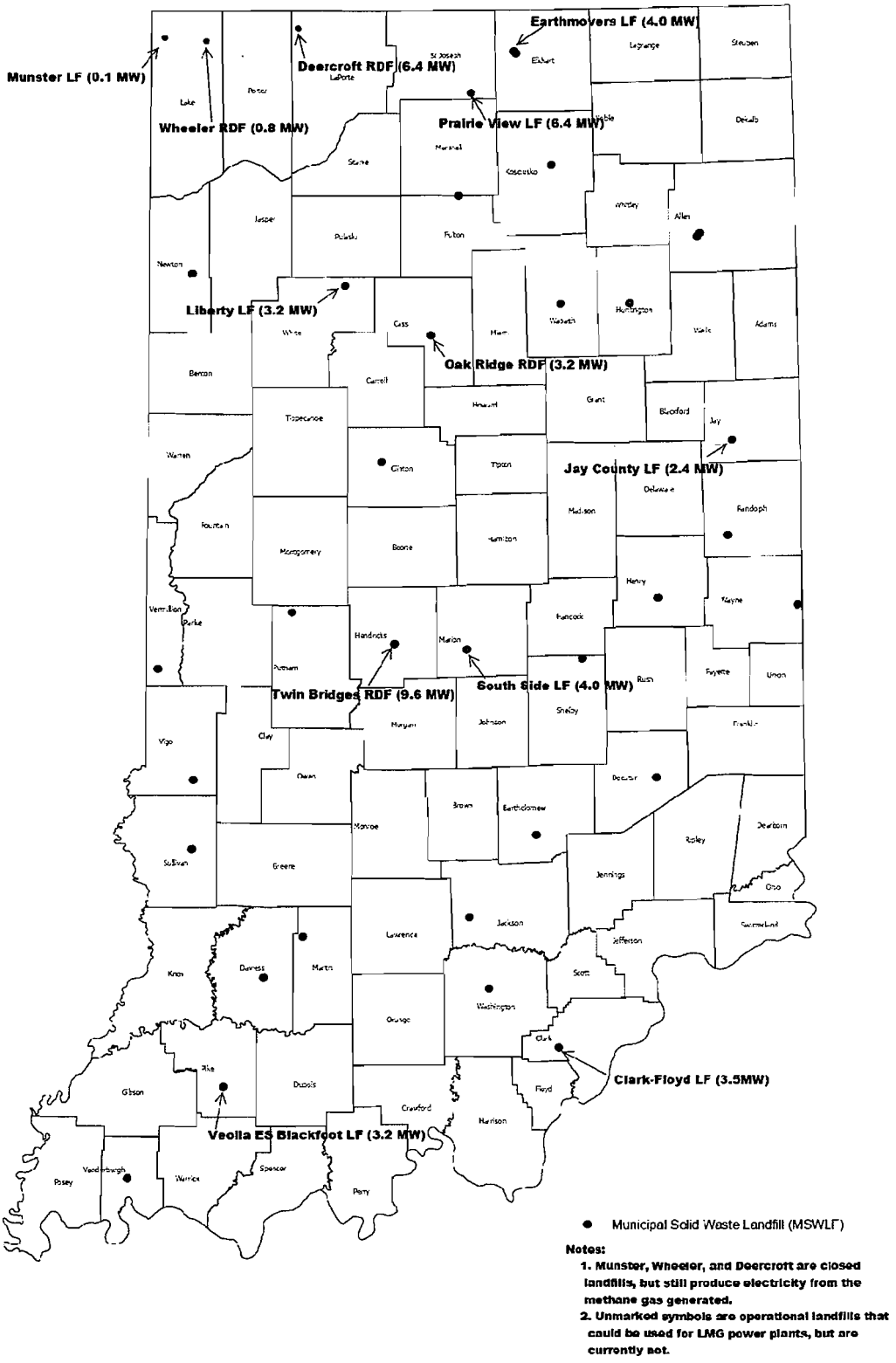
[25]http://waterquality.montana.edu/docs/methane/cbmfaq.shtml#whatiscoalbedmethane
[26]ProLiance Energy is an Indianapolis-based natural gas marketing and supply company.
[27]Order in Cause No. 43500, approved on December 17, 2008

and use this gas has allowed it to grow as a renewable energy resource. Currently, there are 22 operational LMG utilization projects in Indiana, with the potential to develop additional facilities in the future.[28] Map 4 identifies these facilities.

[28]www.epa.gov/lmop/

Map 4

Operational Landfill Methane Gas Utilization Projects in Indiana



Source: Indiana Department of Environmental Management

Energy Efficiency

The federal Energy Independence and Security Act of 2007 (EISA) promotes energy independence in the United States by increasing energy efficiency measures and usage requirements for clean renewable fuels. The "Energy Savings in Government and Public Institutions" requirement affects the Commission by amending the Public Utility Regulatory Policies Act of 1978. The amendment requires natural gas utilities to adopt policies that establish energy efficiency as a priority in their business operations and planning processes. The amendment also requires regulatory agencies to evaluate rate design modifications and provide for the implementation of rate decoupling programs, creation of incentives for utilities to successfully manage energy efficiency programs, and adoption of rate designs promoting energy efficiency in each customer class.

The Commission has issued Orders fulfilling the requirements of the Energy Independence and Security Act of 2007 by approving decoupling and energy efficiency programs.

Utility-sponsored energy efficiency programs are included in most of the approved decoupled rate designs that separate a utility's profits from its sales, while providing for an allowed rate of return.[29] Although rate decoupling by itself does not achieve energy efficiency, it can provide an incentive to pursue energy efficiency programs by allowing gas utilities to advocate conservation efforts without the fear of losing cost recovery due to declining sales.

In response to the EISA, the Commission issued Orders approving decoupling mechanisms and energy efficiency programs.[30] In addition, eight small gas utilities filed a Joint Petition under Cause No. 43995 requesting the creation of a combined energy efficiency program.[31] The Joint

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[29]Decoupling is the separation of a utility's fixed costs from its variable costs. Decoupled rates normally recover fixed costs with fixed charges and variable costs with variable charges (i.e., per therm of gas consumed).
[30]In Cause Nos. 42943 and 43046, the Commission approved an alternative regulatory plan that included a sales reconciliation decoupling mechanism for Vectren North and Vectren South. In Cause No. 43051, the Commission approved an Energy Efficiency Rider and an alternative regulatory plan that simplified residential gas rates for NIPSCO. In Cause No. 42767, the Commission approved an alternative regulatory plan that included a decoupling mechanism and energy efficiency program for Citizens Gas. In Cause No. 43624, the Commission approved an alternative regulatory plan that included an energy efficiency program for Citizen Gas of Westfield.
[31]The Joint Petitioners in Cause No. 43995 include: Midwest Natural Gas Corp.; Indiana Utilities Corp.; South Eastern Indiana Natural Gas Co., Inc.; Fountaintown Gas Co., Inc.; Community Natural Gas Co. Inc.; Boonville Natural Gas Corp.; Indiana Natural Gas Corp.; and Switzerland County Natural Gas Corp., Inc.

Petitioners have also requested approval of funding and a rate decoupling mechanism similar to approvals for Vectren South and Vectren North, under Cause Nos. 42943 and 43046, respectively.

The Commission established independent oversight boards to govern and encourage the energy efficiency programs of the participating LDCs. These oversight boards are comprised of representatives from various energy groups, utilities, state agencies, consumer groups, and educational institutions such as the State Utility Forecasting Group at Purdue University. The oversight board's duties include voting on issues regarding incentive amounts, program offerings, transfers in funding for program offerings, and other operational concerns.

The Commission reviews the programs of each utility through monthly scorecards detailing monthly, year-to-date, and yearly planning goals for therm savings, measures implemented, and budget expenditures. In the near future, the Commission anticipates that various utility programs may consolidate into a single statewide program to allow for economies of scale and significant market influence, which cannot be realized by smaller, individual programs. Additionally, customers may benefit from a unified oversight board due to consistency in program structure, communications, and education efforts throughout the state.

Pricing and Economics

Rates Lowered in NIPSCO Rate Case

All customer classes in the NIPSCO service territory received a modest reduction in their natural gas rates and charges as a result of the Commission's approval of the settlement agreement in the NIPSCO gas rate case on November 4, 2010, under Cause No. 43894. The residential class, specifically, experienced a decrease in rates of roughly $5 million or 3.3% from existing rates.

In the settlement agreement, the parties agreed to an overall rate reduction of 6.13% or $14.8 million and reached a comprehensive agreement that resolved all

In the settlement agreement, the parties agreed to an overall rate reduction of 6.13% or $14.8 million and reached a comprehensive agreement that resolved all issues, including the structure and design of new gas rates for NIPSCO. This is significant in that this was NIPSCO's first gas rate case in approximately 20 years, and all parties agreed to a revenue decrease.

issues, including the structure and design of new gas rates for NIPSCO. The settlement agreement reflects the significant collaboration and compromise inherent in serious negotiations among a diverse group of interests. The parties to the case included: Citizens Action Coalition of Indiana, the Choice Marketer Group, the Industrial Group, and the Office of Utility Consumer Counselor (OUCC). This is significant because it was NIPSCO's first gas rate case in approximately 20 years, and all parties agreed to a revenue decrease.

Additionally, NIPSCO's existing rates were based on a volumetric rate design, with the utility's cost recovery based on the volume of gas sold. The new rates are mostly decoupled, separating the volume of gas sold from the company's recovery of fixed costs. By separating these components, utilities are able to institute a wholesale cultural change to expand their energy efficiency efforts by helping customers find ways to reduce consumption and the cost of their utility bills.

Adjustable Rate Mechanisms

Natural gas utilities incur costs beyond their control (e.g., federal regulations and market price volatility). These costs often occur outside the context of a rate case. In order for natural gas utilities to recover these costs, they petition the Commission for approval of an adjustable rate mechanism, or tracker, for the timely recovery of these costs. The OUCC is involved in these filings as the state agency representing the public or utility ratepayer interests, to ensure the reasonableness of these requests. Before costs are passed along to customers, the OUCC reviews the underlying support for rate adjustments and may provide evidence supporting or contesting the requested rate adjustment in proceedings.

On average, the cost of gas reflected in the GCA mechanism accounts for approximately 70% of a residential customer's bill.

The Commission holds a hearing and reviews the associated costs with the tracker in an expedited manner. A tracker assists in the recovery of costs, which improves the financial health of the utility. The following examples describe authorized trackers available for consideration:

- *Gas Cost Adjustment (GCA)* – Pursuant to statute, the GCA allows a gas utility to recover the commodity cost of gas not recovered through rates established during a rate case.[32] Most regulated natural gas utilities utilize this mechanism.[33]

- *Pipeline Safety Adjustment (PSA)* – The PSA allows the gas utility to recover prudently incurred, incremental non-capital expenses necessary in order to meet the requirements of the Federal Pipeline Safety Improvement Act of 2002, which imposed many new requirements on pipeline operators. Three natural gas utilities utilize the PSA.

- *Energy Efficiency Funding Component (EEFC) & Sales Reconciliation Component (SRC)* – The EEFC funds the promotion of energy efficiency. The SRC allows recovery of expenses from residential and commercial ratepayers that would otherwise be lost due to reductions in revenue caused by energy efficiency programs. Four natural gas utilities utilize these mechanisms.

- *Normal Temperature Adjustment (NTA)* – The NTA reduces the risk of a gas utility not recovering its approved margin due to warmer-than-normal temperatures and mitigates the possibility of over-earning due to colder-than-normal temperatures during the heating season. Sixteen natural gas utilities utilize the NTA.

On average, gas usage (i.e., commodity cost) accounts for approximately 70% of a residential customer's bill; operating costs account for approximately 28%. All other trackers approved by the Commission account for less than 2% of a customer's monthly gas bill. The following table demonstrates this cost analysis.

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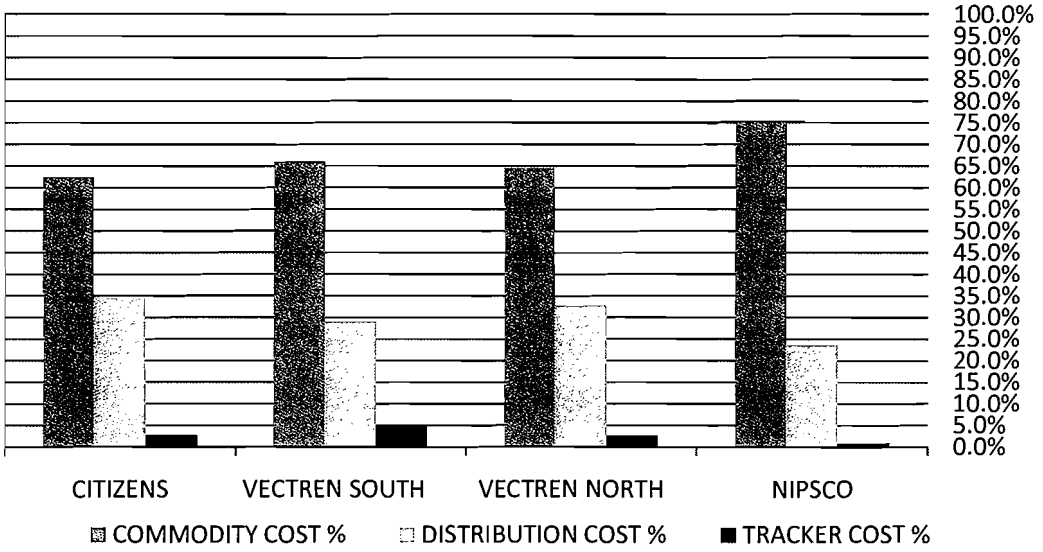
[32] *See*, IC § 8-1-2-42(g)

[33] Snow & Ogden is the only regulated natural gas utility that does not utilize the GCA tracker. Snow & Ogden is a small natural gas utility that receives natural gas from wells they own and operate within the state. Therefore, its gas costs are stable and are built into its base rates.

Table 3

Breakdown of Residential Billing Components for the Four Largest Indiana Gas Utilities



Source: December 2010 Utility Flex Filings

Utilities do not profit from the gas commodity portion of consumers' bills, as the GCA tracker involves a dollar-for-dollar pass-through of the gas cost. The overall weighted cost of gas and a utility's purchasing practices are reviewed by the OUCC before approval by the Commission. For costs to be approved, each utility must demonstrate that its purchases were prudent. Another condition of the GCA is that utilities must incorporate a diversified portfolio mix (i.e., a balance of purchases such as fixed, spot market, and storage gas) to mitigate price volatility and maximize their ability to take advantage of market conditions.

Regulatory Development

Substitute Natural Gas Contract

Coal gasification is a process that converts coal into substitute natural gas (SNG). Given Indiana's vast coal reserves, the prospect of using local coal sources for the production of substitute natural gas is another alternative to importing natural gas into our state. SNG that is produced is of pipeline quality and may be used for home heating, manufacturing facilities, or in the generation of electricity.[34] On March 25, 2009, Governor Daniels signed into law Senate

[34]*See*, IC ch. 4-4-11.6 and modified by IC § 4-4-1.9-1.2

Enrolled Act 423, ultimately codified as IC ch. 4-4-11.6, which directs the Indiana Finance Authority (IFA) to enter into contracts for the sale of SNG with 3rd parties, with net proceeds from and the costs of those sales being reflected on natural gas customers' bills.[35] In addition, IC ch. 4-4-11.6 establishes Commission authority over the allocation of the costs and proceeds from the sale, transportation, and delivery of SNG to retail end-use customers.

Pursuant to IC ch. 4-4-11.6, the Commission has specific responsibilities that include:

- Approving an SNG purchase contract for the IFA;[36]
- Allocating purchased SNG to retail end use customers of regulated utilities;[37]
- Ordering regulated energy utilities to include in rates the cost of the SNG;[38]
- Upon request by the IFA, ordering regulated energy utilities to enter into management contracts for billing and collection of the delivered SNG;[39]
- If the IFA enters into a contract with a 3rd party to sell SNG, ensuring the proceeds and costs of the sales are reflected on each customer's bill of a regulated energy utility;[40] and
- If the IFA sells the SNG to a 3rd party, determining a just and reasonable method for allocating the credits and charges to retail end use customers.[41]

Furthermore, the SNG purchase contract presented to the Commission must contain specific components. The contract must be entered into between the IFA and a producer of SNG. The contract must contain a 30-year term that guarantees savings for retail end use customers. Finally, the contract may contain any terms or conditions determined necessary by the IFA.

The IFA and Indiana Gasification, LLC (IG) petitioned the Commission on December 16, 2010 under Cause No. 43976 for the following:

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[35] P.L. 113-2010
[36] IC § 4-4-11.6-14
[37] IC § 4-4-11.6-18
[38] IC § 4-4-11.6-19
[39] IC § 4-4-11.6-22
[40] IC § 4-4-11.6-30
[41] IC § 4-4-11.6-30(c)(5).

1. Approval of an SNG purchase and sales agreement between the IFA and IG;

2. If necessary, for the Commission to order Indiana regulated energy utilities to enter into a management agreement with the IFA; and

3. For the Commission to decline jurisdiction over IG.

In addition, the IFA and IG requested expedited treatment of the Petition. Prior to the evidentiary hearings, the Commission provided the public with an opportunity to voice its opinion on the proposed SNG facility, holding three separate field hearings in Jasper, West Lafayette, and Indianapolis. The Commission then began its evidentiary hearing on May 2, 2011. The case is still pending before the Commission, as of the printing of this report.

Universal Service Programs

The Commission's Order in Cause No. 43669 authorized Citizens Gas, NIPSCO, Vectren North, and Vectren South to reinstate their respective bill assistance programs to provide Hoosiers in need with assistance during the winter heating season. The Commission categorizes the individual utility programs under the term "Universal Service Program" (USP). In order for these programs to continue beyond October 31, 2012, each utility must file a base rate case requesting relief that includes the assistance program. The timeframe provides the Commission with an opportunity to further examine the programs' costs and benefits. Currently, the programs are designed to encourage customers qualifying for USP assistance to also apply for American Recovery and Reinvestment Act weatherization assistance program funds.

LIHEAP Funding

There are two forms of LIHEAP assistance funding available. States can apply for a block grant, which is a formula, established by Congress that determines the amount of money distributed to a State based on weather and its low-income population.

States are also eligible to receive contingency funds, which is money the President releases to help with energy needs based on an emergency. Usually, an emergency is related to extreme weather or dramatic energy price spikes.

Federal funds are also available through the Low Income Home Energy Assistance Program (LIHEAP), a social service program established in 1981. Congressional appropriations fund the program annually. LIHEAP's mission is to help low-income households meet the costs of their home

energy needs, as they pay a higher percentage of their household income for it. An eligible applicant's household income must not exceed 150% of the poverty level or 60% of the state's median income.[42] In Indiana, a family of four at the 150% poverty level has a household income not exceeding $33,075.[43]

Congress appropriated $4.9 billion for LIHEAP funding consisting of $4.5 billion[44] in block grants and an additional $490 million[45] in emergency funds during the fiscal year 2010. Of this, Indiana received approximately $117.5 million in LIHEAP funding. This total consisted of $104.1 million in block grant funds and $13.4 million in emergency funds.[46] Indiana had approximately 730,000 households eligible for LIHEAP financial assistance in fiscal year 2010, of which about 197,800 households received assistance. The average assistance to eligible Indiana households was roughly $420.

Currently, available funding for the fiscal year 2012 may decrease under the proposed federal budget, and one of the funding areas reduced is LIHEAP. The 2012 proposed budget provides $2.57 billion in funding, which includes $1.98 billion in base grants and $590 million in emergency funds. This proposed funding level is comparable to the 2008 LIHEAP funding level.

San Bruno Report & Indiana's Risk-Based Assessments

Despite the nation's overall excellent pipeline safety record, recent pipeline incidents in California, Michigan, Pennsylvania, and other locations have elevated the awareness of stakeholders and the public to the potential dangers of natural gas and hazardous liquid pipelines across the country. It has also prompted the IURC's Pipeline Safety Division to closely monitor the findings of the incidents, especially the one in San Bruno, California.

On August 30, 2011, the National Transportation Safety Board (NTSB) issued a report about the rupture of a 30" pipeline in San Bruno, California in September 2009.[47] The report stated that the rupture "...was caused by a fracture that originated in the partially welded longitudinal seam

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[42]www.acf.hhs.gov/programs/ocs/liheap/about/factsheet.html
[43]www.liheap.org
[44]www.liheap.ncat.org/Funding/funding.htm
[45]www.acf.hhs.gov/programs/ocs/liheap/funding/emergency10.html
[46]Indiana Housing and Community Development Authority data
[47]http://www.ntsb.gov/investigations/2010/sanbruno_ca.html

of one of six short pipe sections…" that "…would have been visible when it was installed…" in 1956. This means that the failed section was faulty when installed, and over time the fracture grew until it failed completely.

The NTSB found fault in Pacific Gas & Electric's (PG&E) pipeline integrity management program, indicating that procedures should have been written and carried out to identify and remove the threat of the faulty pipe. The NTSB also "determined that the California Public Utilities Commission failed to detect the inadequacies in PG&E's integrity management program and that the Pipeline and Hazardous Materials Safety Administration integrity management inspection protocols need improvement."

The NTSB's report focused on such matters as inadequate records, weak regulations (specifically a provision in the pipeline safety laws that grandfathered pipeline systems installed prior to 1971 from having all installed pipe pressure tested before placing it in service), and a lack of oversight – on the part of the California Public Utilities Commission over PG&E and on the part of PHMSA over the state's pipeline safety program. In response to the incident, the California Public Utilities Commission ordered all operators to pressure test any and all transmission pipeline systems in the absence of documentation that verifies a test had occurred and also effectively removed the grandfather clause for pipelines installed prior to 1971.

IURC Pipeline Safety Engineers are actively reviewing historical records to verify that pipeline system segments were pressure tested prior to being placed in service. Starting in 2009, the Pipeline Safety Division began to review and verify operators' written pipeline integrity procedures, including operations and maintenance. Follow-up integrity program inspections are also conducted for all transmission operators to determine how an operator identifies high consequence areas. The Pipeline Safety Division plans to review the entire inspection form to determine the value in expanding the inspections.

The IURC's Pipeline Safety Division has also moved to a risk-based assessment of the intrastate natural gas operators to identify, prioritize and correct any vulnerable pipelines. Indiana's risk-based assessment of operators and pipelines is data driven, not calendar driven (i.e., the physical characteristics of the pipe and its surroundings are assessed). The assessment of threats to an operator's pipeline (transmission or distribution) includes an analysis

of the type and age of pipe in the system; inspection of installation/operation procedures; inspection of material or welds; and analysis of any leaks due to corrosion, natural forces, excavation, or other damage from outside forces. An operator may be subject to more frequent inspections due its heightened risk based on the data gathered. Should an infraction of state or federal pipeline safety law be discovered, the operator can expect the violation to be dealt with firmly, but fairly by the IURC.

Depth Study

In 2009, the General Assembly mandated a report for best practices concerning the vertical location of underground facilities for purposes of IC ch. 8-1-26. Therefore, this section of the Report addresses the viability and economic feasibility of technologies used to locate underground facilities.

The Common Ground Alliance (CGA) is a member-driven association dedicated to public safety, environmental safety, and prevention of damage to underground facilities. In 1999, the CGA completed a study sponsored by the U.S. Department of Transportation identifying the best practices regarding damage prevention. The CGA recommends hand digging or soft digging within an 18-inch tolerance on each side of the underground facilities. Vacuum digging, the use of high-pressure water or air that breaks up the soil accompanied by a powerful vacuum that removes the loosened soil, is an acceptable alternative identified by CGA.[48]

GPR and EM equipment provides depth estimates and underground facility locates but equipment manufacturers do not guarantee depth readings.

Ground Penetrating Radar (GPR) and Electromagnetic (EM) instruments are technologies available to locate underground equipment. The costs of these instruments range from $15,000 to $18,000 for GPR equipment, while EM equipment ranges from $2,000 to $8,000. GPR and EM equipment provide depth estimates and underground facility locates, but equipment manufacturers do *not* guarantee depth readings. The CGA, equipment manufacturers, and Pipeline Safety all strongly recommend hand-digging or vacuum excavation to expose underground pipe for visual verification. This is the safest means to accurately determine the true

[48]www.subtronic.com

depth and location of underground facilities and the only acceptable means an excavator can use to comply with IC ch. 8-1-26. The Pipeline Safety Division hopes that in the near future, lawmakers will consider requiring all operators of locate equipment to be certified by an accredited organization in order to better protect underground facilities.

III. NATURAL GAS APPENDICES

Appendix A – Jurisdictional Gas Utility Revenues

Rank	Utility Name	Operating Revenues*	% of Total Revenues
1	Northern Indiana Public Service Company	$ 717,138,055	36.82%
2	Vectren North	624,300,165	32.05%
3	Citizens Gas (Municipal)	320,682,072	16.47%
4	Vectren South	106,754,683	5.48%
5	Northern Indiana Fuel & Light Company, Inc.**	38,810,679	1.99%
6	Kokomo Gas and Fuel Company**	35,355,429	1.82%
7	Ohio Valley Gas Corporation	30,268,156	1.55%
8	Midwest Natural Gas Corporation	16,636,985	0.85%
9	Sycamore Gas Company (f/k/a Lawrenceburg Gas Co.)	10,299,146	0.53%
10	Indiana Natural Gas Corp.	8,569,931	0.44%
11	Community Natural Gas Co., Inc.	7,465,405	0.38%
12	Boonville Natural Gas Corporation	6,571,572	0.34%
13	Indiana Utilities Corporation	5,774,094	0.30%
14	Ohio Valley Gas, Inc.	4,803,277	0.25%
15	Citizens Gas of Westfield	4,362,035	0.22%
16	Fountaintown Gas Co., Inc.	3,981,502	0.20%
17	Aurora Municipal Gas (Municipal)	2,343,881	0.12%
18	South Eastern Indiana Natural Gas Company, Inc.	1,697,174	0.09%
19	Switzerland County Natural Gas Co., Inc.	1,408,994	0.07%
20	Valley Rural Utility (Not for profit)	364,175	0.02%
21	Snow & Ogden	15,239	<0.01%
	Total Revenue	$ 1,947,603,649	100.00%

*Year ending December 31, 2010

**Recently Kokomo and NIFL merged with NIPSCO, with NIPSCO being the surviving company.

Appendix B – Jurisdiction over Municipal Gas Utilities

Municipal Utilities under the IURC's Jurisdiction		
Aurora	Citizens Gas	

Municipal Utilities Withdrawn from the IURC's Jurisdiction (IC § 8-1.5-3-9)		
Bainbridge	Jasper	Osgood
Batesville	Lapel	Pittsboro
Chrisney	Linton	Poseyville
Grandview	Montezuma	Rensselaer
Huntingburg	Napoleon	Roachdale
Jasonville	New Harmony	

Appendix C – Jurisdiction over Investor-Owned Gas Utilities

Investor-Owned Utilities under the IURC's Jurisdiction	
Boonville Natural Gas Corporation	Ohio Valley Gas Corporation
Community Natural Gas Company, Inc.	Ohio Valley Gas, Inc.
Citizens Gas of Westfield	Snow and Ogden Gas Company, Inc.
Fountaintown Gas Company, Inc.	South Eastern Indiana Natural Gas Company, Inc.
Indiana Natural Gas Corporation	Switzerland County Natural Gas Company
Indiana Utilities Corporation	Valley Rural Utility Company
Lawrenceburg Gas Company	Vectren North
Midwest Natural Gas Corporation	Vectren South
Northern Indiana Public Service Company	

2011 Water/Wastewater Report

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I. WATER/WASTEWATER OVERVIEW

Industry Structure

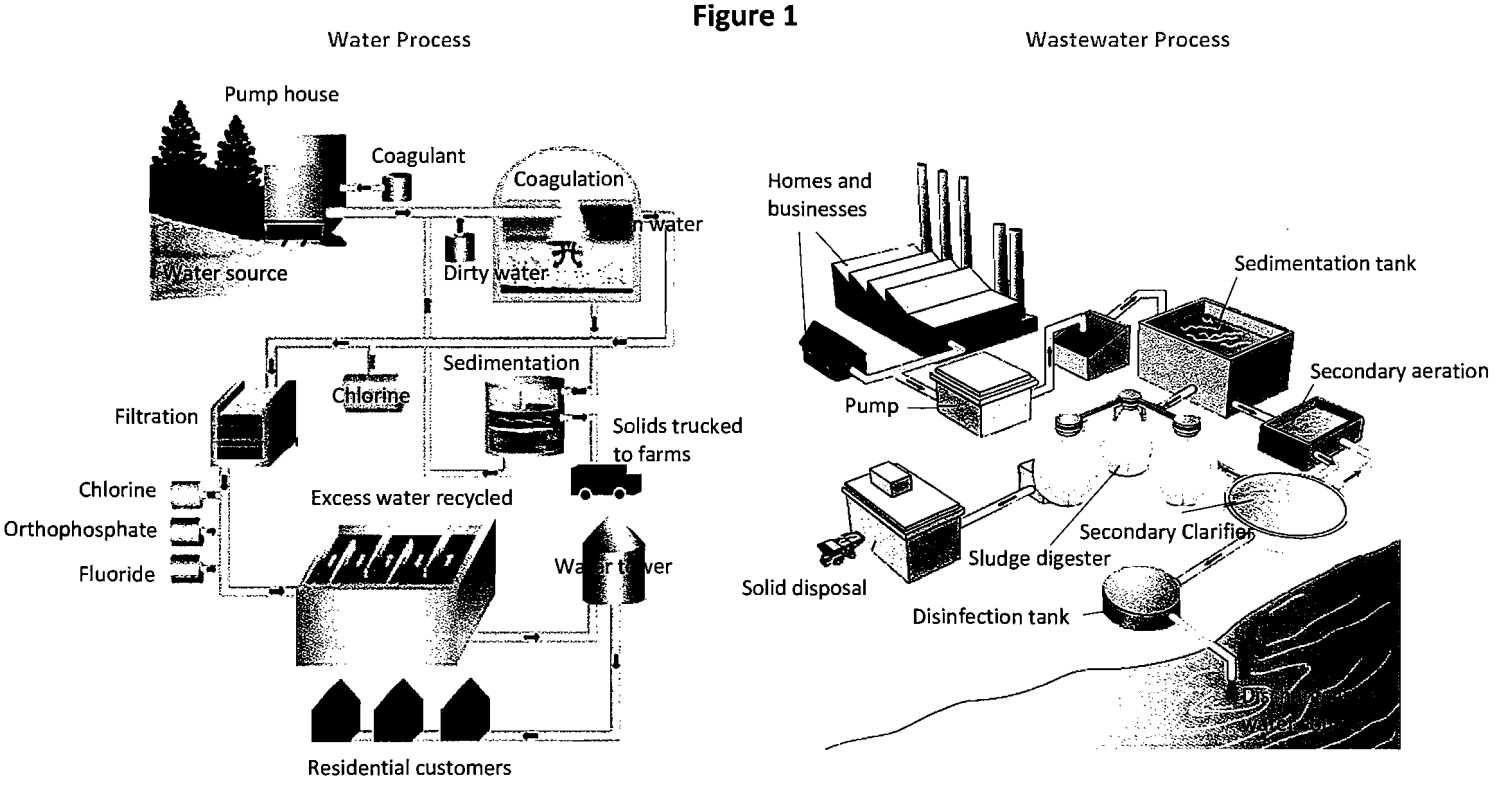
There are many utilities providing water and wastewater service to Hoosiers, taking on one of several legal forms. These legal forms include: investor-owned utilities, municipal utilities, not-for-profit utilities, regional water/wastewater districts, water authorities, and conservancy districts. The Indiana Utility Regulatory Commission (Commission or IURC) is the economic regulator over certain types of these entities, while the Indiana Department of Environmental Management (IDEM) is the water quality regulator.

The legal form of a utility determines whether the utility is subject to the Commission's jurisdiction and the extent of the Commission's regulatory oversight.

Process

Before water is ready for retail use, it usually must be treated to make it potable. Similarly, wastewater must be treated before it can be released back into a water source. Both processes are shown in Chart 1.

Figure 1



Regulatory Structure

According to the Commission's data and that of the IDEM, the Commission regulates approximately 104 of the 824 water utilities and 47 of the 531 wastewater utilities. Although the Commission only regulates and has partial oversight over a fraction of the state's water utilities, those who are regulated serve approximately 90% of Indiana's water consumers. This is because numerous small systems serve a relatively small percentage of the population, while a small number of larger systems serve the majority of the population. Because the Commission does not regulate municipal wastewater systems and most investor-owned wastewater utilities are small, the percentage of wastewater customers under Commission jurisdiction is low. Of the regulated wastewater utilities, only two serve more than 5,000 customers: Hamilton Southeastern Utilities, Inc. with 17,670 customers and Utility Center, Inc. with 11,908 customers.

The regulated water systems have $3.7 billion of utility plant in service, annual revenues of $493 million, and a total rate base of $2.2 billion. The regulated wastewater utilities have $199.1 million of utility plant in service, annual revenues of $29.0 million, and a total rate base of $84.1 million. As promulgated in state law, certain utilities have the option to withdraw from regulation. Table 1 shows the number of water/wastewater utilities that have withdrawn (Appendices C and D list the withdrawn utilities).

Table 1

Water/Wastewater Utilites Withdrawn From Commission Jurisdiction

Type of Utility	Number
Municipal Water	358
Not-For-Profit Water	51
Investor-Owned Water	1
Not-For-Profit Wastewater	11
Investor-Owned Wastewater	4
Not-For-Profit Water/Wastewater	14
Investor-Owned Water/Wastewater	1

The legal form of a utility determines the existence and extent of the Commission's regulation. Table 2 details some of the IURC's jurisdiction and shows which utilities the agency generally does not regulate with regard to rates and charges or rules and regulations.

Table 2

Commission Jurisdiction over Water/Wastewater Utilities

Type of Utility	Rates and Charges	Rules and Regulations	Ability to Withdraw from Jurisdiction	No Jurisdiction	CTA
Investor-Owned Water*	✓	✓	✓		
Investor-Owned Sewer*	✓	✓	✓		✓
Not-for-Profit Water	✓	✓	✓		
Not-for-Profit Sewer	✓	✓	✓		
Municipal Water	✓		✓		
Municipal Sewer				✓	
Regional Water District				✓	
Regional Sewer District				✓	
Conservancy Water District**	✓		✓		
Conservancy Sewer District				✓	

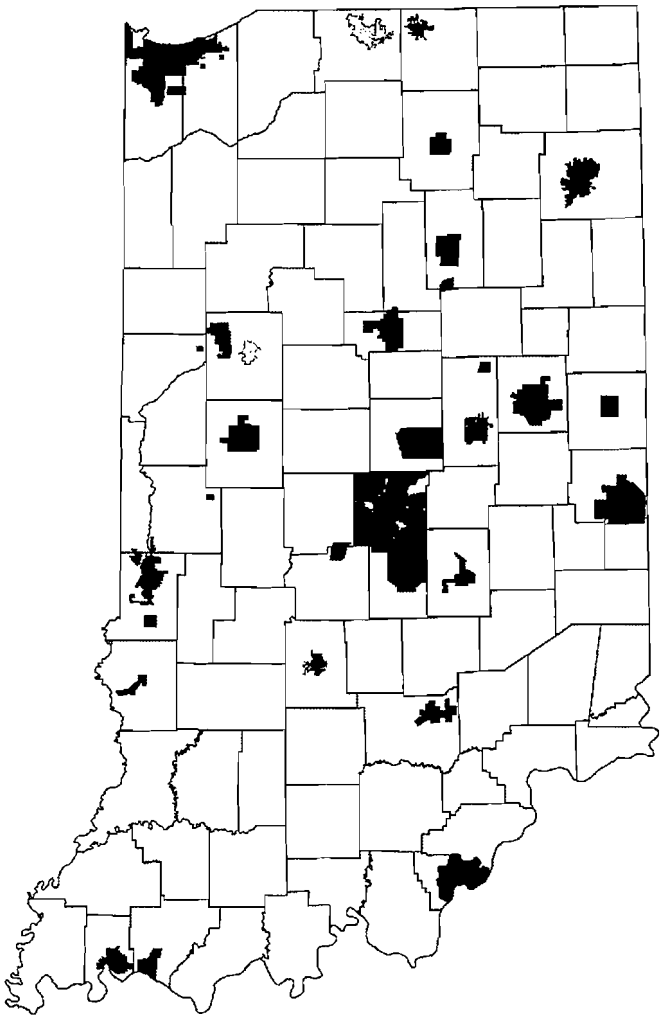
* Investor-owned water and sewer utilities with 300 customers or less can opt out of the IURC's jurisdiction, per IC § 8-1-2.7-1.3.
** Water conservancy districts with fewer than 2,000 customers can opt out of the IURC's jurisdiction, per IC § 8-1-2.7-1.3.

Small utilities, those with 300 customers or less, can opt out of the Commission's jurisdiction. Because smaller utilities have less expertise to manage their systems, they are often times the most problematic and "troubled." Though the Commission has training and programs in place to help these utilities, it remains a challenging issue for the Commission. The steps taken by the agency to address this issue are further discussed on page 95.

Map 1 shows the 11 largest regulated water utilities based on the 2009 Annual Reports. As the map shows, these utilities provide service to more densely-populated areas.

Map 1

Largest Regulated Water Utilities and the Number of Customers



- Indianapolis Water - 298,678
- Indiana American Water - 279,257
- Fort Wayne Municipal Water - 78,769
- Evansville Municipal Water - 60,722
- South Bend Municipal Water - 41,931
- Elkhart Municipal Water - 35,100
- Lafayette Municipal Water - 28,260
- Hammond Municipal Water - 26,405
- Bloomington Municipal Water - 22,961
- Anderson Municipal Water - 22,049
- Mishawaka Municipal Water - 14,898

Source: 2009 Commission Annual Reports
Note: Fire protection customers and interdepartmental sales have been removed; municipal systems are based on city boundaries and may not represent the actual service territory.

Acquisition and Consolidation

Acquisitions and consolidations can take many forms, but the most prevalent are investor-owned utilities buying smaller investor-owned utilities, investor-owned utilities buying municipal systems, and municipalities buying investor-owned systems. Over the last nine years, the pace of mergers and acquisitions by investor-owned utilities has slowed significantly as the most attractive utilities have been acquired; however, transaction proposals are still taking place.

- Municipalization -

The practice of municipalities taking over investor-owned systems, commonly referred to as municipalization, has been aided by a recent Indiana Supreme Court decision. The City of Fort Wayne completed its acquisition of a large portion of Utility Center, Inc.'s system by initiating a condemnation proceeding in civil court, which was an action later affirmed by the Indiana Supreme Court.[1] Condemnation is a legal proceeding, whereby a municipality exercises its power of eminent domain and condemns utility property that results in the transfer of utility property to the municipality. In its decision, the Supreme Court held that under IC §§ 8-1-2-92 and 8-1-2-93, an investor-owned utility's license, permit, and franchise are conditioned on the ability of municipalities to purchase utility property.

Recent acquisitions have raised issues of asset valuation and rates for existing customers.

Recent utility transfers have highlighted several issues of particular concern for the Commission. One issue is determining the fair value of the property to effect a change in ownership. Without accurate accounting records of the municipality's assets, it is difficult to accurately determine the fair value of the assets. Even when the accounting records are accurate, there may be a conflict between Indiana statutes that explains how the price is determined for the assets and what the Commission sets as the fair value. Under IC § 8-1.5-2-6(b), municipal assets may not be sold for less than their full appraised value; however, the Commission must adhere to IC § 8-1-2-6, which disallows Contributions in Aid of Construction (CIAC) in determining the

[1]*See, Utility Center, Inc. v. Fort Wayne*, 868 N.E.2d 453 (Ind. 2007)

fair value.[2] In some cases, appraisers do not eliminate all utility plant that has been contributed by developers or was funded by a government grant.

Another issue rests with the determination of whether the customers acquired through the condemnation process should be required to pay more for water than existing customers. Although there is a general lack of consensus on these issues among policymakers, the Indiana General Assembly remedied one aspect of the condemnation matter. Going forward, when a municipality condemns the property of a public utility, all customers shall bear the costs associated with the condemnation process through their normal rates and charges.[3]

- Unique Transfer: City of Indianapolis to Citizens Energy Group -

In August 2010, the City of Indianapolis and Citizens Energy Group (Citizens) petitioned the Commission to transfer the city's water and wastewater systems to Citizens and place both utilities under the Commission's jurisdiction.[4] Then on April 12, 2011, the City of Indianapolis and Citizens submitted a settlement agreement reached with the OUCC, industrial customers, and the Service Advisory Board. The key components of the settlement agreement are as follows:

- Wastewater rates will increase 10.75% in 2012 and 2013, while water rates will remain unchanged.
- Citizens will adopt the water rates approved by Commission for Indianapolis' Department of Waterworks in Cause No. 43645.
- Citizens will document its savings for four years from the date of closing.

On July 13, 2011 the Commission approved Citizens Energy Group's acquisition of the city of Indianapolis' water and wastewater utilities. This is the first wastewater system of Indiana's 108 combined sewer systems under Commission jurisdiction.

Upon approval of the acquisition by the Commission, the wastewater system became the first of Indiana's 108 combined sewer systems under Commission jurisdiction. A combined sewer

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[2]CIAC is utility plant that was not funded by the utility such as plant contributed by a developer or obtained as part of a government grant.
[3]*See,* IC § 8-1.5-3-8 (eff. July, 2009)
[4]Cause No. 43936

system directs wastewater and stormwater to flow into a single pipe. The discharge into a body of water is called combined sewer overflow (CSO).

Age Profile

One of the most problematic issues in the water industry is the age of the infrastructure.[5] Water systems are comprised of wells (for groundwater), treatment facilities, water tanks, and distribution systems. Distribution systems are composed of the pipes, valves, and pumps through which water is moved from the treatment plant or water tanks to end users. Throughout Indiana, pipes range widely in their age and material. Many older systems, built during the turn of the last century, consist of cast iron (CI) and wood piping that would not be used today.

Many of Indiana's oldest communities are experiencing increased main breaks in CI pipe, as the distribution system ages. Distribution system piping manufactured and installed during the growth periods of the 1940s and early 1950s are particularly vulnerable due to common use of a thinner pipe wall and utilization of "gray iron." This particular generation of CI has become more brittle with age and is beginning to fail under varied operating pressures. Further, deterioration can be aggravated in piping that was installed in highly corrosive soils from that era. As this generation of piping requires replacement, our oldest and largest communities are hit the hardest financially, because these pipes constitute the majority of the distribution system.

Newer systems rely on polyvinyl chloride (PVC), high-density polyethylene (HDPE) and ductile iron (DI) piping. Although the materials used in modern pipe manufacturing should be far superior, some materials are unquestionably thinner and cheaper than their predecessors. This places more emphasis on ground conditions and proper installation in attaining the desired longevity of the infrastructure. Modern plastic pipe such as PVC and HDPE have very good corrosion resistance properties but generally have very weak structural properties. In many cases, utilities may prefer a structurally stronger pipe such as DI at a greater material cost to mitigate the risk associated with installation errors.

While pipe design is easy to control and monitor, the underground construction must be closely monitored to ensure that the specified bedding material is being used in appropriate

[5]Infrastructure needs and costs are detailed on pg. 89.

quantities and is being properly bedded. Unlike other materials, PVC piping is subject to ultra-violet degradation, which may compromise the pipe if improperly stored. Improperly installed pipe is often subject to rapid failure and can compromise the road, sidewalk or other covering and adjacent underground infrastructure. Utility owners must monitor the installation of pipe closely, often requiring full-time construction inspection.

Demand and Supply

Water Usage

Although the United States uses more water per capita than any other country, the amount of water consumed per customer has been declining. American Water, the holding company for Indiana American Water, published a study in May 2011 about seven states, including Indiana, and found that monthly residential sales per customer decreased 1.21% per year from 2000 to 2009, which is an annual decline of 913 gallons/customer/year.[6] The decline can be attributed to the following factors:

- Increased use of water efficient appliances;
- Low water use landscaping;
- Utility water efficiency programs;
- Rate structures penalizing higher consumption; and
- The general increase in water rates.

However, water shortages are still a serious issue for many areas throughout the U.S. and occasionally affect parts of Indiana when low rainfall causes drought conditions. For example, in October 2010 after a prolonged drought, the Indiana Department of Homeland Security and the Indiana Department of Natural Resources issued a "water shortage warning" for much of southern Indiana where public water systems were requested to reduce water use by 10 to 15%. It was lifted following recovery by precipitation.

Water Conservation

American Water, the holding company for Indiana American Water Inc., conducted a study of seven states, including Indiana, and found that monthly residential sales per customer decreased 1.21% per year from 2000 to 2009, which is an annual decline of 913 gallons/customer/year.

[6] "Declining Residential Water Use Presents Challenges, Opportunities," Opflow, Vol. 37, No. 5, pgs. 18-20.

Although per capita consumption may be decreasing, levels of supply can still be strained. Therefore, conservation efforts and per capita decreases will be important components in meeting future supply needs.

New Sources of Supply/Enhanced Reliability

Maintaining quality ground and surface water is critical, because contaminated water cannot be considered a resource. In Indiana, much of the water supply comes from underground water bearing permeable rock formations called aquifers, which utilities tap into by digging wells. To increase the reliability of water from rivers, reservoirs are constructed. Reservoirs play an important role in water treatment, because they allow time for particles to settle and provide early-stage natural biological treatment. Although not a natural resource, water tanks also play an important role as a source of backup supply due to their ability to help maintain sufficient water pressure in systems for potable water and fire suppression. Not every water utility in Indiana has its own source of supply. Based on the Commission's Annual Reports, 15% of the Commission-regulated water utilities share source of supply infrastructure through wholesale purchase agreements.

Legal and Policy Foundations

Water and Wastewater Quality

Utilities that provide drinking water and treat wastewater are subject to federal regulations. Water quality regulation falls under the Safe Drinking Water Act (SDWA), passed in 1974 and amended in 1996;[7] whereas, wastewater regulation falls under the Federal Water Pollution Control Act or Clean Water Act (CWA), most recently amended in 1987.[8] The U.S. Environmental Protection Agency (U.S. EPA) is the primary federal agency that implements these regulations, while the IDEM is delegated enforcement and has some implementation authority.[9]

Water quality standards are two-fold: 1) health-related (focusing on inorganic and organic chemicals and microorganisms); and 2) aesthetics (focusing on taste, odor, and appearance). These

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[7]*See,* 42 U.S.C. §§ 300f to 300j-26
[8]*See,* 33 U.S.C. §§ 1251-1387
[9]To the extent that wastewater treatment is provided by a septic system or constructed wetland, the Indiana State Department of Health is the jurisdictional agency.

standards are developed by setting a maximum contaminant level and a maximum contaminant level goal, both of which are periodically updated. For example, based on the U.S. EPA's Groundwater Rule, the IDEM now requires increased monitoring to detect viral and bacterial contamination in ground water sources of drinking water.

In recent years, Indiana utilities have incurred costs associated with maintaining and improving their systems, and these costs are expected to keep increasing as new rules are approved. Examples of several new or pending U.S. EPA rules are provided below:

- Total coliform rule (final revisions are expected to be published in the summer of 2012)
- Evaluation of selected contaminants for further regulation under the SDWA (final determination is expected by 2013)
- New analytical methods to test for certain contaminants (approved in June 2011)
- Perchlorate rule (final rule expected by 2015)

The water quality standards, which are enforced by the IDEM, are two-fold: health-related, focusing on inorganic and organic chemicals and microorganisms; and aesthetics, focusing on taste, odor, and appearance.

Several wastewater utilities under the Commission's jurisdiction have also been required to invest in their systems due to consent decrees, which were issued due to violations of the CWA. Because infrastructure improvements may be required, customer rates could be impacted. However, before the costs can be passed on to consumers, projects are subject to IURC approval and review by the Office of Utility Consumer Counselor.

II. WATER/WASTEWATER LANDSCAPE

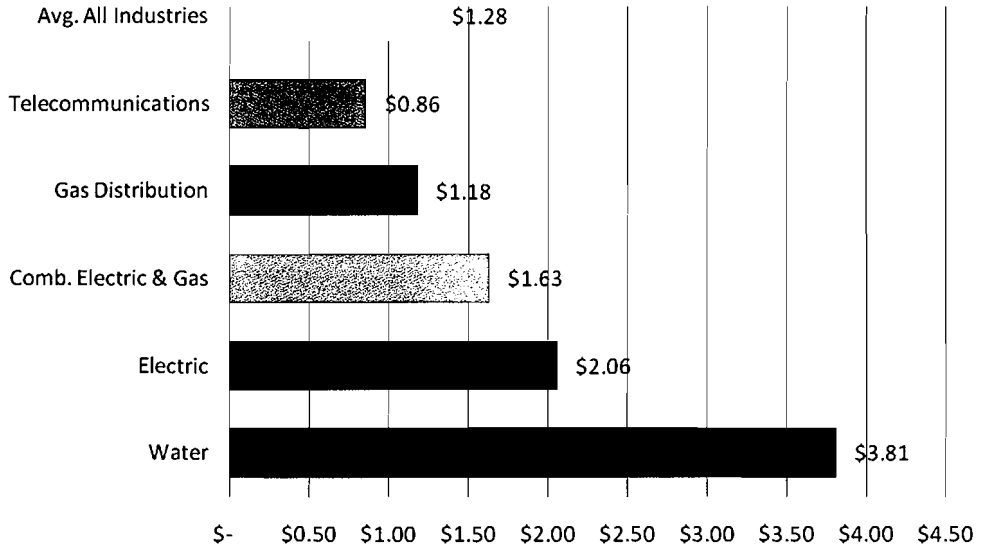
Infrastructure

To prosper economically, Indiana communities need safe, reliable and affordable water and wastewater systems. However, a funding shortfall in Indiana exists due to the need to replace aging infrastructure and its attendant high capital requirements, as much of the United States' drinking water and wastewater infrastructure was built shortly following World War II.

A significant portion of this infrastructure has aged and will need full-scale replacement over the next few decades. This is problematic because the water sector remains extremely capital intensive, investing more capital per dollar of revenue generated than any other industry, as demonstrated in Chart 1. The need for such large investment is due to high capital costs and relatively low revenues. Consequently, water utilities are increasing general rates and exploring other ways to increase revenues.

Chart 1

Capital Invested per Dollar of Revenue



Source: AUS Utility Reports – 2010

Projected Infrastructure Costs

The Indiana Advisory Commission on Intergovernmental Relations issued its most current report, titled "Financial Needs for Wastewater and Water Infrastructure in Indiana," in 2003. It estimated that the statewide wastewater and drinking water infrastructure needs for the period 2000 to 2020 will require $12.4 to $13.9 billion. Several of the recommended projects include: correction of CSOs, wastewater conveyance and

The water sector remains extremely capital intensive due to high costs and relatively low revenues; investing more capital per dollar of revenue generated than any other industry.

treatment, remediation of failing septic systems, storm water conveyance and management, drinking water production, and construction or renovation of treatment and distribution facilities.

Funding Programs

Though numerous federal and state funding options are available for infrastructure investment, it is not enough to cover the infrastructure needs. Annual investments made by governmental entities between January 1990 and March 2002 were approximately $253 million, far short of the estimated $658 million investment needed annually to meet the needs identified in this report. Grants from the U.S. EPA are leveraged in bond markets to generate State Revolving Loan Fund (SRF) proceeds. The Indiana Finance Authority (IFA) then administers these funds through low-interest loans at 20-year terms to investor-owned, municipal and not-for-profit utilities. Based on the Drinking Water and Clean Water 2010 Annual Reports, the Drinking Water SRF (DWSRF) Loan Program closed 35 loans for Indiana utilities, totaling approximately $80 million in state fiscal year 2010. Treatment infrastructure projects accounted for 60% of the projects, while transmission and distribution infrastructure projects accounted for 18.5%. The Clean Water SRF Loan Program in Indiana closed 63 loans totaling approximately $376 million.

Loans and grants are available for utility infrastructure investment through the State Revolving Loan Fund, Rural Development Loans and Grants, and the Community Focus Fund.

Rural Development Loans and Grants are also available to assist rural areas and towns serving a population of less than 10,000. Extended 40-year terms are available at or below market interest rates, depending on community demographics. As part of this program, Indiana water/wastewater utilities received approximately $53 million in loans and $9 million in grants, of which approximately $13 million in loans were made to Commission-regulated utilities.[10]

Grants for planning and up to 75% of project costs are another option. These planning and construction grants are available to non-entitlement cities,[11] towns, or counties through the Community Focus Fund, which is administered through the Indiana Office of Community and

[10]American Recovery and Reinvestment Act of 2009 funds were not included.
[11]Non-entitlement cities must go through a state-funding program instead of receiving funds directly from the federal government.

Rural Affairs (OCRA). Out of the more than 200 grant issuances made by OCRA during 2010, two Commission-regulated water systems were beneficiaries of approximately $5.8 million of the approximate $90 million granted by this state agency. Over three-fourths of funds issued were the result of federal funding received to aid in economic recovery due to several natural disasters that occurred throughout the state during 2008.

Although the amount of SRF funding to investor-owned and not-for-profit utilities is limited, other options are available. For example, another avenue to obtain low-interest rate loans is private activity bonds (PABs), which are municipal bonds issued to finance facilities for investor-owned or not-for-profit water utilities.[12] The benefits of reduced financing costs go directly to utility customers, rather than to the shareholders, owners, or parent companies. The federal government sets the overall loan volume cap for each state and then allocates that amount based on a formula.[13]

Under the current federal rules for the funding process, investor-owned and not-for-profit utilities are disadvantaged, because they have limited access to low-cost debt. Without access to low-cost debt, costs to serve those customers increase despite the fact that all customers pay federal income tax to support the funding programs. To gain access to additional SRF funding, several not-for-profit utilities have converted to water authorities to avoid the volume cap for PABs. The National Association of Regulatory Utility Commissioners and the National Association of Water Companies support federal legislation to lift the ban on wastewater utilities and to remove water projects from the volume cap. In 2010 the U.S. House of Representatives passed such legislation several times and in May 2011, two U.S. Senators sponsored the Water Infrastructure Investment Act of 2011 that provides such relief.

Under the current funding regime, investor-owned and not-for-profit utilities are discriminated against, because they have limited access to low-cost debt.

[12]PABs are not available to private wastewater utilities.
[13]*See,* IC ch. 4-4-11.5

Pricing and Economics

Rate Increases

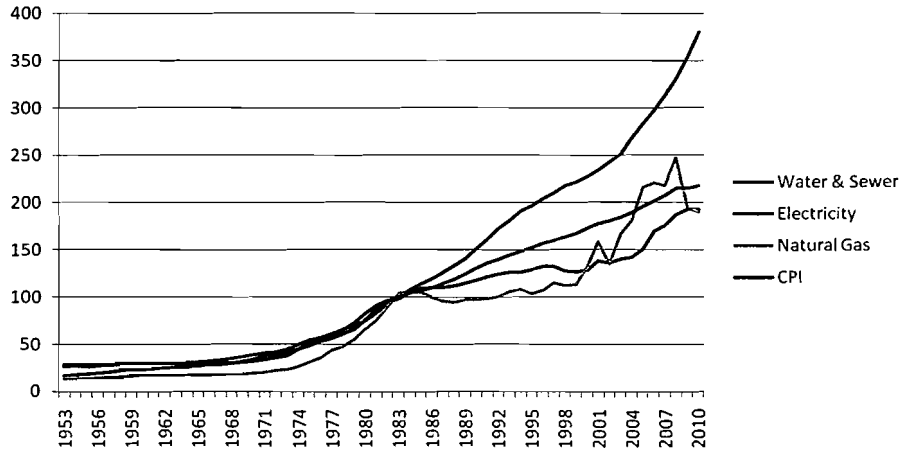
Increasing costs for water and wastewater utilities are driven by the need for replacement of aging infrastructure, compliance with U.S. EPA standards (e.g., water quality and wastewater effluent), increase in expenses (e.g., labor, chemical, and power), growing demand, and the relocation of facilities. As the costs for water and wastewater services continue to rise, rates are following suit. Two recent rate cases before the Commission involve the Indianapolis Department of Waterworks and Indiana-American Water. In February 2011, the Commission granted the City of Indianapolis a 25.99% permanent rate increase,[14] and in May 2011, Indiana-American Water petitioned the Commission for a 9.76% rate increase.[15]

Chart 2 shows the price index for a variety of utilities, including water/wastewater rates. It shows water/wastewater rates rising more than electricity or natural gas rates and rising much faster than the overall consumer price index (CPI). For example, from 2000 to 2010 water/wastewater rates rose 5.05% per year while the CPI only rose 2.47% per year.

Chart 2

Comparison of Utility Prices from 1953 to 2010

Index is set to 100 for 1982-1984



Source: IPU Research Note, February 2011, Janice Beecher, Ph.D., U.S. Bureau of Labor Statistics

[14] *Dep't of Waterworks of the Consol. City of Indianapolis*, Cause No. 43645, 2011 Ind. PUC LEXIS 30 (IURC Feb. 2, 2011)

[15] Cause No. 44022

Rate cases in Indiana reflect the national trend that shows water and wastewater rates outpacing inflation. Overall, the number of rate increase requests has been significant, with as many as 23 pending at any one time during the past year. In 2010, nine water utilities were approved for general rate increases averaging 25.01%, and twelve wastewater utilities were approved for general rate increases averaging 46.63%. The average rate increase granted by the Commission is high, because the requests are related to infrastructure improvements and maintenance projects to uphold the quality of service. Furthermore, several utilities had not sought a rate increase for many years.

Recovery of Infrastructure Costs within a Rate Case or Tracker

The Commission has several mechanisms within a rate case that allow utilities to recover costs associated with infrastructure projects. Municipal and not-for-profit utilities are allowed to include costs for some types of projects, typically referred to as extensions and replacements, in customer rates. This allows utilities to include future infrastructure projects in rates without relying entirely on debt. In addition, post-in-service Allowance for Funds Used During Construction (AFUDC) and deferred depreciation, if approved, allow investor-owned utilities to defer the capital costs and depreciation expense of a project to the utility's next rate case. This practice helps to reduce the utility's earnings erosion.

All utilities can use the Minimum Standard Filing Requirements process that allows a utility to update its rate base for capital investments incurred up until the final hearing.[16] This can be an incentive to invest in capital improvements, as the utility does not need to wait until a later rate case to earn a return on capital investments.

In 2000, Indiana was the second state in the nation to approve a capital recovery mechanism, called the distribution system improvement charge .

In 2000, the Indiana General Assembly enacted legislation that created a capital recovery mechanism, called the distribution system improvement charge (DSIC).[17] Indiana was the second state to pass such a mechanism. The DSIC allows water utilities to recover the costs of improvements to existing distribution systems without a rate case.

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[16]*See*, 170 IAC 1-5

The DSIC only applies to water utilities, and the Commission believes that making the DSIC mechanism available to wastewater utilities would encourage investments in necessary infrastructure replacements and upgrades. This has been a useful mechanism, without the added costs of a rate case, to encourage needed infrastructure improvements before having to react to a costly disaster. As of May 2011, the Commission approved close to $138 million in utility distribution plant placed in service through the DSIC.

Another way to finance infrastructure investments and minimize the effect on existing customers is through system development charges (SDCs). SDCs are utility fees paid by property owners who connect their properties to the utility's system for the first time and can be more than $1,400 for water connections and $3,000 for wastewater connections. The use of SDCs supports the notion that "growth should pay for growth" and reduces the likelihood that existing customers will pay for construction of new facilities that do not benefit them.

Customer Rate Disparity

Many municipal utilities provide service to customers outside their corporate boundaries, which can create beneficial economies of scale and rate stability for the municipality.[18] However, some municipalities charge outside-city customers higher rates or a surcharge, ranging from modest amounts to those up to 100% greater than rates paid by inside-city customers for the same service.

Different rates between customers located inside and outside a municipality may raise questions about whether the non-city rate is cost-justified and non-discriminatory.

A corporate boundary is usually not like a natural boundary such as a river or mountain, where crossing to the other side may increase the cost of providing service. With corporate boundaries, the imposition of higher rates or a surcharge may be a device to stimulate support for annexation, represent revenue enhancement, or subsidize in-city customers. It may be difficult to support different dollar amounts for inside-city and outside-city water rates due to the fact that rates approved by the Commission must be cost-justified and non-discriminatory.

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[17] *See*, IC ch. 8-1-31

[18] This can also constrain the proliferation of small developer-owned systems that sometimes become troubled.

When municipal utilities opt out of the Commission's jurisdiction, citizen-customers (i.e., city residents) of that municipality still have a voice in how the utility is operated when voting for local leaders. However, non-citizen-customers cannot participate in the local municipal elections; therefore, they have no such voice. One possible remedy is to provide the Commission with limited jurisdiction over municipal water rates charged to outside-city customers when a surcharge is assessed, even if the municipality has opted out of the Commission's jurisdiction. Alternatively, municipalities could be allowed to assess a surcharge within a statutorily specified level (i.e., a "safe harbor" provision) and not be subject to Commission oversight.

Regulatory Development

Small Utilities

Small water/wastewater utilities are prevalent in Indiana. Because of their size, they often lack the expertise to manage and operate effectively. In some instances, the Commission classifies water/wastewater utilities as "troubled." These are typically small utilities (fewer than 300 customers) that were constructed by a developer as part of a housing development.[19]

To determine whether a utility is troubled, the Commission may examine several key factors including: technical, financial, and managerial capacity; the physical condition and capacity of the plant; the utility's compliance with state and federal law and/or the Commission's orders; and provision of service to customers.[20] If the utility has continued violations, even after the Commission orders it to remedy the deficiencies, the Commission can order the acquisition of the utility by a new owner, or appoint a receiver to operate the utility and work to find a new

Assistance for Small Utilities

The Commission is taking proactive steps to improve the management and operations of small utilities in the water industry, including developing a small utility accounting manual to assist utilities with improving their financial books and records.

[19]The Commission can only monitor utilities under its jurisdiction. Once withdrawal occurs, the Commission is no longer able to proactively monitor the progress and development of those systems that are historically most likely to become troubled.
[20]*See,* IC § 8-1-30-3

owner.[21] On a practical basis, neither is an ideal option.

The Commission's primary goal, however, is to prevent utilities from becoming troubled in the first place. One way is to ensure utilities can provide reliable service prior to serving the customers. Both the Commission and the IDEM have rules regarding the operational abilities of water and wastewater utilities.

A second way is for the Commission to try to improve the management and operations of small utilities. Several years ago IURC staff designed and implemented a Small Utility Workshop. This workshop offers hands-on training to municipal and not-for-profit utilities. Workshop participants are provided training on how to complete the Commission's annual report and Small Utility Rate Application (an application that provides a utility the opportunity to request a rate increase without going through the Commission's full formal filing process.) The workshop also provides accounting and asset management training, as well as an opportunity for the utilities to discuss other issues with staff.

To assist utilities with their financial books and records, staff is also developing a small utility accounting manual. Financial record keepers for small utilities often have no accounting or financial background. In small municipalities, this responsibility falls on the elected Clerk-Treasurer, a position for which there is no financial education or experience requirement. Accurate and timely financial records are necessary to provide utility managers with the ability to make informed decisions, provide data to develop accurate rate structures, and lower fees charged by utility consultants.

In an effort to assist the small systems with their rate application filings, the small utility rate application forms are being revised for all types of utilities. The new application is more automated and is tied to a utility's annual report.

Modernization and Efficiency

While frequently a topic in the arid Southwest, and even recently in the Southeast, water supply issues have seldom been of concern to the relatively water-rich Midwest. The water

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[21] *See,* IC § 8-1-30-5

supply in Indiana has generally been plentiful, but over the past few years, water rights and access issues have arisen. In fact, Indiana has not always been able to economically access the amount of water needed and has found that even areas that typically have plenty of water go through periods of drought.

Water Efficiency

Water efficiency programs are being developed by individual utilities and at state and national levels in an effort to manage customer usage. For example, in March 2011, the Commission approved a rate increase for the city of Bloomington, which included funds to hire a water conservation coordinator who will prioritize the measures and programs identified in the Conservation Plan and develop an educational outreach effort to explain and promote Bloomington's conservation program.

Summer watering costs utilities millions of dollars as they are required to meet peak demand by finding or building additional water supply and expanding water treatment plant capacity.

At the state level, the Indiana Department of Natural Resources has developed water conservation and efficiency goals and objectives, as required by the Great Lakes Compact.[22] At the national level, the U.S. EPA has developed the WaterSense® program that labels products, services, and practices as water efficient. This program is similar to the Energy Star program, which identifies energy efficient appliances. The water efficiency issues state and national programs are trying to address are as follows:

- Lack of Rain and High Temperatures -

One issue related to water efficiency planning is summer watering and the shortages that it may cause. The lack of rain and high temperatures causes increased summer watering, which can strain a water system. Summer watering costs utilities millions of dollars as they are required to meet peak demand by finding or building additional water supply and expanding water treatment plant capacity.

[22]P.L. 90-419 (90th Congress, S 660) The Great Lakes Compact includes rules and regulations to protect the Great Lakes and the tributary waters of several states and Canadian provinces. Economic development will be balanced with sustainable water use to ensure Great Lakes waters are managed responsibly.

- Low Water Pressure -

In severe cases of drought, water shortages can lead to low water pressure, which adversely affects fire protection and increases the potential for water contamination. Municipal utilities have recently taken action to control water usage during periods of low supply. While some municipalities have passed ordinances that levy fines on customers when they irrigate on restricted days, there are other utility initiatives, mainly outside of Indiana, that modify rate structures such that consumers are provided price signals to conserve water and reduce consumption.

- Unaccounted-for-Water -

Utilities can reduce the need to develop new sources of supply by reducing the amount of water loss in their system. Some water loss, however, is necessary (e.g., main flushings, maintenance of the treatment plant, and fire suppression). The IDEM considers a system deficient if is it has greater than 25% water loss based on a one-year average.[23]

Energy and Water/Wastewater

Water efficiency not only protects the supply of an important natural resource, it also conserves energy. Energy efficiency campaigns usually include information on how to save water and provide energy efficiency kits containing water-saving devices such as low-flow shower heads. According to the U.S. EPA, energy costs for water and wastewater utilities can be a third of a municipality's total energy bill.

Energy Savings

Water efficiency not only reduces the amount of water consumed, it also saves energy. According to the U.S. EPA, if drinking water and wastewater systems reduce energy use by just 10% through cost-effective investments, collectively they could save approximately $400 million and 5 billion kWh annually.

The federal government and universities are developing programs to educate water and wastewater utilities on ways to conserve and improve upon their existing energy consumption. In January 2008, the U.S. EPA published the "Energy Management Guidebook for Water and Wastewater Utilities," a step-by-step method based on a Plan-Do-Check-Act management system approach. This guidebook aids utilities in identifying, implementing,

[23] *See,* 327 IAC 8-2-8.2(3)(d)

measuring, and improving energy efficiency and renewable opportunities. Purdue University created the Energy Efficiency & Sustainability program, which is a best practices awareness, training, and implementation assistance program funded through a fee for service work, the U.S. Department of Energy, and the U.S. EPA. In 2010, Purdue's Program helped several water and wastewater utilities in Indiana, including the City of Bloomington, a Commission-regulated system.

III. WATER/WASTEWATER APPENDICES

Appendix A – Jurisdictional Water Utility Revenues

Rank	Utility Name	Operating Revenues*	% of Total Revenues
1	Indiana-American Water Company, Inc.	$ 157,062,917	31.83%
2	Indianapolis Water	125,598,009	25.46%
3	Fort Wayne Municipal Water Utility	31,077,401	6.30%
4	Evansville Municipal Water Works Dept.	16,112,509	3.27%
5	South Bend Municipal Water	14,110,591	2.86%
6	Bloomington Municipal Water	10,128,801	2.05%
7	Hammond Municipal Water Works	8,317,725	1.69%
8	Mishawaka Municipal Utilities	7,943,459	1.61%
9	Anderson Municipal Water Works	7,491,432	1.52%
10	Elkhart Municipal Water Works	7,387,742	1.50%
11	Lafayette Municipal Water Works	7,328,644	1.49%
12	Michigan City Municipal Water Works	6,520,905	1.32%
13	Utility Center, Inc.	5,771,129	1.17%
14	East Chicago Municipal Water Dept.	5,488,139	1.11%
16	Marion Municipal Water Works	4,487,194	0.91%
17	Columbus Municipal Water Utility	4,469,422	0.91%
18	Stucker Fork Conservancy District	3,174,625	0.64%
19	Ramsey Water Company, Inc.	2,979,918	0.60%
20	Brown County Water Utility, Inc.	2,855,134	0.58%
21	Jackson County Water Utility, Inc.	2,770,726	0.56%
22	Chandler Municipal Water Works	2,679,074	0.54%
23	New Castle Municipal Water Works	2,355,894	0.48%
24	Auburn Municipal Water Utility	2,092,330	0.42%
25	Silver Creek Water Corporation	2,074,126	0.42%
26	Eastern Heights Utilities, Inc.	2,040,428	0.41%
27	North Lawrence Water Authority	1,940,786	0.39%
28	Edwardsville Water Corporation	1,875,460	0.38%
29	Morgan County Rural Water Corporation	1,794,710	0.36%
30	Mishawaka-Clay Municipal Utilities	1,617,775	0.33%
31	Eastern Bartholomew Water Corporation	1,606,840	0.33%
32	Martinsville Municipal Water Utility	1,547,067	0.31%
33	German Township Water District, Inc.	1,524,295	0.31%
34	Princeton Municipal Water	1,461,213	0.30%

35	Boonville Municipal Water Works	1,441,460	0.29%
36	Columbia City Municipal Water Utility	1,387,786	0.28%
37	Peru Municipal Water Dept.	1,328,595	0.27%
38	East Lawrence Water Authority	1,326,664	0.27%
39	South Harrison Water Corporation	1,290,311	0.26%
40	Pike-Gibson Water, Inc.	1,288,617	0.26%
41	Ellettsville Municipal Water Utility	1,282,081	0.26%
42	Southwestern Bartholomew Water Corporation	1,255,738	0.25%
43	South Lawrence Utilities, Inc.	1,249,368	0.25%
44	Watson Rural Water Co., Inc.	1,214,066	0.25%
45	Corydon Municipal Water Works	1,018,021	0.21%
46	Gibson Water, Inc.	982,707	0.20%
47	Tri-Township Water Corporation	978,969	0.20%
48	Twin Lakes Utilities, Inc.	924,670	0.19%
49	Charlestown Municipal Water Dept.	874,787	0.18%
50	Southern Monroe Water Corporation	845,997	0.17%
51	Aurora Municipal Water Utility	795,862	0.16%
52	Floyds Knobs Water Company, Inc.	764,501	0.15%
53	North Dearborn Water Corporation	719,236	0.15%
54	Marysville Otisco Nabb Water Corporation	687,527	0.14%
55	Reelsville Water Authority	599,315	0.12%
56	Van Buren Water, Inc.	577,726	0.12%
57	Sullivan-Vigo Rural Water Corp.	570,805	0.12%
58	LMS Townships Conservancy District	569,287	0.12%
59	Fortville Municipal Water Works	544,182	0.11%
60	Washington Township Water Corporation of Monroe County	513,609	0.10%
61	Petersburg Municipal Water Works	510,840	0.10%
62	B & B Water Project, Inc.	477,930	0.10%
63	Posey Township Water Corporation	430,863	0.09%
64	Clinton Township Water Company	428,720	0.09%
65	Cataract Lake Water Corporation	425,387	0.09%
66	Indiana Water Service, Inc.	420,746	0.09%
67	Riverside Water Company, Inc.	366,021	0.07%
68	Tri-County Conservancy District	340,994	0.07%
69	Knightstown Municipal Water Utility	331,283	0.07%
70	Eaton Municipal Water Utility	307,991	0.06%
71	St. Anthony Water Utilities, Inc.	292,528	0.06%
72	Everton Water Corporation	282,366	0.06%
73	Town of Cedar Lake Utilities	260,025	0.05%
74	Ogden Dunes Municipal Water	257,124	0.05%
75	Kingsford Heights Municipal Water Utility	246,663	0.05%

76	Painted Hills Utilities Corporation	227,008	0.05%
77	Consumers Indiana Water Company	216,816	0.04%
78	Pioneer Water, LLC	214,478	0.04%
79	Darlington Waterworks Company	203,501	0.04%
80	Mapleturn Utilities, Inc.	190,574	0.04%
81	Troy Municipal Water	182,510	0.04%
82	South 43 Water Association, Inc.	169,941	0.03%
83	Kingsbury Utility Corporation	126,194	0.03%
84	Oak Park Conservancy District	118,601	0.02%
85	Rhorer Harrel & Schacht Roads Water Corp	80,663	0.02%
86	Water Service Company of Indiana, Inc.	76,405	0.02%
87	Wedgewood Park Water Co., Inc.	63,878	0.01%
88	Apple Valley Utilities, Inc.	62,773	0.01%
89	Pleasantview Utilities, Inc.	53,832	0.01%
90	American Suburban Utilities, Inc.	37,738	0.01%
91	J.B. Waterworks, Inc.	30,919	0.01%
92	Wastewater One d/b/a River's Edge Utility, Inc.	17,108	<0.01%
93	Wells Homeowners Association, Inc.	13,950	<0.01%
94	Shady Side Drive Water Corporation	8,689	<0.01%
95	Bluffs Basin Utility Company, LLC	7,467	<0.01%
96	Hessen Utilities, Inc.	7,350	<0.01%
97	Pence Water Works	6,720	<0.01%
98	Country Acres Property Owners Association	6,432	<0.01%
	Total Revenue	$493,381,785	100.00%

*Year ending December 31, 2010

Appendix B – Jurisdictional Wastewater Utility Revenues

Rank	Utility Name	Operating Revenues	% of Total Revenues
1	Hamilton Southeastern Utilities, Inc.	$ 8,974,966	30.90%
2	Utility Center, Inc.	7,140,120	24.58%
3	Aqua Indiana South Haven	3,474,218	11.96%
4	American Suburban Utilities, Inc.	2,531,894	8.72%
5	Twin Lakes Utilities, Inc.	1,530,415	5.27%
6	Eastern Richland Sewer Corporation	970,610	3.34%
7	L.M.H. Utilities Corporation	753,211	2.59%
8	Wymberley Sanitary Works, Inc.	509,463	1.75%
9	Driftwood Utilities, Inc.	492,268	1.69%
10	Indiana-American Water Company, Inc.	346,512	1.19%
11	Kingsbury Utility Corporation	301,905	1.04%
12	Mapleturn Utilities, Inc.	284,841	0.98%
13	Consumers Indiana Water Company	284,823	0.98%
14	Apple Valley Utilities, Inc.	212,155	0.73%
15	Doe Creek Sewer Utility, Inc.	206,694	0.71%
16	Eastern Hendricks County Utility, Inc.	131,204	0.45%
17	Northern Richland Sewer Corporation	128,033	0.44%
18	Water Service Company of Indiana, Inc.	112,070	0.39%
19	Howard County Utilities, Inc.	87,984	0.30%
20	Wildwood Shores Utility Corp., Inc.	86,120	0.30%
21	Old State Utility Corporation	72,074	0.25%
22	Centurian Corporation	64,183	0.22%
23	Galena Wastewater Treatment Plant	63,253	0.22%
24	Southeastern Utilities, Inc.	63,232	0.22%
25	Pleasantview Utilities, Inc.	50,095	0.17%
26	Heir Industries, Inc.	47,101	0.16%
27	East Shore Corp.	29,400	0.10%
28	Hillview Estates Subdivision, Inc.	23,438	0.08%
29	JLB Development, Inc.	15,334	0.05%
30	Wastewater One d/b/a River's Edge Utility, Inc.	12,563	0.04%
31	Brushy Hollow Utilities, Inc.	11,298	0.04%
32	Bluffs Basin Utility Company, LLC	11,098	0.04%
33	Anderson Lakes Estates Homeowners Assoc.	7,623	0.03%
34	Country Acres Property Owners Assoc.	7,108	0.02%
35	Harbortown Sanitary Sewage Corporation	5,400	0.02%
36	Hessen Utilities, Inc.	4,900	0.02%
37	Webster Development, LLC	1,314	<0.01%
38	Sanitrol, Inc.	Not Operational	0.00%
	Total Revenue	$ 29,048,920	100.00%

*Year ending December 31, 2010

Appendix C – Withdrawn Water Utilities

Utility Name	
Albion	Camden
Alexandria	Campbellsburg
Alfordsville	Canaan Water Utility
Ambia	Cannelton
Andrews	Carbon
And-Tro, Inc.	Carlisle
Angola	Carmel
Arcadia	Carthage
Argos	Cayuga
Ashley	Center Point
Atlanta	Centerville
Attica	Chalmers
Avilla	Chesterfield
Bainbridge	Chesterton
Bargersville	Chrisney
Batesville	Churubusco
Bean Blossom - Patricksburg Water Corp.	Cicero
Bedford	Clarks Hill
Berne	Clay City
Bethany	Claypool
Beverly Shores	Clinton
Bicknell	Cloverdale
Big Walnut Company, Inc.	Colfax
Birdseye	Connersville
Bloomingdale	Converse
Bluffton	Covington
Boswell	Crane
Bourbon	Crawford County Water Company
Brazil	Cromwell
Bremen	Crothersville
Bristol	Crown Point
Brook	Culver
Brooklyn	Cynthiana
Brookston	Dale
Brookville	Daleville
Brownsburg	Dana
Bruceville	Danville
Bunker Hill	Daviess County Rural Water System, Inc.
Burns City	Dayton
Burnt Pines Water Association	Decatur
Butler	Decatur County Rural Water Corporation
Cambridge City	Decker

Delphi	Garrett
Dillsboro	Gas City
Dublin	Gaston
Dubois Water Utilities, Inc.	Gem Water, Inc.
Duff Water Corporation	Geneva
Dugger	Gentryville
Dune Acres	Georgetown
Dunkirk	Georgetown, IL
Dupont Water Company, Inc.	Glenwood
Dyer	Goodland
Earl Park	Goshen
East Fork Water, Inc.	Gosport
East Monroe Water Corporation	Grabill
East Washington Rural Water Corporation	Grandview
Edgewood	Grantsburg Rural Water, Inc.
Edinburgh	Greencastle
Edwardsport	Greendale
Elberfeld	Greenfield
Elizabeth	Greensburg
Ellis Water Company	Greentown
Elnora	Greenville
Elrod Water Company, Inc.	Griffith
Elwood	Hagerstown
English	Hamilton
Etna Green	Hamlet
Fairmount	Hanover
Fairview Park	Hartford City
Farmersburg	Haubstadt
Farmland	Hayden Water Association, Inc.
Fayette Township	Haysville Water Utilities, Inc.
Fayette Township Water Association, Inc.	Hazleton
Ferdinand	Hebron
Fillmore	Highland
Finch Newton Water, Inc.	Hill Water Corp.
Flora	Hillsboro
Fort Branch	Hogan Water Corp.
Fountain City	Holland
Fowler	Holton Community Water Corp.
Francesville	Hope
Francisco	Hudson
Frankfort	Huntertown
Franklin County Water Association, Inc.	Huntingburg
Frankton	Huntington
Freelandville Water Association	Hymera
Fremont	Ingalls
Galveston	Ireland Utilities, Inc.

Jamestown	Middletown
Jasonville	Milan
Jasper	Milford
Jennings Water, Inc.	Millersburg
Jonesboro	Milltown
Kendallville	Milton
Kent Water Company, Inc.	Mitchell
Kentland	Monon
Kewanna	Monroe
Kingman	Monroe City
Kirklin	Monroeville
Knightsville	Montezuma
Knox	Montgomery
Knox County Water, Inc.	Monticello
Kouts	Montpelier
LaCrosse	Morgantown
Ladoga	Morocco
LaFontaine	Morristown
LaGrange	Mount Summit
Lagro	Mount Vernon
Lake Station	Mulberry
Lakeville	Munster
Lanesville	Napoleon Community Water
Lapel	Nappanee
LaPorte	Nashville
Laurel	New Carlisle
Lawrence	New Chicago
Lawrenceburg	New Harmony
Leavenworth	New Haven
Lebanon	New Market
Lewisville	New Pekin
Liberty	New Richmond
Ligonier	New Whiteland
Linden	Newberry
Linton	Newport
Logansport	North Brown Water
Long Beach	North Judson
Loogootee	North Liberty
Lowell	Pierceton
Lyford Waterworks, Inc.	Pittsboro
Lynn	Plainfield
Lynnville	Pleasantville Water Co.
Lyons	Plymouth
Mentone	Portland
Merom	Poseyville
Middlebury	Prince's Lake

Redkey	Tell City
Reelsville Water Authority	Tennyson
Remington	Thorntown
Rensselaer	Tipton
REO Water Corp.	Topeka
Reynolds	Trafalgar
Ridgeville	Troy
Riley	Troy Township Water Association, Inc.
Rising Sun	Union City
Roachdale	Universal
Roann	Upland
Roanoke	Valparaiso
Rochester	Van Buren
Rockport	Veedersburg
Rockville	Vernon
Rosedale	Versailles
Rossville	Vevay
Royal Center	Vincennes
Rural Membership Water Corporation	Wakarusa
Rushville	Walkerton
Russellville	Walton
Russiaville	Wanatah
Rykers Ridge Water Co.	Warren
Salem	Washington
Sandborn	Washington Township Water Corp.
Santa Claus	Waterloo
Santa La Hill, Inc.	Waveland
Schneider	Waynetown
Scottsburg	West College Corner
Seelyville	West Lebanon
Sellersburg	West Terre Haute
Sharpsville	Westfield
Shelburn	Westport
Sheridan	Westville
Shipshewana	Westwood Water Co., Inc.
Shirley	Wheatland
Shoals	Whiteland
Silver Lake	Whitestown
Slygo Water Corp.	Whiting
South Whitley	Wilfred Water Corporation
Southern Madison Utilities, LLC	Williamsport
Speedway	Winamac
Sunman	Windfall
Swayzee	Wingate
Switz City	Winslow
Syracuse	Wolcott

Wolcottville	
Woodburn	
Yankeetown Water Authority	
Yorktown	

Appendix D – Withdrawn Wastewater Utilities

Utility Name	
Canyonlands Homeowners, Inc.	M.E.K.A. Inc.
C & M Utility Inc. (Water and Sewer)	Mt. Pleasant Utilities, LLC
Deerwood Environmental, Inc.	Salt Creek Services, Inc. (Water and Sewer)
Evanston Utility, Inc.	Shady Hills Utility Company (Water and Sewer)
Forest Ridge Utilities, Inc.	Shorewood Forest Utilities, Inc.
Gem Utilities, Inc.	St. Meinrad Utilities
Golfview Partners, LLC	Tamerix Lake Wastewater Treatment Plant
Grandview Lot Owners Association, Inc.	Thieneman Environmental, LLC
Hardin Monroe, Inc.	Thrall's Station, Inc.
Harrison Lake Town Meeting, Inc.	Valley Rural Water and Sewer Utility
Henryville Membership Sanitation	West Boggs Sewer District, Inc.
Lakeview Estates of Wabash County, Inc.	Western Hancock Utilities, LLC

2011 Communications Report

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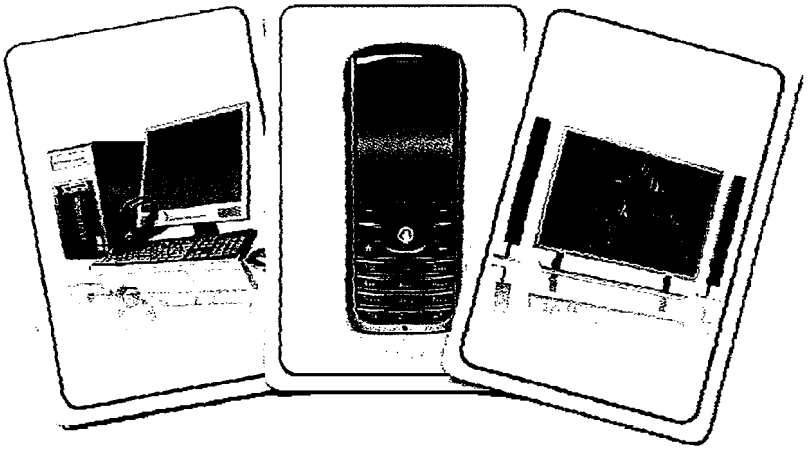
I. COMMUNICATIONS OVERVIEW

Industry Structure

The past five years have experienced as much change in the telecommunications industry as at any time since the breakup of AT&T in 1984, and Indiana has been at the forefront of those changes. Our state witnessed competitive forces set in motion on the national level with the passage of the Telecommunications Act of 1996, which focused squarely on establishing a framework for competition. This trend was accelerated at the state level in 2006, with the passage of industry deregulation (House Enrolled Act 1279).[1] House Enrolled Act 1279 (HEA 1279) embraced a "light regulatory touch," as well as competition not only in telecommunications but also in the delivery of video services. Finally, the past five years have seen dramatic changes in the delivery of communications technology. Broadband, heretofore delivered primarily by wireline companies and cable providers, has grown dramatically with the build out of 3G and 4G mobile wireless service and with the introduction of so-called "smartphones."

Commission involvement remains necessary in areas where competition alone may not provide solutions.

There are currently 648 communications service providers (CSPs) that hold a Certificate of Territorial Authority (CTA) to provide telecommunications, information, or video services in Indiana. In 2010, the intrastate revenues for telecommunications services provided by Indiana's CSPs totaled $2.78 billion,[2] which is approximately 24% of the total intrastate revenues for all Indiana public utilities.



Indiana Utility Regulatory Commission (Commission or

[1]P.L. 27-2006
[2]2011 Annual IURC Fee Billing Report

IURC) involvement remains necessary in areas of the communications industry where competition alone may not provide solutions. For example, the Commission resolves carrier-to-carrier disputes, manages policies regarding telephone numbering resources (pursuant to federal law), and works to implement streamlined certification processes to facilitate competition by reducing barriers to entry. The Commission also protects consumers from unauthorized changes to their service, ensures that all areas of the state continue to have a provider of last resort for local exchange telecommunications service, and ensures continued access to basic telecommunications services in high-cost areas of the state.[3] The Communications Division also participates in federal proceedings and serves as a resource on communications complaints that are filed with the Commission's Consumer Affairs Division.

As a result of HEA 1279 and market forces, the communications industry in Indiana continues to transition away from the historical model of a regulated market where monopoly or near-monopoly carriers provided single communications services to customers with little or no choice of provider. In today's market, CSPs offer multiple services, utilizing different technologies in order to compete with companies that were once in separate and distinct industries.

For example, many telephone companies now provide video service, cable companies provide telephone service, and both provide high-speed Internet service. Widespread rollout and adoption of "triple play" (telephone service, Internet service, and video service) or even "quadruple play" (triple play, plus mobile wireless service) have also resulted in multiple providers offering packages and bundles of services to consumers, leading to increased competition and customer choice. Many companies also offer the bundles or packages at a discount over stand-alone pricing. In areas of the state where "triple play" is not available, consumers are demanding to know why. More consumers are also pressing companies to roll out access to high-speed Internet and video service in areas where it is not yet available.

The reason why these areas may lack one or more services is because there is an absence of a traditional business case for offering these additional services due to higher costs to deploy in areas with a low population density. However, CSPs with the ability to diversify and provide

[3] *See*, IC § 8-1-2.6-0.1

"one-stop shop" packaging have continued to prosper in the current economy. The bundling of services is further discussed on page 126.

Legal and Policy Foundations

Indiana law requires all CSPs that offer service to Indiana customers to obtain a CTA without regard to the medium or technology used to provide the services.[4] This includes providers of telecommunications and information services.[5] It also explicitly includes providers of video, broadband, advanced services, and Internet Protocol-enabled services, however classified by the FCC.[6] In order to implement this new section of the statute, the IURC modified its policies to require that all CSPs be similarly certified by the Commission, thereby allowing competitors to receive similar "light regulatory" treatment. The Commission also developed a streamlined "Notice of Change" process to be used by CSPs that already hold a CTA, to notify the Commission when there are circumstances that would require a change in the terms of the certificate.

The Communications Division has eliminated or streamlined many regulations and procedures since the phase-in of telecommunications regulatory reform that began in 2006. However, it has retained jurisdiction over other areas.

Pursuant to Indiana law, the Communications Division has eliminated or streamlined many regulations and procedures since the phase-in of telecommunications regulatory reform that began in 2006. IURC authority has changed and evolved, but has not been eliminated.

The rules and policies currently in place ensure that the Commission can fulfill its responsibilities outlined in state statute. These include:

- Enforcing rules to prevent unauthorized switching of telecommunications providers or unauthorized charges added to customers bills (i.e., slamming or cramming);[7]

[4]IC § 8-1-32.5-4 Public utilities that received a certificate of territorial authority (CTA) or a certificate of convenience and necessity (CPCN) from the Commission prior to July 1, 2009, were grandfathered and did not need to obtain a new certificate. *See,* IC § 8-1-32.5-6(c).
[5]IC § 8-1-32.5-3(a).
[6]IC § 8-1-32.5-3(b).
[7]IC § 8-1-2.6-13(d)(4)

- Performing duties concerning the provision of dual-party relay services to speech and hearing impaired persons in Indiana;[8]

- Performing duties concerning the administration of 211, a hotline for consumers to obtain information about health and human services;[9]

- Fulfilling the obligations under the Telecommunications Act of 1996 (TA-96) concerning universal service and access to telecommunications services and equipment, including designation of eligible telecommunications carriers;[10]

Customer Refunds

In 2010, the IURC's Consumer Affairs Division was responsible for refunding $18,186.71 in illegal slamming and cramming charges on consumers' bills.

- Fulfilling the obligations under Section 706 of the Telecommunications Act of 1996 (TA-96) requires the FCC and each state commission to encourage the reasonable and timely deployment of advanced telecommunications capability to all Americans.

    - **"The Commission and each State Commission with regulatory jurisdiction over telecommunications services shall encourage the deployment on a reasonable and timely basis of advanced telecommunications capability to all Americans . . . by utilizing, in a manner consistent with the public interest, convenience, and necessity, price cap regulation, regulatory forbearance, measures that promote competition in the local telecommunications market, or other regulating methods that remove barriers to infrastructure investment." – 47 U.S.C. § 706**

- Mediating the disconnection of one carrier by another carrier to protect end-user customers from losing their service with no advance notice, pursuant to Section 251 of the TA-96;[11]

[8]IC § 8-1-2.6-13(d)(2)
[9]IC § 8-12.6-13(d)(3)
[10]IC § 8-1-2.6-13(d)(5)
[11]IC § 8-1-2.6-1.5(a)

- Arbitrating and resolving interconnection disputes between telecommunications carriers, pursuant to Section 252 of TA-96;[12]

- Implementing the authority granted by state or federal law, such as numbering administration, area code relief, and federal truth-in-billing requirements for common carriers;[13]

- Implementing the Indiana Lifeline Assistance Program, which makes basic telephone service more affordable for low-income customers;[14]

- Overseeing the Indiana Universal Service Fund, which provides cost recovery so that companies in high-cost areas[15] may continue to offer services at rates that are "just, reasonable, and affordable."

    - **"Consumers in all regions of the Nation, including . . . those in rural, insular, and high cost areas, should have access to telecommunications and information services . . . that are reasonably comparable to those services provided in urban areas and that are available at rates that are reasonably comparable to rates charged for similar services in urban areas." – Section 254(b)(3) of TA-96**

- Issuing Certificates of Territorial Authority (CTAs), which are licenses required to operate in specific Indiana communities, to all communications service providers;[16]

- Issuing Certificates of Franchise Authority (CFAs), which are licenses required to operate in specific Indiana communities, to video service providers;[17]

- Enforcing video service standards, as the designated franchise authority, regarding statutory reporting requirements; public, educational, and governmental (PEG)

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[12]IC § 8-1-2.6-1.5(b)
[13]IC § 8-1-2.6-13(f)
[14]IC ch. 8-1-36
[15]High-cost service areas are designated by the federal government due to the high fixed costs of building and maintaining a telecom network in rural areas with low population densities or rugged terrain; 47 U.S.C. 254(b)(3) requires the availability of comparable service at a comparable price.
[16]IC ch. 8-1-32.5
[17]IC § 8-1-34-16(a)

channels; and customer service standards for video service providers, pursuant to FCC rules in 47 C.F.R. 76.309;[18]

- Participating in federal matters concerning Indiana (e.g., intercarrier compensation); and

- Reporting requirements to the General Assembly.[19]

IURC Rulemakings

State statute directed the Commission to eliminate rules and policies applicable to telecommunications service providers if the rules or policies were no longer necessary, in the public interest, or for the protection of consumers, as the result of full and fair facilities-based competition among providers of telecommunications services.[20] Therefore, on July 1st of each odd-numbered year, the Commission is required to identify all telecommunications rules and policies it has reviewed and those it has eliminated during the two most recent fiscal years.

The IURC significantly streamlined and reduced Article 7 of the IAC in order to be consistent with regulatory reform measures passed by the Indiana General Assembly. Approximately half of the former rules were eliminated.

The IURC's regulations and procedures for telecommunications carriers are detailed at 170 Indiana Administrative Code (IAC) 7. The IURC began the administrative process in 2009, which significantly streamlined and reduced Article 7 of the IAC in order to be consistent with regulatory reform measures passed by the Indiana General Assembly. Approximately half of the former rules were eliminated, ending retail rate regulation, regulated customer service standards, and service quality measurement for telecommunications carriers. The new streamlined rules became effective in December of 2010.

Federal Universal Service

The IURC is required to "fulfill its obligations under TA-96 and IC ch. 20-20-16 concerning universal service and access to telecommunications service and equipment including the

[18]General Administrative Order 2007-2
[19]IC § 8-1-2.6-4(c)
[20]IC § 8-1-2.6-4(c)(3)

designation of eligible telecommunications carriers."[21] One such obligation is to evaluate telecommunications carriers' petitions for designation as eligible telecommunication carriers (ETCs). ETC designation permits a carrier to receive support from the Federal Universal Service Fund, which supports telecommunications companies that provide service in high-cost areas and offers assistance to low-income consumers, schools, libraries and rural health care providers.

Indiana Universal Service Fund

The Commission also oversees the Indiana Universal Service Fund (IUSF). Due to changes in the Federal Universal Service Program that could have had a potentially detrimental impact on Indiana's rural companies, the IURC implemented a state universal service fund for Indiana in 2007. Indiana is one of 16 states with a state fund.[22] The purpose of the IUSF is to provide cost recovery so that companies in high-cost areas may continue to offer services at rates that are "just, reasonable, and affordable."[23] Without universal service support, residents in some rural areas of the state would pay significantly more for telephone services than those living in other areas, which could result in a reduction in telephone penetration in the high-cost rural areas and violate federal law.[24] Without this support, telecommunications companies that serve these areas could decide they cannot afford to modernize their networks or provide services of the same quality as is available in urban areas. Each year, more than $11 million is collected through a charge on customers' phone bills. These funds are then redistributed to eligible rural phone companies. Absent this subsidy, companies that serve these areas would struggle to earn a reasonable profit and therefore lack an adequate incentive to continue operation.

Indiana is one of 16 states with a state universal service fund. The purpose of the IUSF is to provide cost recovery so that companies in high-cost areas may continue to offer services at rates that are "just, reasonable, and affordable."

[21] *See*, IC § 8-1-2.6-13(d)(5)
[22] Making the High Cost Decision: How to Assess your State's Needs, National Regulatory Research Institute, 2010.
[23] High-cost service areas are designated by the federal government due to the high fixed costs of building and maintaining a telecom network in rural areas with low population densities or rugged terrain; 47 USC 254(b)(3) requires the availability of comparable service at a comparable price to that charged in urban areas.
[24] Ibid.

Federal Policies

As Indiana's communications industry continues its evolution toward a competitive market, the continued monitoring of federal communications issues is essential to identify and, when appropriate, act upon the many federal policy matters that have the potential to affect Indiana's economy. In fact, the FCC's development of the National Broadband Plan (NBP) and its potentially far-reaching impacts provided a catalyst for the development of a specific process at the Commission, called the federal communications issues process. This process provides for monitoring, review, analysis and recommendation by Commission staff regarding issues under consideration at the federal level. The NBP, as it is implemented through rulemakings and Orders, demands close attention to ensure that the interests and concerns of the state of Indiana are addressed through filings made by the IURC. The Commission's role and comments on this matter are further detailed in the "Service for All" section of the report.

Expertise in federal communications issues is essential to identify and, when appropriate, act upon the many federal policy matters that have the potential to affect Indiana's economy.

Many other important issues over which the IURC has state-level authority are also under review at the FCC. The modification of requirements for ETC designations at the federal level and eligibility for the receipt of funds from the Federal Universal Service Fund could affect the designation of Indiana companies as ETCs by the IURC and the level of funds those companies receive from the Indiana Universal Service Fund. Further, changes to federal numbering policies regarding number portability, number conservation, and 911 safety issues could also directly affect Indiana customers. Additionally, changes in the Federal Cable Act and other federal video policies could affect the IURC's ability to carry out its authority to enforce video customer service standards.

II. COMMUNICATIONS LANDSCAPE

Service for All

The IURC is charged with analyzing the effects of competition and technological change on universal service and the pricing of all telecommunications services offered in Indiana.[25] The number and percentage of Indiana households with voice telecommunications service is a fundamental barometer of the universality and affordability of telecommunications services. High telephone subscribership increases the value and functionality of the telecommunications network for everyone by providing a reliable and instant means of communication to employers, schools, government agencies and emergency services. Indiana tends to be below the national average in telephone penetration or "take rates," according to the FCC's Universal Service Monitoring Report.[26]

Lack of broadband in rural areas is an important issue facing the nation today. Affordable broadband can be an important driver of economic development and improve the opportunities of low-income and at-risk populations.

Lack of broadband in rural areas is an important issue facing the nation today. Affordable broadband can be an important driver of economic development and improve the opportunities of low-income and at-risk populations. In an effort to address it, the FCC is grappling with the complex issues stemming from how to reform its universal service, intercarrier compensation, and broadband policies. The IURC is actively engaged in these issues at the national level.

For the past 5 ½ years, Indiana has been fortunate to have one of its members among four commissioners nationally representing the states on the Federal State Joint Board on Universal Service, and to also be represented as State Members' Chair of the Federal State Joint Conference on Advanced Services, which serves in an advisory capacity to the FCC on broadband and related issues.

As the FCC proceeds with reforming USF and broadband policies, care needs to be taken to not undermine the progress already achieved with broadband deployment in rural areas. It is also

[25]IC § 8-1-2.6-4(c)
[26]Universal Service Monitoring Report, Federal Communications Commission, Released December 2010

important to point out that some carriers serving rural areas in Indiana have managed to deploy broadband while others have made business decisions to not offer broadband service in sparsely populated areas of the state. As such, carriers that took the initiative to expand broadband to unserved areas prior to the USF reform should not to penalized.

On March 16, 2010, the FCC released the NBP. The NBP addresses the nation's digital divide between rural and urban areas; low-income and at-risk populations; and the lack of affordable access, connectivity, and features for commercial and anchor institutions. During 2010 and 2011, the FCC issued Notices of Inquiry (NOI) and Notices of Proposed Rulemaking (NPRM) to implement significant portions of the NBP. After the IURC's Communications Division reviewed the NOIs and NPRMs, the Commission filed comments in specific FCC proceedings – some of which are detailed below.

Universal Service Reform

- Universal Service Fund and Intercarrier Compensation NOI (April 21, 2010) -

In its April 2010 NOI and NPRM on Universal Service Reform, the FCC made several proposals that could have an adverse impact on Indiana rural local exchange carriers (RLECs) and mid-size incumbent local exchange carriers (ILECs). The Commission filed comments on July 14, 2010, outlining its concerns with the FCC's proposals. Specifically, the Commission is concerned that while there are many proposals that reflect much needed reform, existing providers in rural areas, their customers, and economic development in those areas could be adversely affected by other proposed changes in federal USF and broadband policy. To view the Commission's comments, please visit: http://www.in.gov/iurc/files/FCC_Comments_071410.pdf (11 pages).

- Detailed Request for Comment; USF/ICC NPRM (February 9, 2011) -

On February 9, 2011, the FCC released a 300-plus page NPRM that proposed dramatic changes in the structure of federal USF and intercarrier compensation mechanisms (USF/ICC NPRM). The FCC proposed to combine multiple USF programs into a single mechanism, known as the Connect American Fund (CAF). Additionally, the FCC is proposing to change the criteria used to qualify for USF support, as well as the expenses supported. Many Indiana rural telephone

companies count on federal USF support to build and operate their networks and could be negatively affected by the changes proposed by the FCC. For calendar year 2009, Indiana RLECs collectively relied on federal USF and access charges for over half of their total operating revenue. Ten Indiana RLECs depend on USF and access charges for over 70% of their operating revenue. In the USF/ICC NPRM, the FCC also proposed significant changes in the rules and the system outlining how carriers exchange traffic and compensate each other for telephone calls originated by one carrier and completed by another. The IURC filed extensive comments cautioning the FCC against drastic premature changes. To view the Commission's comments, please visit: http://www.in.gov/iurc/files/FCC_Comments_071410.pdf (7 pages).

- Building Mobile Wireless in Unserved Areas NPRM (October 10, 2010) -

On October 14, 2010, the FCC released an NPRM that proposed the creation of a dedicated fund from funds previously used to assist providers of high-cost areas to promote the deployment of wireless service and bring all states up to a minimum speed for mobile broadband service. In its filed comments, the Commission applauded the FCC's efforts to improve wireless broadband coverage, but cautioned against doing so at the cost of support for existing wireline broadband in high-cost rural areas provided by rural ILECs. To view the Commission's comments, please visit: http://www.in.gov/iurc/files/Mobility_Fund_NPRM-_Final_Comments_Filed.pdf (9 pages).

Lifeline/Link-Up

Lifeline/Link-Up is a federal program designed to increase the rate of telephone subscribership among low-income citizens. It provides two different discounts to those who are eligible: monthly discounts toward the cost of maintaining telephone service (Lifeline) and a one-time discount towards the costs of setting up service (Link-Up). The program reimburses ETCs for discounts provided to low-income households on basic telephone service, and all ETCs are required to offer Lifeline/Link-Up. Eligibility requires either consumers to have a total household income

Where to Find More Information

The IURC's Consumer Affairs Division can assist constituents with the application process. By having consumers call the Consumer Affairs Division at 1-800-851-4268, our analysts can provide callers with an application and instructions on how to apply.

that does not exceed 135% of the Federal Poverty Guidelines or participation in one of the following programs: Medicaid, Food Stamps, Supplemental Security Income (SSI), Federal Public Housing Assistance (Section 8), Low-Income Home Energy Assistance Program (LIHEAP), Temporary Assistance to Needy Families (TANF), or the National School Lunch Programs Free Lunch Program.

Historically, it has been challenging for Indiana, along with many other states, to raise awareness among eligible low-income households of the availability of the Lifeline/Link-Up discount. Indiana's Lifeline subscribership peaked in 2006 at 59,065 households and has been declining since, for a total of 51,015 households in 2009.[27] However, two developments could boost participation in the Lifeline/Link-Up program in Indiana and hopefully, the overall telephone subscribership rate: 1) the Indiana Lifeline Assistance Program and 2) entry of prepaid wireless ETCs .

Indiana Lifeline Assistance Program

The Indiana General Assembly created the Indiana Lifeline Assistance Program (ILAP) and charged the IURC with implementing the program.[28] The ILAP provides additional emphasis on outreach as compared to the federal Lifeline program. The ILAP also expands upon the federal program by increasing the monthly discount available to low-income households. The federal program provides reimbursement for Lifeline customers' federal subscriber line charge ($5.48 to $6.39 depending upon the phone company), plus $1.75. Enacting a state Lifeline program ensures that Indiana will receive an additional federal match of 50% of the state's contribution. Therefore, the existence of Indiana's program will provide an additional $1.50 discount, including the federal match.[29] Further, the ILAP is designed to reach more low-income residents by expanding the eligibility criteria to households with

More Help for Hoosiers

Once the Indiana Lifeline Assistance Program is implemented, the average monthly Lifeline discount for income-eligible Hoosiers will increase from $7.54 to $9.04.

[27] Universal Service Monitoring Report, Federal Communications Commission, Released December 2010, Table 2.6
[28] IC ch. 8-1-36
[29] Universal Service Monitoring Report, December 2010, Table 2.3

incomes up to 150% of the Federal Poverty Guidelines as opposed to the 135% used in the federal Lifeline Program.

The IURC approved a Proposed Rule implementing the ILAP program on February 9, 2011. A hearing on the Final Rule was held on May 16, 2011. The Rule is awaiting approval by the State Budget Agency and must be signed by the Governor before it becomes effective.[30] The Commission expects this will occur before the end of the year.

- Prepaid Wireless Providers -

In recent years, some prepaid wireless carriers received approval from the FCC to seek designation from states as ETCs for the limited purpose of offering Lifeline benefits. The prepaid wireless carriers use the federal subsidy to provide free minutes each month, and they often provide a free basic wireless phone. Since the service is prepaid and revenue is not at risk of nonpayment, poor credit is not a barrier to obtaining the service.

Many states have approved the designation of prepaid wireless ETCs, finding they may increase the take rate among Lifeline-eligible consumers. Other states, however, have concerns that prepaid wireless carriers cannot properly verify that only one discount is being applied per household per month as required by federal rules. The IURC strives to ensure responsible use of the program (i.e., one monthly Lifeline discount per eligible household). Thus far, the IURC has designated three prepaid wireless Lifeline providers as eligible to receive the federal subsidy with conditions intended to prevent misuse of the program. These providers include: Virgin Mobile (d/b/a Assurance Wireless), Tracfone (d/b/a SafeLink Wireless), and i wireless. Four other petitions are pending.

- Reform of Lifeline NPRM -

The FCC issued an NPRM on March 16, 2011 that contained a set of sweeping proposals to reform and modernize the Lifeline/Link Up Program. Many of the proposed reforms are intended to bolster protections against waste, fraud, and abuse; control the size of the program; strengthen program administration and accountability; improve enrollment and outreach efforts; and support pilot projects that would assist the FCC in assessing strategies to increase broadband adoption,

[30] IURC RM#10-01/LSA# 10-478

while not increasing overall program size. Indiana was represented on the Federal-State Joint Board on Universal Service that produced a recommended decision, which shaped the FCC's response to this set of issues.

Also, IC ch. 8-1-36 establishes the ILAP based on the structure of the federal lifeline program. Therefore, any changes made to this program at the federal level could directly affect the pending ILAP Rulemaking at the Commission. To view the Commission's comments, please visit:
http://www.in.gov/iurc/files/Lifeline_and_Link_Up_Reform_and_Modernization_NPRM_Comments_(2).pdf (17 pages).

Pricing and Economics

Basic Local Service

In the 1990s and early 2000s, Indiana took its first steps away from traditional price regulation with the adoption of Price Cap regulation. Over time, the IURC and the carriers negotiated a series of multi-year agreements (dubbed Alt Reg agreements) in which the Commission progressively loosened the regulation on optional services, and in return the carriers committed to expand the areas in which broadband was offered. A few core services, notably basic local service, remained regulated and price-controlled throughout the Price Cap era. In many respects, this mechanism worked reasonably well for the better part of a decade, but by mid-decade had reached a point of diminishing returns.

When HEA 1279 was passed in 2006, it was with the expectation that by largely lifting regulation of the price of services, providers would be able to compete for a larger "share of the wallet," meaning that traditional incumbent carriers would be able to compete for video services revenue, and cable providers would be better able to compete for voice service.

When HEA 1279 was passed in 2006, it was with the expectation that by largely lifting regulation of the price of services, providers would be able to compete for a larger "share of the wallet," meaning that traditional incumbent carriers would be able to compete for video services revenue, and cable providers would be better able to compete for voice service. In addition, both would continue to compete for broadband customers. With a

growth in revenue, so the logic went, the providers' business case could include enhanced investment, further enhancing the scope, extent and adoption of advanced technology.

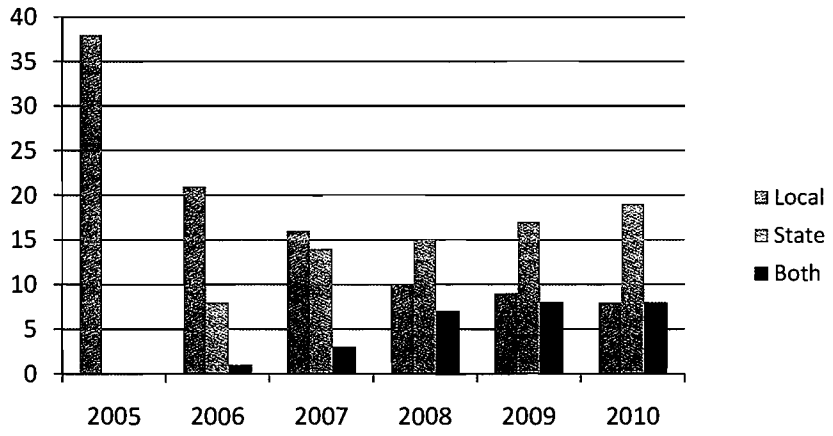
The sole exception to the deregulatory trend was with basic local service. Concerned that basic local service remain affordable to the vast majority of all Hoosiers, the General Assembly left existing Alt Reg agreements in place for the three largest companies serving Indiana (at the time, AT&T Indiana, Verizon and Sprint/Embarq) and froze basic local service rates. As the Alt Reg agreements expired, providers were allowed to incrementally re-price basic local service over time, provided they also met certain broadband requirements. Over time, the significance of capping or controlling basic local service has diminished significantly, as the vast majority of customers elect service packages that reach well beyond basic local service. Consequently, only a very small number of customers purchase "basic service only" offerings.

Video Service

Increasingly, video service is being offered by providers under state-issued franchises. As of December 31, 2009, 27 of the 35 video service providers (VSPs) serving in Indiana held state-issued video service franchises, while the other eight continued to provide service under local franchises. In the case of incumbent cable providers, a company that chose not to terminate the local franchise agreement with its respective communities in 2006 kept the existing agreements in effect until they expired. Upon expiration, the provider must file for a state franchise.

Chart 1

Number of Video Franchises by Year



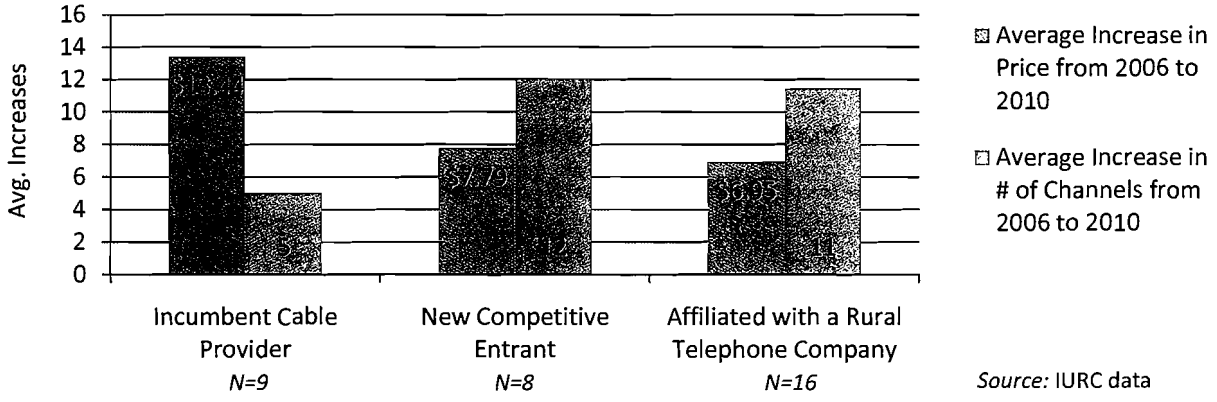
Source: Communications Surveys

Analysis of the benefits of competition in the video market is complicated by a number of factors. For example, most providers offer multiple video packages, ranging from a "basic" package with a relatively small number of channels to larger packages with more channels. In addition, an increasing number of providers offer optional "on demand" services and programming offered at incremental "a la carte" pricing. National content providers tend to bundle their offerings, requiring providers wanting to offer the most popular channels to take several offerings, often with significantly smaller audiences, for a package price in order to get the most popular channel. All of these factors make it difficult to compare offerings and prices from any given provider over time, let alone compare the offerings of one provider with another.

Over roughly four years, incumbent cable providers, new entrants, and video services affiliated with rural telephone companies all reported increases both in the price of service and in the number of channels offered, as shown in Chart 2. However, new competitive entrants as a group averaged just slightly more than half the four-year increase in price as was reported by incumbent providers. At the same time they were adding twice as many incremental channels on average. In other words, the new entrants provided competition and price discipline, as advocates of statewide franchising had argued would occur.

Chart 2

Price and Channel Trends by Type of Provider



Source: IURC data

- Cost of Content -

Many video providers attribute the need to increase prices to the ever-increasing cost of content. This is a concern that the Commission raised in recent comments to the FCC in its Notice of Proposed Rulemaking (NPRM) related to Retransmission Consent. The comments of

the IURC pointed out that, "discrimination in the pricing of content does occur and that it is detrimental not only to the small network providers (cable companies and local exchange companies) involved and to their customers, but also to competition in the video market and the build out of Broadband, particularly in rural, unserved and high cost areas."[31] Unless the FCC addresses this issue, it is likely that some smaller providers of video will cease providing video services and video rates of those providers that remain will likely continue to rise.

Bundling of Telecommunications and Video Services

In the past, customers purchased individual services from providers that specialized in providing a specific type of service. However, with competition emerging in the video market and in the voice market, many cable and telephone companies have responded by offering existing and new customers packages and bundles that consist of services from two or more categories (e.g., telephone, Internet, video, and wireless phone).

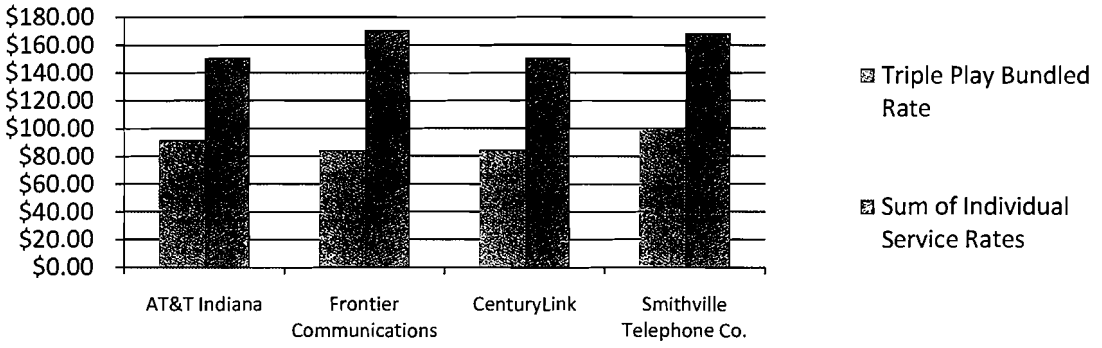
Companies attempt to retain existing customers and attract new customers by offering packages at a significant discount.

The objective is to capture a greater market share in the communications sector. Package prices are typically lower than the sum of the stand-alone prices. Of course, some customers receive more benefits than others, and some customers may perceive a diminished benefit if they purchase a bundle containing services they would not ordinarily purchase in order to obtain services they want. In response to this concern, companies have begun offering "build your own" packages and bundles. The following chart includes prices for select triple-play bundles and compares them with separately priced components of those bundles.

[31]Initial comments of the Indiana Utility Regulatory Indiana Commission, MB Docket No. 10-71(FCC 11-31, Rel. March 3, 2011)

Chart 3

Comparison of Bundled Rates to Sum of Individual Service Rates



Source: Company information

It is important to note that packages and bundles may feature limited-term promotional pricing. Thus, comparisons between package prices and stand-alone prices that are valid today may not be valid comparisons in the future, as existing promotions expire and new promotions are introduced. It should also be pointed out that the significant consolidation in the communications industry over the last few years – particularly in the wireless industry – has reinforced the trend toward obtaining packages and bundles from a single provider. In the future, it will be more difficult for customers to obtain multiple services on a stand-alone basis from multiple providers.

Broadband

A great deal of debate has occurred over where we stand nationally with regard to broadband buildout. Unfortunately, as broadband becomes a central part of American life, and more essential to economic development and viability, this debate becomes more and more an ideological one at the national level. Are we in fact 14th or 15th or 16th, or are we the most or second most successful nation in terms of the number of discrete broadband subscribers served?

Vinton (Vint) Cerf, one of two men widely acknowledged as the true fathers of the Internet, points us to a far more relevant and important focus: "the Internet lives where anyone can access it," and conversely, where no one can access it, the absence of service has become more and more critical.

In most endeavors, as an enterprise becomes more widespread, it becomes easier to promulgate and less expensive to expand, on the margin, due to economies of scale. Such is not the case with broadband. As its presence becomes more widespread, the absence of broadband necessarily becomes more and more focused on the needs of the least, the last and the lost – that is, those for whom it is least affordable; those who are located at or beyond the furthest reach of current technological limitations; and those who have yet to recognize the value proposition of broadband.

There are essentially three ways to expand the broadband footprint:

1. Broaden the business case to expand the reach of broadband further into those areas that are most costly to serve and for which it did not make sense at an earlier time to build.
2. Expand the mission of an existing enterprise or government entity or create a partnering arrangement with an anchor or lead organization to support the build out of broadband (e.g., the City of Scottsburg used the community's electric utility as the business platform for development of a successful fixed wireless broadband system).
3. Create a private or partnering entity which underwrites a portion of the expense of buildout, or fund a program through government subsidy.

Broadband Buildout

Information obtained from the Indiana Office of Technology shows the 67 wireline companies for which they have data provide broadband in at least a portion of 61.85% of the census blocks in Indiana, covering just more than 84% of the state's geography. The 26 wireless providers for which they have data provide wireless broadband in approximately 95.34% of the state's geography.

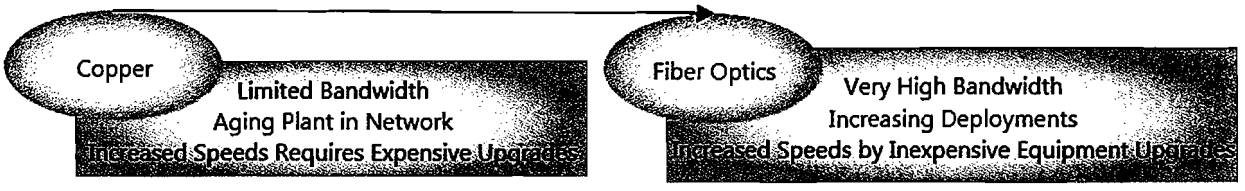
In rural areas of Indiana and in other states with a sizeable rural population, the challenge to 100% buildout is cost. The more widely spread the population, the more challenging the geography and terrain, and the greater the distances from the customer to the landline central (switching) office, cable head end, or wireless tower and backhaul facilities, the greater the cost. It is not unusual that the cost of providing service to truly rural areas is ten times or more greater than the cost of providing otherwise identical service in the small towns and cities that are the hub of the typical rural community.

Technology Trends

The evolution of technology used in communication services has made services faster than ever before. The dynamic changes the industry is undergoing are multidimensional. These new technologies are moving from circuit switching (dedicated end-to-end connections) to packet switching (dynamic routing) and from the use of traditional electric signaling (copper wiring) to widespread use of wavelengths of light for signaling (fiber optics).

Copper to Fiber Optic Cabling

For more than 100 years, copper cabling served as the basis for customer connections to the telephone network. Copper cabling was reliable and a relatively cheap conduit for telephone calls. However, bandwidth-intensive applications like the Internet and video have exploded in recent years, and copper alone cannot provide adequate throughput. Therefore, copper is increasingly being replaced by fiber for at least a portion of the physical connection between customers and the network. Offering much higher speeds and a lower cost to upgrade capacity by replacing equipment instead of the cabling itself, fiber optics now occupy an ever increasing percentage of local loop, which provides the physical connection from the location of switching equipment (connects to the remainder of the network) to the landline customers' premises.

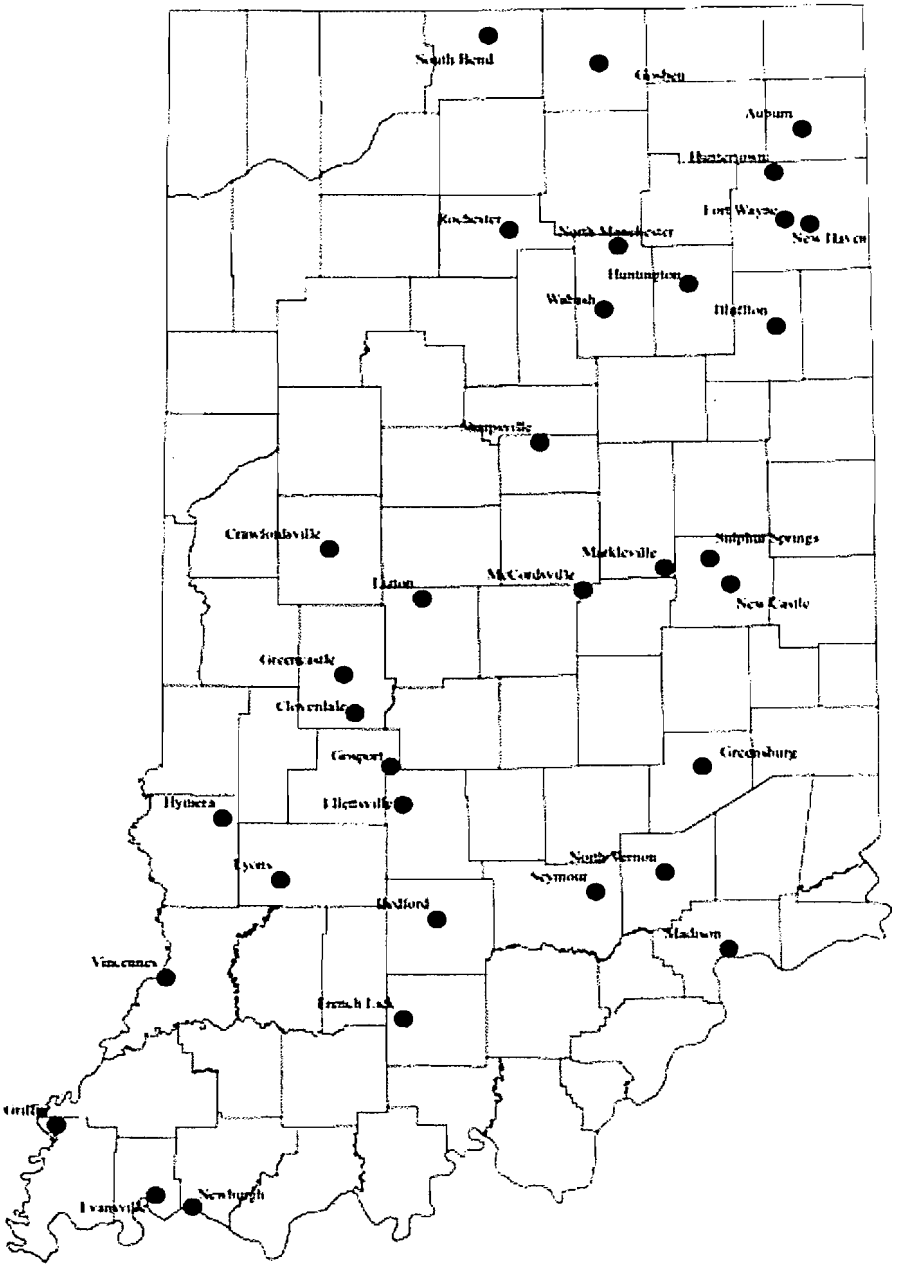


In some instances, fiber optic cables comprise the entire loop, a configuration that is known as Fiber-to-the-Home (FTTH). In other instances, fiber optic cable makes up a portion of the local loop, which is closest to the switching equipment, known as Fiber-to-the-Node (FTTN). Typically, with FTTN configurations, the remaining portion of the local loop is traditional copper cabling. Although FTTN does not have the same capacity as FTTH, the speed is much greater than copper cable local loops and costs less to build than FTTH. The greater capacities offered by FTTN and FTTH provide a faster Internet web browsing experience and access to video content, as well as the potential to enable advanced, next-generation broadband products

and services yet to be developed. Map 1 shows the locations of communities in Indiana with FTTH systems, according to the High Performance Government Network.[32] A written list of those communities appears in Appendix A.

Map 1

Areas in Indiana with Fiber-to-the-Home (2011)



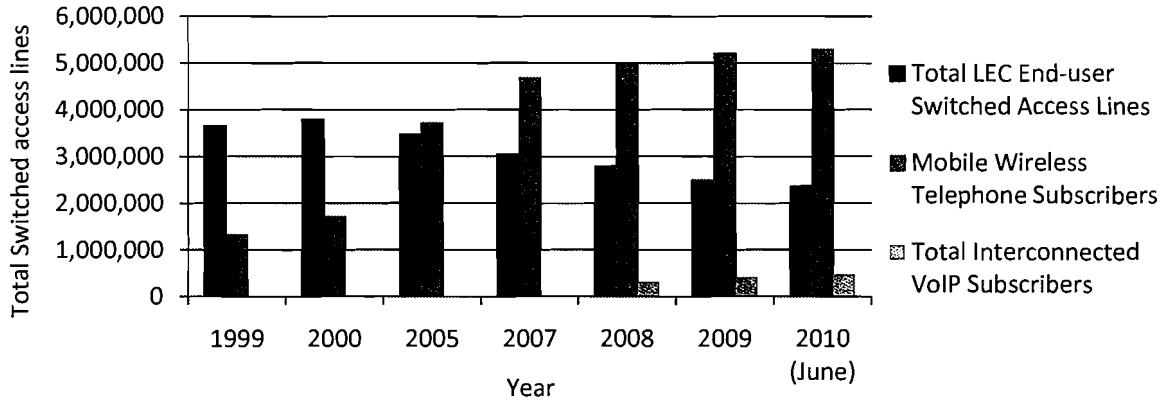
[32] As of January 2010

Wireline to Wireless

Wireless devices have become the leading method for consumers to exchange voice calls and are becoming a more popular method for accessing information via the Internet. The inherent mobile nature of wireless devices is the driving force, and increases in wireless subscriptions have contributed to the drop in traditional telephone service. These trends can be seen in Chart 4.

Chart 4

Trends in Indiana Telephone, Wireless, and VoIP Subscribers



Source: FCC Report on Local Telephone Competition: Status as of December 31, 1999, 2000, 2005, 2007, 2008, 2009, and as of June 30, 2010. Data was taken from various tables in the reports.

It is important to note that using the number of subscribers as the comparison results in higher numbers of subscribers for mobile wireless, because one household is likely to have multiple mobile wireless phone numbers on a family plan; whereas, most households have only a single line. This is because second lines for children/family and dial-up Internet use declined in the last decade. It is true, however, that a growing number of consumers have abandoned landlines altogether. The U.S. Centers for Disease Control and Prevention (CDC)[33] estimated that, as of June 2010, 26.6% of adults (ages 18 and over) in the U.S. had only a wireless phone account, up from 13.6% in 2007.[34] The CDC also estimated that 13.8% of adults (ages 18 or

[33]The CDC conducts telephone surveys on a wide variety of health-related topics. Up until a few years ago, the CDC intentionally excluded wireless numbers from the list of telephone numbers it would call when it conducted those surveys.

[34]*Wireless Substitution: Early Release of Estimates From the National Health Interview Survey, January – June 2010.* U.S. Centers for Disease Control and Prevention, Division of Health Interview Statistics, National Center for Health Statistics. Table 1 (May 12, 2011).

over) in Indiana households were wireless-only households, as of December 2007,[35] compared to the more recent Indiana estimate of 25.2%, as of June 2010.

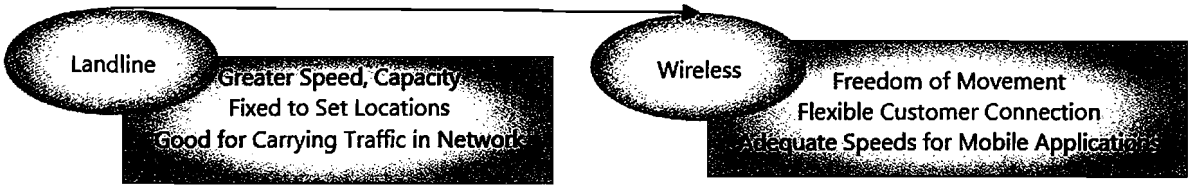
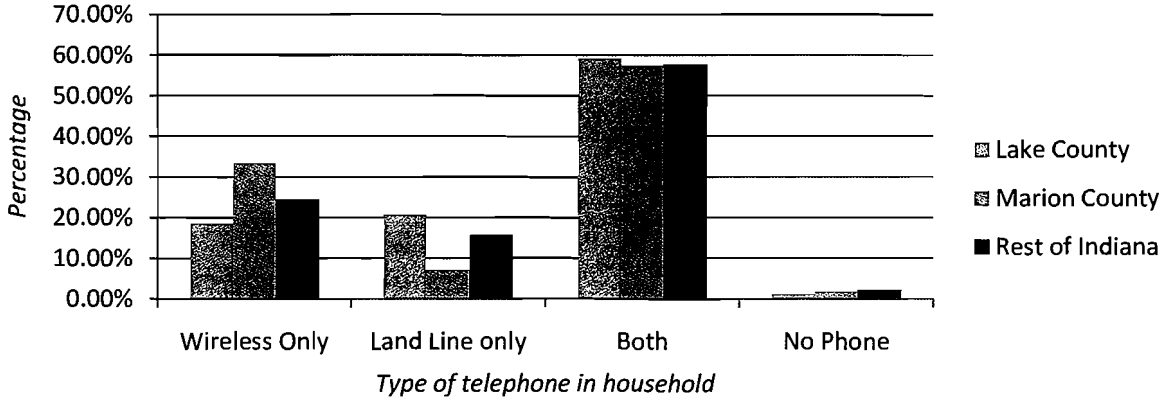


Chart 5 shows within Indiana, Marion County leads the state in the estimated percentage of "wireless-only" households by a significant margin. Lake County leads the state in the estimated percentage of "landline-only" households. It also shows a majority of Hoosier households maintain both a landline and a wireless telephone. If the trends continue, it would not be unreasonable to expect that half of the households in Marion County will be wireless-only within the next few years.

Chart 5

Household Telephone Status by Geographic area, as of June 2010



Source: Wireless Substitution: Early Release of Estimates From the National Health Interview Survey, January – June 2010. U.S. Centers for Disease Control and Prevention, Division of Health Interview Statistics, National Center for Health Statistics

[35] *Wireless Substitution: State-level Estimates From the National Health Interview Survey, January – December 2007.* Unnumbered Table ("Modeled state-level estimates of the percentage of wireless-only households and the percentage of adults living in wireless-only households: United States, 2007)" (U.S. Centers for Disease Control and Prevention, National Health Statistics Reports, Number 14, March 2009).

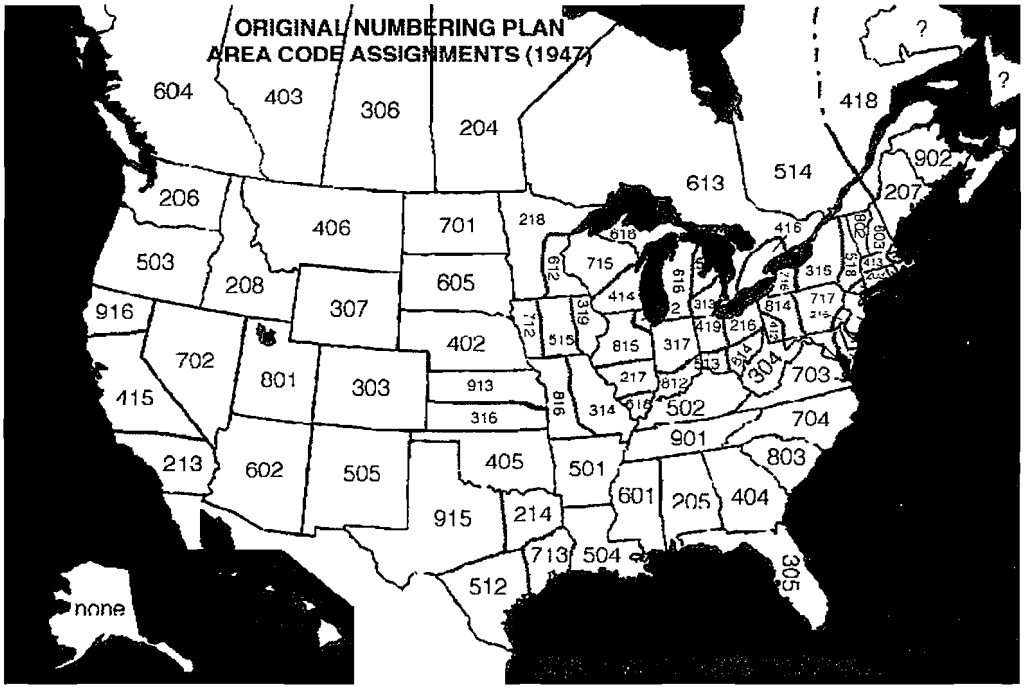
Regulatory Development

Area Code Relief

Numbering administration rules, which are overseen by the FCC and partially delegated to the states, have evolved since the development of the North American Numbering Plan (NANP) in 1947. The NANP was originally designed and administered by AT&T when the company had a monopoly over local and long-distance services in the United States. This system accommodates direct dialing of long-distance calls to the 19 countries in the NANP.[36] After this system was created, some area codes gradually "exhausted" (or ran out of unused or unallocated ten-digit telephone numbers). After the passage of the Telecommunications Act of 1996, competition among multiple local exchange and wireless carriers placed additional demands upon numbering resources. As a result, state utility commissions and the FCC have implemented policies to conserve blocks of telephone numbers to postpone area code exhaust dates.

Map 2 shows the original area codes designed by AT&T, many of which have been split several times since 1947.

Map 2



[36] http://www.nanpa.com/about_us/abt_nanp.html , accessed on April 29, 2011

When an area code is three years from its projected exhaust date, the North American Numbering Plan Administrator (NANPA) files a petition on behalf of the Indiana telecommunications industry with the IURC. The petition usually proposes different scenarios for relief of the area code, such as how to split the area code into two or three areas or implement an "area code overlay," which requires new number holders to receive a new area code but allows the existing number holders to keep their phone number. In the end, the IURC will determine how the area code will be relieved.

Area code relief can be accomplished with an area code split or overlay.

Pros and Cons of an Area Code Split or Overlay

	Pro	Con
Area Code Split	• When an area code is split some people get to keep their phone numbers and dial as usual. • Seven-digit dialing for local calls continues for everyone.	• Some consumers are inconvenienced by the need to notify others of their new phone number. • Business customers face significant expenses related to changing marketing materials
Area Code Overlay	**Pro**	**Con**
	• Customers do not have to change their telephone numbers. • Existing number holders keep the same area code. • It is easy to implement another area code when necessary.	• Residents living within an area code overlay need to become accustomed to dialing ten digits for all local calls.

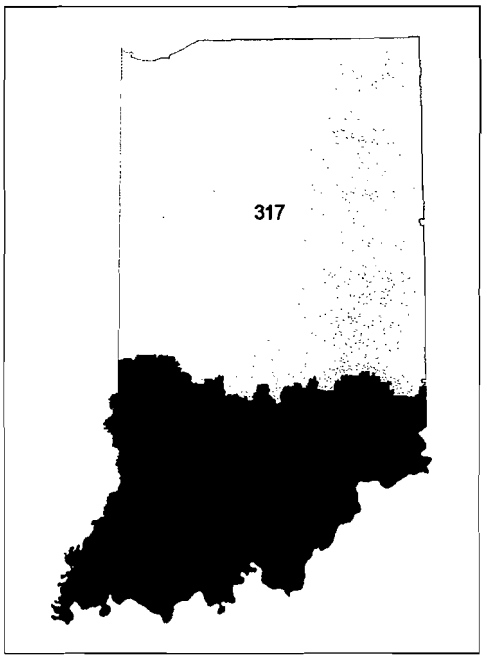
The most recent exhaust of an Indiana area code was area code 219 in 2001, which covered northern Indiana. The Commission conducted a large number of field hearings in affected communities throughout the area and gathered testimony from industry representatives and citizens. In that instance, the IURC determined that an area code split was the best solution. Consequently, the area was split into three area codes: 219, 260, and 574.[37] Map 3 shows the evolution of area code relief in Indiana from 1947 to the present.

[37] Cause No. 41535, Final Order, June 14, 2001.

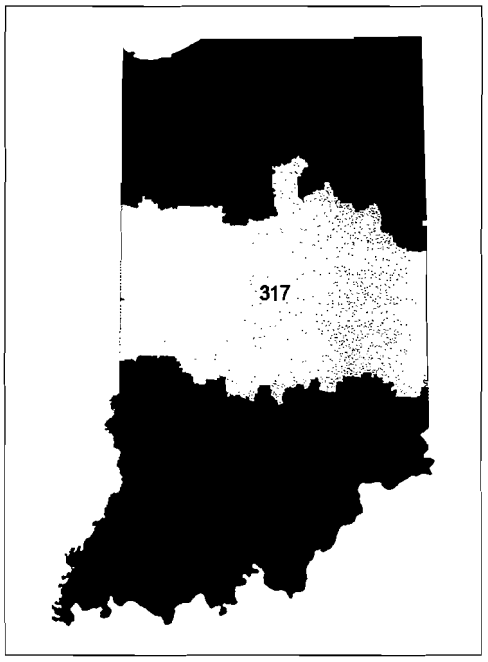
Map 3

Area Code Relief from 1947 to 2011

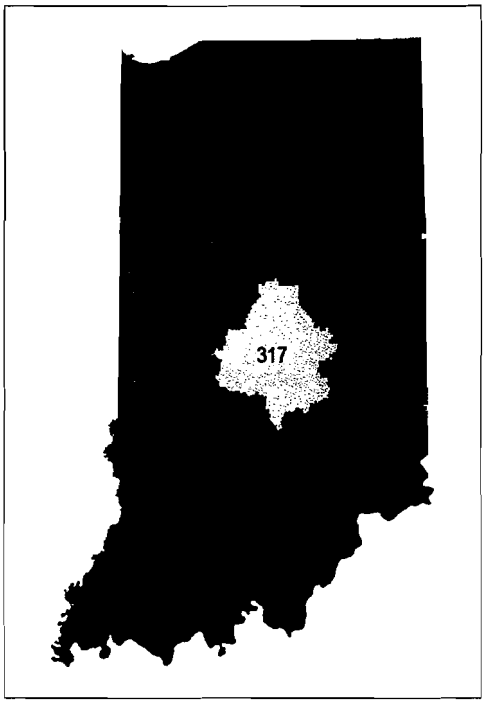
Indiana Area Codes (1947)



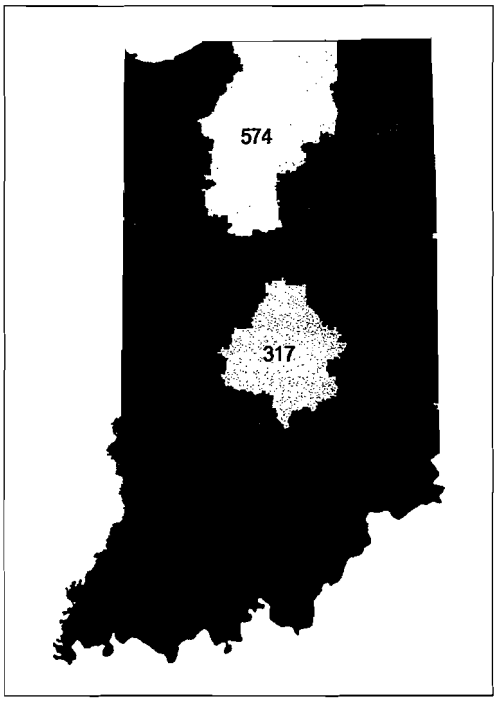
Indiana Area Codes (Post 1947-Pre 1997)



Indiana Area Codes (1997-2002)



Indiana Area Codes (2002-2011)



Current forecasting reports from the NANPA indicate that area code 812, serving southern Indiana, has the shortest remaining life of the Indiana area codes; the current exhaust projection date is 2015. Exhaust projections for 812 have been extended several times. In the 2008 report to this committee, the IURC reported the 812 area code would exhaust in the 3rd quarter of 2011. That date has been pushed back to 2015 due, in part, to conservation efforts by the IURC and the Indiana telecommunications industry. For example:

Conservation efforts have resulted in pushing out the exhaust date for 812 to 2015.

1. The IURC petitioned the FCC to implement mandatory thousand block number pooling. The FCC granted the IURC's petition on May 18, 2010[38] and mandatory number pooling was implemented on January 15, 2011.[39] Number pooling requires carriers to break unallocated "codes" (an area code and a three-digit exchange that comprises a total of 10,000 telephone numbers) into blocks of 1000 numbers and return unused blocks back to the pool of numbers available for other carriers.

2. IURC staff reviews requests for numbering resources from telecommunications carriers to the NANPA on a daily basis and works with the NANPA and the telecommunications industry to prevent new codes from being used when an existing code can be reused. Due to the legacy call rating and routing system, local exchange carriers wishing to serve a new rate center need to request a full code. But under certain circumstances, the IURC and the NANPA staff can encourage two carriers to work together to use an existing code. IURC staff also reviews requests to ensure only telecommunications carriers entitled to numbering resources (local exchange and wireless carriers) receive them.

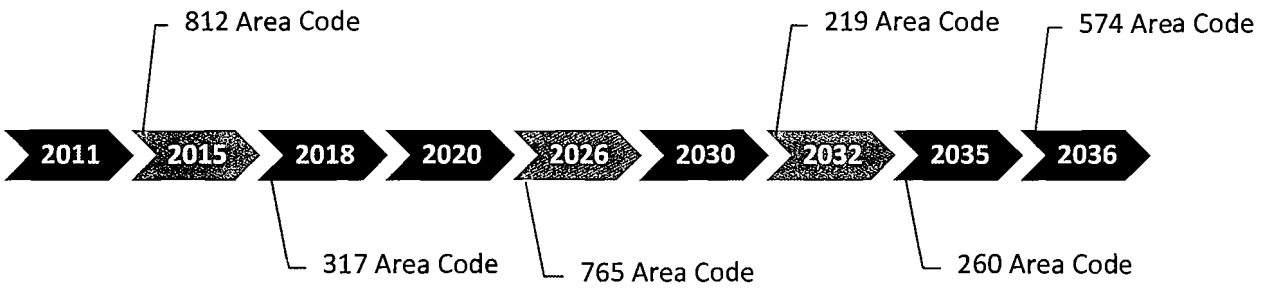
3. Pursuant to federal rules, IURC staff also works with the NANPA on a monthly basis to reclaim numbering resources that are not being assigned to customers in a timely manner.

[38] In the Matter of the Petition of the Indiana Utility Regulatory Commission to Implement Additional Number Conservation Measures, WC Docket No. 08-66, Released May 18, 2010
[39] IURC General Administrative Order 2010-2, issued September 22, 2010

The current life projections for Indiana's six area codes are reflected in the following timeline:

Chart 6

Projected Area Code Exhaust Dates



Source: North American Number Plan Administration, 2010-1 NRUF and NPA Exhaust Analysis, released April 2011

III. COMMUNICATIONS APPENDICES

Appendix A - Fiber-to-the-Home Systems in Indiana

List of Cities, Towns, and other Government Units where a Provider had Built or was Building a FTTH System (January 2010)

City/Town	Provider
Auburn	Auburn Essential Services
Bluffton	Craigville Telephone
Cadiz	Hancock
Cloverdale	Hancock
Connersville	Cinergy Metronet
Crawfordsville	Crawfordsville Electric Light & Power
Eden Township	Hancock
Ellettsville	Smithville
Evansville	WOW (formerly Sigecom) but may be to node
Fort Wayne	Frontier
French Lick	Smithville
Goshen	Goshen Fiber Network
Gosport	Smithville
Greencastle	Cinergy Metronet
Greensburg	Enhanced Telecommunications Corporation
Griffin	Smithville
Huntertown	Frontier
Huntington	Cinergy Metronet
Hymera	Smithville
Lake Monroe area	Smithville
Lizton	Smithville
Lyons	Smithville
Madison	Cinergy Metronet
Markleville	Hancock
Maxwell area	Hancock
McCordsville	Hancock
Mohawk area	Hancock
New Haven	Verizon
Newburgh	WOW (formerly Sigecom) but may be to node
North Manchester	Cinergy Metronet
North Vernon	Cinergy Metronet
New Castle	Cinergy Metronet
Bedford	Cinergy Metronet
Owensburg area	Smithville
Rochester	Rochester Telephone Company
Seymour	Cinergy Metronet
Sharpsville	Smithville

Smithville area	Smithville
South Bend	St. Joe Valley Metronet (Zing)
Stanford area	Smithville
Sulphur Springs	Hancock
Vincennes	Cinergy Metronet
Wabash	Cinergy Metronet
Willow Branch area	Hancock

Source: High Performance Government Network

Acronyms

A

ADSL – Asynchronous Digital Subscriber Line

AEP – American Electric Power

AFUDC – Allowance for Funds Used During Construction

AGA – American Gas Association

AOS – Alternative Operator Service

ARP – Alternative Regulatory Plan

AWWA – American Water Works Association

B

Bcf – Billion cubic feet

BPL – Broadband over Power Lines

BTS – Basic Telecommunications Service

Btu – British thermal unit

C

CAIR – Clean Air Interstate Rule

CalWaRN – California Water/Wastewater Agency Response Network

CAMR – Clean Air Mercury Rule

CCT – Clean Coal Technology

CETCs – Competitive Eligible Telecommunications Carriers

CGA – Common Ground Alliance

CLEC – Competitive Local Exchange Carrier

CPCN – Certificate of Public Convenience and Necessity

CT – Combustion Turbine

CTA – Certificate of Territorial Authority

CWA – Communications Workers of America

D

DIMP – Distribution Integrity Management Program

DNR – Indiana Department of Natural Resources

DSA – Designated Service Area

DSIC – Distribution System Improvement Charge

DSL – Digital Subscriber Line

DVR – Digital Video Recorder

E

EEFC – Energy Efficiency Funding Component

EIA – Energy Information Administration

EPA – U.S. Environmental Protection Agency

EPAct – Energy Policy Act of 2005

ERO – Electric Reliability Organization

ETC – Eligible Telecommunications Carrier

F

FAC – Fuel Adjustment Clause

FCC – Federal Communications Commission

FERC – Federal Energy Regulatory Commission

FT – Firm Transportation

FTR – Financial Transmission Rights

FTTH – Fiber-to-the-Home

H

HEA – House Enrolled Act

I

ICTA – Indiana Cable Telecommunications Association

IDEM – Indiana Department of Environmental Management

IEDC – Indiana Economic Development Corporation

IGCC – Integrated Gasification Combined Cycle

ILAP – Indiana Lifeline Assistance Program

ILEC – Incumbent Local Exchange Carrier

I&M – Indiana Michigan Power Company, subsidiary of AEP

IMP – Integrity Management Program

IMPA – Indiana Municipal Power Agency

INWARN – Indiana Water/Wastewater Agency Response Network

IOU – Investor-owned utility, financed by the sale of securities

IPTV – Internet Protocol Television

IPL – Indianapolis Power and Light

ISDH – Indiana State Department of Health

ISO – Independent System Operator

ISP – Internet Service Provider

IT – Interruptible Transportation

ITU – International Telecommunication Union

IUPPS – Indiana Underground Plant Protection Service

IURC – Indiana Utility Regulatory Commission

IUSF – Indiana Universal Service Fund

L

LDC – Local Distribution Company

LFA – Local Franchise Authority

LMG – Landfill Methane Gas

LMOP – Landfill Methane Outreach Program

LNG – Liquefied Natural Gas

M

Mcf – Million cubic feet

MGT – Midwestern Gas Transmission

Midwest ISO – Midwest Independent Transmission System Operator

MMBtu – One million British thermal units, rough equivalent to an Mcf

MMcf – One million cubic feet

MMTCE – Million metric tons of carbon equivalent

MS4 – Municipal Separate Storm Sewer System

MSW – Municipal Solid Waste

MTEP – Midwest ISO Transmission Expansion Plan

MVPD – Multichannel Video Programming Distributor

MW – Megawatts

MWH – Megawatt hour

N

NANPA – North American Numbering Plan Administrator

NAPSR – National Association of Pipeline Safety Representatives

NARUC – National Association of Regulatory Utility Commissioners

NCTA – National Cable and Telecommunications Association

NERC – North American Electric Reliability Council

NIPSCO – Northern Indiana Public Service Company

NO_x – Nitrogen Oxides

NOAA – National Oceanic and Atmospheric Administration

NOPR – Notice of Proposed Rulemaking

NPDES – National Pollutant Discharge Elimination System

NPMS – National Pipeline Mapping System

NRRI – National Regulatory Research Institute

NTA – Normal Temperature Adjustment

O

OECD – Organization for Economic Cooperation and Development

OMS – Organization of Midwest ISO States

OPS – Office of Pipeline Safety

OQ – Operator Qualification

OUCC – Office of Utility Consumer Counselor

P

PHMSA - Pipeline Hazardous Materials Safety Administration

PIPES – Pipeline Integrity, Protection, Enforcement, and Safety

PJM – The PJM Interconnection

POLR – Provider of Last Resort

PPA – Purchase Power Agreement

PPTT – Purchased Power and Transmission Tracker

PSA – Pipeline Safety Adjustment

PSAPs – Public Safety Answering Points

PSI – PSI Energy

PSTN – Public Switched Telephone Network

PUHCA – Public Utility Holding Company Act of 1935

PUHCA 2005 – Public Utility Holding Company Act of 2005

PURPA – Public Utility Regulatory Policies Act of 1978

R

RFP – Request for proposals

RLECs – Rural Incumbent Local Exchange Carriers

RSD – Regional Sewer District

RSG – Revenue Sufficiency Guarantee

RTO – Regional Transmission Organization

S

SDC – System Development Charge

SIGECO – Southern Indiana Gas & Electric Company

SNG – Synthetic Natural Gas

SO2 - Sulfur Dioxide

SOHO – Small Office Home Office

SRC – Sales Reconciliation Component

SUFG – State Utility Forecasting Group

T

TA-96 –Telecommunications Act of 1996

U

UGS – Underground storage

UNEs – Unbundled Network Elements

USAC – Universal Service Administrative Company

USF – Universal Service Fund

V

VoIP – Voice over Internet Protocol

W

Wi-Fi – Wireless Fidelity

Wi-Max – Worldwide Interoperability for Microwave Access

Glossary

A

Access Charges: Charges designed to compensate local exchange carriers for the maintenance and operation of the local exchange network after the break up AT&T in 1984 in the Modified Final Judgment. Access charges take two forms: 1) an end user access charge, also known as Subscriber Line Charge that appears on the customer's bill as a separate line item; 2) carrier access charges paid by interexchange carriers to local exchange carriers when they connect to their local networks. Such charges are determined by tariffs subject to state or federal approval depending upon the intrastate or interstate nature of the call.

Alternative Fuels: Any non-traditional energy source.

Alternate Ratemaking for Pipelines: In a series of orders in February 1996, the Federal Energy Regulatory Commission opened the door to non-cost-based rates for pipeline services, including transmission and storage, provided that a pipeline could show: 1) it did not have market power or that the power was mitigated; and (2) cost-based recourse rates were available for customers who might be disadvantaged under the new system. Pipelines are also required to show the quality of service was maintained and that market-based, incentive or negotiated rates did not shift costs to captive customers.

American Gas Association (AGA): Trade group representing natural gas distributors and pipelines. The AGA also operates a laboratory for appliance certification.

Aquifer: Water bearing permeable rock formation that is capable of storing natural gas.

Area Code Overlay: A method used to relieve area code exhaust. A new three-digit area code is associated with the same geographic boundaries of an existing area code. Because the same seven-digit telephone numbers could then be assigned out of each area code, local calls are required to be dialed with 10-digits.

Area Code Split: A method used to relieve area code exhaust. The geographic area that uses the area code is split in two and a different area code is assigned to part of the geographic area while the other area keeps the existing area code.

Asynchronous Digital Subscriber Line (ADSL): A DSL designed to deliver more bandwidth downstream (from the central office to the customer's site) than upstream. Downstream rates range from 1.5 to 9 million bits per second. See also Digital Subscriber Line.

B

Base Gas: Gas required in a storage pool to maintain sufficient pressure to keep the working gas recoverable. Also called "cushion" gas.

Basic Telecommunications Service (BTS): A term used in House Enrolled Act 1279 to distinguish between telecommunication services regulated until June 30, 2009 and services that were unregulated on or before March 27, 2006. BTS is defined as standalone telephone exchange service that is provided to a residential customer through the customer's primary line; is the sole service purchased by the customer; is not a part of a package, promotion, or contract; and, not otherwise offered at a discounted price.

British Thermal Unit (Btu): The quantity of heat required to raise one pound of water (about one pint) one degree Fahrenheit at or near its point of maximum density. A common unit of measurement for gas prices. 1,034 Btus = 1 cubic foot.

Broadband: Advanced communications systems capable of providing high-speed transmission of services such as data, voice, and video over the Internet and other networks. Transmission is provided by a wide range of technologies, including digital subscriber line and fiber optic cable, coaxial cable, wireless technology, and satellite. Broadband platforms make possible the convergence of voice, video and data services onto a single network.

Bundled Resale of Local Exchange: Competitive local exchange carriers can compete by reselling the services of the incumbent local exchange carrier (ILEC) in this form. They purchase the services of the ILEC at wholesale rates hoping to resell them to retail customers at a profit. Each of Indiana's three large ILECs offer wholesale discounts to competitive carriers.

Bundled Service: Gas utility that operates as both the supplier and distributor of natural gas.

C

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Carbon Capture: The process of capturing carbon dioxide produced in the combustion of fuel to facilitate its disposal.

Carbon Sequestration: The storage of carbon dioxide in geological formations to prevent its release into the atmosphere.

Certificate of Public Convenience and Necessity (CPCN): A special permit commonly issued by a state commission that authorizes a utility to engage in business, construct facilities or perform some other service. Also a permit issued by the Federal Energy Regulatory Commission to engage in the transportation or sale for resale of natural gas in interstate commerce, or to construct or acquire and operate any facilities necessary.

City Gate: The physical location where gas is delivered by a pipeline to a local distribution company.

Coal Gasification: The controlled process of placing coal, steam, and oxygen under pressure to produce a low Btu gas.

Coal Bed Methane: Any gas produced from a coal seam.

Commodity Charge: The charge that covers the pipeline's variable costs in a Straight Fixed Variable rate design. Also referred to as a "usage charge."

Communications Service Provider: A term used in House Enrolled Act 1279 that means a person or entity offering communications services to customers in Indiana, without regard to the technology or medium used by the person or entity to provide the communications service.

Condemnation Action: A legal proceeding whereby a municipality exercises its power of eminent domain and condemns utility property that results in the transfer of utility property to the municipality.

Conditional Congestion Area: As designated by the U.S. Department of Energy, as areas where electric utilities have planned generation, and while some transmission congestion is present, significant congestion would result if transmission is not built in conjunction with the new generation resources.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Cost-of-Service Rates: Rates based on prudently incurred costs of doing business, plus a reasonable rate of return on investment in plant and equipment, and throughput projections. This is the rate development methodology commonly used by state or federal regulators.

Cramming: A practice in which customers are billed for unexpected and unauthorized telephone charges or services. Refers to the fact that the charges are crammed into the telephone bill in an inconspicuous place so the charges go unnoticed by the customer.

Customer Charge: A fixed amount to be paid periodically by a customer without regard to demand or energy actually used. The customer charge recovers the cost of meters and other administrative costs of billing.

D

Decoupling: Alternative rate design theory that separates the recovery of a utility's fixed costs from the volume of natural gas sold.

Dekatherm (Dth): A unit of heating value equal to 10 therms or one million Btus (1MMBtu). Roughly, 1Mcf = 1, MMBtu = 1 Dth

Demand Response: Reducing the use of electricity to meet local or regional power system needs rather than increasing the output of electricity.

Digital Subscriber Line (DSL): A generic term for digital lines provided by incumbent or competitive local exchange carriers that allows the customer to use the same subscriber line for voice and data simultaneously without subscribing to a second line for Internet access.

Distribution: The component of a gas, electric or water system that delivers gas, electricity, or water from the transmission component of the system to the end-user. Usually the commodity has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Distribution System Improvement Charge: A mechanism available to water utilities to pass the costs
of infrastructure replacement onto their customers between rate cases on a more expedited basis.

E

Effluent: The water that is discharged after being treated at a sewage plant.

Eligible Telecommunications Carrier (ETC): A common carrier eligible to receive universal service
support. An ETC is required to offer services that are supported by the federal universal support mechanisms either using their own facilities or a combination of its own facilities and resale of another carrier's services. State commissions are responsible for the designation of ETCs.

End Use: The final use to which gas or electricity is put by the ultimate consumer.

Energy Information Administration: Statistical information collection and analysis branch of the Department of Energy.

Energy Independence & Security Act of 2007: A comprehensive energy law that focuses on improved efficiency standards, and the research and development of energy technologies and infrastructure.

Energy Policy Act of 1992: This act authorized the Federal Energy Regulatory Commission to order wholesale wheeling of electricity while explicitly restraining its power to order retail wheeling. The Act also created a new legal category of electricity generating and sales companies, referred to as "Exempt Wholesale Generators," that are free from the Public Utility Holding Company Act of 1935 restrictions.

Energy Policy Act of 2005: Major provisions regarding the electricity industry included the creation of the Public Utility Holding Company Act of 2005, clean coal, nuclear, wind, and alternative energy initiatives, establishment of an Electric Reliability Organization, incentive rates for transmission investment, transmission siting, smart metering, net metering, utility interconnection with distributed generation, increased efficiency of fossil-fuel power plants, and the increased diversity of fuel sources to generate electricity.

Environmental Protection Agency: A federal agency created in 1970 to execute federal research, monitoring, standard setting and enforcement actions related to protecting the environment.

F

Facilities-based Interexchange: A carrier that offers facilities-based interexchange deploys their own tandems and/or trunks as opposed to purchasing blocks of time from other interexchange carriers and reselling the services to retail customers.

Facilities-based Local Exchange: A carrier that offers facilities-based local exchange may construct and deploy its own networks or it may rely on unbundled network elements from incumbent local exchange carriers or a combination of the two.

Federal Energy Regulatory Commission (FERC): The U.S. federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, and oil pipeline rates. The FERC also authorizes liquefied natural gas terminals, interstate natural gas pipelines and non-federal hydropower projects.

FiOS: Verizon's broadband initiative featuring fiber to the premise that is being deployed in several areas throughout the U.S.

Firm Service: The highest quality sales or transmission service that is offered to customers under a filed rate schedule that anticipates no planned interruption.

Fixed Costs: All costs included in the cost of service that do not fluctuate with the volume of the commodity passing through the system (e.g., labor, maintenance, and taxes).

G

Gigabit: A unit of measurement for the amount of data that is transferred in a second between two telecommunication points. One gigabit per second (Gbps) equals one billion bps.

Gasification: 1) The conversion of carbonaceous material into gas or the extraction of gas from another fuel. 2) The process during which liquefied natural gas is returned to its vapor or gaseous state through an increase in temperature and a decrease in pressure.

Gathering System: Pipelines and other equipment installed to collect, process, and deliver natural gas from the field, where it is produced, to the trunk or main transmission lines of pipeline systems.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

H

Heartland: Heartland Gas Pipeline, LLC

Hedging: A method by which a purchaser or producer of natural gas or electricity uses a derivative position to protect against adverse price movements in the cash market by "locking in" a price for future delivery.

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

I

Indiana Lifeline Assistance Program (ILAP): A state program required by House Enrolled Act 1279 for the purpose of offering reduced charges for basic telecommunications services to eligible customers (customers with income that falls within 150 percent of the Federal Poverty Guidelines or participates in certain assistance programs, such as Medicaid, food stamps, etc).

Independence Hub: A large natural gas production platform in the Gulf of Mexico.

Independent System Operator (ISO): An independent organization or institution that controls the electric transmission system in a particular region.

Indiana Utility Regulatory Commission: An independent fact-finding body that hears evidence in cases filed before it and makes decisions based on the evidence presented in those cases. An advocate of neither the public nor the utilities, the Commission is required by state statute to make decisions that balance the interests of all parties to ensure the utilities provide adequate and reliable service at reasonable prices.

Integrated Gasification Combined Cycle (IGCC) Facility: A power plant using synthetic gas as a source of clean fuel. Syngas is produced from coal (or other fuels) in a gasification unit. Steam generated by waste heat boilers of the gasification process is utilized to help power steam turbines.

Integrity Management: Specifies how pipeline operators must identify, prioritize, assess, evaluate, repair and validate - through comprehensive analyses - the integrity of gas pipelines that, in the event of a leak or failure, could affect High Consequence Areas.

Internet Protocol Television (IPTV): A system where a digital television service is delivered by using Internet Protocol over a network infrastructure that may include delivery by a broadband connection.

Interruptible Transportation Service: Conditional gas service interrupted at the option of the pipeline. Also, referred to as "best efforts." Tariffs for interruptible service are cheaper than firm service. Electric providers may offer a similar service.

Interstate Gas: Gas transported through interstate pipelines to be sold and consumed in states other than the one in which it was produced. Also, refers to gas produced in the federal domain of the Outer Continental Shelf.

Intrastate Gas: Gas sold and consumed in the state in which it was produced and not transported in interstate pipelines.

Investor-Owned Utility: A utility financed by the sale of securities.

J

Joint Board: Also known as the Federal-State Joint Board, instituted by the Federal Communications
Commission to recommend changes of any of its regulations in order to implement section 214(e) of the Telecommunications Act of 1996, including the definition of services that are supported by the Federal universal service support mechanisms.

K

Kilobit: A unit of measurement for the amount of data that is transferred in a second between two telecommunication points. One kilobit per second (Kbps) equals 1000 bit per second (bps).

Kilowatt (kW): A basic unit of measurement; 1kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

L

Landfill Gas: Gas produced by aerobic and anaerobic decomposition of a landfill generally composed of approximately 55% methane and 45% carbon dioxide, sometimes refined with membrane methods to eliminate the carbon dioxide.

Liquefied Natural Gas (LNG): Natural gas converted to a liquid state by pressure and severe cooling, and then returned to a gaseous state to be used as a fuel. It is stored by many distributors for peak season use.

M

Mandatory Number Pooling: Requires carriers to share a pool of numbers with the same exchange.
Without number pooling each competitive local exchange carrier is assigned an entire exchange or 10,000 block of phone numbers, which may not all be needed. With number pooling, exchanges can be broken down into blocks of 1,000, as known as "thousand block number pooling."

Megabit: A unit of measurement for the amount of data that is transferred in a second between two telecommunication points. One megabit per second (Mbps) equals one million bps.

Megawatt (MW): One thousand kilowatts or one million watts.

Megawatt-Hour (MWh): One megawatt of power supplied to or taken from an electric circuit steadily for one hour.

Merchant Plant: A power plant that is funded by investors and sells electricity in the competitive wholesale market.

Methane: The main component of natural gas.

Midwest ISO: The Midwest ISO was formed by transmission owners in 1996, and is based in Carmel,
Indiana. The Midwest ISO's main responsibility is to ensure the safe and reliable transfer of electricity in the Midwest and ensure fair access to the transmission system.

Multi-Association Group Order (MAG Order): A Federal Communications Commission Report and
Order adopted October, 2001 which prescribed access charge reform measures that affected small, rural incumbent local exchange carriers.

Municipalization: When a municipally-owned utility acquires an investor-owned utility serving a city or town.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

N

National Interest Electric Transmission Corridor: As established in the Energy Policy Act of 2005, any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers.

Normal Temperature Adjustment (NTA): A decoupling mechanism that reduces the risk of the gas utility not recovering margin due to warmer-than-normal (vice versa) during the heating season.

Not-for-profit Utility: A utility that does not distribute its surplus funds to owners or shareholders but uses them to pursue its goals.

NPDES Permits: Permits that allow utilities to discharge wastewater effluent into waterways.

O

Order 436: A Federal Energy Regulatory Commission rule promulgated in October 1985, establishing a voluntary, open-access system of natural gas transportation.

Order 500: An interim natural gas rule on open-access transportation, replacing Order 436. Order 500 embodied all the elements of Order 436 with three additions: forcing producers to credit transportation volumes against accruing take-or-pay (cross-crediting); allowing pipelines to direct bill customers for part of past take-or-pay charges; and allowing pipelines to fashion gas inventory charges (or supply reservation fees) to take care of future take-or-pay.

Order 636: Commonly known as the "Restructuring Rule," Order 636 provides for pipeline companies to change from being merchants of natural gas to being transporters of natural gas and allows open-access transportation services regardless of who owns the gas.

Order 712: Revised regulations governing interstate natural gas pipelines to reflect changes in the market for short-term transportation services on pipelines and to improve the efficiency of the capacity release program.

Organization of Midwest ISO States (OMS): A group of state utility commissions in the Midwest ISO footprint that acts as an adviser on some Midwest ISO functions.

P

Peak Shaving: Supply of fuel gas for distribution systems from an auxiliary source of limited supply and higher cost (e.g., propane, liquefied natural gas) during periods of maximum demand when the primary source is not adequate. Electricity providers may also use peak shaving to reduce demand at peak periods. Service interruptions and customer-owned generation are methods electricity providers use for peak shaving.

PJM Interconnection: The PJM Interconnection is the regional transmission organization (RTO)
responsible for the operation and control of the bulk power system throughout all or portions of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM became the first fully functioning RTO in 1997.

Point-to-Point Transmission: The reservation and/or transmission of electricity on either a firm basis and/or a non-firm basis from point(s) of receipt to points(s) of delivery, under a tariff, including any ancillary services that are provided by the transmission provider.

Private Activity Bonds: Municipal bonds that are issued to finance facilities for investor-owned or not-for-profit water utilities.

Privatization: When an investor-owned utility acquires a municipally-owned utility.

Public Utility Holding Company Act of 1935 (PUHCA): A federal law to facilitate the regulation of electric utilities, by either limiting their operations to a single state, and thus subjecting them to effective state regulation, or forcing divestitures so that each became a single integrated system servicing a limited geographic area. Another purpose of the PUHCA was to keep utility holding companies engaged in regulated businesses from engaging in unregulated businesses. The PUHCA required Securities and Exchange Commission approval prior to a holding company engaging in a non-utility business and that such businesses be kept separate from the regulated business. The PUHCA was repealed by the Energy Policy Act of 2005, and replaced by what is known as the Public Utility Holding Company Act of 2005.

Public Utility Regulatory Policies Act (PURPA): A federal law passed in 1978 as part of the National Energy Act. It was meant to promote greater use of renewable energy. Implementation of the act was left to the states. The PURPA was amended in 2005 by the Energy Policy Act of 2005 sections 1251 through 1254.

Pulverized Coal: Coal that is ground into dust using a powdered coal mill and used as the fuel in a power plant to generate electricity.

Purchasing Cooperative: A type of cooperative arrangement, often among businesses, to agree to aggregate demand to get lower prices from selected suppliers.

Q

Quadruple Play: A service bundle that includes high-speed data, telephony, television and wireless communications services.

R

Rate Base: The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return.

Rate Design: The method of classifying fixed and variable costs between demand and commodity components.

Rate of Return: The percentage that a company earns on its investment.

Raw Natural Gas: Natural gas brought from underground up to the wellhead. Natural gas found at the wellhead is not as pure as processed or pipeline quality natural gas used by consumers. Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells.

Reclaimed Water: Wastewater that has been treated to remove solids and certain impurities, and used for irrigation or recharging aquifers.

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Renewable Portfolio Standard: A requirement that a specified portion of a utility's electricity be supplied by energy sources defined as renewable.

S

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

Slamming: The practice of switching a telephone customer's long distance or local service provider without obtaining permission from the customer.

Smart Grid: An electricity delivery system that encompasses devices and technologies designed to improve the efficiency of energy use and the transfer of energy across it.

Small Utility Filing: A process where a utility, which serves under 5,000 customers, primarily residential, and does not serve extensively another utility, can increase its rates without a formal public hearing.

Spot Market: A market characterized by short-term, typically interruptible, or best efforts contracts for specified volumes. The bulk of natural gas spot market trades on a monthly basis, while power marketers sell spot supplies on an hourly basis.

Storage: Facilities used to store natural gas that is transferred from its original location. Usually consists of natural geological reservoirs like depleted oil or gas fields, waterbearing sands sealed on top by impermeable cap rock, underground salt domes, bedded salt formations, or in rare cases, abandoned mines.

Straight-Fixed Variable Rate Design: Rate design methodology that allocates all fixed costs to the demand component and allocates all variable costs to the commodity, or volumetric, component. Also called "Fixed Variable."

Supply Side Management: The systematic development of a gas supply plan or an electric resource plan.

Synthetic Natural Gas: Energy-rich vapors manufactured from coal.

System Development Charge: A one-time charge assessed by water and wastewater utilities to new customers to finance development of utility systems necessary to serve those new customers. The purpose is to impose a portion of the cost of capital improvements upon those developments that create the need for, or increase demand for capital improvements.

Sub-metering/Sub-billing: The practice where a consumer of utility service, usually an apartment complex or a mobile home park, passes along the cost of water or electric service to the tenants of the complex or park through a separate utility bill.

T

Take-and-Pay: Clause that requires a minimum quantity of natural gas to be physically taken and paid for, usually in association with oil, or wells, that will be damaged by failure to produce.

Tariff: Compilation of all effective rate schedules for a company, along with general terms and conditions of service.

Therm: Unit of heating value equivalent to 100,000 Btus.

Transmission: The process of transferring energy (either gas or electricity) or water from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Triple Play: A service bundle that includes telephone, high-speed Internet access and television.

U

Unaccounted for Gas: The difference between the total gas available from all sources and the total gas accounted for as sales, net interchange, and company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly billing lag.

Unbundled Network Elements: The Telecommunications Act of 1996 required that independent local exchange carriers unbundled their network elements to make them available to competitive local exchange carriers on the basis of incremental costs.

Universal Service: A policy to keep local rates low and encourage every household to have a telephone.

Unserved Energy: Electricity demand that the utility is unable to supply. In the electric utility planning process, unserved energy helps identify when and what type of new resources may be needed in the future.

V

Volatility: The market's price and movement within that range. The direction of the price move, whether up or down, is not relevant. Historic volatility indicates how much prices have changed in the past and is derived by using daily settlement prices for futures. Implied volatility measures how much the market thinks prices will change in the future, obtained from daily settlement prices for options.

Voltage: The rate at which energy is drawn from a source that produces a flow of electricity in a circuit; expressed in volts.

Voice over Internet Protocol (VoIP): Technology used to transmit voice conversations over a data network using the Internet Protocol. Such data network may be the Internet or a corporate Intranet.

W

Weatherization: Any change made to a home or building that is designed to conserve energy.

Well: A well that produces at surface conditions the contents of a gas reservoir.

Wellhead: The assembly of fittings, valves, and controls located at the surface and connected to the flow lines, tubing, and casing of the well as to control the flow from the reservoir.

Wireless Fidelity (Wi-Fi): Wi-Fi was originally a brand licensed by the Wi-Fi Alliance to describe the embedded technology of wireless local area networks (WLAN) based on the IEEE 802.11 standard. As of 2007, common use of the term Wi-Fi has broadened to describe the generic wireless interface of mobile computing devices, such as laptops in local area networks.

Withdrawal: Those uses of water that involve the physical removal of water from the ground or surface source.

Worldwide Interoperability for Microwave Access (Wi-Max): Wi-Max is a telecommunications technology aimed at providing wireless data over long distances in a variety of ways, from point-to-point links to full mobile cellular type access. Wi-MAX allows a user, for example, to browse the Internet on a laptop computer without physically connecting the laptop to a wall jack.

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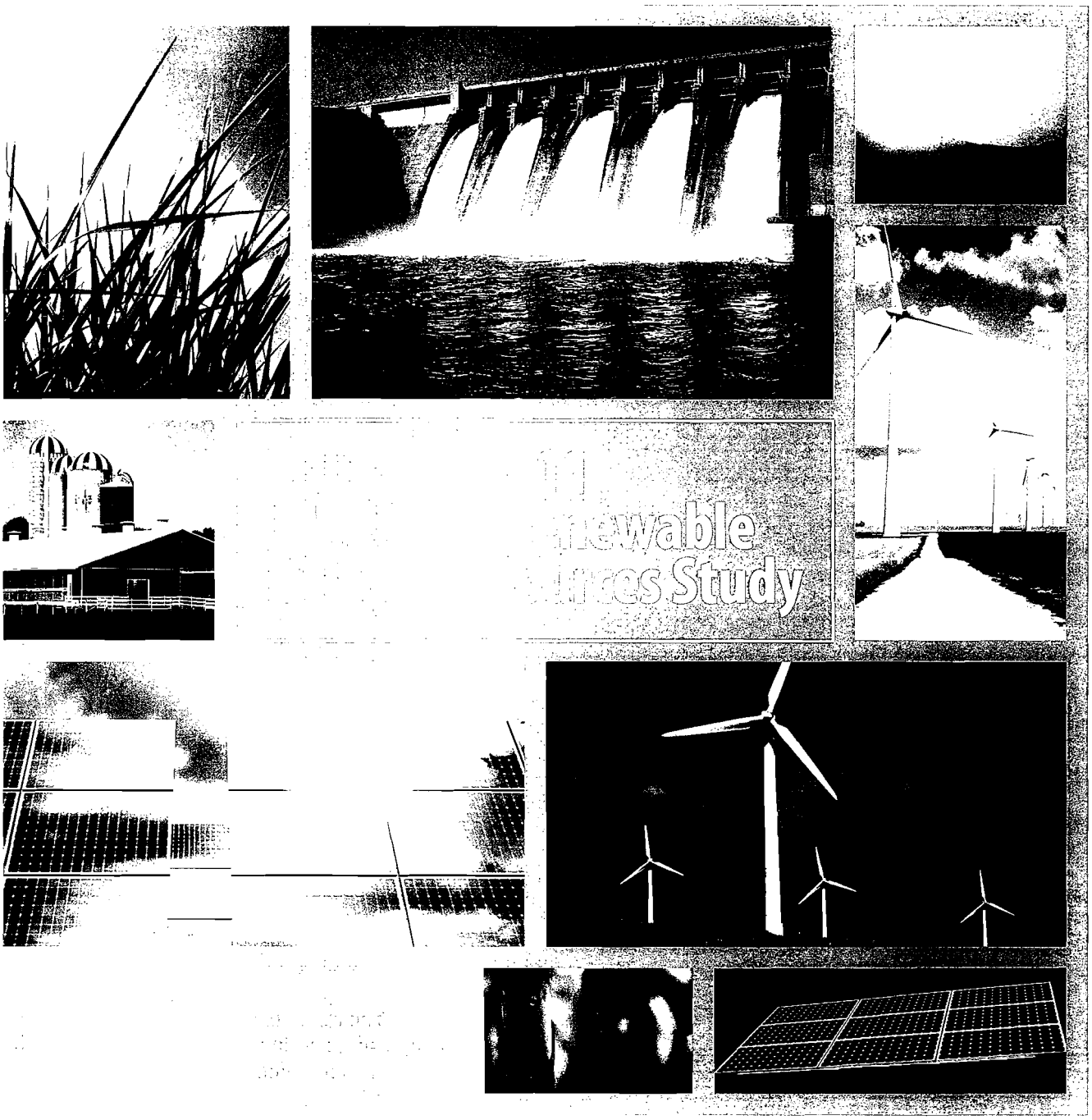

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2011 INDIANA RENEWABLE ENERGY RESOURCES STUDY

State Utility Forecasting Group

Energy Center

Purdue University

West Lafayette, Indiana

David Nderitu

Tianyun Ji

Benjamin Allen

Douglas Gotham

Paul Preckel

Darla Mize

Forrest Holland

Marco Velastegui

Tim Phillips

September 2011

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Acronyms and Abbreviations

AMP	American Municipal Power
AWEA	American Wind Energy Association
BIPV	Building Integrated Photovoltaic Panels
Btu	British Thermal Unit
CF	Capacity factor
CO_2	Carbon dioxide
CPV	Concentrating photovoltaic
CREB	Clean Renewable Energy Bonds
CSP	Concentrating Solar Power
CPS	Clean Energy Portfolio Standard
DOE	U.S. Department of Energy
DOI	U.S. U.S. Department of the Interior
DSIRE	Database of State Incentives for Renewables and Efficiency
EDP	Energias de Portugal energy corporation
EERE	Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy
EIA	Energy Information Administration, U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FHA	Federal Housing Authority
FY	Financial year
GW	Gigawatt
GWh	Gigawatthour
IEA	International Energy Agency
IMPA	Indiana Municipal Power Agency
INEL	Idaho National Engineering and Environmental Laboratory, U.S. Department of Energy

IPL	Indianapolis Power and Light Company
IREC	Interstate Renewable Energy Council
ITC	Business energy investment tax credit
IURC	Indiana Utility Regulatory Commission
kW	Kilowatt
kWh	Kilowatthour
LMOP	Landfill Methane Outreach Program, Energy Information Administration, U.S. Department of Energy
m/s	Meters per second
MACRS	Modified Accelerated Cost-Recovery System
MGY	Million gallons per year
mmBtu	million British Thermal Unit
mmscfd	million standard cubic feet per day
MMTCE	million metric tons of carbon equivalent
MOU	Memorandum of Understanding
mph	Miles per hour
MSW	Municipal solid waste
MACRS	Modified accelerated cost-recovery system
MTBE	Methyl tertiary butyl ether – a gasoline oxygenating additive
MW	Megawatt
MWh	Megawatthour
NIPSCO	Northern Indiana Public Service Company
NO_x	Nitrogen oxide
NRCS	Natural Resources Conservation Service, U.S. Department of Agriculture
NREL	National Renewable Energy Laboratory, U.S. Department of Energy
O&M	Operation and maintenance
OED	Indiana Office of Energy Development
ORNL	Oak Ridge National Laboratory, U.S. Department of Energy
POLYSYS	Policy Analysis System

PTC	Production tax credit
PV	Photovoltaic
REAP	Rural Energy for America Program, U.S. Department of Agriculture
REP	Renewable energy production – Indianapolis Power & Light feed-in tariff for renewable energy
REPI	Renewable Energy Production Incentive
QECB	Qualified Energy Conservation Bonds
RFA	Renewable Fuels Association
SEDS	State Energy Data System, Energy Information Administration, U.S. Department of Energy
SEGS	Solar Electric Generation System
SEIA	Solar Energy Industries Association
SOx	Sulphur oxides
SUFG	State Utility Forecasting Group
USDA	U.S. Department of Agriculture
VA	Veterans Affairs
VEETC	Volumetric ethanol tax credit
W/m^2	Watts Per Meter Squared
WVPA	Wabash Valley Power Association
WWT	Waste water treatment

Foreword

This report represents the ninth annual study of renewable resources in Indiana performed by the State Utility Forecasting Group. It was prepared to fulfill SUFG's obligation under Indiana Code 8-1-8.8 (added in 2002) to "conduct an annual study on the use, availability, and economics of using renewable energy resources in Indiana." The code was further amended in 2011, clarifying the topics to be covered in the report. In accordance with this change, fuel cells are no longer included and energy from algae is incorporated in the section on organic waste biomass.

The report consists of seven sections. Section one provides an overview of the renewable energy industry in the United States and in Indiana. It includes a discussion of trends in penetration of renewable energy into the energy supply, both nationally and in Indiana. The other six sections are each devoted to a specific renewable resource: energy from wind, dedicated crops grown for energy production, organic biomass waste, solar energy, photovoltaic cells, and hydropower. They are arranged to maintain the format in the previous reports as follows:

- Introduction: This section gives an overview of the technology and briefly explains how the technology works.
- Economics of the renewable resource technology: This section covers the capital and operating costs of the technology.
- State of the renewable resource technology nationally: This section reviews the general level of usage of the technology throughout the country and the potential for increased usage.
- Renewable resource technology in Indiana: This section examines the existing and potential future usage for the technology in Indiana in terms of economics and availability of the resource.
- Incentives for the renewable resource technology: This section contains incentives currently in place to promote the development of the technology and recommendations that have been made in regards to how to encourage the use of the renewable resource.
- References: This section contains references that can be used for a more detailed examination of the particular renewable resource.

This report was prepared by the State Utility Forecasting Group. The information contained in it should not be construed as advocating or reflecting any other organization's views or policy position. For further information, contact SUFG at:

State Utility Forecasting Group
203 South Martin Jischke Drive
Mann Hall, Suite 154
West Lafayette, IN 47907-1971
Phone: 765-494-4223
e-mail: sufg@ecn.purdue.edu
https://www.purdue.edu/dp/energy/SUFG/

1. Overview

This first section of the 2011 Indiana Renewable Energy Resources Report presents an overview of the trends in renewable energy consumption in the U.S. and in Indiana.

1.1 Trends in renewable energy consumption in the United States

Figure 1-1 shows the amounts of renewable energy in quadrillion British thermal units (Btu) consumed in the U.S. from 1949 to 2010. Until the early 2000s hydroelectricity and woody biomass were the dominant sources of renewable energy consumed in the U.S. The last decade has seen a rapid increase in biofuels (mainly corn-based ethanol) and wind sources of renewable energy. The rapid increase in corn-ethanol has been driven by two factors: first as a replacement of the oxygenating additive MTBE which started being phased out in 2000, then due to the Federal Renewable Fuel Standard first authorized in the 2005 Energy Policy Act and then expanded in 2007. Similarly the rapid increase in wind energy started with the introduction of the Federal Production Tax Credit in 1992.

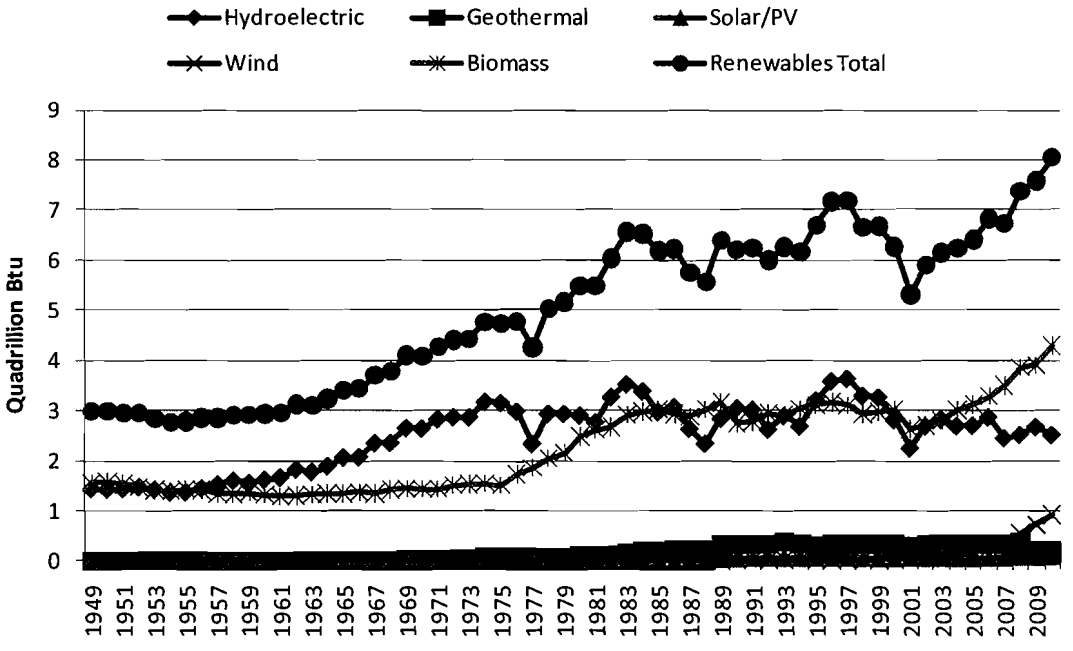

Figure 1-1: Renewable energy consumption in the U.S. (1949-2010) (Data source: EIA [1, 2])

Despite the growth shown in Figure 1-1, renewable energy's share of the total energy consumed in the U.S. remains modest at less than 10 percent. Figure 1-2 shows percentage contributions of renewable resources to the total energy consumed in the U.S. from 1949 to 2010. The share from renewable sources had been on steady decline from a high of 9 percent in 1983 to a low of 6

percent in 2001. With the expansion of corn-ethanol production capacity this share has risen to 8 percent in 2009 and 2010.

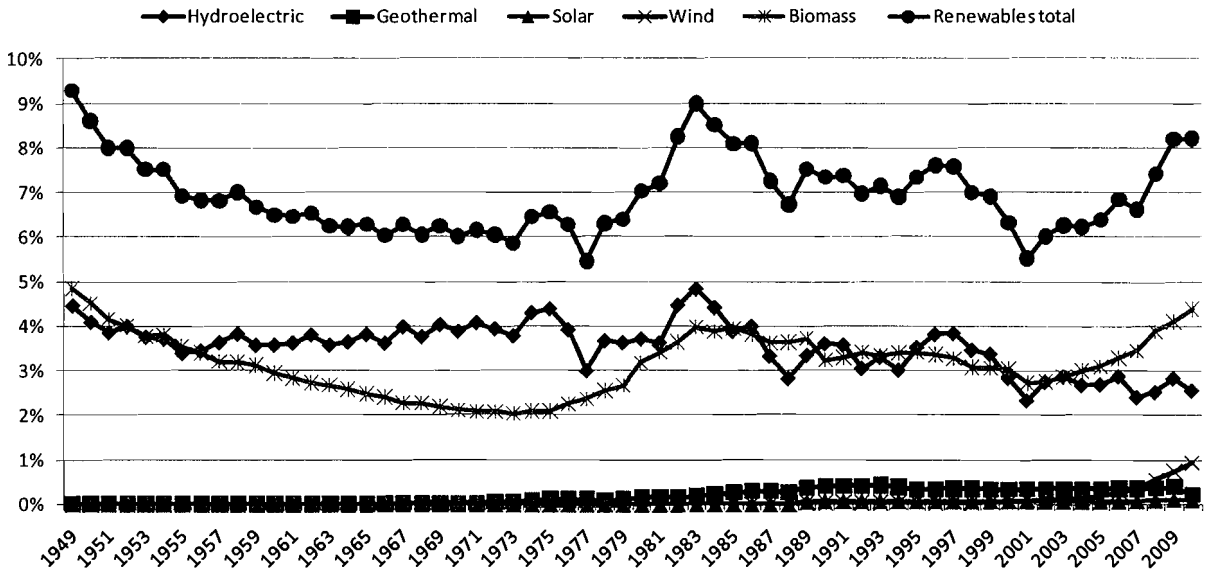

Figure 1-2: U.S. energy consumption by source (1949-2010) (Data source: EIA [1, 2])

Figure 1-3 shows the contribution of the various energy sources to total energy consumed in the U.S. in 2010. Petroleum continues to be the dominant energy source supplying 37 percent, followed by natural gas at 25 percent and coal at 21 percent. Among the renewable resources, biomass (including wood, biofuels, municipal solid waste, landfill gas and others) comprised over half of the renewable energy total, followed by hydroelectricity at 31 percent. Wind power's contribution increased to 11 percent from 9 percent in 2009, geothermal dropped from 5 percent in 2009 to 3 percent, and solar remained at 1 percent.

When one considers renewable resources in electricity generation (Figure 1-4), hydroelectricity plays a dominant role, exceeding all other renewable resources combined. Hydroelectricity makes up 60 percent of the renewable electricity generated. Wind energy takes second place at 22 percent of the renewable electricity and wood biomass takes third place at 9 percent. Waste biomass and geothermal each contributed 4 percent of the electricity generation in 2010 and solar contributes just 0.3 percent despite its rapid growth. As expected pumped hydroelectricity's net energy contribution was negative.[1]

[1] Pumped hydroelectric facilities use electricity from the grid during periods of low demand so as to be available to generate electricity during high demand periods. Due to evaporation and inefficiencies in the pumping and generating processes, less energy is generated than is used. The value of the lost energy is more than compensated because low cost, off-peak electricity is converted to high cost, on-peak electricity.

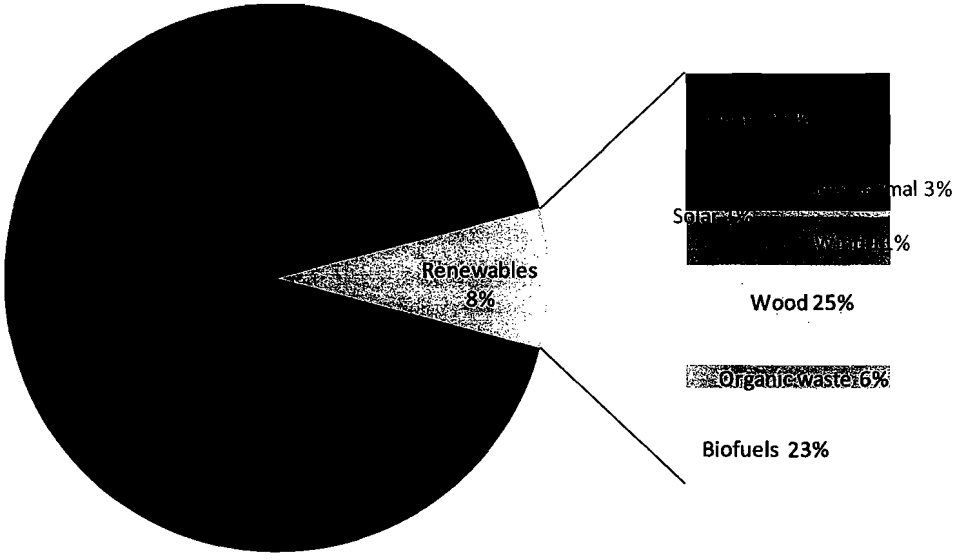

Figure 1-3: U.S. total energy consumption by energy source in 2010 (Data source: EIA [2])

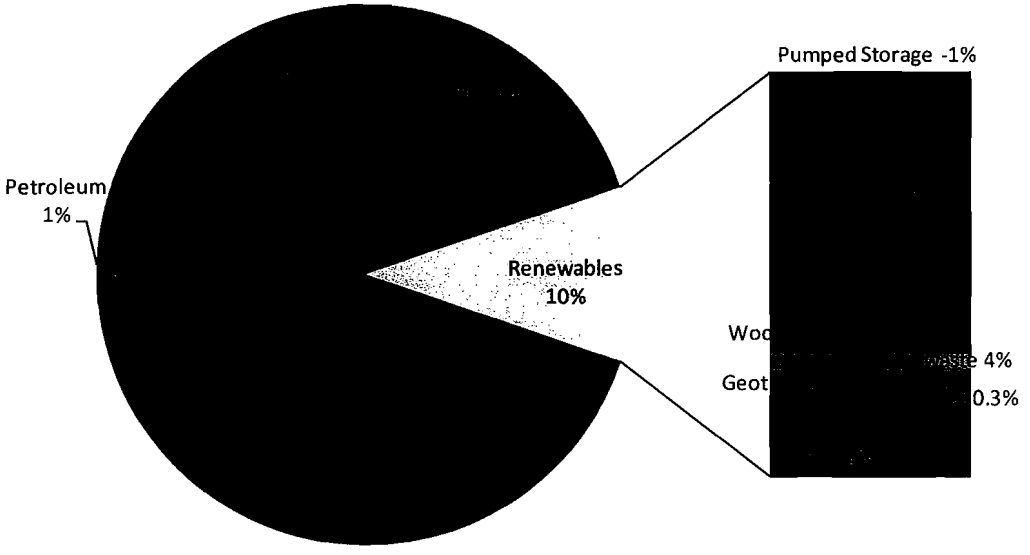

Figure 1-4: Net U.S. electricity generation by energy source in 2010 (Data source: EIA [3])

1.2 Trends in renewable energy consumption in Indiana

Figure 1-5 shows renewable energy consumption in Indiana from 1960 to 2009. In the 1980s, renewable resources contributed over 3 percent of total energy consumed in Indiana. In the 1990s the share fell to below 2 percent, before the recent increase in ethanol and wind increased it to over 4.6 percent. Woody biomass had been the main source of renewable energy in Indiana, contributing over 80 percent of the total renewable energy until the recent rise of corn-based ethanol.

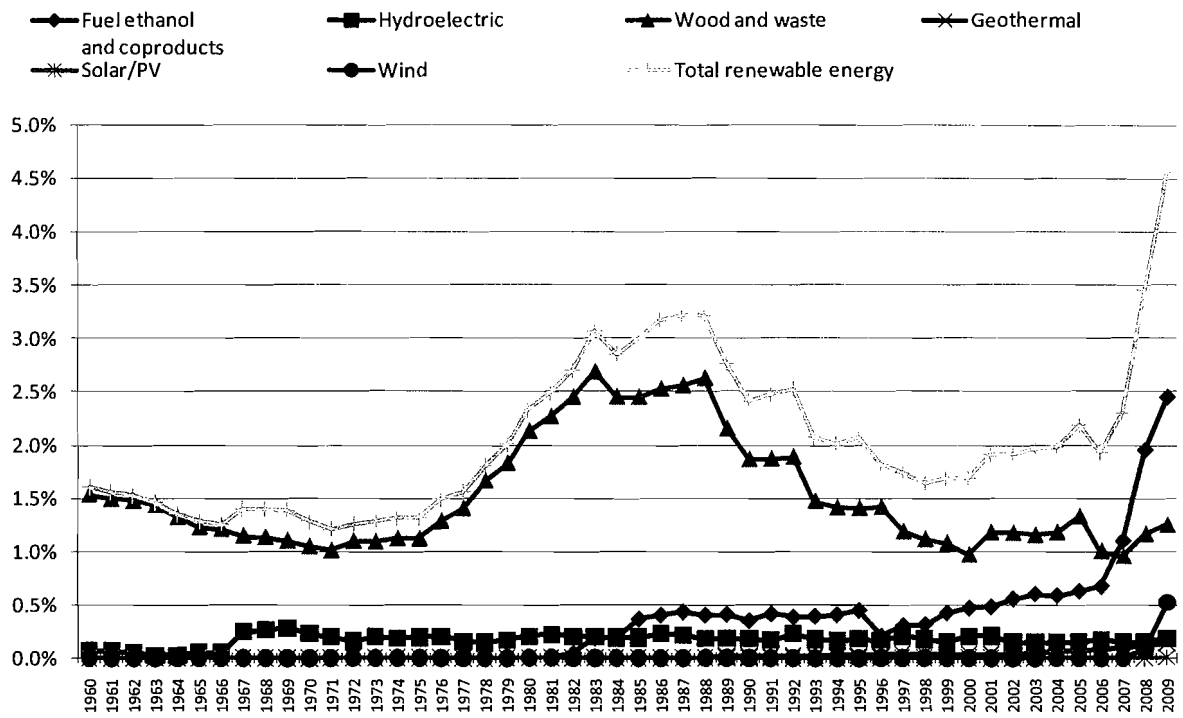

Figure 1-5: Renewables share of Indiana total energy consumption (1960-2009) (Data source: EIA [4])

Figure 1-6 shows the contribution of renewable energy to Indiana's electricity generation from 1990 to 2009. The arrival of utility scale wind energy projects in 2007 caused a rapid increase in renewable energy's share of Indiana's electricity generation. The share changed from a low of 0.5 percent in 2006 to 1.9 percent in 2009. Wind energy's share of the annual generation in 2009 was 1.5 percent and 2.4 percent in 2010 [5]. Hydroelectricity, which until 2007 was the dominant source of renewable electricity, has maintained its share at approximately 0.4 percent.

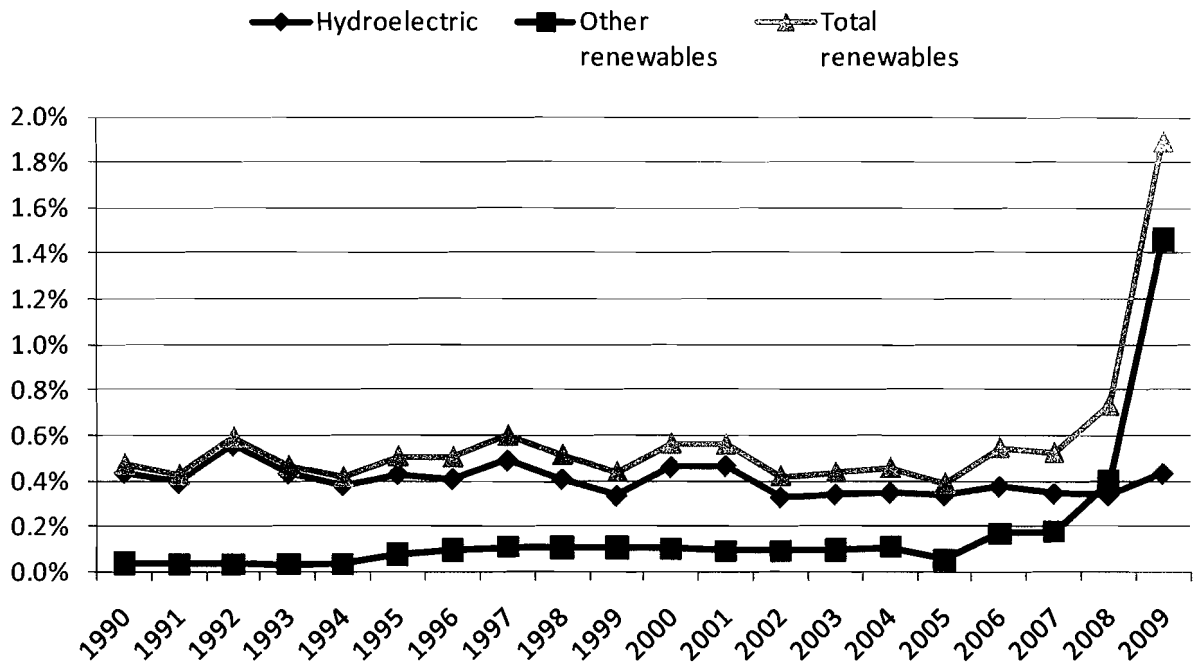

Figure 1-6: Renewables share of Indiana net electricity generation (1990-2009) (Data source: EIA [6])

The rapid growth in Indiana's wind generating capacity has slowed substantially, from a high of 907 MW wind capacity commissioned in 2009 to 301 MW commissioned in 2010. As of the writing of this section of the report, SUFG was not aware of any utility scale wind farm commissioned in 2011. This reduction in wind installation in Indiana is part of a national trend that has been attributed to factors such as

- the delayed impact of the 2008 global financial crisis affecting the availability of capital,
- the reduced demand for electricity and resulting low electricity wholesale prices, and
- the relatively low price of natural gas as a result of the development of shale gas [5].

Figure 1-7 shows the growth in Indiana wind capacity from 2008 to 2010. Three wind farms with a combined capacity of 352 MW had been approved for construction and one 200 MW wind farm was at an advanced stage of the application process at the writing of this report. Indiana utilities had signed agreements to purchase 871 MW of wind generation, 487 MW from wind farms located in Indiana and 384 MW from out of state.

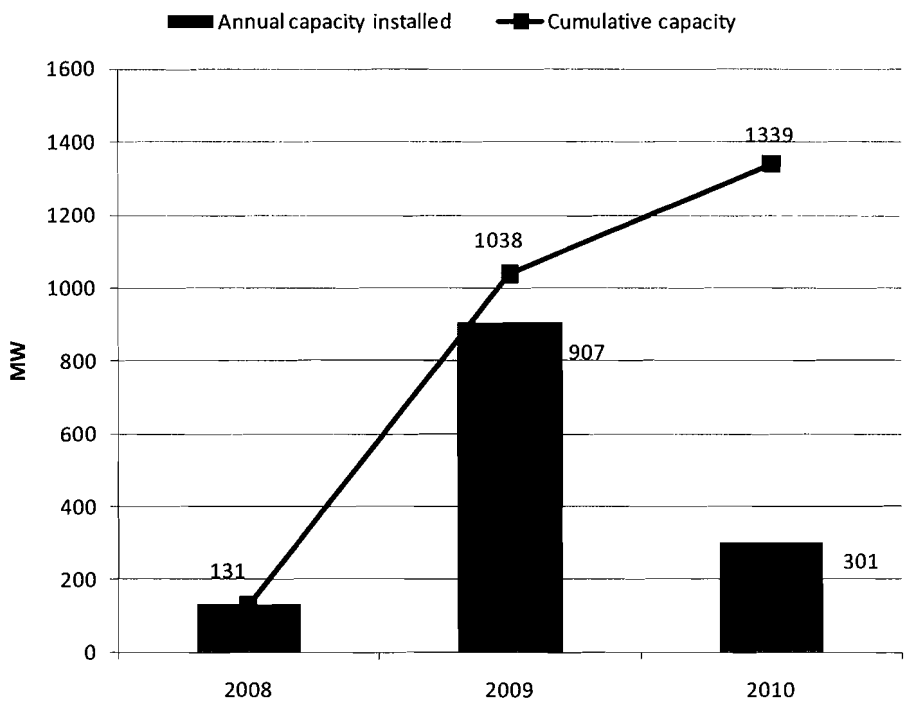

Figure 1-7: Wind energy installed capacity in Indiana (Data source: IURC [7]).

1.3 References

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7. Indiana Utility Regulatory Commission. Personal communication with staff.

2. Energy from Wind

2.1 Introduction

Wind turbines convert the kinetic energy in wind into mechanical energy and then into electricity by turning a generator. There are two main types of wind turbines, vertical and horizontal axis. The horizontal axis turbine with three blades facing into the wind is the most common configuration in modern wind turbines. Figure 2-1 shows the basic parts of a modern wind turbine used for electricity generation.

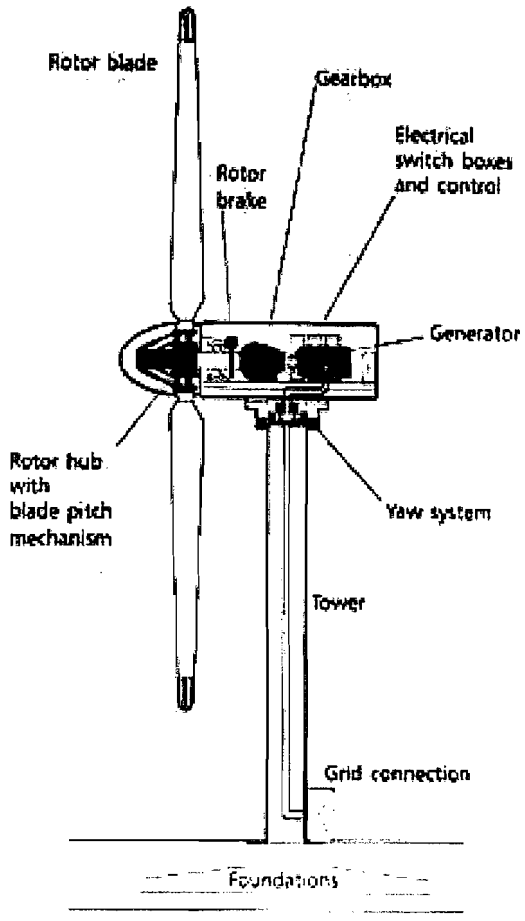


Figure 2-1: Horizontal wind turbine configuration (Source: South Ayrshire Council [1])

Utility scale wind farms in the U.S. began in California in the 1980s, with individual wind turbines on the order of 50 – 100 kilowatt (kW) of rated capacity. This has grown steadily to the point where the 1.5 megawatt (MW) wind turbine is common in modern day wind farms [2]. Despite this dramatic increase in size and capacity, a wind farm's generating capacity is still small compared to coal and nuclear power plants. The largest wind farm in the U.S. is the Horse

Hollow Wind Farm in Texas with a name plate capacity of 736 MW [3], while the largest coal power plant in Indiana is composed of five 600 MW units adding up to a plant capacity of 3,000 MW. Furthermore the capacity factor of a wind farm is typically far less than that of a baseload power plant.[2] A baseload coal or nuclear power plant in the U.S. will typically have an annual capacity factor of over 80 percent while the capacity factors of wind farms are estimated to range between 25 and 40 percent, depending on the average annual wind speeds at their location [4].

Wind speeds are important in determining a turbine's performance. Generally, annual average wind speeds of greater than 3 meters per second (m/s), or 7 miles per hour (mph), are required for small electric wind turbines not connected to the grid, whereas utility-scale wind plants require a minimum wind speed of 5 m/s (11 mph). The power available to drive wind turbines is proportional to the cube of the speed of the wind. This implies that a doubling in wind speed leads to an eight-fold increase in power output. A measurement called the wind power density measured in watts per square meter (W/m^2), calculated from annual observed wind speeds and the density of air, is used to classify sites into "wind power classes" [5]. Table 2-1 lists the class distinctions currently used.

	10 m (33 ft) Elevation		**50 m (164 ft) Elevation**	
Wind Power Class	Wind Power Density (W/m^2)	Speed m/s (mph)	Wind Power Density (W/m^2)	Speed m/s (mph)
1	< 100	< 4.4 (9.8)	< 200	< 5.6 (12.5)
2	100 – 150	4.4 – 5.1 (9.8 – 11.5)	200 – 300	5.6 – 6.4 (12.5 – 14.3)
3	150 – 200	5.1 – 5.6 (11.5 – 12.5)	300 – 400	6.4 – 7.0 (14.3 – 15.7)
4	200 – 250	5.6 – 6.0 (12.5 – 13.4)	400 – 500	7.0 – 7.5 (15.7 – 16.8)
5	250 – 300	6.0 – 6.4 (13.4 – 14.3)	500 – 600	7.5 – 8.0 (16.8 – 17.9)
6	300 – 400	6.4 – 7.0 (14.3 – 15.7)	600 – 800	8.0 – 8.8 (17.9 – 19.7)
7	> 400	> 7.0 (15.7)	> 800	> 8.8 (19.7)

Table 2-1: Wind resource classification (Source: AWEA [5])

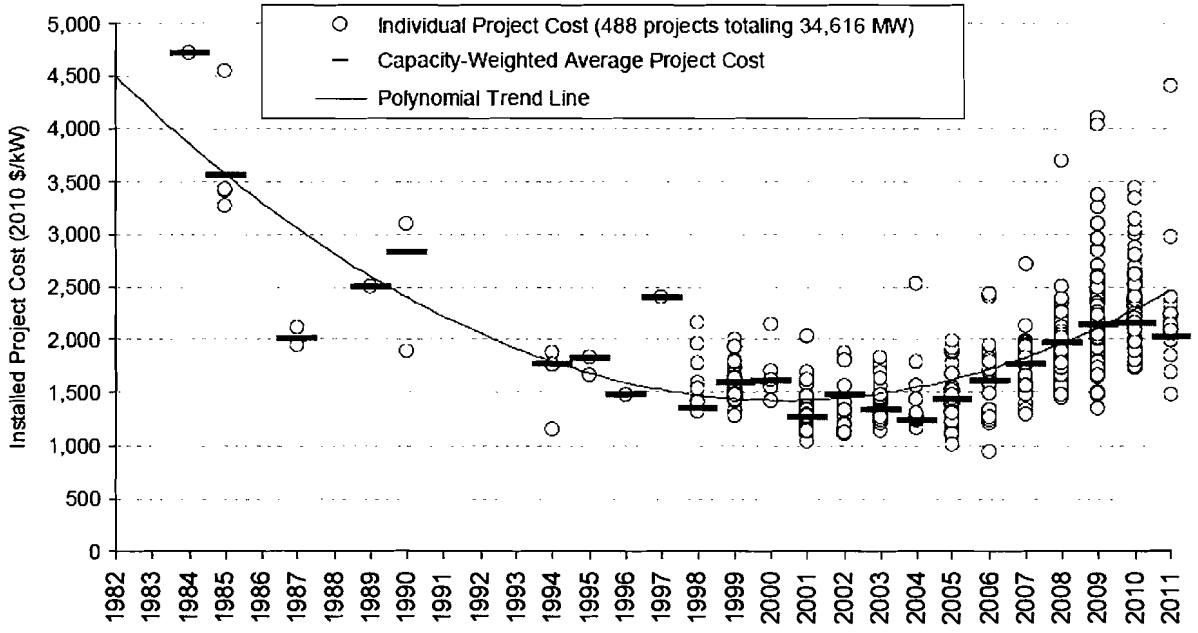
In addition to its being a virtually inexhaustible renewable resource, wind energy has the advantage of being modular; that is a wind farm's size can be adjusted by simply

[2] $\text{Annual capacity factor} = \dfrac{\text{Actual amount of energy produced in a year}}{\text{Energy that would have been produced if plant operated at full rated capacity all year}}$

adjusting the number of turbines on the farm. Wind technology's main disadvantage when compared to traditional fossil fuel generation is that the amount of energy coming out of the turbine is solely dependent on the wind and the electric system operator cannot dispatch it to match the varying demand as is done with traditional generation. Another significant disadvantage is that good wind sites tend to be located far from main load centers and transmission lines. Concerns have also been raised about the death of birds and bats flying into wind turbines and the possibility of turbines causing radar interference.

2.2 Economics of wind energy

Through 2010, the installed cost of wind energy projects continued to follow an upward trend that started in the early 2000s. The $2,155/kW capacity-weighted average costs of projects installed in 2010 was 65 percent higher than the average cost of projects installed from 2001 through 2004. Figure 2-2 shows the trends in the installed projects costs from 1982 to 2010. Nevertheless, the $2,155/kW capacity-weighted average installed cost in 2010 was essentially unchanged from the $2,144/kW in 2009; it is also expected that average installed costs may decline in 2011 [6].



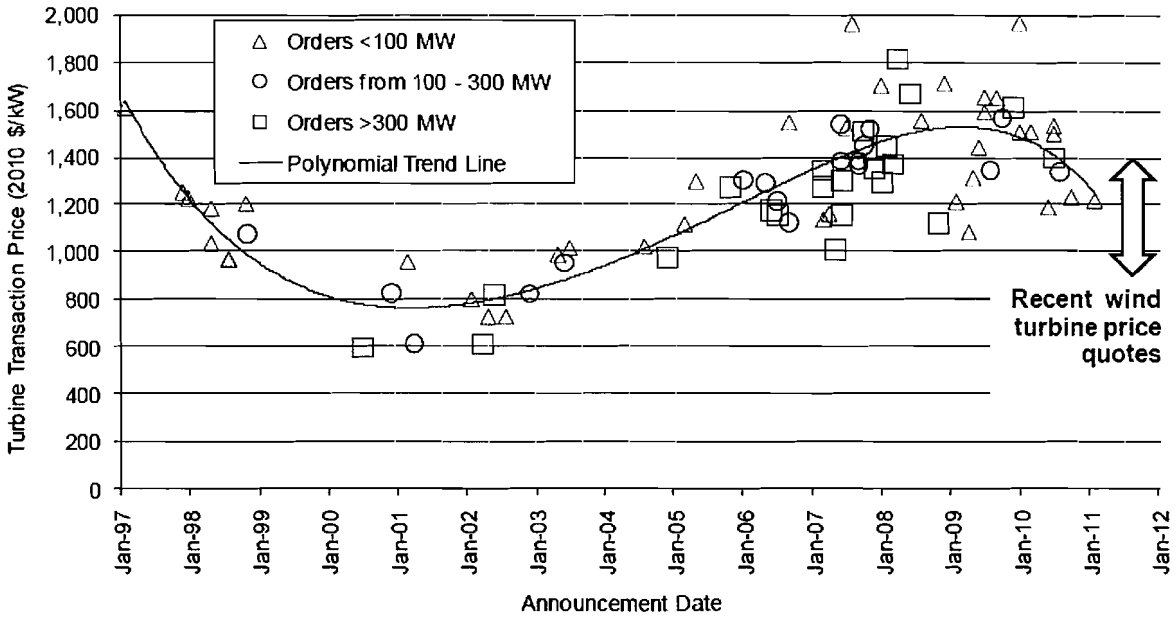
Note: 2011 data represent preliminary cost estimates for a sample of 17 projects totaling 1.1 GW that have either already been or will be built in 2011, and for which reliable cost estimates were available.

Source: Berkeley Lab (some data points suppressed to protect confidentiality)

Figure 2-2: Installed wind project costs over time (Source: EERE [6])

The expected decline in wind farm project costs is already being reflected by a reduction in prices of turbines in the beginning months of 2011. Figure 2-3 shows

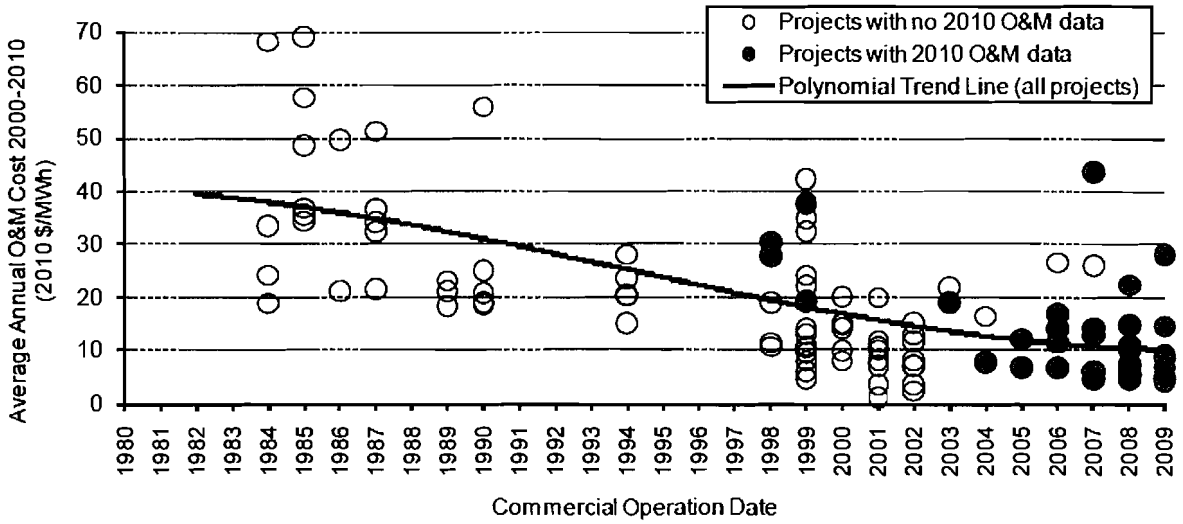
wind turbine costs over time as calculated for the projects included in the Lawrence Berkeley National Laboratory dataset used in the *2010 Wind Technologies Market Report* [6]. As illustrated in the diagram, turbine prices were in a steady decrease since 2008, when turbine prices achieved their peak. This decline reflected similar declines in energy and commodity prices, and a shift in the supply-demand balance for turbines towards a buyer's market. These price reductions are expected to drive down total project costs and wind power prices.



Source: Berkeley Lab

Figure 2-3: Reported U.S. wind turbine prices over time (Source: EERE [6])

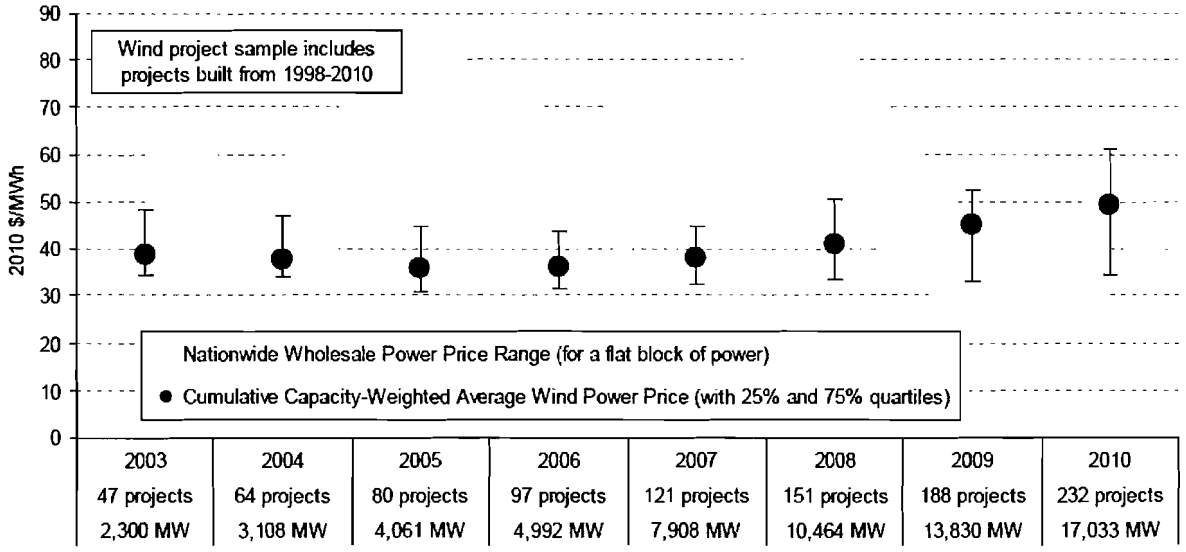
Operation and maintenance (O&M) costs are a significant component of the overall cost of wind energy, but can vary substantially among projects. Figure 2-4 shows O&M costs using data compiled by Berkeley Lab for 126 wind projects installed between 1982 and 2009 with a total capacity of 7,502 MW. It suggests that projects installed recently have incurred lower average O&M costs. Specifically, capacity-weighted average O&M costs for the 24 sampled projects constructed in the 1980s were $33/MWh, which dropped to $22/MWh for the 37 projects installed in the 1990s, and to $10/MWh for the 65 projects installed since 2000 [6].



Source: Berkeley Lab; seven data points suppressed to protect confidentiality

Figure 2-4: Reported U.S. wind turbine O&M costs over time (Source: EERE [6])

Figure 2-5 shows the range of average annual wholesale electricity prices for a flat block of power and the cumulative capacity-weighted average price received by wind power projects in each year from 2003 to 2010. On a cumulative basis, average wind power prices compared favorably to wholesale electricity prices from 2003 through 2008. However, increasing wind power prices combined with a sharp drop in wholesale electricity prices in 2009 (driven by lower natural gas prices and reduced electricity demand), decreased the competitiveness of wind power. Low wholesale electricity prices continued to challenge the relative economics of wind power in 2010 [6].



Source: Berkeley Lab, FERC, Ventyx, ICE

Figure 2-5: Average cumulative wind and wholesale electricity prices (Source: EERE [6])

2.3 State of wind energy nationally

In 2010 the U.S. wind power industry experienced a significant reduction in new builds compared to both 2008 and 2009. As can be seen in Figure 2-6, the 5,113 MW of new capacity added in 2010 is much lower than the 9,994 MW added in 2009. In 2010 $11 billion were invested in wind power project installations. This level was similar in magnitude to investment in 2007, but just half the investment in 2009 and 40 percent lower than in 2008. Wind power comprised 25 percent of U.S. electric generating capacity additions in 2010; this is down from 42 percent in 2009, 43 percent in 2008, and 34 percent in 2007. The reduced growth in 2010 can be attributed to the following factors [6]:

1. The delayed impact of the global financial crisis affected the capital availability for 2010 projects that were being planned in 2009;
2. The prices of natural gas and wholesale electricity were relatively low, inhibiting the development of merchant projects that were more common in previous years;
3. Slumping overall demand for energy reduced utility demand for wind energy power purchase agreements; and
4. 2009 capacity additions being largely determined by decisions made prior to the global financial crisis, while decisions on 2010 capacity additions were often made at the height of the financial crisis.

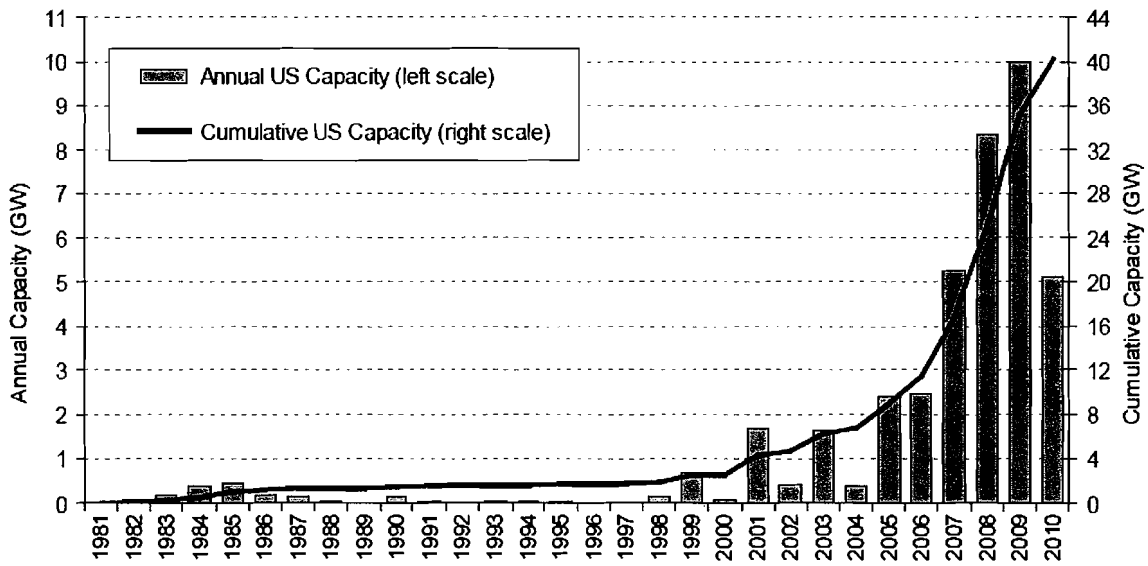


Figure 2-6: Annual capacity additions and cumulative capacity in the U.S. (Source: EERE [6])

Despite the low growth in 2010, cumulative wind power capacity still had a healthy growth of 15 percent in 2010, bringing the total to 40,267 MW. Expectations are for moderately higher capacity additions in 2011 than in 2010, but still below the 2009 level [6]. Continued and

expanded federal and state incentives and renewable portfolio standards and goals at the state level played important roles in keeping the wind industry active. Figure 2-7 is a map showing the states that have enacted some form of renewable portfolio standard or set a non-binding goal.

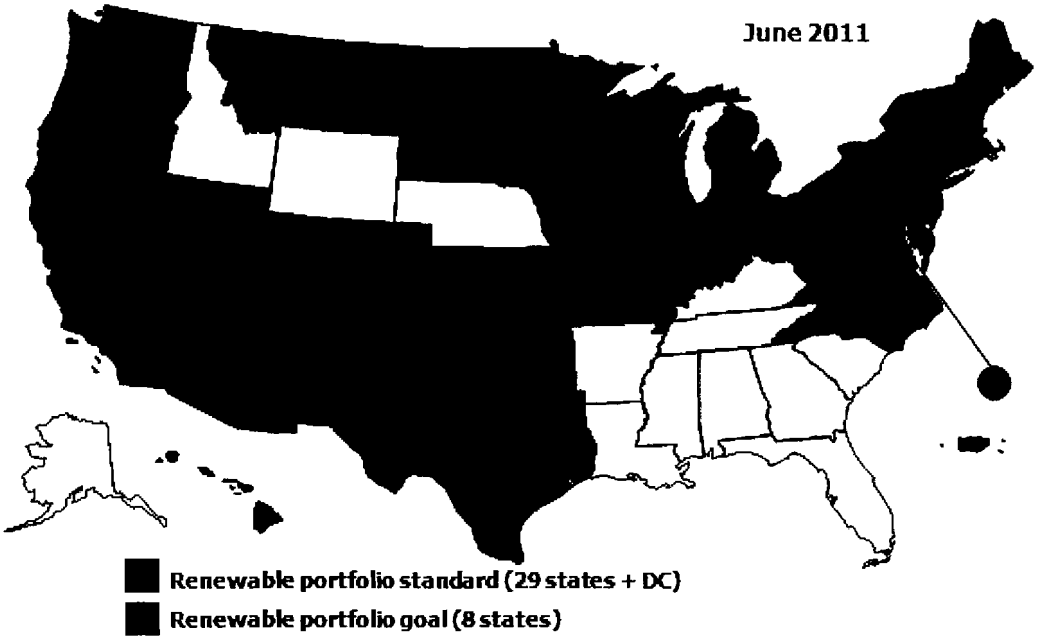


Figure 2-7: Renewable portfolio standards across the U.S. (Source: DSIRE[7])

Figure 2-8 shows the cumulative capacity of wind energy installed in states as of the end of 2010. Texas continued to lead with a total capacity of 10,089 MW installed, which is the first state to exceed the 10 GW milestone. Texas also led in terms of new wind power capacity, with 680 MW installed in 2010, but this figure is much lower than the 2,292 MW installed in 2009 and 2,671 MW installed in 2008. The other top five states in terms of cumulative capacity were Iowa – 3,675 MW; California – 3,253; Minnesota – 2,205; and Washington/Oregon – 2,104. Indiana's place as a wind energy state has changed dramatically, from having no utility-scale wind project in 2007 to being ranked 11th nationally with an installed capacity of 1,339 MW at the end of 2010.

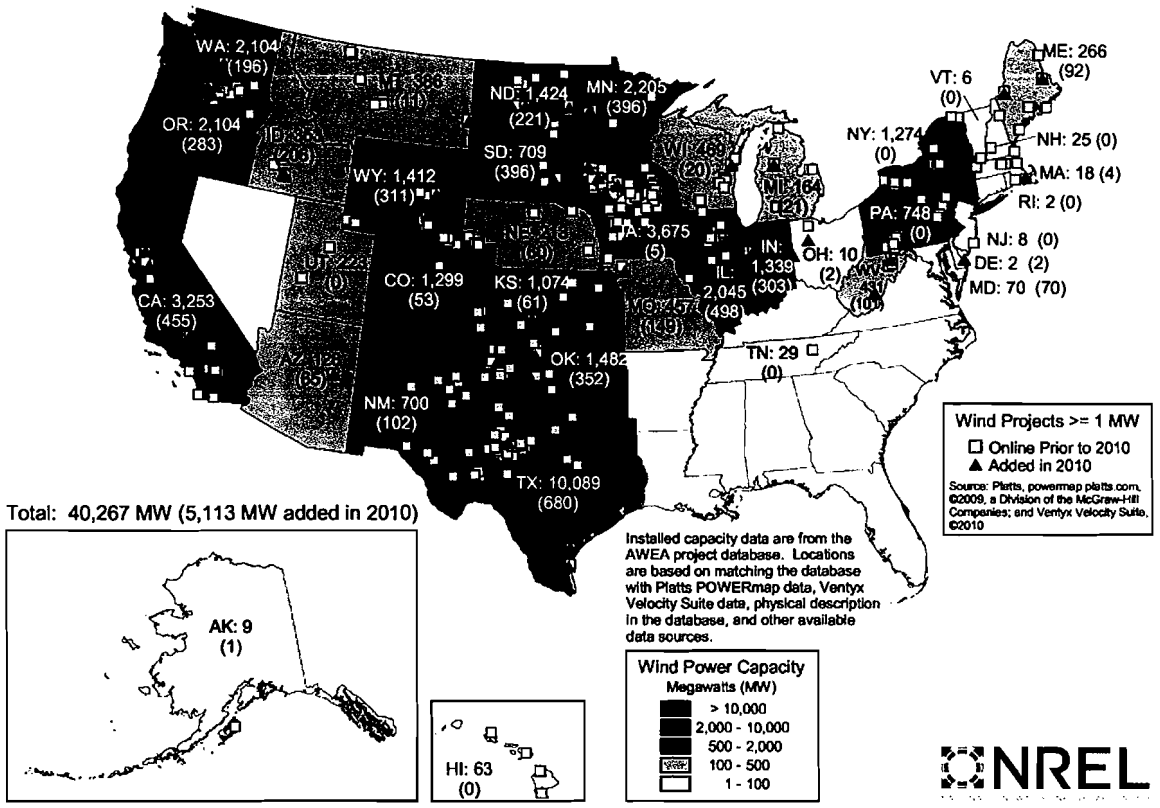


Figure 2-8: Wind power capacity by state at the end of 2010 (MW) (Source: EERE [6])

With regard to the penetration of wind energy as a percent of the total electricity generated in 2010, Texas dropped to ninth place with 6.4 percent. The leading five states in wind energy penetration in 2010 are Iowa –15.4 percent; North Dakota – 12 percent; Minnesota – 9.7 percent; South Dakota – 8.3 percent; and Kansas – 7.1 percent. Table 2-2 shows the top twenty states in capacity added in 2010, total cumulative capacity, actual and estimated penetration of wind energy in 2010. Indiana's wind penetration ranks 17th nationally at 2.4 percent of total in-state electricity generation, which is slightly above the U.S. average of 2.3 percent.

Capacity (MW)				Percentage of In-State Generation			
Annual (2010)		Cumulative (end of 2010)		Actual (2010)*		Estimated (end of 2010)**	
Texas	680	Texas	10,089	Iowa	15.4%	South Dakota	23.2%
Illinois	498	Iowa	3,675	North Dakota	12.0%	Iowa	16.9%
California	455	California	3,253	Minnesota	9.7%	North Dakota	13.5%
South Dakota	396	Minnesota	2,205	South Dakota	8.3%	Minnesota	12.3%
Minnesota	396	Washington	2,104	Kansas	7.1%	Oregon	9.8%
Oklahoma	352	Oregon	2,104	Oregon	7.1%	Wyoming	8.2%
Wyoming	311	Illinois	2,045	Wyoming	6.7%	Colorado	7.8%
Indiana	303	Oklahoma	1,482	Colorado	6.6%	Kansas	7.6%
Oregon	283	North Dakota	1,424	Texas	6.4%	Idaho	7.3%
North Dakota	221	Wyoming	1,412	Oklahoma	5.1%	Oklahoma	6.9%
Idaho	206	Indiana	1,339	New Mexico	5.0%	Texas	6.7%
Washington	196	Colorado	1,299	Washington	4.6%	New Mexico	6.0%
Missouri	149	New York	1,274	Idaho	4.0%	Washington	5.2%
New Mexico	102	Kansas	1,074	California	3.3%	Maine	4.4%
West Virginia	101	Pennsylvania	748	Montana	3.1%	Montana	3.9%
Maine	92	South Dakota	709	Maine	2.9%	California	3.9%
Maryland	70	New Mexico	700	Indiana	2.4%	Indiana	3.0%
Arizona	65	Wisconsin	469	Hawaii	2.3%	Illinois	2.8%
Kansas	61	Missouri	457	Illinois	2.2%	Hawaii	2.3%
Nebraska	60	West Virginia	431	New York	2.0%	New York	2.0%
Rest of U.S.	118	*Rest of U.S.*	1,974	*Rest of U.S.*	0.3%	*Rest of U.S.*	0.3%
TOTAL	**5,113**	**TOTAL**	**40,267**	**TOTAL**	**2.3%**	**TOTAL**	**2.6%**

* Based on 2010 wind and total generation by state from EIA's *Electric Power Monthly*.

** Based on a projection of wind electricity generation from end-of-2010 wind power capacity, divided by total in-state electricity generation in 2010.

Source: AWEA project database, EIA, Berkeley Lab estimates

Table 2-2: U.S. wind power rankings: Top 20 states (Data source: EERE [6])

Access to transmission continued to be a major issue in wind energy development since the most abundant on shore wind energy resource is in the Great Plains (Figure 2-9) and distant from the major population centers along the coasts. Although Figure 2-9 does not show it, the wind resources off the coasts are typically better than onshore winds, with higher wind speeds that are steadier and with less ground level interference. To date, no offshore projects have been installed in the United States, but interest in developing offshore wind energy exists in several parts of the country. The U.S. Department of the Interior (DOI) signed a Memorandum of Understanding (MOU) with the governors of 10 coastal states in June 2010 forming the Atlantic Offshore Wind Energy Consortium, to facilitate the coordination of offshore development off the East Coast. Also, DOI's Bureau of Ocean Energy Management, Regulation, and Enforcement formed renewable energy task forces in several coastal states to facilitate offshore wind project development. There are nine proposed offshore wind projects with capacity of 2,322 MW that have made significant advances in the permitting and development process in the U.S. [6]

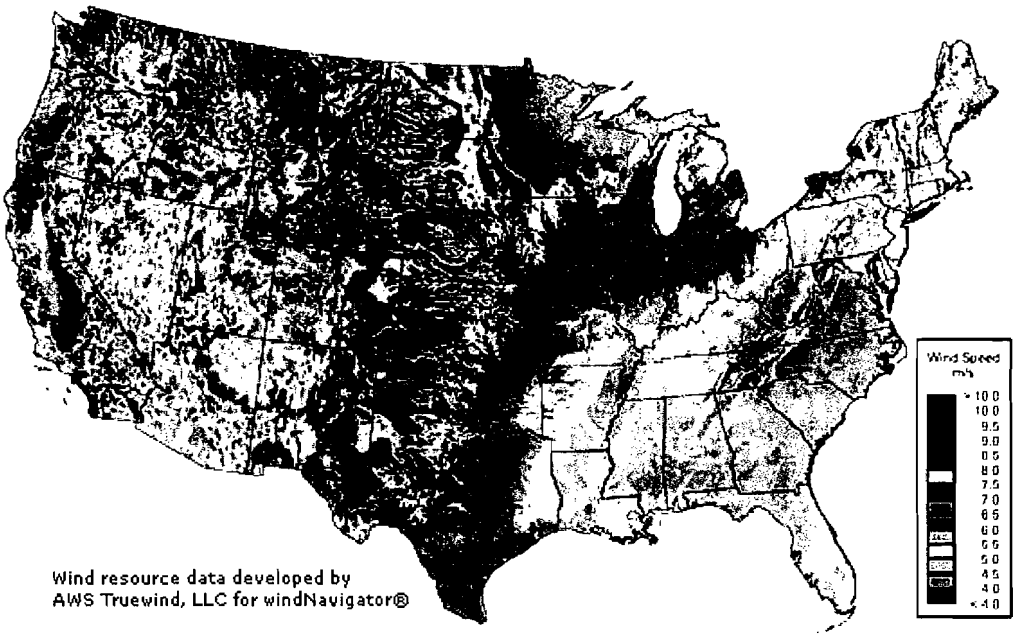


Figure 2-9: 80-meter onshore wind resource map (Source: EERE [8]

The U.S. has significant wind energy potential. Areas with gross capacity factor (without loss) greater than 30 percent at 80-meter height are generally considered as windy land areas, which have suitable wind resource for potential wind development with today's advanced wind turbine technology. National Renewable Energy Laboratory (NREL) estimated that the potential rated capacity that could be installed on available windy land areas across U.S. is 10,956,912 MW, and the annual wind energy that could be generated from these potential installed capacities is 38,552,706 GWh. Current installed capacity of the entire U.S. is only 40,267 MW [6], indicating potential for additional wind energy. Figure 2-10 shows the potential gigawatts of rated capacity above a given gross capacity factor (without losses) at 80-meter and 100-meter heights above ground [8].

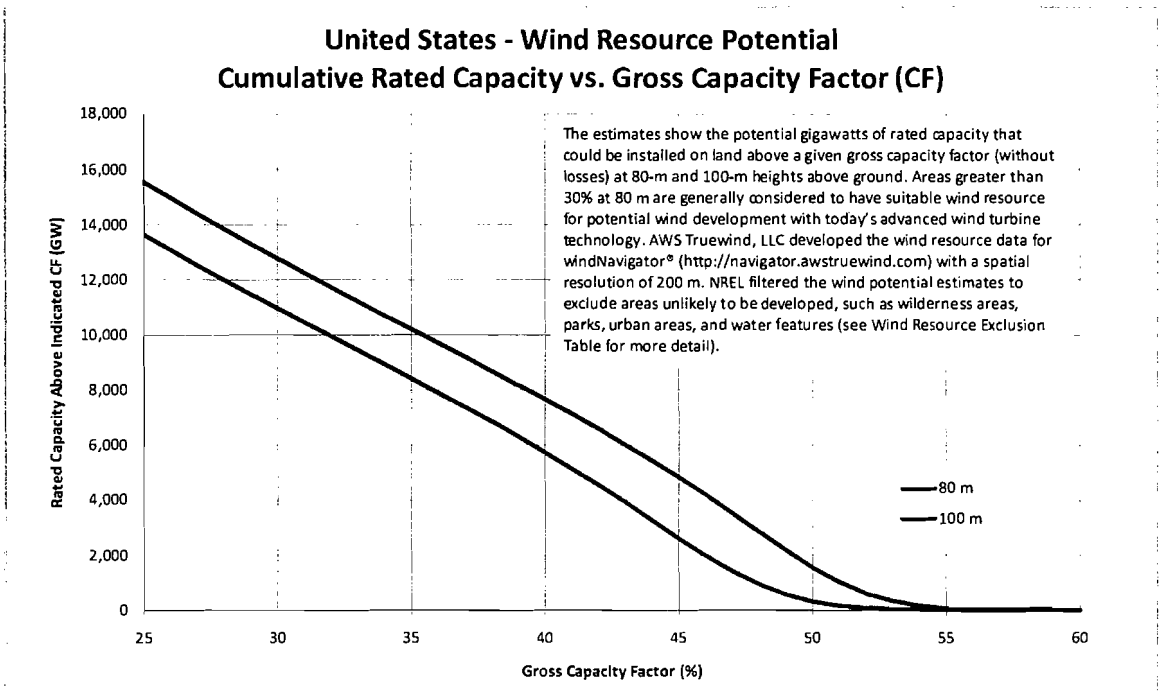


Figure 2-10: U.S. wind resource potential chart (Source: NREL [8]

2.4 Wind energy in Indiana

Indiana has roughly two wind regions, with the northern half having class 2 winds (12.5 – 14.3 mph at a height of 50 meters) and the southern half having class 1 winds (0 – 12.5 mph). Figures 2-11through 2-13 show the wind energy distribution in Indiana at 50, 70 and 100 meters, respectively [9]. The higher altitude wind maps indicate that wind speeds are significantly faster farther up. For instance, much of northern Indiana experiences class 4 or better winds at 100 meters. The total wind resource in the entire state is 148,288 MW at 80 meters [10].

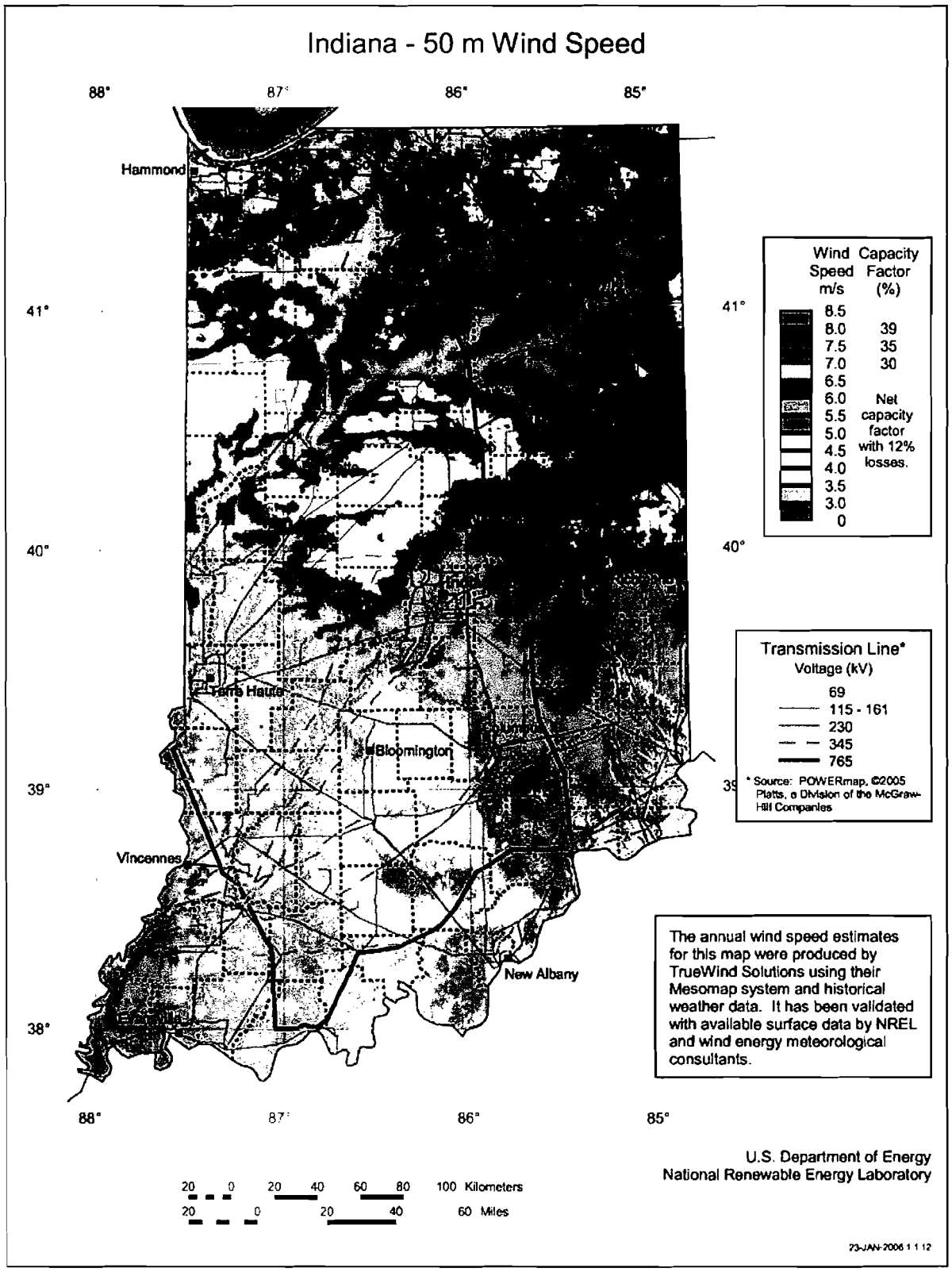


Figure 2-11: Indiana wind speed at 50 meters height (Source: OED/NREL [9])

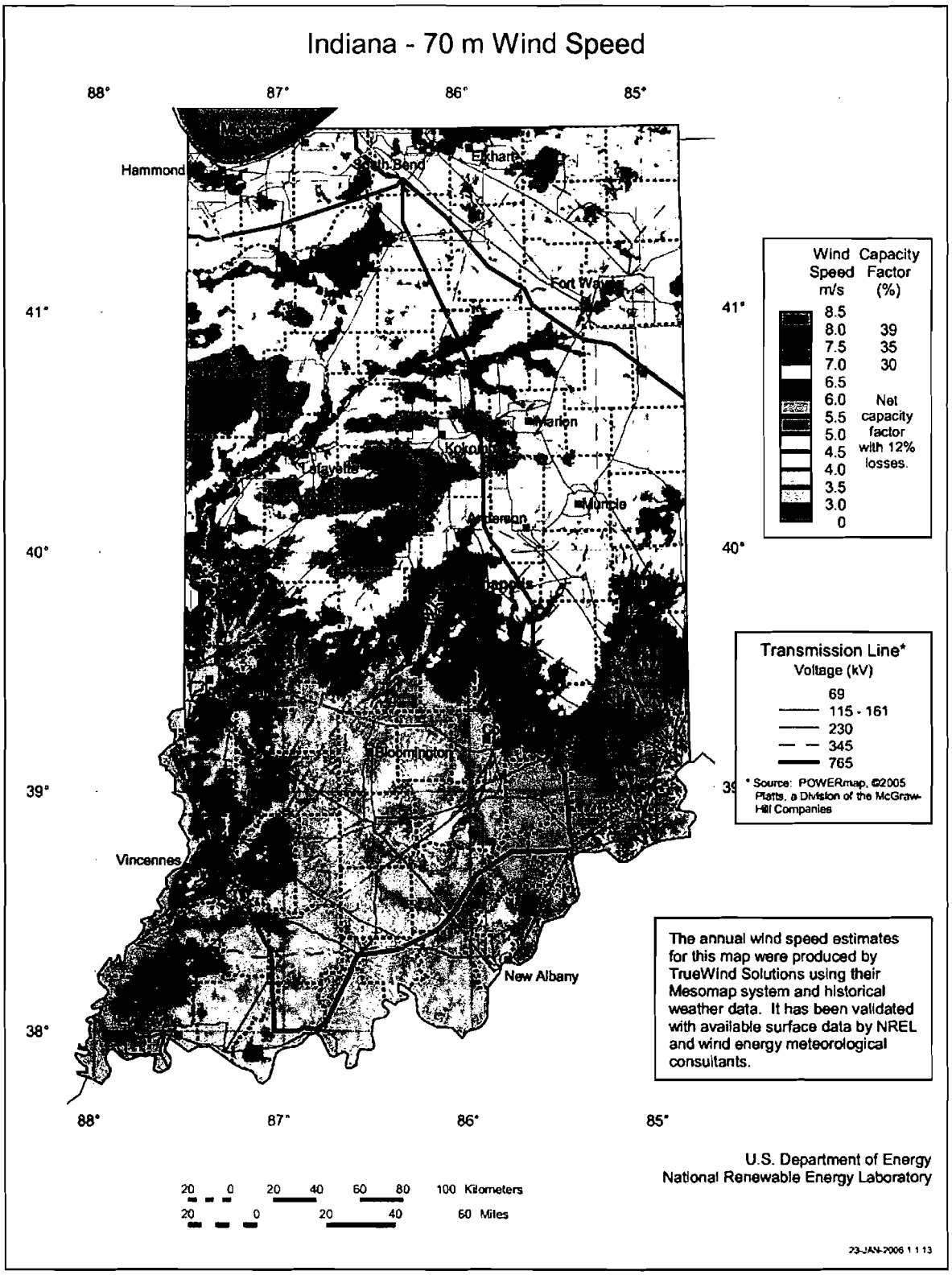


Figure 2-12: Indiana wind speed at 70 meters height (Source: OED/NREL [9])

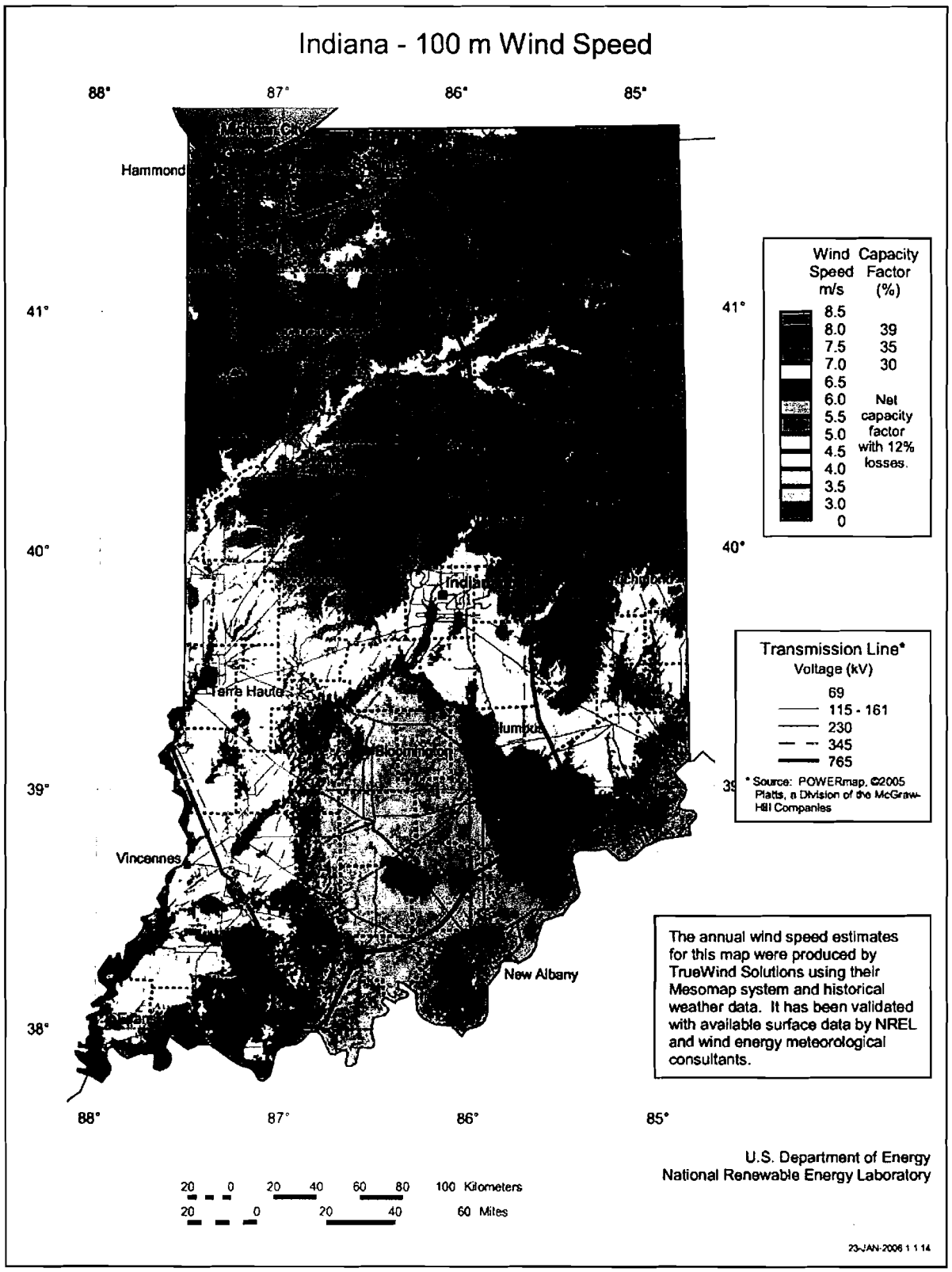


Figure 2-13: Indiana wind speed at 100 meters height (Source: OED/NREL [9])

Indiana wind energy generation capacity has grown rapidly from only 20 kW grid connected capacity before 2007 to the 1,339 MW by the end of 2010. The first utility wind project in Indiana was the Benton County Wind Farm completed in 2008. The most rapid growth was in 2009 with 908 MW of capacity commissioned. This consisted of 600 MW for the first phases of the Fowler Ridge Wind Farm in Benton County, 200 MW of the first phase of Meadow Lake Wind Farm in White County, 106 MW of Hoosier Wind Farm in Benton County and a 2 MW project at the Randolph Eastern School Corporation. The pace of construction dropped to 301 MW in 2010, and as of July no utility scale wind farm had been commissioned in 2011. Four wind farm projects with a total capacity of 552 MW had successfully completed the approval process for construction. They include continuing phases of the Fowler Ridge and Meadow Lake projects, a 101 MW project in Newton County and a 200 MW project in Tipton and Madison Counties. Table 2-3 shows the status of the various Indiana wind farm projects.

Project Name	County	Capacity (MW)	Developer	Date Completed	Power Purchaser
Benton County Wind Farm	Benton	131	Orion	May 2008	Duke (101 MW) Vectren (30 MW)
Fowler Ridge Wind Farm 1	Benton	301	BP / Dominion	March 2009	I&M (100 MW), Dominion (201 MW)
Fowler Ridge Wind Farm IIA	Benton	200	BP / Sempra	December 2009	AEP (50x3 MW), Vectren (50 MW)
Fowler Ridge Wind Farm III	Benton	99	BP / Sempra	February 2009	AEP Appalachian (99 MW)
Hoosier Wind Project	Benton	106	enXco	November 2009	IPL (106 MW)
Union City/Randolph Eastern School Corporation	Randolph	2	Operated by Performance Services Corporation	2009	
Meadow Lake Phase I	White	200	Horizon (EDP)	October 2009	Wholesale market COMED (50 MW)
Meadow Lake Phase IIA	White	99	Horizon (EDP)	September 2010	Wholesale market COMED (25 MW) Ameren (25 MW)
Meadow Lake Phase III	White	104	Horizon (EDP)	September 2010	Wholesale market Ameren (25 MW)

Approved or under construction

Spartan Wind Farm 1	Newton	101	Duke Generation Services		Wholesale market
Wildcat Wind Farm 1	Tipton & Madison	200	E.ON Climate & Renewables		Wholesale market
Meadow Lake Phase V	White	101	Horizon (EDP)		Wholesale market
Fowler Ridge IIB	Benton	150	Dominion / BP		Wholesale market

Table 2-3: Status of wind generation projects in Indiana (Data source: IURC [11])

Indiana utilities have signed power purchase agreements to purchase electricity from these wind farms and from wind farms outside Indiana as shown in Table 2-4.

Utility	Project	State	Power Purchase Agreement (MW)
Duke Energy	Benton County Wind Farm	Indiana	100
Vectren	Benton County Wind Farm	Indiana	30
Vectren	Fowler Ridge Wind Farm 2	Indiana	50
Indiana Michigan	Fowler Ridge Wind Farm 1	Indiana	100
Indiana Michigan	Meadow Lake Wind Farm	Indiana	50
NIPSCO	Buffalo Ridge	South Dakota	50
NIPSCO	Barton Windpower	Iowa	50
IPL	Hoosier Wind	Indiana	106
IPL	Lakefield Wind	Minnesota	201
WVPA	AgriWind	Illinois	8
IMPA	Crystal Lake Wind	Iowa	50

Table 2-4: Wind energy purchase agreements by Indiana utilities (Data source: IURC [11])

2.5 Incentives for wind energy

The following federal and state incentives are available for wind energy projects.

Federal Incentives

- Renewable Electricity Production Tax Credit (PTC) credits wind energy producers with 2.2 cents/kWh during the first ten years of operation. The PTC was modified in the February 2009 American Recovery and Reinvestment Act to allow producers who would qualify for the PTC to opt to take the federal business energy investment tax credit (ITC) or equivalent cash grant from the U.S. Department of Treasury (Renewable Energy Grants: 30 percent of

property that is part of a qualified small wind property) [7].

- Business Energy Investment Tax Credit (ITC) credits up to 30 percent of expenditures with no maximum credit on qualifying wind energy installations (small wind turbines placed in service after December 31, 2008). Eligible small wind property includes wind turbines up to 100 kW in capacity [7].
- Renewable Energy Production Incentive (REPI) provides financial incentives similar to the Production Tax Credit to wind generators owned by not-for-profit groups, public-owned utilities and other such organizations. REPI payments are subject to availability of annual appropriations by Congress [7].
- Residential Renewable Energy Tax Credit allows taxpayers to claim 30 percent of their qualifying expenditures on installation of small wind-energy systems for the dwelling in which they reside. The maximum credit is $500 per 0.5 kW, not to exceed $4,000, for systems placed in service in 2008; there is no maximum credit for systems placed in service after 2008 [7].
- Modified Accelerated Cost-Recovery System (MACRS): This program allows businesses to recover investments in qualified solar, wind and geothermal property through depreciation deductions. For property acquired and placed in service after September 8, 2010 and before January 1, 2012, the allowable first year deduction is 100 percent of the adjusted basis. For property placed in service from 2008 to 2012, for which the placed in service date does not fall within this window, the allowable first-year deduction is 50 percent of the adjusted basis [7].
- Qualified Energy Conservation Bonds (QECBs) are tax credit bonds to qualified energy conservation projects, which are not subject to the U.S. Department of Treasury application process and instead are allocated to each state based upon its percentage of the U.S. population. The states are then required to allocate a certain percentage to "large local governments (i.e., municipalities and counties with populations of 100,000 or more)". Qualified energy conservation projects include energy efficiency capital expenditures in public buildings; green community programs; renewable energy production; various research and development applications; mass commuting facilities that reduce energy consumption; several types of energy related demonstration projects; and public energy efficiency education campaigns [7].
- Energy Efficiency Mortgage can be used by homeowners to finance a variety of energy efficiency measures, including renewable energy technologies, in a new or existing home. The federal government supports these loans by insuring them through FHA or VA programs. This allows borrowers who might otherwise be denied loans to pursue energy efficient improvements [7].
- Rural Energy for America Program (REAP) promotes energy efficiency and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for energy efficiency improvements and renewable energy systems, and (2) grants for energy audits and renewable energy development assistance. The program

covers up to 25 percent of costs. Congress has allocated funding for the new program in the following amounts: $60 million for FY 2010, $70 million for FY 2011, and $70 million for FY 2012 [7].

- High Energy Cost Grant Program administered by the U.S. Department of Agriculture (USDA) is aimed at improving the electricity supply infrastructure in rural areas having home energy costs exceeding 275 percent of the national average. Eligible infrastructure includes renewable resources generation. The USDA has allocated a total of $15.5 million for the 2010 funding cycle. The individual grants range from $75,000 to $5 million [12].

Indiana Incentives

- Net metering rule: Renewable resource facilities with a maximum capacity of 1 MW are qualified for net metering. The net excess generation is credited to the customer in the next billing cycle [7].
- Renewable Energy Property Tax Exemption: provides property tax exemptions for solar thermal, wind, hydroelectric and geothermal systems [7].
- Emissions Credits: Electricity generators that do not emit nitrogen oxides (NO_x) and that displace utility generation are eligible to receive NO_x emissions credits under the Indiana Clean Energy Credit Program [13].
- Clean Energy Portfolio Standard (CPS) passed in May 2011 sets a voluntary goal of 4 percent between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent clean energy by 2025, based on 2010 retail sales. Participation in CPS makes utilities eligible for incentives in order to pay for the compliance projects [7].
- Indianapolis Power & Light Co. – Rate REP Renewable Energy Production: IPL is offering a "feed-in tariff" to facilities that produce renewable energy. IPL can purchase renewable energy and contract the production for up to 10 years. Compensation for small wind facilities is $0.14/kWh and for large wind facilities is $0.075/kWh [7].
- Northern Indiana Public Service Company: The NIPSCO feed-in tariff offers incentive rates for electricity generated from renewable resources. The payments for electricity from wind generating facilities are $0.17/kWh for facilities with a capacity less than 100 kW and $0.10/kW for facilities with capacities between 100 and 2,000 kW. The renewable tariff is an experimental tariff running until December 31, 2013. The generating unit size allowed under the tariff is between 5 and 5,000 kW while the total allowed system-wide capacity is 30 MW. Five hundred kilowatts of the system-wide cap is reserved for wind projects of capacity less than 10 kW [14].

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3. Dedicated Energy Crops

3.1 Introduction

Dedicated energy crops represent one of three types of biomass or organic matter that can be converted into energy. The other two types are dual-use food crops, such as corn and soybeans, and organic waste such as forest residues, agricultural residues, livestock manure and municipal solid waste. The use of organic waste biomass as a source of energy is the subject of the next section (Section 4) of this report.

Unlike dual-use food crops and organic waste biomass, the dedicated energy crop industry is still in its infancy. Among renewable resources, biomass has the added feature of being readily converted to liquid fuels for the transportation industry. This ability to be used for transportation fuels, electric energy and chemicals is the drive behind the substantial research effort by the Federal Government to develop a sustainable biomass industry [1, 2].

Biomass, including energy crops, can be converted into energy in the following ways:

- In direct combustion the biomass is burned directly in a boiler to produce steam which can then be used to drive a turbine to generate electricity. Combustion can be done either in a dedicated biomass-only boiler or cofired with other fuels such as coal. Cofiring of biomass in coal boilers has the advantage of lowering the emission of sulfur oxides (SOx), nitrogen oxides (NOx) and net lifecycle carbon. However, the widespread application of cofiring with coal has been hindered by the occurrence of alkali deposits that cause slag and corrosion in boiler heat transfer surfaces in the coal boilers [3].

- In biochemical conversion processes the biomass material is broken down into sugars using either enzymes or chemical processes. These sugars are then fermented to make ethanol [4].

- In thermochemical conversion heat is used to break down the biomass material into intermediate products (synthetic gas) which can then be converted into fuels using heat, pressure and catalysts. Two common thermochemical processes are gasification and pyrolysis. Gasification is a high temperature conversion of solids into a flammable mixture of gases. Pyrolysis is a process of thermal decomposition of biomass at high temperatures in the absence of oxygen into charcoal, bio-oil and synthetic gas [5].

3.3 State of energy crops nationally

Dedicated energy crops (trees and grasses) are not yet being produced for the most part on large scale for the purposes of bioenergy production. Herbaceous crops (grasses) are currently grown as livestock feed and for soil conservation purposes. The short rotation woody biomass crops (trees) being grown commercially today are mainly for production of fiber and in a few locations for bioenergy demonstration projects [17]

In a combined effort with the USDA, DOE's Biomass Program has a major research and development effort aimed at increasing the biomass production in the U.S. to a level where it will be able to replace 30 percent of the nation's petroleum consumption by the year 2030 distributed as follows: 5 percent of the nation's electric power, 20 percent of the nation's transportation fuel and 25 percent of its chemicals. Figures 3-3 show the locations of the bioenergy crops test sites.

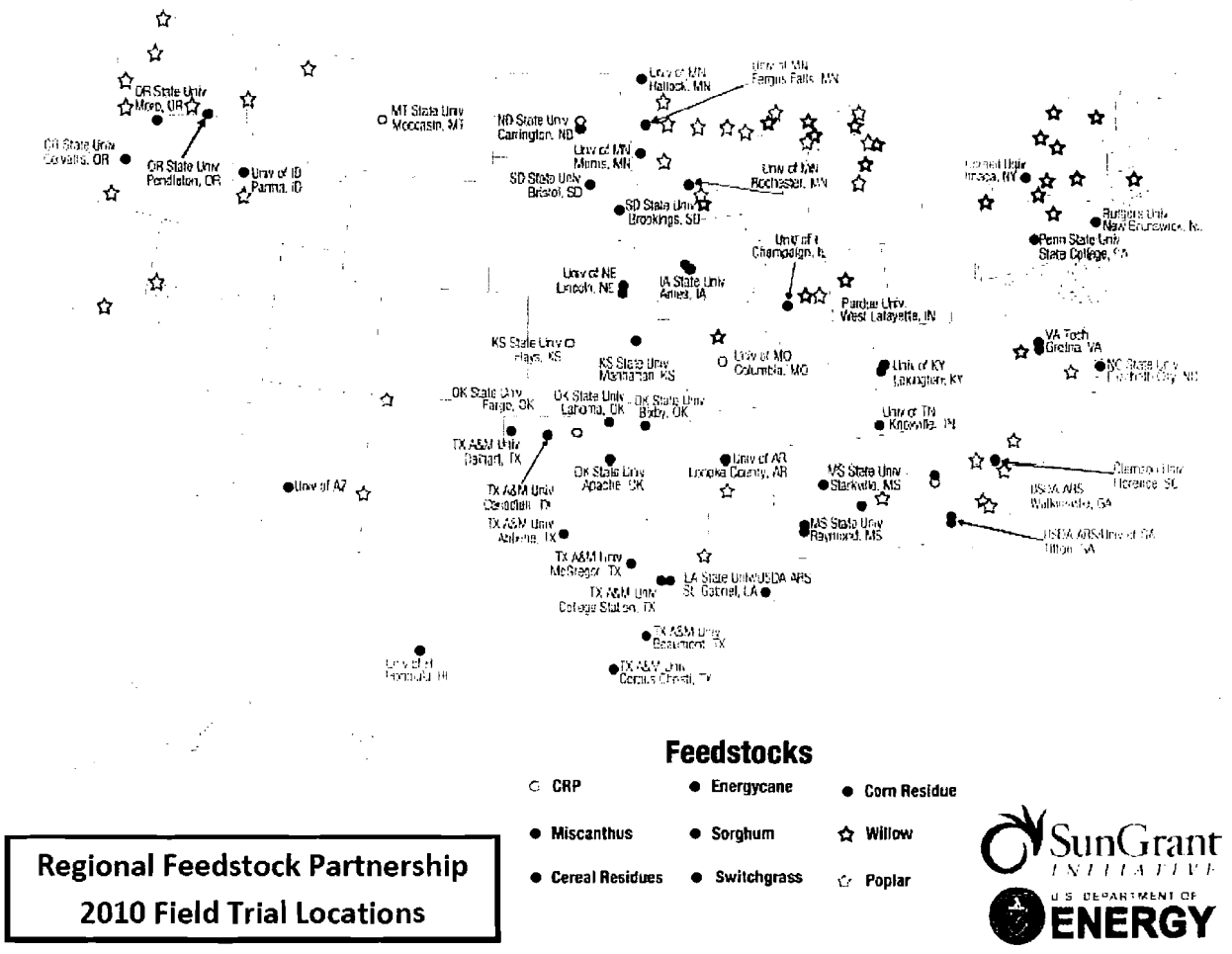

Figure 3-3 2010 energy crop test stations (Source EERE [17])

3.4 Energy crops in Indiana

Figure 3-4 shows the levels of energy crops that would be produced in Indiana at three different biomass price levels used in a 1998/1999 USDA/DOE study using the POLYSYS model. As the figure shows, energy crops do not begin to be competitive with traditional food crops until the biomass price approaches $40 per dry ton. At $50 per ton, biomass production jumps to 5 million tons per year [18, 19]. The biomass price levels needed to achieve the production levels shown in Figure 3-4 will be even higher today given that food crop price levels are much higher than they were in 1999.

The estimates of switchgrass and poplar production potential in a 2006 ORNL [20] study are shown in Figure 3-5. The study used the same agricultural sector model (POYSYS) referred to previously. As can be seen in Figure 3-5, central Indiana has the highest potential for switchgrass production while the northeast and southeast regions of Indiana have the highest potential for hybrid poplar production.

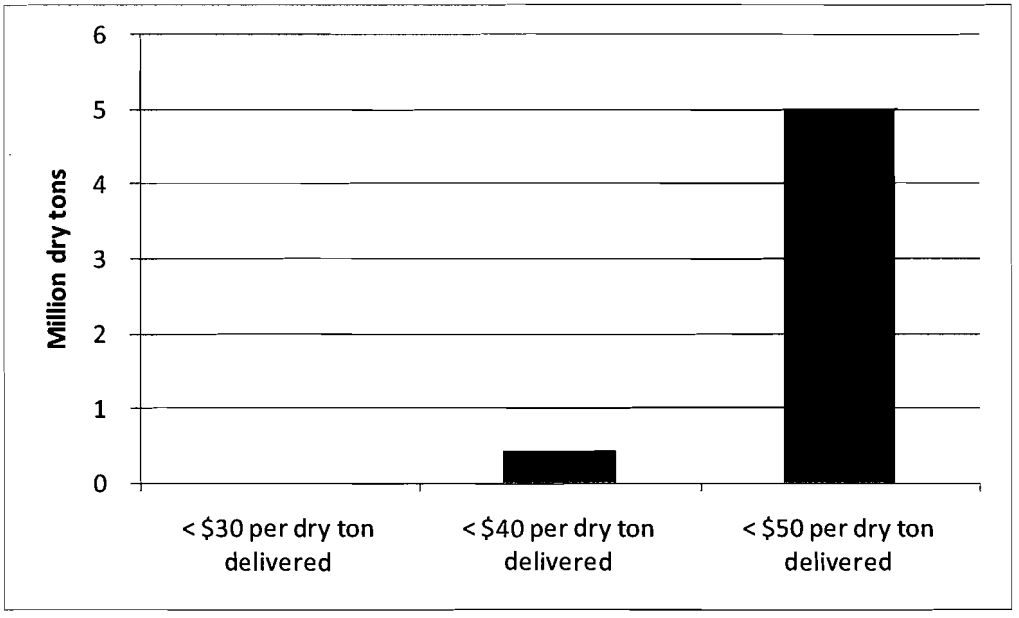

Figure 3-4: Estimated annual cumulative energy crop quantities by delivered price (1997 dollars) for Indiana (Data source: ORNL [18])

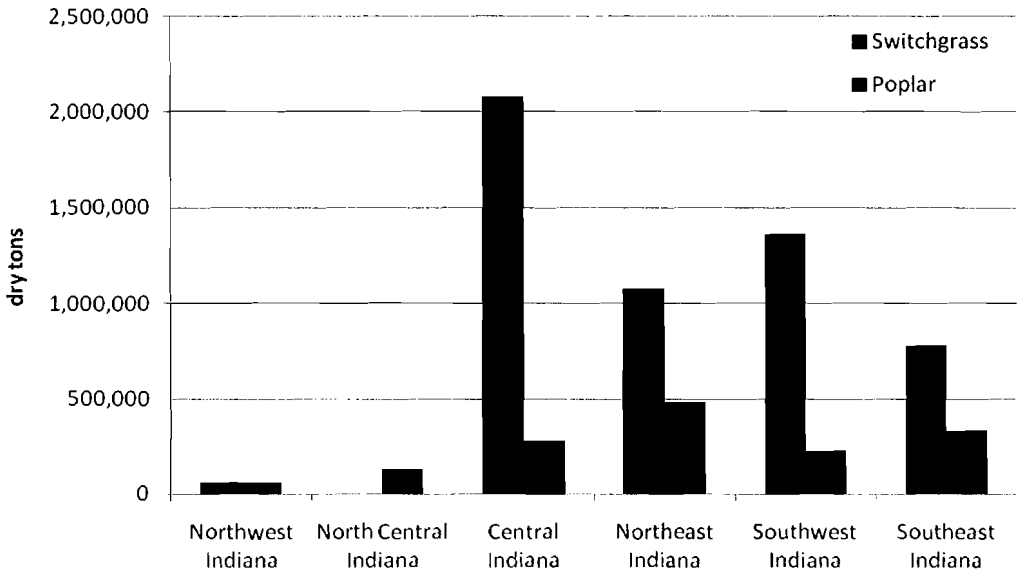

Figure 3-5: Estimated annual potential production of switchgrass and hybrid poplar for Indiana, USDA baseline 2001 (Source: ORNL [20])

A 2002 study at Ball State University estimated that there was potential to produce 90 million tons per year of switchgrass in Indiana if all the crop land was converted to the production of this energy crop. These 90 million tons of switchgrass would produce 450,000 GWh of energy, which is approximately four times Indiana's annual electrical energy consumption.

In an April 2008 working paper, Brechbill and Tyner of Purdue's Agricultural Economics Department did an extensive study of the cost of producing switchgrass and harvesting corn stover for the energy industry. Table 3-4 shows the average cost of producing switchgrass given in this study [21]. The table includes the farmer's choice to either: purchase and own the harvesting equipment or hire the services of a specialized custom operator.

	500 acre farm	**1,000 acre farm**	**1,500 Acre farm**	**2,000 acre farm**
Custom hired equipment	$53.23	$53.23	$53.23	$53.23
Owned equipment	$54.54	$52.43	$51.73	$51.38

Table 3-4: Average cost ($/ton) for producing switchgrass in Indiana (Data source: Brechbill & Tyner [21])

3.5 Incentives for energy crops

The following incentives have been available to assist in the use of energy crops.

Federal Incentives

- Renewable Electricity Production Tax Credit (PTC) provides a 2.2 cents/kWh tax credit for wind, geothermal and closed-loop biomass and 1.1 cents/kWh for open-loop biomass, landfill gas municipal solid waste, small hydroelectric and marine energy technologies. As part of the February 2009 American Recovery and Reinvestment Act the PTC was modified to provide the option for qualified producers to take the federal business energy investment tax credit (ITC) or an equivalent cash grant from the U.S. Department of Treasury. Dedicated energy crops fall under the closed loop biomass category [22].
- Business Energy Investment Tax Credit (ITC) credits up to 30 percent of expenditures on qualified renewable energy systems [22].
- Renewable Energy Production Incentive (REPI) provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Qualifying facilities are eligible for annual incentive payments of 1.5 cents/kWh for the first ten years of production, subject to the availability of annual appropriations in each federal fiscal year of operation. The Energy Policy Act of 2005 expanded the list of eligible technologies and facilities owners, and reauthorized the payment for fiscal years 2006 through 2026 [22].
- Rural Energy for America Program promotes energy efficiency and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for energy efficiency improvements and renewable energy systems, and (2) grants for energy audits and renewable energy development assistance. The program covers up to 25 percent of costs [22].
- Qualified Energy Conservation Bonds (QECBs) are qualified tax credit bonds that are allocated to each state based upon their state's percentage of the U.S. population. The states are then required to allocate a certain percentage to "large local governments." In February 2009, these funds were expanded to $3.2 billion [22].
- Value-Added Producer Grant Program: Grants are available to independent producers, agricultural producer groups, farmer or rancher cooperatives, and majority-controlled producer-based business ventures seeking funding. Previously awarded grants supported energy generated on-farm through the use of agricultural commodities, wind power, water power, or solar power. The maximum award per grant was $300,000 [23].
- High Energy Cost Grant Program administered by the U.S. Department of Agriculture (USDA) is aimed at improving the electricity supply infrastructure in rural areas having home energy costs exceeding 275 percent of the national average. Eligible infrastructure includes renewable resources generation. The USDA has allocated a total of $15.5 million for the 2010 funding cycle. The individual grants range from $75,000 to $5 million [24].

Indiana Incentives

- Net metering rule: Renewable resource facilities with a maximum capacity of 1 MW qualify for net metering. The net excess generation is credited to the customer in the next billing cycle [22].
- Emissions Credits: Electricity generators that do not emit NO_x and that displace utility generation are eligible to receive NO_x emissions credits under the Indiana Clean Energy Credit Program [IDEM]. These credits can be sold on the national market.
- Clean Energy Portfolio Standard (CPS) passed in May 2011 sets a voluntary goal of 4 percent between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent clean energy by 2025, based on 2010 retail sales. Participation in CPS makes utilities eligible for incentives in order to pay for the compliance projects [22].
- Indianapolis Power & Light Co. – Rate REP Renewable Energy Production: IPL is offering a "feed-in tariff" to facilities that produce renewable energy. IPL can purchase renewable energy and contract the production for up to 10 years. Biomass compensation is $6.18/kW per month plus $0.085/kWh [22, 26].
- Northern Indiana Public Service Company – The NIPSCO feed-in tariff offers incentive rates for electricity generated from renewable resources on 10 year contracts. Payment for biomass facilities is $106/kW. The tariff is an experimental on running until December 31, 2013. The generating unit size allowed under the tariff is between 5 and 5,000 kW while the total allowed system-wide cap is 30 MW [27].

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4. Organic Waste Biomass

4.1 Introduction

In the previous section (Section 3) organic biomass in the form of dedicated energy crops was presented. In this section the use of organic wastes and residues as a source of renewable energy is discussed. The organic waste biomass in this section is separated into main categories: organic waste biomass that is in use currently as an energy source and organic waste biomass that is being considered for use in the future as an energy source in the effort to increase the proportion of renewable energy in the nation's energy mix. Those already in use as an energy source include:

- Residues from the forestry and wood products industry: includes material left from logging, residues from the paper and pulp industry and residues from primary wood milling.
- Municipal solid waste (MSW): the organic portion of the post-consumer waste collected in community garbage collection services.
- Gas extracted from landfills: naturally occurring gas resulting from decomposition of landfill material.
- Livestock manure: mainly from large swine and dairy farms where it is used to produce gas in biodigesters.
- Municipal wastewater: sewage, which is used to produce gas in biodigesters.

Organic waste biomass resources that are not yet in large-scale use as an energy source but are being considered for future use include:

- Agricultural crops residues: stalks, leaves and other material left in the fields when conventional crops such as corn are harvested.
- Aquatic plants: such as algae that has high oil content that can be converted to biodiesel.

Historically organic waste biomass, and in particular residues from the wood products industry, has been one of the main sources of renewable energy in the U.S. As can be seen in Figure 4-1, wood and wood-derived fuels have been second only to hydroelectricity as a source of renewable energy in the U.S. Up until the increase in wind and biofuels in the last decade, wood and wood-derived fuels comprised nearly half of the renewable energy consumed in the U.S.

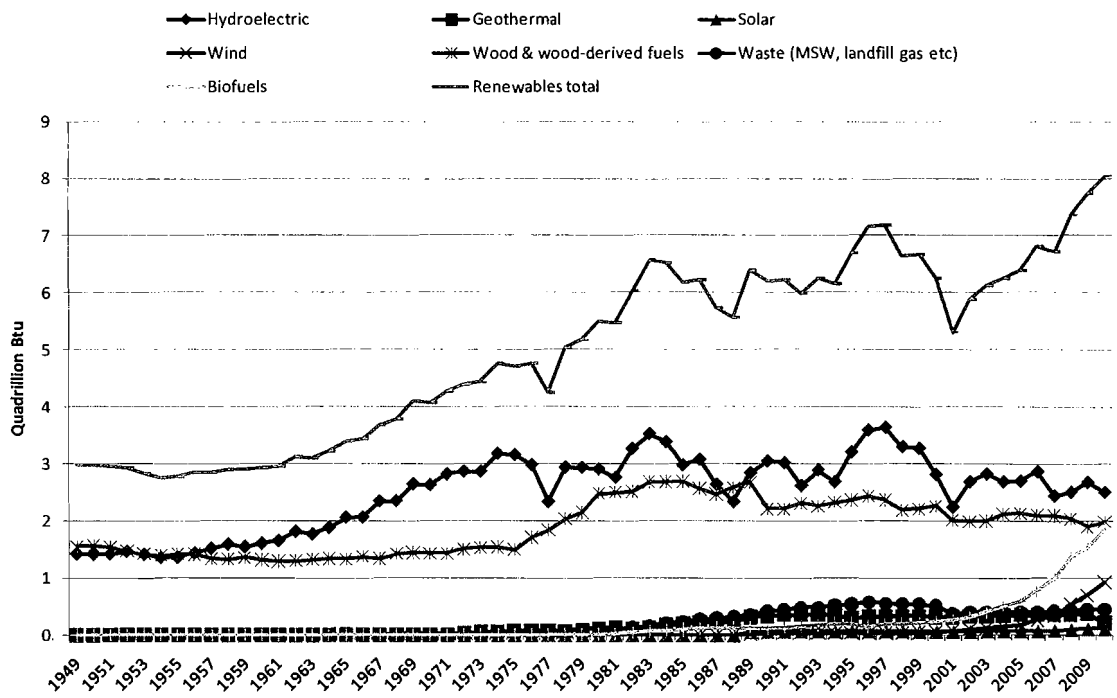


Figure 4-1: U.S. renewable energy consumption 1949-2009 (Source: EIA [1])

Although not as large a source as wood and wood-derived fuels, municipal solid waste has also been a significant contributor to the nation's renewable energy mix. According to the U.S. Environmental Protection Agency (EPA), there are 86 municipal solid waste burning power plants operating in 24 states with a combined electricity generating capacity of 2,720 MW. One such plant is the Covanta Energy facility in Indianapolis that is used to generate steam for heating in downtown Indianapolis [2]. The Covanta facility in Indianapolis does not generate electricity.

Another significant source of organic waste based energy is landfill gas. Landfill gas contains about 50 percent methane. One of the main motivations for capturing and burning landfill gas is because landfills are one the main sources of human-related methane emissions in the U.S. Methane gas is 21 times more effective than carbon dioxide as a heat trapping greenhouse gas. Thus, converting landfill gas to energy provides a financial benefit to the environmental task [3].

Livestock manure is in use currently as an energy source with 160 anaerobic digester biogas recovery systems in operation in livestock farms in the U.S. at the end of 2010. Anaerobic digestion of biomass waste consists of a controlled breakdown of organic wastes by microorganisms in an oxygen deficient environment. EPA estimates that 8,200 swine and dairy farms in the U.S. have the capability to support biogas recovery systems producing enough biogas to supply 1,600 MW of electricity generating capacity [4].

Municipal wastewater is yet another waste stream that is being used as a source of energy and that has potential for substantial expansion. According to EPA out of the approximately 1,000 wastewater treatment facilities nationwide that had enough effluent inflow to support anaerobic digesters at the end of 2006, only about 500 of them had digesters installed. And out of these 500 that had installed anaerobic digesters only 106 capture the biogas for energy conversion resulting in a combined 220 MW electricity generating capacity. EPA estimated that if all the 500 wastewater treatment plants that had anaerobic digesters in place captured the biogas for energy conversion, they could support a further 340 MW of electricity generating capacity [5].

Biomass, including agricultural crop residues, is expected to play a significant role in the energy supply portfolio in the U.S. in the future. One of the characteristics that makes biomass a very attractive source of renewable energy is its ability to be converted both to electricity and to liquid fuels for the transportation industry. In 2005 the U.S. Department of Agriculture (USDA) and the U.S. Department of Energy (DOE) issued a joint report from a study done to investigate the viability of using energy from biomass to replace 30 percent of U.S. petroleum consumption by the year 2030. According to this report, titled *Biomass Feedstock for a Bioenergy and Bioproducts Industry: the Technical Feasibility of a Billion-Ton Annual Supply* [6], corn stover is the most abundant untapped source of biomass currently available from croplands. Corn stover is the material left in the field after the grain is harvested. It consists of the stalk, the leaves, the husks and the cobs. The USDA/DOE report estimates that 75 million dry tons per year of corn stover can be sustainably removed from U.S. croplands under current farming conditions. All other crops can together contribute 38 million tons a year under current farming practices [6].

Large scale farming of algae is another area being considered as a potential source of bioenergy. Algae are simple organisms, ranging from microscopic-sized algae to seaweeds that grow to over 100 feet. Like other plants, they utilize energy from the sun through photosynthesis to convert carbon dioxide from the air into biomass usable for energy production. Algae have several advantages over other biomass as a source of energy and especially in the production of biodiesel. These advantages include [7, 8]:

- Algae grows more rapidly and has higher photosynthetic efficiency than other biomass;
- It has a much higher oil content than other biomass (20 to 80 times more than soybeans);
- It is not a food crop;
- It can be grown in water with very high salt concentration that is not usable for other agriculture;
- It can be grown in otherwise non-arable land such as deserts;
- It has the potential for recycling of CO_2 from fossil fueled power plants; and
- Both biofuels and valuable co-products can be produced from algae.

Algae can be grown in either open ponds or in enclosed bioreactors. Although open pond algae farms are much more cost competitive, they have the disadvantages of being vulnerable to contamination by faster growing native algae, water loss through evaporation and exposure to extreme weather variations. Enclosed bioreactors overcome these drawbacks by growing the algae entirely enclosed in transparent containers of various forms. Not surprisingly, the enclosed bioreactors' main disadvantage is cost; bioreactors are much more expensive to build than open ponds. One elegant application for the use of algae is the coupling of an algae bioreactor with a coal power plant to allow the power plant to provide the carbon dioxide needed for algae growth. In this way a combined benefit of producing bioenergy while reducing carbon dioxide emission is achieved. Such an experiment was conducted at the Arizona Public Service Red Hawk power plant in 2006 and 2007 [9].

The production of algae for energy is still in the development stage. According to the DOE algae research program there are major technical hurdles to be overcome before commercial scale energy production from algae is a reality and energy from algae is more of a long term goal [7, 8].

4.2 Economics of organic waste biomass

Most of the current waste biomass energy is generated and consumed in the paper and pulp industry where the paper and pulp making byproducts are combusted in combined heat and power plants to supplement the electricity and steam supply of the paper and pulp mills. Several factors have combined to make the use of these residues and byproducts as an energy source economically attractive at pulp and paper mills. They include:

- The burning of the pulp making residue (black liquor) serves not only to generate energy, but also to recover process chemicals,
- The co-location of electricity and steam demand in the mills greatly increases the efficiency of the energy conversion process, and
- The ability to sell excess generation through either the favorable provisions of Public Utility Regulatory Policies Act of 1978 or more recently through the open transmission access associated with wholesale electricity markets provides a market for times when the plant's generation exceeds internal demand.

In the case of municipal solid waste, the need to reduce the amount of material going into landfills is the main motivation for building MSW based energy conversion facilities. Without this motivation MSW Power plants would be hard to justify financially since they are some of most expensive plants to build and operate [2]. In the November 2010 Energy Information Administration (EIA) plant cost estimates, the MSW power plant was listed as having the highest capital cost at over $8,000/kW among the technologies considered and the highest fixed O&M cost at over $370/kW [10].

Similarly, other organic waste streams such as animal waste, wastewater treatment and landfills that generate methane have greenhouse gas emissions reduction as a major objective and energy conversion as an added benefit. Further, the energy conversion efficiency, and therefore economics, is improved by the onsite co-location of both heat and electricity demand. The anaerobic digesters used to produce the biogas in all cases except landfill gas provide a demand for the heat to maintain optimum temperatures for the microorganisms.

Currently agricultural crop residues are not being collected for use as bioenergy feedstock because it is not yet profitable for farmers. In 2002 EIA published a report authored by Dr. Zia Haq containing the EIA's estimation of the amount biomass, including crop residues, used as input into the National Energy Modeling System. Dr. Haq utilized an agricultural sector model called POLYSYS (Policy Analysis System), which was developed by the Oak Ridge National Laboratory, to estimate possible future supplies of agricultural crop residues. The estimated national supply curve for biomass and energy crops produced by POLYSYS for the year 2020 is shown in Figure 4-2. According to these supply curves agricultural crop residues supply to the energy industry will start occurring when the price paid at the plant gate passes the 2.00 $/mmBtu level (2000 dollars). This price threshold translates to approximately 2.53 $/mmBtu in 2010 dollars. Comparing this to the 2.30 $/mmBtu [11] average price of coal delivered to electric utilities in 2010 shows that agricultural crop residue is not yet competitive against coal as fuel for electricity generation.

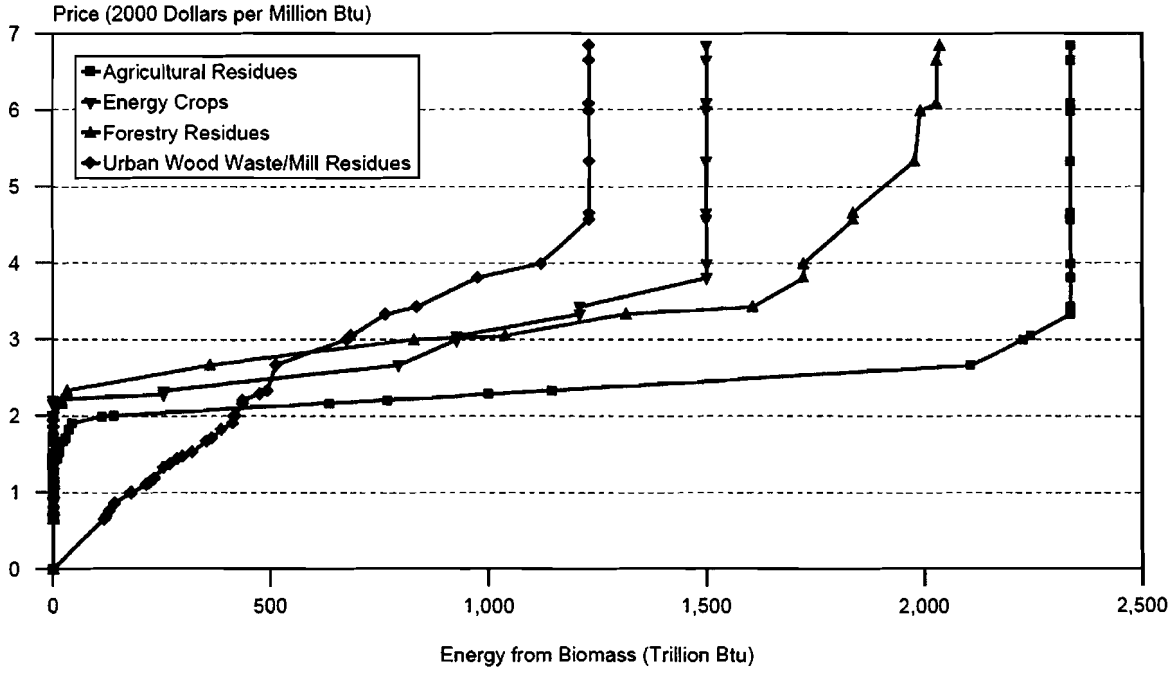


Figure 4-2: POLYSYS estimated biomass supply curve for year 2020 (Source: EIA [12])

Although the concept of using algae for energy production has been proven at the laboratory level, no commercial scale sustainable production facility has been established. According to the 2010 DOE National Algal Biofuels Technology Roadmap document there was not yet a credible estimate of the cost of algal biofuel [8].

4.3 State of organic waste biomass nationally

As has already been stated in previous sections and illustrated in Figure 4-1, organic biomass has historically been one of the main sources of renewable energy in the U.S., second only to hydroelectricity. Thirty percent of the 8 quadrillion Btu of renewable energy consumed in the U.S. in 2010 was from organic waste biomass. Wood contributed 25 percent and other organic wastes together contributed 6 percent. Figure 4-3 shows the contribution of renewable resources to the total energy consumed in the U.S. in 2010.

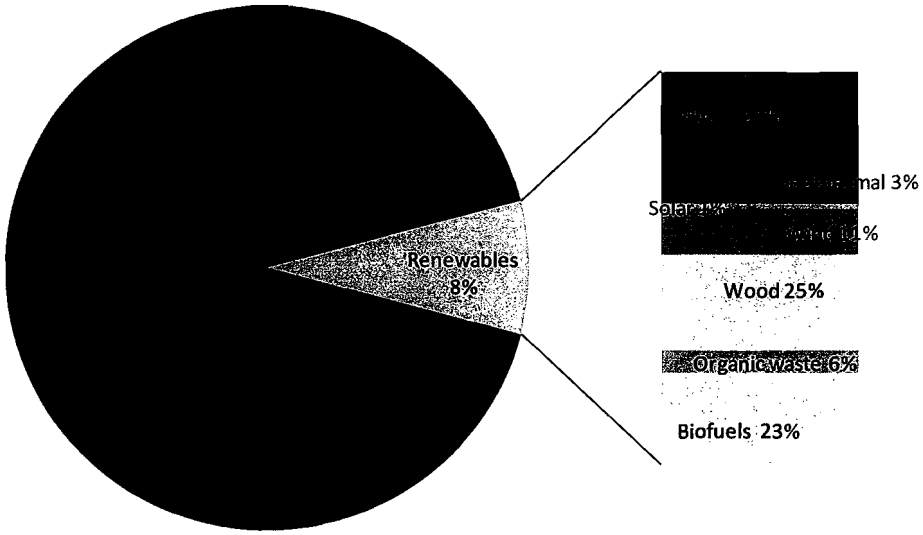


Figure 4-3: Summary of U.S. energy consumption in 2010 (Data source: EIA [1])

Organic waste biomass is also a significant source of electricity generation, ranking third after hydroelectricity and wind for renewable electricity generation in the U.S. in 2010. Figure 4-4 shows net electricity generation in the U.S. in 2010 by fuel type. Among the biomass resources, wood is the dominant source of renewable electricity contributing 4 percent of total renewable energy, followed by municipal solid waste and landfill gas, which together contributed 4 percent of the renewable energy. Municipal solid waste and landfill gas are grouped together in the 'other wastes' category.

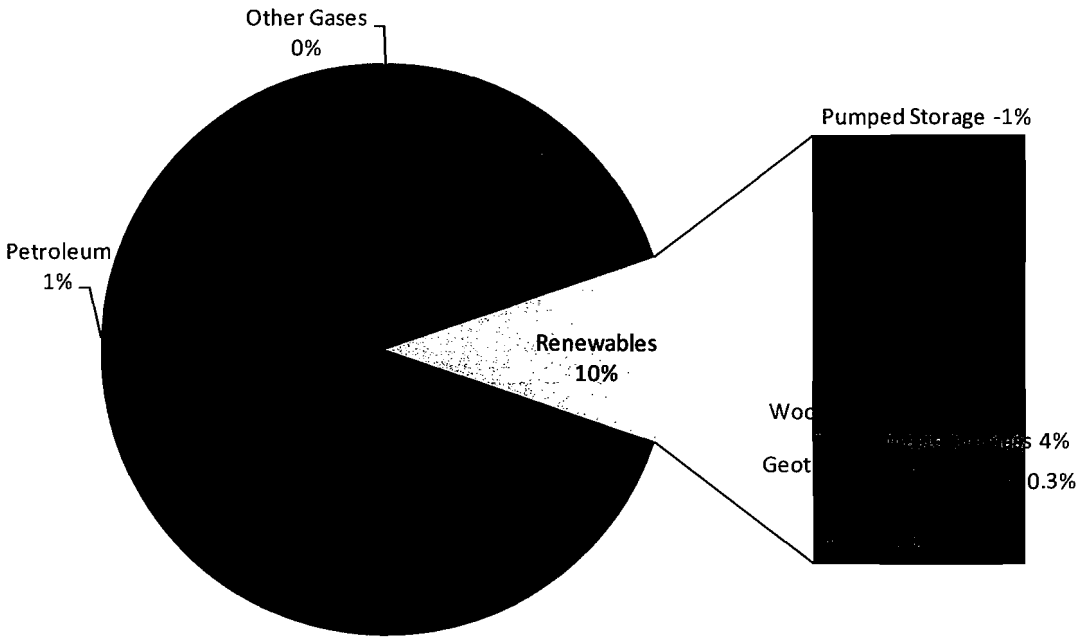


Figure 4-4: Summary of U.S net electricity generation in 2010 (Data source: EIA [13])

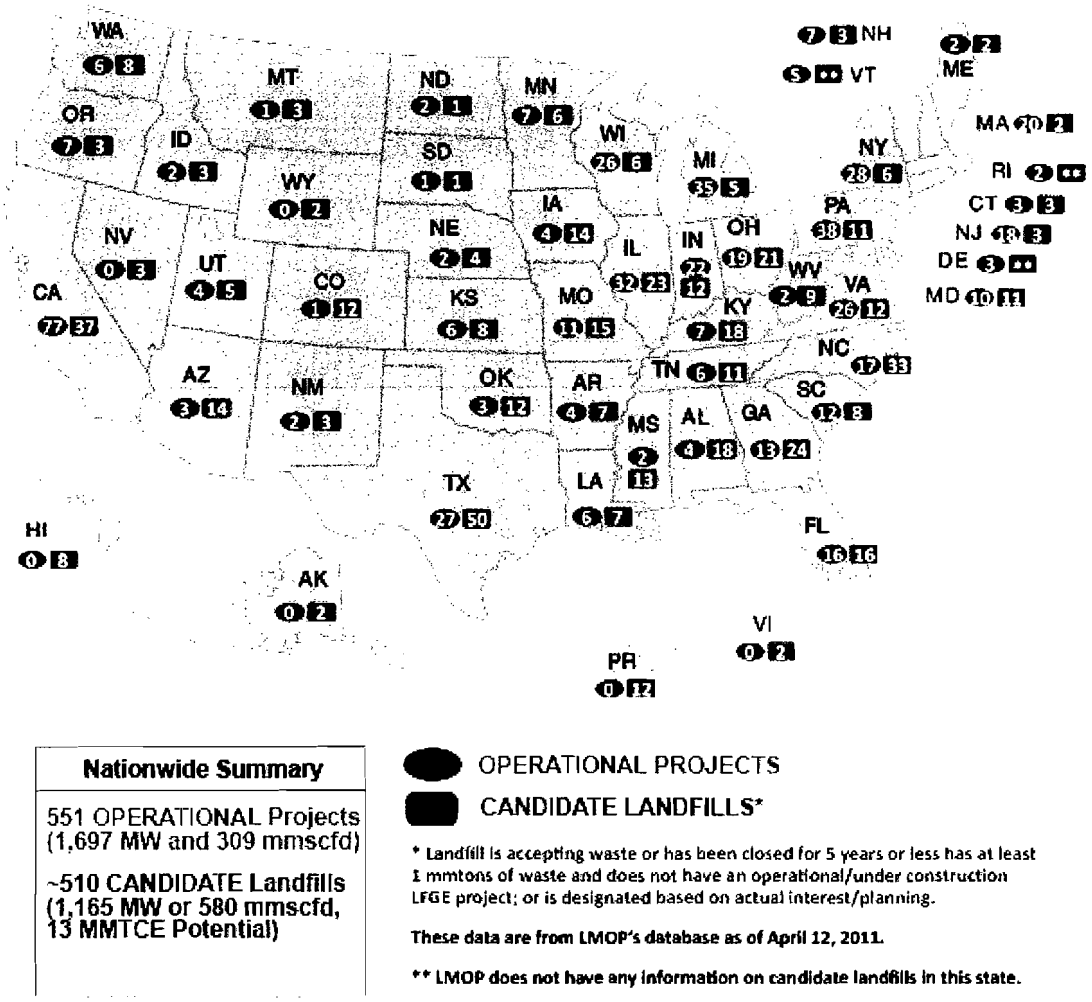
At the end of 2010 there were 86 MSW-to-energy power plants operating in 24 states in the U.S. distributed as shown in Table 4-1. The combined electric generating capacity of the plants was 2,572 MW plus the equivalent of 218 MW in steam output [14].

State	Number of facilities
Alabama	1
Alaska	1
California	3
Connecticut	6
Florida	11
Hawaii	1
Indiana	1
Iowa	1
Maine	4
Maryland	3
Massachusetts	7
Michigan	3

State	Number of facilities
Minnesota	9
New Hampshire	2
New Jersey	5
New York	10
North Carolina	1
Oklahoma	1
Oregon	1
Pennsylvania	6
Utah	1
Virginia	5
Washington	1
Wisconsin	2

Table 4-1: Operating municipal solid waste energy plants (Data source: Energy Recovery Council [14])

Figure 4-5 shows the location of operational and 'candidate' landfill gas energy projects in the U.S. The candidate designation is for landfills that have the potential for installation of an energy recovery system. There are currently 561 landfills with energy conversion projects in operation. Approximately two thirds of these operational projects convert the landfill gas to electricity and one third provide biogas gas for direct use as a source of thermal energy. The operational projects have a combined capacity for 1,697 MW of electricity generation and 309 million standard cubic feet per day (mmscfd) of gas for thermal energy production. There are a 510 'candidate' landfills that have the size and other characteristics necessary to support energy projects with a combined capacity of 1,165 MW of electricity generation and 580 mmscfd of gas for direct use [3].



Legend
mmscfd – million standard cubic feet per day; MMTCE – million metric tons of carbon equivalent

Figure 4-5: Landfill gas projects (Source: EPA [3])

Table 4-2 shows the top states with the potential for electricity generation from livestock farms. Biogas is more readily recovered from swine and dairy farms because the manure is handled in the wet slurry state that is hospitable to the waste-digesting microorganisms. Indiana is ranked among the top ten with potential for producing 3.5 billion cubic feet per year from 296 farms [4].

	Number of Candidate Farms	Methane Emissions Reductions (Thousand Tons)	Methane Production Potential (billion ft3/ year)	Energy Generation Potential (Thousand MMBtu/ year)	Electricity Generation Potential (Thousand MWh/year)
Swine Farms					
Iowa	1,997	301	21.5	6,243	1,829
North Carolina	939	203	13.2	3,826	1,121
Minnesota	707	63	7.3	2,119	621
Illinois	350	39	4.3	1,240	363
Missouri	154	34	3.5	1,028	301
Indiana	296	31	3.5	1,011	296
Oklahoma	56	51	3.4	997	292
Nebraska	177	27	3.2	927	272
Kansas	80	22	2.3	681	199
Texas	10	25	1.6	477	140
Remaining 40 States	830	109	10.6	3,096	907
Sub Total	5,596	905	74.4	21,645	6,341
Dairy Farms					
California	889	341	27.9	8,104	2,375
Idaho	203	99	8.9	2,601	762
New Mexico	110	64	5.3	1,553	455
Texas	155	66	5.0	1,463	429
Wisconsin	251	41	4.5	1,316	386
Washington	125	35	3.4	1,003	294
Arizona	54	44	3.1	898	263
Michigan	107	26	2.9	838	246
New York	111	18	2.1	603	177
Colorado	54	22	2.0	595	174
Remaining 40 States	588	152	14.6	4,244	1,243
Sub Total	2,647	908	79.7	23,218	6,804
U.S. Total	**8,243**	**1,813**	**154.1**	**44,863**	**13,145**

Table 4-2: Top ten states for electricity generation from swine and dairy farms (Data source: AgStar [4])

Table 4-3 shows the location of the 220 MW of electricity generating capacity installed in wastewater treatment plants in the U.S. According to the EPA Combined Heat and Power Partnership Program, this capacity could be increased by a further 340 MW if all the wastewater treatment plants that used anaerobic digestion technology to process their waste would capture the biogas and use it to generate electricity and heat. Out of the approximately 500 wastewater treatment facilities that utilized anaerobic digestion technology only 106 of them convert the biogas to energy.

State	Number of Sites	Capacity (MW)
Arkansas	1	1.7
Arizona	1	4.2
California	23	38.1
Colorado	2	7.9
Connecticut	1	0.2
Florida	1	6.0
Iowa	2	3.4
Idaho	2	0.5
Illinois	2	4.3
Massachusetts	1	76.0
Minnesota	2	5.1
Montana	3	1.1
Nebraska	3	5.4
New Hampshire	1	0.4
New Jersey	3	4.6
New York	5	13.3
Ohio	1	0.1
Oregon	10	5.9
Pennsylvania	3	22.4
Utah	2	2.6
Virginia	1	3.0
Washington	3	13.6
Wisconsin	2	0.5
Wyoming	1	0.03
Total	**76**	**220.1**

Table 4-3: Wastewater treatment combined heat and power systems in the U.S.
(Source: EPA [5])

Although crop residues are not in use today as a source of energy, it is the most readily available biomass feedstock. Figure 4-6 shows the amount of biomass available annually from agricultural residues and waste streams under current farming practices according to the USDA/DOE billion-ton of biomass by 2030 vision report [6].

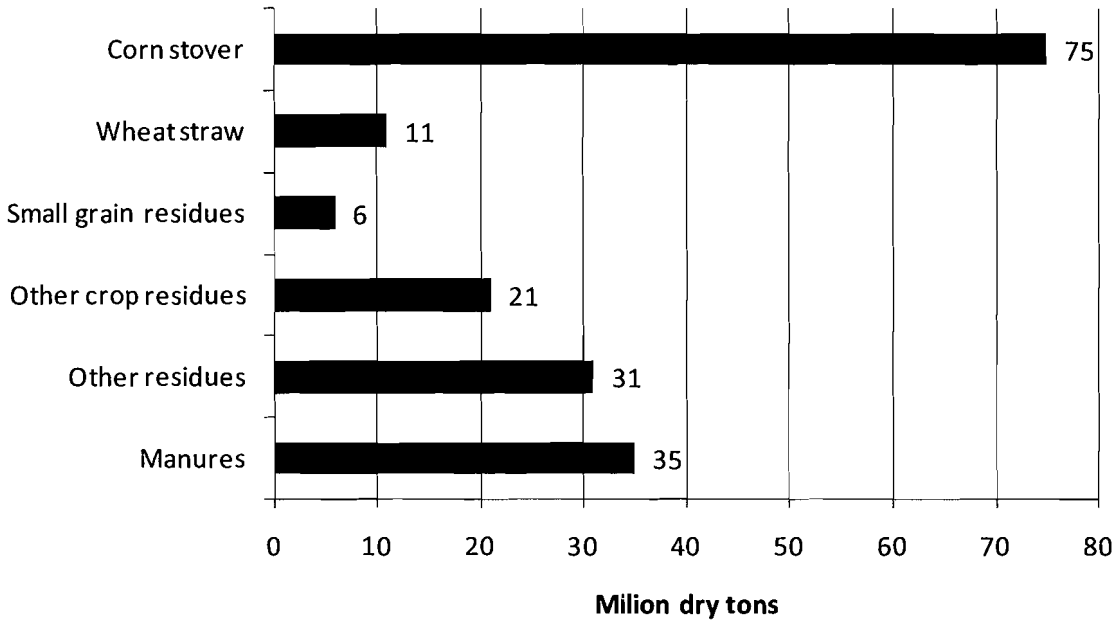


Figure 4-6: Current available organic waste biomass from agricultural lands (Data source: USDA/DOE [6])

The "small grain residues" bar in Figure 4-6 includes residues from sorghum, barley, oats and rice. The "other residues" bar in Figure 4-6 includes residues from cotton, oil seeds, tobacco, sugar crops, potatoes, beans, miscellaneous secondary agricultural processing residues, MSW and fats and greases.

4.4 Organic waste biomass in Indiana

Organic waste biomass, in particular wood residue and byproducts, has historically been the main source of renewable energy in Indiana. Figure 4-7 shows the contribution of the various renewable resources to the total annual energy consumed in Indiana since 1960. It was not until the rapid growth in corn ethanol production starting in 2007 that woody biomass energy's contribution was overtaken by ethanol as the primary source of renewable energy consumed in Indiana. The types of industries using wood residue and byproducts include the paper and pulp industry that has traditionally used the paper-making byproducts for cogeneration of electricity and process heat. Municipal solid waste is the other major source of energy from woody biomass, for example the Covanta Energy Corporation's Indianapolis facility uses municipal solid waste to generate steam used for district heating in downtown Indianapolis. The plant has capacity to process 2,175 tons of solid waste per day to produce at least 4,500 tons of steam per ton of solid waste [15].

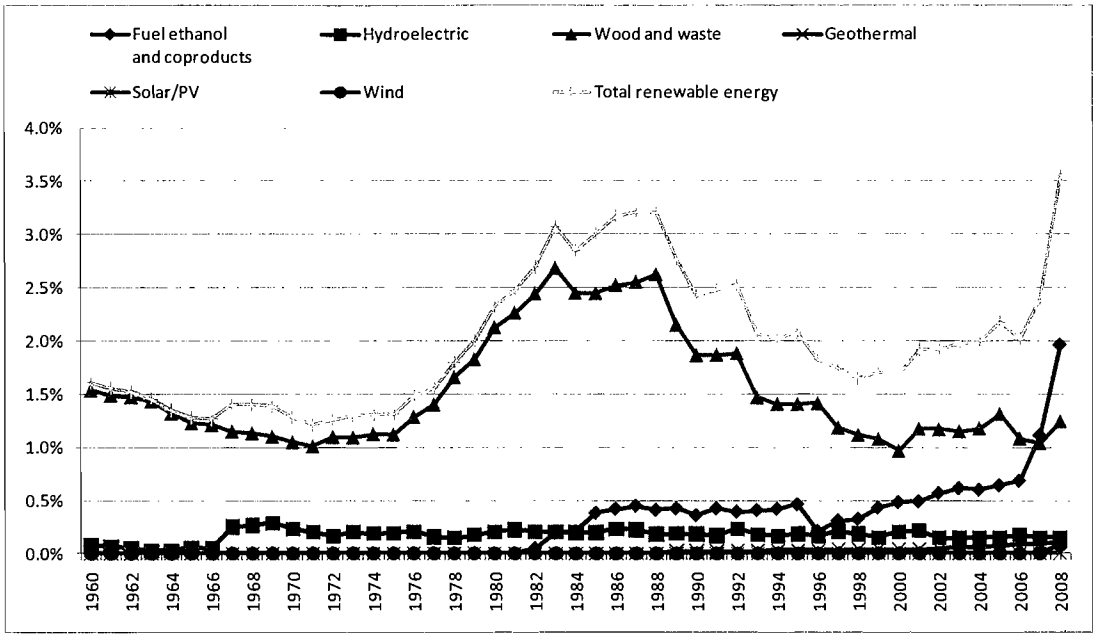


Figure 4-7: Renewables share of Indiana total energy consumption (Source EIA [16])

The other organic waste biomass that is a significant source of energy in Indiana is landfill gas. The most active user of landfill gas is Wabash Valley Power Association which has a total of 39.2 MW of electricity generating capacity from thirteen power plants on 7 landfills. Other major users of landfill energy include Hoosier Energy with 3.5 MW electricity generating capacity in a Clark County landfill and Granger Energy that has several energy conversion projects in the Southside landfill in Indianapolis. The Granger Energy project in the Southside Indianapolis landfill includes 4 MW of electricity generating capacity and supplies landfill gas to various area businesses for heating and steam generation. The total electricity generating capacity installed in Indiana landfills is 50.1 MW. Other operators of landfill electricity generating projects include Energy Systems LLC and the town of Munster [17].

Another source of biomass fuel use for electricity generation in Indiana is the anaerobic digestion of animal manure at three dairy farms in Northwest Indiana. The three dairies are the Boss Dairy No. 4, the Fair Oaks Dairy, and the Herrema Dairy. Each of these dairies has over 600 kW of generating capacity [18]. The Fair Oaks Farm is in the process of expanding its biogas production to include purification and compression of the biogas to pipeline quality methane to fuel 42 milk delivery trucks and a 1 MW electricity generator to power the methane cleaning and compression equipment [19].

In addition, SUFG is aware of a total of 195 kW of electricity generating capacity in wastewater treatment facilities in the cities of Jasper (65 kW) and West Lafayette (130 kW). The West

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5. Solar Energy

5.1 Introduction

Solar energy is captured and converted into various forms of energy in two main ways: directly into electricity using photovoltaic cells and indirectly using solar thermal conversion technologies. The two conversion methods and associated technologies are presented in this report, starting with solar thermal conversion technologies in this section followed by photovoltaic cells in Section 6.

The capture of solar thermal energy is done using solar energy collectors, of which there are two main types: concentrating and non-concentrating collectors. Concentrating collectors use mirrors of various configurations to focus the solar energy onto a receiver containing a working fluid that is used to transfer the heat to a conversion engine. Concentrating collectors are typically used for large scale electricity generating projects while non-concentrating collectors are typically used for small scale projects that require relatively low temperatures, such as solar water heating for pools and homes.

The most commonly used non-concentrating collectors are flat-plate designs. Of the various flat-plate design types, all consist of (1) a flat-plate absorber, which intercepts and absorbs the solar energy, (2) a transparent cover (glazing) that allows solar energy to pass through but reduces heat loss from the absorber, (3) a heat-transport fluid (air or water) flowing through tubes to remove heat from the absorber, and (4) a heat insulating backing. Figure 5-1 shows the basic components of a flat-plate collector. Other non-concentrating collectors include evacuated-tube collectors and integral collector-storage systems [1].

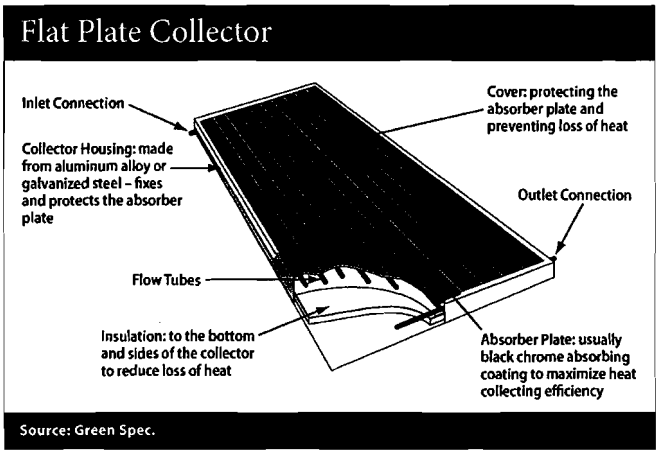


Figure 5-1: General layout of a flat-plate collector (Source: Texas Energy Report [2])

The three main types of thermal concentrating solar power (CSP) systems are parabolic trough, solar power tower, and solar dish/engine system. Figure 5-2 shows the general layout of the three systems.

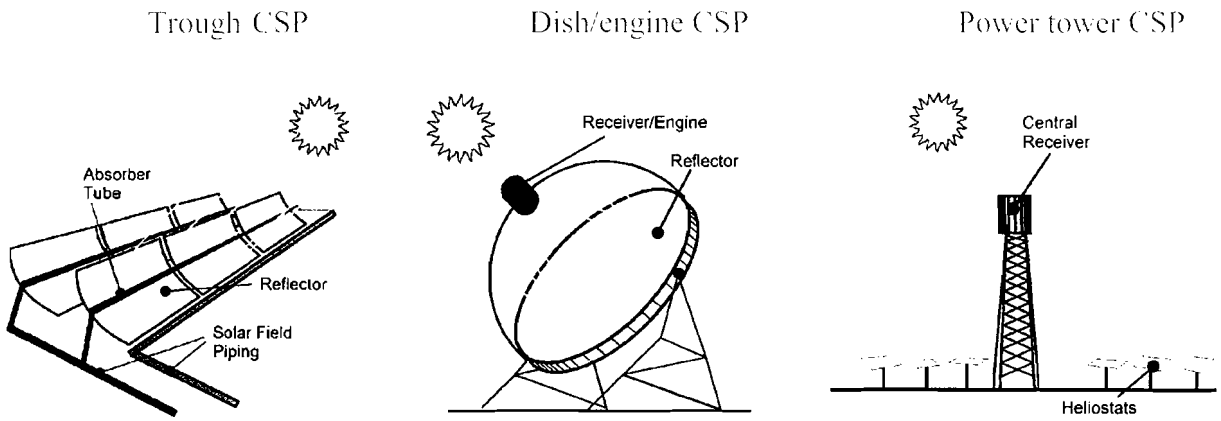


Figure 5-2: Types of concentrating solar power (CSP) collectors (Source: NREL [3])

The trough CSP system has trough shaped collectors with a parabolic cross section and a receiver tube located at the focal line of the trough. A working fluid is used to transport the heat from the receivers to heat exchangers. Trough CSP systems in use for utility scale electricity generation are typically coupled with a fossil-fuel fired boiler to supplement the supply of heat when the solar energy collected is not adequate. Trough systems can also be coupled with facilities to store the hot working fluid, thereby providing the ability for the plant to be dispatched to match system demand. Current trough systems range from small-scale (1 MW) to the large-scale 354 MW *Solar Electric Generating System* (SEGS) in California [4]. The trough system does not achieve as high temperatures as the power tower system and therefore has lower energy conversion efficiency. It is however the most developed and widely used CSP technology currently. Both the trough and the power tower systems have substantial cooling water requirements, a potentially limiting factor in the Southwestern desert terrain where the solar resource is most abundant [3].

A recently developed variation of the parabolic trough system is the linear Fresnel reflector. In this system the parabolic trough is approximated by a series of flat or slightly curved mirrors that focus the radiation onto a stationary conductor as shown in Figure 5-3.

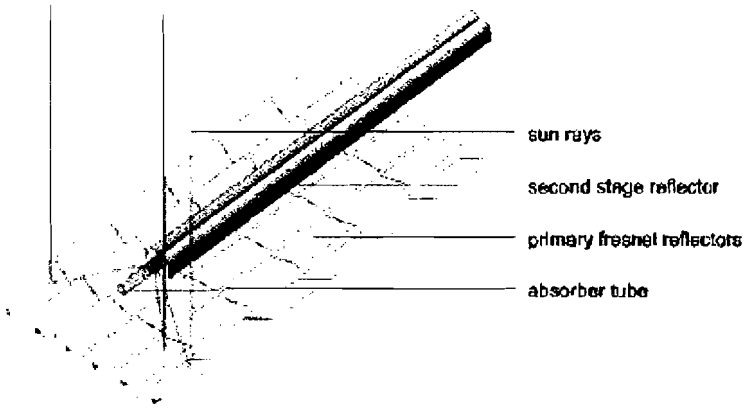


Figure 5-3: A linear Fresnel CSP collector (Source: IEA [6])

The power tower CSP system utilizes thousands of flat sun-tracking mirrors that concentrate the solar energy on a tower-mounted heat exchanger. This system avoids the heat lost during transportation of the working fluid to the central heat exchanger. Power tower CSP systems are typically equipped with molten salt energy storage tanks at the base of the towers that enable them to store energy for several hours [4]. This system provides higher efficiency than the trough system because all sunlight is concentrated on a single point, which can then reach a very high temperature [3].

The dish/engine system utilizes a parabolic shaped dish that focuses the sun's rays to a receiver at the focal point of the dish. An engine/generator located at the focal point of the dish converts the absorbed heat into electricity. Individual dish/engine units currently range from 3-25 kW [5]. Many of these dish systems would have to be combined to make a utility-scale power plant. The dish/engine design results in the highest efficiency of the thermal designs; an array of dishes can produce 60 percent more electricity per acre than a trough system [3]. The dish/engine system does not use any cooling water which puts it at an advantage over the other two systems. However, it is the least developed of the three CSP technologies with several challenges to be overcome in the design of the reflectors and the solar collectors. Table 5-1 displays the main characteristics of the three CSP technologies [7].

		Parabolic Trough	Power Tower	Dish/Engine
Size		30 – 320# MW	10 – 200# MW	5 – 25# kW
Operating Temperature (°C/°F)		390 / 734	565 / 1,049	750 / 1,382
Annual Capacity Factor#		23 – 50 percent	20 – 77 percent	25 percent
Net Annual Efficiency#		11 – 16 percent	7 – 20 percent	12 – 25 percent
Commercial Status		Available	Scale-up Demonstration	Prototype Demonstration
Technology Development Risk		Low	Medium	High
Storage Available		Limited	Yes	Battery
Hybrid Designs		Yes	Yes	Yes
Cost (1997$)	$/m^2	630 - 275#	475 – 200#	3,100 – 320#
	$/kW	4,000 – 2,700#	4,400 – 2,500#	12,600 – 1,300#
	$/kW$_p$+	4,000 – 1,300#	2,400 - 900#	12,600 – 1,100#

Values indicate changes over the 1997 – 2030 time frame.
+ $/kW$_p$ removes the effect of thermal storage (or hybridization for dish/engine).

Table 5-1: Characteristics of solar thermal electric power systems (Data source: EERE [7])

5.2 Economics of solar technologies

Figures 5-4 and 5-5 show the cost estimates of utility scale electricity generating technologies given in the November 2010 EIA update of generating plant costs [8]. Figure 5-4 shows the EIA estimate of the overnight[3] capital costs, and Figure 5-5 shows the estimate of the fixed and variable operating and maintenance (O&M) costs. The solar thermal technology's capital cost of approximately $4,700 /kW is in the mid-range among the renewable technologies between the low end of wind generation at $2,400/kW and the high end $8,200/kW for municipal solid waste based generation technology.

[3] Overnight capital cost "*is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day*" [8]. The overnight cost concept is used to avoid the impact of the differences in financing methods chosen by project developers on the estimated costs.

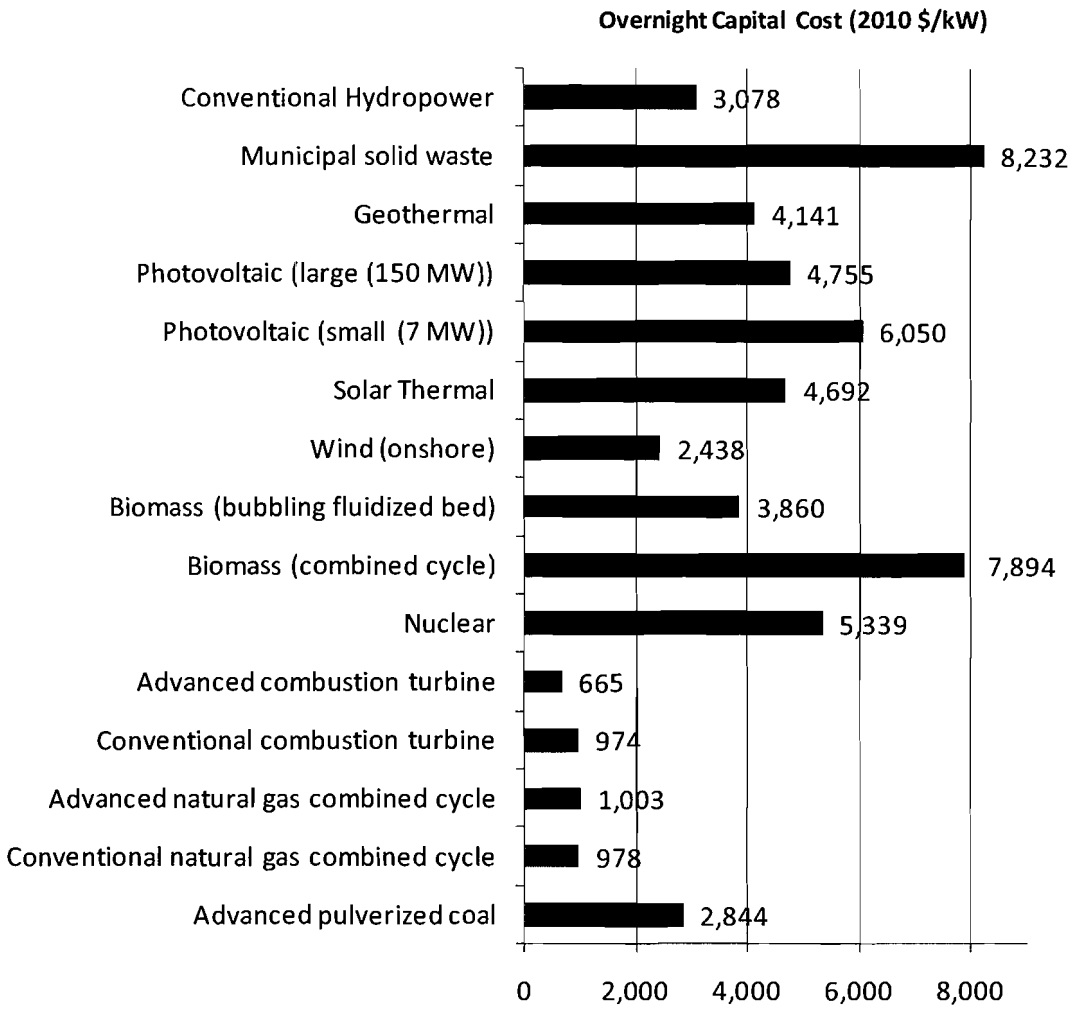


Figure 5-4: Capital cost of generating technologies (Data source: EIA [8])

As can be seen in Figure 5-5 solar thermal technology has moderate O&M cost, with a zero variable O&M cost and a fixed annual O&M cost of $64 /kW. This fixed annual O&M cost is higher than that of photovoltaic technologies which is estimated at $17 /kW for large scale photovoltaic plants and $26 /kW for small utility scale photovoltaic systems.

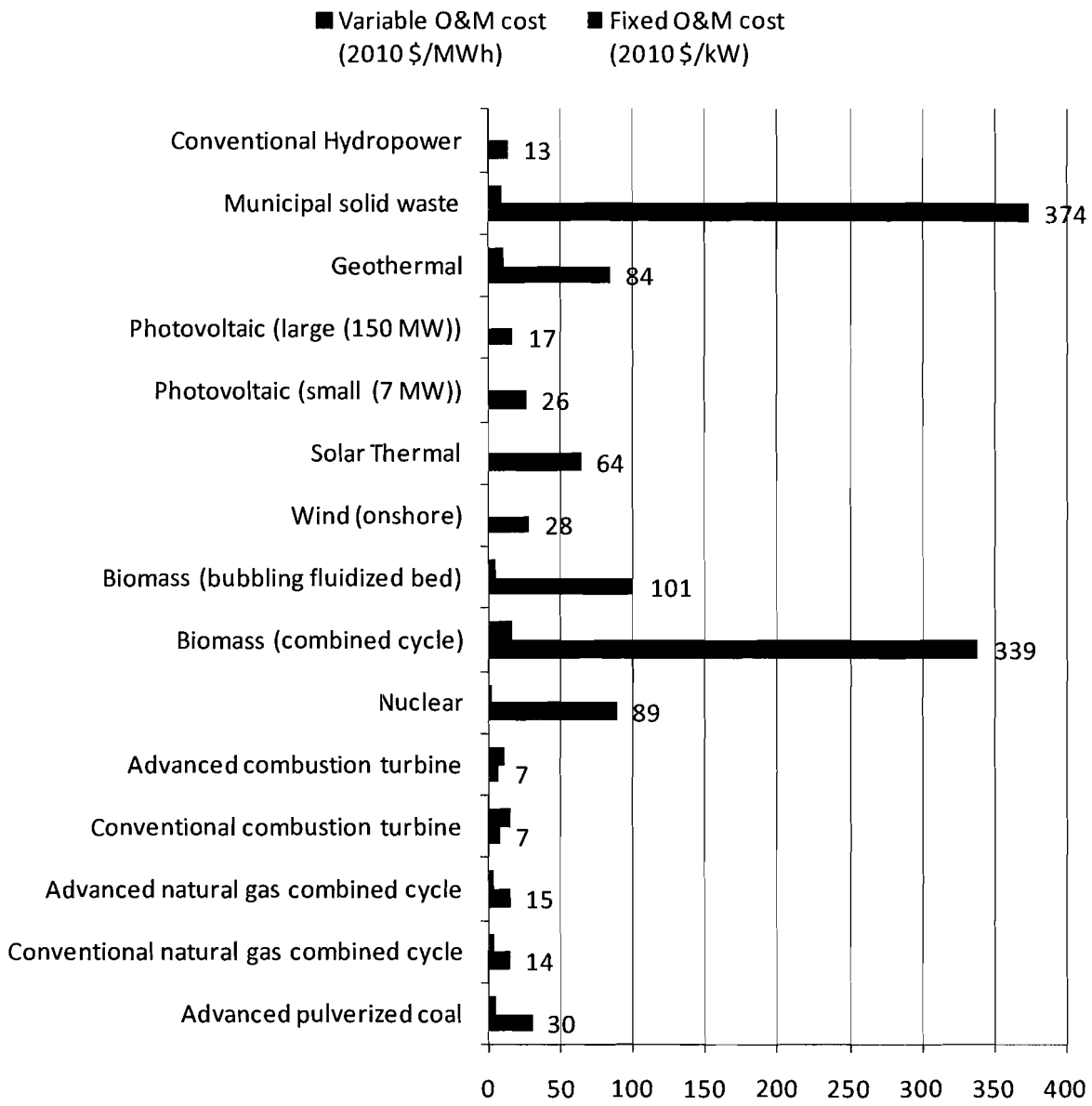


Figure 5-5: Operating and maintenance cost of generating technologies (Data source: EIA [8])

Table 5-1 shows the relative costs of the three common concentrating solar power systems. Although the power tower has the lowest capital cost of the three it is not yet a proven technology. The trough system, and in particular the parabolic trough system, is a commercially proven technology. Most of the CSP systems in commercial operation in the U.S. today, including the 354 MW SEGS system in California are based on parabolic trough technology [7, 9]. More details about the SEGS and other solar thermal systems in the U.S. are given in Section 5.3 of this report.

5.3 State of solar energy nationally

The combined effect of high capital cost and the intermittent nature of solar energy has kept its contribution to the national energy portfolio very low, lowest among all energy conversion technologies. In 2010 solar energy supplied approximately 0.1 percent of the total energy consumed in the U.S. and 0.03 percent of the electricity generated.

As can be seen in Figures 5-6 and 5-7, there are substantial solar resources available in the U.S., especially in the Southwestern region. Figure 5-6 shows the solar resources available to a stationary concentrating collector, and Figure 5-7 shows the solar resource available to a concentrating collector that tracks the sun throughout the day.

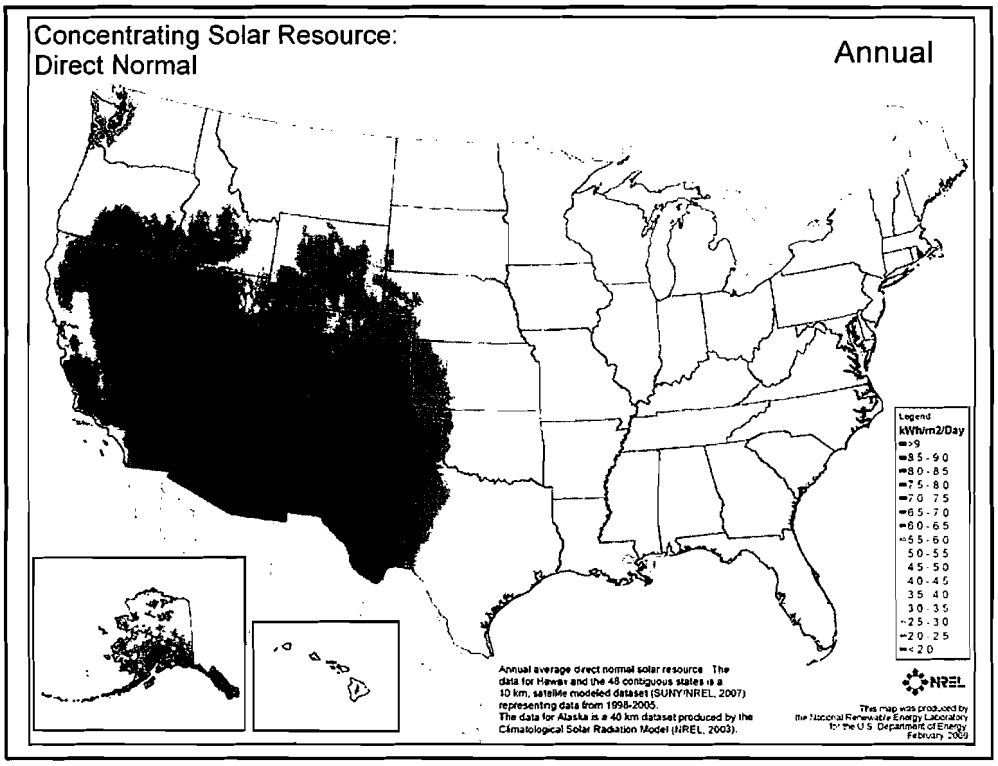


Figure 5-6: Concentrating solar power resource in the U.S. (Source: NREL [10])

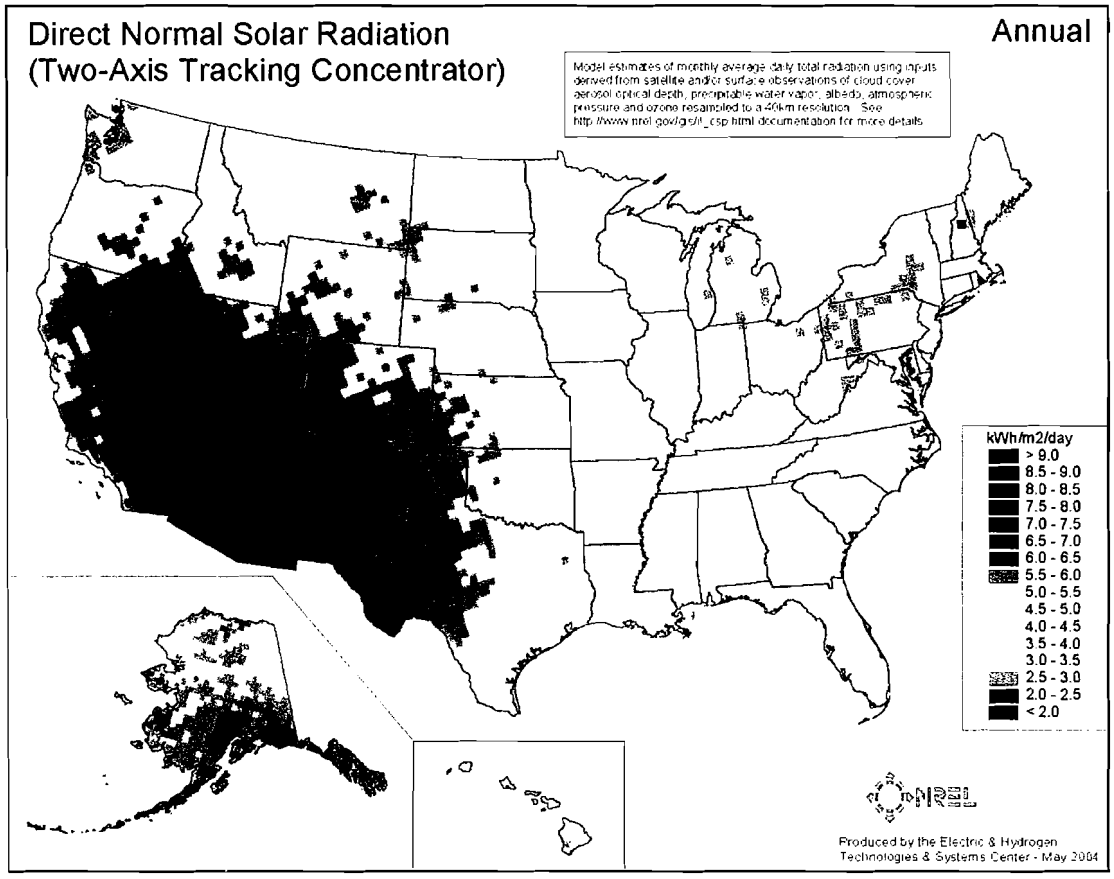


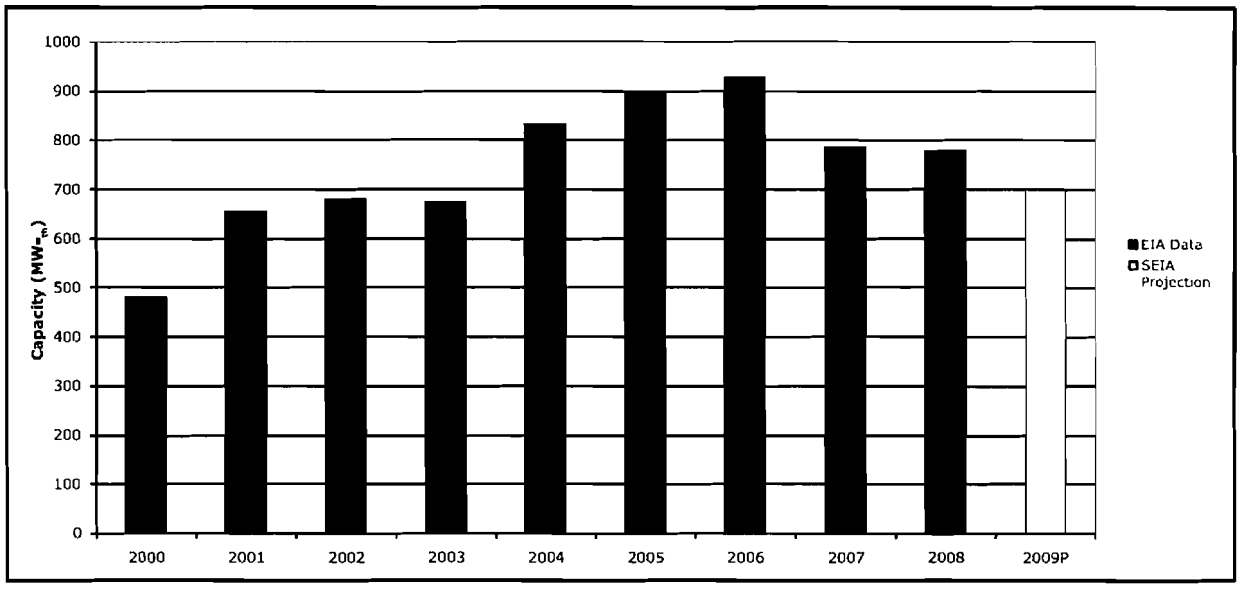
Figure 5-7: Solar resource available to a tracking concentrator (Source: NREL [10])

According to the *CSP today* website [11], there was a total of 433 MW of CSP capacity installed in the U.S. at the end of 2010. The largest and oldest of these is the 354 *MW Solar Electric Generation System* (SEGS) located in the Mojave Desert in California. SEGS consists of nine parabolic trough collector systems with associated power plants built between 1982 and 1991. The SEGS power plants are hybrid stations, equipped with natural gas fired boilers to supplement electricity generation when solar production is low [3, 9]. The next largest CSP is the 64 MW *Nevada Solar One* plant located in Boulder City, Nevada completed in 2007. Table 5-2 is a list of CSP power plants in the U.S. at the end of 2010. Four out of the seven systems with a total 421 MW capacity are of the parabolic trough type, one 5 MW facility is a linear Fresnel trough system, one 5 MW plant is a power tower system, and one 1.5 MW system is a dish/engine facility.

Name	Location	Developer	Capacity (MW)	Technology	Year online
Solar Energy Generating Systems (SEGS I - VIII)	Dagett, Kramer Junction, & Harper Lake California	NextEra Energy	354	Parabolic Trough	1982 -1991
Saguaro Power Plant	Red Rock, Tucson Arizona	Acciona (Solargenix)	1.2	Parabolic Trough	2005
Nevada Solar One	Boulder City Nevada	Acciona Solar Power	64	Parabolic Trough	2007
Holaniku, Keyhole Point	Kona, Hawaii	Sopogy	2	Parabolic Trough	2009
Kimberlina	Bakersfield California	AREVA /Ausra	5	Linear Fresnel	2008
Sierra SunTower	Lancaster California	eSolar	5	Power Tower	2009
Maricopa Solar Project	Peoria Arizona	Tessera Solar	1.5	Dish Engine	2010

Table 5-2: Concentrating solar power plants in the U.S. (Data source: CSP today [11])

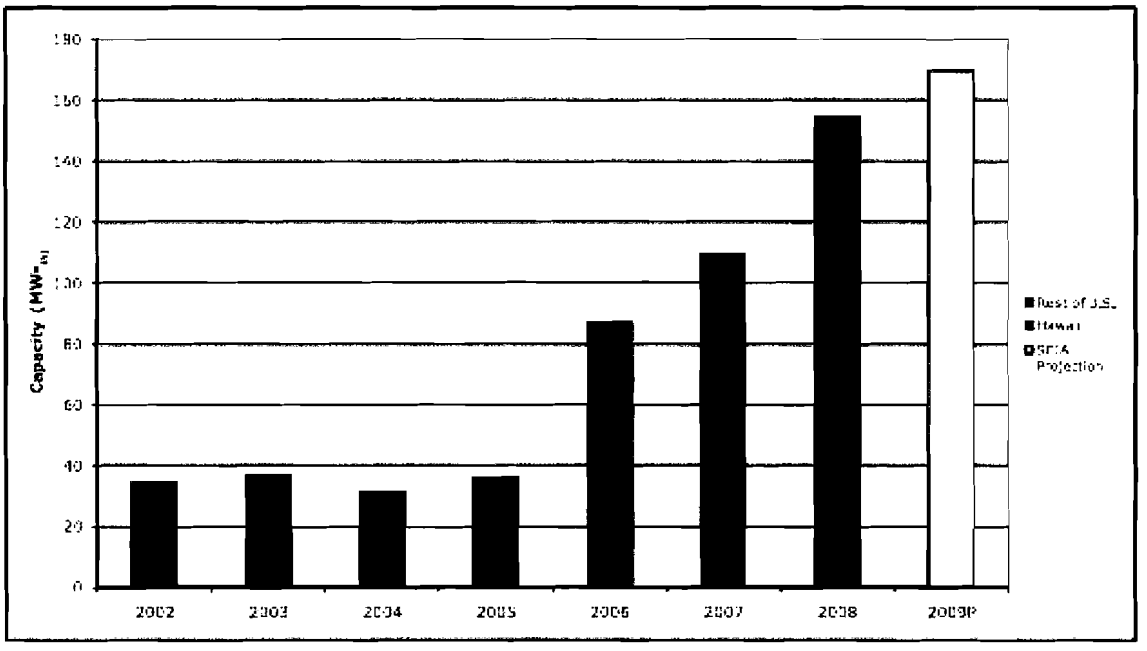
According to the *Solar Energy Industries Association* (SEIA) [12], the most widely used application for solar thermal energy in the U.S. is for heating of swimming pools. These solar pool heating systems can either be stand alone units or in parallel with a conventional heater [12]. Figure 5-8 shows the capacity installed annually, in thermal megawatts (MW_{th}), of solar thermal systems used for heating swimming pools.



*Capacity in thermal megawatts (MW_{th})

Figure 5-8: Annual installed U.S. capacity for solar pool heating (2000-2009) (Source: IREC [13])

The other major users of solar thermal energy are water heating and space heating/cooling. Figure 5-9 shows the annual installed capacity of solar thermal systems used for water heating and space heating/cooling from 2002 to 2009.



*Capacity in thermal megawatts (MW_{th})

Figure 5-9: Annual installed U.S. capacity for solar heating and cooling (2002-2009) (Source: IREC [13])

5.4 Solar energy in Indiana

As can be seen in the U.S. solar radiation maps (Figures 5-5 and 5-6) Indiana is in a region of the country that has the lowest annual average solar radiation. It is therefore very unlikely that it would be the location of choice for multi-megawatt electricity generating plants such as the 354 MW SEGS facility in California or the 64 MW Nevada Solar One plant referred to in Section 5.3. However there is some potential for water heating application of solar thermal technologies. According to the EIA 2011 solar thermal collector manufacturing report, Indiana was the 20th top destination for solar thermal collectors in 2009 [14].

Figure 5-10 shows the solar radiation available to a concentrating collector in Indiana and Figure 5-11 the radiation available to a flat collector facing south. As can be seen in Figure 5-11, the Southern half of the state has more radiation available to flat plate collectors typically used for water heating applications.

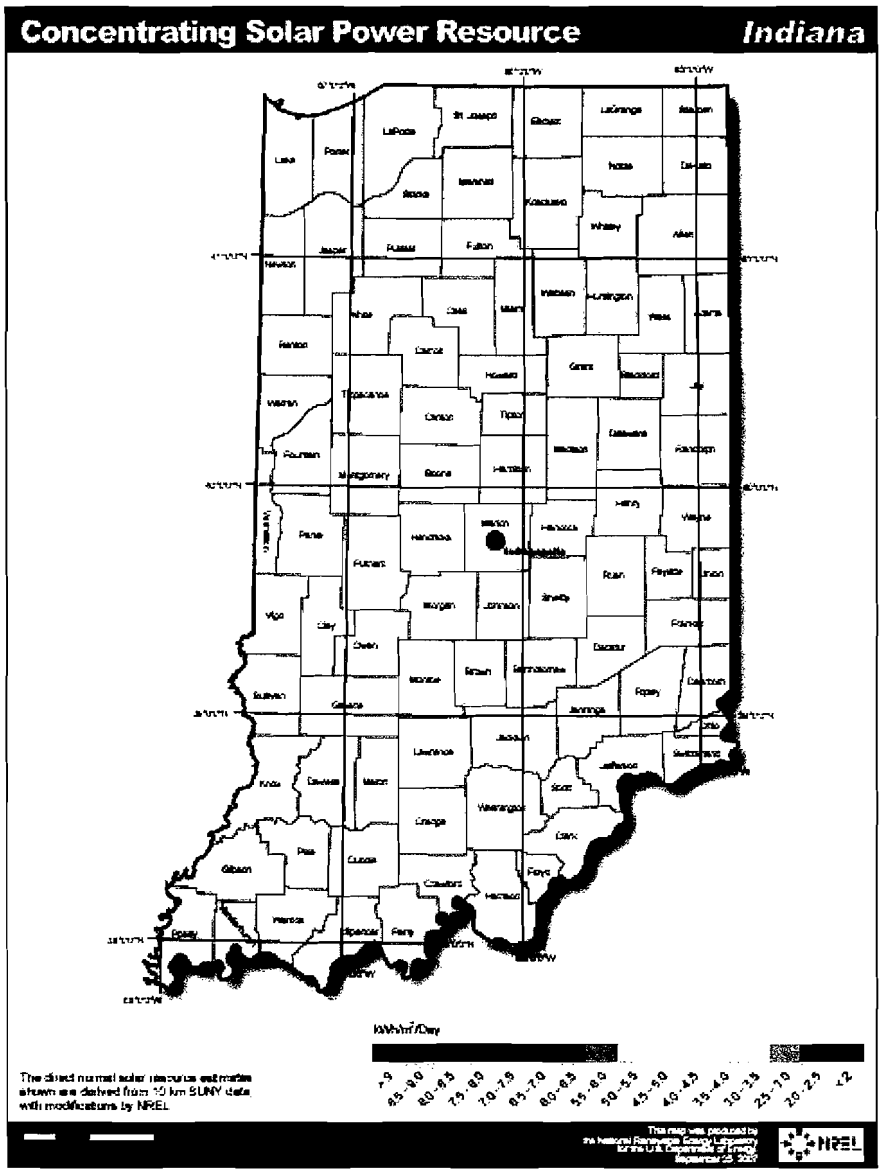


Figure 5-10: Direct normal solar radiation (two-axis solar concentrator) (Source: NREL [15])

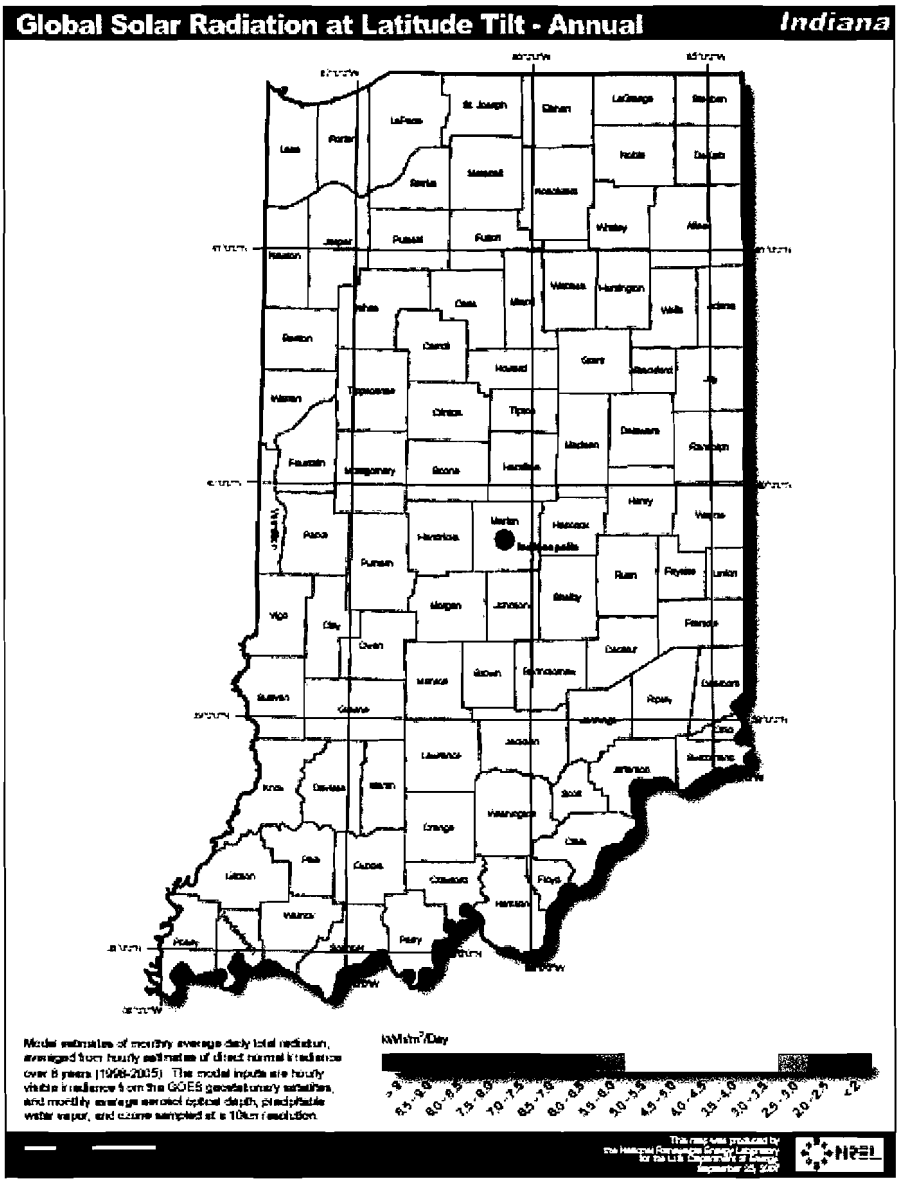


Figure 5-11: Direct normal solar radiation (flat-plate collector) (Source: NREL [15])

5.5 Incentives for solar energy

The following available incentives could help increase use of solar energy within Indiana:

Federal Incentives

- Business Energy Investment Tax Credit (ITC) credits up to 30 percent of expenditures on solar systems. 2009 American Recovery and Reinvestment Act provided for treasury cash grant in lieu of the ITC [16].

- Energy Efficiency Mortgage can be used by homeowners to finance a variety of energy efficiency measures, including renewable energy technologies, in a new or existing home. The federal government supports these loans by insuring them through FHA or VA programs. This allows borrowers who might otherwise be denied loans to pursue energy efficient improvements, and it secures lenders against loan default and provides them with confidence in lending to customers who would usually have been denied credit [16].
- Modified Accelerated Cost-Recovery System (MACRS) allows businesses to recover investments in solar, wind and geothermal property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to fifty years, over which the property may be depreciated. For solar, wind and geothermal property placed in service after 1986, the current MACRS property class life is five years [16].
- Qualified Energy Conservation Bonds (QECBs) are qualified tax credit bonds and are allocated to each state based upon their state's percentage of the U.S. population. The states are then required to allocate a certain percentage to "large local governments". In February 2009, these funds were expanded to $3.2 billion [16].
- Renewable Energy Production Incentive (REPI) provides financial incentive payments for electricity produced and sold by renewable energy generation facilities owned by non-profit groups, public utilities, or state governments [16].
- Residential Energy Conservation Subsidy Exclusion established by Section 136 of the IRS Code, makes direct and indirect energy conservation subsidies provided by public utilities nontaxable [16].
- Rural Energy for America Program (REAP) covers up to 25 percent of costs for eligible projects at certain types of institutions [26]. Eligible renewable energy projects include wind, solar, biomass and geothermal; and hydrogen derived from biomass or water using wind, solar or geothermal energy sources. REAP incentives are generally available to state government entities, local governments, tribal governments, land-grant colleges and universities, rural electric cooperatives and public power entities, and other entities, as determined by USDA.
- Value-Added Producer Grant Program support planning activities and provide working capital for farm-based renewable energy projects. Independent producers, agricultural producer groups, farmer or rancher cooperatives, and majority-controlled producer-based business ventures are eligible for the program. Previously awarded grants supported energy generated on-farm through the use of agricultural commodities, wind power, water power, or solar power [17].
- High Energy Cost Grant Program administered by the U.S. Department of Agriculture (USDA) is aimed at improving the electricity supply infrastructure in rural areas having home energy costs exceeding 275 percent of the national average. Eligible infrastructure includes renewable resources generation [18].

Indiana Incentives

- Net metering rule: Renewable resource facilities with a maximum capacity of 1 MW are qualified for net metering. The net excess generation is credited to the customer in the next billing cycle [16].
- Renewable Energy Property Tax Exemption provides property tax exemptions for solar thermal, wind, hydroelectric and geothermal systems [16].
- Solar Access Laws prevent planning and zoning authorities from prohibiting or unreasonably restricting the use of solar energy. Indiana's solar-easement provisions do not create an automatic right to sunlight, though they allow parties to voluntarily enter into solar-easement contracts which are enforceable by law [16].
- Clean Energy Portfolio Standard (CPS) passed in May 2011 sets a voluntary goal of 4 percent between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent clean energy by 2025, based on 2010 retail sales. Participation in CPS makes utilities eligible for incentives in order to pay for the compliance projects [16].
- Emissions Credits are available by electricity generators that do not emit NO_x and that displace utility generation are eligible to receive NO_x emissions credits under the Indiana Clean Energy Credit Program [28]. These credits can be sold on the national market.
- Indiana Solar Thermal Grant Program provides cost share grants to public, non-profit and business sectors for solar water heating systems [20].
- Northern Indiana Public Service Company – The NIPSCO feed-in tariff offers incentive rates for electricity generated from renewable resources. The payments for solar facilities are $0.30/kW for solar facilities with a capacity below 10 kW and $0.26/kW for facilities up to 2 MW. The tariff is experiment running until December 31, 2013. The allowable generator generating unit size under the tariff is between 5 and 5,000 kW and the total system-wide capacity allowed is 30 MW. 500 kW of the total system-wide cap is reserved for solar projects of capacity less than 10 kW [21].

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6. Photovoltaic Cells

6.1 Introduction

Unlike solar thermal systems, photovoltaic (PV) cells allow for the direct conversion of sunlight into electricity. The photovoltaic cell is a non-mechanical device constructed from semiconductor materials (see Figure 6-1). When the photons in sunlight strike the surface of a photovoltaic cell, some of them are absorbed. The absorbed photons cause free electrons to migrate in the cell, thus causing "holes." The resulting imbalance of charge between the cell's front and back surfaces creates a voltage potential like the negative and positive terminals of a battery. When these two surfaces are connected through an external load, electricity flows [1].

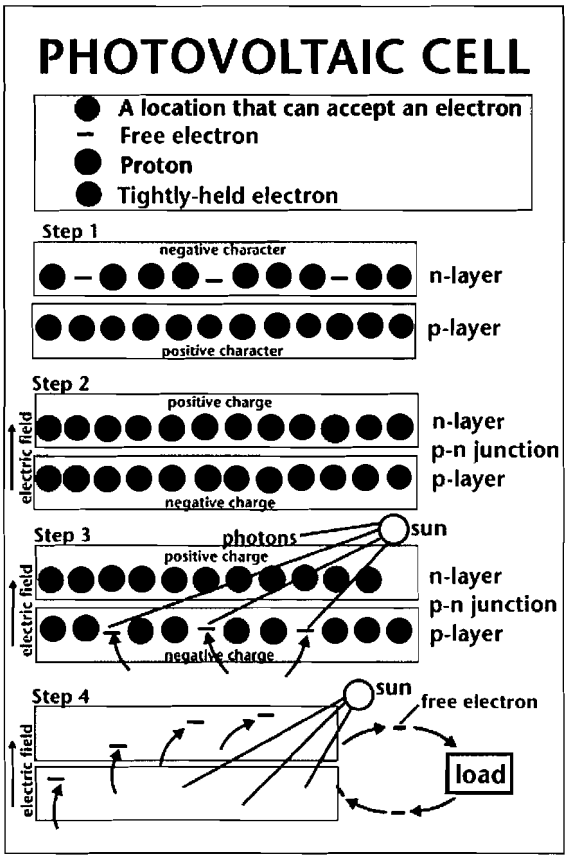

Figure 6-1: Photovoltaic cell operation (Source: EIA [1])

The photovoltaic cell is the basic building block of a PV system. The individual cells range in size from 0.5 to 4 inches across with a power output of 1 to 2 watts. To increase the power output of the PV unit, the cells are usually electrically connected into a packaged weather-tight module. About 40 cells make up a module, providing enough power for a typical incandescent light bulb. These

modules could further be connected into arrays to increase the power output. Hundreds of arrays could be connected together for larger power applications. The performance of PV units depends upon sunlight, with more sunlight leading to higher power output. Figure 6-2 illustrates how cells can combine to make a module, and how modules are combined to make an array [2].

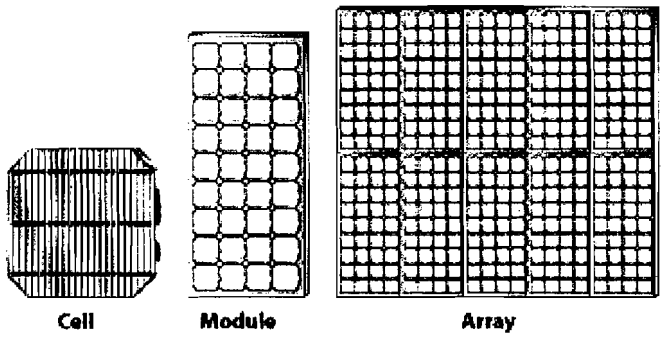

Figure 6-2: Illustration of a cell, module and array of a PV system (Source: EERE [2])

Simple PV systems are used to power calculators and wrist watches, whereas more complicated systems are used to provide electricity to pump water, power communication equipment, and even provide electricity to houses and buildings.

There are currently three major types of PV cells: crystalline silicon-based, thin film-based, and concentrator-based. A new experimental type of cell, the spheral cell, aims to reduce the amount of silicon used to construct solar cells; spheral cells remain mostly in the research phase. Silicon PV cells, the most common type, typically cost more than thin film cells but are more efficient [3]. Efficiency ranges of 13 to 17 percent are normal, though Sanyo announced in 2007 that they had built a silicon-based cell that achieves 22 percent efficiency [4]. Thin-film cells have a normal efficiency of 10 percent. Concentrator cells and modules utilize a lens to gather and converge sunlight onto the cell or module surface [3].

PV cells can be arranged into two different types of arrays: flat-plate PV arrays and concentrating PV arrays. Flat-plate PV arrays can be mounted at a fixed-angle facing south, or they can be mounted on a tracking device that follows the sun throughout the day. Concentrating PV (CPV) arrays use a lens to focus sunlight onto cells. CPV arrays cannot use diffuse sunlight and as such are generally installed on tracking devices. The advantage of CPV arrays is that they use less semiconductor material than flat-plate arrays to produce the same output. A disadvantage, though, is that because they are unable to make use of indirect sunlight, CPV arrays can only be used in the sunniest parts of the country, unlike the broad geographical range of flat-plate PV arrays [5].

NREL is actively researching CPV technology, especially as an alternative to the dish/engine solar thermal system discussed in Section 5. CPV systems have no moving parts (besides the

tracking device) and no heat transfer, making them potentially more reliable than dish/engine systems. Also, CPV systems result in efficiencies greater than 40 percent and a reduction in the use of expensive semiconductor materials, lowering the effective total cost compared to flat-plate PV systems. The cost of CPVs is similar to that of solar thermal technologies, and CPVs may eventually be used at the utility-scale. NREL is currently focusing on the development of multi-cell packages (dense arrays) to improve overall performance and reliability [6].

Figure 6-3 illustrates the historical progress of solar cell efficiencies until 2009. As shown in the graph, experimental multi-junction concentrator-based PV cells reported the highest efficiency levels, approximately 40 percent.

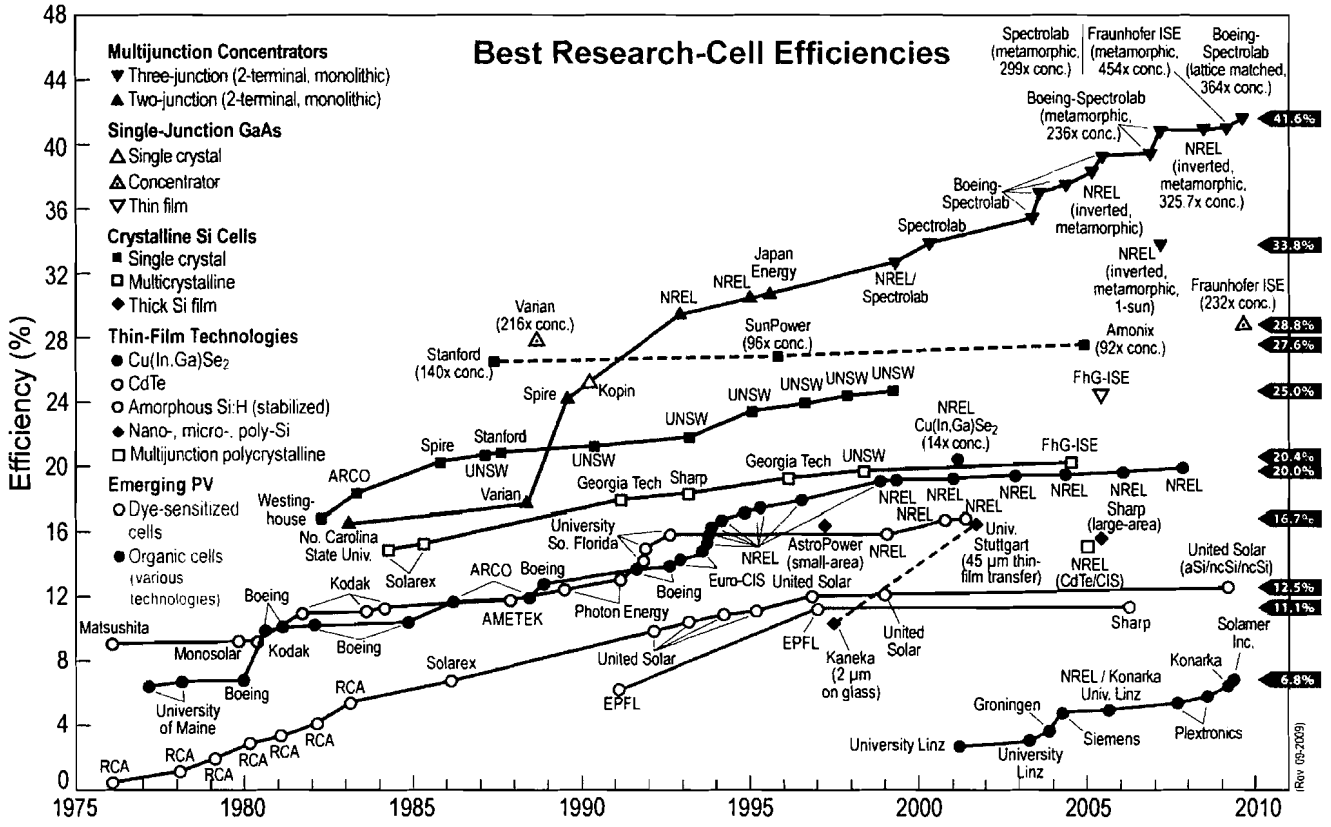

Figure 6-3: Improvements in solar cell efficiency, by system, from 1976 to 2009 (Source: NREL [7])

In addition to multi-junction CPV cells, other advanced approaches to solar cells are under investigation. For example, dye-sensitized solar cells use a dye-impregnated layer of titanium dioxide to generate a voltage as opposed to the semiconducting materials used in most solar cells currently in the industry. Because titanium dioxide is fairly inexpensive, it offers the potential to significantly reduce the cost of solar cells. Other advanced approaches include polymer (or plastic)

solar cells and photo electrochemical cells, which produce hydrogen directly from water in the presence of sunlight [8].

Flat-plate PV arrays, CPVs, and other types of solar PV technology are used in many different ways across the U.S. In 1998, a study was carried out by EIA to determine trends in the U.S. photovoltaic industry. The report divided the national PV market into several niche markets that were labeled and described as follows [9]:

- Building Integrated Photovoltaics (BIPV): These are PV arrays mounted on building roofs or facades. For residential buildings, BIPV capacities may reach up to 4 kW per residence. Systems may consist of conventional PV modules or PV shingles. This market segment includes hybrid power systems, combining diesel generator, battery, and photovoltaic generation capacity for off-grid remote cabins.
- Non-BIPV Electricity Generation (grid interactive and remote): This includes distributed generation (e.g., stand-alone PV systems or hybrid systems including diesel generators, battery storage, and other renewable technologies), and water pumping power for irrigation systems. The U.S. Coast Guard has installed over 20,000 PV-powered navigational aids (e.g., warning buoys and shore markers) since 1984.
- Communications: PV systems provide power for remote telecommunications repeaters, fiber-optic amplifiers, rural telephones, and highway call boxes. Photovoltaic modules provide power for remote data acquisition for both land-based and offshore operations in the oil and gas industries.
- Transportation: Examples include power on boats, in cars, in recreational vehicles, and for transportation support systems such as message boards or warning signals on streets and highways.
- Consumer Electronics: A few examples are calculators; watches; portable and landscaping lights; portable, lightweight PV modules for recreational use; and battery chargers.

Some advantages of using PV systems are:

- Sunlight is a free and inexhaustible resource;
- The lack of moving parts[4] results in lower maintenance costs; and
- The modular nature of PV arrays allow for variable output power configurations.

The main disadvantages to using PV systems are:

- The sun is an intermittent source of energy, not available at night and reduced output on cloudy days; and
- They have high capital cost relative to traditional technologies.

[4] There are no moving parts for fixed-orientation PV units and minimal slow-moving parts for tracking PV units.

Despite the intermittent nature of sunlight, PV has the added potential as a supplier of electricity during periods of peak demand, since it produces more electricity on sunny days when air conditioning loads are the greatest.

6.2 Economics of PV systems

Figure 6-4 shows EIA's estimates of the overnight[5] capital cost of a utility scale photovoltaic electricity generating plant alongside other utility scale electricity generating technologies. As can be seen in the figure, the photovoltaic capital cost is one of the highest. The smaller of the two systems (7 MW) considered by EIA has a capital cost of $6,050 /kW, which is third highest after municipal solid waste's estimated cost of $8,232/kW and biomass combined cycle's estimated cost of $7,894 /kW. The larger of the two PV systems (150 MW) considered by EIA has a lower estimated capital cost of $4,755/kW, which is still among the highest, ranking fourth after municipal solid waste, biomass combined cycle, large PV and nuclear, with nuclear power's estimated cost at $5,339 /kW.

[5] Overnight capital cost "*is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day*" [10]. The overnight cost concept is used to avoid the impact of the differences in financing methods chosen by project developers on the estimated costs.

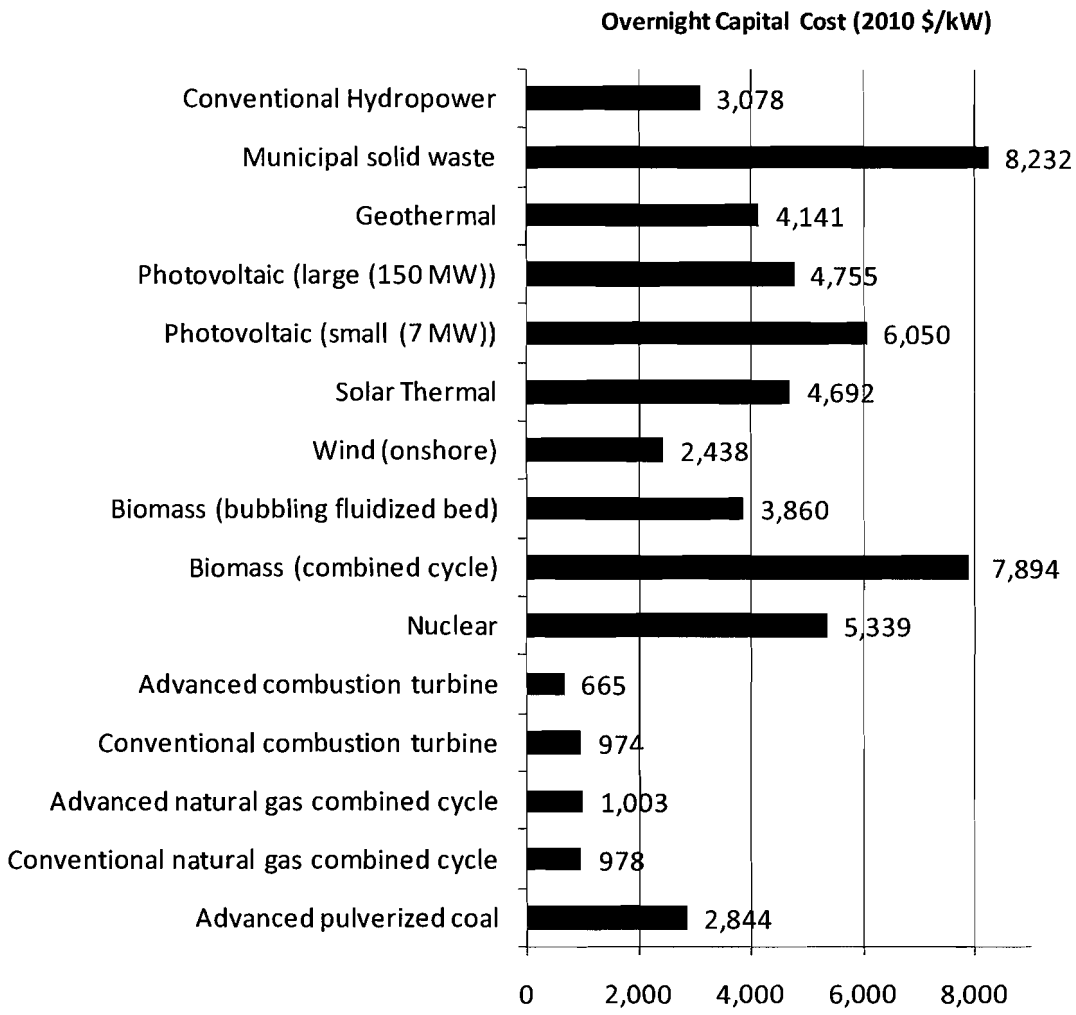

Figure 6-4: Capital cost of generating technologies (Data source: EIA [10])

Figure 6-5 shows the capacity-weighted average costs of actual systems installed in the U.S. between 1998 and 2009 compiled by the Lawrence Berkeley National Laboratory [11]. According to the Berkeley report, the approximately 78,000 PV systems in the dataset represent 70 percent of all grid-connected PV systems installed in the U.S. through 2009. The size of the systems in the dataset range from as small as 100 watts to 2.3 MW with approximately 90 percent of the systems in the dataset having a capacity of 10 kW or less. As can be seen from the Figure, the capacity-weighted average installed cost prior to any financial incentives has been dropping steadily from $10,800/kW in 1998 to $7,500/kW in 2009.

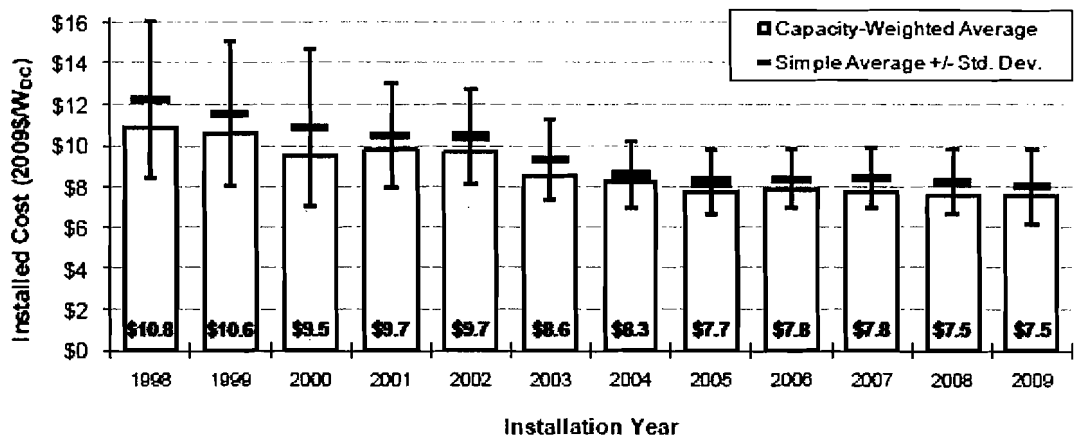

Figure 6-5: Installed cost trends over time (Source: Berkeley [11])

Figure 6-6 shows the breakdown of the installed costs for PV systems installed in 2009 for the three system ranges in the dataset. In all three size ranges the cost of the PV module was slightly over half the total system's installed cost. The 'other' costs category ranges from 36 to 42 percent of the total system cost and includes such items as mounting hardware, labor, overhead and installer profit.

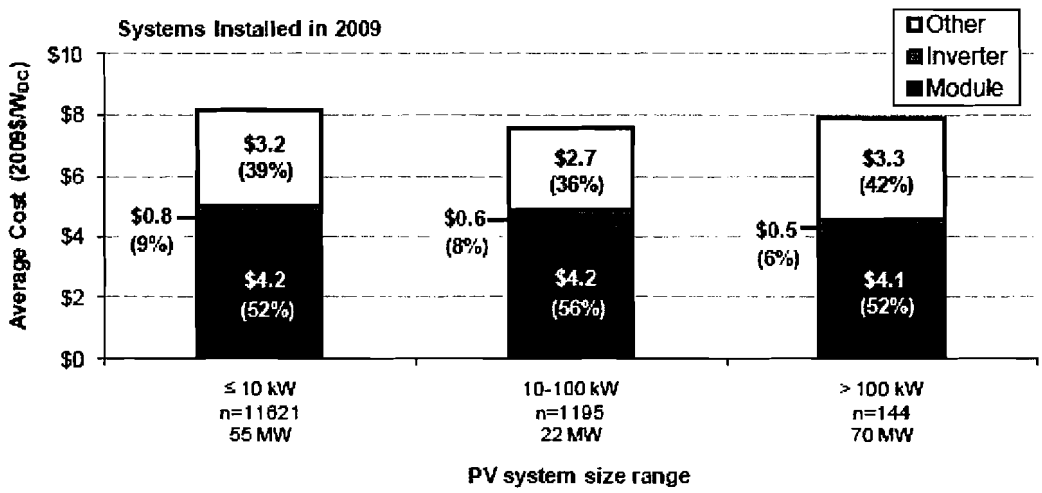

Figure 6-6: Module, inverter, and other costs (Source: Berkeley [11])

6.3 State of PV systems nationally

Most PV systems in use today use non-concentrating flat plate collectors. Since flat plate collectors can absorb and make use of both direct and indirect solar radiation, the potential areas where they can be used extends across a much wider geographical region of the U.S. than the sunny Southwest. Figure 6-7 shows the solar resource availability across the U.S. for a flat plate solar collector facing south at the appropriate angle. Figure 6-8 shows the solar resource availability for a two-axis tracking concentrating collector. At the writing of this report SUFG was aware of only one grid-

connected PV power plant in operation in the U.S. using concentrating lens technology, the 1 MW Chevron Mining plant in Questa, New Mexico.

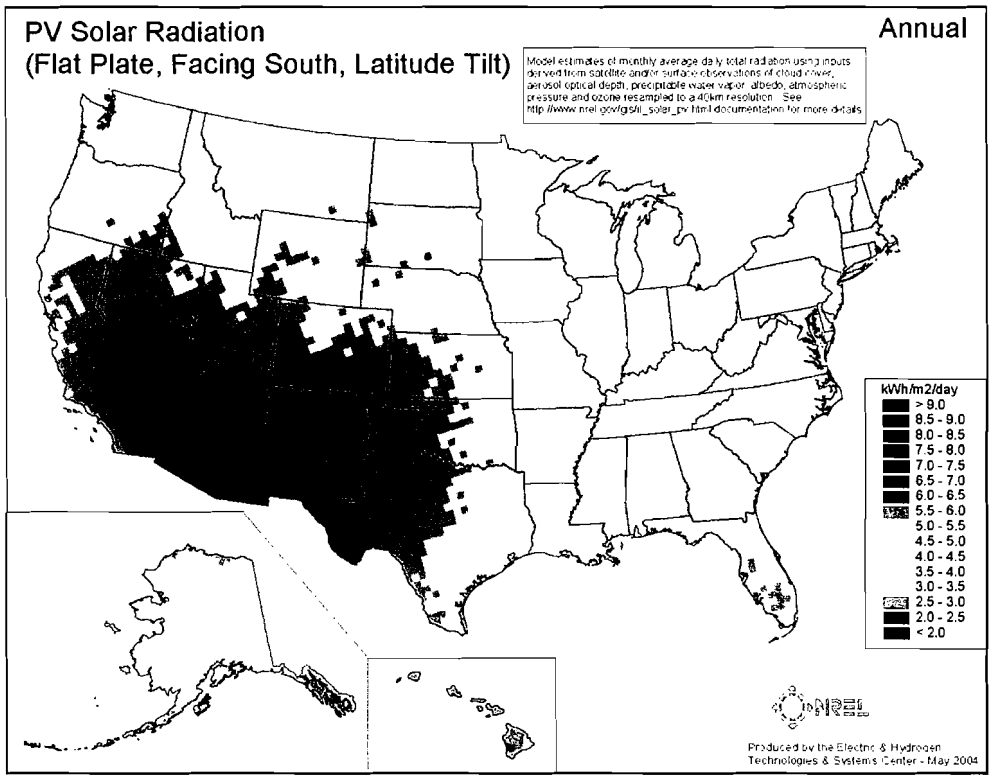

Figure 6-7: Annual average solar radiation for a flat-plate collector (Source: NREL [12])

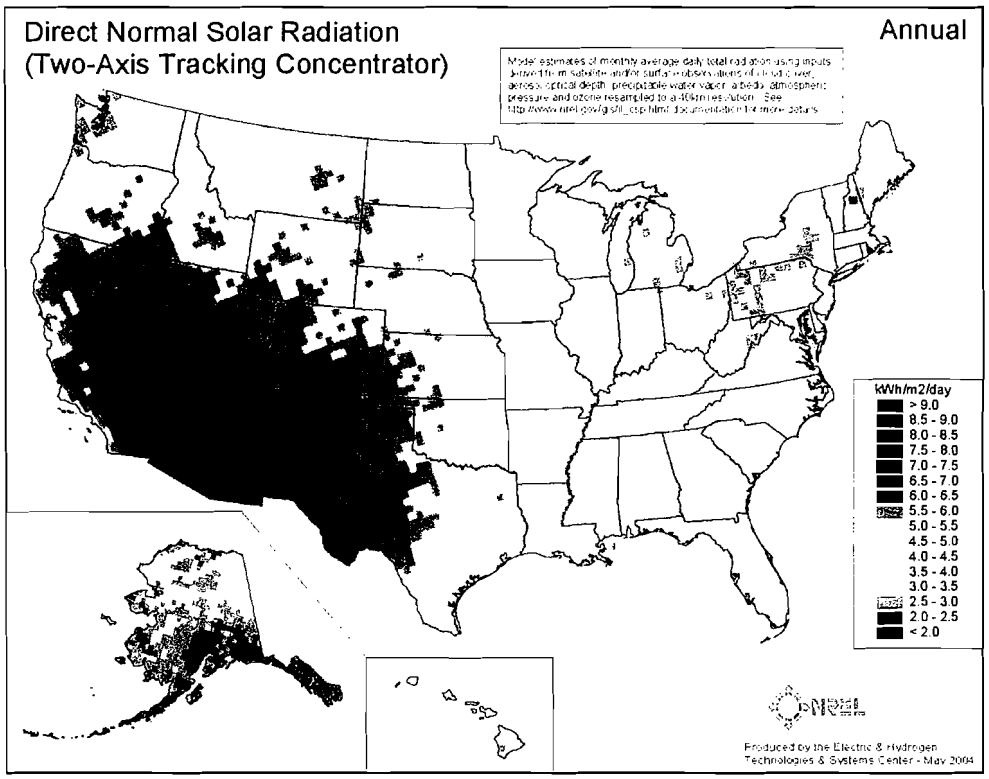

Figure 6-8: Direct normal solar radiation (two-axis solar concentrator) (Source: NREL [12])

PV installations have been growing rapidly in the last decade. Figure 6-9 shows the annual and the cumulative installed capacity of grid-connected PV in the U.S. The main factors influencing the rapid growth in the last few years are federal and state financial incentives and state renewable portfolio standards that have specific solar-electric provisions. Top among the federal financial incentives is the 30 percent investment tax credit (ITC) that was extended in 2008 and 2009 to remove the $2,000 cap on personal ITC, to allow electric utilities access to the ITC and to provide for an alternative 30 percent investment cash grant in lieu of the tax credit. In addition, the American Recovery and Reinvestment Act provided funds for a DOE loan guarantee program targeted towards renewable energy projects [13, 14, 15].

At the state level, sixteen states have renewable portfolio standards that have a specific quota for solar-electric technologies or for customer-side distributed generation. PV systems are the most common renewable energy technologies in use for residential customer-side distributed generation. In addition several states, including California, New Jersey, Florida, Colorado, New York, Connecticut and Massachusetts, have rebates with various types of funding mechanisms targeted at solar-electric systems [13, 14, 15].

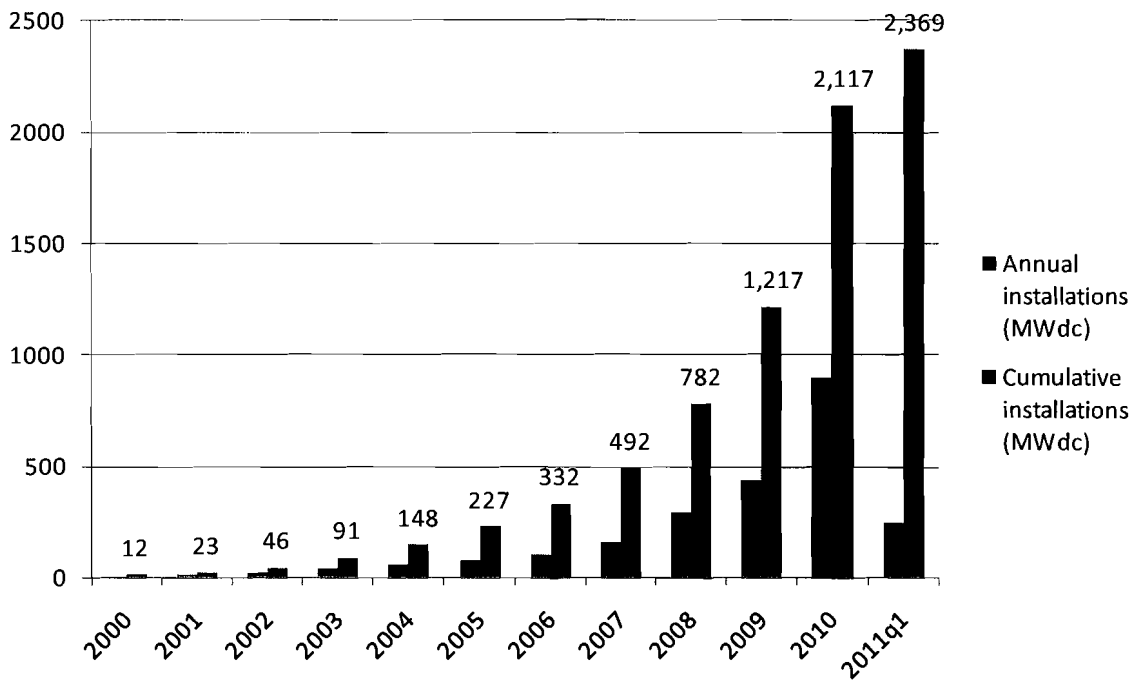

Figure 6-9: Grid-connected U.S. PV installed 2000 to 2011 first quarter (Data source SEIA [14, 16])

Part of the rapid expansion in PV capacity in the last decade stems from the installation of several major utility scale projects such as the 55 MW Copper Mountain PV power plant in Boulder, Nevada commissioned in 2010, the 30 MW Cimarron I plant in Cimarron, New Mexico commissioned in 2010, and the 25 MW DeSoto plant in Arcadia, Florida. Table 6-1 lists PV projects of one MW and above capacity in operation in the U.S. as of May 2011.

Project Name	Developer	Capacity (MW)	Online Date	Electricity Purchaser	City/County	State
Rancho Seco	ARCO Solar/Siemens	3	1984	Sacramento Municipal Utility District	Herald	CA
Springerville	Global Solar Energy	5	2003	Tuscon Electric Power	Springerville	AZ
Prescott	Arizona Public Service	3	2006	Arizona Public Service	Prescott	AZ
Nellis	MMA Renewable Ventures	14	2007	Nellis Air Force Base	Clark County	NV
Alamosa	SunEdison	8	2007	Xcel Energy	Alamosa	CO
Exelon-Conergy	Conergy	3	2008	Exelon Generation LLC	Philadelphia	PA
Soleil	enXco	1	2008	Sacramento Municipal Utility District	Sacramento	CA
El Dorado	First Solar/Sempra	10	2008	Pacific Gas & Electric	Boulder City	NV
Fort Carson	Three Phases /Green Rock Capital	2	2008	Fort Carson Army Base	Colorado Springs	CO
Vineland Solar One	Conectiv Energy	4	2009	Vineland Municipal Electric Utility	Vineland	NJ
FSE Blythe	First Solar	21	2009	Southern California Edison	Blythe	CA
DeSoto	Florida Power & Light	25	2009	Florida Power & Light Co.	Arcadia	FL
CalRENEW-1	Cleantech America Inc.	5	2010	Pacific Gas & Electric	Mendota	CA
	Efficient Energy of Tennessee	1	2010	Tennessee Valley Authority	Knox County	TN
Cimarron I	First Solar	30	2010	Tri-State Generation and Transmission	Cimarron	NM
Copper Mountain	First Solar/Sempra	55	2010	Pacific Gas & Electric	Boulder City	NV
Space Coast	Florida Power & Light	10	2010	Florida Power & Light Co.	Kennedy Space Center	FL
Jacksonville	juwi solar Inc.	15	2010	Jacksonville Electric Authority	Jacksonville	FL
Wyandot	juwi solar Inc.	12	2010	American Electric Power Co. Inc.	Salem Township	OH
Blue Wing	juwi solar Inc.	16	2010	CPS Energy	San Antonio	TX
Vaca-Dixon	Solon	2	2010	Pacific Gas & Electric	Vacaville	CA
West Pullman	SunPower	10	2010	Exelon Generation LLC	Chicago	IL
Shelby	SunPower/Duke	1	2010	NCMPA1	Shelby	NC
William Stanley	Western Massachusetts Electric	2	2010	Western Massachusetts Electric Co.	Pittsfield	MA
	ESA Renewables /Suniva	1	2011	Tennessee Valley Authority	Blairsville	GA
	SunEdison	17	2011	Duke Energy	Davidson County	NC
Greater Sandhil	SunPower	19	2011	Xcel Energy	Alamosa	CO
Chevron Technology Ventures*		1	2011	Kit Carson Electric Cooperative	Questa	NM

*The Chevron Technology Ventures project is the only project in the list using concentrating photovoltaic (CPV) technology

Table 6-1: PV systems of one megawatt and above installed in the U.S. (Data source: SEIA [17])

6.4 PV systems in Indiana

In keeping with the nationwide trend, PV installations have been growing rapidly in Indiana with 75 installations totaling over 2.6 MW of capacity entered into the NREL *Open PV* [18] database at the time this report was written. The largest of these installations is the 2.1 MW PV system installed on the Emmett Building at the Fort Harrison Federal Compound in Indianapolis completed in April 2011. The next largest unit is the 100 kW project at the Johnson Melloh renewable energy demonstration site in Indianapolis. Table 6-2 is a list of the 16 photovoltaic systems with at least 10 kW capacity installed in Indiana as of July 2011.

As explained previously, the factors being credited with the rapid growth in the PV market in the last few years include federal, state and utility incentives. The federal incentives include the renewal and expansion of the investment tax credit to remove the $2,000 cap on personal tax credit and to allow electric utilities access to the investment tax credit. In addition the 2009 American Recovery and Reinvestment Act provided for an alternative 30 percent cash grant in lieu of the investment tax credit and provided additional funds for renewable energy projects in the DOE loan guarantee program. The recently enacted expansion of the Indiana net metering rule to include all customer classes and systems up to 1 MW is expected to improve the financial viability of customer side PV systems. In Addition two Indiana utilities, Indianapolis Power and Light (IPL) and Northern Indiana Public Service Company (NIPSCO), offer feed-in tariffs for electricity generated from renewable resources. IPL offers a feed-in tariff of $0.24/kWh for PV systems between 20 and 100 kW and $0.20/kWh for systems greater than 100kW up to 10 MW and NIPSCO offers $0.30/kWh for electricity and the associated renewable credits for units less than 10 kW and $0.26 for solar facilities up to 2 MW.

Owner /Developer	Capacity (kW)	Location	Date Installed	Cost ($/Watt)
US General Services Administration	2,010	Emmett Bean Building, Fort Benjamin Harrison, Indianapolis	4/2011	n/a
Johnson Melloh	99.96	Indianapolis Marion County	2/2011	n/a
Bus Station	93	South Bend, St. Joseph County	2010	n/a
Stinson-Remick Hall Notre Dame	50	University of Notre Dame, St. Joseph County	2010	10
Cool Creek Park	15.68	Carmel, Hamilton County	2010	8.35
International Brotherhood of Electrical Workers	14.1	Terre Haute, Vigo County	2010	6.04
Residential	13.68	Connersville, Fayette County	2007	14.25
Residential	13.4	Terre Haute, Vigo County	2009	7.76
Newburgh Library	11	Newburgh, Warrick County	2007	10
Evansville-Vanderburgh Public Library	10.8	Evansville, Vanderburgh County	2010	7.94
Evansville-Vanderburgh Public Library	10.8	Evansville, Vanderburgh County	2010	7.94
Commercial	10.75	Kokomo	2009	7.93
Fitzpatrick Hall Notre Dame	10	University of Notre Dame, St. Joseph County	7/2011	n/a
Big Fish'n Campground	10	Lafayette	2010	n/a
Residential	10	New Harmony, Posey County	2010	8.13
Residential	10	New Harmony, Posey County	2010	8.32

Table 6-2: PV systems in Indiana of 10kW and above capacity (Data source: NREL [18])

6.5 Incentives for PV systems

Federal Incentives

- Business Energy Investment Tax Credit (ITC) credits up to 30 percent of expenditures on solar systems. 2009 American Recovery and Reinvestment Act provided for treasury cash grants in lieu of the ITC [19].
- Energy Efficiency Mortgage program provides mortgages that can be used by homeowners to finance a variety of energy efficiency measures, including renewable energy technologies, in a new or existing home. The federal government supports these loans by insuring them through FHA or VA programs. This allows borrowers who might otherwise be denied loans to pursue energy efficient improvements, and it secures lenders against loan default, providing them confidence in lending to customers whom they would deny without the federal insurance [19].
- Modified Accelerated Cost-Recovery System (MACRS) allows businesses to recover investments in solar, wind and geothermal property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to fifty years, over which the property may be depreciated. For solar, wind and geothermal property placed in service after 1986, the current MACRS property class life is five years [19].
- Qualified Energy Conservation Bonds (QECBs) are qualified tax credit bonds that are allocated to each state based upon their state's percentage of the U.S. population. The states are then required to allocate a certain percentage to "large local governments". In February 2009, these funds were expanded to $3.2 billion [19].
- Renewable Energy Production Incentive (REPI) provides financial incentive payments for electricity produced and sold by renewable energy generation facilities owned by non-profit groups, public utilities, or state governments [19].
- Residential Energy Conservation Subsidy Exclusion established by Section 136 of the IRS Code, makes direct and indirect energy conservation subsidies provided by public utilities nontaxable [16].
- Rural Energy for America Program (REAP) covers up to 25 percent of costs for eligible projects at certain types of institutions. Eligible renewable energy projects include wind, solar, biomass and geothermal; and hydrogen derived from biomass or water using wind, solar or geothermal energy sources. REAP incentives are generally available to state government entities, local governments, tribal governments, land-grant colleges and universities, rural electric cooperatives and public power entities, and other entities, as determined by USDA [26].

- Value-Added Producer Grant Program support planning activities and provide working capital for farm-based renewable energy projects. Independent producers, agricultural producer groups, farmer or rancher cooperatives, and majority-controlled producer-based business ventures are eligible for the program. Previously awarded grants supported energy generated on-farm through the use of agricultural commodities, wind power, water power, or solar power [17].
- High Energy Cost Grant Program administered by USDA is aimed at improving the electricity supply infrastructure in rural areas having home energy costs exceeding 275 percent of the national average. Eligible infrastructure includes renewable resources generation [21].

Indiana Incentives

- Emissions Credits are available by electricity generators that do not emit NO_x and that displace utility generation are eligible to receive NO_x emissions credits under the Indiana Clean Energy Credit Program [28]. These credits can be sold on the national market.
- Net Metering Rule: Renewable resources with a maximum capacity of 1 MW are qualified for net metering in Indiana. The net excess generation is credited to the customer in the next billing cycle [19].
- Renewable Energy Systems Property Tax Exemption provides property tax exemptions for the entire renewable energy device and affiliated equipment. The exemption applies to both real property and mobile homes equipped with renewable energy systems and may only be claimed by property owners [19].
- Solar Access Laws prevent planning and zoning authorities from prohibiting or unreasonably restricting the use of solar energy. Indiana's solar-easement provisions do not create an automatic right to sunlight, though they allow parties to voluntarily enter into solar-easement contracts which are enforceable by law [16].
- Clean Energy Portfolio Standard (CPS) passed in May 2011 sets a voluntary goal of 4 percent between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent clean energy by 2025, based on 2010 retail sales. Participation in CPS makes utilities eligible for incentives in order to pay for the compliance projects [19].
- Indianapolis Power & Light Co. – Rate REP (Renewable Energy Production) offers a "feed-in tariff" to solar, wind and biomass electricity generating facilities located in their service territory. IPL will purchase renewable energy and contract the production for up to 10 years. Solar compensation is $0.24/kWh for systems between 20 and 100 kW and $0.20/kWh for systems greater than 100kW up to 10MW [19, 23].
- Indianapolis Power & Light Co. – Small Scale Renewable Energy Incentives Program offers compensation for new photovoltaic installations for residential and small-business customers. The compensation for solar is $2 per watt up to $4,000. Eligible solar systems are between 1kW and 19.9 kW [19, 24].

- Northern Indiana Public Service Company – The NIPSCO feed-in tariff offers incentive rates for electricity generated from renewable resources. The payments for solar facilities are $0.30/kW for solar facilities with a capacity below 10 kW and $0.26/kW for facilities up to 2 MW. The tariff is an experimental tariff running until December 31, 2013. The maximum allowed generating unit size is 5 MW and the total system-wide capacity allowed under the tariff is 30 MW. 500 kW of the system-wide cap is reserved for solar projects of capacity less than 10 kW [25].

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7. Hydropower

7.1 Introduction

Hydroelectric energy is produced by converting the kinetic energy of falling water into electrical energy [1]. The moving water rotates a turbine, which in turn spins an electric generator to produce electricity. There are several different types of hydropower facilities, including [2]:

- Impoundment hydropower: This facility uses a dam to store water. Water is then released through the turbines to meet electricity demand or to maintain a desired reservoir level. Figure 7-1 shows a schematic of this type of facility.
- Pumped storage: When electricity demand is low, excess electricity is used to pump water from a lower reservoir to an upper reservoir. The water is released through the turbines to generate electricity when electricity demand is higher.
- Diversion projects: This facility channels some of the water through a canal or penstock. It may require a dam but is less obtrusive than that required for impoundment facilities.
- Run-of-river projects: This facility utilizes the flow of water of the river and requires little to no impoundment. Run-of-river plants can be designed for large flow rates with low head[6] or small flow rates with high head.
- Microhydro projects: These facilities are small in size (about 100 kW or less) and can utilize both low and high heads. These are typically be used in remote locations to satisfy a single, nearby home or business.

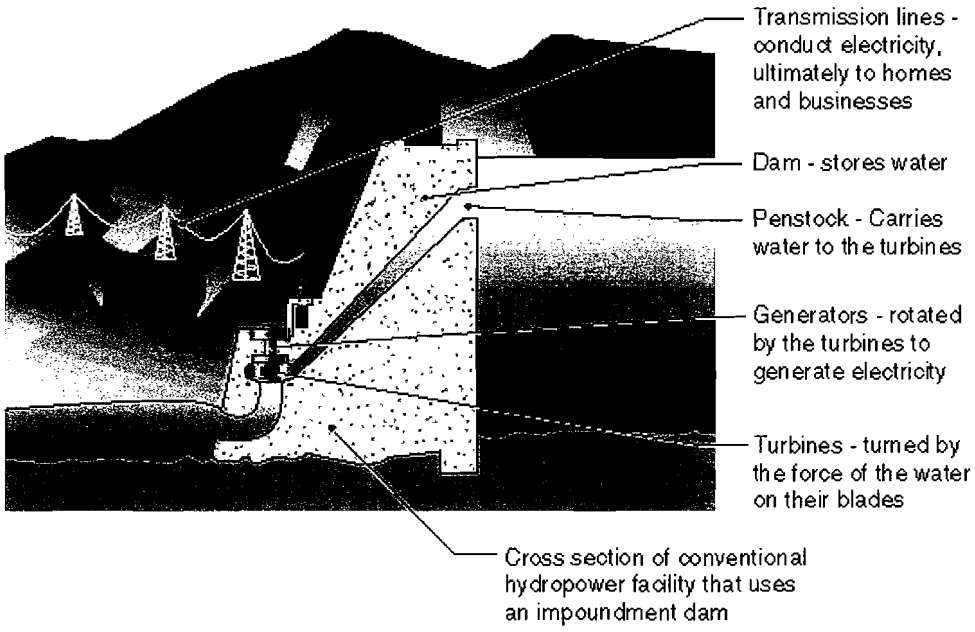

Figure 7-1: Schematic of impoundment hydropower facility (Source: INEL [2])

[6] Head is the elevation difference between the water level above the turbine and the turbine itself.

In addition, there are a variety of turbine technologies that are utilized for hydropower production. The type of turbine is chosen based on its particular application and the height of standing water. The turning part of the turbine is called the runner, and the most common types of turbines are listed below [3]:

- Pelton Turbines: The Pelton turbine has multiple jets of water impinging on the buckets of a runner that looks like a water wheel. These turbines are used for high-head sites (50 feet to 6,000 feet) and can be as large as 200 MW.
- Francis Turbines: These turbines have a runner with a number of fixed vanes (usually nine). The water enters the turbine in a radial direction with respect to the shaft, and is discharged in an axial direction. Francis turbines usually operate with head from 10 feet to 2,000 feet and can be as large as 800 MW.
- Propeller Turbines: These turbines have a runner with three to six fixed blades, much like a boat propeller. The water passes through the runner and provides a force that drives the blades. These turbines can operate with head from 10 feet to 300 feet and can be as large as 100 MW.

Hydropower is a renewable resource that has many benefits, including [4]:

- Hydropower is a domestic energy resource and does not require the transportation of fuels;
- Current hydropower turbines are capable of converting 90 percent of available energy to electricity, which is more efficient than any other form of generation;
- Hydroelectric facilities have quick startup and shutdown times, making them an operationally flexible asset, which is desirable in competitive and fluctuating electricity markets; and
- Hydroelectric facilities with impoundment can be used as a means of energy storage when combined with a pumped storage system.

Hydropower facilities also provide recreational opportunities for the community such as fishing, swimming, and boating in its reservoirs. Other benefits may include water supply and flood control. It has been estimated that of the 82,000 U.S. dams, only 3 percent have electricity production as their primary function [5].

One of the main limitations of hydroelectricity is that the amount of electricity that a facility can produce is very sensitive to the amount of precipitation in the watershed feeding the facility. Prolonged periods of below-normal rainfall can significantly cut hydropower production potential. Other unfavorable environmental impacts of hydroelectric facilities include:

- Blockage of upstream fish passage;
- Fish injury and mortality from passage through the turbine; and
- Changes in the quality and quantity of water released below dams and diversions, including low dissolved oxygen levels [6].

Other factors may also act as deterrents to potential hydropower projects, including the increasingly costly and uncertain process of licensing or relicensing of hydropower projects. About 300 hydroelectric facilities will have to be relicensed through 2017 [7]. Though the Energy Policy Act of 2005 helped reform the licensing procedure, many still consider the process to be burdensome and complicated [8]. Obtaining a license for a new facility, or renewing the license of an older facility, can take 8-10 years or longer [7].

7.2 Economics of hydropower

Hydropower projects are very capital intensive and the cost is very site specific. Table 7-1 shows the capital costs estimates from various sources. The capital estimates range from as low as $1,700/kW in 1996 dollars done by Idaho National Laboratory to nearly $14,000/kW cost estimate for the Susitna project in Alaska in 2008. Once constructed, a hydroelectric project has a major cost advantage since the fuel (water) is virtually free and also because hydroelectric plants have very low O&M costs.

Project		**Time***	**Initial Capital Costs ($/kW)**
Idaho National Lab estimates		1996	1,700-2,300
EIA estimates	Hydroelectric	2010	3,076
	Pumped Storage	2010	5,595
Hawaii Pumped Storage Hydroelectric Project (Maui Electric Co.)	Umauma	2005	1,966
	East/WestWailuaiki		3,011
	Big Island		2,432-2,842
	Maui		3,477
Susitna Project (Alaska)		2008	7,713-13,833
American Municipal Power (AMP)	Belleville	1999	2,857
	Cannelton	2009	4,951
	Smithland	2010	5,898
	Meldahl	2010	4,260
	Willow Island	2011	6,275
	Robert C. Byrd	2015	6,250
	Pike Island	2016	7,414

[a] Time the project's cost estimate was made or the project's expected start date

Table 7-1: Initial capital costs of hydropower projects (Data sources: [9-14])

According to the EIA November 2010 updated plant costs [11] hydroelectric plants have one of the lowest O&M costs among electricity generating technologies. Figure 7-2 shows the variable and fixed O&M costs of various generating technologies. As can be seen in the Figure 7-2, hydroelectricity's variable O&M costs are estimated at zero and the fixed O&M cost of $13/kW is the second lowest after natural gas combustion turbines.

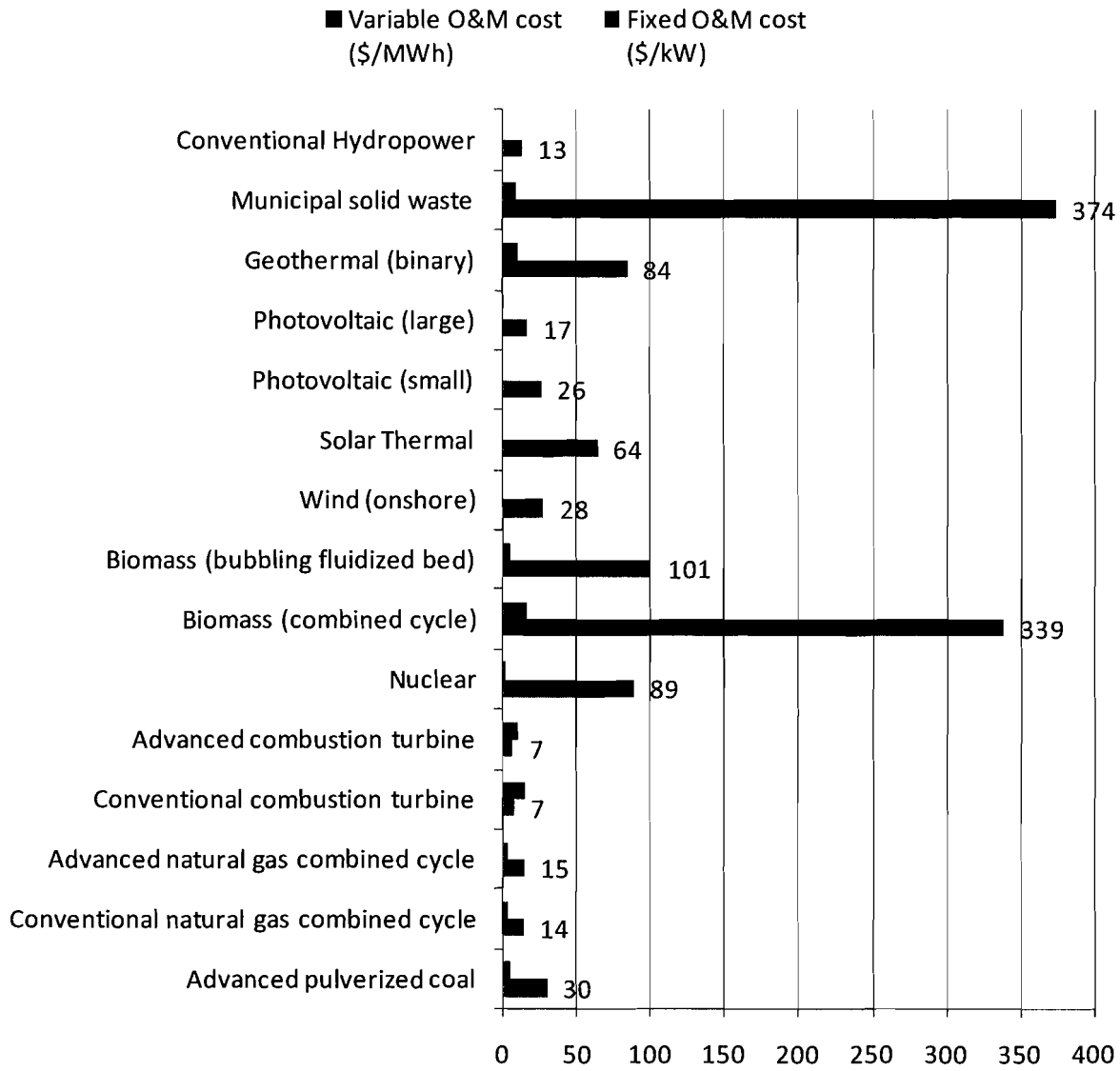

Figure 7-2: Variable and fixed O&M costs of generating technologies (Data source: EIA [11])

7.3 State of hydropower nationally

In 2010, hydroelectricity accounted for 2.5 (31 percent) of the 8 quads of renewable energy consumed in the U.S. and 6 percent of the total electricity generated. In 2009 the total conventional hydropower generation in the U.S. was 273,445,095 MWh. The states of Washington, Oregon, and California account for 49 percent of total hydropower capacity in the country [15].

1.Washington	72,932,704		6.Idaho	10,434,264
2.Oregon	33,033,513		7.Tennessee	10,211,962
3.California	27,888,036		8.Montana	9,505,940
4.New York	27,615,016		9.Arizona	6,427,345
5.Alabama	12,535,373		10.North Carolina	5,171,257

Table 7-2: Top ten U.S. hydropower generating states in 2009 (MWh) (Data source: National Hydropower Association [15])

The Idaho National Laboratory launched an effort to catalogue untapped hydropower potential in the U.S. in 1989. The U.S. Hydropower Resource Assessment Final Report was issued in 1998 with subsequent revisions in 2004 and 2006. At the heart of this assessment effort is a computer model known as the Hydropower Evaluation Software, which identified 5,677 sites with a total undeveloped capacity of 30 GW. Of this capacity, 57 percent (17.0 GW) is at sites with some type of existing dam or impoundment but with no power generation. Another 14 percent (4.3 GW) exists at projects that already have hydropower generation but are not developed to their full potential; only 28 percent (8.5 GW) of the potential would require the construction of new facilities. Therefore the potential for hydropower from existing dams is about 21.4 GW [16]. The breakdown of the state-by-state contribution to the total 30 GW identified is shown in Figure 7-3 [17].

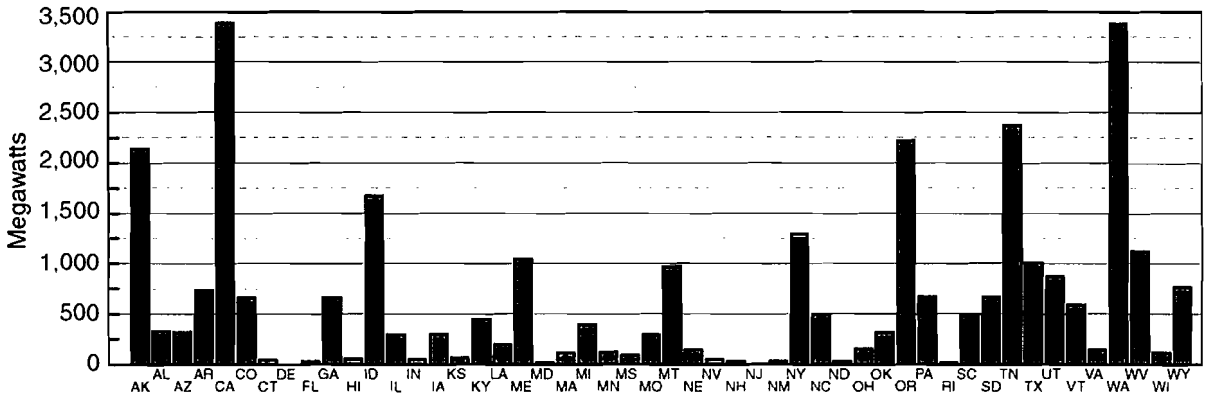

Figure 7-3: State breakdown of potential hydropower capacity (Source: INEL [17])

The National Hydropower Association estimates that more than 4,300 MW of additional or "incremental" hydropower capacity could be brought on line by upgrading or augmenting existing facilities [18]. Oak Ridge National Laboratory (ORNL) is updating hydropower potential assessments based on INEL's study. ORNL concentrates on existing, non-powered dams, predicting that 54,000 such dams could supply 12.6 GW of power. Of this total power, 3,000 MW would come from 10 large dams on the following rivers: 4 Ohio River Dams, 1 Mississippi River Facility, 1 Alabama River Facility, 2 Tombigbee River Facilities, and 2 Arkansas-Red River Facilities [19]. Figure 7-4 shows the distribution of non-powered dams in the U.S.

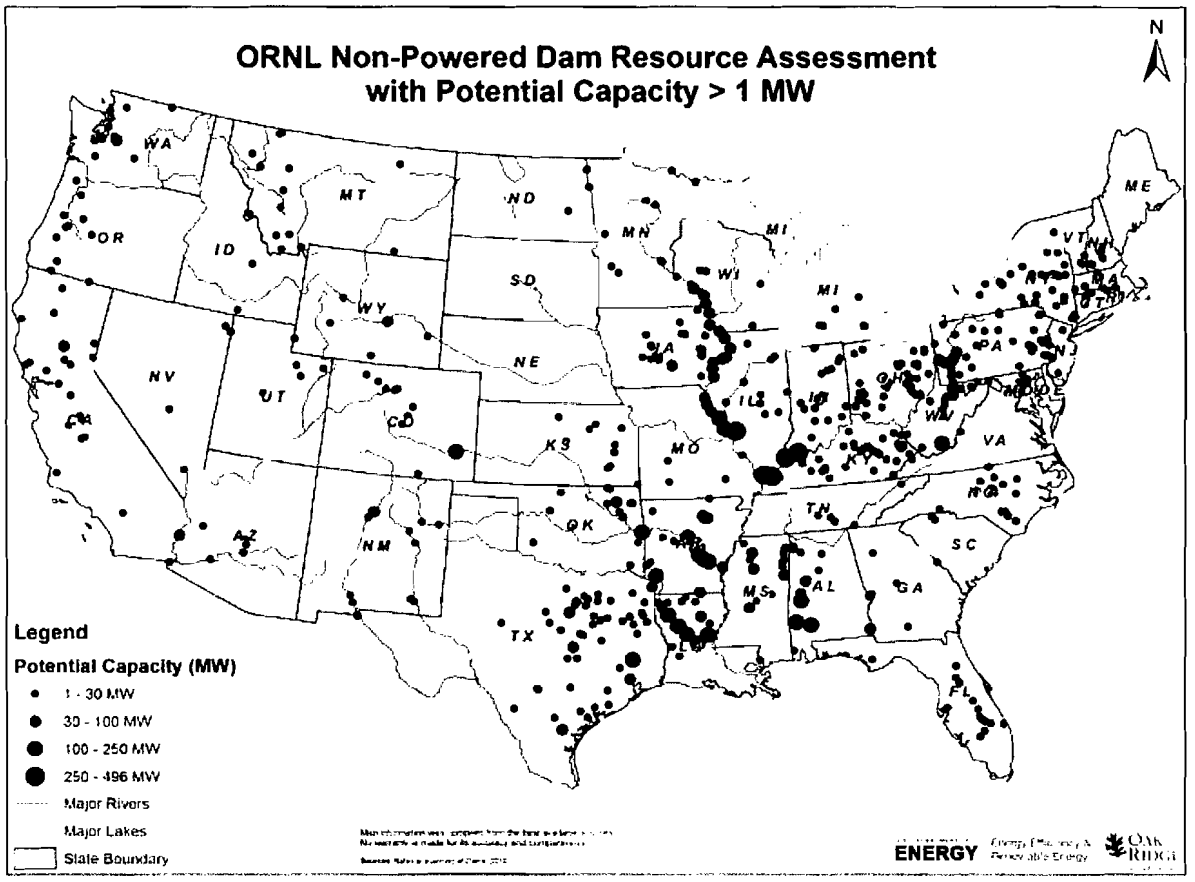

Figure 7-4: Non-powered dams with potential capacity over 1 MW (Source: ORNL [19])

Although there are substantial undeveloped resources for hydropower, its share of the nation's total electricity production is predicted to decline through 2020, with minimal capacity increases, due to a combination of environmental issues, regulatory complexities and pressures, and changes in economics [6]. The most viable hydropower capacity addition in the coming years will be the 4.3 GW of "incremental" capacity available at existing facilities. Improvements in turbine design to minimize environmental impacts and federal and state government incentives could help further develop potential hydropower projects at existing dams.

Currently, DOE is researching technologies that will enable existing hydropower projects to generate more electricity with less environmental impact. The main objectives are to develop new turbine systems with improved overall performance, develop new methods to optimize hydropower operations, and conduct research to improve the effectiveness of the environmental mitigation practices required at hydropower projects. Together, these advances in hydropower technology should reduce the cost of implementation and help smooth the hydropower integration process [20]. On April 5, 2011, DOE and DOI announced $26.6 million in funding to develop advanced hydropower technologies. The funding would concentrate on four areas: sustainable small hydropower, environmental mitigation technologies for conventional hydropower, sustainable

pumped storage hydropower, and advanced conventional hydropower system testing at a bureau of reclamation facility [21].

7.4 Hydropower in Indiana

Until the commissioning of the first wind farm in Indiana in 2008, hydroelectricity was the main source of renewable electricity in Indiana as shown in Figure 7-5. With 1,339 MW of installed wind capacity compared to 73 MW of hydroelectricity in Indiana, wind is now the dominant source of renewable electricity. This is a significant change from the situation in 2008 where there was only 20 kW of grid-connected wind capacity in Indiana.

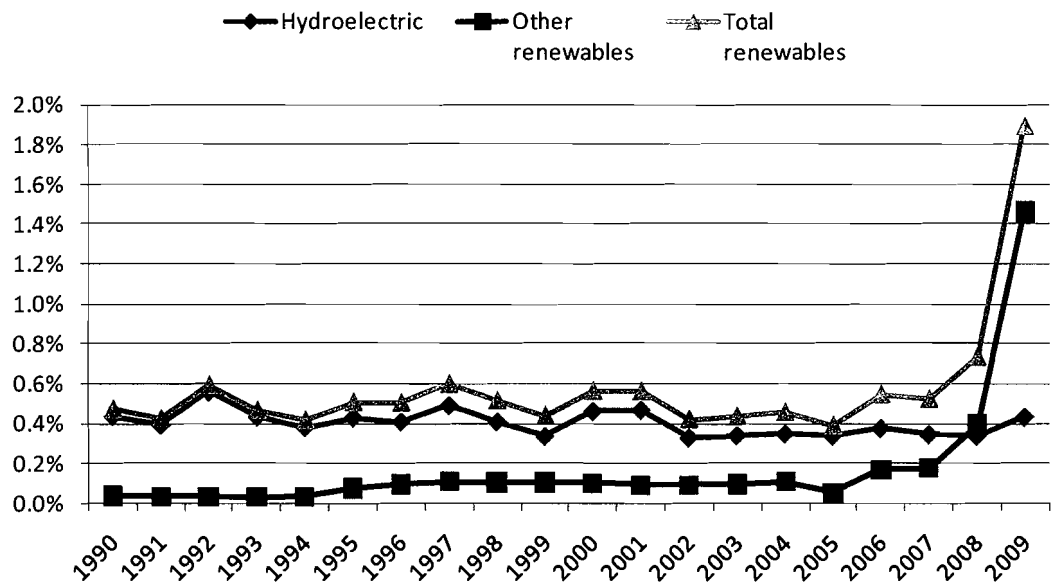

Figure 7-5: Renewables share of Indiana net electricity generation (1990-2009) (Data source: EIA [22])

However when one considers total Indiana energy consumption, wood and more recently ethanol take the more dominant role as sources of renewable energy consumed in Indiana as shown in Figure 7-6. Hydroelectricity comes in third contributing less 0.2 percent of the total energy consumed in Indiana.

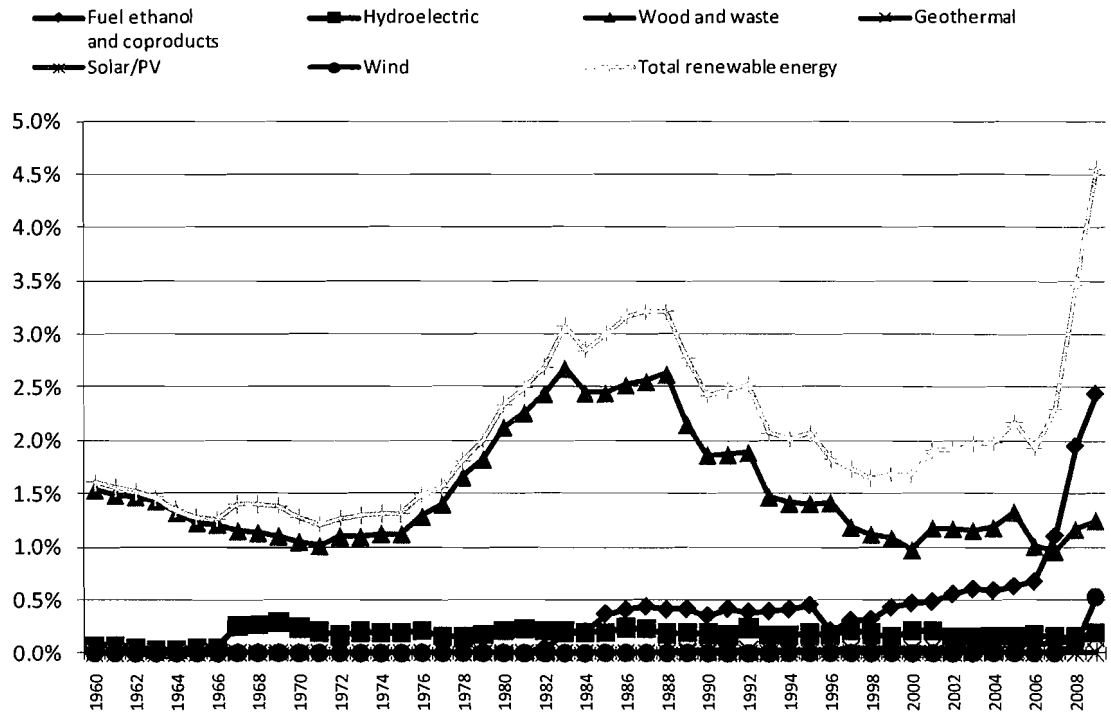

Figure 7-6: Renewables share of Indiana total energy consumption (1960 – 2009) (Data source: EIA [23])

A 1995 national hydro-potential study conducted by DOE estimated Indiana to have the potential for approximately 43 MW of exploitable capacity on 5 of Indiana's river basins as shown in Table 7-3 [24].

	Exploitable hydro potential (MW)	**Number of sites**	**Number of sites with existing power generation**	**Number of sites without existing power generation**	**Number of un-developed sites**
Wabash river basin	22.73	12	0	11	1
St. Joseph river basin	10.32	12	3	9	0
Ohio main stream	9.23	3	0	2	0
Maumee river basin	1.08	2	0	2	0
Cumberland River basin	0.0045	1	0	0	1
Total	**43.4**	**30**	**3**	**24**	**2**

Table 7-3: Hydropower potential in Indiana (Source: INEL [24])

The 43 MW shown in Table 7-3 is the net capacity that can exploited after screening out capacity deemed unsuitable for development due to environmental factors. The gross total capacity before the screening was assessed at 84 MW.

American Municipal Power is in the process of developing five new run-of-the-river hydroelectric projects on existing dams along the Ohio River whose combined capacity will be more than 350 MW. Four of these projects, including the one near Cannelton, Indiana, are under construction. The other four are located at the Smithland, Meldahl, Willow Island and Robert C. Byrd Locks and Dams in the Illinois, Ohio and Pennsylvania sections of the Ohio River. Currently, manufacturing of the equipments, including turbines and generators, gate equipment, cranes, and transformers is ahead of schedule. Additionally, working with one member community of Wadsworth, Ohio, AMP secured a permit from the Federal Energy Regulatory Commission (FERC) for a project at the Robert C. Byrd Locks and Dam in Ohio, and an application for license was filed with the FERC on March 28, 2011 [13, 14]. Table 7-4 lists the general plan and profile of these five projects.

Project	Capacity (MW)	Capital Investment (million $)	Starting Time	Expected Commercial Operation Date
Cannelton	84	415.9	April 2009	Fall 2013
Smithland	76	448.3	April 2010	Spring 2014
Meldahl	111	472.9	April 2010	Summer 2014
Willow Island	44	276.1	June 2011	Spring 2015
Robert C. Byrd	48	300	2015	2017

Table 7-4: AMP hydropower projects along Ohio River (Source: AMP [13, 14, 25])

7.5 Incentives for hydropower

Federal Incentives

- Renewable Electricity Production Tax Credit (PTC) provides a 2.2 cents/kWh tax credit for wind, geothermal and closed-loop biomass and 1.1 cents/kWh for open-loop biomass, landfill gas, municipal solid waste, small hydroelectric and marine energy technologies. As part of the February 2009 American Recovery and Reinvestment Act the PTC was modified to provide the option for qualified producers to take the federal business energy investment credit (ITC) or an equivalent cash grant from the U.S. Department of Treasury [26].

- Conservation Security Program The Conservation Security Program offers a $200 payment for each renewable energy generation system installed on an eligible farm [27, 28]. The Food, Conservation, and Energy Act of 2008 re-incorporated the program as the "Conservation Stewardship Program" in 2009 and increased funding in the program by $1.1 billion [29].
- Rural Energy for America Program (REAP) was converted by the Food, Conservation, and Energy Act of 2008 from the USDA Renewable Energy Systems and Energy Efficiency Improvements Program to the Rural Energy for America Program (REAP). Hydroelectric facilities are eligible for grants of up to 25 percent of the cost of the system, and loans for another 50 percent of the cost [26].
- High Energy Cost Grant Program administered by the USDA is aimed at improving the electricity supply infrastructure in rural areas having home energy costs exceeding 275 percent of the national average. Eligible infrastructure includes renewable resources generation. The USDA has allocated a total of $15.5 million for the 2010 funding cycle. The individual grants range from $75,000 to $5 million [30].

Indiana Incentives

- Net metering rule Renewable resource facilities with a maximum capacity of 1 MW are qualified for net metering. The net excess generation is credited to the customer in the next billing cycle [26].
- Renewable Energy Property Tax Exemption provides property tax exemptions for solar thermal, wind, hydroelectric and geothermal systems [26].
- Clean Energy Portfolio Standard (CPS) passed in May 2011 sets a voluntary goal of 4 percent between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent clean energy by 2025, based on 2010 retail sales. Participation in CPS makes utilities eligible for incentives in order to pay for the compliance projects [26].
- Emissions Credits Electricity generators that do not emit NO_x and that displace utility generation are eligible to receive NO_x emissions credits under the Indiana Clean Energy Credit Program. These credits can be sold on the national market [31].
- Northern Indiana Public Service Company: The NIPSCO feed-in tariff offers incentive rates for electricity generated from renewable resources for up to 10 years. The payment for hydroelectric facilities is $0.12/kW. The tariff is an experimental one running until December 31, 2013. The total system-wide renewable capacity allowed under the tariff is 30 MW with 500 kW of the cap reserved for solar projects of capacity less than 10 kW and 500 kW reserved for wind projects of capacity less than 10 kW [32].

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2011 Forecast

Indiana Electricity Projections

State Utility Forecasting Group

PURDUE UNIVERSITY
Discovery Park Energy Center

West Lafayette, Indiana

September 2011

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Indiana Electricity Projections: The 2011 Forecast

Prepared by:

Forrest D. Holland
Marco A. Velastegui
Douglas J. Gotham
David G. Nderitu
Paul V. Preckel
Timothy A. Phillips
Darla J. Mize

State Utility Forecasting Group
The Energy Center at Discovery Park
Purdue University
West Lafayette, Indiana

September 2011

Prepared for:

Indiana Utility Regulatory Commission
Indianapolis, Indiana

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Foreword

This report presents the 2011 projections of future electricity requirements for the state of Indiana for the period 2010-2029. This study is part of an ongoing independent electricity forecasting effort conducted by the State Utility Forecasting Group (SUFG). SUFG was formed in 1985 when the Indiana legislature mandated a group be formed to develop and keep current a methodology for forecasting the probable future growth of electricity usage within Indiana. The Indiana Utility Regulatory Commission contracted with Purdue and Indiana Universities to accomplish this goal. SUFG produced its first set of projections in 1987 and has updated these projections periodically. This is the thirteenth set of projections.

The objective of SUFG, as defined in Indiana Code 8-1-8.5 (amended in 1985), is as follows:

To arrive at estimates of the probable future growth of the use of electricity... *"the commission shall establish a permanent forecasting group to be located at a state supported college or university within Indiana. The commission shall financially support the group, which shall consist of a director and such staff as mutually agreed upon by the commission and the college or university, from funds appropriated by the commission. This group shall develop and keep current a methodology for forecasting the probable future growth of the use of electricity within Indiana and within this region of the nation. To do this the group shall solicit the input of residential, commercial and industrial consumers and the electric industry."*

This report provides projections from a statewide perspective. Individual utilities will experience different levels of growth due to a variety of economic, geographic, and demographic factors.

SUFG has maintained a similar format for this report as was used in recent reports to facilitate comparisons. Details on the operation of the modeling system are not included; for that level of detailed information, the reader is asked to contact SUFG directly or to look back to the 1999 forecast that is available for download from the SUFG website located at:

http://www.purdue.edu/dp/energy/SUFG/

The authors would like to thank the Indiana utilities, consumer groups and industry experts who contributed their valuable time, information and comments to this forecast. Also, the authors would like to gratefully acknowledge the Indiana Utility Regulatory Commission for its support, input and suggestions.

This report was prepared by the State Utility Forecasting Group. The information contained in this forecast should not be construed as advocating or reflecting any other organization's views or policy position. Further details regarding the forecast and methodology may be obtained from SUFG at:

State Utility Forecasting Group
Purdue University
Mann Hall, Room 154
203 S. Martin Jischke Drive
West Lafayette, IN 47907-1971
Phone: 765-494-4223
FAX: 765-494-6298
e-mail: sufg@ecn.purdue.edu

Chapter 1

Forecast Summary

Overview

In this report, the State Utility Forecasting Group (SUFG) provides its thirteenth set of projections of future electricity usage, peak demand, prices and resource requirements. This forecast contains generally lower projections of electricity sales and peak demand, especially in the residential and commercial sectors, than were found in previous SUFG forecasts. Consequently, fewer future resources are expected to be needed, with no significant additional resources expected to be needed until 2015 unless additional plant retirements occur before then.

This forecast projects electricity usage to grow at a rate of 1.30 percent per year over the 20 years of the forecast. This growth rate is considerably lower than Indiana has historically experienced and somewhat lower than the 2009 SUFG projections. The lower growth in electricity usage is primarily due to increasing efficiency; that is, using less electrical energy to operate homes and businesses. Efficiency gains are projected to occur from three sources: higher projected electricity prices making investments in higher efficiency equipment more cost-effective, utility-sponsored conservation efforts, and stricter federal energy efficiency standards. Peak electricity demand is projected to grow at an average rate of 1.28 percent annually. This corresponds to about 275 megawatts (MW) of increased peak demand per year.

The 2011 forecast predicts Indiana electricity prices to increase by 20 percent in real (inflation adjusted) terms between 2010 and 2017 and then level off through the remainder of the forecast period. The price increase is caused by three factors; costs associated with ongoing new plant construction, costs associated with extending the life of existing generating facilities, and costs associated with meeting environmental rules. It should be noted that this report includes only the costs associated with regulations in place at the time the forecast was prepared. Additional proposed and expected regulations would likely cause additional expenses as plants are retrofitted or retired and replaced. In the fall of 2011, SUFG intends to release a study of the expected impacts of such regulations.

As in the previous two forecasts, these projections indicate a relatively balanced need for the three types of resources modeled: baseload, cycling (also referred to as intermediate) and peaking. Peaking resources are characterized by relatively low construction costs, but high operating costs. They are intended to be operated only during periods of high electricity usage. Baseload generators, which are intended to be used even during periods of low demand, have relatively high construction costs but low operating costs. Cycling resources have construction and operating cost characteristics between those of peaking and baseload resources. This forecast identifies a need for 770 MW of peaking, 640 MW of cycling, and 1,190 MW of baseload resources by 2020. These requirements are roughly two-thirds those identified in the 2009 forecast.

While SUFG identifies resource needs in its forecasts, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Outline of the Report

The current forecast continues to respond to SUFG's legislative mandate to forecast electricity demand. It includes projections of electric energy requirements, peak demand, prices, and capacity requirements. It also provides projections for each of the three major customer sectors: residential, commercial and industrial.

Chapter 2 of the full report briefly describes SUFG's forecasting methodology, including changes made from previous forecasts. A complete description of the SUFG regulated modeling system used to develop this forecast was included in the 1999 forecast and is available at the SUFG website:

http://www.purdue.edu/dp/energy/SUFG/

Chapter 3 presents the projections of statewide electricity demand, resource requirements, and price, while Chapter 4 describes the data inputs and Chapters 5 through 7 present integrated projections for each major consumption sector in the state under three scenarios:

- the base scenario, which is intended to represent the most likely electricity forecast, i.e., the forecast has an equal probability of being low or high;
- the low scenario, which is intended to represent a plausible lower bound on the electricity sales forecast and thus, has a low probability of occurrence; and

- the high scenario, which is intended to represent a plausible upper bound on the electricity sales forecast and thus, has a low probability of occurrence.

Chapter 8 provides an overview of potential environmental regulations. Finally, an Appendix depicts the data sources used to produce the forecast and provides historical and forecast data for energy, peak demand and prices.

The Regulated Modeling System

The SUFG modeling system explicitly links electricity costs, prices and sales on a utility-by-utility basis under each scenario. Econometric and end-use models are used to project electricity use for each major customer group — residential, commercial and industrial — using fuel prices and economic drivers to simulate growth in electric energy use. The projections for each utility are developed from a consistent set of statewide economic, demographic and fossil fuel price projections. In order to project electricity costs and prices, generation resource plans are developed for each utility and the operation of the generation system is simulated. These resource plans reflect "need" from both a statewide and utility perspective.

Beginning with the 2009 forecast, SUFG made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin.[1] Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. Recently, the regional transmission organizations that encompass Indiana utilities have determined planning reserve requirements for their members. In 2009 SUFG began using reserve margins that reflect the planning reserve requirements of the utilities' regional transmission organizations to determine the reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity among the utilities provides a statewide reserve requirement of approximately 15.8 percent. This represents a slightly lower reserve margin than the 16.3 percent figure used in the 2009 forecast due to changing regional transmission organization (RTO) requirements. It should be noted that the change from a 15 percent to a 16.3 or 15.8 percent target reserve margin in the SUFG forecasts does not represent an increase in reserves (and hence, an increase in costs) due to the utilities' memberships in the regional transmission organizations. Rather, it represents a change by SUFG to a target reserve margin that is based on a more rigorous analysis.

Major Forecast Assumptions

In updating the modeling system to produce the current forecast, new projections were developed for all major exogenous variables.[2] These assumptions are summarized below.

Economic Activity Projections

One of the largest influences in any energy projection is growth in economic activity. Each of the sectoral energy forecasting models is driven by economic activity projections, i.e., personal income, population, commercial employment and industrial output. The economic activity assumptions for all three scenarios were derived from the Indiana macroeconomic model developed by the Center for Econometric Model Research (CEMR) at Indiana University. SUFG used CEMR's February 2011 projections for its base scenario. A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy. The CEMR Indiana projections are based on a national employment projection of 1.25 percent growth per year over the forecast period. Indiana total employment is projected to grow at an average annual rate of 1.21 percent.

Other key economic projections are:

- Real personal income (a residential sector model driver) is expected to grow at a 2.02 percent annual rate.

[1] SUFG reports reserves in terms of reserve margins instead of capacity margins. Care must be taken when using the two terms since they are not equivalent. A 15.8 percent reserve margin is equivalent to a 13.6 percent capacity margin.
Capacity Margin = [(Capacity-Peak Demand)/Capacity]
Reserve Margin = [(Capacity-Peak Demand)/Peak Demand]

[2] Exogenous variables are those variables that are determined outside the modeling system and are then used as inputs to the system.

- Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.31 percent annual growth rate over the forecast horizon.
- Manufacturing gross state product (GSP) (the primary industrial sector model driver) is expected to rise at a 3.44 percent annual rate as gains in productivity outpace slight gains in employment.

To capture some of the uncertainty in energy forecasting, SUFG also requested CEMR to produce low and high growth alternatives to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection.

Demographic Projections

Population growth for all scenarios is 0.49 percent per year. This projection is from the Indiana Business Research Center (IBRC) at Indiana University. The SUFG forecasting system includes a housing model that utilizes population and income assumptions to project the number of households. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of 1.00 percent over the forecast period.

Fossil Fuel Price Projections

SUFG's current assumptions are based on the April 2011 projections produced by the Energy Information Administration (EIA) for the East North Central Region. SUFG's fossil fuel real price[3] projections are as follows:

Natural Gas Prices: Natural gas price projections exhibit a significant decrease in 2009 coming off of the high prices of 2008. Prices are then projected to remain relatively constant through 2015, with a gradual increase following for the remainder of the forecast horizon.

Utility Price of Coal: Coal prices are relatively unchanged in real terms throughout the entire forecast horizon as growth in demand is offset by improvements in mining productivity.

The Base Scenario

Figure 1-1 shows the current base scenario projection for electricity requirements in gigawatthours (GWh), along with the projections from the previous two forecast reports. Similarly, the base projection for peak demand in MW is shown in Figure 1-2. The annual growth rate for electricity requirements in this forecast is 1.30 percent, while the growth rate for peak demand is 1.28 percent. The growth rates in the previous forecast for electricity requirements and peak demand were 1.55 and 1.61 percent, respectively.

The growth within sectors varies considerably with higher growth in the industrial sector and lower growth in the residential and commercial sectors (see Table 1-1). See Chapters 5 through 7 for more detail on the sectoral forecasts.

The projections of peak demand are for normal weather patterns, and projected peak demand for long-run planning is reduced by interruptible loads. Another measure of peak demand growth can be obtained by considering the year to year MW load change. In Figure 1-2, the annual increase is about 275 MW.

Table 1-1. Annual Electricity Sales Growth (Percent) by Sector (Current vs. 2009 Projections)

Sector	Current (2010-2029)	2009 (2008-2027)
Residential	0.71	1.75
Commercial	0.89	1.18
Industrial	2.11	1.63
Total	1.30	1.55

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. Demand-side management (DSM) impacts and interruptible loads are netted from the demand projection and supply-side resources are added as necessary to maintain a 15.8 percent reserve margin. Although this approach provides a reasonable basis for estimating future electricity prices for planning purposes, it does not ensure that the resource plans are least cost.

[3] Real prices are calculated to reflect the change in the price of a commodity after taking out the change in the general price levels (i.e., the inflation in the economy).

Figure 1-1. Indiana Electricity Requirements in GWh (Historical, Current, and Previous Forecasts)

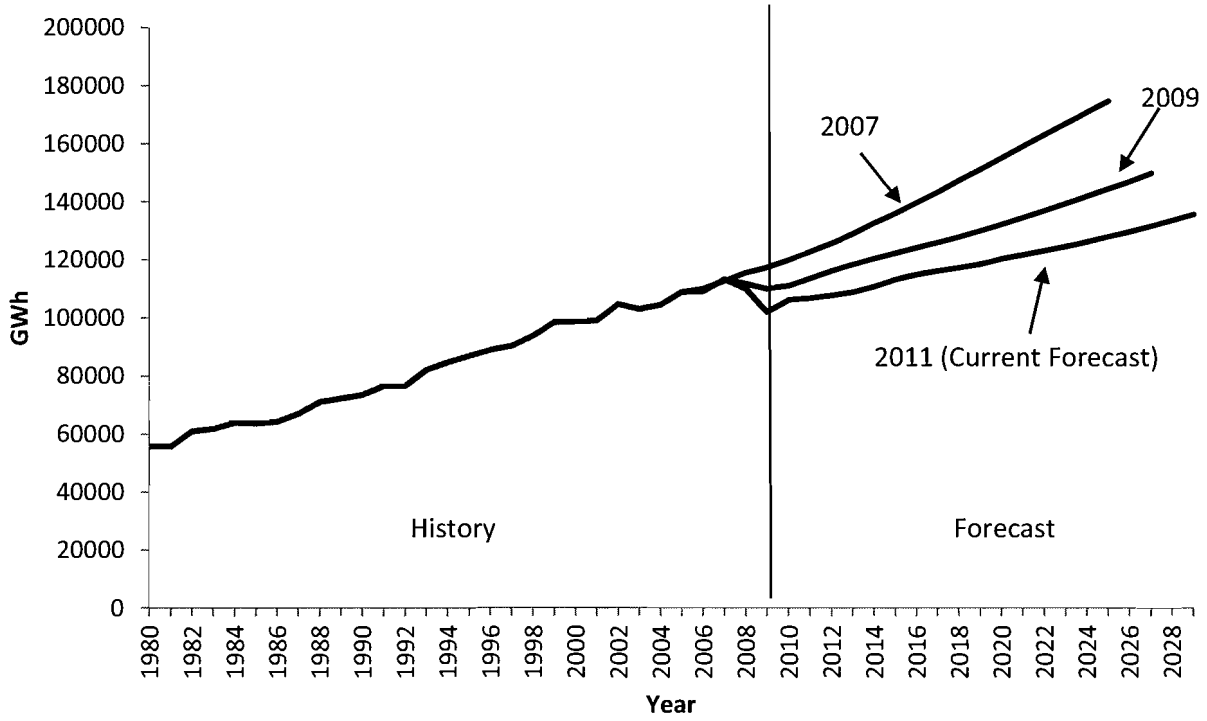
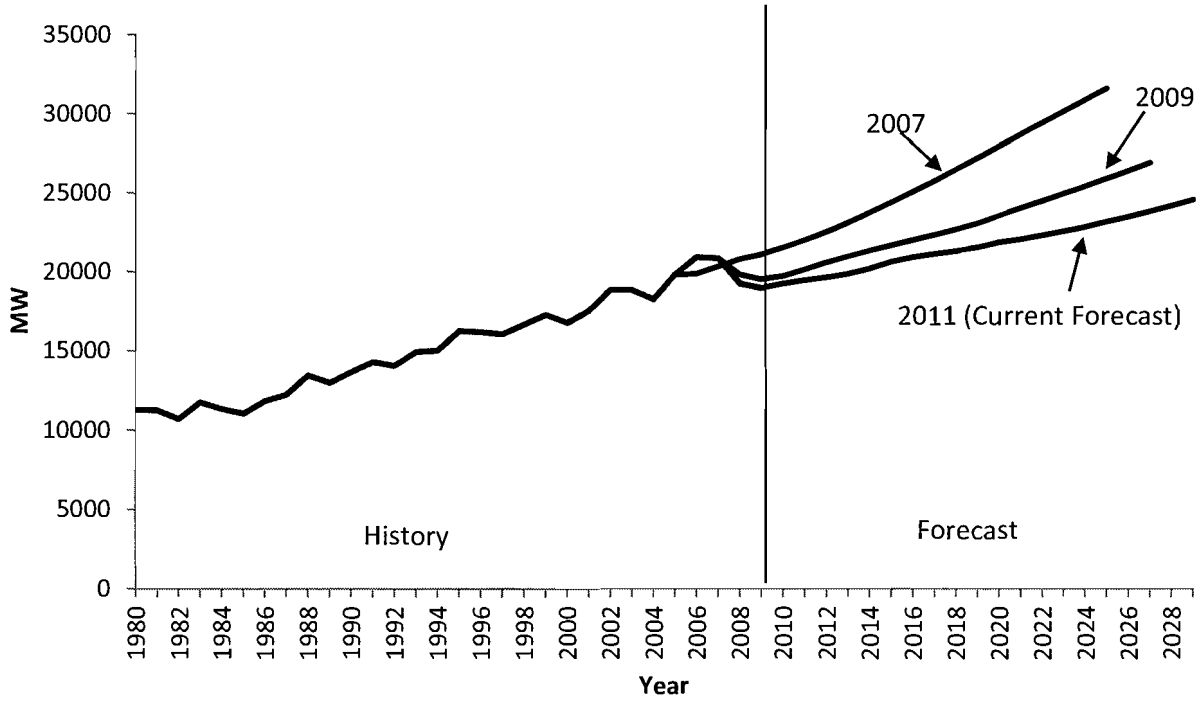


Figure 1-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Demand-Side Resources

The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs. Incremental DSM programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 240 MW at the beginning of the forecast period and by over 800 MW at the end of the forecast. DSM projections were estimated by SUFG based on rules established in December 2009 by the Indiana Utility Regulatory Commission (IURC).

These DSM projections do not include the reductions in peak demand due to interruptible load contracts with large customers. Interruptible loads are projected to increase from 770 MW to about 900 MW over the forecast horizon. See Chapter 4 for additional information about DSM and interruptible loads.

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, de-ratings due to pollution control retrofits and net changes in firm out-of-state purchases and sales. Due to the timing and uncertainty over Duke Energy's shutdown of three Wabash River units, SUFG has not removed those units from the existing mix of generators.[4] SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic firm wholesale purchases are then added as necessary during the forecast period to maintain a statewide 15.8 percent reserve margin.

Resource Needs

Figure 1-3 and Table 1-2 show the statewide resource plan for the SUFG base scenario. Over the first half of the forecast period, nearly 1,500 MW of additional resources are required. The net change in generation includes the retirement of units as reported in the utilities' 2009 Integrated Resource Plan (IRP) filings. Over the second half of the forecast period, an additional 3,900 MW of resources are required to maintain target reserves. If Duke Energy retires the affected Wabash River units, additional resources of approximately 250 MW will be required.

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data is 2009. Therefore, 2010 and 2011 numbers represent projections. The resource requirements identified in Table 1-2 for 2010 and 2011 were most likely met by a combination of short-term purchases and longer-term purchases of which SUFG was not aware at the time the forecast was prepared.

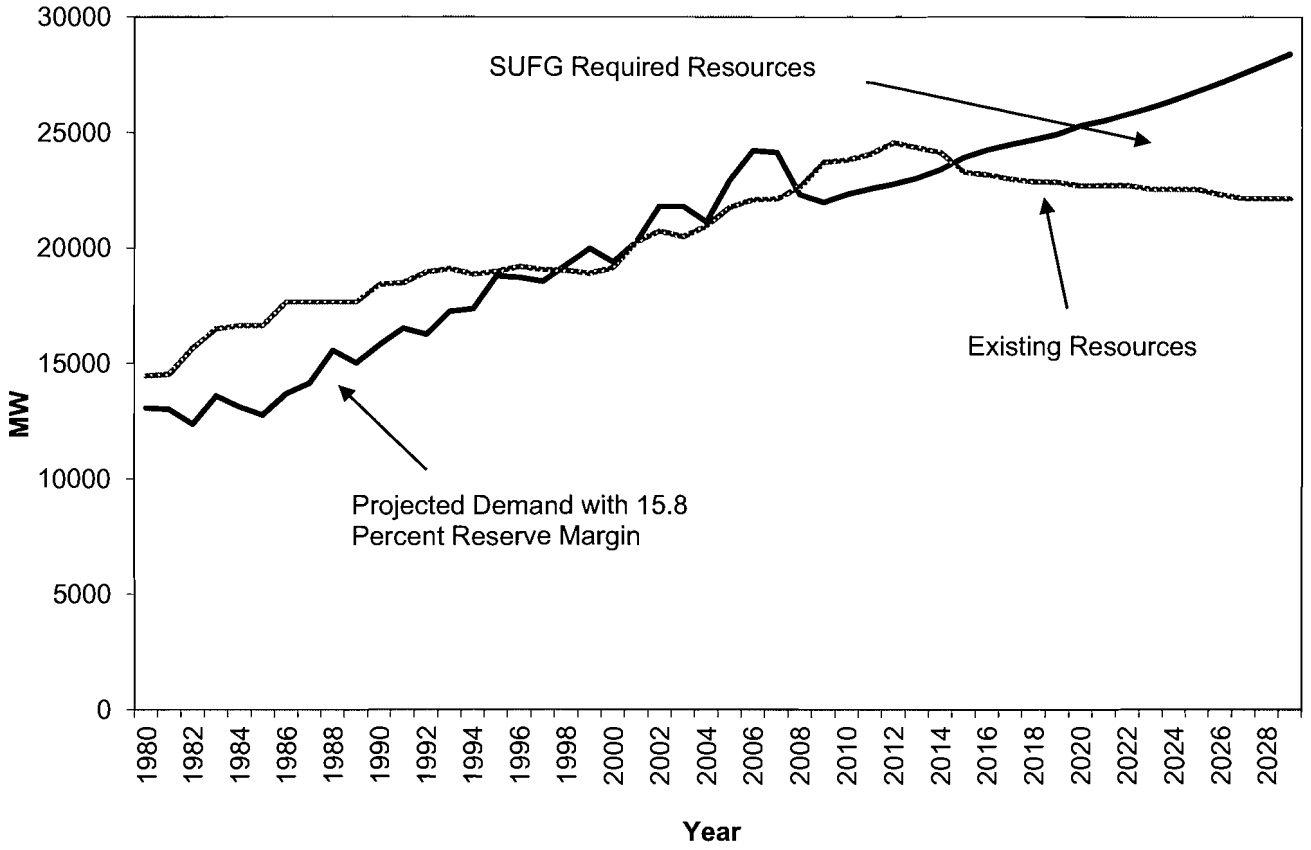
Equilibrium Price and Energy Impact

SUFG's base scenario equilibrium real electricity price trajectory is shown in Figure 1-4. Real prices are projected to increase significantly through 2016 and then remain fairly constant for the remainder of the forecast period. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected.

SUFG's equilibrium price projections for two previous forecasts are also shown in Figure 1-4. The price projection labeled "2009" is the base from SUFG's 2009 forecast and the price projection labeled "2007" is the base case projection contained in SUFG's 2007 forecast. For the prior price forecasts, SUFG rescaled the original price projections to 2009 dollars (from 2005 dollars for the 2007 projection, and from 2007 dollars for the 2009 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

[4] Duke Energy shut down its Wabash River units 2, 3, and 5 in September 2009 as a result of a U.S. District Court ruling regarding alleged violations of the Clean Air Act. At the time this forecast was prepared, the status of any appeal of that ruling was unknown.

Figure 1-3. Indiana Total Demand and Supply in MW (SUFG Base)



The price increase through 2016 in Figure 1-4 is caused by three factors; costs associated with ongoing new plant construction, costs associated with extending the life of existing generating facilities, and costs associated with meeting environmental rules. It should be noted that costs associated with environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not. Thus, the costs associated with meeting the first phase of the Clean Air Interstate Rule (CAIR) are included. The replacement for CAIR, the Cross-State Air Pollution Rule (CSAPR) was finalized after the model runs for this report were completed, thus CSAPR is not modeled in its final form. Other non-finalized rules, such as the Mercury and Air Toxics Standards (MATS), which was proposed in March 2011, and rules affecting greenhouse gas emissions, cooling water, and coal ash disposal are not included. SUFG will produce a separate report that specifically addresses the impact of the various proposed and potential rules. This report is expected to be completed in the fall of 2011. See Chapter 8 for an overview of potential regulations.

Low and High Scenarios

SUFG has constructed alternative low and high economic growth scenarios. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Figure 1-5 provides the statewide electricity requirements for the base, low and high scenarios. The annual growth rates for the base, low and high scenarios are 1.30, 0.98, and 1.64, respectively. These differences are due to economic growth assumptions in the scenario-based projections. The trajectories for peak demand in the low and high scenarios are similar to the electricity requirements trajectories.

Table 1-2. Indiana Resource Plan in MW (SUFG Base)

	Uncontrolled Peak Demand[1]	Interruptible	Net Peak Demand[2]	Existing/ Approved Capacity[3]	Incremental Change in Capacity[4]	Projected Additional Resource Requirements[5]				Total Resources[6]	Reserve Margin[7] (percent)
						Peaking	Cycling	Baseload	Total		
2009				23,719							
2010	20,047	778	19,269	23,800	81	0	0	0	0	23800	17
2011	20,251	770	19,481	24,055	255	0	0	0	0	24055	21
2012	20,437	783	19,654	24,543	488	0	0	0	0	24543	24
2013	20,676	795	19,881	24,340	-204	100	20	0	120	24460	23
2014	21,008	805	20,203	24,128	-212	220	30	70	320	24448	25
2015	21,468	818	20,650	23,292	-836	310	90	330	730	24022	23
2016	21,767	832	20,935	23,171	-121	380	160	520	1060	24231	21
2017	21,987	846	21,141	22,991	-180	480	310	700	1490	24481	16
2018	22,180	861	21,319	22,873	-118	520	510	780	1810	24683	16
2019	22,396	876	21,520	22,851	-23	570	550	920	2040	24891	16
2020	22,730	889	21,841	22,696	-155	770	640	1190	2600	25296	16
2021	22,915	889	22,026	22,715	20	800	680	1300	2780	25495	16
2022	23,166	889	22,277	22,725	10	860	740	1470	3070	25795	16
2023	23,419	891	22,528	22,565	-160	920	920	1670	3510	26075	16
2024	23,702	893	22,810	22,565	0	990	1010	1830	3830	26395	16
2025	24,035	895	23,140	22,558	-7	1030	1090	2110	4230	26788	16
2026	24,350	896	23,454	22,322	-236	1060	1330	2440	4830	27152	16
2027	24,696	898	23,798	22,173	-150	1270	1400	2690	5360	27533	16
2028	25,052	900	24,152	22,168	-4	1350	1470	2940	5760	27928	16
2029	25,423	902	24,521	22,153	-15	1490	1590	3160	6240	28393	16

1 Uncontrolled peak demand is the peak demand without any interruptible loads being called upon.

2 Net peak demand is the peak demand after interruptible loads are taken into account.

3 Existing/approved capacity includes installed capacity plus approved new capacity plus firm purchases minus firm sales.

4 Incremental change in capacity is the change in existing/approved capacity from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, and changes in firm purchases and sales.

5 Projected additional resource requirements is the cumulative amount of additional resources needed to meet future requirements.

6 Total resource requirements are the total statewide resources required including existing/approved capacity and projected additional resource requirements.

7 Resources may be required by individual utilities even if the state as a whole meets or exceeds the statewide reserve margin. Individual utility reserve margins are not allowed to fall below 6 percent.

Figure 1-4. Indiana Real Price Projections in cents/kWh (2009 Dollars) (Historical, Current and Previous Forecasts)

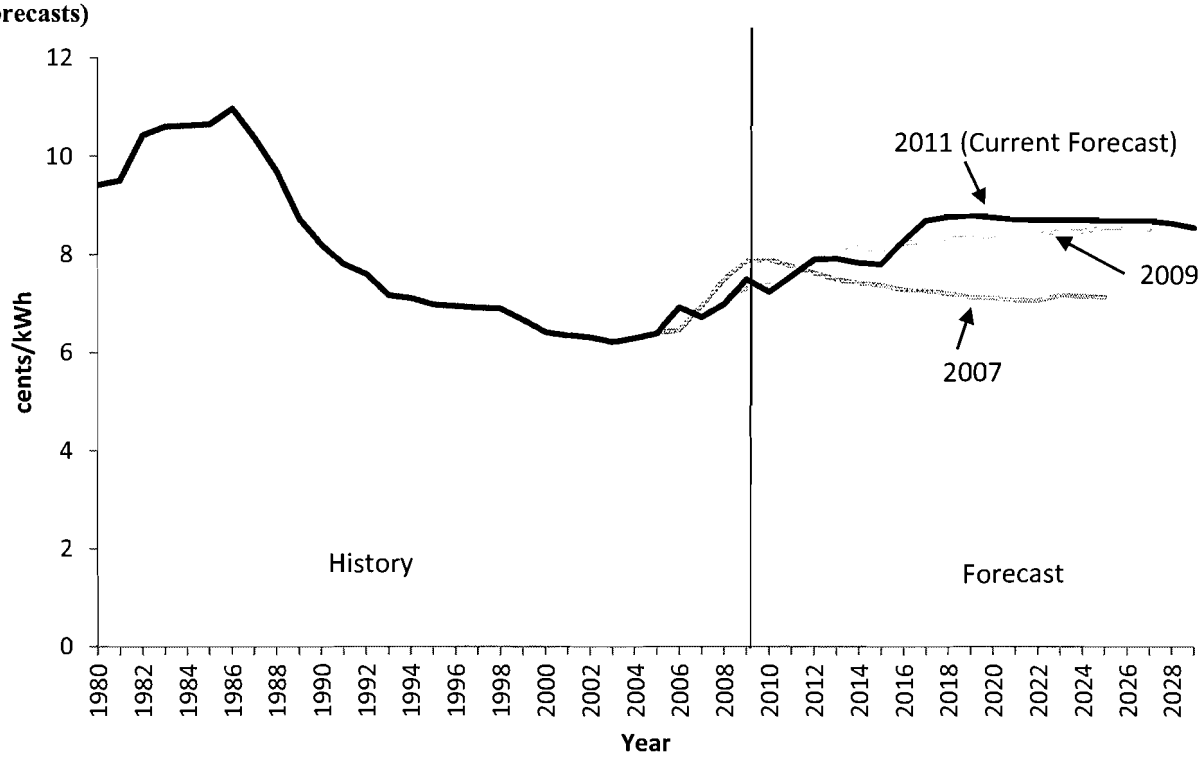
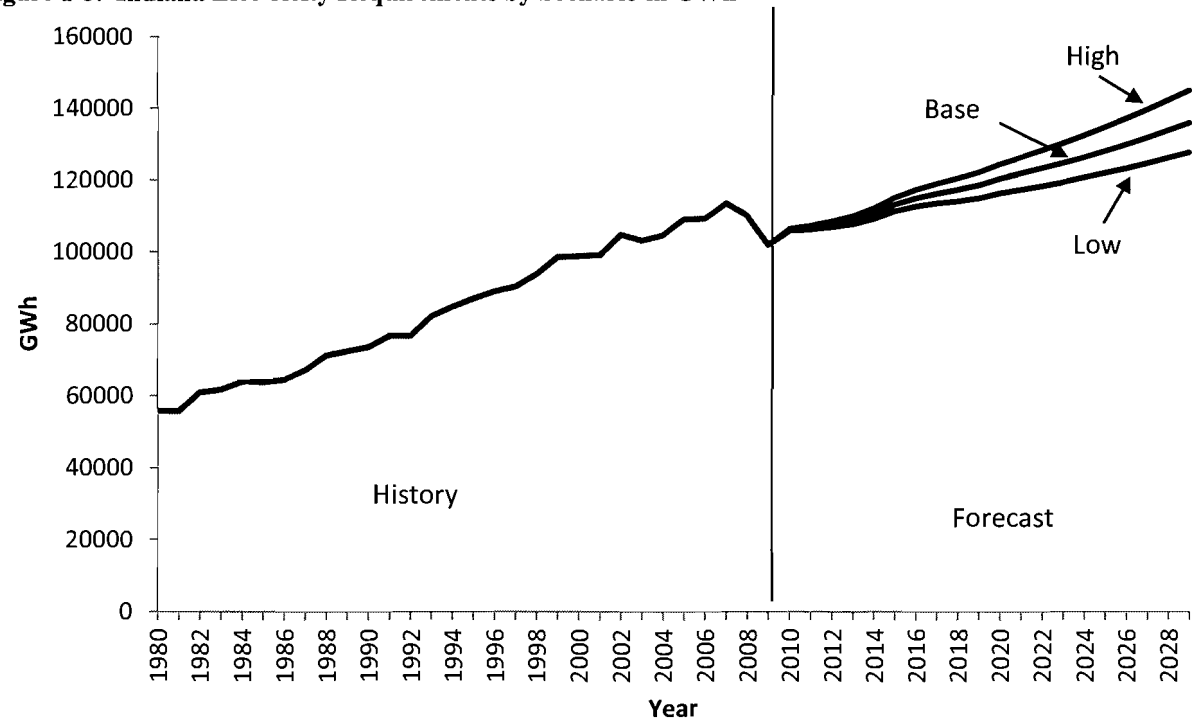


Figure 1-5. Indiana Electricity Requirements by Scenario in GWh



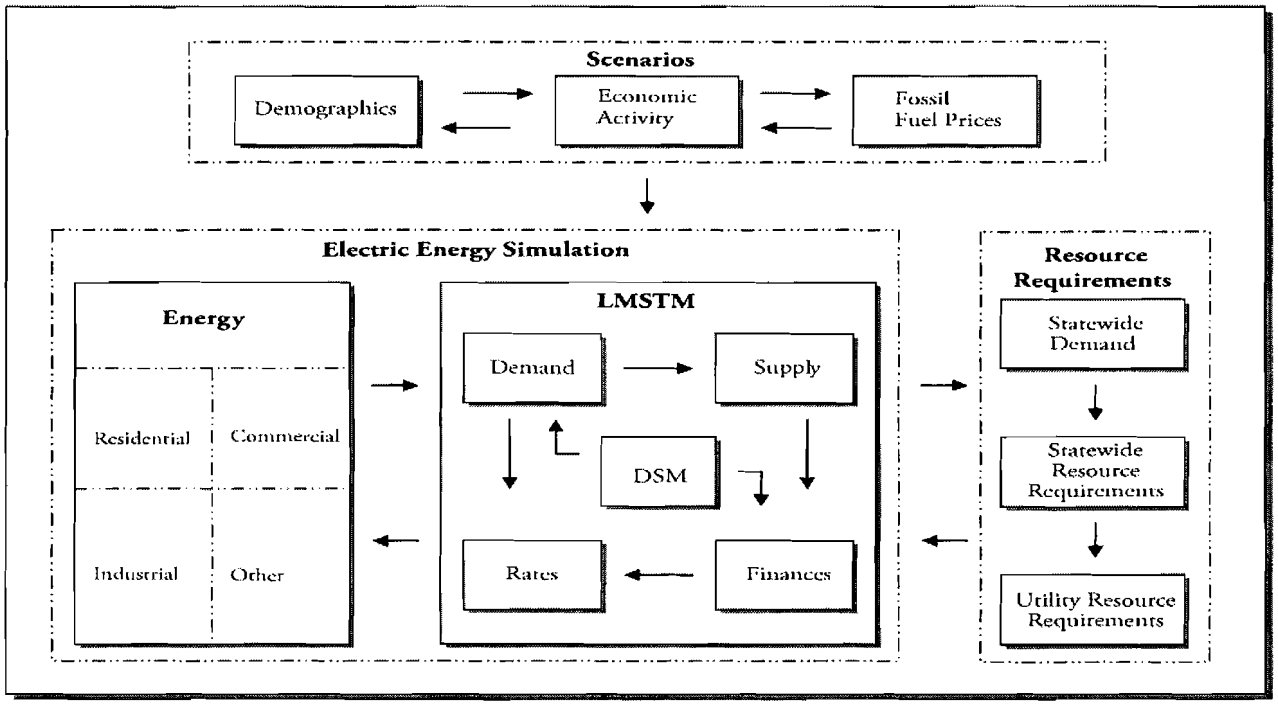
Chapter 2

Overview of SUFG Electricity Modeling System

Regulated Modeling System

SUFG's integrated electricity modeling system projects electricity demand, supply and price for each electric utility in the state under Indiana's present regulatory structure. The modeling system captures the dynamic interactions between customer demand, the utility's operating and investment decisions, and customer rates by cycling through the various submodels until equilibrium is attained. The SUFG modeling system is unique among utility forecasting and planning models because of its comprehensive and integrated characteristics. The basic system components (submodels) and their principal linkages are illustrated in Figure 2-1 and then briefly described.

Figure 2-1. SUFG's Regulated Modeling System



Scenarios

SUFG's electricity projections are based on assumptions, such as economic growth, construction costs and fossil fuel prices. These assumptions are a principal source of uncertainty in any energy forecast. Another major source of uncertainty is the statistical error inherent in the structure of any forecasting model. To provide an indication of the importance of these sources of uncertainty, scenario-based projections are developed by operating the modeling system under varying sets of assumptions. These low probability, low and high growth scenarios capture much of the uncertainty associated with economic growth, fossil fuel prices and statistical error in the model structure.

Electric Utility Simulation

The electric utility simulation portion of the modeling system develops projections for each of the five investor-owned utilities (IOUs): Duke Energy Indiana, Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company,

and Southern Indiana Gas & Electric Company. In addition, projections are developed for the three not-for-profit (NFP) utilities: Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association.

Utility-specific projections of sectoral energy use and prices are developed for each of the three scenarios. These projections are based on projections of demographics, economic activity and fossil fuel prices that are developed outside the modeling system. They are also based on projections of supply additions for the utilities that are developed within the framework of the modeling system.

Energy Submodel

SUFG has developed and acquired both econometric and end-use models to project energy use for each major customer group. These models use fuel prices and economic drivers to simulate growth in energy use. The end-use models provide detailed projections of end-use saturations, building shell choices and equipment choices (fuel type, efficiency and rate of utilization). The econometric models capture the same effects but in a more aggregate way. These models use statistical relationships estimated from historical data on fuel prices and economic activity variables. For this forecast, SUFG is using end-use models for the residential and commercial sectors and an econometric model for the industrial sector. SUFG has switched to the residential end-use model for this forecast after previously using an econometric model. The change was made for a number of reasons, including the enhanced ability of the end-use model to capture the impacts of federally mandated lighting efficiency standards. Additional information regarding SUFG's energy models for the residential, commercial and industrial sectors can be found in chapters five, six and seven, respectively.

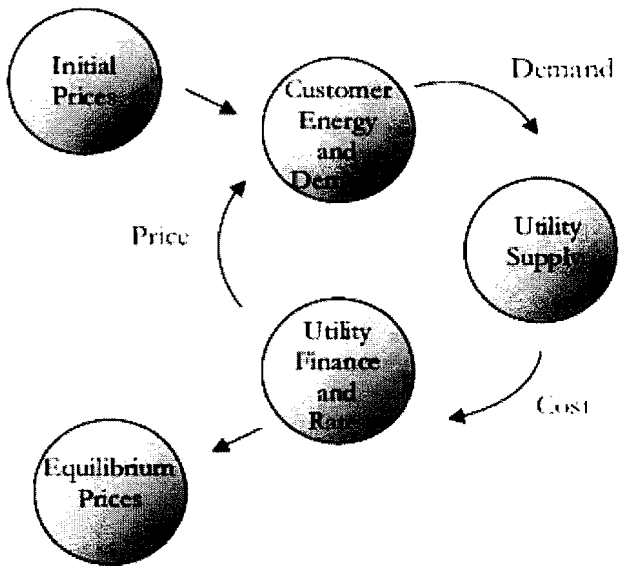
Load Management Strategy Testing Model

Developed by Electric Power Software, the Load Management Strategy Testing Model (LMSTM) is an electric utility system simulation model that integrates four submodels: demand, supply, finance and rates. Combined in this way, LMSTM simulates the interaction of customer demand, system generation, total revenue requirements and customer rates. LMSTM also preserves chronological load shape information throughout the simulation to capture time dependencies between customer demand (including demand side management or DSM), system operations and customer rates.

Price Iteration

The energy modeling system cycles through five integrated submodels: energy, demand, supply, finance and rates. During each cycle, price changes in the model cause customers to adjust their consumption of electricity, which in turn affects system demand, which in turn affects the utility's operating and investment decisions. These changes in demand and supply bring forth yet another change in price and the cycle is complete. After each cycle, the modeling system compares the "after" electricity prices from the rates submodel to the "before" prices input to the energy consumption models. If these prices match, they are termed equilibrium prices in the sense that they balance demand and supply, and the iterative process ends. Otherwise, the modeling system continues to cycle through the submodels until equilibrium is attained as is illustrated in Figure 2-2.

Figure 2-2. Cost-Price-Demand Feedback Loop



Resource Requirements

Beginning with the 2009 forecast, SUFG has made a slight modification to the methodology used in determining future resource requirements. For the 1999-2007 forecasts, SUFG determined required resources according to a target statewide 15 percent reserve margin. Forecasts prior to 1999 used a 20 percent statewide reserve margin. These reserve margins were essentially rules-of-thumb, based on industry observations. Recently, the regional transmission

organizations that encompass Indiana utilities have determined planning reserve requirements for their members. Starting with the 2009 forecast, SUFG has used individual utility reserve margins that reflect the planning reserve requirements of the utility's RTO to determine the reserve requirements in this forecast. Applying the individual reserve requirements and adjusting for peak load diversity[1] among the utilities provides a statewide reserve requirement of approximately 15.8 percent. This represents a slightly lower reserve margin than the 16.3 percent figure used in the 2009 forecast due to changing RTO requirements. It should be noted that the change from a 15 percent to a 16.3 or 15.8 percent target in the SUFG forecasts does not represent an increase in reserves (and hence, an increase in costs) due to the utilities' memberships in the RTOs. Rather, it represents a change by SUFG to a target that is based on a more rigorous analysis.

The process used to determine resource requirements is illustrated in the flowchart in Figure 2-3. Individual utility peak demands developed from LMSTM are aggregated while accounting for load diversity and interruptible loads to determine the statewide peak demand for each year of the forecast. The additional resources required are determined for each year by comparing the peak demand with a 15.8 percent reserve margin to the existing capacity. The existing capacity has been adjusted for retirements, utility purchases and sales, and new construction projects that have been approved by the Indiana Utility Regulatory Commission (IURC).

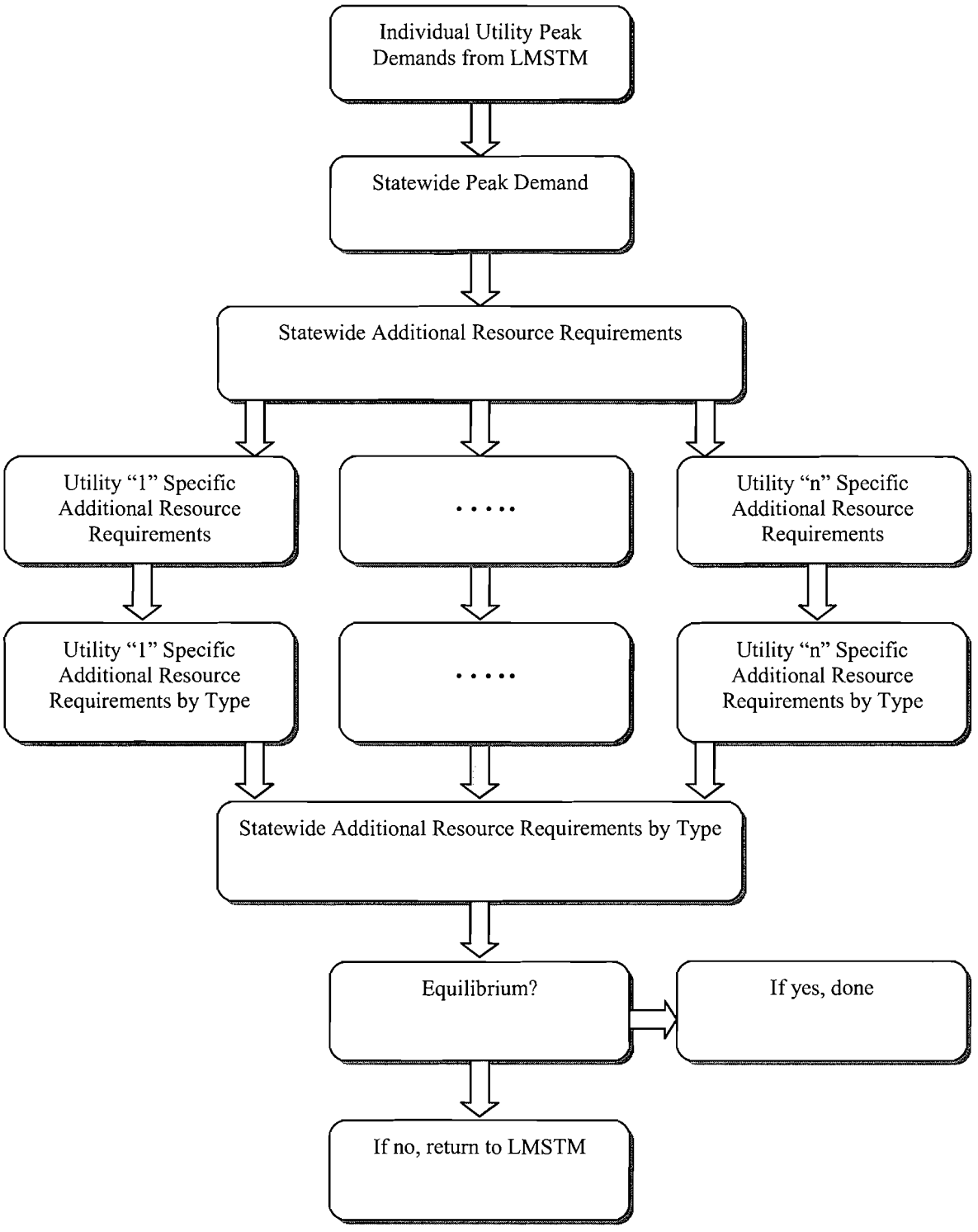
The required resources are then assigned to the individual utilities with the lowest reserve margins, so that all utilities have similar reserve margins. Even if the state's reserve margin meets the 15.8 percent target, resources will be assigned to an individual utility if necessary to bring the utility's reserve margin up to 6 percent. These utility specific additional resource requirements are then assigned to one of the three types. This is accomplished by comparing the utility's demand, which is divided into the three types using actual historical annual load shapes, to the utility's existing generation resources, which are also assigned to the three types. The statewide resource requirements by type are determined by summing the individual utility requirements. The overall process is done iteratively until equilibrium is reached where resource requirements do not change from one iteration to the next.

Presentation and Interpretation of Forecast Results

There are several methods for presenting the various projections associated with the forecast. The actual projected value for each individual year can be provided or a graph of the trajectory of those values over time can be used. Additionally, average compound growth rates can be provided. There are advantages and disadvantages associated with each method. For instance, while the actual values provide a great deal of detail, it can be difficult to visualize how rapidly the values change over time. While growth rates provide a simple measure of how much things change from the beginning of the period to the end, they mask anything that occurs in the middle. For these reasons, SUFG generally uses all three methods for presenting the major forecast projections.

[1] Load diversity occurs because the peak demands for all utilities do not occur at the same time. SUFG estimates the amount of load diversity by analyzing the actual historical load patterns of the various utilities in the state.

Figure 2-3. Resource Requirements Flowchart



Chapter 3

Indiana Projections of Electricity Requirements, Peak Demand, Resource Needs and Prices

Introduction

This chapter presents the forecast of future electricity requirements and peak demand, including the associated new resource requirements and price implications. This report includes three scenarios of future electricity demand and supply: base, low and high. The base scenario is developed from a set of exogenous macroeconomic assumptions that is considered "most likely," i.e., each assumption has an equal probability of being lower or higher. Additionally, SUFG included low and high growth macroeconomic scenarios based on plausible sets of exogenous assumptions that have a lower probability of occurrence. These scenarios are designed to indicate a plausible forecast range, or degree of uncertainty underlying the base projection. The most probable projection is presented first.

Most Probable Forecast

As shown in Tables 3-1 and 3-2 and Figures 3-1 and 3-2, SUFG's current base scenario projection indicates annual growth of 1.30 percent for electricity requirements and 1.28 percent for peak demand. As shown in Table 3-3, the growth rate for electricity sales in this forecast is about 0.25 percent lower than the 2009 forecast. As one would expect, the current economic situation and the projected future path of the economy have a dramatic effect on the electricity sales forecast. The growth within sectors varies considerably with lower growth in the residential and commercial sectors offsetting higher growth in the industrial sector, but the forecast growth for all sectors is only moderately below the forecast in 2009. See Chapters 5, 6, and 7 for discussions of the forecast growth in the residential, commercial, and industrial sectors.

A comparison of the forecast trajectory of electricity requirements between the current and previous forecast shows that the current forecast starts out below the previous forecast and that the gap between the projections widens over the forecast horizon. The drop in electricity requirements in 2008 and 2009 is due to a combination of the economic recession and milder than normal weather, both of which suppress electricity usage. This general pattern is followed in all three sectors.

The growth in peak demand is similarly lower than that projected in 2009 and follows the same pattern that is observed for the total energy requirements. Forecast peak demand growth is slightly lower than that of electricity requirements (1.28 versus 1.31 percent) because lower energy growth in the residential and commercial sectors, both of which have weather sensitive heating and cooling load, tends to affect peak demand more than the industrial sector load. Another measure of peak demand growth can be obtained by considering the average year to year peak MW load change. In Figure 3-2, the annual increase is 275 MW compared to about 350 MW per year in the previous forecast.

Resource Implications

SUFG's resource plans include both demand-side and supply-side resources to meet forecast demand. DSM impacts and interruptible load are netted from the demand projection, and generic resources are added as necessary to maintain a 15.8 percent reserve margin (see Chapter 2 for discussions of the future resource allocation methodology and the target reserve margin). Although this approach provides a reasonable basis for estimating future electricity prices for planning purposes, it does not ensure that the resource plans are obtained at least cost.

Demand-Side Resources

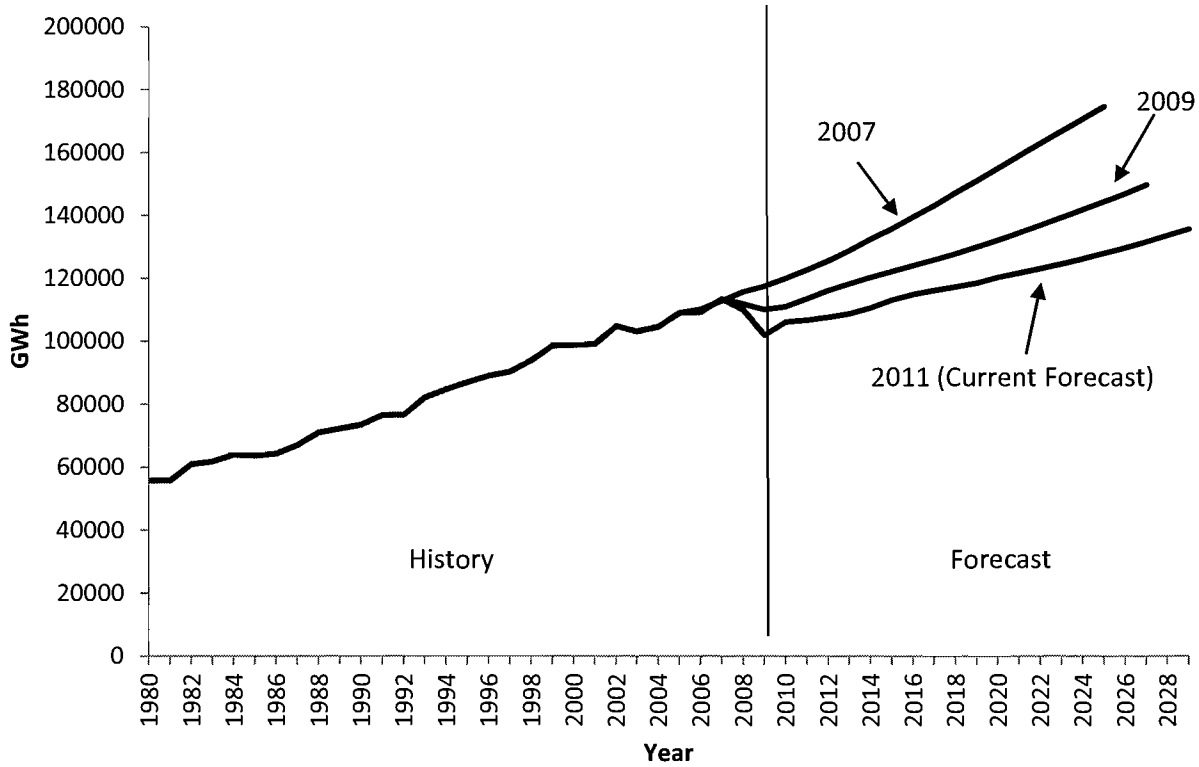
The current projection includes the energy and demand impacts of existing or planned utility-sponsored DSM programs. Incremental DSM programs, which include new programs and the expansion of existing programs, are projected to reduce peak demand by approximately 240 MW at the beginning of the forecast period and by over 800 MW at the end of the forecast. DSM projections reflect the estimated impact of the IURC's DSM order of December 2009.

In addition to DSM, peak demand projections are reduced due to interruptible load contracts with large customers. Interruptible loads are projected to increase from 770 MW to about 900 MW over the forecast horizon. See Chapter 4 for additional information about DSM and interruptible loads.

Table 3-1. Indiana Electricity Requirements Average Compound Growth Rates (Percent)

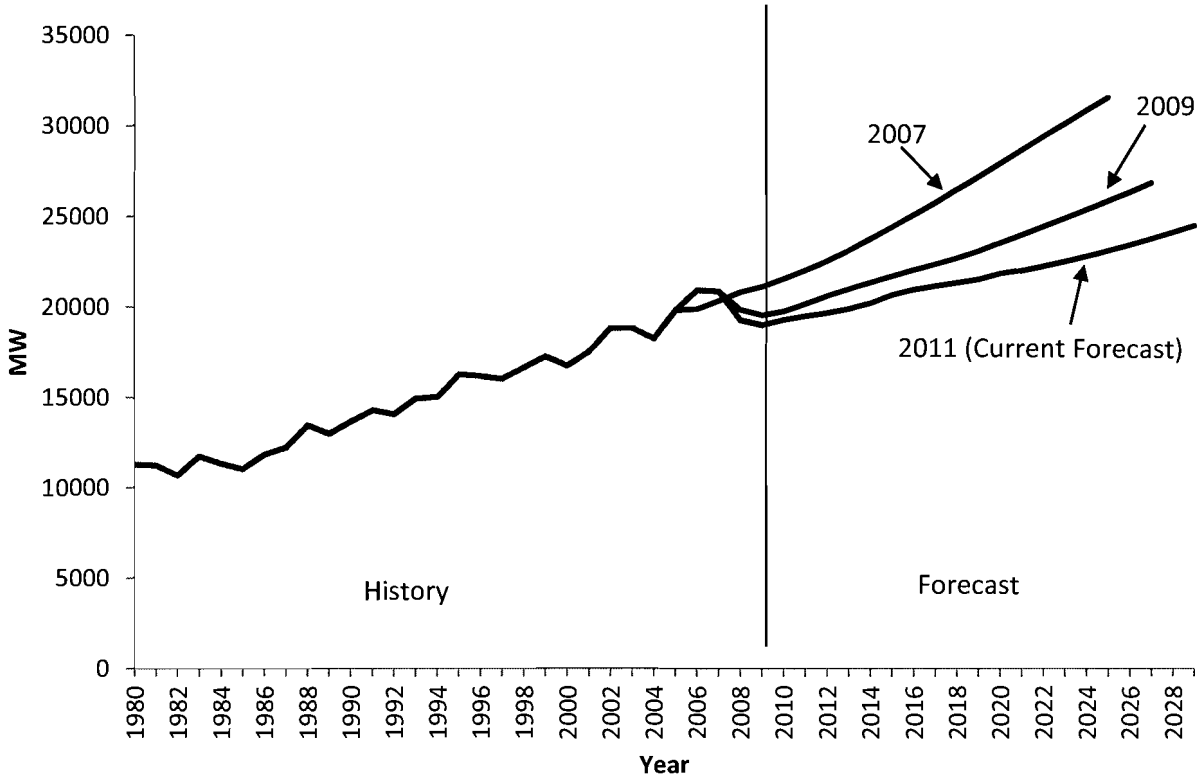
Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.46	2006-2025
2009	1.55	2008-2027
2011	1.30	2010-2029

Figure 3-1. Indiana Electricity Requirements in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Figure 3-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Table 3-2. Indiana Peak Demand Requirements Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.46	2006-2025
2009	1.61	2008-2027
2011	1.28	2010-2029

Table 3-3. Annual Electricity Sales Growth (Percent) by Sector (Current vs. 2009 Projections)

Sector	Current (2010-2029)	2009 (2008-2027)
Residential	0.71	1.75
Commercial	0.89	1.18
Industrial	2.11	1.63
Total	1.31	1.55

Supply-Side Resources

SUFG's base resource plan includes all currently planned capacity changes. Planned capacity changes include: certified, rate base eligible generation additions, retirements, and net changes in firm out-of-state purchases and sales. Due to the timing and uncertainty over Duke Energy's shutdown of three Wabash River units, SUFG has not removed those units from the existing mix of generators. SUFG does not attempt to forecast long-term out-of-state contracts other than those currently in place. Generic firm wholesale purchases are added at prices that reflect SUFG estimates of long-run average costs for these purchases as necessary during the forecast period to maintain a 15.8 percent statewide reserve margin. This level of statewide reserves is derived from individual utility reserve margins that reflect the planning reserve requirements of the utility's regional transmission organization. Note that the reserve margin incorporated in this forecast is slightly lower than the 16.3 percent figure used in 2009. This is due to revisions in planning reserve requirements by the regional transmission organizations.

Three types of generic firm wholesale purchases are included:

1. peaking purchases;
2. cycling purchases; and
3. baseload purchases.

Based on projections of fuel and equipment costs and likely capacity factors for these units, SUFG would expect peaking units to be gas-fired combustion turbines (CT), and both cycling and baseload units to be gas-fired combined cycle (CC) plants. This represents a change from previous forecasts, which used pulverized coal (PC) units as the basis for baseload purchases. This change was made because the most recent fuel price projections and capital cost estimates indicate that CC units would be a lower cost option than PC units. Purchase price projections for each of these purchase types are set to recover the long-run cost of generating electricity from each unit. Continued increases in construction costs have resulted in significantly higher purchase price projections than were used in the previous SUFG forecast.

Table 3-4 and Figure 3-3 show the statewide resource plan for the SUFG base scenario. This forecast identifies no need for peaking, cycling or baseload resources required before 2015. These requirements are lower than those identified in the 2009 forecast because of a number of factors, including lower peak demand projections (due to economic factors and increased energy efficiency), a lower target reserve margin, and new long-term power purchases of wind generated power. By 2020, a total of 2,600 MW of resource additions are required, of which 770 MW is peaking, 640 MW is cycling, and 1,190 MW is baseload. About 4,200 MW of resource additions are required by 2025, and approximately 6,200 MW by 2029. The net change in generation includes the retirement of units as reported in the utilities' 2009 IRP filings, changes in firm purchases and sales, and the addition of approved new capacity. If Duke Energy retires the affected Wabash River units, additional resources of approximately 250 MW will be required.

While SUFG identifies resource needs in its forecasts, it does not advocate any specific means of meeting them. Required resources could be met through conservation measures, purchases from merchant generators or other utilities, construction of new facilities or some combination thereof. The best method for meeting resource requirements may vary from one utility to another.

Due to data availability restrictions at the time that SUFG prepared the modeling system to produce this forecast, the most current year with a complete set of actual historical data is 2009. Therefore, 2010 and 2011 numbers do not include short term purchases and any longer term purchases of which SUFG was not aware at the time the forecast was prepared.

[1] Duke Energy shut down its Wabash River units 2, 3, and 5 in September 2009 as a result of a U.S. District Court ruling regarding alleged violations of the Clean Air Act. At the time this forecast was prepared, the future status of those generating units was unknown.

Table 3-4. Indiana Resource Plan in MW (SUFG Base)

	Uncontrolled Peak Demand[1]	Interruptible	Net Peak Demand[2]	Existing/ Approved Capacity[3]	Incremental Change in Capacity[4]	Projected Additional Resource Requirements[5]				Total Resources[6]	Reserve Margin[7] (percent)
						Peaking	Cycling	Baseload	Total		
2009				23,719							
2010	20,047	778	19,269	23,800	81	0	0	0	0	23800	17
2011	20,251	770	19,481	24,055	255	0	0	0	0	24055	21
2012	20,437	783	19,654	24,543	488	0	0	0	0	24543	24
2013	20,676	795	19,881	24,340	-204	100	20	0	120	24460	23
2014	21,008	805	20,203	24,128	-212	220	30	70	320	24448	25
2015	21,468	818	20,650	23,292	-836	310	90	330	730	24022	23
2016	21,767	832	20,935	23,171	-121	380	160	520	1060	24231	21
2017	21,987	846	21,141	22,991	-180	480	310	700	1490	24481	16
2018	22,180	861	21,319	22,873	-118	520	510	780	1810	24683	16
2019	22,396	876	21,520	22,851	-23	570	550	920	2040	24891	16
2020	22,730	889	21,841	22,696	-155	770	640	1190	2600	25296	16
2021	22,915	889	22,026	22,715	20	800	680	1300	2780	25495	16
2022	23,166	889	22,277	22,725	10	860	740	1470	3070	25795	16
2023	23,419	891	22,528	22,565	-160	920	920	1670	3510	26075	16
2024	23,702	893	22,810	22,565	0	990	1010	1830	3830	26395	16
2025	24,035	895	23,140	22,558	-7	1030	1090	2110	4230	26788	16
2026	24,350	896	23,454	22,322	-236	1060	1330	2440	4830	27152	16
2027	24,696	898	23,798	22,173	-150	1270	1400	2690	5360	27533	16
2028	25,052	900	24,152	22,168	-4	1350	1470	2940	5760	27928	16
2029	25,423	902	24,521	22,153	-15	1490	1590	3160	6240	28393	16

1 Uncontrolled peak demand is the peak demand without any interruptible loads being called upon.

2 Net peak demand is the peak demand after interruptible loads are taken into account.

3 Existing/approved capacity includes installed capacity plus approved new capacity plus firm purchases minus firm sales.

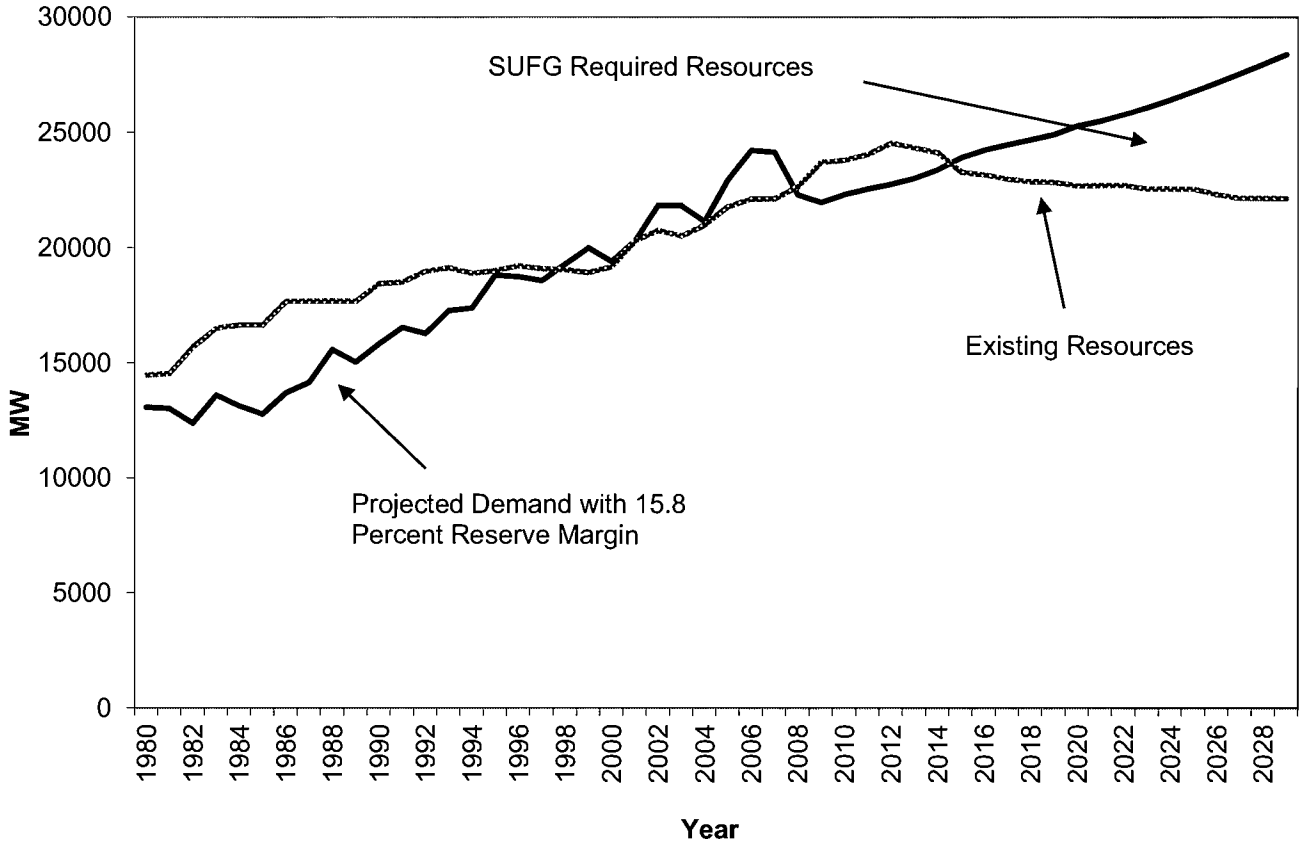
4 Incremental change in capacity is the change in existing/approved capacity from the previous year. The change is due to new, approved capacity becoming operational, retirements of existing capacity, and changes in firm purchases and sales.

5 Projected additional resource requirements is the cumulative amount of additional resources needed to meet future requirements.

6 Total resource requirements are the total statewide resources required including existing/approved capacity and projected additional resource requirements.

7 Resources may be required by individual utilities even if the state as a whole meets or exceeds the statewide reserve margin. Individual utility reserve margins are not allowed to fall below 6 percent.

Figure 3-3. Indiana Total Demand and Supply in MW (SUFG Base)



Equilibrium Price and Energy Impact

The SUFG modeling system is designed to forecast an equilibrium price that balances electricity supply and demand. This is accomplished through the cost-price-demand feedback loop. The impact of this feature on the forecast of electricity requirements can be significant if price changes are large.

SUFG's base scenario equilibrium real electricity price trajectory is shown in Table 3-5 and Figure 3-4. Real prices are projected to increase by 20 percent from 2010 to 2017 and then maintain that level for the remainder of the forecast period. The change in prices early in the forecast horizon is significant, thus the electricity requirements projection for this portion of the forecast period is affected. SUFG's equilibrium price projections for two previous forecasts are also shown in Table 3-5 and Figure 3-4. The price projection labeled "2007" is the base case projection contained in SUFG's 2007 forecast and the one labeled "2009" is the base case projections from SUFG's 2009 report. For the prior price forecasts, SUFG rescaled the original price projections to 2009 dollars (from 2005 dollars for the 2007 projection, and from 2007 dollars for the 2009 projections) using the personal consumption deflator from the CEMR macroeconomic projections.

Three major factors primarily determine the differences among the price projections in Figure 3-4: first, the cost of controlling emissions from coal-fired generation facilities to meet air emission standards; second, purchase power costs; and third, capital costs associated with generation plant additions and life extension. It should be noted that a new generating facility is only included after a Certificate of Public Convenience and Necessity is granted by the IURC. Similarly, environmental rules that are in place at the time the forecast was prepared are included, while proposed and potential future rules are not. Thus, the costs associated with meeting the first phase of the Clean Air Interstate Rule (CAIR) are included. The replacement for CAIR, the Cross-State Air Pollution Rule (CSAPR) was finalized after the model runs for this report were completed, thus CSAPR is not modeled in its final form. Other non-finalized rules, such as the Mercury and Air Toxics Standards (MATS), which was proposed in March 2011, and rules affecting greenhouse gas

emissions, cooling water, and coal ash disposal are not included. SUFG will produce a separate report that specifically addresses the impact of the various proposed and potential rules. This report is expected to be completed in the fall of 2011. See Chapter 8 of this report for more information on potential future regulations.

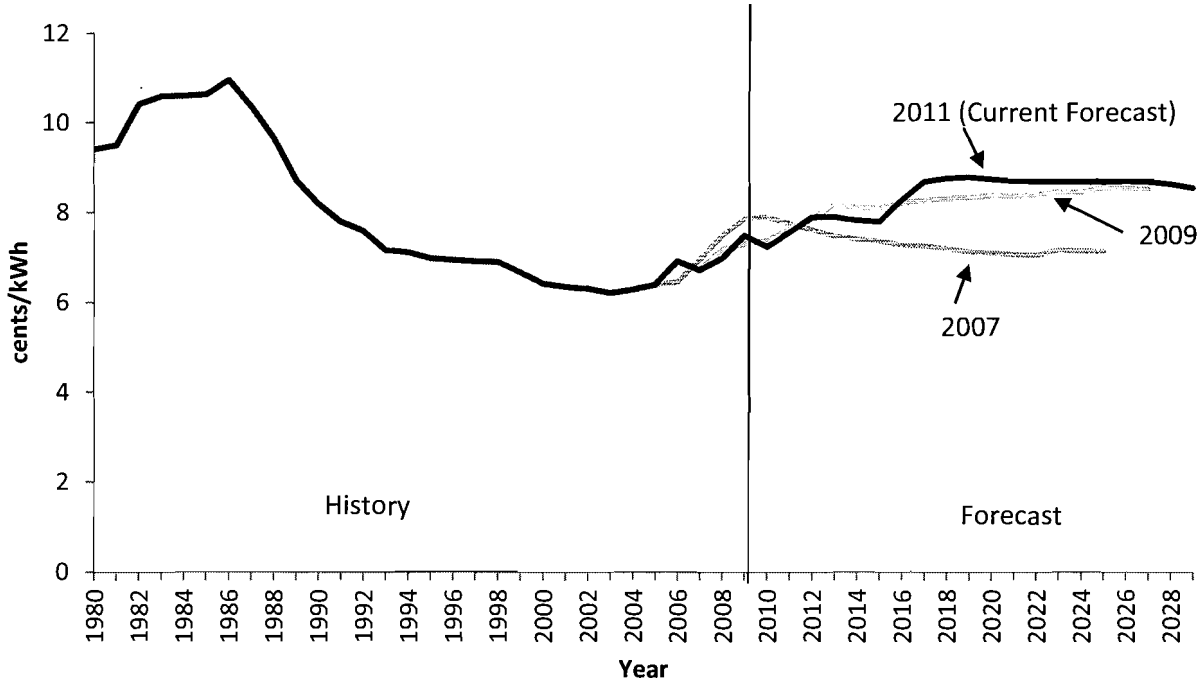
Low and High Scenarios

SUFG has used alternative macroeconomic scenarios, reflecting low and high growth in real personal income, non-manufacturing employment and gross state product. These low probability scenarios are used to indicate the forecast range, or dispersion of possible future trajectories. Tables 3-6 and 3-7 and Figures 3-5 and 3-6 provide the statewide electricity requirements and peak demand projections for the base, low and high scenarios. As shown in those figures, the annual growth rates for the low and high scenarios are about 0.30 percent lower and 0.35 percent higher than the base scenario for both energy requirements and peak demand. These differences are due to economic growth assumptions in the scenario-based projections.

Table 3-5. Indiana Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	0.52	2006-2025
2009	0.89	2008-2027
2011	0.88	2010-2019

Figure 3-4. Indiana Real Price Projections in cents/kWh (2009 Dollars) (Historical, Current and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

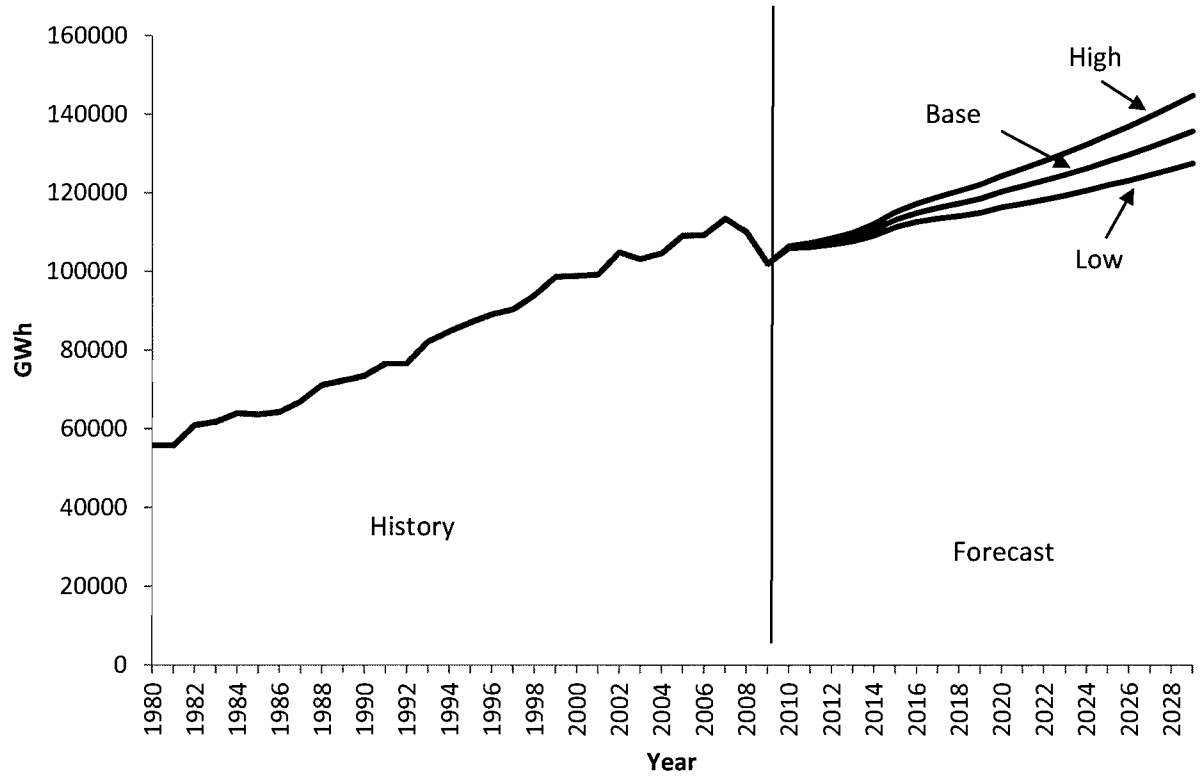
Resource and Price Implications of Low and High Scenarios

Resource plans are developed for the low and high scenarios using the same methodology as the base plan. Demand-side resources, including interruptible loads, are the same in all three scenarios, as are retirements of generating units. Table 3-8 shows the statewide resource requirements for each scenario. Approximately 6,900 MW over the horizon are required in the high scenario compared to 4,000 MW in the low scenario. By the end of the forecast period, electricity prices in both the high case and the low case are within about 3.0 percent of those projected in the base case. This is because the changes in wholesale purchases required relative to the base scenario tend to be offset somewhat by the allocation of resource cost of more or less energy.

Table 3-6. Indiana Electricity Requirements Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2010-29	1.30	0.98	1.64

Figure 3-5. Indiana Electricity Requirements by Scenario in GWh

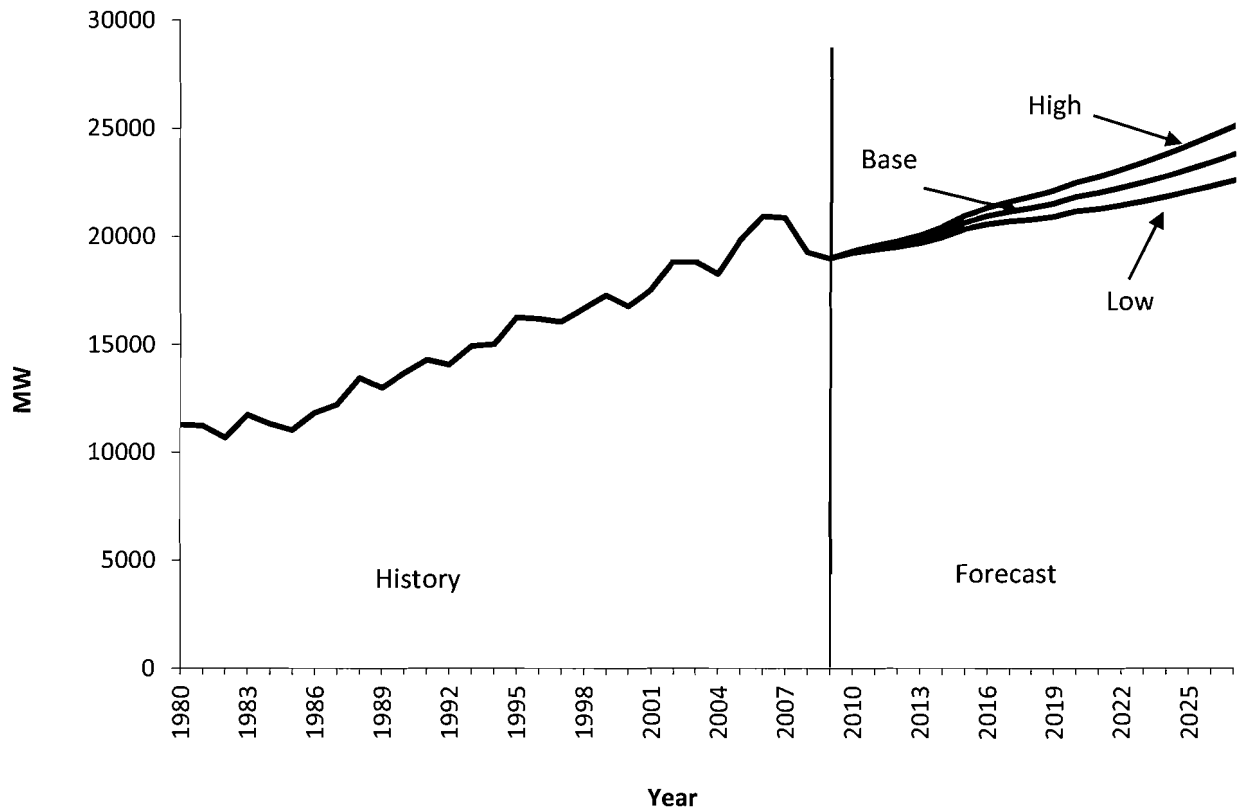


Note: See the Appendix to this report for historical and projected values.

Table 3-7. Indiana Peak Demand Requirements Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2010-29	1.26	0.98	1.58

Figure 3-6. Indiana Peak Demand Requirements by Scenario in MW



Note: See the Appendix to this report for historical and projected values.

Table 3-8. Indiana Resource Requirements in MW (SUFG Scenarios)

Year	Base				High				Low			
	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total	Peaking	Cycling	Baseload	Total
2010	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0
2013	100	20	0	120	140	20	20	180	60	10	0	70
2014	220	30	70	320	250	40	100	390	170	20	30	220
2015	310	90	330	730	370	150	500	1020	270	50	170	490
2016	380	160	520	1060	470	240	780	1490	320	90	320	730
2017	480	310	700	1490	590	410	1000	2000	360	200	390	950
2018	520	510	780	1810	640	650	1120	2410	450	410	590	1450
2019	570	550	920	2040	710	720	1310	2740	480	440	710	1630
2020	770	640	1190	2600	900	810	1640	3350	650	470	820	1940
2021	800	680	1300	2780	950	850	1820	3620	660	480	880	2020
2022	860	740	1470	3070	1030	900	2060	3990	690	540	1010	2240
2023	920	920	1670	3510	1110	1130	2320	4560	740	720	1110	2570
2024	990	1010	1830	3830	1220	1250	2540	5010	780	760	1220	2760
2025	1030	1090	2110	4230	1310	1380	2840	5530	810	840	1390	3040
2026	1060	1330	2440	4830	1340	1610	3250	6200	860	1060	1640	3560
2027	1270	1400	2690	5360	1620	1720	3520	6860	1020	1110	1880	4010
2028	1350	1470	2940	5760	1760	1850	3800	7410	1090	1170	2040	4300
2029	1490	1590	3160	6240	1910	1980	4090	7980	1170	1250	2210	4630

Chapter 4

Major Forecast Inputs and Assumptions

Introduction

The models SUFG utilizes to project electric energy sales, peak demand and prices require external, or exogenous, assumptions for several key inputs. Some of these input assumptions pertain to the level of economic activity, population growth and age composition for Indiana. Other assumptions include the prices of fossil fuels, which are used to generate electricity and compete with electricity to provide end-use service. Also included are estimates of the energy and peak demand reductions due to utility load management programs.

This section describes SUFG's scenarios, presents the major input assumptions and provides a brief explanation of forecast uncertainty.

Macroeconomic Scenarios

The assumptions related to macroeconomic activity determine, to a large degree, the essence of SUFG's forecasts. These assumptions determine the level of various activities such as personal income, employment and manufacturing output, which in turn directly influence electricity consumption. Due to the importance of these assumptions and to illustrate forecast uncertainty, SUFG used alternative projections or scenarios of macroeconomic activity provided by the Center for Econometric Model Research (CEMR) at Indiana University.

- The *base scenario* is intended to represent the electricity forecast that is "most likely" and has an equal probability of being high or low.
- The *low scenario* is intended to represent a plausible lower bound on the electricity sales forecast and has a low probability of occurrence.
- The *high scenario* is intended to represent a plausible upper bound on the electricity sales forecast and also has a low probability of occurrence.

These scenarios are developed by varying the major forecast assumptions, i.e., Indiana's share of the national economy.

Economic Activity Projections

National and state economic projections are produced by the CEMR twice each year. For this forecast, SUFG adopted CEMR's February 2011 economic projections as its base scenario. CEMR also produced high and low growth alternatives to the base projection for SUFG's use in the high and low scenarios.

CEMR developed these projections from its U.S. and Indiana macroeconomic models. The Indiana economic forecast is generated in two stages. First, a set of exogenous assumptions affecting the national economy are developed by CEMR and input to its model of the U.S. economy. Second, the national economic projections from this model are input to the Indiana model that translates the national projections into projections of the Indiana economy.

The CEMR model of the U.S. economy is a large scale quarterly econometric model. Successive versions of the model have been used for more than 15 years to generate short-term forecasts. The model has a detailed aggregate demand sector that determines output. It also has a fully specified labor market submodel. Output determines employment, which then affects the availability of labor. Labor market tightness helps determine wage rates, which, along with employment, interest rates and several other variables determine personal income. Fiscal policy variables, such as spending levels and tax rates, interact with income to determine federal, state and local budgets. Monetary policy variables interact with output and price variables to determine interest rates.

A major input to CEMR's Indiana model is a projection of total U.S. employment, which is derived from CEMR's model of the U.S. economy.

The Indiana model has four main modules. The first disaggregates total U.S. employment into manufacturing and non-manufacturing sectors. The second module then projects the share of each industry in Indiana. Additional relationships are used to project average weekly hours and average hourly earnings by industry. These are used with employment to calculate a total wage bill. The third module projects the remaining components of personal income. In the fourth module, labor productivity combined with employment projections is used to calculate real Gross State Product (GSP), or output, by industry.

The main exogenous assumptions in the national projections used in the CEMR forecast, as cited from "Long-Range Projections 2010-2031" [CEMR] are:

Federal tax rates are assumed to increase over the projection period. Specifically, the average tax rate on personal income and the payroll tax rate each increased by 18 percent. Federal grants to state and local governments are assumed to grow at about 4.6 percent annually early in the projection period and then decline to about a 4.1 percent by the end of the projection period. The federal government deficit declines somewhat but is still more than 6.0 percent of GDP at the end of the projection period as compared to 9.2 percent in 2010.

State and local tax rates are roughly stable over the projection period. This allows these governments to run moderate surpluses through the projection period.

Real exports are assumed to grow at about 5.3 percent through 2019, and then to decelerate gradually to 4.7 percent growth. This produces a (nominal) net export deficit that declines from 3.6 percent of GDP to 2.9 percent (CEMR, 2011).

As a result of these assumptions, real Gross Domestic Product (GDP) for the U.S. economy is projected to grow at an average annual rate of 3.05 percent and U.S. employment growth averages 1.25 percent over the 2010 to 2029 period.

In Indiana, total employment is projected to grow at an average annual rate of 1.21 percent from 2010 through 2029. The key Indiana economic projections are:

Real personal income (a residential sector model driver) is expected to grow at a 2.02 percent annual rate.

Non-manufacturing employment (the commercial sector model driver) is expected to average a 1.31 percent annual growth rate over the forecast horizon.

Despite the low growth in manufacturing employment, manufacturing GSP (the industrial sector model driver) is expected to rise at a 3.44 percent annual rate as gains in productivity far outpace meager growth in employment.

CEMR's macroeconomic projections reflect a continuation of the economic recovery. Real Indiana personal income began recovering in 2010. Indiana nonmanufacturing employment and manufacturing output (real GSP) also began to increase in 2010.

A summary comparison of CEMR's projections used in SUFG's previous and current electricity projections and historical growth rates for recent historical periods is provided in Table 4-1.

To capture some of the uncertainty in energy forecasting, CEMR provided a low and high growth alternative to its base economic projection. In effect, the alternatives describe a situation in which Indiana either loses or gains shares of national industries compared to the base projection. In the high growth alternative, the Indiana average growth rate of real personal income is increased by about 0.35 percent per year (to 2.37), non-manufacturing employment growth increases 0.11 percent (to 1.42) while Indiana real manufacturing GSP growth is increased by 0.80 percent (to 4.24). In the low growth alternative, the average growth rates of real personal income, non-manufacturing employment and real manufacturing GSP are reduced by similar amounts (to 1.68, 1.21 and 2.44 percent, respectively).

Demographic Projections

Household demographic projections are a major input to the residential energy forecasting model. The SUFG forecasting system includes a housing model which utilizes population and income assumptions to project households or customers.

The population projections utilized in SUFG's electricity forecasts were obtained from the Indiana Business Research Center at Indiana University (IBRC). The IBRC population growth forecast for Indiana is 0.49 percent per year, for the period 2005-2025. This projection was developed in 2004 and includes projections of county population by age group, the fastest growing age groups are those of age 45-64 (0.45 percent) and age 65 and over (2.39 percent). Population growth is low during the projection period because the age distribution in Indiana is skewed from young adults of childbearing age to older adults with higher mortality rates.

Indiana population growth has slowed markedly in recent years. The number of people over age 45 (the groups with fewer occupants per household) is projected to grow more rapidly than the younger population. Thus, the number of people per household is projected to decline and household formations are expected to grow more rapidly than total population.

The historical growth of household formations (number of residential customers) has slowed down significantly from slightly over 2 percent during the late 1960s and early 1970s to about 1.4 percent currently. The IBRC population projection, in combination with the CEMR projection of real personal income, yields an average annual growth in households of about 1.00 percent over the forecast period.

Table 4-1. Growth Rates for CEMR Projections of Selected Economic Activity Measures (Percent)

	Short-Run History for Selected Recent Periods					Long-Run Forecast		
						Feb 2007	Feb 2009	Feb 2011
	1985-1990	1990-1995	1995-2000	2000-2005	2005-2010*	2006-2025	2008-2027	2010-2029
United States								
Real Personal Income	2.95	2.04	4.08	1.73	1.43	3.25	2.76	2.80
Total Employment	2.36	1.38	2.37	0.25	-0.52	0.97	1.00	1.25
Real Gross Domestic Product	3.25	2.38	4.36	2.39	0.93	3.20	2.76	3.05
Personal Consumer Expenditure Deflator	3.79	2.77	1.87	2.20	2.12	1.94	1.72	1.51
Indiana								
Real Personal Income	2.50	2.48	3.37	1.17	0.59	2.10	1.63	2.02
Employment								
Total Establishment	2.84	1.91	1.22	-0.28	-1.09	0.80	0.83	1.21
Manufacturing	0.91	1.40	0.07	-2.95	-5.05	-1.10	-1.29	0.30
Non-Manufacturing	3.82	2.20	1.97	0.47	0.05	1.12	1.16	1.31
Real Gross State Product								
Total	6.17	5.83	4.78	1.98	0.83	3.21	2.62	3.02
Manufacturing	4.76	7.95	4.68	3.26	0.63	3.49	2.23	3.44
Non-Manufacturing	6.81	4.86	4.84	1.43	0.90	3.07	2.78	2.86

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"
*2010 values are projections not actual history

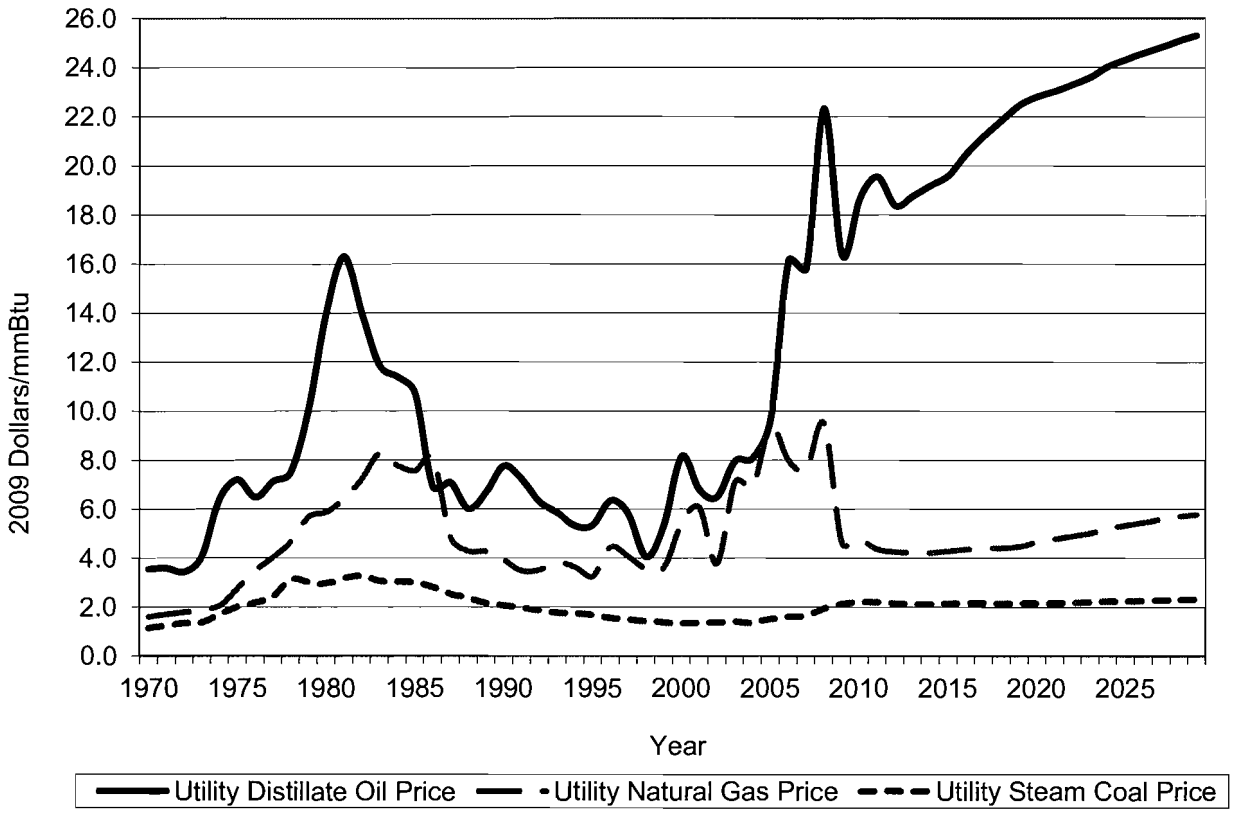
Fossil Fuel Price Projections

The prices of fossil fuels such as coal, natural gas and oil affect electricity demand in separate and opposing ways. To the extent that any of these fuels are used to generate electricity, they are a determinant of average electricity prices. Electricity generation in Indiana is currently fueled almost entirely by coal. Thus, when coal prices increase, electricity prices in Indiana rise and electricity demand falls, all else being equal. On the other hand, fossil fuels compete directly with electricity to provide end-use services, i.e., space and water heating, process use, etc. When prices for these fuels increase, electricity becomes relatively more attractive and electricity demand tends to rise, all else being equal. As fossil fuel prices increase, the impacts on electricity demand are somewhat offsetting. The net impact of these opposing forces depends on their impact on utility costs, the responsiveness of customer demand to electricity price changes and the availability and competitiveness of fossil fuels in the end-use services markets. The SUFG modeling system is designed to simulate each of these effects as well as the dynamic interactions among all effects.

SUFG's modeling system incorporates separate fuel price projections for each of the utility, industrial, commercial and residential sectors. Therefore, SUFG uses four distinct natural gas price projections (one for each sector). Similarly, four distinct oil price projections are used. Coal price projections are included for the utility and industrial sectors only. In this forecast, SUFG has used April 2011 fossil fuel price projections from EIA for the East North Central Region of the U.S. [EIA]. All projections are in terms of real prices (2009 dollars), i.e., projections with the effects of inflation removed. The general patterns of the fossil fuel price projections are:

- Coal price projections are relatively unchanged in real terms throughout the entire forecast horizon as growth in demand is offset by improvements in mining productivity.
- Natural gas price projections exhibit a significant decrease in 2009 coming off of the high prices of 2008. Prices are then projected to remain relatively constant through 2015, with a general increase following for the remainder of the forecast horizon.
- Distillate prices also are projected to decrease significantly in 2009, but recover more quickly with a steady increase through the remainder of the forecast horizon.

Figure 4-1. Utility Real Fossil Fuel Prices



The fossil fuel price projections for the utility sector are presented in Figure 4-1. The general trajectories for the other sectors are similar.

Demand-Side Management and Interruptible Loads

Demand-side management (DSM) refers to a variety of utility-sponsored programs designed to influence customer electricity usage in ways that produce desired changes in the utility's load shape, i.e., changes in the time pattern or magnitude of a utility's load. These programs include energy conservation programs that reduce overall consumption and load shifting programs that move demand to a time when overall system demand is lower.

Incremental DSM, which includes new programs and the expansion of existing programs, require adjustments to be made in the forecast. These adjustments are made by changing the utility's demand by the appropriate level of energy and peak demand for the DSM program. DSM programs that were in place in 2009 are considered to be embedded in the calibration data, so no adjustments are necessary.

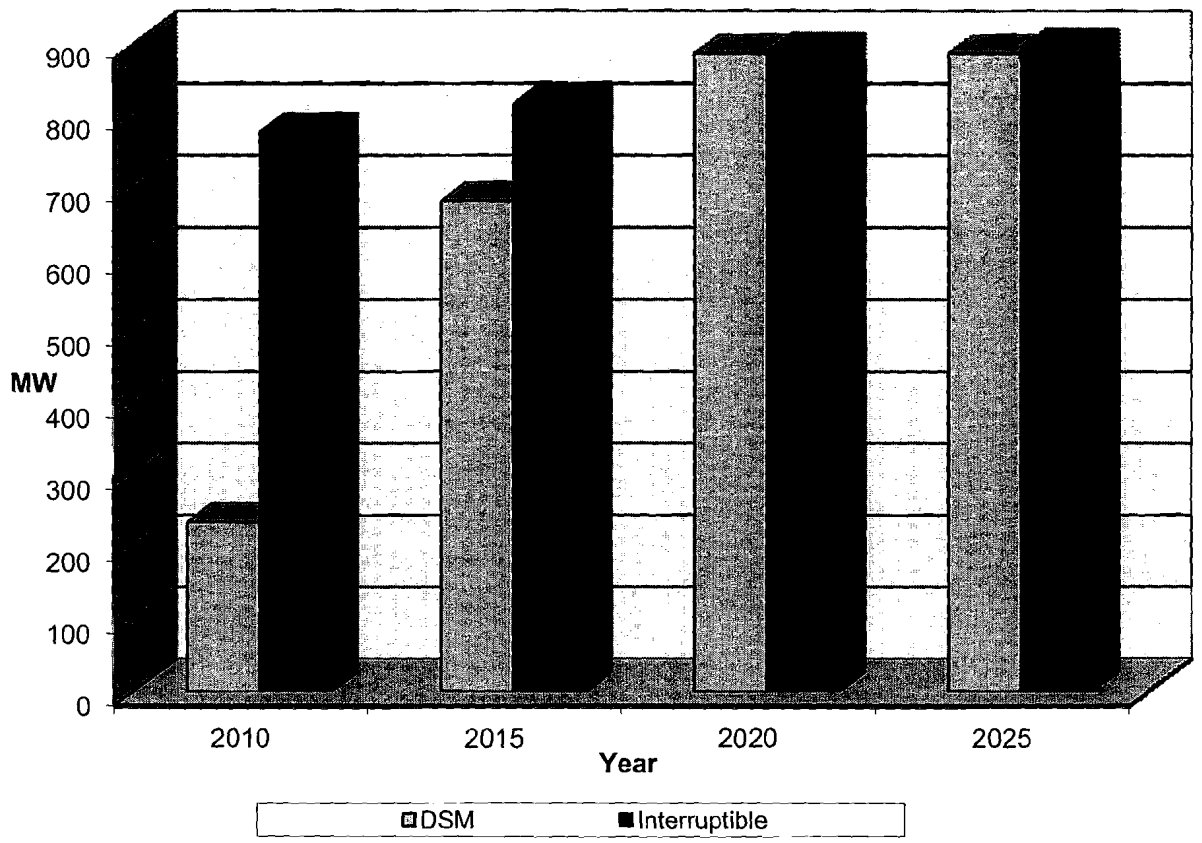
Interruptible loads, such as large customers who agree to curtail a fixed amount of their demand during critical periods in exchange for more favorable rates, are typically treated differently than traditional DSM. Interruptible loads are subtracted from the utility's peak demand in order to determine the amount of new capacity required.

Table 4-2 shows the peak demand reductions from embedded DSM in 2009 and from incremental DSM and interruptible loads available in 2010 in Indiana. These estimates are derived from utility integrated resource plan (IRP) filings and from information collected by SUFG directly from the utilities. DSM projections after 2010 are primarily driven by the IURC's DSM order of December 2009. Since long-term program information was not available at the time this forecast was prepared, SUFG estimated the energy and peak demand savings, as well as the program costs, associated with meeting the DSM rule. Figure 4-2 shows projected values of peak demand reductions for incremental DSM and interruptible loads at five year intervals starting in the year 2010.

Table 4-2. 2009 Embedded DSM and 2010 Peak Demand Reductions (MW)

2009 Embedded DSM	2010 Incremental DSM	2010 Interruptible
461	236	778

Figure 4-2. Projections of Peak Demand Reductions from DSM and Interruptible Loads



The interruptible load numbers include both traditional interruptible contracts, whereby the customer shuts off its load when certain criteria are met, and buy through contracts, whereby the customer has the option of shutting off the load or purchasing the power at the wholesale price. For both types of interruptible load, the utility does not have to acquire additional peak generating capacity ahead of time to meet that load. Therefore, interruptible and buy through loads are subtracted from total peak demand for resource planning purposes. The peak demand projections in this report are net of both types of interruptible loads; that is, those loads have been removed from the projections.

When analyzing wholesale markets, the distinction between interruptible and buy through loads becomes more important. Traditional interruptible loads may be assumed to be absent from the system during times of high demand and prices, while buy through loads may still be present, with the higher prices passed directly to the customer.

Changes in Forecast Drivers from 2009 Forecast

The SUFG forecast requires exogenous economic assumptions to project electric energy sales, peak demand and prices. Fluctuations in the national and state economies

therefore have direct effects on the forecast. SUFG analyzed the impact of the recent recession on different economic variables in Indiana to obtain a better understanding of how these changes affect electricity demand in the state. This section compares the CEMR's projections used in SUFG's 2009 and 2011 forecasts.

Electricity demand is a function of a number of factors, including real personal income, manufacturers' electricity consumption, labor usage intensity, and other economic variables. The economy has direct and indirect implications for electricity consumption in Indiana.

In the time between CEMR's February 2009 (herein referred to as CEMR2009) and February 2011 (CEMR2011) long-range projections, the U.S. economy recovered slightly but some remnants of the recession persist even in 2011.

Tables 4-3 through 4-5 provide comparisons between the two projections. Selected economic variables are reported annually from 2008 through 2014 and for each five year interval beginning in 2015. The tables show long-run projections of real values and percentage change at annual rates for total manufacturing GSP, non-manufacturing employment and personal income. The tables also show the percentage change between CEMR2009 and CEMR2011. Figures 4-3 through 4-5 show long-run projections of real values for the same selected economic variables from 2003 through 2031. Some of the historical values before 2007 differ between the two projections because of data revisions and the use of chain-weighted price indices and deflators.

Non-manufacturing Employment

CEMR forecasts employment at the sectoral level, separating employment into sectors for durable goods manufacturing, non-durable goods manufacturing, and non-manufacturing. Analyzing the non-manufacturing, or service, sector's employment provides insight into Indiana's commercial electricity demand.

Table 4-3 shows that the impact of the recession on non-manufacturing employment occurs largely in the 2008 to 2015 timeframe. In CEMR2011, the projection of non-manufacturing employment for 2010 is about 70,000 employees (or 3.05 percent) lower than in CEMR2009. In 2011 this gap increases and non-manufacturing employment falls to about 85,500 employees (or 3.63 percent) lower than projected in CEMR2009. From 2012 on, CEMR2011 exhibits higher growth than previously estimated, but employment in this sector never returns to previously expected levels.

Figure 4-3 illustrates the comparison between past and current projections for employment in non-manufacturing. CEMR2011 exhibits a similar trajectory to CEMR2009 for part of the forecast horizon, with the most significant deviation between 2008 and 2017.

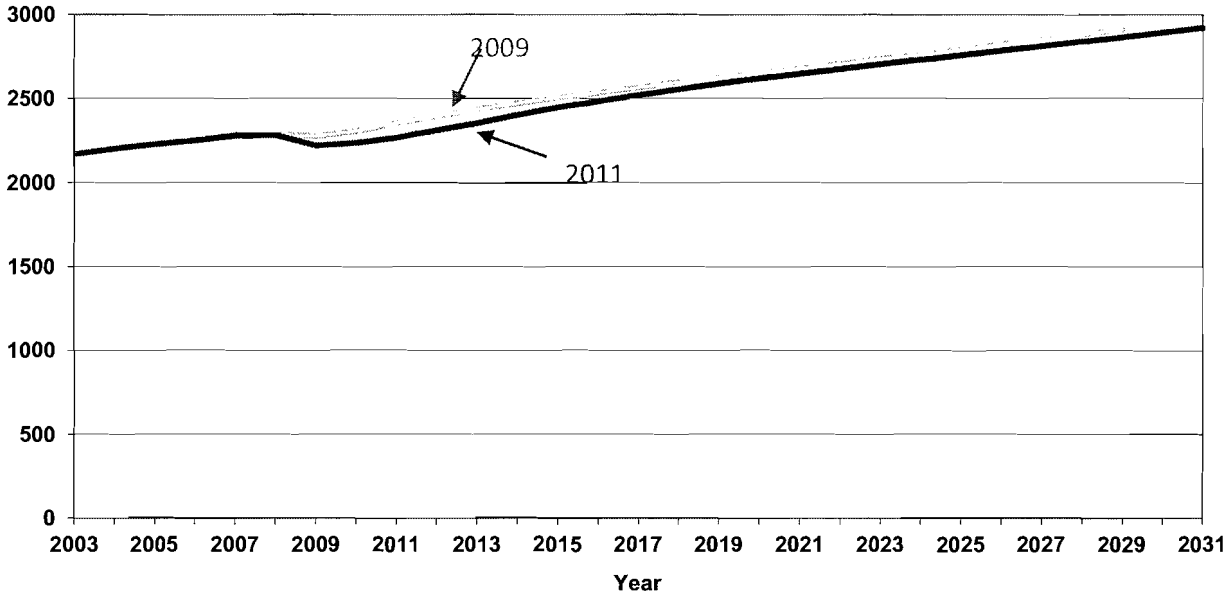
Table 4-3. 2009 and 2011 CEMR Projections for Non-manufacturing Employment

	Year										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**	**2029**
	Thousands of persons										
CEMR2009	2288.8	2276.5	2305.3	2351.6	2395.3	2433.9	2469.0	2502.2	2650.2	2791.9	2910.9
	(0.35)	(-0.54)	(1.27)	(2.01)	(1.86)	(1.61)	(1.44)	(1.34)	(1.16)	(1.05)	(1.05)
CEMR2011	2284.3	2220.3	2235.0	2266.1	2311.8	2353.2	2400.4	2444.8	2618.7	2758.2	2864.5
	(0.31)	(-2.80)	(0.66)	(1.39)	(2.02)	(1.79)	(2.00)	(1.85)	(1.38)	(1.04)	(1.04)
Percentage change between two projections	-0.20	-2.47	-3.05	-3.63	-3.48	-3.32	-2.78	-2.29	-1.19	-1.21	-1.60

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

Figure 4-3. Indiana Non-manufacturing Employment (thousands of people)



Real Personal Income

Real personal income provides an important picture of the recession's effects on Indiana. Changes in real personal income will directly influence electricity demand. Real personal income is an input to the residential energy forecasting model.

Table 4-4 and Figure 4-4 show the CEMR projections of real personal income. CEMR2011 follows a similar trajectory to the one for non-manufacturing employment in that it slows in 2008, then decreases in 2009 before beginning to rebound in 2010. However, while the trajectory is similar, the magnitude of the difference between the two sets of projections is larger. CEMR2011 indicates real personal income more than $2 billion dollars (1.04 percent) above CEMR2009 in 2009, with the difference rising to over $10 billion (4.00 percent) by 2025. Unlike the non-manufacturing employment projection, real personal income does reach higher levels than projected in CEMR2009.

Figure 4-4 illustrates that the CEMR2011 real personal income is projected to grow at a steady rate after 2010, with higher growth rates than in CEMR2009.

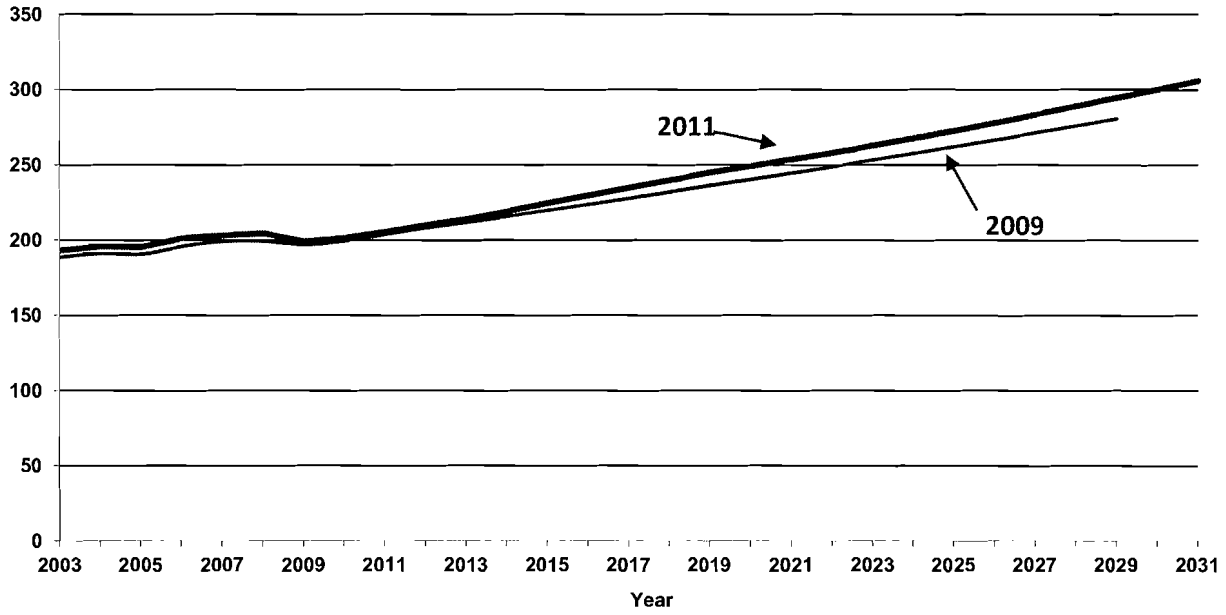
Table 4-4. 2009 and 2011 CEMR Projections for Real Personal Income

	Year										
	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2029
	Billions of 2005 $										
CEMR2009	199.54 (0.20)	197.32 (-1.11)	199.25 (0.98)	203.78 (2.27)	208.15 (2.15)	211.79 (1.75)	215.62 (1.81)	219.58 (1.83)	240.49 (1.84)	262.13 (1.74)	280.73 (1.73)
CEMR2011	204.67 (0.83)	199.37 (-2.59)	201.37 (1.01)	205.28 (1.94)	209.87 (2.24)	214.02 (1.98)	218.99 (2.32)	224.48 (2.51)	249.25 (2.12)	272.61 (1.81)	294.67 (1.96)
Percentage change between two projections	2.57	1.04	1.06	0.74	0.83	1.05	1.56	2.23	3.64	4.00	4.96

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

Figure 4-4. Indiana Real Personal Income (billions of 2005 dollars)



Real Manufacturing Gross State Product

Changes in manufacturing Gross State Product (GSP) will have significant implications for electricity use in the industrial sector. The recession has had a larger impact on manufacturing GSP growth than it has on either non-manufacturing employment or personal income.

Table 4-5 and Figure 4-5 show the CEMR projections for real manufacturing GSP. While the CEMR2011 projection follows a similar pattern to that for real personal income, the deviation from the CEMR2009 projections is more pronounced. As the figure illustrates, after not increasing in 2008 and 2009, real manufacturing GSP shows a modest growth in 2010. The CEMR2011 projection for 2010 was over $2 billion (4.35 percent) above the 2009 level for that year. Real manufacturing GSP continues to grow at a higher rate than in CEMR2009. By 2025, the difference between the two projections grows to over $11 billion, or 11.99 percent.

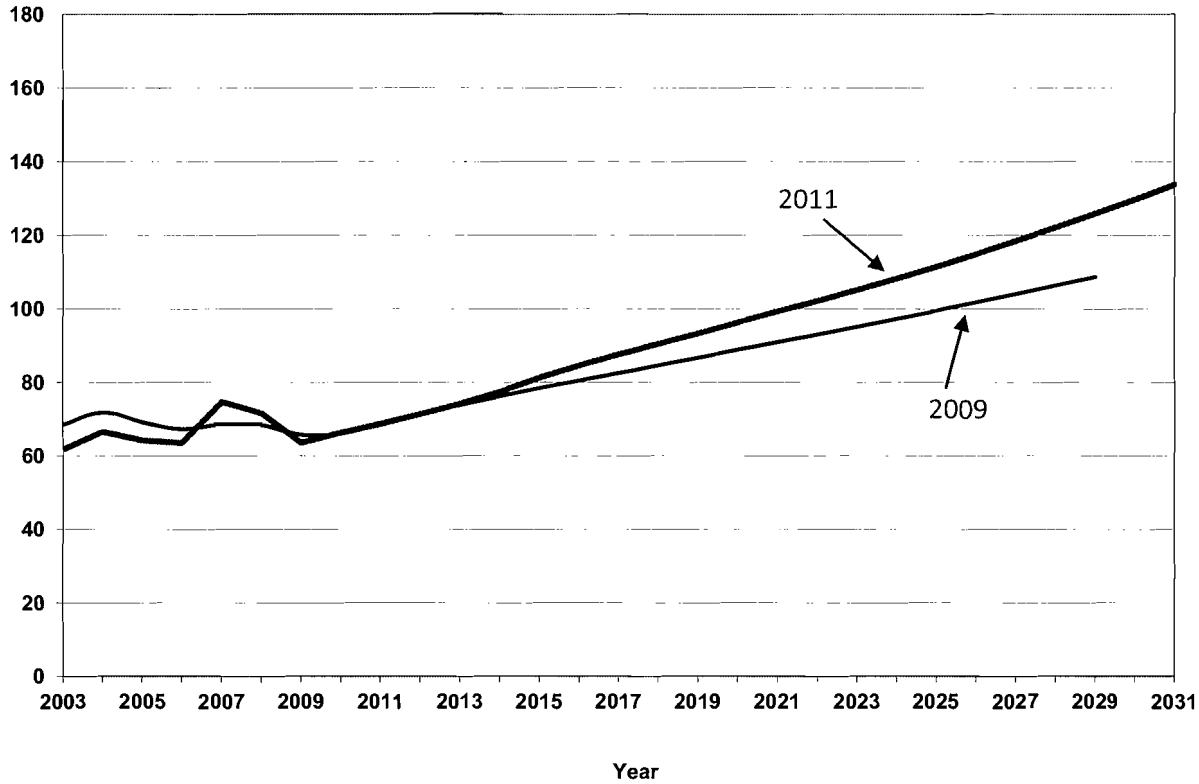
Table 4-5. 2009 and 2011 CEMR Projections for Real Manufacturing GSP

	Year										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**	**2029**
	Billions of 2005 $										
CEMR2009	68.42 (-0.25)	65.71 (-3.97)	66.06 (0.52)	68.54 (3.77)	71.25 (3.94)	73.84 (3.65)	76.17 (3.15)	78.35 (2.86)	88.83 (2.54)	99.54 (2.30)	108.79 (2.25)
CEMR2011	71.60 (-4.18)	63.51 (-11.30)	66.27 (4.35)	68.69 (3.65)	71.37 (3.91)	74.19 (3.95)	77.41 (4.34)	81.16 (4.84)	96.32 (3.49)	111.47 (2.97)	125.94 (3.10)
Percentage change between two projections	4.64	-3.35	0.33	0.21	0.18	0.48	1.63	3.58	8.43	11.99	15.77

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

Figure 4-5. Indiana Real Manufacturing GSP (billions of 2005 dollars)



The transportation equipment industry, including automobile and auto parts manufacturing, accounts for a considerable portion of the total manufacturing GSP in Indiana. In 2009, this sector represented slightly less than one sixth (15.9 percent) of the total real value of products manufactured in the state.

Table 4-6 shows projected growth rates, actual values and percentage rate changes for the transportation equipment industry and includes the comparison between the CEMR2009 and CEMR2011 projections. The table indicates that the recession is having a significant impact on the performance of the automobile sector.

CEMR2011 shows a large reduction in the production of transportation equipment from 2008 to 2009, with a major decline of over 25 percent in 2009. The industry is projected to keep recovering from the recession for the entire forecast period and reach the level projected in CEMR2009 by the year of 2016. Production does not return to pre-2007 levels until after 2014 and is about 11 percent lower than that projected in CEMR2009 after 2010.

While the primary metals industry, including production of steel and aluminum, represented slightly more than 8 percent of Indiana manufacturing GSP in 2008, it accounted for 30.1 percent of the state's industrial electricity sales.

Table 4-7 compares the CEMR projections for 2009 and 2011 for the primary metals industry, which saw about a 16 percent reduction between 2008 and 2010. As in most of the other sectors of the economy, the primary metals industry is projected to see increasing output after 2010. Unlike other industries, CEMR2011 indicates a sustained major recovery for this industry. Real GSP for this sector is projected to exceed the 2008 levels after 2015 for the entire the forecast horizon.

Table 4-6. 2009 and 2011 CEMR Projections for Real GSP Transportation Equipment

	Year										
	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2029
	Billions of 2005 $										
CEMR2009	14.69	13.41	13.45	13.95	14.49	15.03	15.52	15.98	18.18	20.39	22.26
	(-8.12)	(-8.69)	(0.27)	(3.73)	(3.90)	(3.72)	(3.24)	(2.95)	(2.43)	(2.27)	(2.21)
CEMR2011	13.59	10.11	11.34	12.17	12.86	13.57	14.41	15.41	20.15	25.52	30.83
	(-8.00)	(-25.60)	(12.15)	(7.33)	(5.66)	(5.53)	(6.22)	(6.94)	(5.12)	(4.80)	(4.79)
Percentage change between two projections	-7.50	-24.63	-15.70	-12.77	-11.29	-9.75	-7.15	-3.55	10.84	25.15	38.49

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

Table 4-7. 2009 and 2011 CEMR Projections for Real GSP Primary Metals

	Year										
	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2029
	Billions of 2005 $										
CEMR2009	2.94	2.78	2.71	2.74	2.77	2.79	2.80	2.81	2.78	2.72	2.66
	(-1.68)	(-5.63)	(-2.28)	(0.89)	(1.05)	(0.88)	(0.41)	(0.13)	(-0.36)	(-0.50)	(-0.55)
CEMR2011	5.21	4.61	4.38	4.41	4.51	4.60	4.73	4.89	5.41	5.80	6.13
	(-9.47)	(-11.64)	(-4.85)	(0.55)	(2.26)	(2.11)	(2.75)	(3.43)	(1.66)	(1.35)	(1.35)
Percentage change between two projections	77.09	65.82	61.45	60.92	62.85	64.84	68.67	74.23	94.50	113.21	130.29

Sources: SUFG Forecast Modeling System and various CEMR "Long-Range Projections"

Note: Numbers in parentheses indicate percentage change at annual rate

Forecast Uncertainty

There are three sources of uncertainty in any energy forecast:

1. exogenous assumptions;
2. stochastic model error; and,
3. non-stochastic model error.

Projections of future electricity requirements are conditional on the projections of exogenous variables. Exogenous variables are those for which values must be assumed or projected by other models or methods outside the energy modeling system. These exogenous assumptions, including demographics, economic activity and fossil fuel prices, are not known with certainty. Thus, they represent a major source of uncertainty in any energy forecast.

Stochastic error is inherent in the structure of any forecasting model. Sampling error is one source of stochastic error. Each set of observations (the historical data) from which the model is estimated constitutes a sample. When one considers stochastic model error, it is implicitly assumed that the model is correctly specified and that the data is correctly measured. Under these assumptions the error between the estimated model and the true model (which is always unknown) has certain properties. The expected value of the error term is equal to zero. However, for any specific observation in the sample, it may be positive or negative. The errors from a number of samples follow a pattern, which is described as the normal probability distribution, or bell curve. This particular normal distribution has a zero mean, and an unknown, but estimable variance. The magnitude of the stochastic model error is directly related to the magnitude of the estimated variance of this distribution. The greater the variance, the larger the potential error will be.

In practice, virtually all models are less than perfect. Non-stochastic model error results from specification errors, measurement errors and/or use of inappropriate estimation methods.

References

Center for Econometric Model Research, "Long-Range Projections 2010-2031," Indiana University, February 2011.

Energy Information Administration, "Annual Energy Outlook 2011," April 2011.

Chapter 5

Residential Electricity Sales

Overview

SUFG has access to both econometric and end-use models to project residential electricity sales. These different modeling approaches have specific strengths and complement each other. The econometric model is used to project the number of customers in two groups, those with and those without electric space heating systems, as well as average electricity use by each customer group. The SUFG staff originally developed the econometric model in 1987 when it was estimated from utility specific data. Since then, it has been updated four times, most recently prior to the SUFG 2005 forecast when major components of the model were partially updated. After the release of the 2007 SUFG Indiana Electricity Projections report, SUFG acquired a proprietary end-use model, Residential Energy Demand Model System (REDMS), which blends econometric and engineering methodologies to project energy use on a disaggregated basis. REDMS was obtained to replace an older residential sector end-use oriented model known as REEMS. Both end-use models are descendants of the first generation of end-use models developed at Oak Ridge National Labs (ORNL) during the late 1970s. Initial review indicates that given the same set of primary inputs, REDMS produces forecasts somewhat lower but similar to the econometric model which SUFG has used for several years. This result is markedly different from the results that SUFG experienced with the older end-use model REEMS which projected much lower growth than the econometric model. SUFG has continued to evaluate REDMS and has had the vendor update the model to the latest U. S. Department of Energy (DOE) efficiency standards. SUFG has adapted this end-use model (REDMS) as the primary residential sector energy model, and it is used to project residential electricity sales in this forecast. The end-use model has been implemented for the five Indiana investor-owned utilities (IOUs) and SUFG continues to model residential energy for the not-for-profit utilities (NFPs) with an econometric approach. A discussion of the reasons for SUFG's switch to REDMS and a general description of the residential end-use model follow, along with a brief historical perspective on residential electricity consumption trends in Indiana.

Historical Perspective

The growth in residential electricity consumption has generally reflected changes in economic activity, i.e., real household income, real energy prices and total households. Each of five recent periods has been characterized by distinctly different trends in these market factors and in each case, residential electricity sales growth has reflected the change in market conditions. Beginning in 2008 economic activity slowed dramatically. Due in large part to economic weakness, low electric energy sales growth is projected in the residential sector for the near term (see Figure 5-1).

The explosion in residential electricity sales (nearly 9 percent per year) during the decade prior to the Organization of Petroleum Exporting Countries (OPEC) oil embargo in 1974 coincided with the economic stimuli of falling prices (nearly 6 percent per year in real terms) and rising incomes (about 1 percent per year in real terms). This period also was marked by a boom in the housing industry as the number of residences increased at an average rate of 2 percent per year. In the decade following the embargo, the growth in residential electricity sales slowed dramatically. Except for some softening in electricity prices during 1979-81, real electricity prices climbed at approximately the same rate during the post-embargo era as they had fallen during the pre-embargo era. This resulted in a swing in electric prices of more than 10 percent. Growth in real household income was a miniscule 0.5 percent, less than one-third that seen in the previous period. The housing market also went from boom to bust, averaging only half the growth of the pre-embargo period. This turnaround in economic conditions and electricity prices is reflected in the dramatic decline in the growth of residential electricity sales from nearly 9 percent per year prior to 1974, to just over 2 percent per year for the next decade. Events turned again during the mid-1980s. Real household income grew at more than the pre-embargo rate, 3.1 percent per year. Real electricity prices declined 2.0 percent per year at one third the pre-embargo rate. Households grew at only a slightly higher rate than in the post-embargo decade, about 1.3 percent per year. Despite these more favorable market conditions, annual electricity sales growth increased only 0.4 percent to 2.5 percent per year.

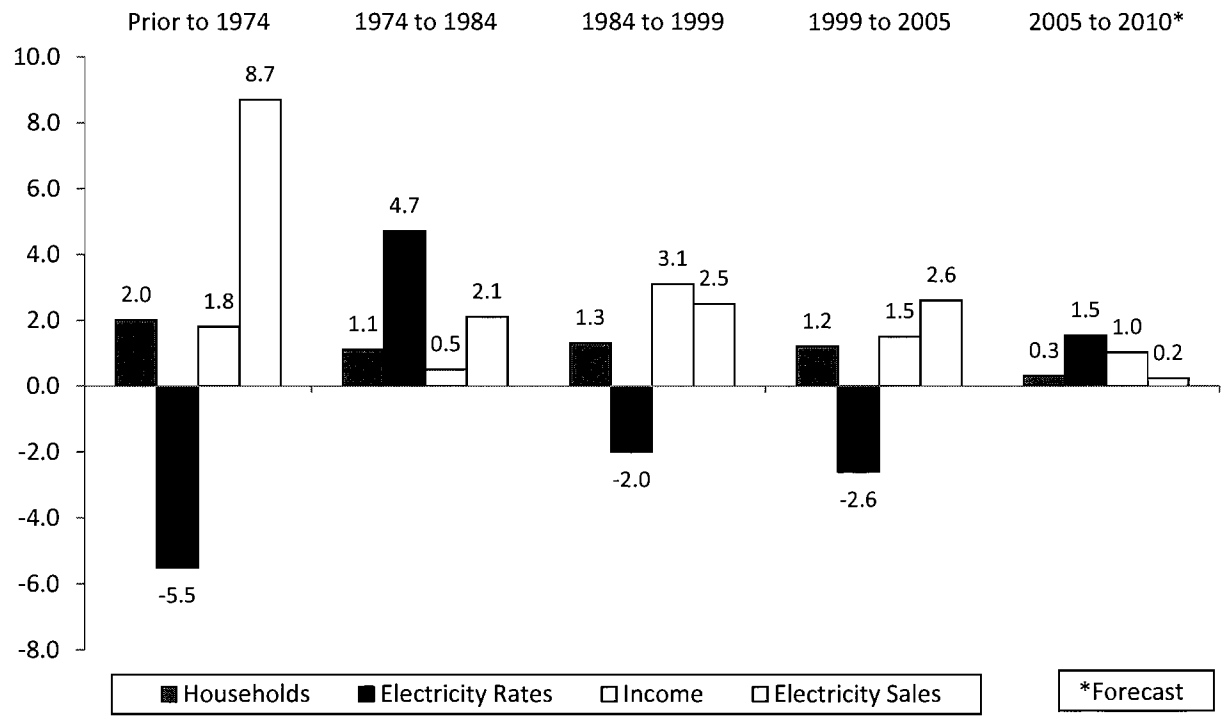
Several market factors contributed to the small difference in sales growth between the post-embargo and more recent period. First and perhaps most importantly, is the difference in the availability and price of natural gas between the two periods. Restrictions on new natural gas hook-ups during the post-embargo period and supply uncertainty caused electricity to gain market share in major

end-use markets previously dominated by natural gas, i.e., space heating and water heating. More recently, plentiful supply and falling natural gas prices through 1999 caused natural gas to recapture market share. Next in importance are equipment efficiency standards and the availability of more efficient appliances. Appliance efficiency improvement standards did not begin until late in the post-embargo era. Lastly, appliance saturations tend to grow more slowly as they approach full market saturation, and the major residential end uses are nearing full saturation.

From 1999 to 2005, residential household growth has decreased slightly to a 1.2 percent annual rate similar to the 1984 to 1999 period, real electric rates have continued to decline, but the growth in personal income, while positive, has slowed markedly. Despite the slow growth in income, electricity sales have continued to grow at roughly the rate observed during the 1984 to 1999 period.

More recently, from 2005 through the SUFG forecast for 2010, the effects of the economic downturn coupled with rising electricity prices result in much lower growth in electricity sales. Household growth slows to less than one-fourth the rate observed over the preceding twenty years, real electricity prices increase at an average annual rate of 1.5 percent reversing the trend of the previous twenty years, and real household income growth is only about two-thirds of that observed in the early 2000s. The net effect of these changes is to cut projected electricity sales growth rate to less than one-tenth of that observed over the previous twenty years to 0.2 percent per year.

Figure 5-1. State Historical Trends in the Residential Sector (Annual Percent Change)



REDMS Model Used In Current Forecast

SUFG chose REDMS as the primary residential sector energy projection model for three reasons which are discussed in the following paragraphs.

First, the SUFG econometric model divides customers into two distinct classes depending upon the space heating fuel employed: electricity and other fuels. Over time the distinction between electric space heating and natural gas (or liquefied petroleum gas) space heating has blurred due to the emergence and acceptance of hybrid systems. Hybrid space heating systems combine an electric air to air heat pump with a natural gas or liquefied petroleum gas (LPG) forced air furnace. During the periods of the heating season with relatively warm outdoor air temperatures the heat pump is more efficient than the furnace and is used as a heat source. As the outdoor air temperature drops the efficiency of the heat pump declines (and operating costs

increase per unit of heat delivered) and a point is eventually reached at which the gas furnace becomes the more cost effective source of heat. The operating cost breakeven point depends upon the efficiencies of the heat pump and the gas furnace as well as the costs of electricity and gas. These systems are being used in both new construction and retrofit situations since the incremental cost of replacing a failed central air conditioning unit with an air to air heat pump is relatively small. Obviously with these hybrid systems the heat pump is used during the cooling season to provide air conditioning.

Second, at least one major Indiana utility no longer offers a specific electric rate schedule to new customers that choose to use electricity as a space heating fuel source. Also, at least one additional Indiana utility offers a restricted electric space heating rate which is dependent upon equipment efficiency criteria.

Third, federal law has mandated lighting efficiency standards which SUFG feels are best modeled in a direct end-use context. The standards call for a 30 percent improvement in lighting efficiency beginning in 2012 with a phased in efficiency improvement of 60 percent by 2020. Lighting represents a little less than 10 percent of residential electric energy use, so a 60 percent efficiency improvement from current use will reduce residential electricity use by nearly 6 percent in 2020 and thereafter.

Econometric methods work reasonably well to capture trends in efficiency over time, but the lighting standards are more aggressive than historical equipment standards in both the level and timing of the mandated efficiency improvements. For this reason SUFG did not feel comfortable relying on the traditional econometric energy model and chose the direct end-use modeling approach rather than make adjustments to the econometric model projections.

Model Description

The residential end-use model REDMS is the residential analogue to CEDMS, the commercial sector end-use model described in the next chapter of this report. For this reason the description of REDMS below is nearly identical to that of CEDMS in the commercial sector chapter.

Figure 5-2 depicts the structure of the residential end-use model. As the figure shows, REDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in the modeling of the residential sector as it is for modeling the commercial sector. REDMS divides residential dwellings among 3 dwelling types. It also divides energy use in each dwelling type among 10 possible end uses, including a miscellaneous or residual use category. For end uses such as space heating, where non-electric fuels compete with electricity, REDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 5-2.) REDMS also divides dwellings among vintages, i.e., the year the dwelling was constructed, and simulates energy use for each vintage and dwelling type.

REDMS projects energy use for each dwelling vintage according to the following equation:

$$Q(T, i, k, l, t) = U(i, k, l, t) * e(i, k, l, t) * a(i, k, l, t) * A(l, t) * d(l, T-t)$$

where

* = multiplication operator;

T = forecast year;

Q = energy demand for fuel i, end use k, dwelling type l and vintage t in the forecast year;

t = dwelling vintage (year);

U = utilization, relative to some base year;

e = energy use index, kWh/year or Btu/year;

a = fraction of dwelling served by fuel i, end use k, and dwelling type l for dwelling additions of vintage t;

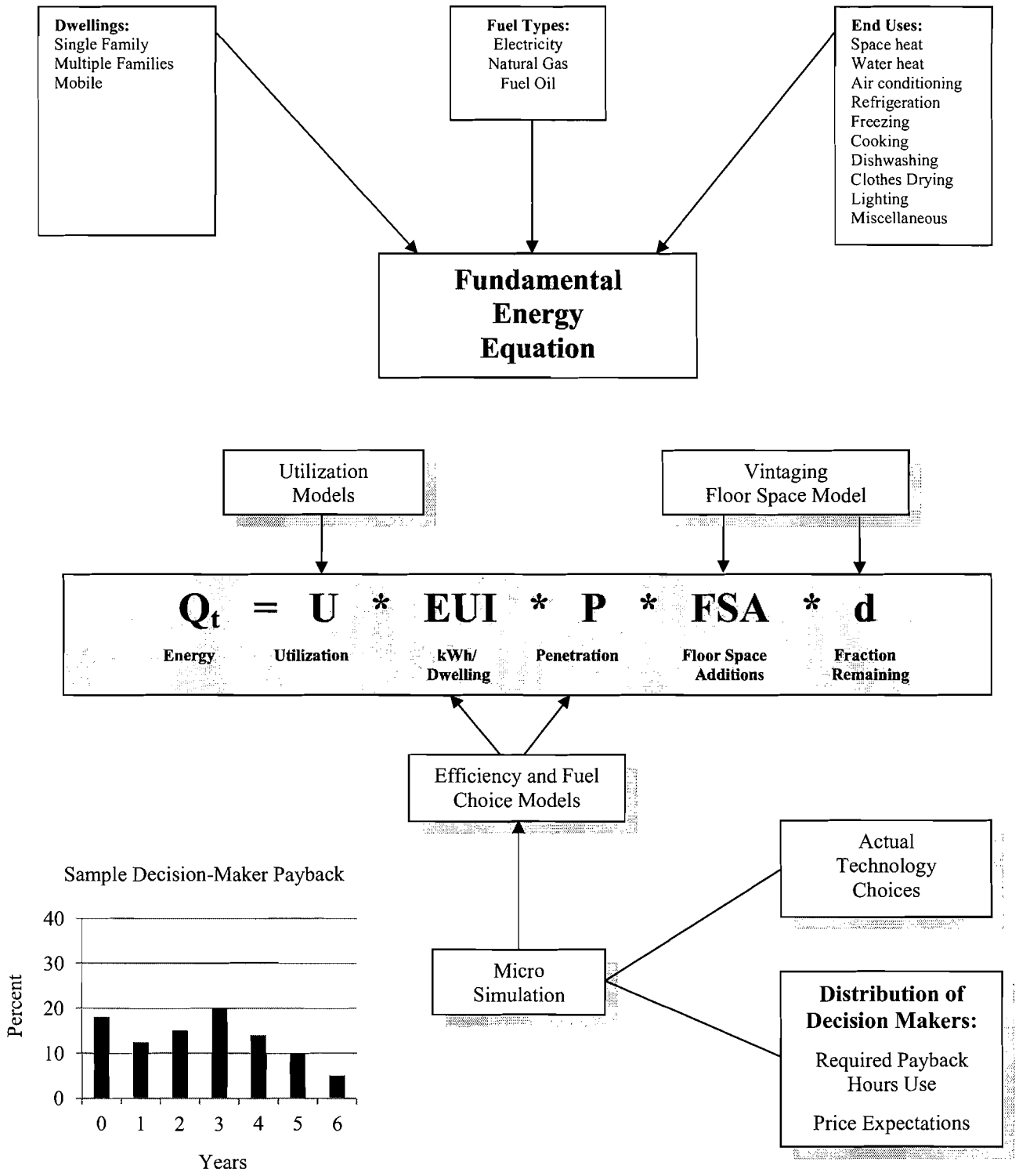
A = dwelling additions by vintage t and dwelling type l; and

d = fraction of dwellings of vintage t still standing in forecast year T.

REDMS' central features are its explicit representation of the joint nature of decisions regarding fuel choice, efficiency choice and the level of end-use service, as well as its explicit representation of costs and energy use characteristics of available end-use technologies in these decisions.

REDMS jointly determines fuel and efficiency choices through a methodology known as discrete choice microsimulation. Essentially, sample decision-makers in the model make choices from a set of discrete equipment options. Each discrete equipment option is characterized by its fuel type, energy use and cost. REDMS uses the discrete technology choice methodology to model equipment choices for all major end-uses.

Figure 5-2. Structure of Residential End-Use Energy Modeling System



Equipment standards are easily incorporated in REDMS' equipment choice sub-models. Besides efficiency and fuel choices, REDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices.

For new equipment installed in the current year, utilization depends on both equipment efficiency and fuel price. For example, a 10 percent improvement in efficiency and a 10 percent increase in fuel prices would have offsetting effects since the total cost of producing the end-use service is unchanged.

Summary of Results

The remainder of this chapter describes SUFG's current residential electricity sales projections. First, the current projection of residential sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current high and low scenario projections. Also, at each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

The major economic drivers in the residential end-use model include dwellings (residential customers) and electricity prices. The sensitivity of the residential electricity use projection to changes in these variables was simulated one at a time by increasing each variable ten percent above a base scenario level and observing the change in electricity use. The results are shown in Table 5-1. Electricity consumption increases substantially due to increases in the number of customers. As expected, electricity rate increases reduce electric consumption. Changes in natural gas prices, fuel oil prices, and personal income do not affect electricity consumption due in part to the structure of the model and in part due to the vendor's implementation of the model.

Competing fuels (gas and oil) could potentially affect electricity use through two mechanisms; retrofits and penetration in dwelling additions. Once an intial space heating (and subsequently water heating) fuel for a new dwelling is chosen retrofits to an alternative fuel are generally precluded due to the cost hurdle of the capital cost of switching fuels. Such a fuel choice switch would require the addition of gas service and delivery, fuel oil storage and delivery, or an electrical service upgrade and wiring upgrades. In the case of dwelling additions the vendor was unable to discern a statistically significant relationship between fuel prices and fuel specific end-use penetrations. During the period used for model calibration 1990-2005, electric space heating penetration was remarkedly consistent at around 20 percent with natural gas and LPG largely capturing the remainder, real electricity prices were virtually constant, real gas and oil prices drifted upward with considerably volatility but did not exhibit any persistent lasting changes in level.

Personal income effects on fuel and efficiency choices are reflected in the decision makers behavior through the micro-simulation modeling. On average, one would expect those decision makers facing active income or financial constraints to be the decision makers with shorter payback intervals and those without such constraints to have longer payback horizons. Also, the vendor was unable to identify a statistical significant relationship between end-use utilization and personal income.

Table 5-1. Residential Model Long-Run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Use
Number of Customers	9.9
Electric Rates	-4.0

Indiana Residential Electricity Sales Projections

Actual sales (GWh), as well as past and current projections, are shown in Table 5-2 and Figure 5-3. The line in the area labeled "History" in the figure are historical consumption. The growth rate for the current base projection of Indiana residential electricity sales is 0.71 percent more than 1.0 percent less than SUFG's 2009 projection of 1.75 percent. The historic and 2011 forecast numbers are provided in the Appendix of this report. Long-term patterns for the entire forecast horizon show that the current projection consistently lies well below both the previous projections. Table 5-3 summarizes SUFG's base projections of residential electricity sales growth since 2007.

Table 5-4 shows the growth rates of the major residential drivers for the current scenarios and the 2009 base case. Household formation is determined by two factors. Demographic projections are the primary determinant, with personal income having a smaller impact. The demographic

projections in all four cases are identical. While there is some small variation in personal income among the cases, they are not sufficiently large as to result in a difference in growth rates within two significant digits.

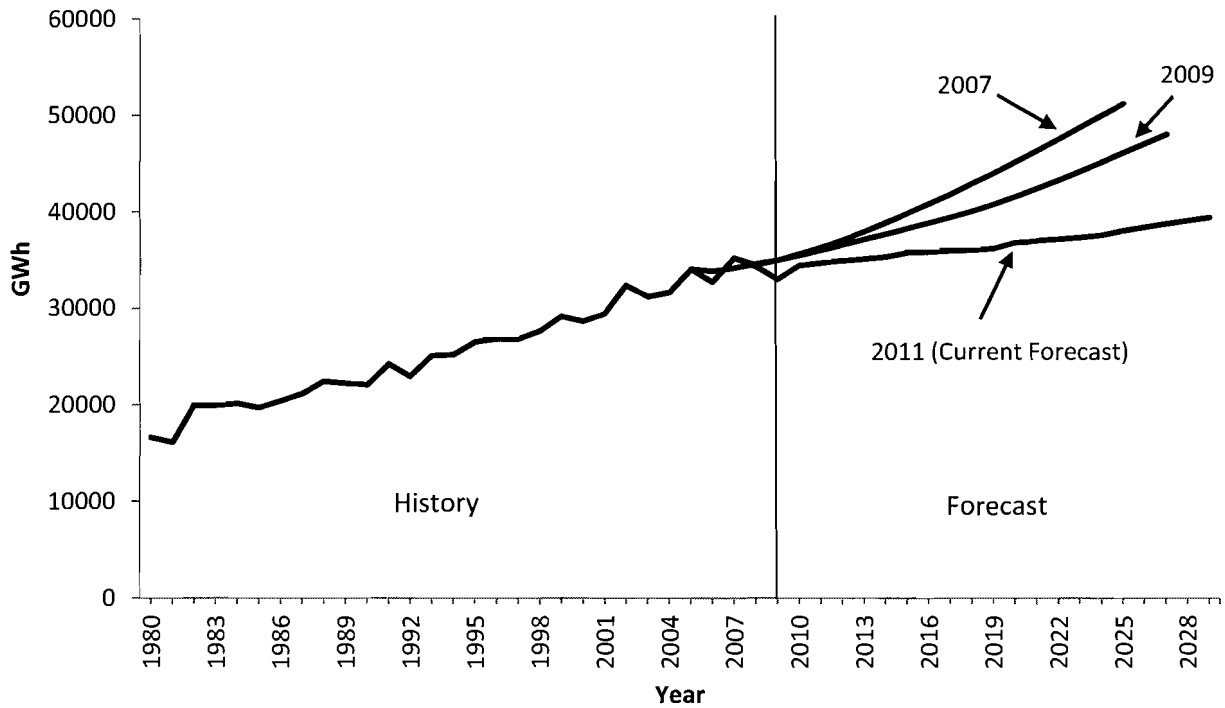
These projections are broken down by the portion of the growth rate attributable to the growth in number of customers and growth in utilization per customer, before and after DSM. As the table shows, more than one half of projected sales growth is attributable to customer growth and the remainder to changes in electric intensity (price and income effects). Much of the residential DSM shifts load from peak usage times to off-peak times and has very little effect on residential electric intensity growth. Overall, residential DSM reduces sales growth by less than 0.1 percent.

As shown in Table 5-5 and Figure 5-4, the growth rates for the high and low residential scenarios are about 0.2 percent higher and 0.1 lower, respectively, than the base scenario. This difference is due primarily to differences in the growth of household income.

Table 5-2. Indiana Residential Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.21	2006-25
2009	1.75	2008-27
2011	0.71	2010-29

Figure 5-3. Indiana Residential Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Table 5-3. History of SUFG Residential Sector Growth Rates (Percent)

Forecast	No. of Customers	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2011 SUFG Base (2010-2029)	1.00	-0.23	0.77	-0.29	0.71
2009 SUFG Base (2008-2027)	1.00	0.83	1.83	0.75	1.75
2007 SUFG Base (2006-2025)	0.94	1.29	2.23	1.27	2.21

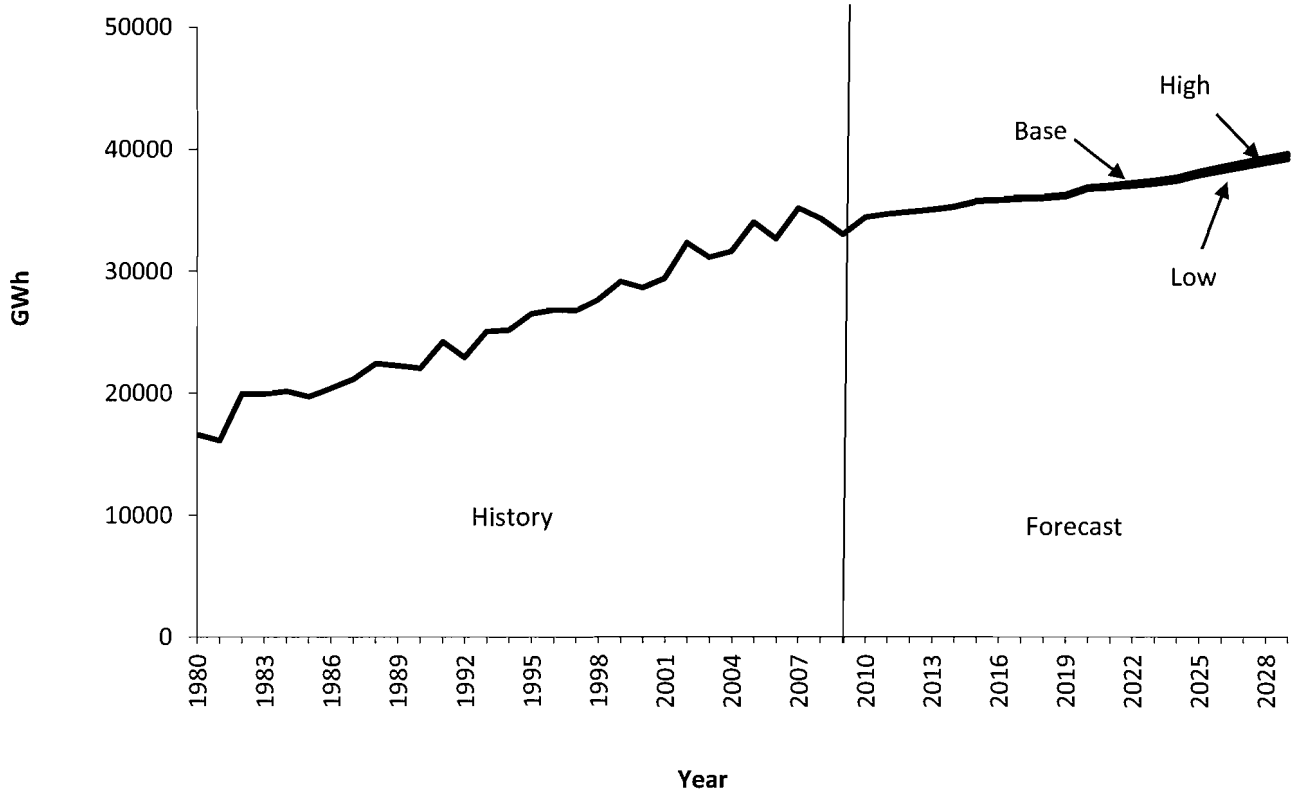
Table 5-4. Residential Model Explanatory Variables - Growth Rates by Forecast (Percent)

Forecast	Current Scenario (2010-2029)			2009 Forecast (2008-2027)
	Base	Low	High	Base
No. of Customers	1.00	1.00	1.00	1.00
Electric Rates	1.08	1.26	0.91	0.66

Table 5-5. Indiana Residential Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates			
Forecast Period	Base	Low	High
2010-29	0.71	0.67	0.74

Figure 5-4. Indiana Residential Electricity Sales by Scenario in GWh



Note: See the Appendix to this report for historical and projected values.

Indiana Residential Electricity Price Projections

Historical values and current projections of residential electricity prices are shown in Figure 5-5, with growth rates provided in Table 5-6. The historic and forecast numbers are provided in the Appendix of this report. In real terms, residential electricity prices declined from the mid-1980s until 2002. Real residential electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real residential electricity prices to rise until 2013 with the need for additional emissions control equipment and then remain relatively constant. SUFG's real price projections for the individual IOUs all follow the same patterns as the state as a whole, but there are variations across the utilities.

Figure 5-5. Indiana Residential Base Real Price Projections (in 2009 Dollars)

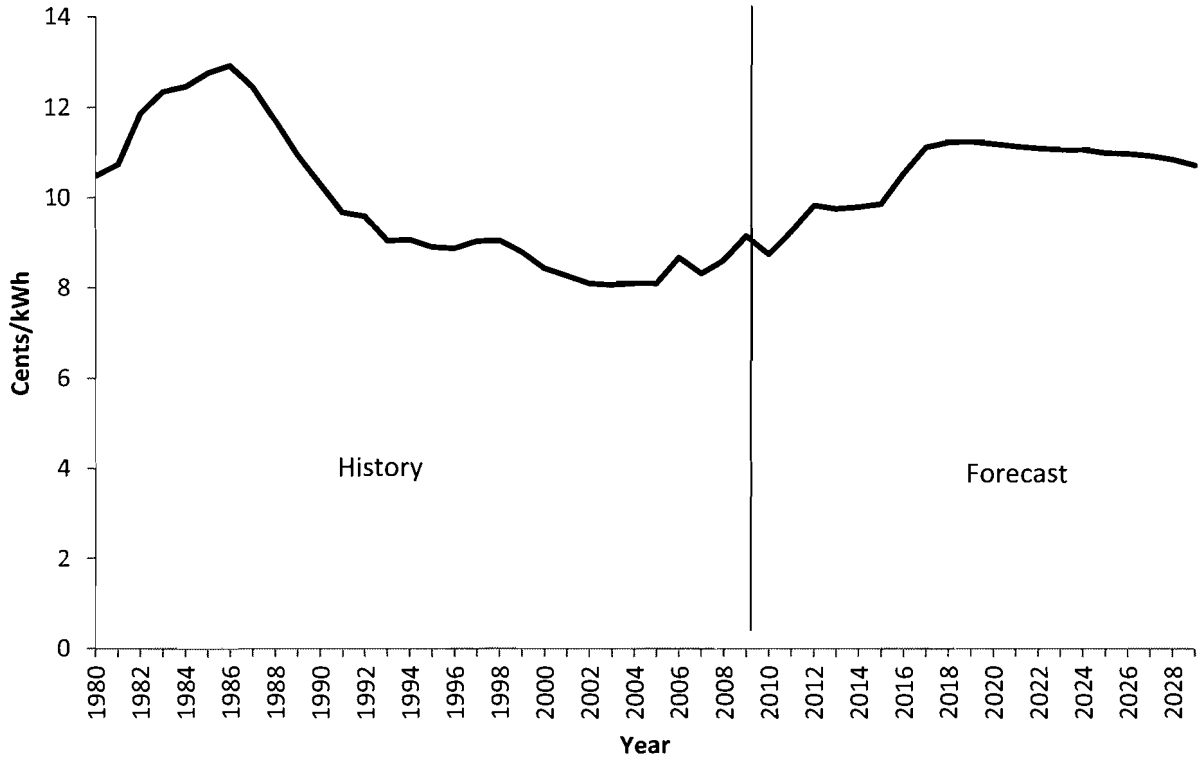


Table 5-6. Indiana Residential Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	4.00
1985-1990	-4.16
1990-1995	-2.88
1995-2000	-1.09
2000-2005	-0.79
2005-2009	3.10
2010-2029	1.08

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 6

Commercial Electricity Sales

Overview

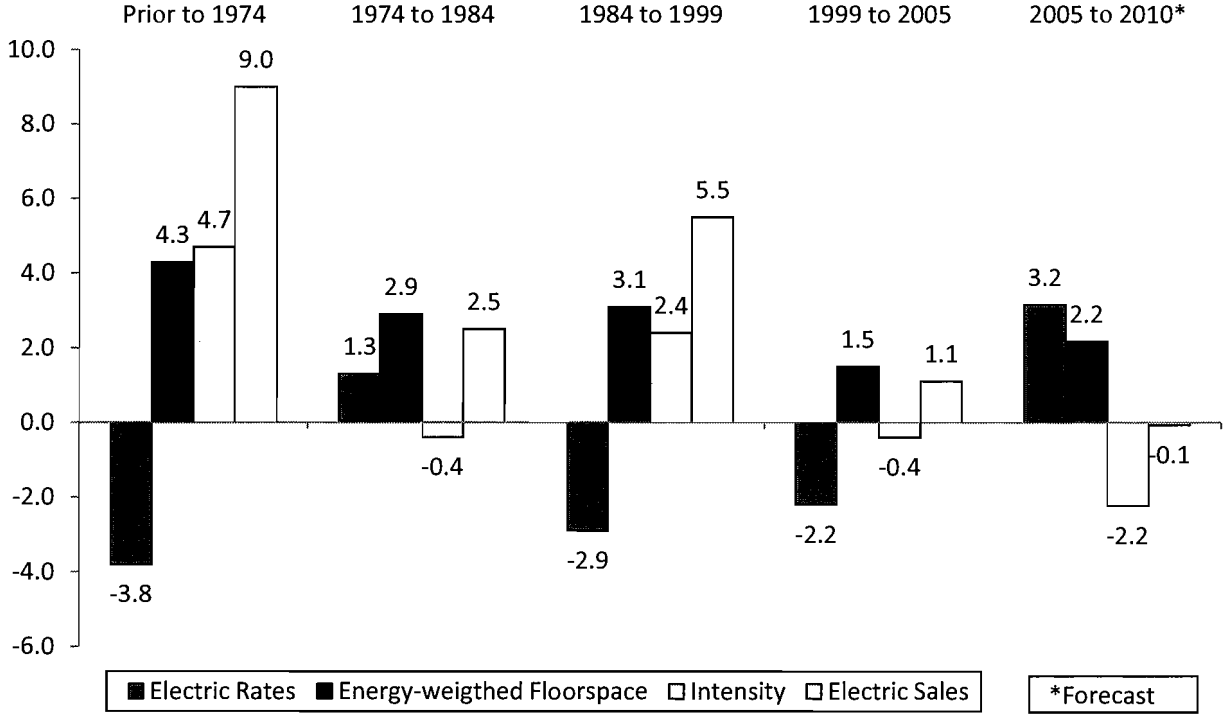
SUFG has two distinct models of commercial electricity sales, econometric and end-use, that have specific strengths and complement each other. SUFG staff developed the econometric model and acquired a proprietary end-use model, Commercial Energy Demand Modeling System (CEDMS). CEDMS is a descendant of the first generation of end-use models developed at ORNL during the late 1970s for the Department of Energy. CEDMS, however, bears little resemblance to its ORNL ancestor. Like the residential sector end-use model REDMS, Jerry Jackson and Associates actively supports CEDMS, and it continues to define the state-of-the-art in commercial sector end-use forecasting models.

For a few years in the mid 1990s, SUFG relied on its own econometric model to project commercial electricity sales. SUFG used the end-use model for general comparison purposes and for its structural detail. CEDMS estimates commercial floor space for building types and estimates energy use for end uses within each building type. SUFG also took advantage of the building type detail in CEDMS to construct the major economic drivers for its econometric model. SUFG then made CEDMS its primary commercial sector forecasting model for several reasons. First, based on experience with the model over several years, SUFG is confident it provides realistic energy projections under a wide range of assumptions. Second, in contrast to the significant differences between the residential end-use and econometric model projections (discussed in Chapter 5), the differences between the commercial end-use and econometric models are small, since both models forecast similar changes in electric intensity. SUFG used a recently upgraded version of CEDMS for this set of projections.

Historical Perspective

Historical trends in commercial sector electricity sales have been distinctly different in each of four recent periods (see Figure 6-1).

Figure 6-1. State Historical Trends in the Commercial Sector (Annual Percent Change)



Changes in electric intensity, expressed as changes in electricity use per square foot (sqft) of energy-weighted floor space, arise from changes in building and equipment efficiencies as well as changes in equipment utilization, end-use saturations and new end uses. Electric intensity increased rapidly during the era of cheap energy (4.7 percent per year) as seen in Figure 6-1 prior to the OPEC oil embargo. This trend was interrupted by the significant upward swing in electricity prices during 1974-84, which resulted in a decrease in energy intensity. As electricity prices fell again during the 1984-99 period, electric intensity rose but at a slower rate (2.4 percent) than that observed during the pre-embargo period. New commercial buildings and energy-using equipment continue to be more energy-efficient than the stock average, but these efficiency improvements are offset by an increased demand for energy services.

Over the 1999 to 2005 timeframe, a decrease in economic activity retarded growth in the stock of commercial floor space, led to negative growth in intensity of electricity use, and slowed growth in electricity sales despite continued declines in real electricity prices. Recently the current recession coupled with increasing real electricity prices has accelerated these trends, with the notable exception of the stock of commercial floor space. For 2005 through 2010 real electricity prices have risen, commercial floor space grew at a slightly faster rate than that observed during the previous few years, with intensity of electricity use continuing to decline, and commercial sector electricity use stagnating.

Model Description

Figure 6-2 depicts the structure of the commercial end-use model. As the figure shows, CEDMS uses a disaggregated capital stock approach to forecast energy use. Energy use is viewed as a derived demand in which electricity and other fuels are inputs, along with energy using equipment and building envelopes, in the production of end-use services.

The disaggregation of energy demand is as important in the modeling of the commercial sector as it is for modeling the residential sector. CEDMS categorizes commercial buildings among 21 building types. It also divides energy use in each building type among 9 possible end uses, including an other or residual use category. For end uses such as space heating, where non-electric fuels compete with electricity, CEDMS further disaggregates energy use among fuel types. (This disaggregation scheme is illustrated at the top of Figure 6-2.) CEDMS also divides buildings among vintages, i.e., the year the building was constructed, and simulates energy use for each vintage and building type.

CEDMS projects energy use for each building vintage according to the following equation:

$$Q(T, i, k, l, t) = U(i, k, l, t) * e(i, k, l, t) * a(i, k, l, t) * A(l, t) * d(l, T-t)$$

where

* = multiplication operator;

T = forecast year;

Q = energy demand for fuel i, end use k, building type l and vintage t in the forecast year;

t = building vintage (year);

U = utilization, relative to some base year;

e = energy use index, kWh/sqft/year or Btu/sqft/year;

a = fraction of floor space served by fuel i, end use k, and building type l for floor space additions of vintage t;

A = floor space additions by vintage t and building type l; and

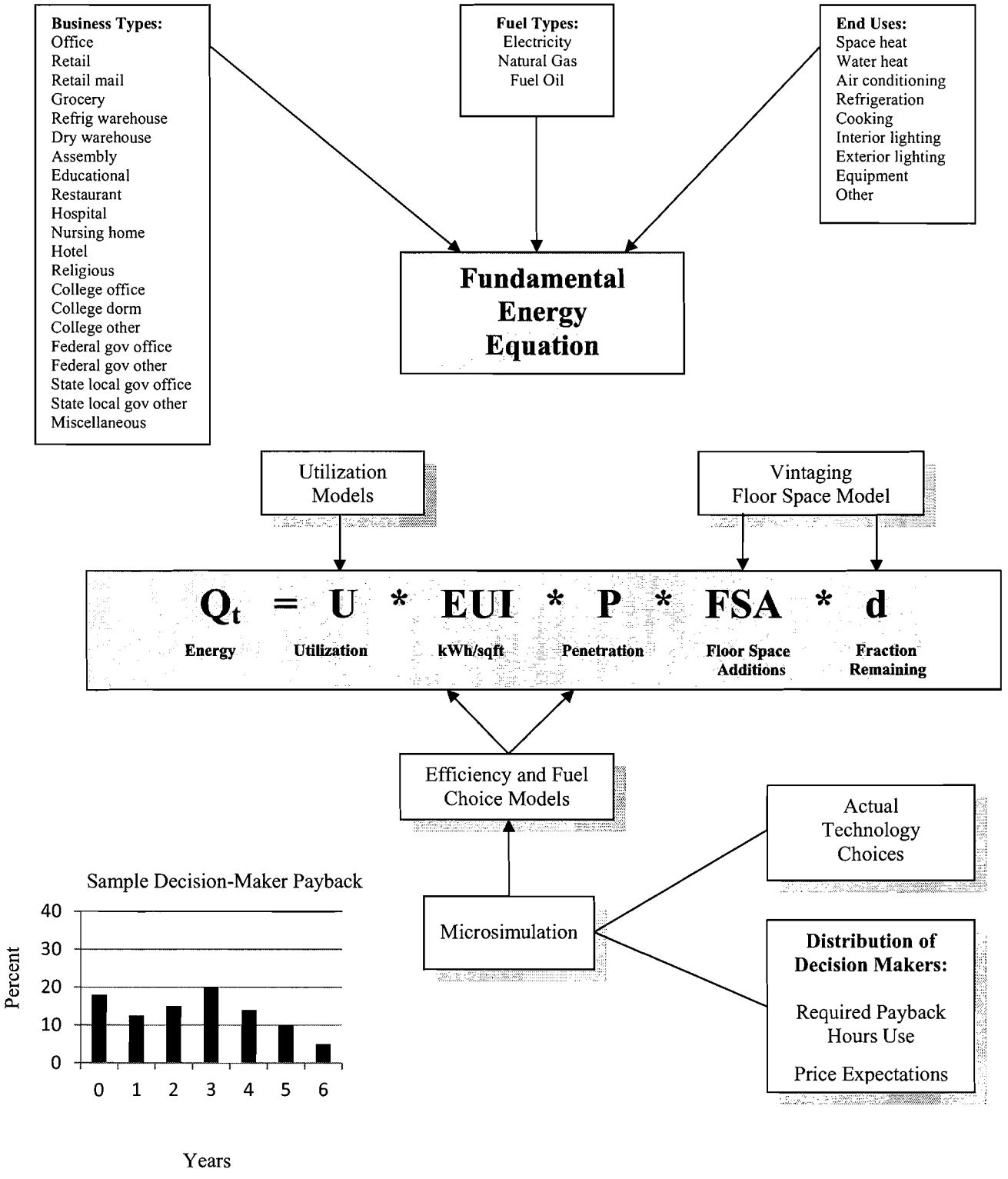
d = fraction of floor space of vintage t still standing in forecast year T.

CEDMS' central features are its explicit representation of the joint nature of decisions regarding fuel choice, efficiency choice and the level of end-use service, as well as its explicit representation of costs and energy use characteristics of available end-use technologies in these decisions.

CEDMS jointly determines fuel and efficiency choices through a methodology known as discrete choice microsimulation. Essentially, sample firms in the model make choices from a set of discrete heating, ventilation and air conditioning (HVAC) equipment options. Each discrete equipment option is characterized by its fuel type, energy use and cost. CEDMS uses the discrete technology choice methodology to model equipment choices for HVAC, water heating, refrigeration and lighting. HVAC and lighting account for 80 percent of total electricity use by commercial firms.

Equipment standards are easily incorporated in CEDMS' equipment choice sub-models. In addition to efficiency and fuel choices, CEDMS also models changes in equipment utilization, or intensity of use. For equipment that has not been added or replaced in the previous year, changes in equipment utilization are modeled using fuel-specific, short-run price elasticities and changes in fuel prices.

Figure 6-2. Structure of Commercial End-Use Energy Modeling System



For new equipment installed in the current year, utilization depends on both equipment efficiency and fuel price. For example, a 10 percent improvement in efficiency and a 10 percent increase in fuel prices would have offsetting effects since the total cost of producing the end-use service is unchanged.

Summary of Results

The remainder of this chapter describes SUFG's commercial electricity sales projections. First, the current base projection of commercial sales growth is explained in terms of the model sensitivities and changes in the major explanatory variables. Next, the current base projection is compared to past base projections and then to the current low and high scenario projections. At each step, significant differences in the projections are explained in terms of the model sensitivities and changes in the major explanatory variables.

Model Sensitivities

The major economic drivers to CEDMS include commercial floor space by building type (driven by non-manufacturing employment and population) and electricity prices. The sensitivity of the electricity sales projection to changes in these variables was simulated one at a time by increasing each variable ten percent above the base scenario levels and observing the change in commercial electricity use. The results are shown in Table 6-1. An interesting result is that changes in commercial floor space lead to more than proportional changes in electricity use. The reason for this is that new buildings tend to have greater saturations of electric end uses, even though they are more efficient.

Table 6-1. Commercial Model Long-run Sensitivities

10 Percent Increase In	Causes This Percent Change in Electric Sales
Buildings	10.5
Electric Rates	-2.6

Indiana Commercial Electricity Sales Projections

Historical data as well as past and current projections are illustrated in Table 6-2 and Figure 6-3. As can be seen, the current base projection of Indiana commercial electricity sales growth is 0.89 percent. The historical and 2011 forecast values are provided in the Appendix of this report. The growth rates for the major explanatory variables are shown in Table 6-3. Table 6-4 summarizes SUFG's base projections of commercial electricity sales growth for the last three SUFG forecasts.

Floor space growth is partially offset by decreases in utilization. Utilization, the amount of energy used per unit of floor space, decreases because of increasing prices and the implementation of new efficiency standards. Incremental DSM programs have a small effect on electricity sales.

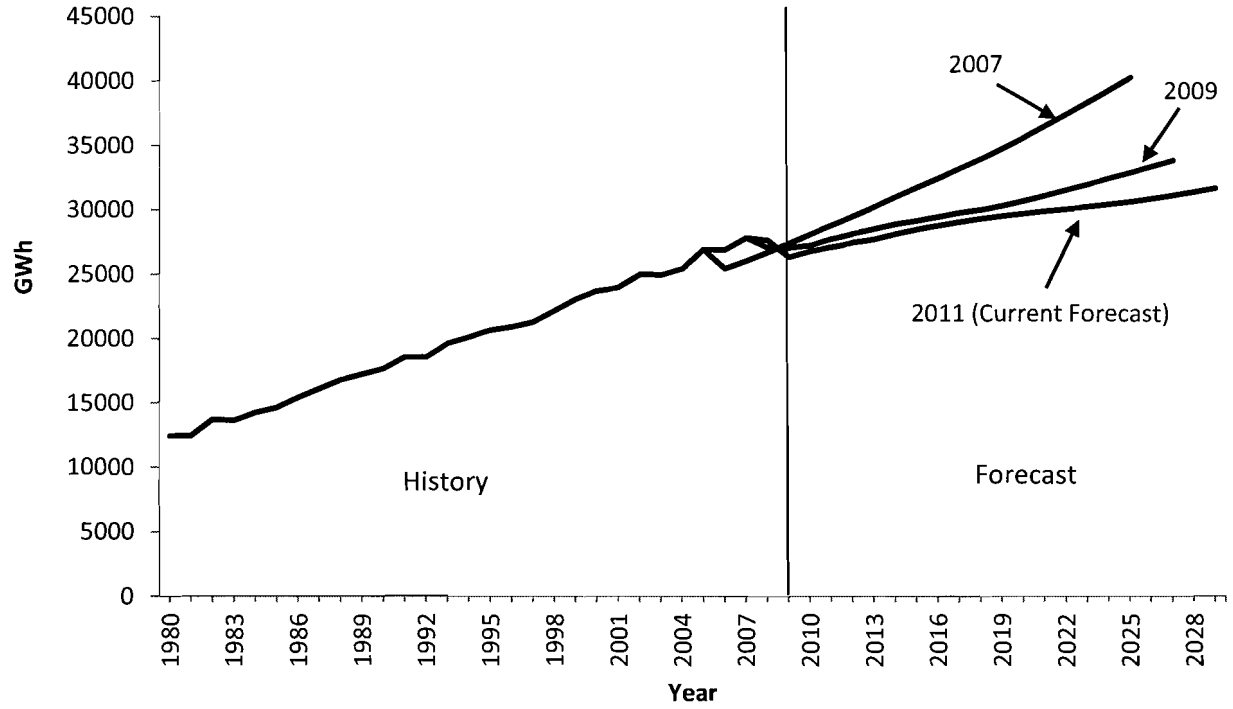
As shown in Figure 6-3, the current projection lies well below the 2007 forecast. The current projection starts out at about the same level but grows at a lower rate. The slower growth rate is due to a combination of the macroeconomic projections and higher projected commercial sector electricity prices.

As shown in Table 6-5 and Figure 6-4, the growth rates for the low and high scenarios are about 0.09 percent lower and 0.08 percent higher than the base scenario, respectively. These differences are almost entirely due to a difference in floor space growth.

Table 6-2. Indiana Commercial Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.46	2006-25
2009	1.18	2008-27
2011	0.89	2010-29

Figure 6-3. Indiana Commercial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

Table 6-3. Commercial Model – Growth Rates (Percent) for Selected Variables (2011 SUFG Scenarios and 2009 Base Forecast)

Forecast	Current Scenario (2010-2029)			2009 Forecast (2008-2027)
	Base	Low	High	Base
Electric Rates	0.87	1.03	0.74	0.73
Natural Gas Price	0.77	0.77	0.77	0.29
Energy-weighted Floor Space	1.18	1.10	1.26	1.21

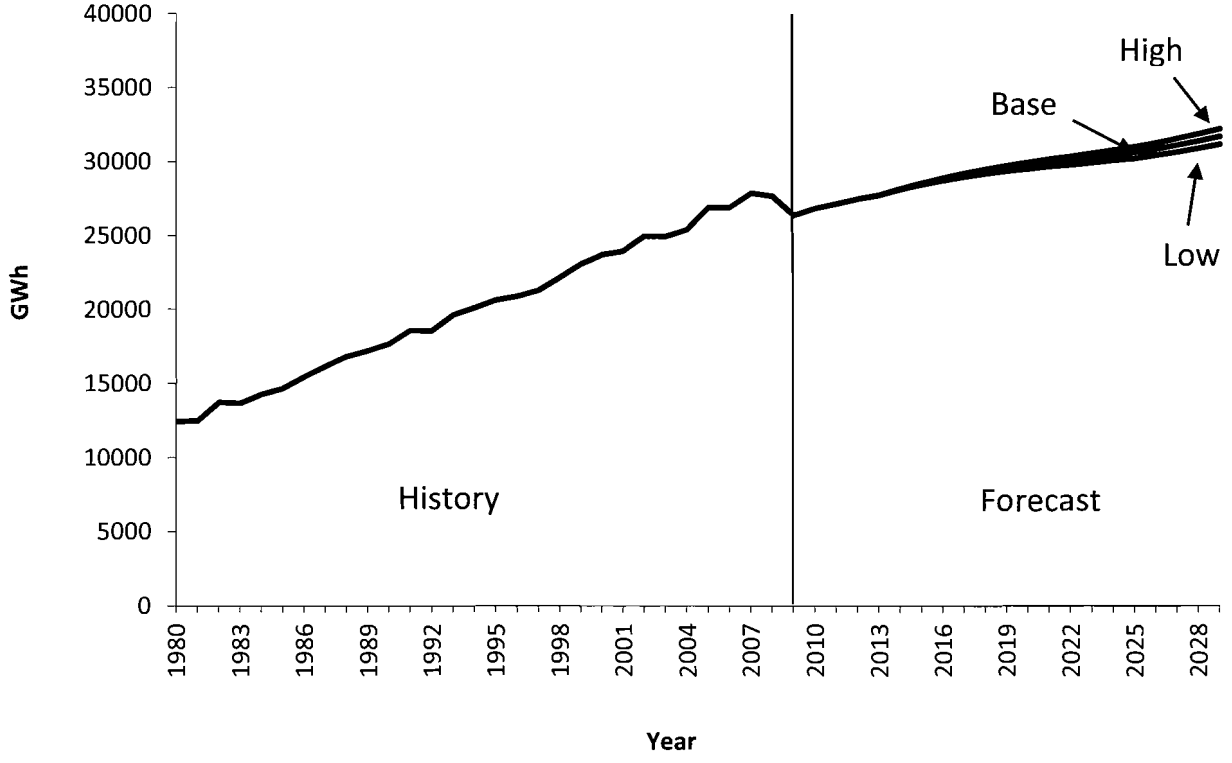
Table 6-4. History of SUFG Commercial Sector Growth Rates (Percent)

Forecast	Electric Energy-weighted Floor Space	Prior to DSM		After DSM	
		Utilization	Sales Growth	Utilization	Sales Growth
2011 SUFG Base (2010-2029)	2.08	-1.13	0.95	-1.19	0.89
2009 SUFG Base (2008-2027)	1.21	0.02	1.23	-0.03	1.18
2007 SUFG Base (2006-2025)	2.11	0.35	2.46	0.35	2.46

Table 6-5. Indiana Commercial Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2010-29	0.89	0.80	0.97

Figure 6-4. Indiana Commercial Electricity Sales by Scenario in GWh



Note: See the Appendix to this report for historical and projected values.

Indiana Commercial Electricity Price Projections

Historical values and current projections of commercial electricity prices are shown in Figure 6-5, with growth rates provided in Table 6-6. The historical and forecast numbers are provided in the Appendix of this report. In real terms, commercial electricity prices declined from the mid-1980s until 2002. Real commercial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real commercial electricity prices to rise until 2013 with the need for additional emissions control equipment and then remain relatively constant. SUFG's real price projections for the individual IOUs all follow the same pattern as the state as a whole, but there are variations across the utilities.

Figure 6-5. Indiana Commercial Base Real Price Projections (in 2009 Dollars)

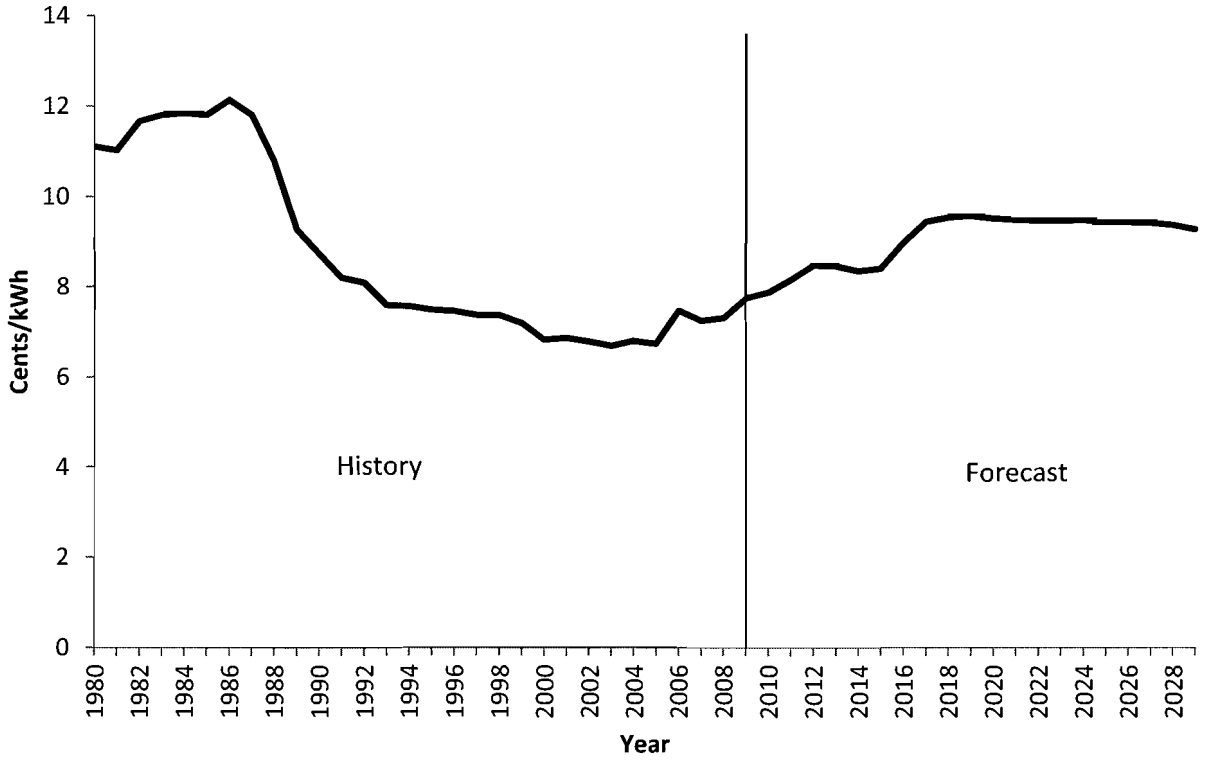


Table 6-6. Indiana Commercial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**%**
1980-1985	1.23
1985-1990	-5.88
1990-1995	-2.98
1995-2000	-1.85
2000-2005	-0.26
2005-2009	3.51
2010-2029	0.87

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 7

Industrial Electricity Sales

Overview

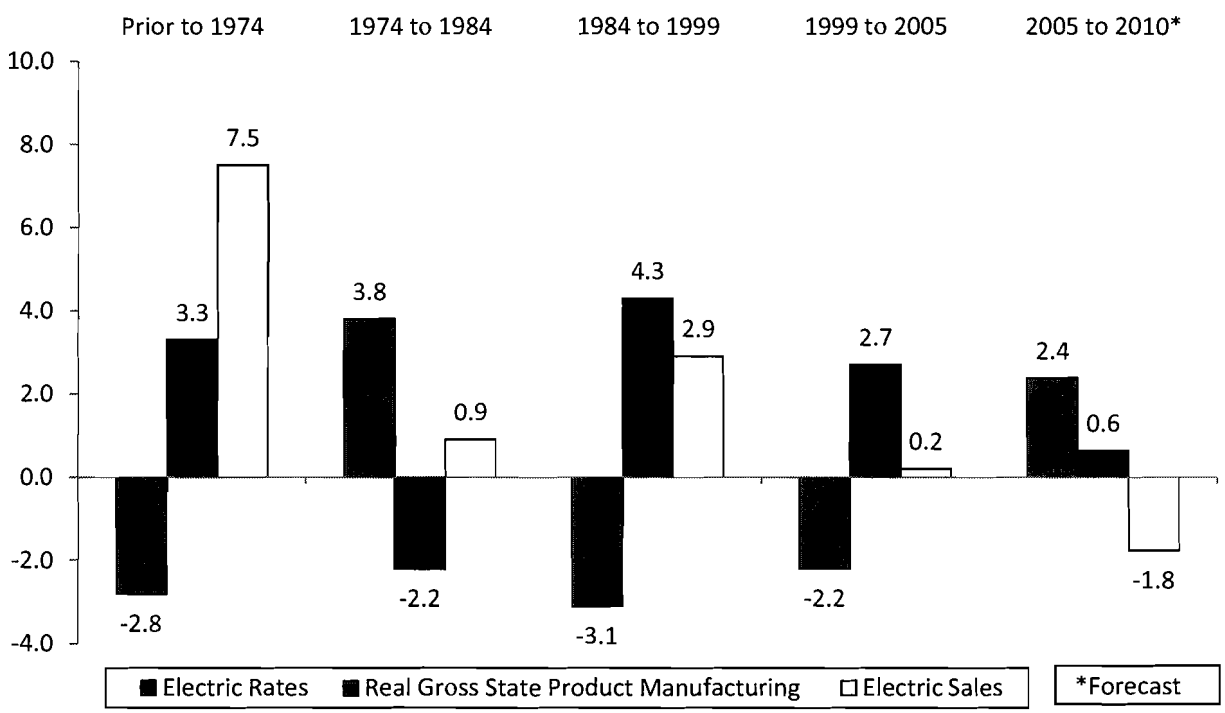
SUFG currently uses several models to analyze and forecast electricity use in the industrial sector. The primary forecasting model is INDEED, an econometric model developed by the Electric Power Research Institute (EPRI), which is used to model the electricity use of 15 major industry groupings in the state. Additionally, SUFG has used in various forecasts a highly detailed process model of the iron and steel industry, scenario-based models of the aluminum and foundries components of the primary metals industry, and an industrial motor drive model to evaluate and forecast the effect of motor technologies and standards.

The econometric model is calibrated at the statewide level of electricity purchases from data on cost shares obtained from the U.S. Department of Commerce Annual Survey of Manufacturers. SUFG has been using INDEED since 1992 to project individual industrial electricity sales for the 15 industries within each of the five IOUs. There are many econometric formulations that can be used to forecast industrial electricity use, which range from single equation factor demand models and fuel share models to "KLEM" models (KLEM denotes capital, labor, energy and materials). INDEED is a KLEM model. A KLEM model is based on the assumption that firms act as though they are minimizing costs to produce given levels of output. Thus, a KLEM model projects the changes in the quantity of each input, which result from changes in input prices and levels of output under the cost minimization assumption. For each of the 15 industry groups, INDEED projects the quantity consumed of eight inputs: capital, labor, electricity, natural gas, distillate and residual oil, coal and materials.

Historical Perspective

SUFG distinguishes five recent periods of distinctly different economic activity and growth — the decade prior to the oil embargo of 1974, 1974-1984, 1984-1999, the more recent period, 1999-2005 and the current period, 2005-2010. The 2005-2010 period includes data from both historical and projected years. Figure 7-1 shows state growth rates for real manufacturing product, real electric rates and electric energy sales for the four periods.

Figure 7-1. State Historical Trends in the Industrial Sector (Annual Percent Change)



During the decade prior to the OPEC oil embargo, industrial electricity sales increased 7.5 percent annually. In Indiana as elsewhere, sales growth was driven by the combined economic stimuli of falling electricity prices (2.8 percent per year in real terms) and growing manufacturing output (3.3 percent per year). During the decade following 1974, sales growth slowed as real electricity prices increased at an average rate of 3.8 percent per year and the state's manufacturing output declined at a rate of 2.2 percent per year. This turnaround in economic conditions and electricity prices resulted in a dramatic decline in the growth of industrial electricity sales from 7.5 percent per year prior to 1974 to 0.9 percent per year in the decade that followed. The fact that electricity sales increased at all is most likely attributable to increases in fossil fuel prices that occurred during the "energy crisis" of 1974-84. The ensuing period, 1984-1999, experienced another dramatic turnaround. The growth rate of industrial output once again became positive, and was substantially above the rate observed prior to 1974. Real electricity prices in Indiana continued to decline in the industrial sector. These conditions caused electricity sales growth to average 2.9 percent per year during these 15 years.

The effect of the economic slowdown from 1999 to 2005 is particularly pronounced in the industrial sector. During this period, real industrial electricity prices declined, but this decline was partially offset by a moderate growth in manufacturing output, resulting in stagnant growth in industrial electricity use. Since 2005 real industrial electricity prices have increased, real growth in manufacturing output has declined, and overall growth in industrial electricity has turned negative. Unlike the residential (Chapter 5) and commercial (Chapter 6) sectors, where decreased economic activity since 1999 has resulted in slower but positive growth in electricity use, industrial electricity use has declined; however, manufacturing sector electricity use is still expected to increase over the forecast horizon.

The Econometric Model

SUFG's primary industrial-sector forecasting model, INDEED, consists of a set of econometric models for each of Indiana's major industries listed in Table 7-1. The general structure of the models is illustrated in Figure 7-2.

Each model is driven by projections of selected industrial GSP over the forecast horizon provided by CEMR. Each industry's share of GSP is given in the first column of Table 7-1. Six-tenths of state GSP is accounted for by the following industries: primary metals, 5 percent; fabricated metals, 5 percent; industrial machinery and equipment, 8 percent; chemicals, 15 percent; transportation equipment, 21 percent; and electronic and electric equipment, 7 percent.

The share of total electricity consumed by each industry is shown in the second column of Table 7-1. Both the chemical and primary metals industries are very electric intensive industries. Combined, they account for nearly one-half of total industrial state electricity use. Column three gives the current base output projections for the major industries obtained from the most recent CEMR forecast. As explained in Chapter 4, CEMR projections are developed using econometric models of the U.S. and Indiana economies. Manufacturing sector GSP projections are obtained by multiplying sector employment projections by a projection of GSP per employee, a measure of labor productivity.

This is the fourth SUFG forecast developed since CEMR switched from the SIC to the newer NAICS (North American Industry Classification System) for categorization of industrial economic activity. Generally, the NAICS is more detailed than the SIC system. Since SUFG is still using the SIC system, SUFG maps industrial economic activity projections from the NAICS measures used by CEMR to the older SIC measures used in SUFG's models. This process was relatively straightforward with the exception of SIC 28, chemical manufacturing. In SIC 28, chemical manufacturing, SUFG used the CEMR GSP growth projections for the manufacturing sector as a whole. This was necessary because CEMR's projections did not specifically include chemical manufacturing, a large purchaser of electricity in Indiana.

Each industrial sector econometric model converts output by forecasting the total cost of producing the given output and the cost shares for each major input, i.e., capital, labor, electricity, gas, oil, coal and materials. The quantity of electricity is determined given the expenditure of electricity for each industry and its price.

As described earlier in this chapter, INDEED captures the competition between the various inputs for their share of the cost of production by assuming firms seek the mix of inputs that minimize the production cost for a given level of output. Unit costs of natural gas, oil, coal, capital, labor and materials are inputs to the SUFG system, while the cost per kWh of electricity is determined by the SUFG modeling system. For fuel prices SUFG uses the current EIA forecast, which assumes that real natural gas prices in the industrial sector "spiked" in 2008, then will decline at about 10.0 percent per year for the next five years and increase at a rate of about 1.8 percent per year thereafter. Distillate fuel prices are assumed to follow a similar pattern, with a maximum real price in 2008 followed by

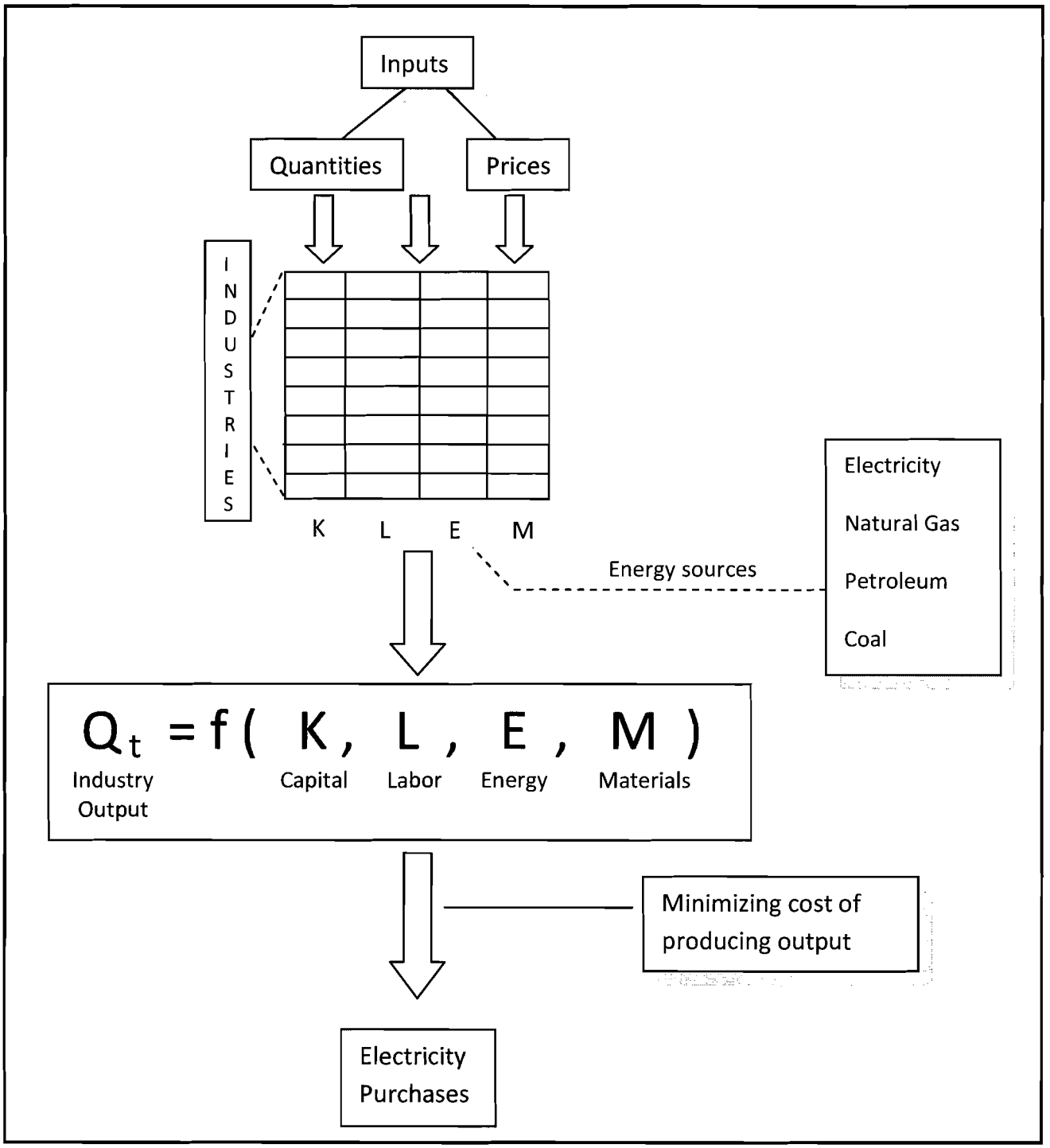
five years of declines at 4.0 percent per year and growing at about the same rate as natural gas (1.9 percent per year) in the later years. Unit costs for capital, labor and materials are consistent with the assumptions contained in the CEMR forecast of Indiana output growth. The changes in electricity intensities, expressed as a percent change in kWh per dollar of GSP, are shown in column five of Table 7-1. With all but one (primary metals) of the intensities expected to decrease, industry-wide electricity intensity is expected to decline modestly over the forecast horizon.

The last column of Table 7-1 contains the projected annual percent increase in electricity sales by major industry. This projected increase is the sum of changes in GSP and kWh/GSP for each industry. Average industrial electricity use across all sectors in the base scenario is expected to increase at an average of 2.16 percent per year, prior to DSM, over the forecast horizon.

Table 7-1. Selected Statistics for Indiana's Industrial Sector (Prior to DSM) (Percent)

SIC	Name	Current Share of GSP	Current Share of Electricity Sales	Current Intensity	Forecast Growth in GSP Originating by Sector	Forecast Growth in Electricity by Intensity by Sector	Forecast Growth in Electricity Sales by Sector
20	Food & Kindred Products	4.47	6.82	0.58	2.84	-1.78	1.06
24	Lumber & Wood Products	2.48	0.69	0.10	2.84	-1.52	1.31
25	Furniture & Fixtures	4.52	0.36	0.03	2.81	-1.17	1.64
26	Paper & Allied Products	1.72	2.76	0.61	2.84	-1.80	1.04
27	Printing & Publishing	3.25	1.34	0.16	2.84	-1.76	1.07
28	Chemicals & Allied Products	15.50	18.95	0.46	2.84	-1.19	1.65
30	Rubber & Misc. Plastic Products	2.88	6.24	0.82	3.42	-1.40	2.03
32	Stone, Clay, & Glass Products	4.58	5.50	0.45	2.81	-1.52	1.29
33	Primary Metal Products	5.23	30.10	2.18	2.35	0.31	2.66
34	Fabricated Metal Products	4.81	5.03	0.40	4.28	-1.49	2.78
35	Industrial Machinery & Equipment	7.81	4.28	0.21	4.53	-1.69	2.83
36	Electronic & Electric Equipment	6.64	5.24	0.30	2.49	-1.75	0.74
37	Transportation Equipment	21.42	8.20	0.14	6.12	-2.15	3.97
38	Instruments And Related Products	6.15	1.08	0.07	2.81	-1.19	1.62
39	Miscellaneous Manufacturing	3.32	0.59	0.07	2.81	-3.87	-1.06
Total	Manufacturing	100.00	100.00	0.38	3.95	-1.79	2.16

Figure 7-2. Structure of Industrial Energy Modeling System



Summary of Results

Model Sensitivities

Table 7-2 shows the impact of a 10 percent increase in each of the model inputs on all industrial electricity consumption in the econometric model. Electricity sales (GWh) are most sensitive to changes in output and electric rates, somewhat sensitive to changes in gas and oil prices, and insensitive to changes in assumed coal prices. Other major variables affecting industrial electricity use include the prices of materials, capital and labor. The model's sensitivities were determined by increasing each variable ten percent above the base scenario levels and observing the percent change in forecast industrial electricity use after 10 years.

Table 7-2. Industrial Model Long-run Sensitivities

A 10 Percent Increase In	Causes This Percent Change in Electric Sales
Real Manufacturing Product	10.0
Electric Rates	-4.8
Natural Gas Price	1.4
Oil Prices	0.9
Coal Prices	0.2

Indiana Industrial Energy Projections: Current and Past

Past and current projections for industrial energy sales as well as overall annual average growth rates for the current and past forecasts are shown in Table 7-3 and Figure 7-3. The area labeled as "History" in the figure indicates historical consumption. Historical and forecast values are provided in the Appendix of this report.

The impact of industrial sector DSM programs on growth rates for the 2007, 2009, and current forecasts is displayed in Table 7-4. The table also disaggregates the impact on energy growth of output, changes in the mix of output and electricity intensity. Like the residential and commercial sectors, industrial sector DSM programs have a modest impact on industrial sector electricity purchases. The effect of earlier conservation activities are embedded in the historical data and SUFG's projections.

The current forecast projects that industrial sector electricity sales will grow from the 2009 level of approximately 35,000 GWh to over 54,000 GWh by 2029. This growth rate of 2.11 percent per year is substantially higher than both the 0.89 percent rate projected for the commercial sector and the 0.71 percent rate projected for the residential sector. As shown in Figure 7-3, the current forecast lies below those of the 2009 and 2007 forecasts throughout the forecast horizon. Like the other sectors, rising real electricity prices coupled with a weak macroeconomic outlook result in a more conservative forecast of electricity use.

Indiana Industrial Energy Projections: SUFG Scenarios

Table 7-5 and Figure 7-4 shows how industrial requirements differ by scenario. Industrial sales, in the high scenario, are expected to increase to about 62,000 GWh by 2029, over 14 percent higher than the base projection. In the low scenario, industrial sales grow more slowly, which results in 47,500 GWh sales by 2029, more than 12 percent below the base scenario.

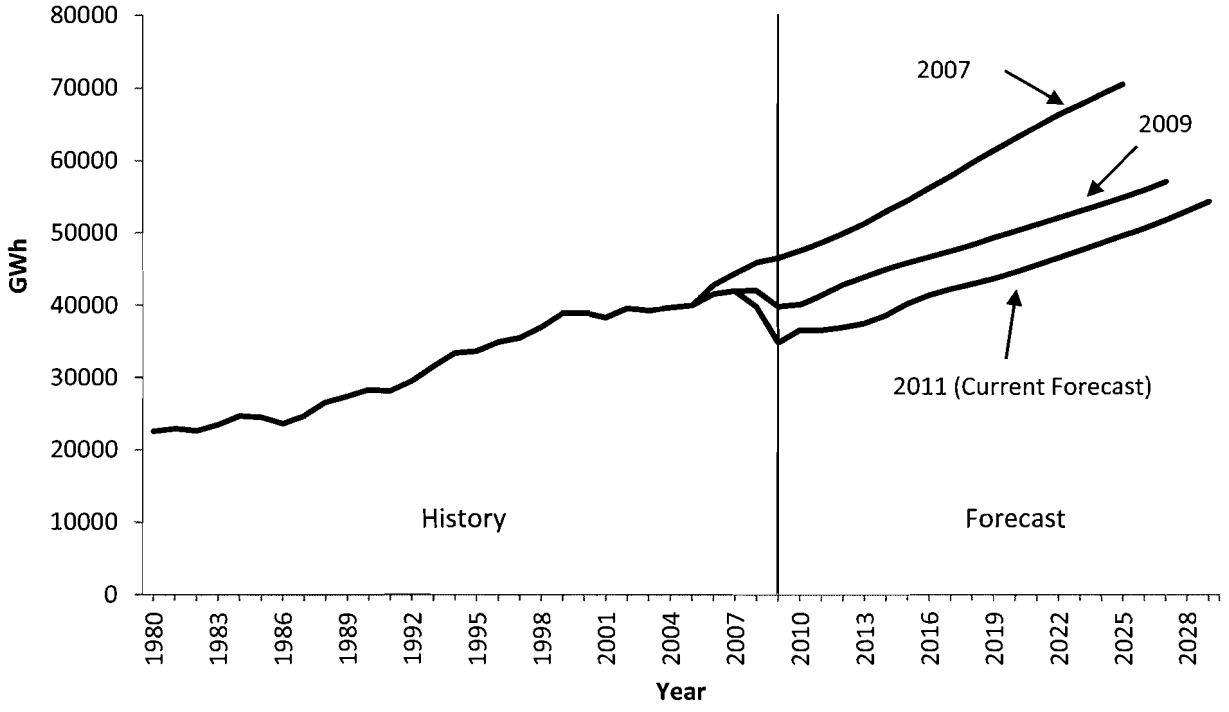
The wide range of forecast sales is caused primarily by the equally wide range of the trajectories of industrial output contained in the CEMR low and high scenarios for the state. In the base scenario GSP in the industrial sector grows 3.95 percent per year during the forecast period. That rate is 4.63 percent in the high scenario and 3.27 percent in the low scenario. This reflects the uncertainty regarding Indiana's industrial future contained in these forecasts.

The high and low scenarios reflect optimistic and pessimistic views, respectively, regarding the ability of Indiana's industries to compete with producers from other states.

Table 7-3. Indiana Industrial Electricity Sales Average Compound Growth Rates (Percent)

Average Compound Growth Rates (ACGR)		
Forecast	**ACGR**	**Time Period**
2007	2.67	2006-25
2009	1.63	2008-27
2011	2.11	2010-29

Figure 7-3. Indiana Industrial Electricity Sales in GWh (Historical, Current, and Previous Forecasts)



Note: See the Appendix to this report for historical and projected values.

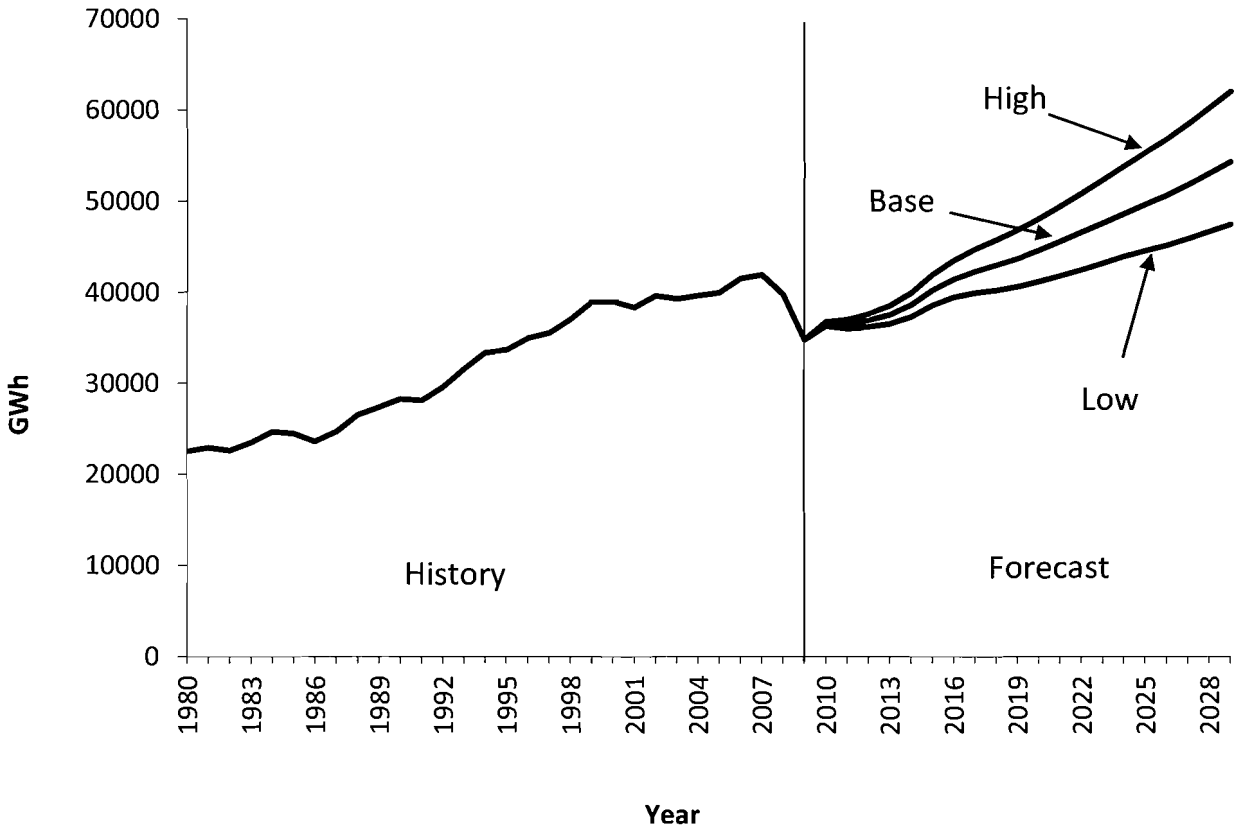
Table 7-4. History of SUFG Industrial Sector Growth Rates (Percent)

Forecast	Output	Mix Effects	Electric Energy-weighted Output	Prior to DSM		After DSM	
				Intensity	Sales Growth	Intensity	Sales Growth
2011 SUFG Base (2010-2029)	3.95	-1.11	2.84	-0.68	2.16	-0.68	2.11
2009 SUFG Base (2008-2027)	2.82	-0.56	2.26	-0.63	1.63	-0.63	1.63
2007 SUFG Base (2006-2025)	3.48	-0.39	3.09	-0.42	2.67	-0.42	2.67

Table 7-5. Indiana Industrial Electricity Sales Average Compound Growth Rates by Scenario (Percent)

Average Compound Growth Rates			
Forecast Period	**Base**	**Low**	**High**
2010-29	2.11	1.42	2.79

Figure 7-4. Indiana Industrial Electricity Sales by Scenario in GWh



Note: See the Appendix to this report for historical and projected values.

Indiana Industrial Electricity Price Projections

Historical values and current projections of industrial electricity prices are shown in Table 7-6 and Figure 7-5. In real terms, industrial electricity prices declined from the mid-1980s until 2002. Real industrial electricity prices have risen since 2002 due to increases in fuel costs and the installation of new emissions control equipment. SUFG projects real industrial electricity prices to rise through the entire forecast horizon with the need for additional emissions control equipment and additional supply/demand resources. SUFG's real price projections for the individual IOUs follow the same patterns as the state as a whole, but there are variations across the utilities. Historical and forecast prices are included in the Appendix of this report.

Figure 7-5. Indiana Industrial Base Real Price Projections (in 2009 Dollars)

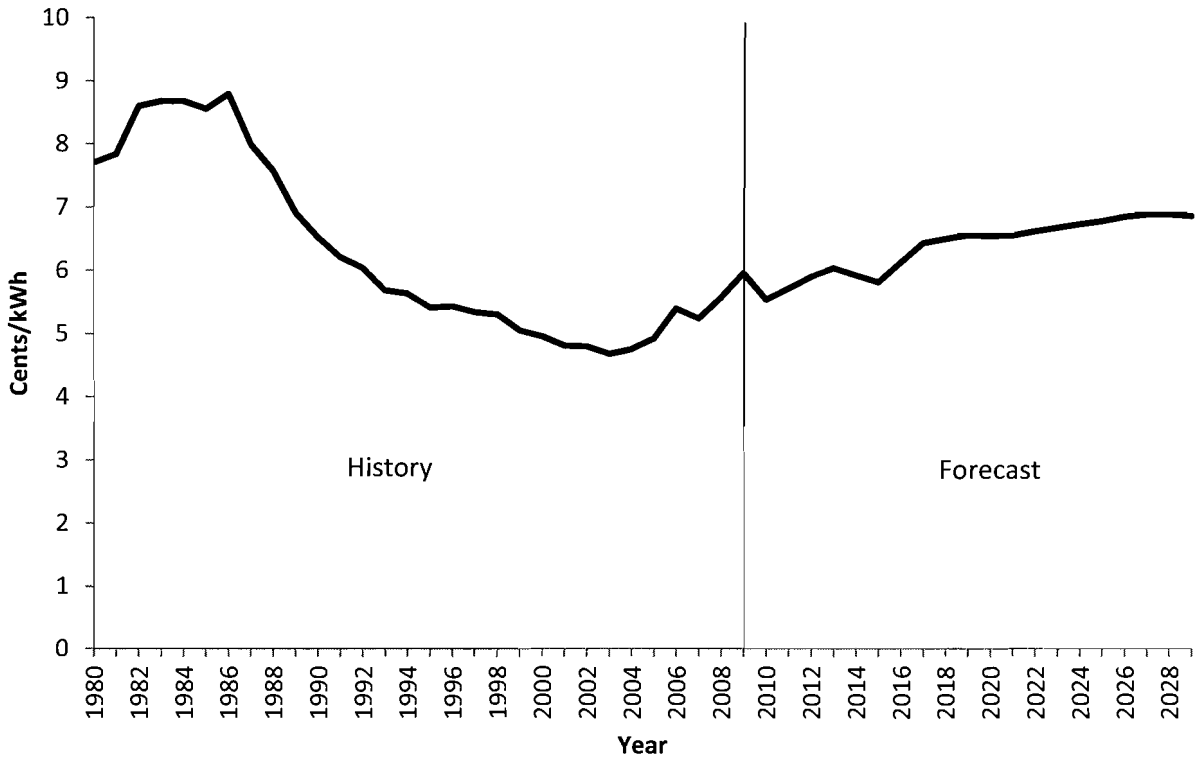


Table 7-6. Indiana Industrial Base Real Price Average Compound Growth Rates (Percent)

Average Compound Growth Rates	
Selected Periods	**Percent**
1980-1985	2.11
1985-1990	-5.28
1990-1995	-3.69
1995-2000	-1.73
2000-2005	-0.12
2005-2009	4.89
2010-2029	1.14

Note: See the Appendix to this report for historical and projected values and an explanation of how SUFG arrives at these numbers.

Chapter 8

Proposed Environmental Regulations

Overview

The U.S. Environmental Protection Agency (EPA) is developing a number of environmental regulations that are likely to have a significant effect on Indiana's electricity generation sector, particularly in terms of coal-fired generation. These rules are not included in this forecast due to the considerable uncertainty over the form and timing of the regulations. SUFG will be performing a separate study examining the expected impacts of these rules, with an expected release in the fall of 2011. This section briefly covers the different rules and looks at some of the characteristics of Indiana's coal-fired generation fleet that may impact its vulnerability to the regulations.

Cross-State Air Pollution Rule

Finalized in July 2011 (after the inputs to the SUFG modeling system for this forecast were finalized) under the Clean Air Act, this rule affects 27 states including Indiana, requiring reductions in sulfur dioxide (SO2) and nitrogen oxides (NOx) emissions beginning in 2012, with stricter reductions in 2014. It establishes an SO2 emissions cap that is considerably smaller for Indiana (43.6 percent lower in 2014 than in 2012) and limits the trading region by separating affected states into two groups with no trading between the groups. It replaces the Clean Air Interstate Rule. A second version of the rule is expected to be proposed in 2011 and finalized in the summer of 2012.

Mercury and Air Toxics Standards (MATS)

Proposed under the Clean Air Act, this rule would limit emissions from mercury, acid gases, and other pollutants from power plants. It would prevent 91 percent of the mercury in coal from being released. The rule would replace the court-vacated Clean Air Mercury Rule. It was proposed in May 2011, with comments accepted until August 2011. The final rule is expected in November 2011.

Greenhouse Gases

To be proposed under the Clean Air Act, this rule would establish performance standards for new and modified generating units, along with emissions guidelines for existing generating units. The proposed rule is expected in September 2011 and the final rule is expected in May 2012.

Cooling Water Intake Structures

Proposed under section §316(b) of the Clean Water Act , the rule is intended to reduce damage to aquatic life through impingement, when the organisms are trapped against inlet screens, or entrainment, when they are drawn into the generator's cooling water system. Facilities that withdraw at least 2 million gallons per day would be subject to a limit on the number of fish that can be killed through impingement. Facilities that withdraw at least 125 million gallons per day and new units at existing facilities may be subject to additional restrictions. The rule was proposed in April 2011, with comments accepted until August 2011 and a final rule expected in July 2012.

Coal Combustion Residuals

Two options were proposed under the Resource Conservation and Recovery Act: (1) list residuals as special wastes when destined for disposal in landfills or surface impoundments and (2) regulate as a non-hazardous waste. The proposed rule was released in June 2010, and comments were received through November 2010. EPA has not yet announced an expected date for the release of the final rule.

Characteristics of Indiana's Coal-fired Generation Fleet

The vulnerability of a particular generating unit to the various potential environmental regulations depends on a number of factors. These factors include the age, size, efficiency and operating condition of the unit; any existing emissions controls device that may be installed; the type of cooling system and ash disposal used by the facility; and physical characteristics of the site (e.g., space availability

for installation of new equipment). While an older, less efficient generator without an SO2 removal system may be a candidate for retirement under a new set of regulations, a newer larger unit with a flue gas desulfurization (FGD) system may be a candidate for additional pollution controls and continue to operate.

SUFG has collected information on the status of pollution control devices, cooling water systems, and ash disposal systems from utility filings with EIA. Since these filings are somewhat dated and SUFG has not yet verified the information with the utilities, this information is summarized here only to provide a sense of the status of the coal-fired generation fleet.

The age of the coal fleet is illustrated in Figure 8-1. About 9 percent of the generating capacity (in MW) was installed before 1960 and about 27 percent dates to pre-1970. As shown in Figure 8-2, 43 percent of Indiana's coal-fired generating capacity has some form of FGD system installed. Figure 8-3 shows similar information for selective catalytic reduction (SCR) systems for NOx removal. While other generators have other forms of NOx control devices installed, SCRs are illustrated here because the new regulations are expected to push the industry toward SCRs. There are also facilities in various stages of the approval and construction process for installing FGDs and SCRs. These retrofits are not reflected in the figures.

Figure 8-1. Vintage of Indiana's Coal-fired Generating Fleet

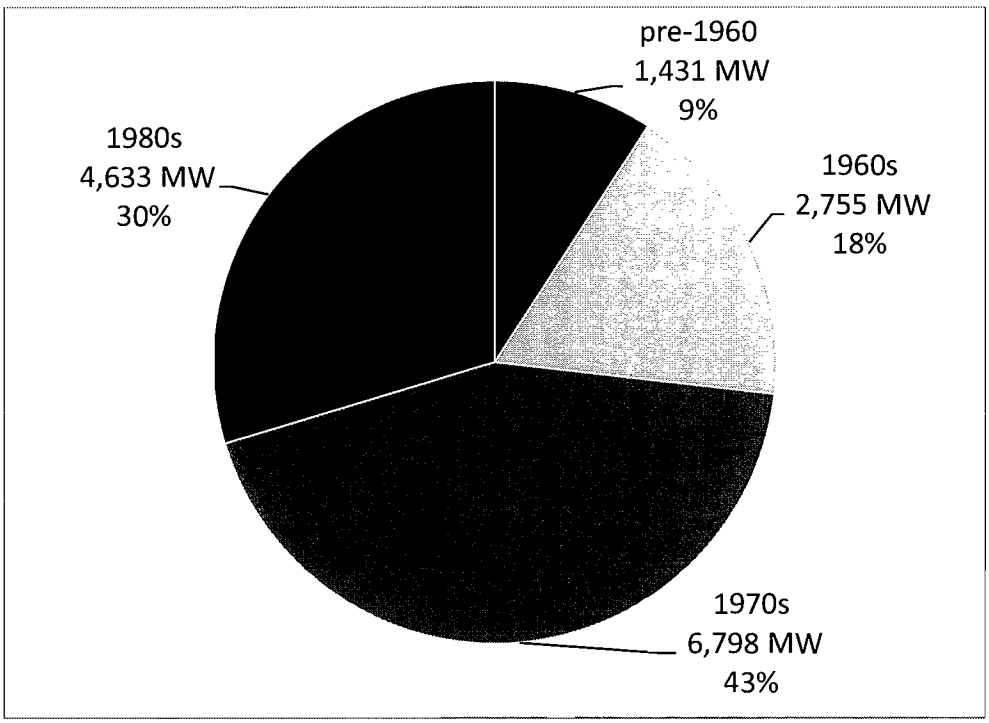


Figure 8-2. Installation of FGDs in Indiana's Coal-fired Generating Fleet

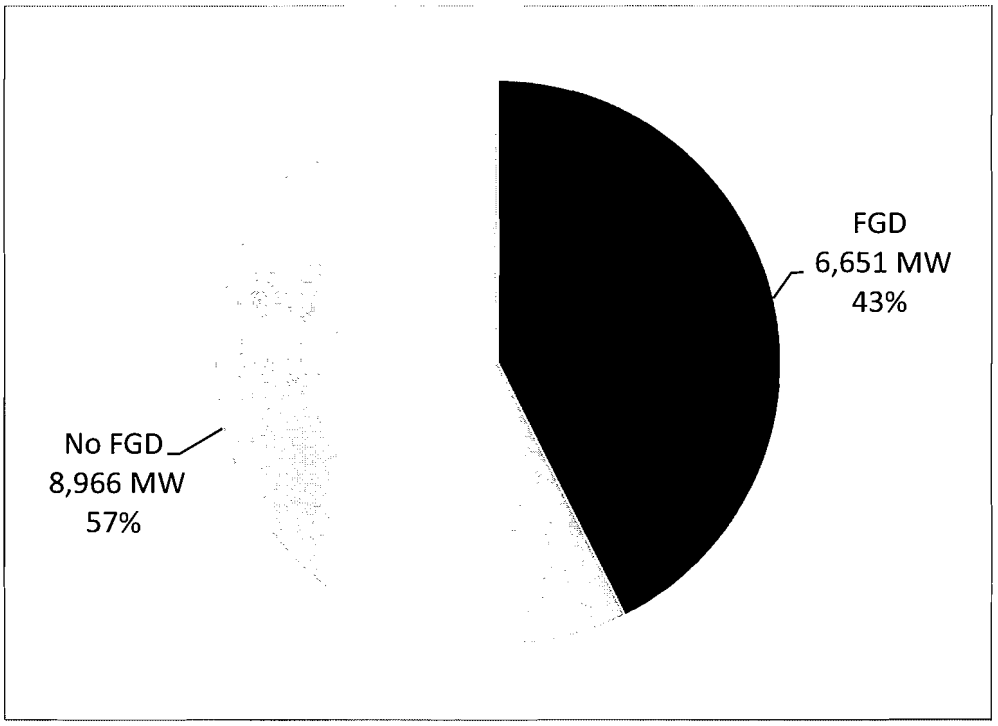
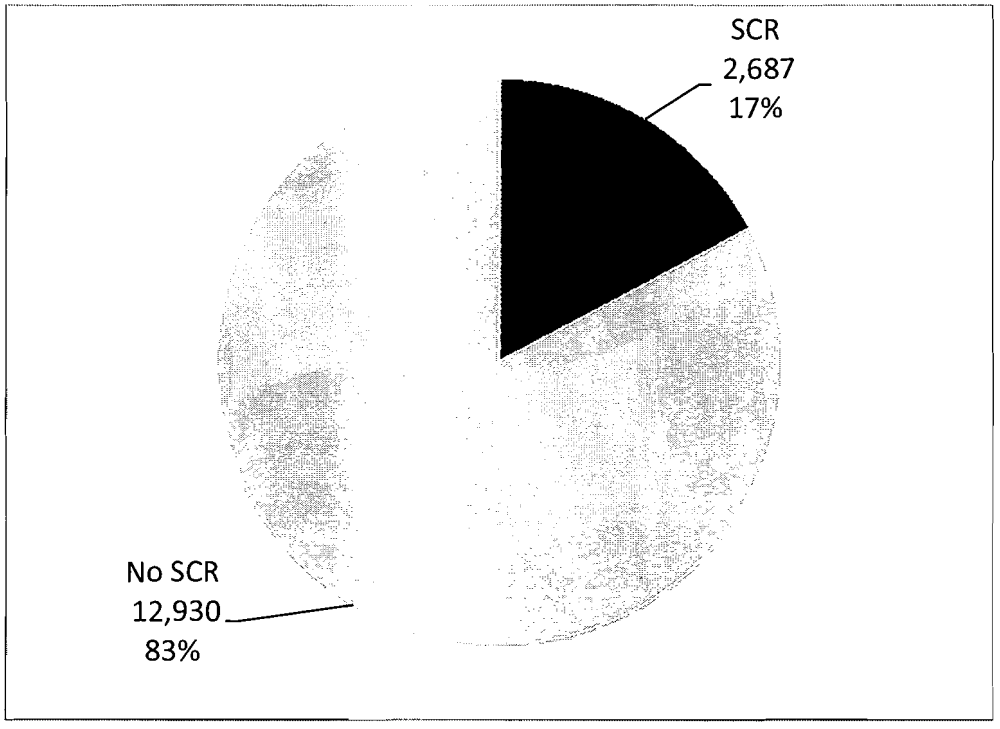


Figure 8-3. Installation of SCRs in Indiana's Coal-fired Generating Fleet



Appendix

In developing the historical energy, summer peak demand and rates data shown in the body and appendix of this document, SUFG relied on several sources of data. These sources include:

1. FERC Form 1;
2. Rural Utilities Service (RUS) Form 7 or Form 12;
3. Uniform Statistical Report;
4. Utility Load Forecast Reports;
5. Integrated Resource Plan Filings;
6. Annual Reports; and
7. SUFG Confidential Data Requests.

SUFG relied on public sources where possible, but some generally more detailed data was obtained from Indiana utilities under confidential agreements of nondisclosure. All data presented in this report has been aggregated to total Indiana statewide energy, demand and rates to avoid disclosure.

In most instances the source of SUFG's data can be traced to a particular page of a certain publication, e.g., residential energy sales for an IOU are found on page 304 of FERC Form 1. However, in several cases it is not possible to directly trace a particular number to a public data source. These exceptions arise due to:

1. geographic area served by the utility;
2. classification of sales data; and
3. unavailability of sectoral level sales data.

Indiana Michigan Power Company (I&M), Wabash Valley Power Association (WVPA), Indiana Municipal Power Agency (IMPA), and Hoosier Energy serve load outside of the state which SUFG excluded in developing projections for Indiana. Slightly less than 20 percent of I&M's load is in Michigan and while the majority of WVPA's load is in Indiana, it does have members in Illinois, Michigan, Missouri, and Ohio. IMPA has a wholesale member in Ohio and Hoosier Energy recently acquired a member cooperative in Illinois. These utilities have provided SUFG with data pertaining to their Indiana load.

Some Indiana utilities report sales to the commercial and industrial sectors (SUFG's classification) as sales to one aggregate classification or sales to small and large customers. In order to obtain commercial and industrial sales for these utilities, SUFG has requested data in these classifications directly from the utilities, developed approximation schemes to disaggregate the sales data, or combined more than one source of data to develop commercial and industrial sales estimates. For example, until recently the Uniform Statistical Report contained industrial sector sales for IOUs. This data can be subtracted from aggregate FERC Form 1 small and large customer sales data to obtain an estimate of commercial sales.

SUFG does not have sectoral level sales data for the unaffiliated rural electric membership cooperatives (REMCs) and unaffiliated municipalities. SUFG obtains aggregate sales data from the FERC Form 1, then allocates the sales to residential, commercial, industrial and other sales with an allowance for losses. These allocation factors were developed by examining the mix of energy sales for other Indiana REMCs and municipalities. Thus, the sales estimates for unaffiliated REMCs are weighted heavily toward the residential sector and those for unaffiliated municipalities are more evenly balanced between the residential, commercial and industrial sectors.

SUFG's estimates of losses are calculated using a constant percentage loss factor applied to retail sales and sales-for-resale (when appropriate). These loss factors are based on FERC Form 1 data and discussions with Indiana utility personnel.

Total energy requirements for an individual utility are obtained by adding retail sales, sales-for-resale (if any) and losses. Total energy requirements for the state as a whole are obtained by adding retail sales and losses for the ten entities which SUFG models. Sales-for-resale are excluded from the state aggregate total energy requirements to avoid double counting.

Summer peak demand estimates are based on FERC Form 1 data for the IOUs with the exception of I&M, which provided SUFG with peak demand for their Indiana jurisdiction, and company sources for Hoosier Energy, IMPA and WVPA.

Statewide summer peak demand may not be obtained by simply adding across utilities because of diversity. Diversity refers to the fact that all Indiana utilities do not experience their summer peak demand at the same instance. Due to differences in weather, sectoral mix, end-use saturation, etc., the utilities tend to face their individual summer peak demands at different hours, days, or even months. To obtain an estimate of statewide peak demand, the summer peak demand estimates for the individual utilities are added together and adjusted for diversity.

The historical energy sales and peak demand data presented in this appendix represent SUFG's accounting of actual

historical values. However, data availability for the REMCs and municipalities prior to 1982 is limited and the reported values for 1980 and 1981 include SUFG estimates for the not-for-profit utilities for these years. SUFG believes that any errors in statewide energy sales and demand for 1980 and 1981 are relatively small and concentrated in the residential sector.

In developing the current forecast, SUFG was required to estimate some detailed sector-specific data for a few utilities. This data was unavailable from some utilities due to changes in data collection and/or reporting requirements. In the industrial sector, SUFG estimates two digit, Standard Industrial Code sales and revenue data for two IOUs. This data was estimated from total industrial sales data by assuming the same allocation of industrial sales to two-digit level as observed during recent years. SUFG was also unable to obtain sales and revenue data for the commercial sector at the same level of detail from some IOUs. The detailed commercial sector data is necessary to calibrate SUFG's commercial sector model, but since the commercial sector model was not recalibrated for this forecast, no estimation was attempted. The not-for-profit utilities have not traditionally been able to supply SUFG with data at this level of detail. However, the not-for-profit utilities were able to provide SUFG with a breakdown of member load by sector.

SUFG feels relatively comfortable with these estimates, but is concerned about the future availability of detailed sector-specific data. If data proves to be unavailable in the future, SUFG will either be forced to develop more sophisticated allocation schemes to support the energy forecasting models or develop less data intensive, detailed energy forecasting models.

SUFG 2011 Base Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales					Losses	Energy Required	Summer Demand
		Res	Com	Ind	Other	Total			
Hist	1982	19927	13725	22600	696	56948	3986	60934	10683
Hist	1983	19950	13665	23476	626	57717	4040	61757	11744
Hist	1984	20153	14274	24678	674	59779	4185	63964	11331
Hist	1985	19707	14651	24480	653	59491	4164	63655	11030
Hist	1986	20410	15429	23618	610	60067	4205	64271	11834
Hist	1987	21154	16144	24694	617	62609	4383	66992	12218
Hist	1988	22444	16808	26546	633	66431	4650	71081	13447
Hist	1989	22251	17205	27394	661	67511	4726	72237	12979
Hist	1990	22037	17659	28311	650	68657	4806	73463	13659
Hist	1991	24215	18580	28141	629	71564	5009	76573	14278
Hist	1992	22916	18556	29540	619	71632	5014	76646	14055
Hist	1993	25060	19627	31562	511	76760	5373	82133	14916
Hist	1994	25176	20116	33395	507	79193	5544	84737	15010
Hist	1995	26510	20646	33659	510	81326	5693	87019	16251
Hist	1996	26833	20909	34920	536	83197	5824	89021	16181
Hist	1997	26792	21295	35499	859	84445	5911	90356	16040
Hist	1998	27663	22166	37012	899	87740	6142	93881	16657
Hist	1999	29180	23078	38916	960	92134	6449	98584	17266
Hist	2000	28684	23721	38957	1012	92373	6466	98839	16757
Hist	2001	29437	23953	38293	987	92670	6487	99157	17531
Hist	2002	32363	24980	39594	1025	97961	6857	104818	18851
Hist	2003	31177	24940	39285	981	96383	6747	103130	18843
Hist	2004	31654	25411	39634	1088	97787	6845	104632	18254
Hist	2005	34058	26905	39940	1021	101924	7135	109058	19819
Hist	2006	32694	26898	41516	1009	102116	7148	109264	20921
Hist	2007	35197	27827	41920	1064	106008	7421	113428	20849
Hist	2008	34360	27635	39762	1088	102845	7199	110044	19257
Hist	2009	33045	26339	34804	1081	95269	6669	101938	18975
Frcst	2010	34470	26806	36554	1081	98911	7237	106148	19269
Frcst	2011	34726	27120	36511	1081	99437	7268	106706	19481
Frcst	2012	34898	27445	36891	1081	100315	7323	107638	19654
Frcst	2013	35093	27703	37480	1081	101357	7388	108745	19881
Frcst	2014	35313	28117	38567	1081	103078	7501	110579	20203
Frcst	2015	35745	28469	40195	1081	105490	7663	113152	20650
Frcst	2016	35841	28798	41391	1081	107110	7770	114880	20935
Frcst	2017	35962	29045	42243	1081	108330	7852	116182	21141
Frcst	2018	36050	29302	42938	1081	109370	7916	117287	21319
Frcst	2019	36216	29552	43689	1081	110538	7994	118532	21520
Frcst	2020	36831	29727	44581	1081	112220	8110	120330	21841
Frcst	2021	36955	29922	45576	1081	113534	8202	121736	22026
Frcst	2022	37137	30074	46574	1081	114866	8297	123163	22277
Frcst	2023	37316	30245	47599	1081	116239	8398	124638	22528
Frcst	2024	37568	30440	48645	1081	117734	8511	126245	22810
Frcst	2025	38033	30616	49678	1081	119407	8638	128045	23140
Frcst	2026	38396	30870	50679	1081	121026	8763	129788	23454
Frcst	2027	38754	31128	51841	1081	122804	8900	131703	23798
Frcst	2028	39098	31410	53081	1081	124669	9043	133712	24152
Frcst	2029	39428	31714	54362	1081	126584	9192	135776	24521

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	2.68	2.68	-0.45
1985-1990	2.26	3.81	2.95	-0.09	2.91	2.91	2.91	4.37
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	14.69	2.58	2.58	2.58	0.61
2000-2005	3.49	2.55	0.50	0.17	1.99	1.99	1.99	3.41
2005-2010	0.24	-0.07	-1.76	1.15	-0.60	0.28	-0.54	-0.56
2010-2015	0.73	1.21	1.92	0.00	1.30	1.15	1.29	1.39
2015-2020	0.60	0.87	2.09	0.00	1.24	1.14	1.24	1.13
2020-2025	0.64	0.59	2.19	0.00	1.25	1.27	1.25	1.16
2025-2029	0.90	0.89	2.28	0.00	1.47	1.57	1.48	1.46
2010-2029	0.71	0.89	2.11	0.00	1.31	1.27	1.30	1.28

SUFG 2011 Low Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales					Losses	Energy Required	Summer Demand
		Res	Com	Ind	Other	Total			
Hist	1982	19927	13725	22600	696	56948	3986	60934	10683
Hist	1983	19950	13665	23476	626	57717	4040	61757	11744
Hist	1984	20153	14274	24678	674	59779	4185	63964	11331
Hist	1985	19707	14651	24480	653	59491	4164	63655	11030
Hist	1986	20410	15429	23618	610	60067	4205	64271	11834
Hist	1987	21154	16144	24694	617	62609	4383	66992	12218
Hist	1988	22444	16808	26546	633	66431	4650	71081	13447
Hist	1989	22251	17205	27394	661	67511	4726	72237	12979
Hist	1990	22037	17659	28311	650	68657	4806	73463	13659
Hist	1991	24215	18580	28141	629	71564	5009	76573	14278
Hist	1992	22916	18556	29540	619	71632	5014	76646	14055
Hist	1993	25060	19627	31562	511	76760	5373	82133	14916
Hist	1994	25176	20116	33395	507	79193	5544	84737	15010
Hist	1995	26510	20646	33659	510	81326	5693	87019	16251
Hist	1996	26833	20909	34920	536	83197	5824	89021	16181
Hist	1997	26792	21295	35499	859	84445	5911	90356	16040
Hist	1998	27663	22166	37012	899	87740	6142	93881	16657
Hist	1999	29180	23078	38916	960	92134	6449	98584	17266
Hist	2000	28684	23721	38957	1012	92373	6466	98839	16757
Hist	2001	29437	23953	38293	987	92670	6487	99157	17531
Hist	2002	32363	24980	39594	1025	97961	6857	104818	18851
Hist	2003	31177	24940	39285	981	96383	6747	103130	18843
Hist	2004	31654	25411	39634	1088	97787	6845	104632	18254
Hist	2005	34058	26905	39940	1021	101924	7135	109058	19819
Hist	2006	32694	26898	41516	1009	102116	7148	109264	20921
Hist	2007	35197	27827	41920	1064	106008	7421	113428	20849
Hist	2008	34360	27635	39762	1088	102845	7199	110044	19257
Hist	2009	33045	26339	34804	1081	95269	6669	101938	18975
Frcst	2010	34470	26806	36311	1081	98668	7219	105888	19226
Frcst	2011	34725	27117	36031	1081	98954	7233	106186	19396
Frcst	2012	34879	27443	36166	1081	99568	7269	106837	19522
Frcst	2013	35072	27684	36499	1081	100336	7314	107650	19701
Frcst	2014	35283	28081	37274	1081	101719	7402	109122	19963
Frcst	2015	35715	28408	38539	1081	103743	7536	111279	20341
Frcst	2016	35792	28710	39411	1081	104994	7617	112611	20560
Frcst	2017	35895	28926	39900	1081	105801	7670	113471	20692
Frcst	2018	35957	29147	40173	1081	106358	7700	114058	20784
Frcst	2019	36097	29359	40619	1081	107155	7751	114906	20917
Frcst	2020	36718	29501	41162	1081	108461	7840	116301	21171
Frcst	2021	36820	29659	41791	1081	109352	7901	117252	21280
Frcst	2022	36983	29774	42449	1081	110286	7966	118253	21459
Frcst	2023	37144	29917	43182	1081	111324	8041	119365	21650
Frcst	2024	37386	30080	43958	1081	112505	8128	120633	21874
Frcst	2025	37840	30216	44601	1081	113738	8221	121959	22126
Frcst	2026	38190	30440	45182	1081	114892	8312	123204	22357
Frcst	2027	38523	30662	45916	1081	116182	8411	124593	22609
Frcst	2028	38850	30911	46694	1081	117537	8516	126053	22869
Frcst	2029	39168	31185	47494	1081	118928	8625	127553	23141

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	2.68	2.68	-0.45
1985-1990	2.26	3.81	2.95	-0.09	2.91	2.91	2.91	4.37
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	14.69	2.58	2.58	2.58	0.61
2000-2005	3.49	2.55	0.50	0.17	1.99	1.99	1.99	3.41
2005-2010	0.24	-0.07	-1.89	1.15	-0.65	0.24	-0.59	-0.61
2010-2015	0.71	1.17	1.20	0.00	1.01	0.86	1.00	1.13
2015-2020	0.56	0.76	1.33	0.00	0.89	0.79	0.89	0.80
2020-2025	0.60	0.48	1.62	0.00	0.95	0.96	0.95	0.89
2025-2029	0.87	0.79	1.58	0.00	1.12	1.21	1.13	1.13
2010-2029	0.67	0.80	1.42	0.00	0.99	0.94	0.98	0.98

SUFG 2011 High Energy Requirements (GWh) and Summer Peak Demand (MW) for Indiana

Year		Retail Sales					Losses	Energy Required	Summer Demand
		Res	Com	Ind	Other	Total			
Hist	1982	19927	13725	22600	696	56948	3986	60934	10683
Hist	1983	19950	13665	23476	626	57717	4040	61757	11744
Hist	1984	20153	14274	24678	674	59779	4185	63964	11331
Hist	1985	19707	14651	24480	653	59491	4164	63655	11030
Hist	1986	20410	15429	23618	610	60067	4205	64271	11834
Hist	1987	21154	16144	24694	617	62609	4383	66992	12218
Hist	1988	22444	16808	26546	633	66431	4650	71081	13447
Hist	1989	22251	17205	27394	661	67511	4726	72237	12979
Hist	1990	22037	17659	28311	650	68657	4806	73463	13659
Hist	1991	24215	18580	28141	629	71564	5009	76573	14278
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Hist	1993	25060	19627	31562	511	76760	5373	82133	14916
Hist	1994	25176	20116	33395	507	79193	5544	84737	15010
Hist	1995	26510	20646	33659	510	81326	5693	87019	16251
Hist	1996	26833	20909	34920	536	83197	5824	89021	16181
Hist	1997	26792	21295	35499	859	84445	5911	90356	16040
Hist	1998	27663	22166	37012	899	87740	6142	93881	16657
Hist	1999	29180	23078	38916	960	92134	6449	98584	17266
Hist	2000	28684	23721	38957	1012	92373	6466	98839	16757
Hist	2001	29437	23953	38293	987	92670	6487	99157	17531
Hist	2002	32363	24980	39594	1025	97961	6857	104818	18851
Hist	2003	31177	24940	39285	981	96383	6747	103130	18843
Hist	2004	31654	25411	39634	1088	97787	6845	104632	18254
Hist	2005	34058	26905	39940	1021	101924	7135	109058	19819
Hist	2006	32694	26898	41516	1009	102116	7148	109264	20921
Hist	2007	35197	27827	41920	1064	106008	7421	113428	20849
Hist	2008	34610	27120	42182	1088	102845	7719	110044	19257
Hist	2009	35194	27216	40176	1081	95269	7619	101938	18975
Frcst	2010	34470	26806	36798	1081	99155	7255	106410	19311
Frcst	2011	34726	27120	36996	1081	99923	7304	107227	19566
Frcst	2012	34900	27446	37628	1081	101054	7377	108431	19783
Frcst	2013	35095	27707	38481	1081	102364	7461	109825	20057
Frcst	2014	35336	28144	39895	1081	104456	7602	112058	20446
Frcst	2015	35774	28520	41907	1081	107282	7792	115074	20965
Frcst	2016	35882	28879	43461	1081	109303	7928	117231	21322
Frcst	2017	36007	29157	44683	1081	110927	8040	118967	21601
Frcst	2018	36108	29447	45716	1081	112351	8133	120484	21848
Frcst	2019	36283	29729	46800	1081	113893	8239	122131	22115
Frcst	2020	36899	29939	48046	1081	115964	8383	124347	22504
Frcst	2021	37038	30164	49408	1081	117691	8506	126197	22764
Frcst	2022	37238	30345	50824	1081	119488	8636	128124	23098
Frcst	2023	37437	30556	52341	1081	121416	8777	130193	23449
Frcst	2024	37701	30783	53855	1081	123420	8928	132348	23824
Frcst	2025	38178	30991	55366	1081	125616	9094	134709	24250
Frcst	2026	38557	31276	56851	1081	127765	9258	137024	24664
Frcst	2027	38928	31568	58515	1081	130092	9435	139528	25106
Frcst	2028	39284	31881	60274	1081	132519	9621	142140	25563
Frcst	2029	39623	32224	62084	1081	135012	9811	144823	26034

Average Compound Growth Rates (%)

Year-Year	Res	Com	Ind	Other	Total	Losses	Energy Required	Summer Demand
1980-1985	3.48	3.36	1.66	3.27	2.68	2.68	2.68	-0.45
1985-1990	2.26	3.81	2.95	-0.09	2.91	2.91	2.91	4.37
1990-1995	3.77	3.17	3.52	-4.74	3.44	3.44	3.44	3.54
1995-2000	1.59	2.82	2.97	14.69	2.58	2.58	2.58	0.61
2000-2005	3.49	2.55	0.50	0.17	1.99	1.99	1.99	3.41
2005-2010	0.24	-0.07	-1.63	1.15	-0.55	0.33	-0.49	-0.52
2010-2015	0.75	1.25	2.63	0.00	1.59	1.44	1.58	1.66
2015-2020	0.62	0.98	2.77	0.00	1.57	1.47	1.56	1.43
2020-2025	0.68	0.69	2.88	0.00	1.61	1.64	1.61	1.51
2025-2029	0.93	0.98	2.90	0.00	1.82	1.92	1.83	1.79
2010-2029	0.74	0.97	2.79	0.00	1.64	1.60	1.64	1.58

Indiana Base Average Retail Rates (Cents/kWh) (in 2009 Dollars)

Year	Res	Com	Ind	Average
1982	11.86	11.67	8.60	10.42
1983	12.34	11.81	8.68	10.59
1984	12.45	11.85	8.67	10.61
1985	12.75	11.81	8.55	10.64
1986	12.91	12.14	8.79	10.96
1987	12.45	11.81	7.99	10.37
1988	11.71	10.80	7.58	9.68
1989	10.94	9.26	6.91	8.72
1990	10.31	8.72	6.52	8.19
1991	9.67	8.19	6.21	7.80
1992	9.58	8.08	6.04	7.60
1993	9.04	7.59	5.68	7.17
1994	9.07	7.57	5.63	7.11
1995	8.91	7.50	5.40	6.98
1996	8.88	7.47	5.42	6.95
1997	9.04	7.38	5.33	6.92
1998	9.06	7.37	5.30	6.90
1999	8.79	7.20	5.04	6.67
2000	8.43	6.83	4.95	6.42
2001	8.26	6.87	4.80	6.35
2002	8.09	6.79	4.80	6.30
2003	8.06	6.70	4.68	6.21
2004	8.10	6.80	4.75	6.29
2005	8.10	6.74	4.92	6.39
2006	8.68	7.48	5.39	6.91
2007	8.32	7.24	5.23	6.72
2008	8.61	7.30	5.57	6.98
2009	9.15	7.74	5.96	7.49
2010	8.74	7.87	5.54	7.23
2011	9.26	8.15	5.71	7.56
2012	9.82	8.47	5.90	7.90
2013	9.75	8.45	6.03	7.91
2014	9.78	8.34	5.91	7.82
2015	9.85	8.40	5.80	7.80
2016	10.53	8.98	6.12	8.27
2017	11.11	9.44	6.43	8.69
2018	11.22	9.54	6.49	8.76
2019	11.24	9.57	6.55	8.78
2020	11.19	9.52	6.54	8.74
2021	11.14	9.49	6.55	8.70
2022	11.09	9.47	6.62	8.69
2023	11.07	9.48	6.67	8.69
2024	11.06	9.49	6.73	8.70
2025	10.98	9.44	6.78	8.67
2026	10.97	9.45	6.85	8.69
2027	10.92	9.43	6.89	8.67
2028	10.84	9.38	6.89	8.63
2029	10.71	9.29	6.86	8.54
Average Compound Growth Rates (%)				
Year-Year	**Res**	**Com**	**Ind**	**Average**
1980-1985	4.00	1.23	2.11	2.50
1985-1990	-4.16	-5.88	-5.28	-5.09
1990-1995	-2.88	-2.98	-3.69	-3.16
1995-2000	-1.09	-1.85	-1.73	-1.66
2000-2005	-0.79	-0.26	-0.12	-0.09
2005-2010	1.53	3.15	2.38	2.51
2010-2015	2.42	1.31	0.95	1.51
2015-2020	2.57	2.53	2.41	2.32
2020-2025	-0.37	-0.17	0.72	-0.16
2025-2029	-0.62	-0.41	0.30	-0.39
2010-2029	1.08	0.87	1.14	0.88

Note: Energy Weighted Average Rates for Indiana IOUs
-Results for the low and high economic activity cases are similar and are not reported

List of Acronyms

ACGR	Average Compound Growth Rates
Btu	British thermal unit
CAIR	Clean Air Interstate Rule
CC	Combined Cycle
CEDMS	Commercial Energy Demand Modeling System
CEMR	Center for Econometric Model Research
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DOE	U. S. Department of Energy
DSM	Demand-Side Management
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GSP	Gross State Product
GWh	Gigawatthour
HVAC	Heating, Ventilation and Air Conditioning
I&M	Indiana Michigan Power Company
IBRC	Indiana Business Research Center
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
IMPA	Indiana Municipal Power Agency
KLEM	Capital, labor, energy and materials
kWh	Kilowatthour
LMSTM	Load Management Strategy Testing Model
LPG	Liquefied Petroleum Gas
MATS	Mercury and Air Toxics Standards
MW	Megawatt
NAICS	North American Industry Classification System
NFP	Not-for-Profit
OPEC	Organization of Petroleum Exporting Countries
ORNL	Oak Ridge National Labs
PC	Pulverized Coal-Fired
REMC	Rural Electric Membership Cooperative
REDMS	Residential Energy Modeling System
REEMS	Residential End-Use Energy Modeling System
RTO	Regional Transmission Organization
RUS	U.S. Department of Agriculture Rural Utilities Service
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SUFG	State Utility Forecasting Group
WVPA	Wabash Valley Power Association

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2011 Indiana Renewables Study & 2011 Forecast

Presented by:
Douglas J. Gotham, Director
State Utility Forecasting Group
Purdue University

Presented to:
Regulatory Flexibility Committee
Indiana General Assembly

September 21, 2011

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2011 Renewable Resources Study

- Renewable energy trends
- Barriers to development
- Individual renewable resources
  - Wind
  - Energy crops
  - Organic waste
  - Solar
  - Photovoltaics
  - Hydropower

2

RFSC
9/21/11
Ex. E

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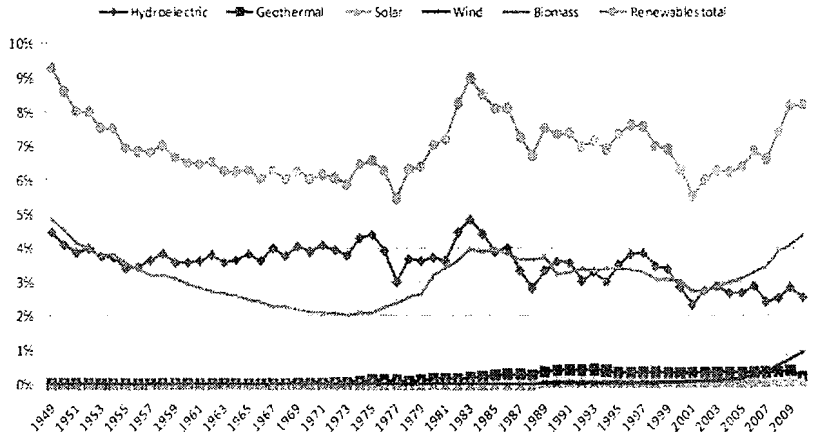
Renewables Share of U.S. Energy Consumption



Source: Energy Information Administration (EIA)

3

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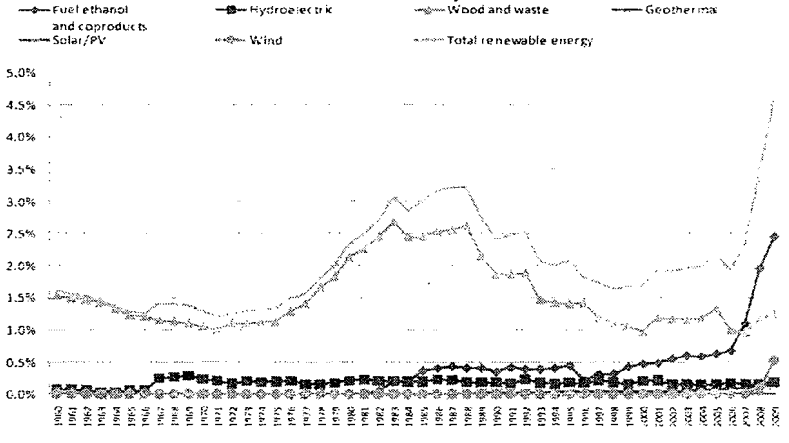
Renewables Share of Indiana Energy Consumption



Source: EIA

4

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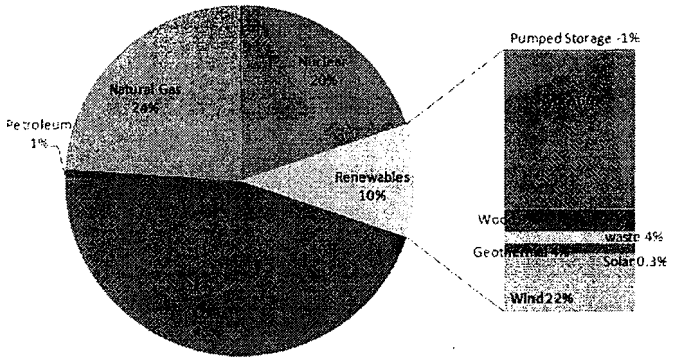
2010 U.S. Electricity Generation by Energy Source



Source: EIA

5

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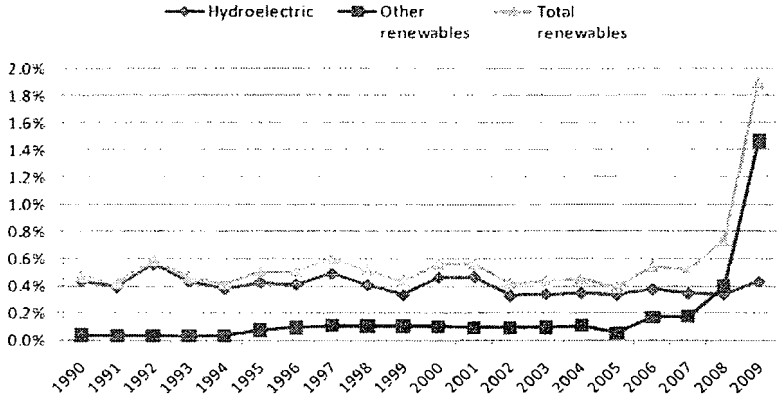
Renewables Share of Indiana Electricity Generation



Source: EIA

6

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Barriers to Renewables

- Major barrier is cost
  - Most renewable technologies have high capital costs
  - According to EIA Indiana's average electric rate in 2009 was 7.62 cents/kWh vs. the national average of 9.82 cents/kWh
- Limited availability for some resources
  - Solar/photovoltaics, hydropower
- Intermittency for some resources
  - Solar/photovoltaics, wind

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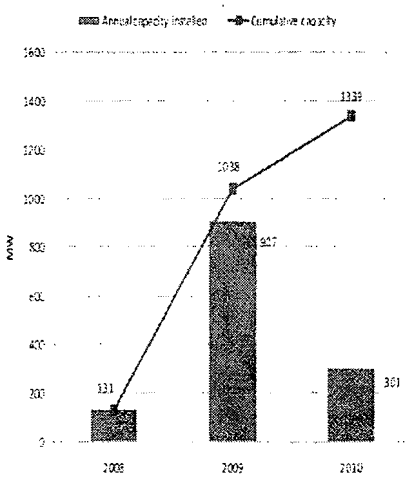
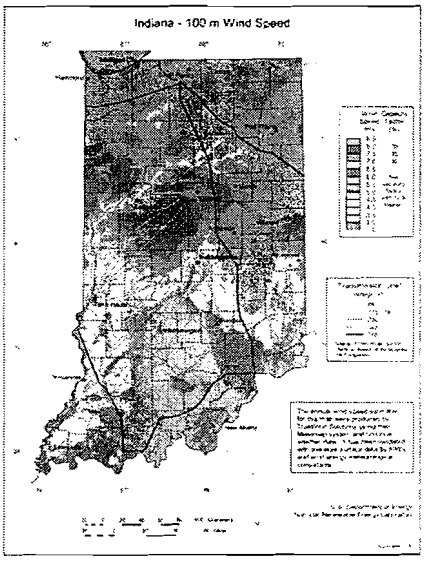
Wind





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Energy Crops

- Transportation fuels
  - Ethanol
  - Biodiesel
- Other possibilities
  - Fast growing hardwood trees (hybrid poplar/willow)
  - Grasses (switchgrass)
- Barriers to be overcome
  - Other high-value uses for the land
  - Harvesting and transportation costs
  - Price of competing fossil fuels

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Organic Waste Biomass

- Until the recent increase in ethanol production, this resource was the largest source of renewable energy in Indiana
  - Primarily due to the use of wood waste
- It is the 3rd largest source of renewable electricity generation in the state
  - Landfill gas
  - Municipal solid waste
  - Animal waste biogas
  - Wastewater treatment

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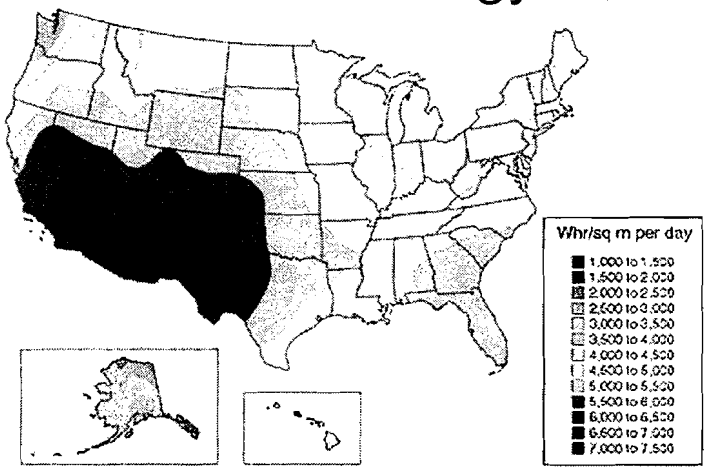
Solar Energy



Solar resource for a flat-plate collector

Source: DOE

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Photovoltaics

- Growing rapidly in Indiana, but still a small contributor overall
- 75 installations totaling over 2.6 MW of capacity
  - Fort Harrison Federal Compound
  - Johnson Melloh

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Hydroelectric Power

- Indiana has 73 MW of hydroelectric generating capacity.
  - mostly run-of-the-river (no dam)
  - 2nd largest source of renewable electricity
- American Municipal Power is constructing an 84 MW facility at the Cannelton Locks on the Ohio River
  - expected to be operational in Fall 2013

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2011 Forecast

- Electricity demand
- Peak demand
- Resource needs
- Electricity prices

PURDUE UNIVERSITY

2011 Forecast

Indiana Electricity Projections

State Utility Forecasting Group

Discovery Park Energy Center

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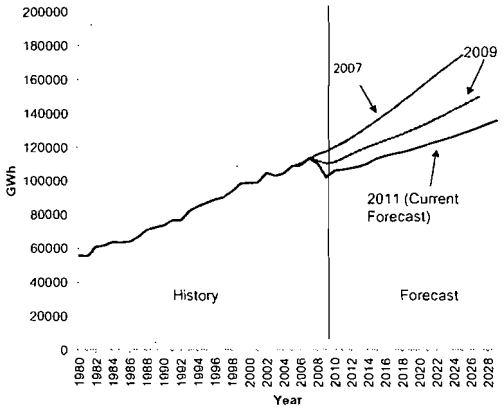
Indiana Electricity Requirements

- Retail sales by investor owned and not-for-profit utilities
- Includes estimated transmission and distribution losses
- Growth rates
  - 2011 forecast: 1.30%
  - 2009 forecast: 1.55%
  - 2007 forecast: 2.46%



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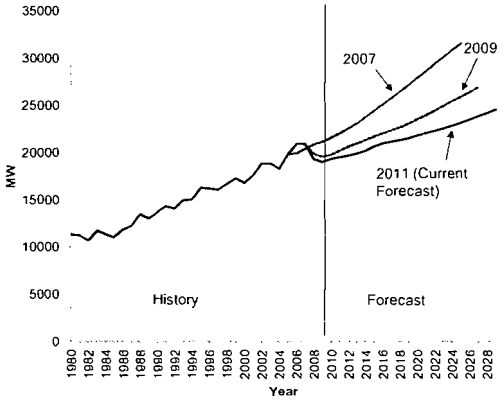
Indiana Peak Demand Requirements

- Peak demand is net of DSM and interruptible loads
- Growth rates
  - 2011 forecast: 1.28%
  - 2009 forecast: 1.61%
  - 2007 forecast: 2.46%



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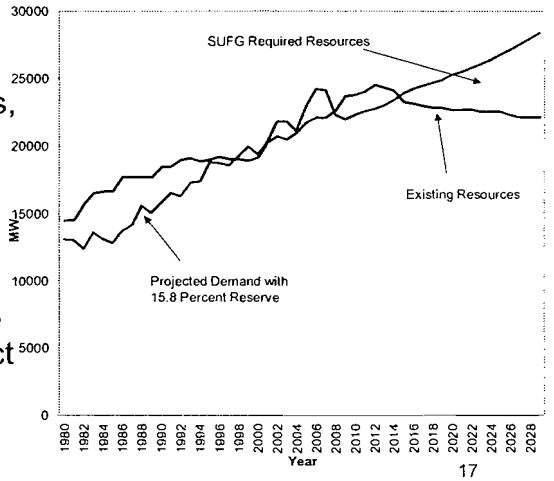
Indiana Resource Requirements

- Resources may be provided by conservation measures, contractual purchases, purchases of existing assets, or new construction
- Existing resources are adjusted into the future for retirements, contract expirations, and IURC approved new resources



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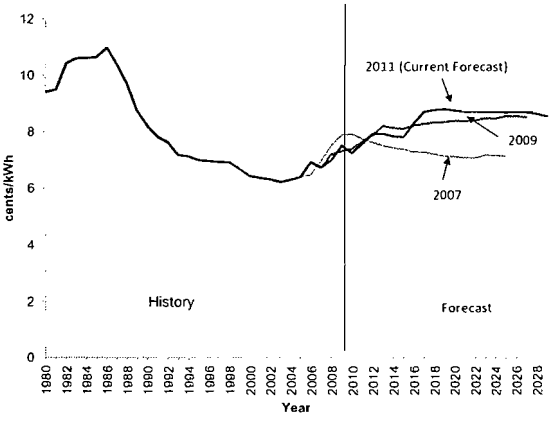
Indiana Real Price Projections (2009 $)

- Effect of inflation removed
- Includes the cost of new resources
- Does not include cost of expected EPA regulations
  - unless utility has already taken steps or included costs in data request



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Environmental Regulations

- SUFG will be doing a study of the expected impacts of recent, proposed, and expected EPA regulations
  - Cross-State Air Pollution Rule
  - Mercury and Air Toxics Standards
  - Greenhouse gases
  - Cooling water
  - Coal ash

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Further Information

State Utility Forecasting Group
765-494-4223
sufg@ecn.purdue.edu
http://www.purdue.edu/dp/energy/SUFG/

Douglas Gotham
765-494-0851
gotham@purdue.edu

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Update on Federal Regulations Impacting the Electric Industry September 21, 2011

RFSC 9/21/2011 Ex F

Thomas W. Easterly, P.E., BCEE, QEP
Commissioner, Indiana Department of Environmental Management

IDEM's Mission

We Protect Hoosiers and Our Environment

IDEM's mission is to implement federal and state regulations to protect human health and the environment while allowing the environmentally sound operations of industrial, agricultural, commercial and government activities vital to a prosperous economy.

How Does IDEM Protect Hoosiers and Our Environment?

- Develop regulations and issue permits to restrict discharges to the environment to safe levels.
- Inspect and monitor permitted facilities to ensure compliance with the permits.

How Does IDEM Protect Hoosiers and Our Environment?

- Use compliance assistance and/or enforcement when people exceed their permit levels or violate regulations.

- Educate people on their environmental responsibilities.

25 Years of Progress

http://www.in.gov/idem/files/state_of_environment_2011.pdf

IDEM
25
Years
Indiana Department of Environmental Management
Air
Land
Water
Pollution Prevention
25th Anniversary
State of the Environment 2011

REMARKABLE AND CURIOUS TIMES

- Power plants are getting cleaner and cleaner.
- Air quality is getting better and better.
- The economy is on its back.
- Worldwide debate over the future of energy policy.
- Increasing restrictions on the mining and burning of coal and the disposal of coal ash.
- An avalanche of new action directly against power generation in general and coal-fired generation, in particular.

UNPRECEDENTED FEDERAL INITIATIVES

Clean Air Act

- CAIR (Clean Air Interstate Rule)/Transport rule/CSAPR (Cross State Air Pollution Rule)
- NAAQS revisions—SO_2, NO_x, Ozone, $PM_{2.5}$
- Mercury / HAPS (Hazardous Air Pollutants)
- Greenhouse Gasses including CO_2

Clean Water Act

- Intake structures (316(b))
- Effluent guidelines

Resource Conservation and Recovery Act (RCRA)

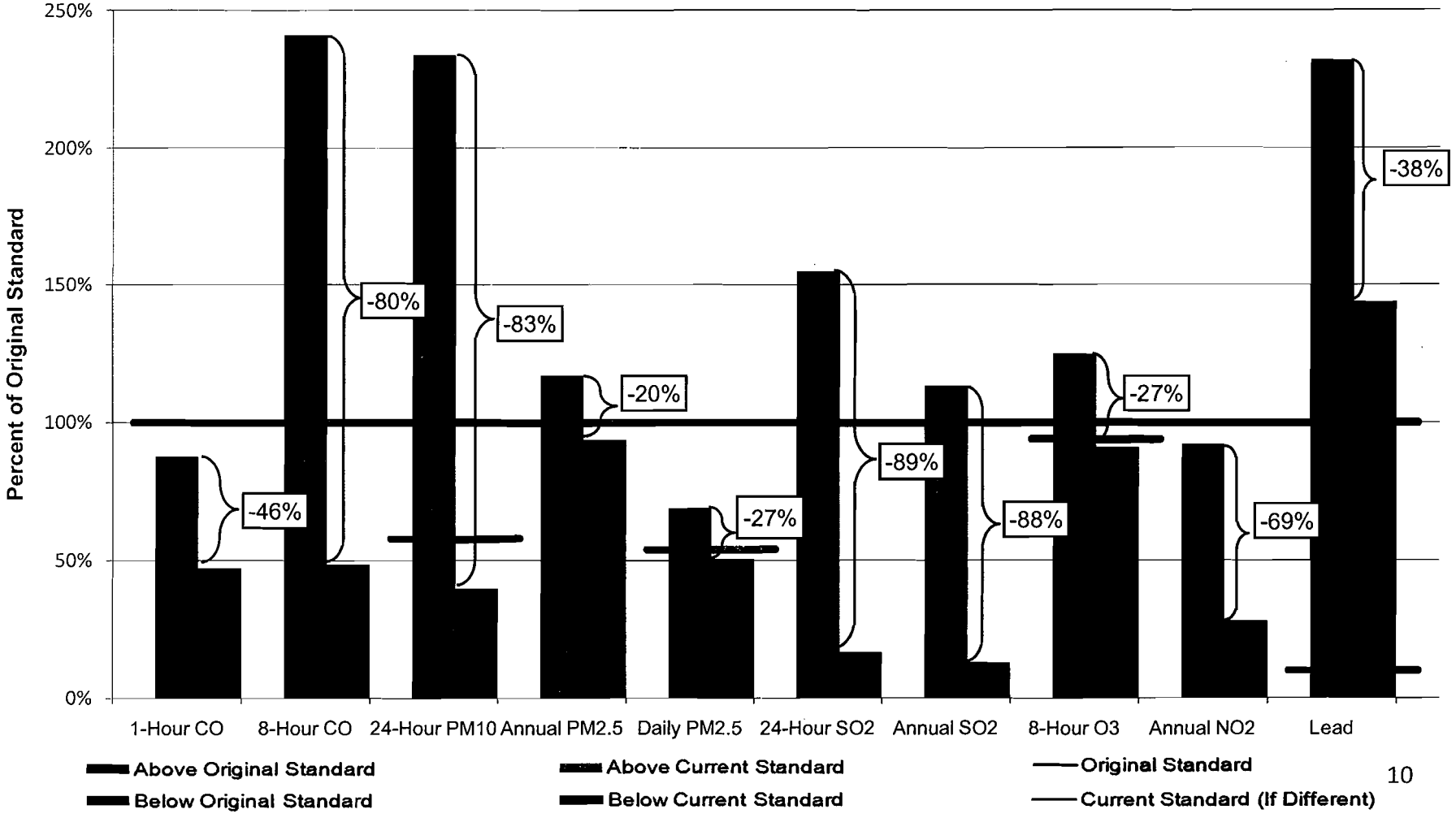
- Coal combustion residuals (CCR)

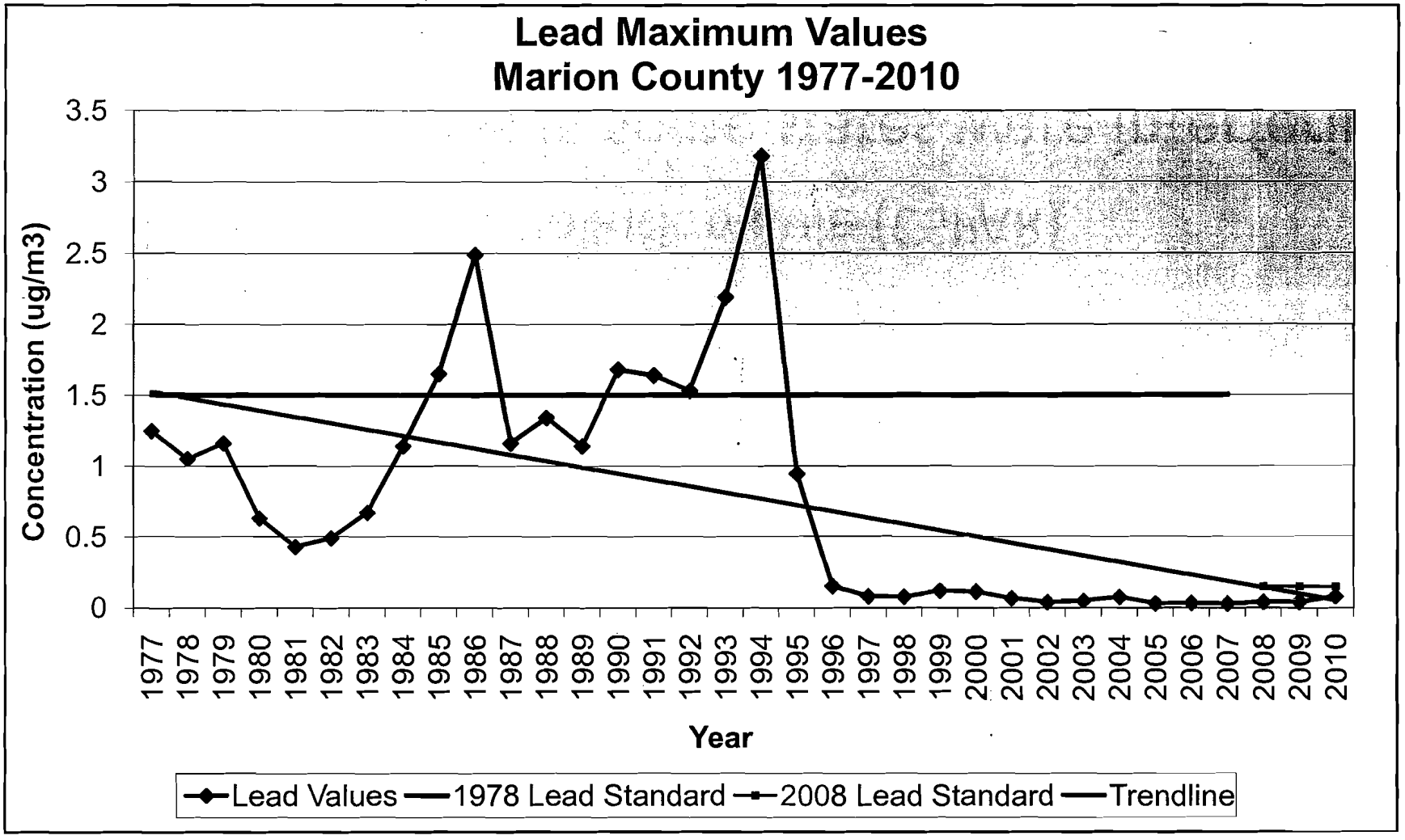
IN Air Quality Progress

- At the end of 2009, for the first time since ambient air quality standards were developed, all of Indiana met all of the health based ambient air quality standards (including the 0.075 ozone standard).

- During 2010, the new 0.15 microgram per cubic meter lead standard became effective and almost 700 people may be breathing air above that new standard. IDEM is working to make sure that those Hoosiers have clean air to breathe.

Percent Difference Between Highest Historical Monitored Concentration (Left Bar) and Highest Most Current Monitored Concentration (Right Bar) - Statewide




Lead Maximum Values
Marion County 1977-2010
Concentration (ug/m3)
3.5
3
2.5
2
1.5
1
0.5
0
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Year
Lead Values
1978 Lead Standard
2008 Lead Standard
Trendline

Protection of Downwind States

- The concept of the series of air transport rules:
  - Clean Air Interstate Rule (CAIR)
  - Transport Rule
  - Cross States Air Pollution Rule (CSPAR)

  is that emissions in some states were interfering with the attainment of air quality standards in other states.

Protection of Downwind States

- In 2005 a number of Counties including three in Indiana did not meet all ozone and $PM_{2.5}$ air quality standards. U.S. EPA projected that over 100 counties would still not meet standards by 2012.
- By the end of 2009 air quality in Indiana and much of the country had improved to meet the Ozone and $PM_{2.5}$ air quality standards.

Protection of Downwind States

	Ozone	$PM_{2.5}$ (Annual)	$PM_{2.5}$ (24-Hour)
EPA predicted 2012 Non Attainment counties (based upon 2005 air quality)	11	32	103
Counties Attaining by 2009	9	27	83
Counties still needing improvement	2	5	20

Protection of Downwind States

- Modeled projections by some groups indicate that all areas of the country impacted by transport may achieve the Ozone and PM standards without the emission reductions being required by CSAPR.
- The use of the 2005 as the base year instead of a more recent year and U.S.EPA's triple weighting of the base year are bad for Indiana.

CAIR/Transport Rule/CSAPR

- IDEM expected to meet the Transport Rule Statewide caps for 2012 without additional controls, CSAPR reduced those caps by 29%--not currently achievable.
- IDEM expected that we would need one current project completed and another source controlled to meet the 2014 caps. CSAPR reduced the caps by 20%.
- CSAPR annual cost estimated to be $2.4 billion.

CAIR/Transport Rule/CSAPR

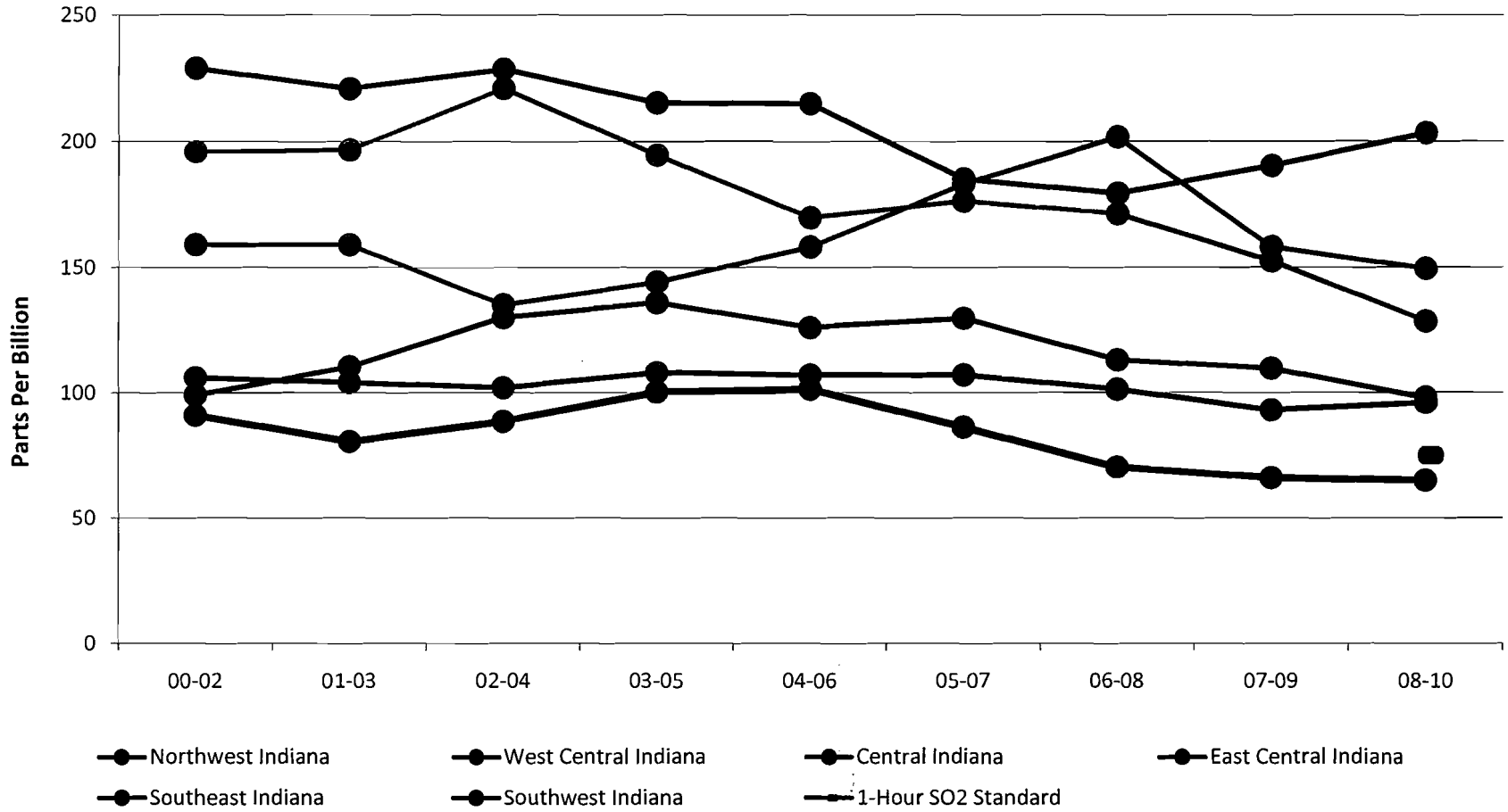
- U.S. EPA is implementing CSAPR through a Federal Implementation Plan (FIP) before allowing the States to implement the rule.
- The State has no role in CSAPR unless we modify our State Implementation Plan (SIP).
- U.S. EPA has told us that they will approve our requests to redesignate the State of Indiana to attainment for $PM_{2.5}$ now that CSAPR is in effect.
- This rule will also allow U.S. EPA to approve our BART SIP submission.

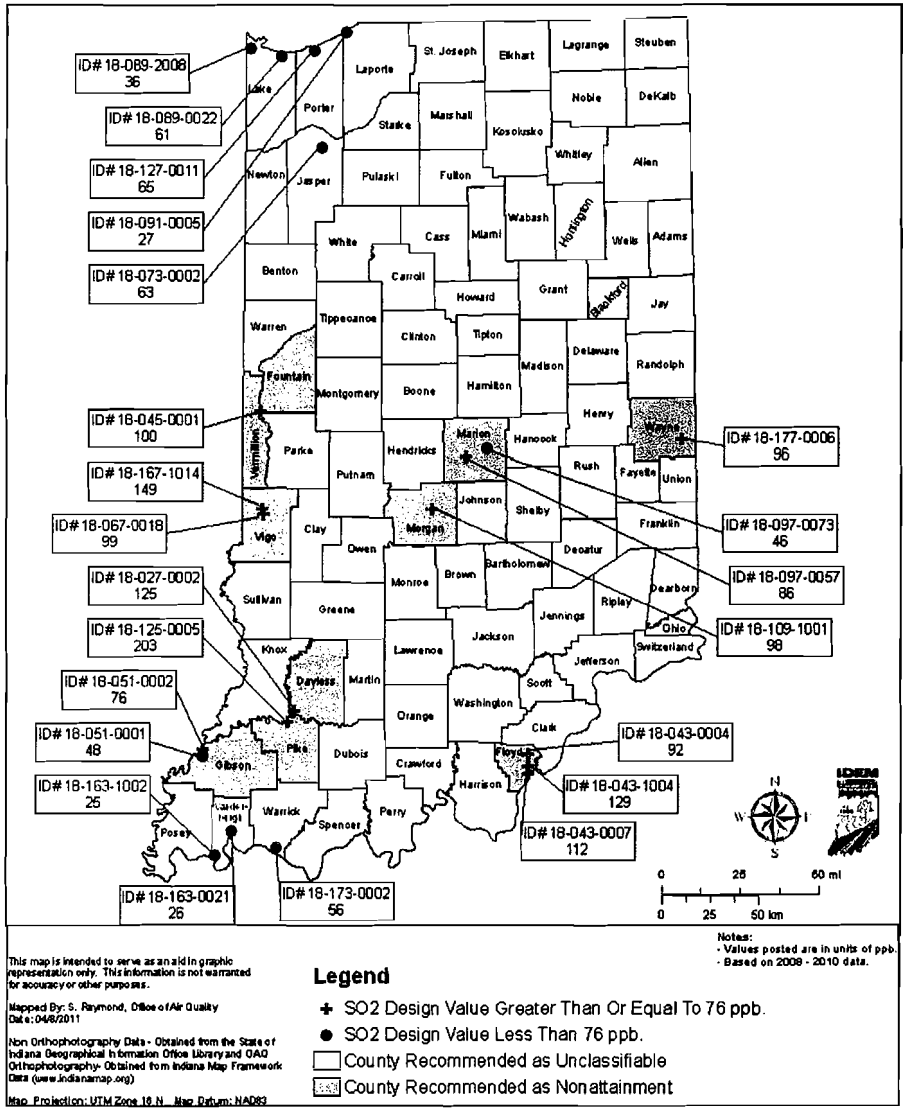
NAAQS Revisions

At the end of 2009, all of Indiana met every currently effective NAAQS for the first time since NAAQS were established in the 1970's.

- New 75 ppb 1 hour SO_2 Air Quality Standard (2010).
- New 100 ppb short term NO_x Air Quality Standard (2010).
- U.S. EPA reconsideration of 0.075 ppm ozone Air Quality Standard.
- U.S. EPA review of the 15 microgram/cubic meter annual $PM_{2.5}$ Air Quality Standard.

1-Hour Sulfur Dioxide (SO_2) – Maximum 1-Hour Design Value Trends





This map is intended to serve as an aid in graphic representation only. This information is not warranted for accuracy or other purposes.

Mapped By: S. Raymond, Office of Air Quality
Date: 04/8/2011

Non Orthophotography Data - Obtained from the State of Indiana Geographical Information Office Library and OAQ Orthophotography- Obtained from Indiana Map Framework Data (www.indianamap.org)

Map Projection: UTM Zone 16 N Map Datum: NAD83

Notes:
- Values posted are in units of ppb.
- Based on 2008 - 2010 data.

Legend

- ✚ SO2 Design Value Greater Than Or Equal To 76 ppb.
- ● SO2 Design Value Less Than 76 ppb.
- County Recommended as Unclassifiable
- County Recommended as Nonattainment

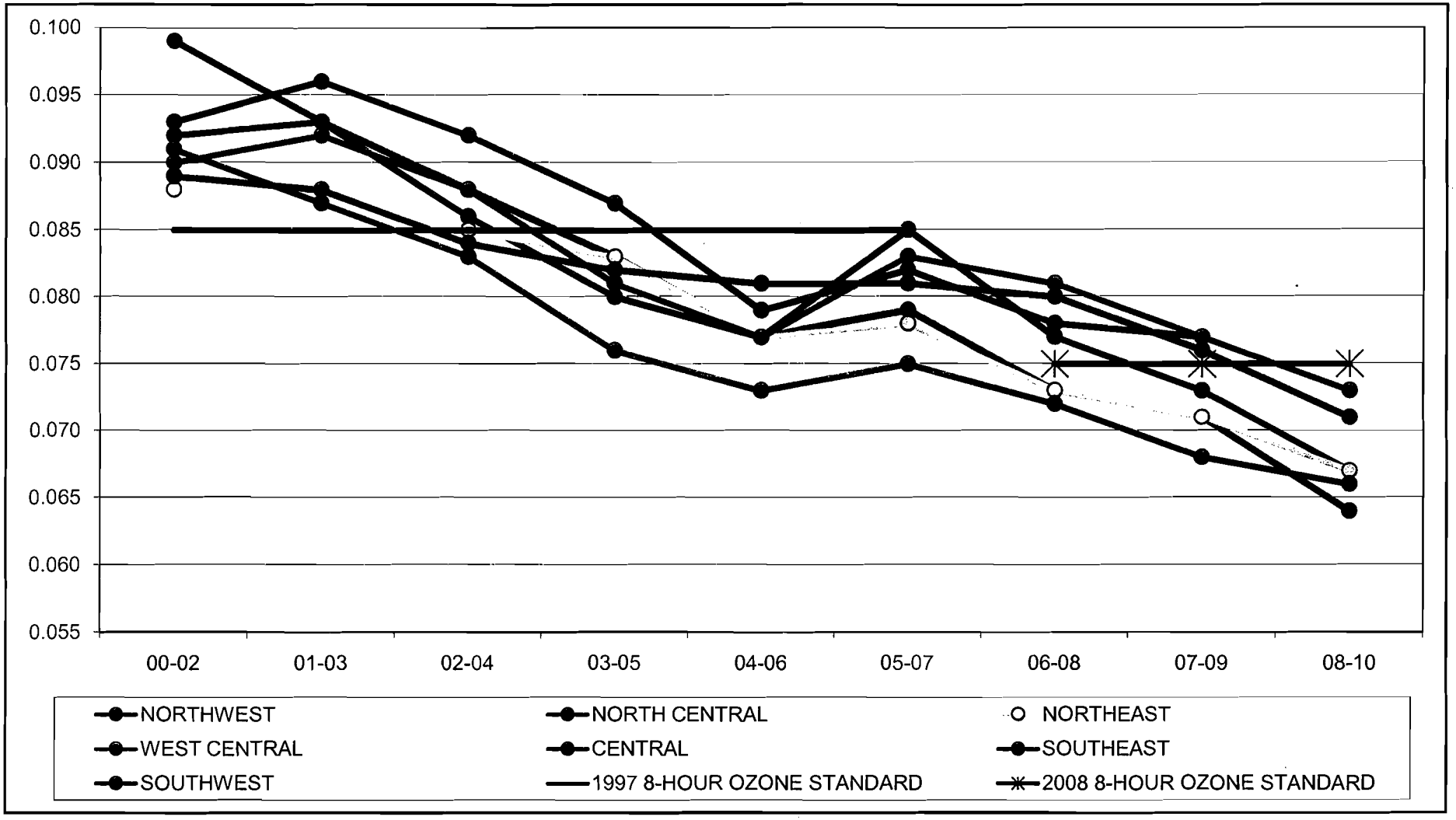
Indiana Preliminary Designation Recommendations SO2 1-Hour Standard

June 6, 2010:
U.S. EPA Announced A New SO2 1-Hour Standard Set At 75 ppb

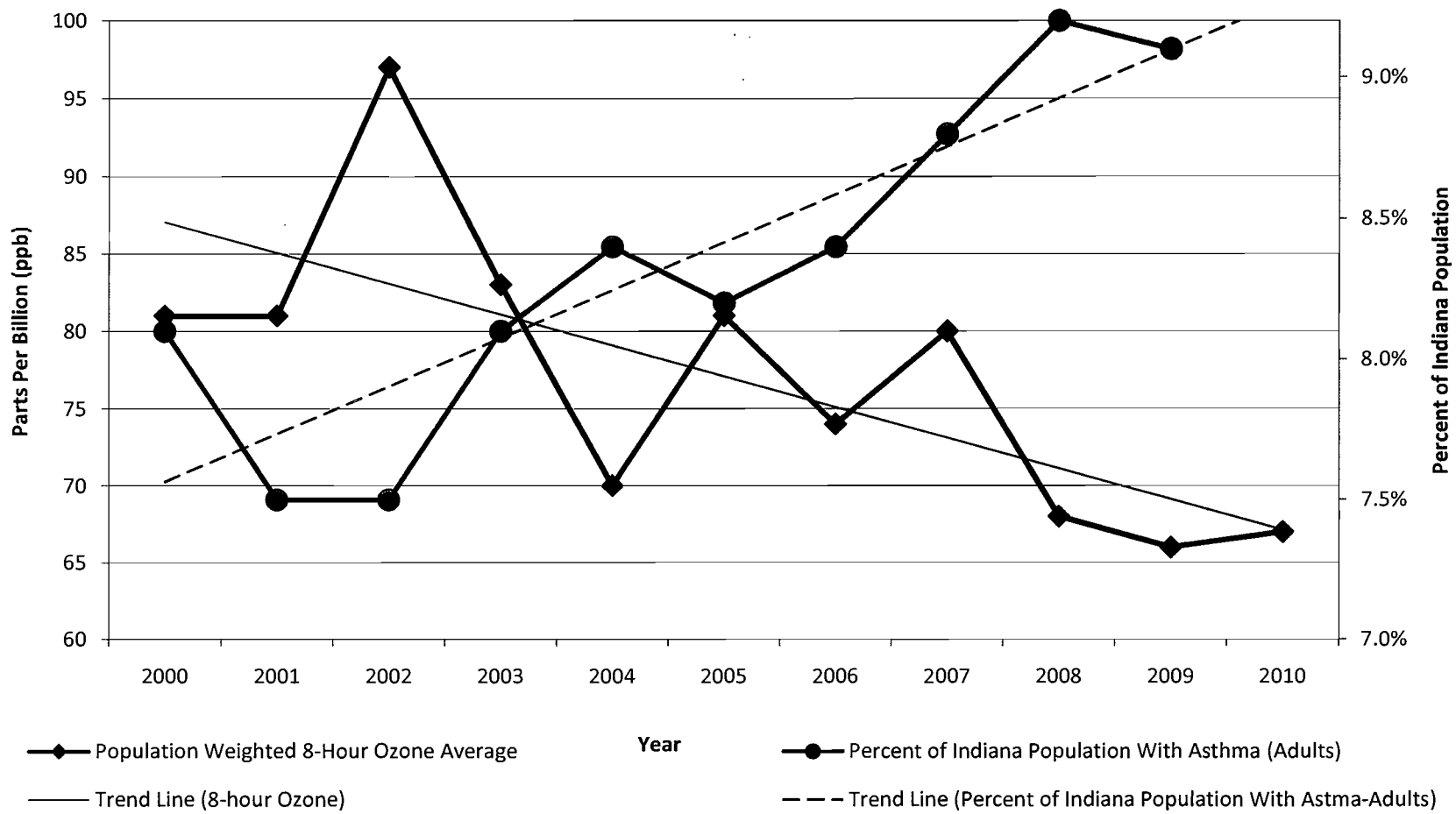
NAAQS REVISIONS - OZONE

- Administrator Jackson stated that the current 0.075 ppm (8 hour average)ozone standard did not protect public health and would be reconsidered.
- On January 19, 2010 U.S. EPA proposed a new standard (0.060 – 0.070 ppm).
- **Good news:** On September 2, 2011, President Obama cancelled the reconsideration—next ozone standard revision will be on the normal schedule (2013).

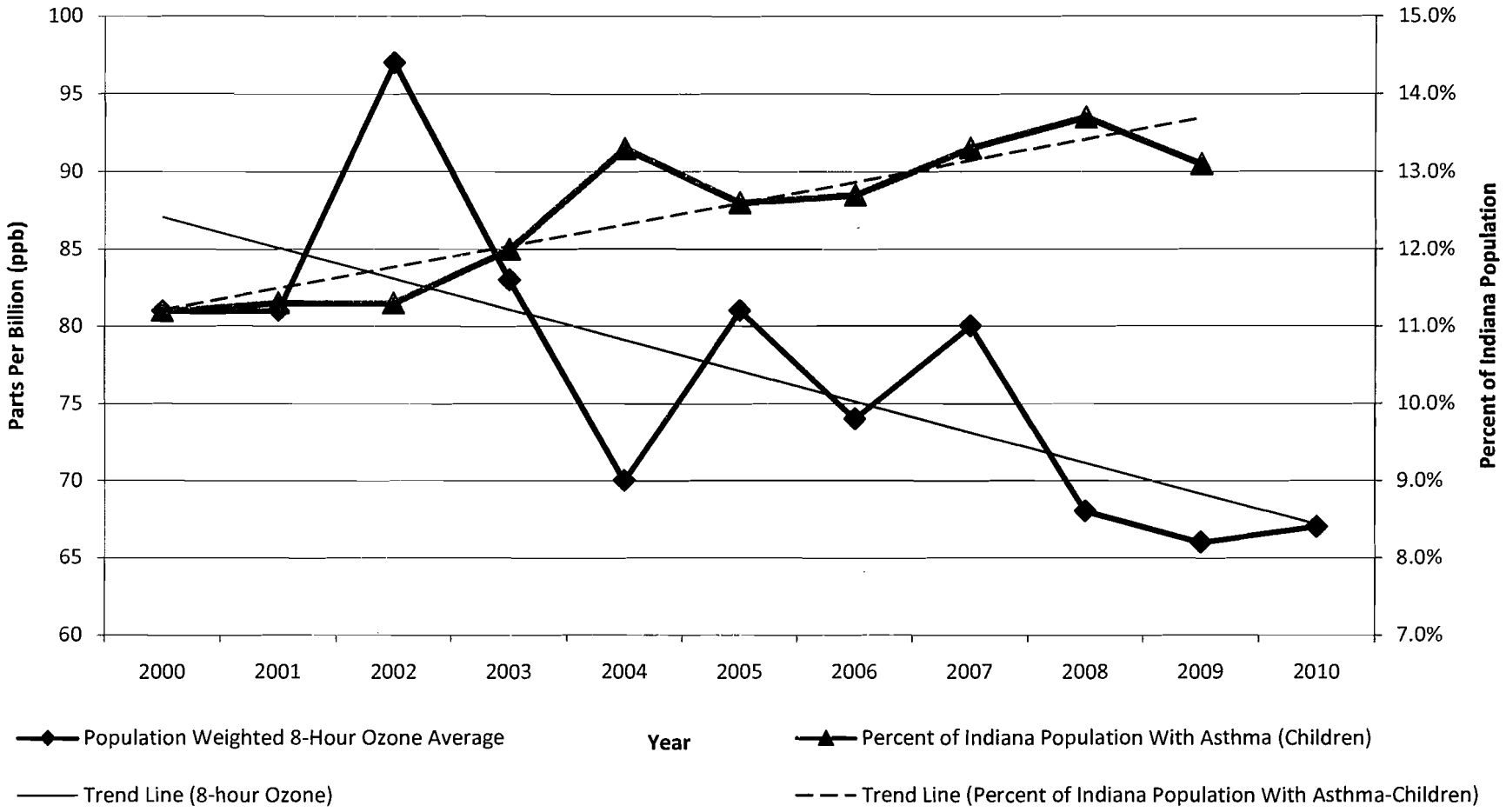
Ozone – Maximum Design Value Trends

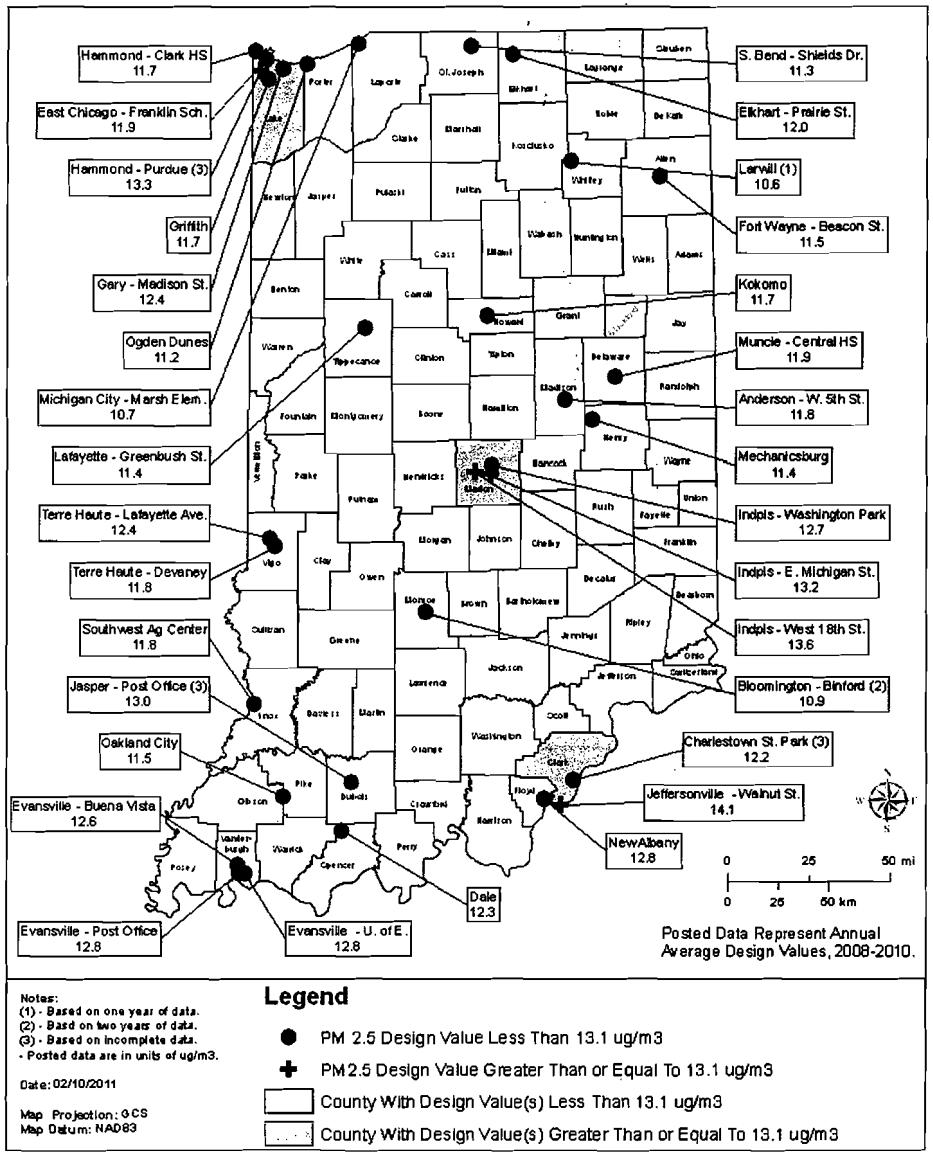


Population Weighted Ozone Trend Compared To Adult Asthma Trend



Population Weighted Ozone Trend Compared To Children Asthma Trend



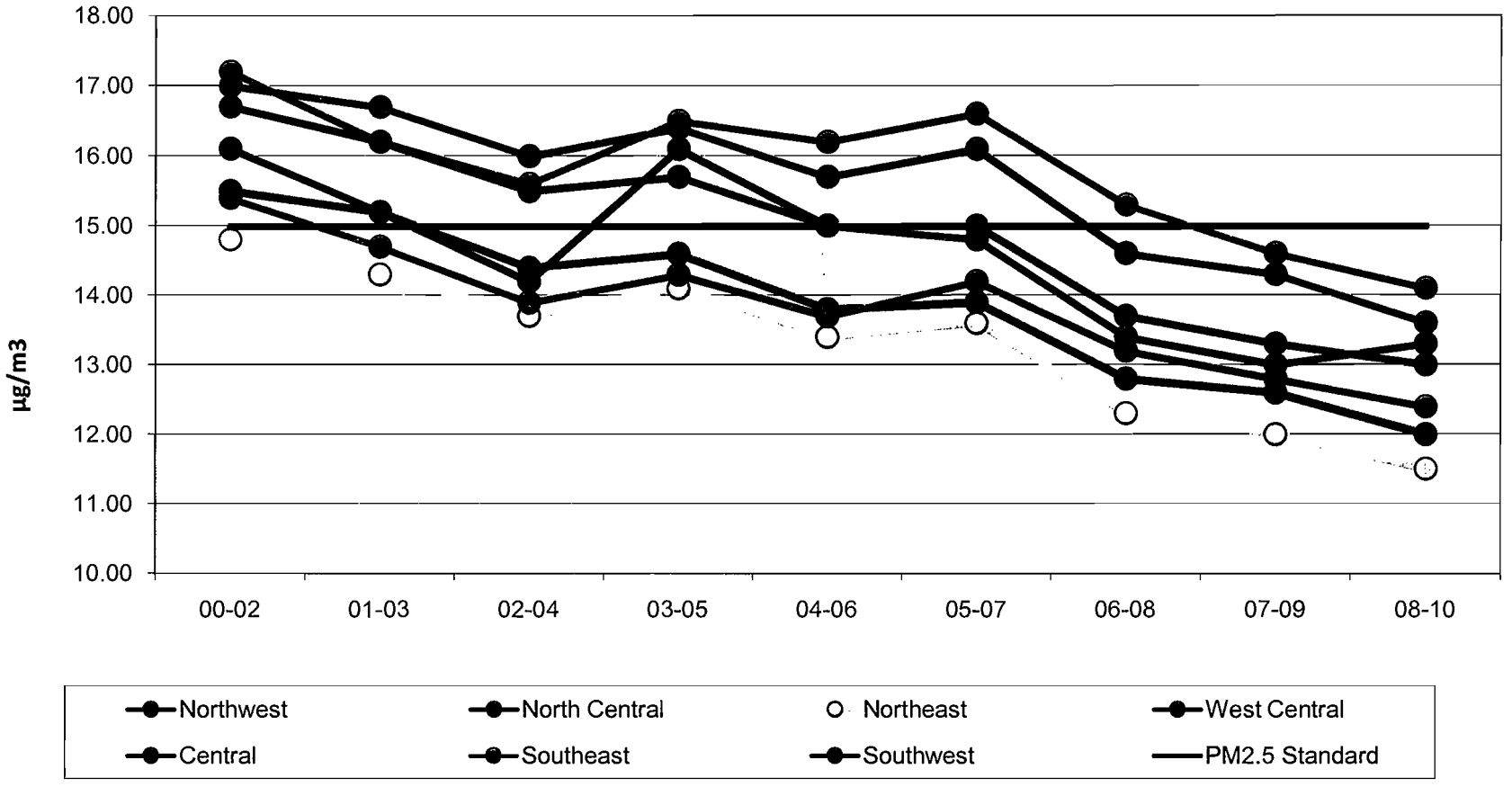


PM2.5 Annual Design Values (3-yr Average) Based on 2008-2010 Monitoring Data

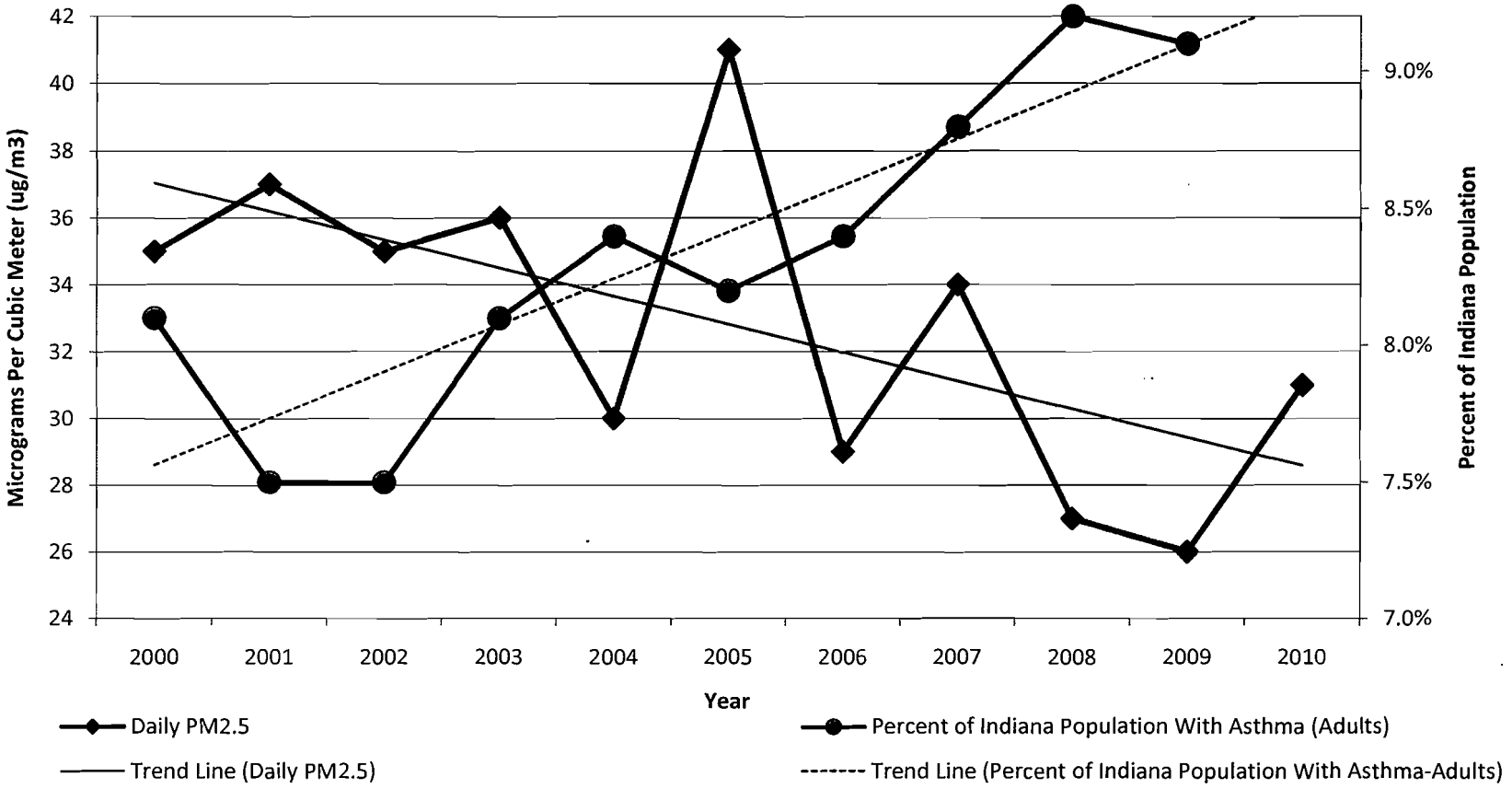
Standard at **13** $\mu g/m^3$

March 15, 2010:
U.S. EPA Announced It Would Reconsider The Annual PM2.5 Standard Within A Range Of 11-14 $\mu g/m^3$

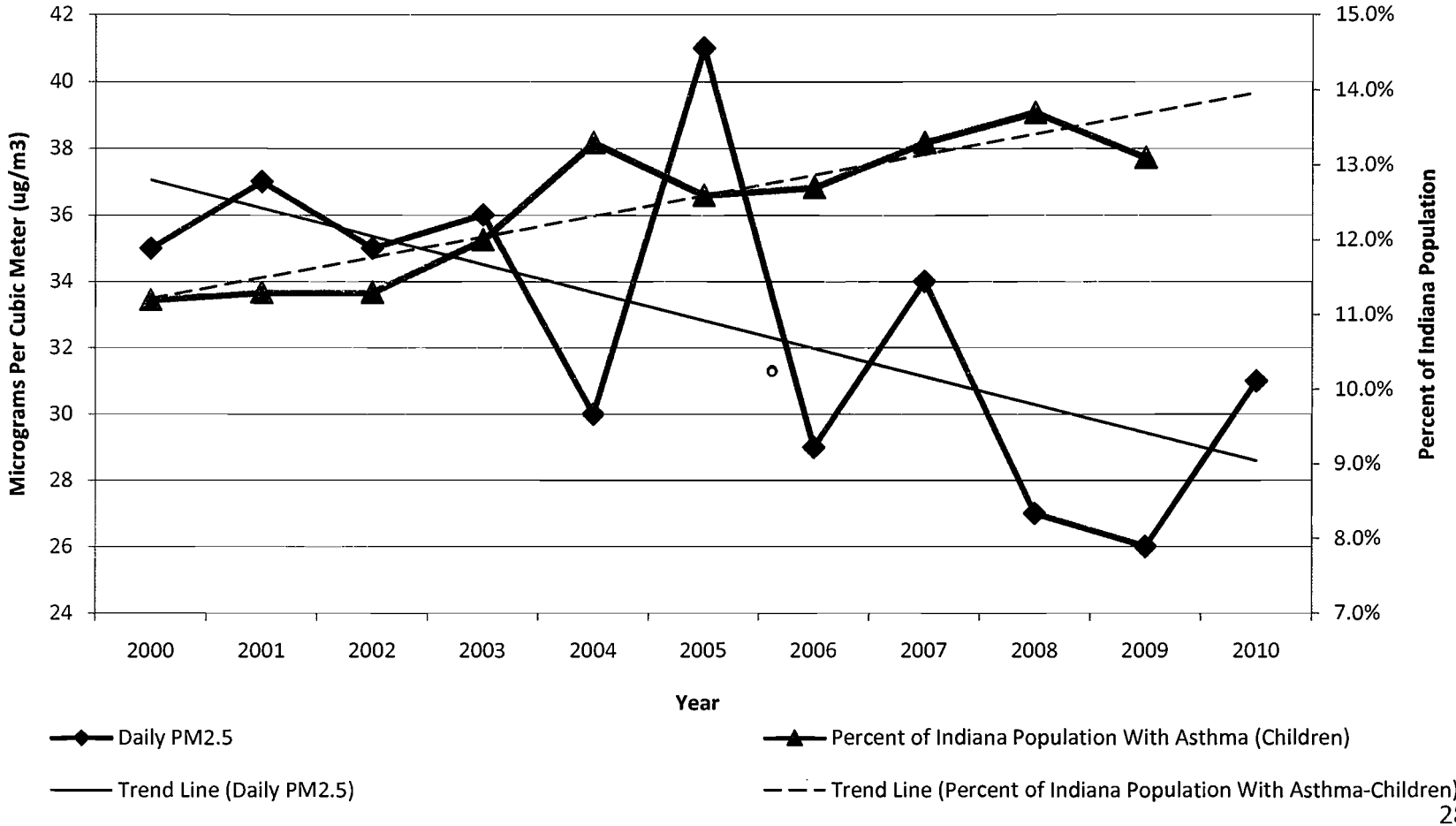
Fine Particle (PM2.5) – Maximum Annual Design Value Trends



Population Weighted Particulate Matter (PM2.5) Trend Compared to Adult Asthma Trend



Population Weighted Particulate Matter (PM2.5) Trend Compared To Children Asthma Trend



MERCURY MACT (NESHAP)

Proposal Published: May 3, 2011

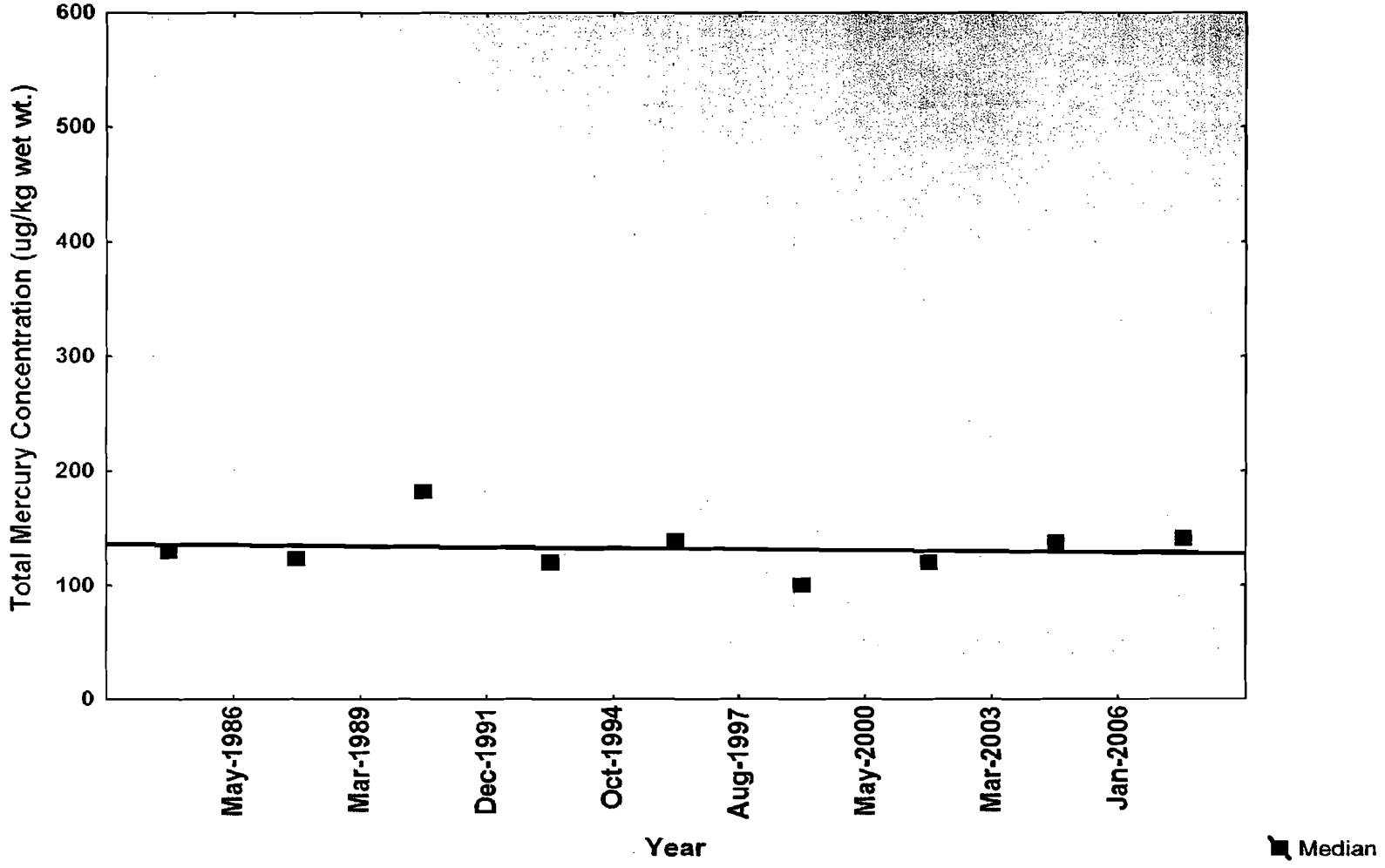
Final Deadline: November 16, 2011

- Annual rule cost $10.9 billion.
- Annual rule HAP benefit $5,000 to $6,000,000 (0.00209 IQ points per exposed person or 510.8 IQ points per year in US out of 31 billion IQ points)
- Rule cost is between $1,211 and $2,180,000 per $1 of HAP benefit.
- Estimated annual co-benefits $53 to $140 billion.

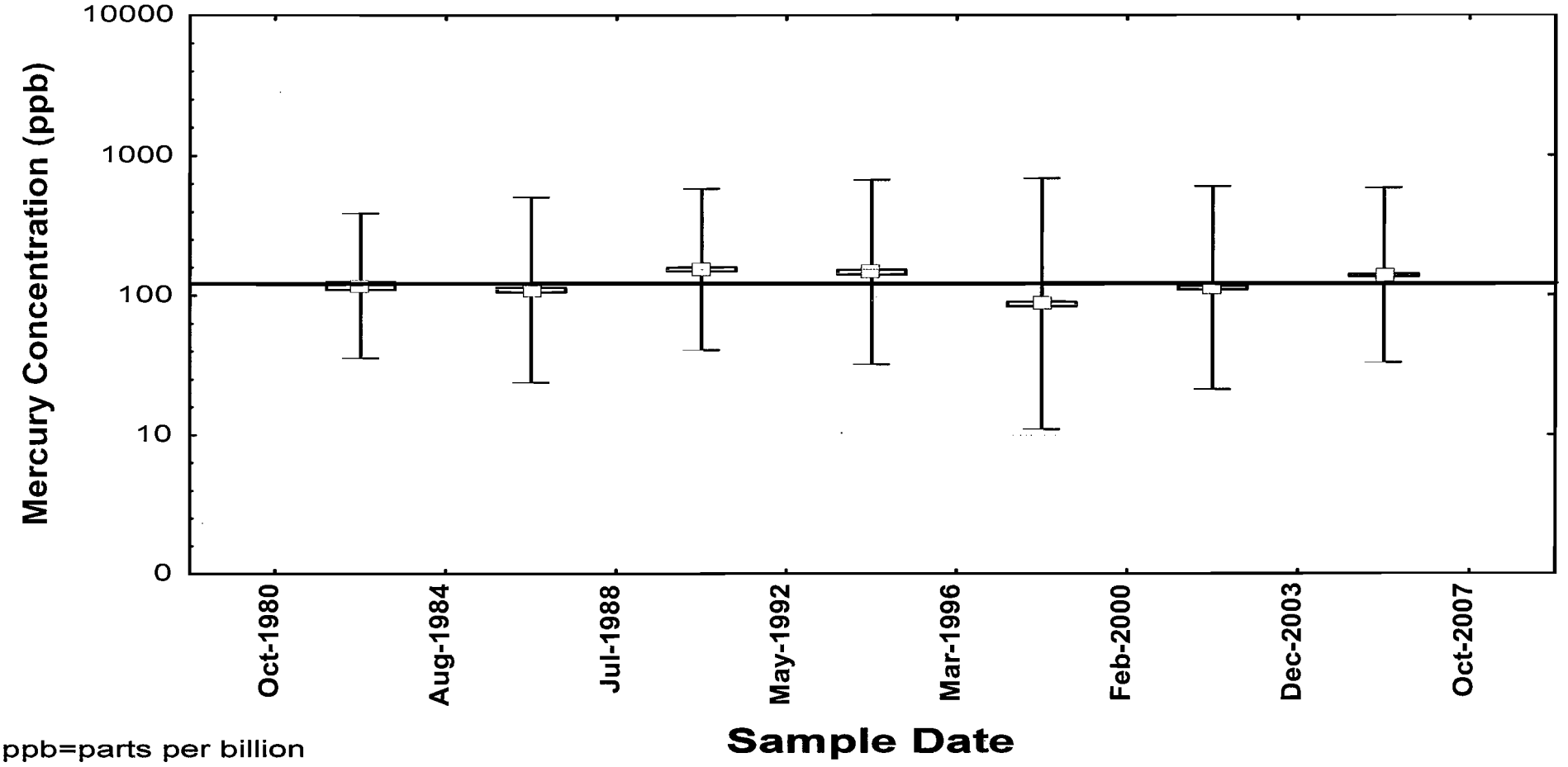
MERCURY MACT (NESHAP)

- HAPS: Hg, HCL, PM, THC, Dioxins / Furans
- Rule requires about 90% reduction in mercury emissions.
- No MACT trading (except units at a single site).
- Mercury emissions in Indiana have decreased by approximately 20% over the past 14 years, but measured mercury deposition has decreased by only 7% and there is no apparent change in mercury fish concentrations in Indiana.

Trend of total mercury concentrations in Indiana fish since 1983

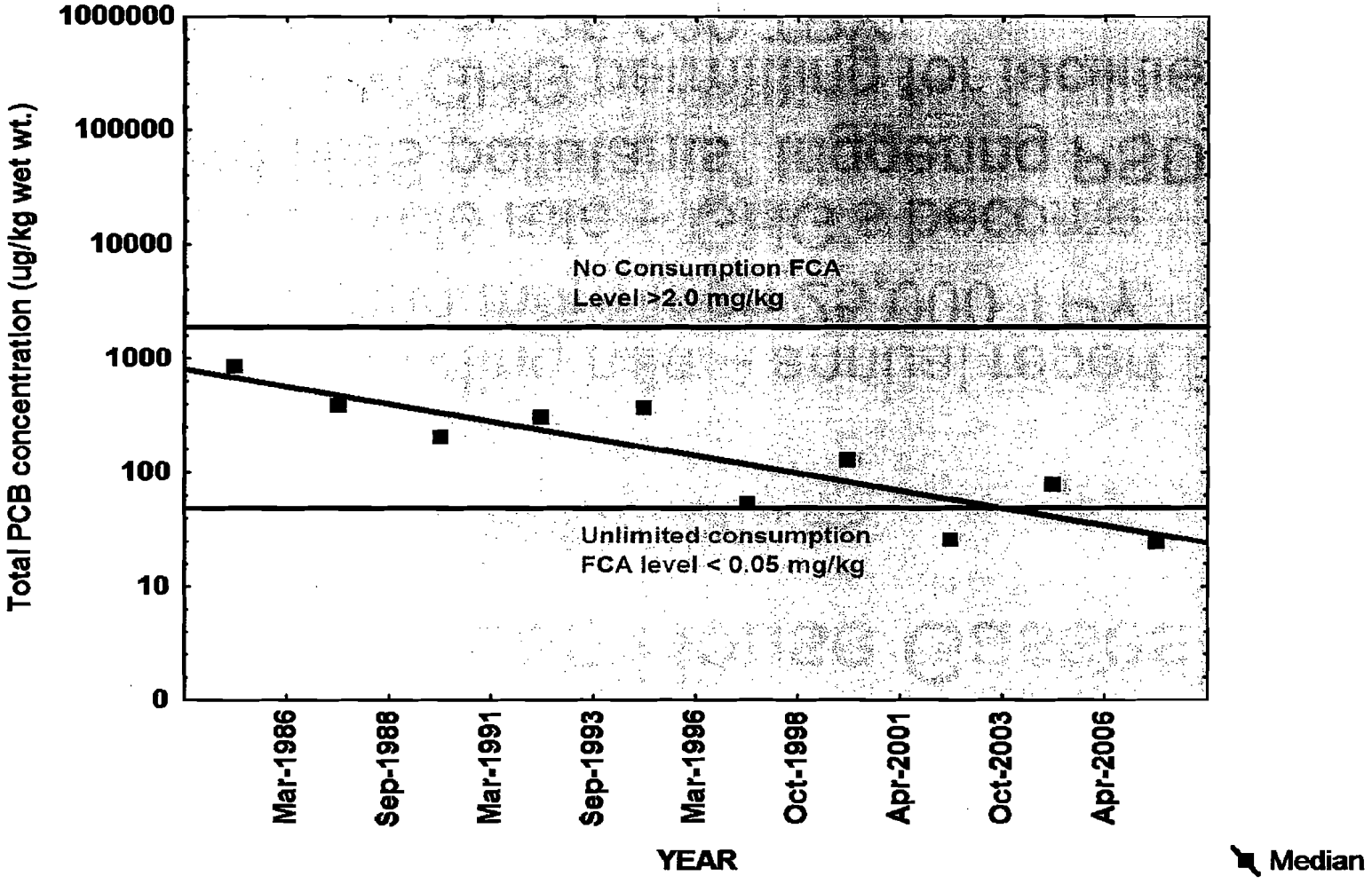


Mercury Concentration in Indiana Fish 1983 - 2006



ppb=parts per billion

Trend of Total PCB in Indiana Fish 1983-2008



CO_2 (Green House Gasses)

U.S. EPA Clean Air Act initiatives:

- Mandatory reporting rule – annual report for facilities emitting more than 25,000 TPY.
- Light duty vehicle rule – GHG's become "regulated NRS pollutants" triggering PSD.
- Tailoring rule – GHG permitting for facilities emitting more than 25,000 TPY.
- BACT Guidance issued November 2010.
- Other initiatives temporarily tabled.

CO_2 (Green House Gasses)

The National Academy of Sciences report, "*America's Climate Choices*" recommends that actions be taken now to start reducing U.S. greenhouse gas emissions to levels between 50% and 80% below 1990 levels.

- Achieving an 80% reduction from 1990 levels would require a 81.4% reduction from 1999 levels.
- If we converted all U.S. fossil fuel use from coal and oil to natural gas, we would achieve a 23.9% reduction from 1999 levels.

CO_2 (Green House Gasses)

- The remaining emissions would need to be reduced by 73.8% to reach the 80% target.
- Apparent choices are:
  - Energy conservation.
  - Increasing non-hydro renewable energy sources from the current 5.5% market share.
  - Carbon sequestration.
  - Nuclear electricity.
- Is it possible to achieve the additional 73.8% reduction?

Clean Water Act – (316(b))

- 316(b) is a section of the Clean Water Act designed to reduce the damage to aquatic organisms from impingement on the intake structures and entrainment in the water passing through a facility.
- Factors to be considered in a 316(b) assessment:
  - Is through screen velocity sufficiently low to allow fish to escape?
  - What is the mortality rate of aquatic life impinged/entrained?
  - Has there been a sufficient reduction in the amount of aquatic life impinged/entrained?
  - Has there been a sufficient reduction in the mortality of aquatic life impinged/entrained?

Clean Water Act – (316(b))

Proposed: April 20, 2011

Good news: Does not mandate retrofitting closed-cycle cooling to address entrainment at all facilities covered by the rule.

Bad news: Inflexible one-size-fits-all approach to minimizing impacts due to impingement of aquatic organisms by cooling water systems.

CLEAN WATER ACT – EFFLUENT GUIDELINES (technology based effluent limits)

- Notice of plan availability: **Preliminary 2010 Effluent Guidelines Program Plan** December 28, 2009
  (74 Fed. Reg. 68599)
- Request for information : **Questionnaire for Steam Electric Power Generating Effluent Guidelines** March 9, 2010
  (75 Fed. Reg. 10791)

Highlights:

- "high levels" of toxic weighted pollutants
- Caused by air pollution control systems
- Various wastewater treatment systems under investigation

Coal Combustion Residuals (CCR)

Proposed rule: June 21, 2010 (75 Fed. Reg. 35127)

- Beville amendment and actual waste characteristics have historically exempted CCR from Subtitle C (hazardous waste) regulation .
- December 2008 coal ash spill in Tennessee has caused that exemption to be reviewed
- Options being considered include:
  - phase out all surface impoundments in favor of landfills.
  - allow surface impoundments, but with stricter controls.

Coal Combustion Residuals

- IDEM data indicates that CCR do not exhibit hazardous characteristics, therefore, they should not be regulated under Subtitle C.
- IDEM believes that U.S. EPA should develop reasonable minimum national management standards for surface impoundments and landfills under Subtitle D.
- Due to volume of public comments, U.S. EPA will not publish a final rule until sometime in 2012.

Questions?

INDIANA OFFICE OF ENERGY DEVELOPMENT

- Update regarding our office and the programs it has been managing over last two years
- Update on current programs
- Update on the Hoosier Homegrown Energy Plan and its accomplishments
- Questions

Past, Present and Future: Program Background

- OED funding primarily comes from the USDOE and currently we are under two major funding sources SEP (state energy program) ARRA and SEP Regular.
- ARRA totaled nearly $90M dollars in multiple prescribed programs, and those are the "stimulus" dollars.
- SEP Regular comes every year and averages between $600K and $1M per year.

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RFSC
9/21/11
Ex. G

The ARRA Programs

- SEP: $68M primarily used for courting green jobs to Indiana in the manufacturing sector.
- EECBG: Energy Efficiency Conservation Block Grant was funded with $14M and 60% went to non-entitlement communities and of that share, 40% went for a small business non-profit energy conservation grant.
- IHIP: Indiana HVAC Incentive Program was funded with $6M and went to ENERGY STAR rated furnaces, boilers, central AC and heat pumps.
- CHIP: Conserving Hoosier Industrial Power was funded with $2M and dedicated to our largest energy users for various eligible energy conservation projects.

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SEP: Green jobs and green manufacturing

- OED continues its partnership with IEDC in placing the SEP ARRA dollars in order to expand the green economy in Indiana
- Sectors include batteries, wind components, solar components, energy efficient appliance makers.
- These dollars are flowing now into the Hoosier economy and will continue through rest of 2011.

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EECBG: Communities and Business benefit

- 104 grants were awarded to 84 eligible communities, counties or local government units in lighting retrofits, traffic signal/street light retrofit, structure retrofits, waste water treatment, and energy management systems.
- 50 grants were awarded to small businesses, health care facilities, higher education, and non-profits for structural energy efficiency retrofits

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IHIP: Helping Hoosiers stay ahead of the weather...

- OED's management of the IHIP program has been recognized by the USDOE a one of the nation's best rebate programs.
- 15,000 Hoosiers received rebates with a average of $400 per rebate
- The program infused $23M dollars into the economy for retailers and manufacturers of the products.

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CHIP: Helping industry help themselves...

- Conserving Hoosier Industrial Power (CHIP) awarded grants for commercial/Industrial energy efficiency projects
- Developed originally to be a low interest loan program but loans garnered very few applications.
- Once becoming a grant program over 30 large energy users applied for grants.
- 11 projects received the awards and many of the projects are saving immense amounts of energy with modest incentive.

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Current Programs-CHIP

Back by popular demand....

- Competitive grants for Commercial/Industrial sector energy efficiency upgrades
- Grants from $100,000 to $500,000
- Application period closes September 23
- Eligible technologies include lighting, HVAC, insulation, windows, energy management systems/controls, pumps, motors and more.

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Current Programs-CEP

- Community Energy Plan
  - 18 of Indiana's smaller communities awarded grants as part of competitive program
  - Audit will lead to creation of strategic energy plan
  - Free to the community.
- Audits/plans will be created Schmidt Associates, chosen thru RFP process

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Current Programs-CEP

- Alternative Fuel Vehicle (AFV) Fleet Grants
  - $40,000-$500,000 grants to buy or retrofit AFV vehicles for fleet use.
  - On-road vehicles
  - Application closes September 30, 2011
  - Applicants must work with Clean Cities organization.

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Current Programs-Energy Action In Schools

- Energy Action in Schools
  - Available to all schools K-12 on a competitive grant basis.
  - Provides curriculum, materials, support for participating schools.
  - Application closes September 30, 2011
  - Partners with National Energy Foundation and Duke Energy
  - Students work with school administrators to improve energy efficiency in their buildings.

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Other Programs/Partnerships

- OED shepherding an overhaul of Indiana energy related building codes
- Retrofit Ramp-up--$25 million project with Indy/Lafayette for community-wide energy efficiency projects
- Greater Indiana Clean Cities Coalition-- $11 million project to convert some 900 public and private sector fleet vehicles to alternative fuels (CNG/Flex-Fuel/Propane)

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Homegrown Energy Plan Update

- First energy plan for state in 20 yrs
- Developed around our strengths coal, biofuels, wind, and energy conservation
- 13 ethanol and 3 biodiesel facilities producing over 1B gallons per yr.
- 7 new clean coal developments in various stages of planning and construction
- Leader in new wind development 2008-2009, over 800 turbines and 1500 MW of power.
- Developed new DSM order to reduce statewide energy use by 2% over next 10 years

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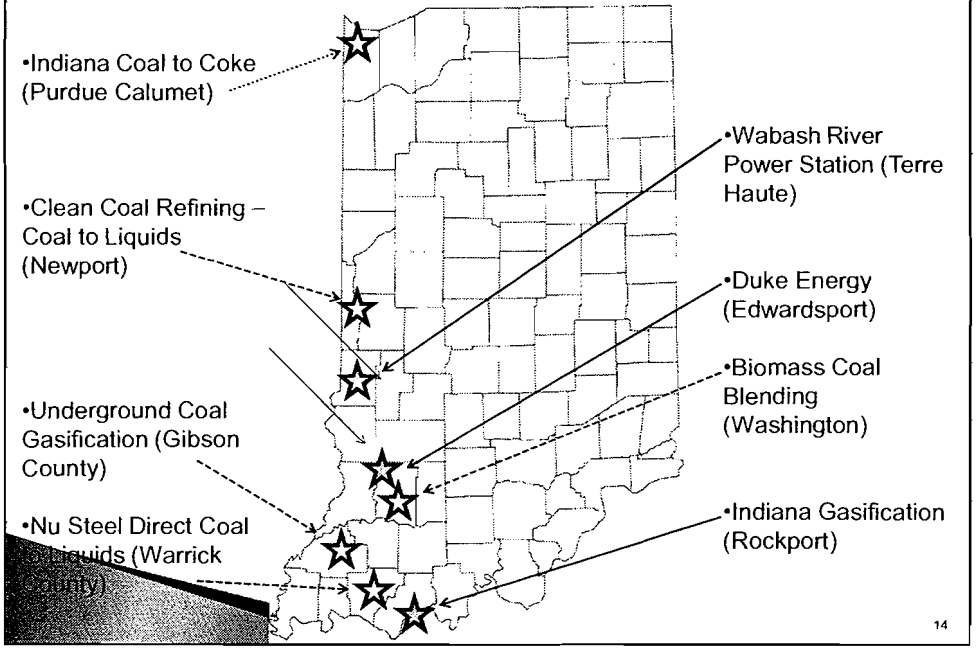
Indiana Coal Development Map



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Wind Power In Indiana

- **First**
- Indiana's first wind farm is the Benton County Wind Farm near Earl Park, Indiana, with 87 turbines generating 131 Megawatts.
- **Biggest**
- Indiana's biggest wind farm is Fowler Ridge in Benton County, with 355 turbines generating 600 Megawatts. When complete, the Meadow Lake wind farm in White County will be the largest wind farm east of the Mississippi River.

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Wind Power In Indiana

- **Numbers**
  - Approx 1500 megawatts of wind power in operation
  - Approx 900 turbines
- **The Future**
  - 4,065 MW of additional wind power anticipated
  - 2,257 additional turbines
- **Wind development, to one degree or another is on going in 32 Indiana counties.**
  - Exact number of new wind farms will depend on market factors

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Wind components

- Brevini in Muncie is making utility scale wind turbine gear boxes.
- GBT in Evansville set to make wind turbine blades and developing new technology
- Wind needs support from other technologies that could be battery or natural gas turbines near wind developed areas
- Over 140 Indiana business from developers, engineers, consultants, construction etc. have been involved in the wind development industry

Biofuels

- Traditional ethanol and biodiesel struggled in 2007-2009 but now these companies are back on track
- Infrastructure of over 140 E85 pumps for public use, still number 3 in the nation
- Industry will look toward new generation fuels made from non-grain sources
- Cellulose, still slowly getting out to commercial-economy and pricing are the big factors

Biomass, electric and gas

- OED has developed the Indiana Biomass working group to promote the industry among interested investors and technical partners
- SB 251 opens doors to wider range of eligible biomass feedstocks
- We should not waste waste...but use it for development of electric and gas substitutes to traditional fuels sources

Solar power

- Solar has been funded by OED in the past, small scale PV and solar thermal
- While some may argue this...numbers are still not economical
- Indiana has increased manufacturing of Solar components by attracting Abound Solar, Fronius, and NuSun to produce solar in Indiana

Electric Vehicles

- Indiana is developing an EV manufacturing sector with TH!NK North America in Elkhart and Ener1 making batteries for electric vehicles on NW side
- Energy Systems Network (ESN) leading the Project Plug-In study for the integration of EVs on the existing grid
- SEP-ARRA dollars specifically sent to enhance these projects

Energy Conservation

- Support of the DSM order that was released by IURC
- Funding SUFG to research and develop a database report on energy conservation in Indiana
- Developing OED programs discussed earlier in program
- Indiana Housing and Community Development is in charge of weatherization and the large conservation programs for residents

Energy Development after SB251

- What do we know?
  - Helps protect energy producers from the cost of federal environmental regulations
  - Brings nuclear power into the conversation of future energy sources and protecting current resources Indiana uses
  - Uses market based price points to insure that utilities and customers are not plagued with higher costs for using renewables
  - Opens up a very broad set of renewable sources and lets Hoosier developers decide which sources of power we will develop

SB 251 cont'd

- What we do not know...
  - What will the final rule from IURC look like?
  - What developments in renewable energy come about in the next 10 yrs to effect pricing?
  - How much energy (plant shut downs)will we be losing to environmental regulations and how will that effect energy costs?
  - Is natural gas the grand solution or today's flavor of the month, will the prices buck the trend and predictions?

Future energy sources

- Indiana has great potentials in all energy development because we have a wide range of resources.
- SMRs (small modular reactors) are being discussed and OED is at the table. Still years away but certainly need to understand what their potentials are.
- As always, there are no silver bullets in energy development, each source has its unique problems

Questions

Brandon Seitz
bseitz@oed.in.gov
317-232-8939

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