2006 INDIANA RENEWABLE ENERGY RESOURCES STUDY

Prepared by:
Douglas Gotham
David Nderitu
Giovanna Facetti
Forrest Holland
Ron Rardin
Zuwei Yu

State Utility Forecasting Group
Purdue University
West Lafayette, Indiana

Prepared for:
Indiana Utility Regulatory Commission and Regulatory Flexibility Committee of the Indiana Legislature
Indianapolis, Indiana

September 2006

Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

AC	Alternating current
AFC	Alkaline fuel cell
ASD	Agricultural Statistical District
AU	Animal unit
AWEA	American Wind Energy Association
Bcf	Billion cubic feet
BIPV	Building integrated photovoltaics
BTC	Breakeven turnkey cost
Btu	British thermal unit
CAFO	Concentrated animal feeding operation
CECA	Consumer Energy Council of America
CHP	Combined heat and power
COE	Costs of energy
CPV	Concentrating photovoltaic
CRP	Conservation Reserve Program
CSP	Conservation Security Program
DC	Direct current
DMFC	Direct methanol fuel cell
DOD	U. S. Department of Defense
DOE	U. S. Department of Energy
DOI	U. S. Department of Interior
EERE	Office of Energy Efficiency and Renewable Energy, DOE
EIA	Energy Information Administration, DOE
EPA	U. S. Environmental Protection Agency
ERO	Indiana Energy and Recycling Office
FCT	Fuel Cell Technologies
FEMP	Federal Energy Management Program
GEFCS	GE Fuel Cell Systems
GWh	Gigawatthour
HERC	Hydrogen Engineering Research Consortium
HES	Hydropower Evaluation Software
IBRC	Indiana Business Research Center, Indiana University
IDEM	Indiana Department of Environmental Management
INEL	Idaho National Engineering and Environmental Laboratory, DOE
kW	Kilowatt
kWh	Kilowatthour
LCOE	Levelized cost of energy
LFG	Landfill gas
LMOP	Landfill Methane Outreach Program, EPA
m/s	Meters per second
MACRS	Modified Accelerated Cost-Recovery System
MCFC	Molten Carbonate Fuel Cell
MGY	Million gallons per year
mmBtu	Million British thermal units

mmcf	Million cubic feet
mph	Miles per hour
MSR	Million Solar Roofs
MSW	Municipal solid waste
MW	Megawatt
MWh	Megawatthour
NIPSCO	Northern Indiana Public Service Company
NOFA	Notice of Funds Availability
NO_x	Nitrogen oxide
NRCS	Natural Resources Conservation Service, USDA
NREL	National Renewable Energy Laboratory, DOE
NYPA	New York Power Authority
O&M	Operation and maintenance
OAQ	Indiana Office of Air Quality
ORNL	Oak Ridge National Laboratory, DOE
PAFCs	Phosphoric Acid Fuel Cells
PEM	Polymer electrolyte membrane
PEMFCs	Polymer Electrolyte Membrane Fuel Cells
POLYSYS	Policy Analysis System
PTC	Production tax credit
PV	Photovoltaic
REPI	Renewable Energy Production Incentive
REPiS	Renewable Electric Plant Information System, NREL
RFC	Regenerative Fuel Cell
RFS	Renewable fuel standard
SAI	Solar America Initiative
SOFC	Solid Oxide Fuel Cells
SUFG	State Utility Forecasting Group
USDA	U. S. Department of Agriculture
VEETC	Volumetric ethanol tax credit
WVPA	Wabash Valley Power Association

Foreword

This report represents the fourth annual study of renewable resources in Indiana performed by the State Utility Forecasting Group (SUFG). 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 report consists of eight sections and three appendices. Section one provides an overview of the renewable energy industry in the United States and in Indiana. It includes a discussion on trends in renewable energy consumption, both nationally and in Indiana. It also includes a review of proposed Federal spending on renewable energy for the upcoming fiscal year.

The other seven 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, fuel cells, and hydropower from existing dams. They are arranged to maintain the format in the previous reports as follows:

- <u>Introduction:</u> This section gives an overview of the technology and briefly explains how the technology works.
- <u>Economics of the renewable resource technology:</u> This section covers the capital and operating costs of the technology.
- <u>State of the renewable resource technology nationally:</u> This section reviews the general level of usage of the technology throughout the country and the potential for increased usage.
- <u>Renewable resource technology in Indiana:</u> This section examines the existing and potential future usage for the technology in Indiana in terms of economics and availability of the resource. It also 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.
- <u>References:</u> This section contains references that can be used for a more detailed examination of the particular renewable resource.

The three appendices provide more detail on three sources of methane gas from waste streams. Appendix A covers biogas from animal wastes, Appendix B reviews landfill gas and Appendix C focuses on biogas from wastewater treatment facilities. The appendices follow the same general format as the main sections of the report.

For the most part, there has been little change in the various technologies from last year's report. Usage levels, cost and efficiency data, and incentives available have been updated where new information is available. Any new developments, particularly those within Indiana, have been included.

SUFG would like to thank several people and organizations for their assistance in collecting the information necessary to produce this report, including the Indiana Utility Regulatory Commission, the Indiana Office of Energy and Defense Development, the Indiana Department of Environmental Management, the Fair Oaks Dairy Farm, the City of West Lafayette Wastewater Treatment Utility, the City of Jasper Wastewater Treatment Facility, Professors Klein Ileleji and Don Jones of Purdue's Department of Agricultural and Biological Engineering, and Professor John Patterson of Purdue's Department of Animal Sciences.

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
Purdue University
500 Central Drive
West Lafayette, IN 47907-2022
Phone: 765-494-4223
Fax: 765-494-2351
e-mail: sufg@ecn.purdue.edu
https://engineering.purdue.edu/IE/Research/PEMRG/SUFG/

1. Overview

This section gives an overview of the renewable energy industry. It includes trends in renewable energy consumption, electricity generation and a summary of the renewable energy funding contained in the proposed Federal fiscal year 2007 budget for the Department of Energy (DOE).

1.1 Trends in renewable energy consumption and electricity generation

According to the Energy Information Administration (EIA) *2004 Renewable Energy Trends* report [1], renewable energy consumption in the United States grew by less than 1 percent from 2003 to 2004, as increases in energy from biomass sources (largely ethanol from corn) and wind overcame a decrease in energy from hydroelectric facilities. This represented the fourth year in a row that renewable energy consumption increased nationwide.

As can be seen in Figure 1-1, biomass and hydropower comprise 92 percent of all the renewable energy produced in the U. S. in 2004. All the renewables combined contributed 6.1 percent of U. S. total energy in 2004. Figure 1-2 shows the equivalent numbers for Indiana. In Indiana the renewables contribution to the total energy used in Indiana in 2002 was 1.5 percent. Biomass (including ethanol blend in gasoline) contributed 88 percent of the renewable energy.

According to the Renewable Energy Trends report [1], a substantial portion of the increase in biomass use is accounted for by the increased presence of ethanol as an oxygenate additive to gasoline. Ethanol increase surged by 65 percent between 2001 and 2003. Alcohol use has risen to replace MTBE whose use has been reduced and altogether banned in some states due to fears of groundwater contamination from leaking tanks.

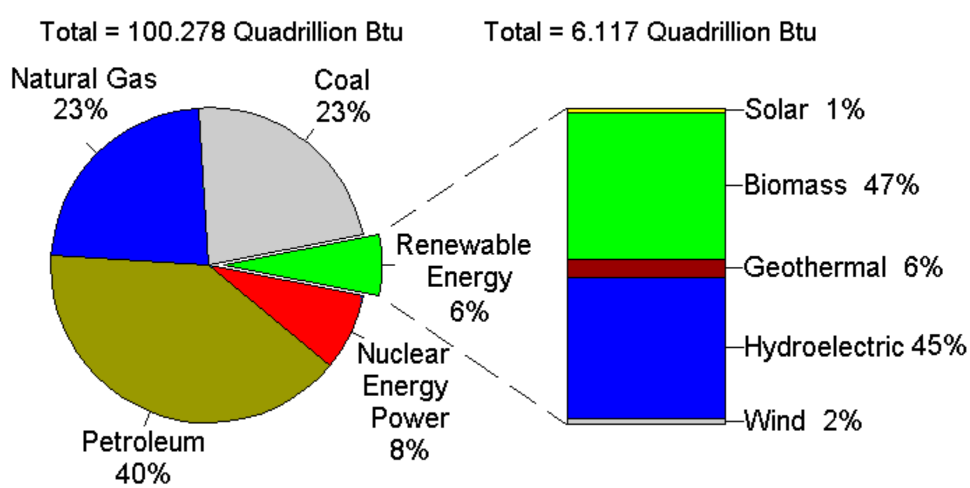
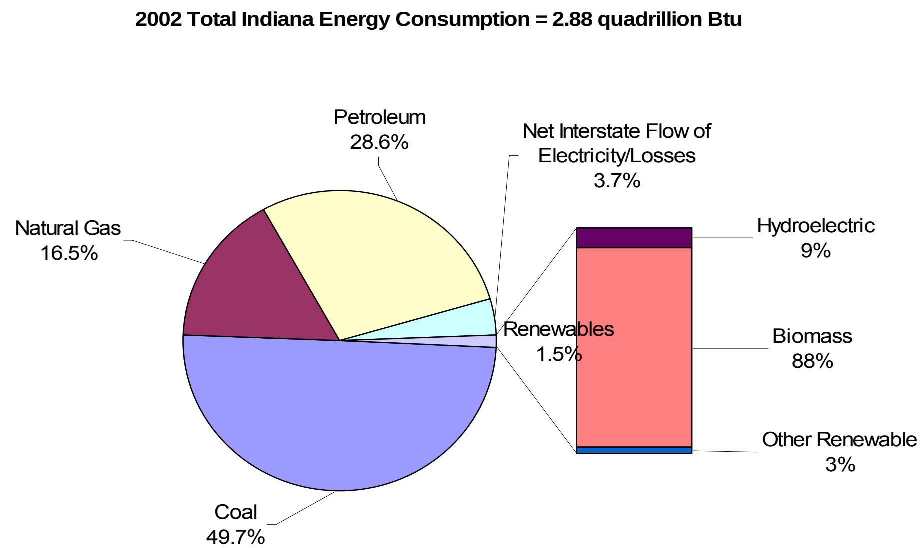
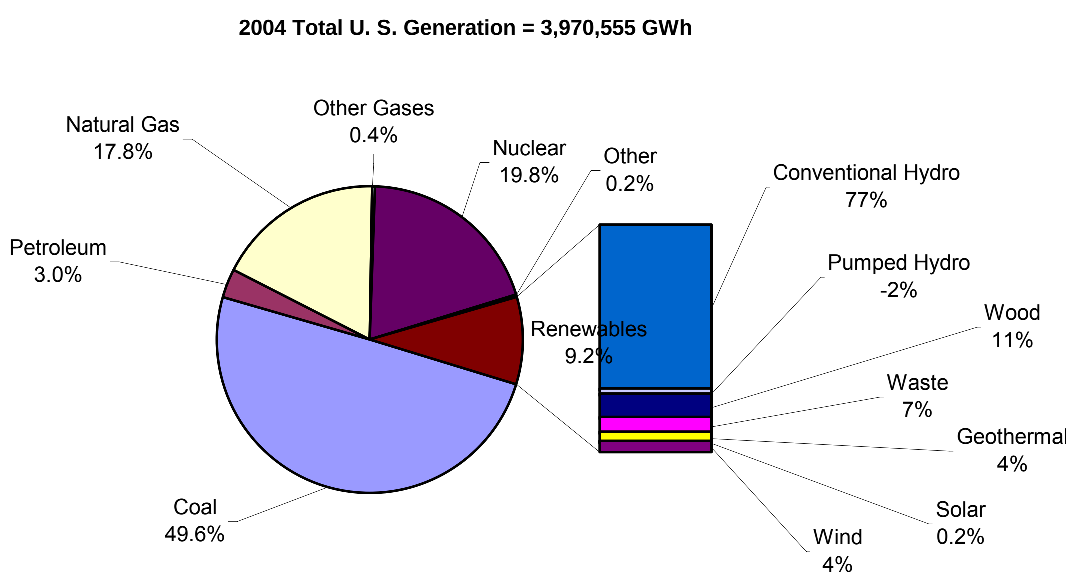


Figure 1-1: 2004 United States total energy consumption by energy source (Source: EIA)

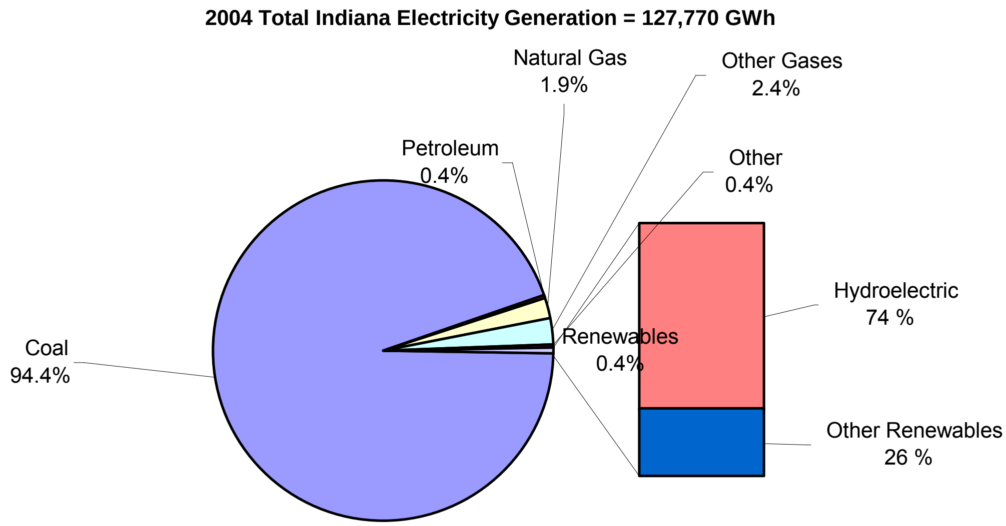


<u>Figure 1-2:</u> <u>2002 Indiana total energy consumption by energy source</u> (Source: EIA)

When one considers the renewable energy used for electricity generation, hydropower takes a much greater role than biomass, contributing over 250,000 Gigawatthours (GWh) or 75 percent of the net U. S. renewable electricity generation in 2004 (Figure 1-3). The contribution of biomass drops to 18 percent. Similarly in Indiana, as shown in Figure 1-4, hydropower accounts for 74 percent of the renewable energy used for electricity generation and other renewables (primarily biomass) account for the remaining 26 percent [2]. The negative 2 percent reported for pumped storage reflects the energy used to time shift the availability of pumped storage hydroelectric generation.



<u>Figure 1-3:</u> <u>2004 U. S. net electricity generation by energy source</u> (Source: EIA)



<u>Figure 1-4:</u> <u>2004 Indiana electricity generation by energy source</u> (Source: EIA)

As shown in Figure 1-5, the 670 GWh of electricity generated from renewable sources in Indiana in 2003 constituted 0.2 percent of the 328,027 GWh of the national total [1]. The major contributors to the renewable generation were the hydropower-rich states of Washington, California and Oregon which together contributed over half of the total renewable generation in that year. Three states: Rhode Island, New Mexico and Kansas produced less renewable energy than Indiana in 2003 while EIA did not provide renewable generation data for Delaware, Mississippi and the District of Columbia.

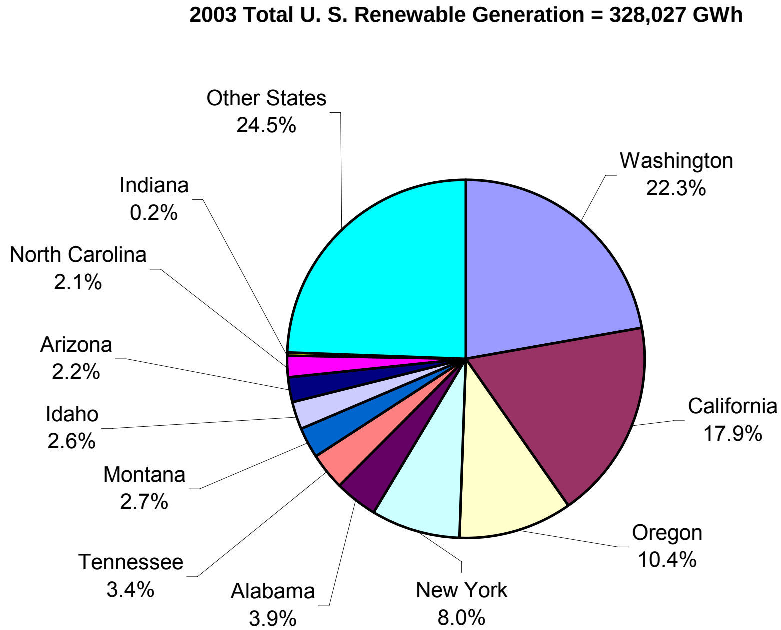


Figure 1-5: 2003 states' share of total U. S. renewable generation (Data Source: EIA)

1.2 Renewable energy funding in the proposed Federal FY2007 budget

According to the Congressional Research Service [3], the Bush Administration has requested $359.2 million for DOE's Renewable Energy Program in the Federal FY2007 budget. This would represent a 30 percent increase over the FY2006 appropriation. A breakdown by some renewable types is provided in Table 1-1.

	FY 2006 appropriation	FY 2007 proposed	Percent change
Wind	$38.9M	$43.8M	+12.6 percent
Solar thermal	$8.9M	$8.9M	no change
Photovoltaics	$60M	$139.5M	+132.5 percent
Biomass/biorefinery	$90.7M	$149.5M	+64.8 percent
Fuel cells	$67.8M	$96.6M	+42.5 percent
Small hydroelectric	$0.5M	$0M	-100 percent

Table 1-1: FY2006 and proposed FY2007 Federal appropriations for renewables (Source: Sissine)

1.3 References

1. Energy Information Administration, "Renewable Energy Trends 2004," August 2005.
2. Energy Information Administration, "State Electricity Profiles 2004."
3. F. Sissine, Congressional Research Service, "Renewable Energy Policy: Tax Credit, Budget, and Regulatory Issues," July 2006.

2. Energy from Wind

2.1 Introduction

Wind energy, defined by the United States Department of Energy as the "process by which the wind is used to generate mechanical power or electricity," is a small but rapidly growing source of electricity. Wind energy is captured with the aid of wind turbines. Modern wind turbines can be classified into one of two different categories [1]. Figure 2-1 illustrates the wind turbine [2].

- Horizontal axis type (traditional windmills)
- Vertical axis type (the "eggbeater" style Darrieus model)

Of the two, the horizontal axis type model is the more popular.

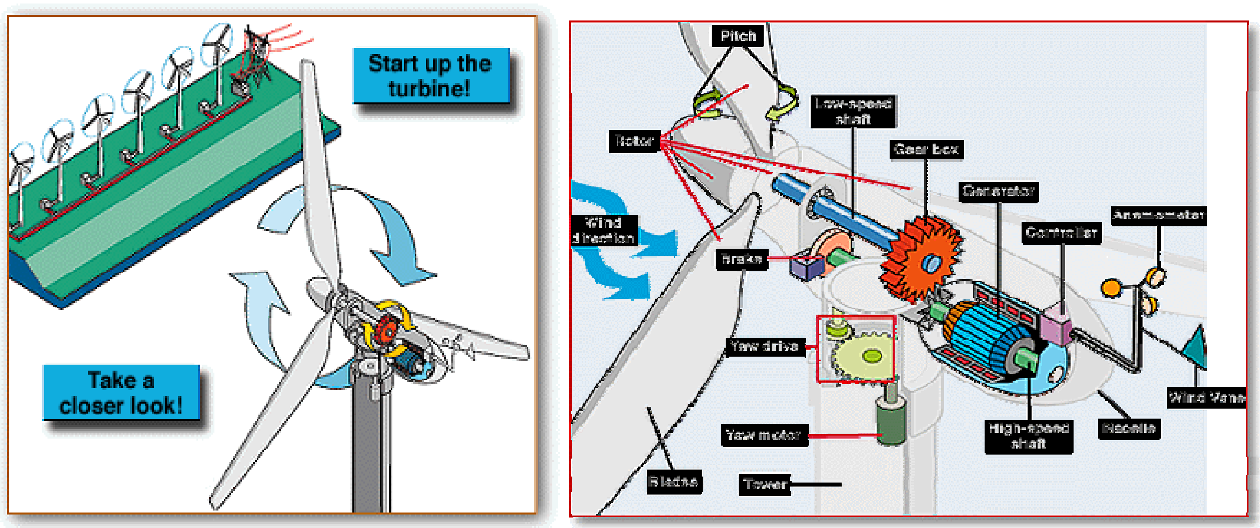


Figure 2-1: Parts of wind turbines (Source: EERE)

The physical size and power output of wind turbines have increased dramatically over the past two decades [1]. Although the power output of wind turbines has increased over the years, they are still small in comparison with generating units using conventional fuels. Capacity of coal and nuclear generating units can be more than 1000 Megawatts (MW). For example, the largest coal power plant in Indiana is composed of five units rated at over 600 MW each adding up to a total plant capacity of over 3000 MW. In comparison, one of the wind farms proposed for Benton County, Indiana is composed of 67 wind turbines rated at 1.5 MW each to make a total wind farm capacity of 100 MW. The other proposed wind farm is for a total of 130 MW. Furthermore the total energy output from a wind turbine will tend to be much less than that from that of a conventional generator since the wind turbine only generates when the wind is blowing at sufficient levels. Turbines vary in size from small 1 kilowatt (kW) structures to large machines rated at 2

MW or more. Figure 2-2 lists the different turbines sizes, the electricity production and the installed costs [3].

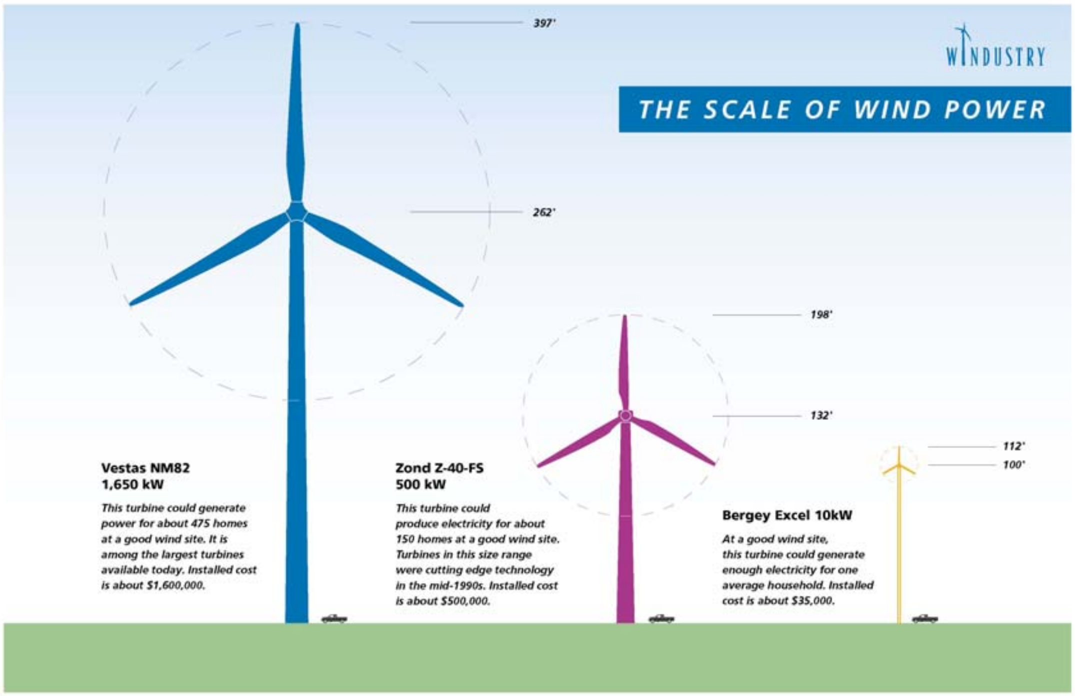


Figure 2-2: Sizes of wind turbines and installed costs (Source: WINDUSTRY)

Wind speeds are important in determining a turbine's performance. Generally, annual average wind speeds of greater than 4 meters per second (m/s) or 9 miles per hour (mph) are required for small electric wind turbines whereas utility-scale wind power plants require a minimum wind speed at an elevation of 50 meters of between 6 to 7 m/s (13-15.7 mph) [4]. The power available in the wind is proportional to the cube of its speed. This implies that a doubling in the wind speed leads to an eight-fold increase in the power output. Wind power density indicates the amount of energy available for conversion by the wind turbine. Sites are classified based on their average annual wind speed and wind power densities. Table 2-1 lists the class distinctions currently used.

The major advantages of wind energy are:

- It is a virtually inexhaustible renewable resource;
- It helps diversify the portfolio of resources, thus reducing the potential impacts of events affecting other fuel sources, such as price increases;
- It reduce dependence on imported fossil fuels
- It is a modular and scalable technology; and
- It helps reduce pollution control costs.

However, there are some disadvantages of wind energy, namely:

- Wind is an intermittent source of energy (i.e., wind is not always blowing when the energy is needed);
- Good wind sites are usually located far away from load centers which may require additional transmission system construction;
- Wind tower/turbines are subject to high winds and lightning;
- Blade rotation can be noisy; and
- Concerns have been raised regarding the death of birds from flying into the turbine blades

Wind Power Class	**10 m (33 ft) Elevation**		**50 m (164 ft) Elevation**	
	Wind Power Density (W/m^2)	**Speed m/s (mph)**	**Wind Power Density (W/m^2)**	**Speed m/s (mph)**
	0	0	0	0
1				
	100	4.4 (9.8)	200	5.6 (12.5)
2				
	150	5.1 (11.5)	300	6.4 (14.3)
3				
	200	5.6 (12.5)	400	7.0 (15.7)
4				
	250	6.0 (13.4)	500	7.5 (16.8)
5				
	300	6.4 (14.3)	600	8.0 (17.9)
6				
	400	7.0 (15.7)	800	8.8 (19.7)
7	1000	9.4 (21.1)	2000	11.9 (26.6)

Table 2-1: Wind resource classification (Source: DOE)

2.2 Economics of wind energy

The levelized cost[1] of wind energy has been decreasing over the past twenty years, as shown in Figure 2-3. Currently, wind turbines are capable of producing electricity at 4.5-5.5 cents/kilowatthour (kWh) in the Class 4 wind regions and state-of-the-art wind farms in high wind areas can generate electricity for between 3 and 4.5 cents/kWh [5]. This is comparable to the cost of conventional energy technologies. Furthermore, a production tax credit of 1.9 cents/kWh during the first ten years of production is available, having been extended to December of 2007 in the Energy Policy Act of 2005 [6]. Wind energy

[1] Levelized costs represent the average capital, maintenance and fuel costs over the lifetime of the equipment.

is also the lowest cost of the emerging renewable energy sources. Rural incomes are affected by companies installing wind turbines in rural areas. Landowners are receiving on average annual lease fees that range from $2,000 to $5,000 per wind turbine [7].

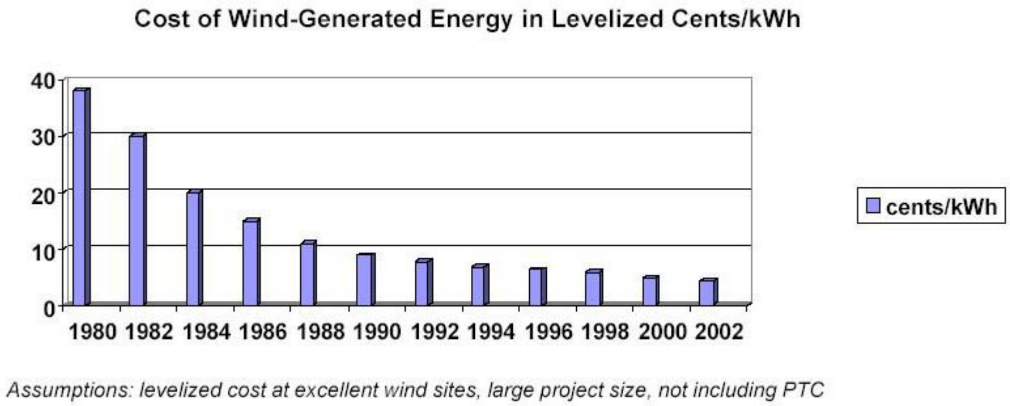


Figure 2-3: <u>Cost of wind energy at excellent wind sites not including production tax credits</u>[2] (Source: American Wind Energy Association (AWEA))

While the cost of wind energy is still high for lower wind speeds (below class 4), DOE is working with three small turbine manufacturers to improve their turbines [8]. The goal of this initiative is to develop tested systems of up to 40 kW in size with a cost/performance ratio of 60 cents/kWh at sites with an annual average wind speed of 5.4 m/s (12.1 mph)[3]. Furthermore, DOE is seeking to reduce the cost of energy (COE) from small wind systems to the point where they have the same cost effectiveness in Class 3 wind resources in 2007 as they currently have in class 5 resources. The COE from wind as projected by DOE's National Renewable Energy Laboratory (NREL) is shown in Figure 2-4 [5].

---

[2] Also called Renewable Electricity Production Credit.

[3] The cost/performance ratio is defined as follows: $\text{Cost/Performance} = \dfrac{\text{Initial Capital Cost}}{\text{Annual Energy Production}}$

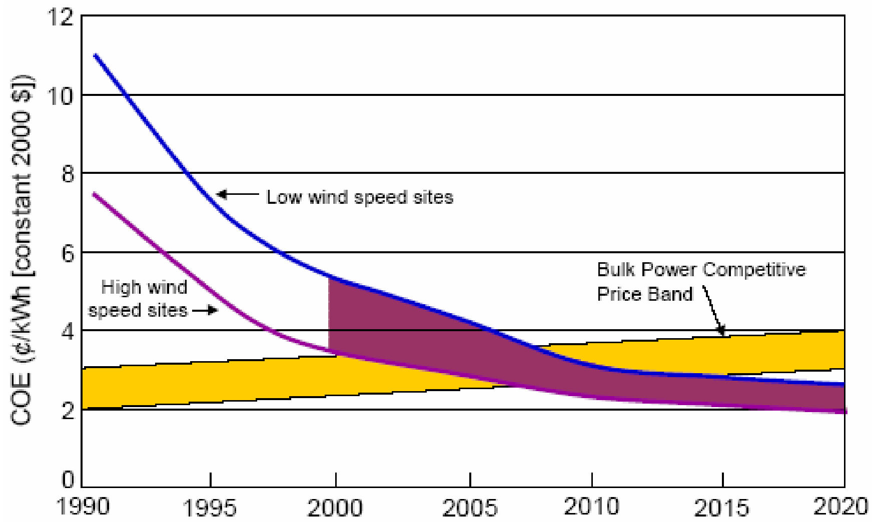


Figure 2-4: Projected cost of wind energy (Source: NREL)

DOE's wind energy program is designed to focus on the following three paths that utility-scale wind technology may follow: Land-Based Electricity, Offshore Electricity, and Emerging Applications. All three paths emanate from current technology, which is oriented towards producing bulk power from land-based wind farms.

With respect to the land-based electricity path, according to the Office of Energy Efficiency and Renewable Energy (EERE), DOE

> "*Envisions that land-based systems will continue to grow in size, to the 2-5 MW range* (Figure 2-5). *This is expected to result in very cost-competitive turbine technology in the 2012 timeframe. Moreover, this effort will open up vast resources to wind development and will bring wind-generated electricity closer to major load centers. Turbine technology development efforts, as previously discussed, will aid in making the technology cost-competitive. Ultimately, the primary barriers to this technology with be those presented by system integration issues, including the capability and availability of the U.S. transmission system"*

> *"The second evolution pathway envisioned is a migration of current technology to offshore sites. At first, wind technology will be expanded into relatively shallow waters, and then later into deeper waters. Offshore turbines are expected to be significantly large – in the 5 MW and greater range. Eventually, the DOE has a goal of 5 cents/kW (*Figure 2-5*) for class 5 shallow water sites by 2012 and is currently evaluating what other goals might be appropriate for deep water technology. As this program continues to proceed, cost and regulatory (siting) barriers are likely to be the most significant obstacles to offshore development."*

Finally, the emerging applications path for wind technology

> "*Leads toward the design of turbine systems tailored for emerging applications like hydrogen production or for the production and delivery of clean water. These efforts would open up an opportunity for wind to provide a low cost, clean energy for the transportation sector. However, both of these applications present significant new challenges to the wind community, and cost and infrastructure barriers are expected to be significant* [9]."

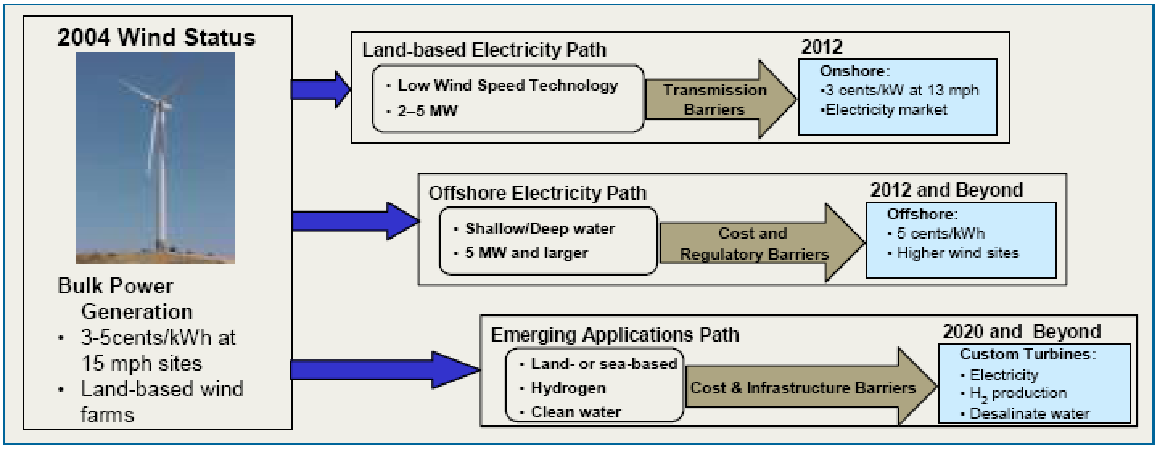


Figure 2-5: Three evolution pathways for utility-scale wind technology (Data Source: EERE)

2.3 State of wind energy nationally

Wind resources are prevalent throughout the U. S. with class 4 or higher winds concentrated in the Northwest, North Central and Northeast regions, as shown in the national wind resource map [8] in Figure 2-6. This map shows annual average wind power; for many locations, there can be a large seasonal variation. In the Midwest, average wind power is highest in the winter and spring, while it is lowest in the summer. This indicates that wind energy may be more suitable for meeting Midwest winter heating demand than for meeting summer cooling needs.

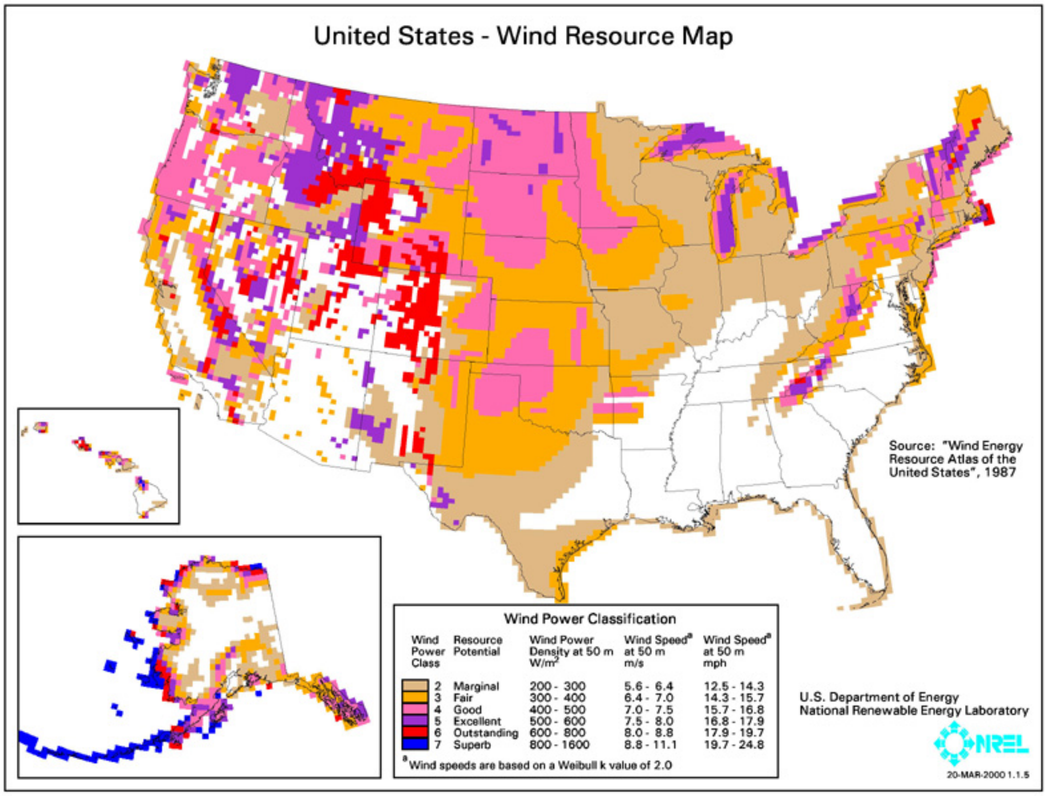
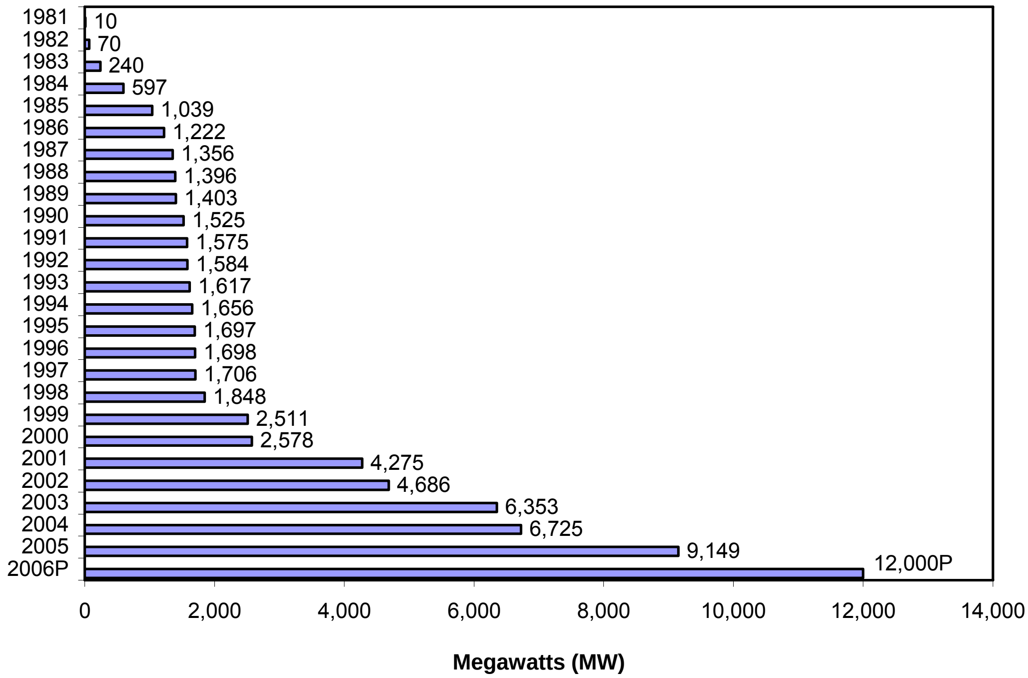


Figure 2-6: National wind energy resource map (Source: NREL)

Wind capacity has been expanding rapidly in the United States within the past 25 years, with 9,149 MW as of the end of 2005 as seen in Figure 2-7. There was a 36 (2,400 MW) percent increase in installed wind power capacity in 2005, the largest amount ever for one year. The projected wind capacity addition in 2006 is over 2,800 MW bringing the total installed capacity in the US to 12,000 MW [10].



*P is projected (2006)

Figure 2-7: Wind power U. S. installed capacity 1981- 2006 (Source: DOE and AWEA; 2006 is projected by AWEA)

The primary drivers behind the rapid expansion of wind farms across the nation are the Federal government financed renewable electricity production tax credit (PTC) and the renewable energy portfolio Standards. The production tax credit, first put in place in the Energy Policy Act of 1992, credits producers with 1.9 cents/kWh during the first ten years of operation. As shown in Figure 2-8, the installation of wind farms paralleled the several expiration and renewal cycles of the production tax credit. The extension of the production tax credit in the 2005 Energy Policy Act to December 31, 2007 is credited with the record 2,400 MW of wind capacity installed in 2005 and the projected 2,800 MW capacity addition projected for 2006 shown in Figure 2-7.

The renewable energy portfolio standards, now in place in 21 states and the District of Columbia, require that a minimum amount of electricity be supplied from renewable sources. Figure 2-9 shows the status of renewable energy portfolio standards.

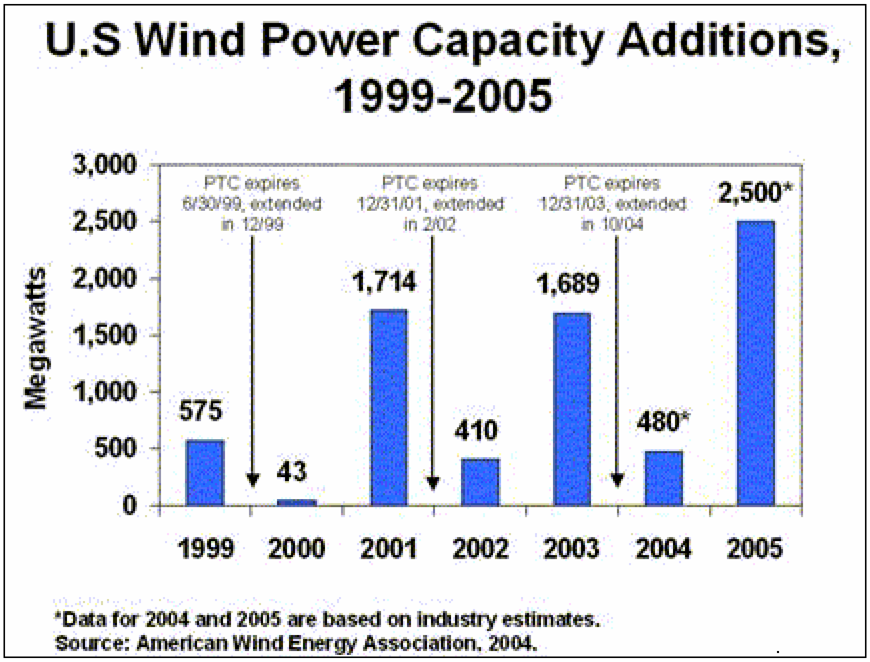


Figure 2-8: Effect of the renewable energy production credit on wind capacity additions (Source: Union of Concerned Scientists [11])

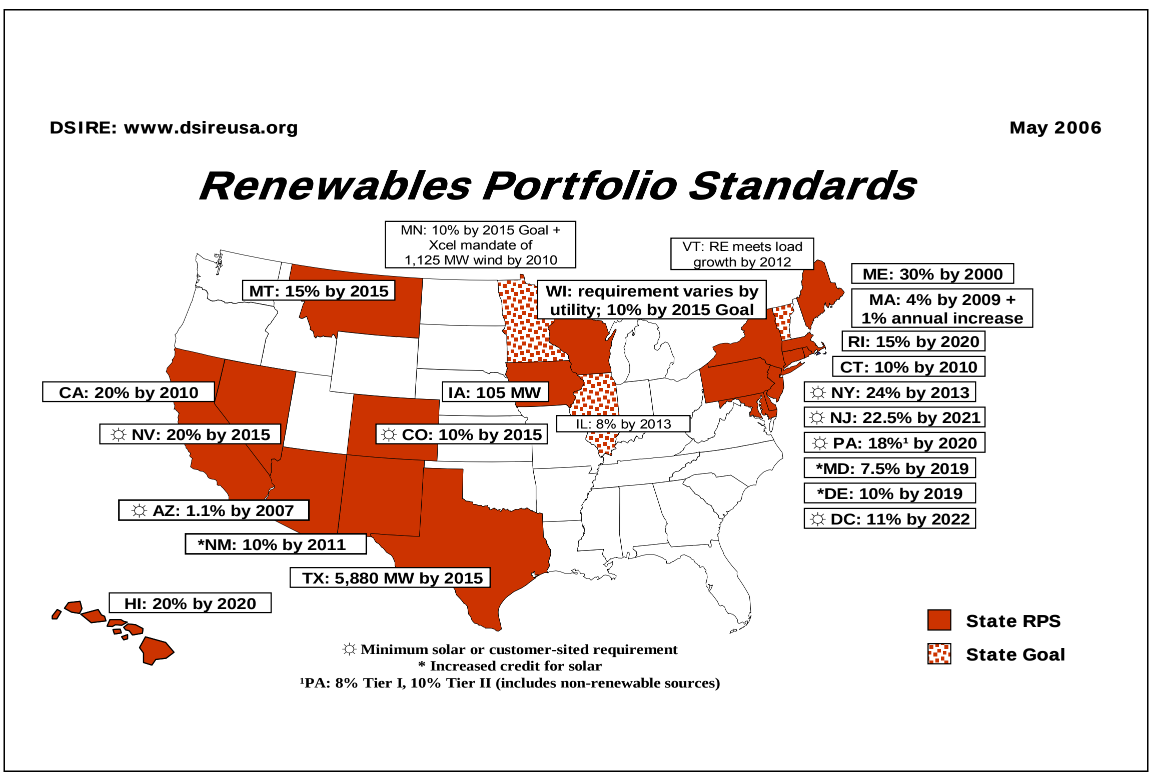


Figure 2-9: Renewables portfolio standards across the U. S. (Source: DSIRE [12]).

As shown in Figure 2-10, the leading wind capacity states at the beginning of 2006 are (in MW): California – 2,150; Texas – 1,995; Iowa – 836; Minnesota – 744; Oklahoma – 475.

In the Midwest, 204 MW of new wind capacity was added in Iowa in 2005 and 129 MW and 56 MW were added in Minnesota and Illinois, respectively. Indiana's neighbors are ranked as follows: Illinois – 107 MW, Ohio – 7 MW and Michigan – 3 MW [13].

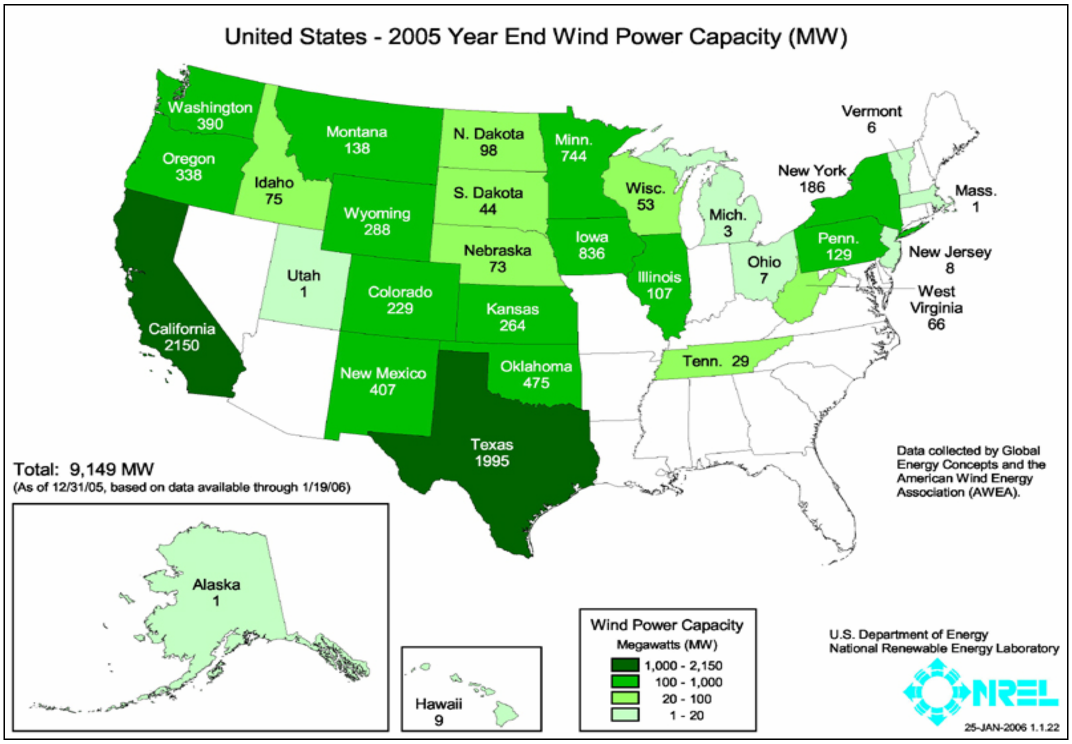


Figure 2-10: Wind energy installed generation capacity (Source: EERE/NREL)

According to the American Wind Energy Association Rankings report [1] the largest wind farms operating in the U. S. at the end of 2005 were as follows

1. Stateline, Oregon-Washington – 300 MW
2. King Mountain, Texas – 278 MW
3. Horse Hollow Wind Energy Center, Texas – 210 MW
4. New Mexico Wind Energy Center, New Mexico – 204 MW
5. Storm Lake, Iowa – 193 MW

The largest owners of wind energy installations were:

1. FPL Energy – 3,192 MW
2. PPM Energy – 518 MW
3. MidAmerican Energy – 360.5 MW
4. Caithness Energy - 346 MW
5. Edison Mission Group – 316 MW
6. Shell Wind Energy - 315 MW

The companies that bought the most wholesale wind power were:

1. Xcel Energy - 1,048 MW
2. Southern California Edison - 1,021 MW
3. Pacific Gas & Electric Co. - 680 MW
4. PPM Energy - 606 MW (for resale)
5. TXU - 580 MW

For the first time in the recent history of the U. S. wind energy industry Xcel Energy has overtaken Southern California Edison as the leading purchaser of wind energy. In addition Xcel Energy has stated plans of purchasing the output from a further 775 MW of wind by 2007 [1].

Table 2-2 shows the installed wind energy capacity by state, as reported by January 24, 2006. The table presents the states with the most potential for wind energy production [1]. Of the states in the Midwest, Minnesota and Iowa have moved to the lead in terms of installed wind energy capacity and wind energy production due in the most part to their favorable positions in terms of high wind sites.

State	Megawatts	Share	Cumulative %
California	2,150	23.5%	23.5%
Texas	1,995	21.8%	45.3%
Iowa	836	9.1%	54.4%
Minnesota	744	8.1%	62.6%
Oklahoma	475	5.2%	67.8%
New Mexico	407	4.4%	72.2%
Washington	390	4.3%	76.5%
Oregon	338	3.7%	80.2%
Wyoming	288	3.1%	83.3%
Kansas	264	2.9%	86.2%
Others	1,264	13.8%	100.0%
U.S. Total	9,151	100.0%	100.0%

Source: AWEA, [http://www.awea.org/projects/].

Table 2-2: Installed wind energy capacity by state, January 24, 2006 (Source: AWEA)

With the rapid growth of wind farms nationally some regulatory issues have arisen that have served to slow its expansion somewhat. In the words of the Congressional Research Service [10] "*a major debate has erupted over the safety and economic and environmental aspects of a proposal by Cape Wind Associates to develop an offshore wind farm near Cape Cod, Massachusetts. The parties to the debate are waiting for the results of a Department of Interior (DOI) environmental impact statement and a Coast Guard study of navigational safety aspects. Also, concern that large wind turbines may disrupt radar systems led to Federal actions to halt several wind farm developments, pending the results of a study by the Department of Defense (DOD) that was due in early May 2006. In late June 2006, the Sierra Club filed suit to compel completion of the DOD radar study. An agency of the United Kingdom has studied modifications to turbines and radar systems that may help solve the problem.*"

2.4 Wind energy in Indiana

The highest wind category in Indiana is class 3, or 11.5 – 12.5 mph, compared to class 7 winds occurring in such wind rich states like Minnesota. The class 3 winds occur in areas around Benton, Clinton and Boone counties. The rest of the state is divided approximately evenly, with the northern half having class 2 winds (9.8 – 11.5 mph) and the southern half class 1 winds (0 – 9.8 mph). As mentioned previously, the power available in the wind speed is proportional to the cube of its speed, thus slight increase in the wind speed results in a large increase in electricity generation as shown in Figure 2-11 [13]. Figure 2-12 shows the wind speed in Indiana at 100 meters from the ground [15]. Figure 2-13 which shows the wind power density of Indiana at 100 meters [16] was prepared by AWS TrueWind, a consulting firm that assists energy projects for local and international customers.

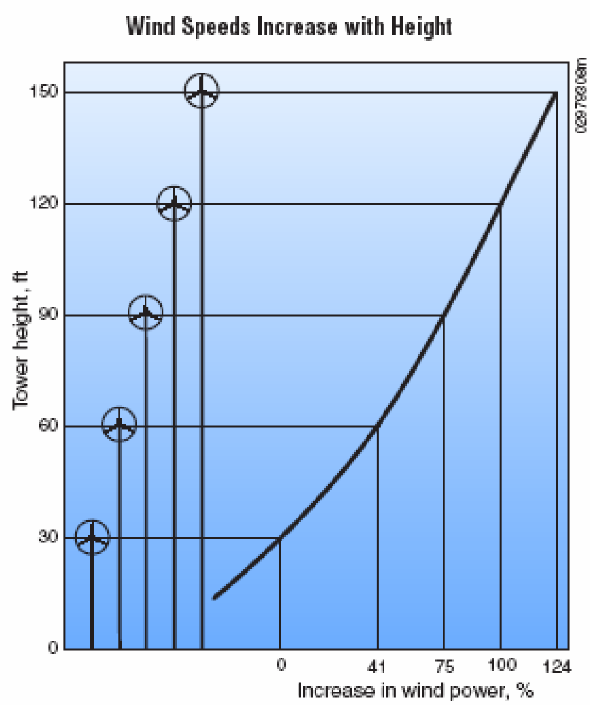


Figure 2-11: Increase in wind speed with increase in height (Source: EERE)

Table 2-3 lists the average wind speeds and wind power densities as measured by the National Climatic Data Center in various cities within Indiana. These wind speeds were most likely collected at lower elevations than those at which a wind turbine would operate, so they may understate the potential for wind power somewhat.

According to the national Renewable Electric Plant Information System (REPiS) [17], as of 2002 Indiana had only 10 kW of wind generation. A wind turbine owned by American Electric Power is located in Fort Wayne [18]. In January 2005, Cinergy/PSI, which is now Duke Energy, commissioned a 10 kW grid connected demonstration project at a rest stop on I-65 in White County that provides supplemental power to the rest area north of

Lafayette [19]. This brings the total installed wind capacity in Indiana that SUFG could find on record to 20 kW.

However, two new wind farm projects in Benton County, northern Indiana can change significantly the state's wind energy production. In June 2006, Orion Energy LLC proposed a wind farm project of 130 MW, while enXco Inc. has proposed a 100 MW project [20]. The enXco project is under development but construction will not begin until a buyer for the electricity is found. Orion Energy is planning to perform the turbine installation by 2007, as a part of a two-phase project. The project is estimated to be $150 million to $175 million and it will be built at two locations in York and Richland townships [21]. Duke Energy has signed a 20 year power purchase agreement to purchase the output of 100 MW of Orion Energy's Benton County wind farm [22].

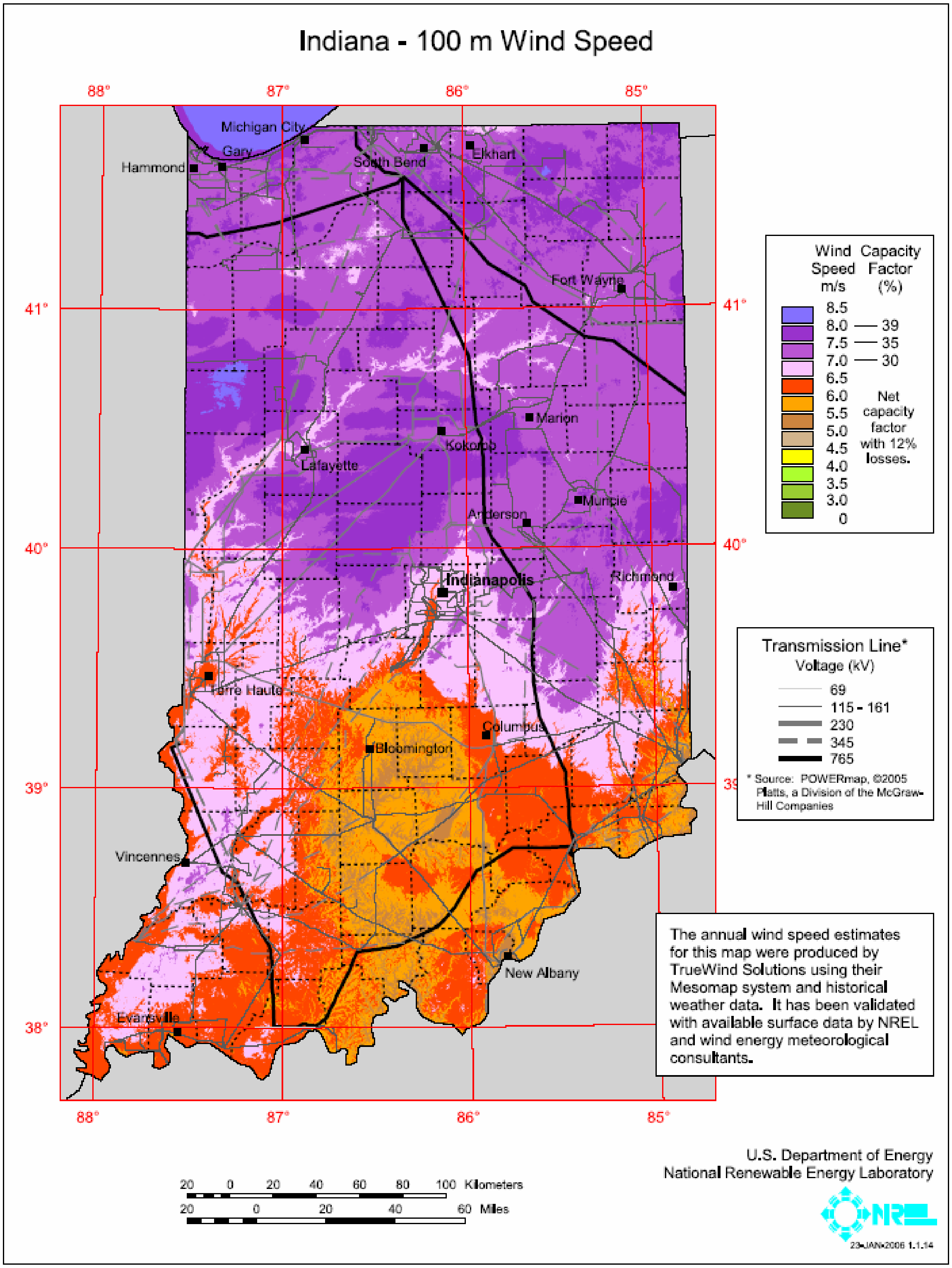


Figure 2-12: Indiana wind speed energy resource map (2006) (Source: NREL)

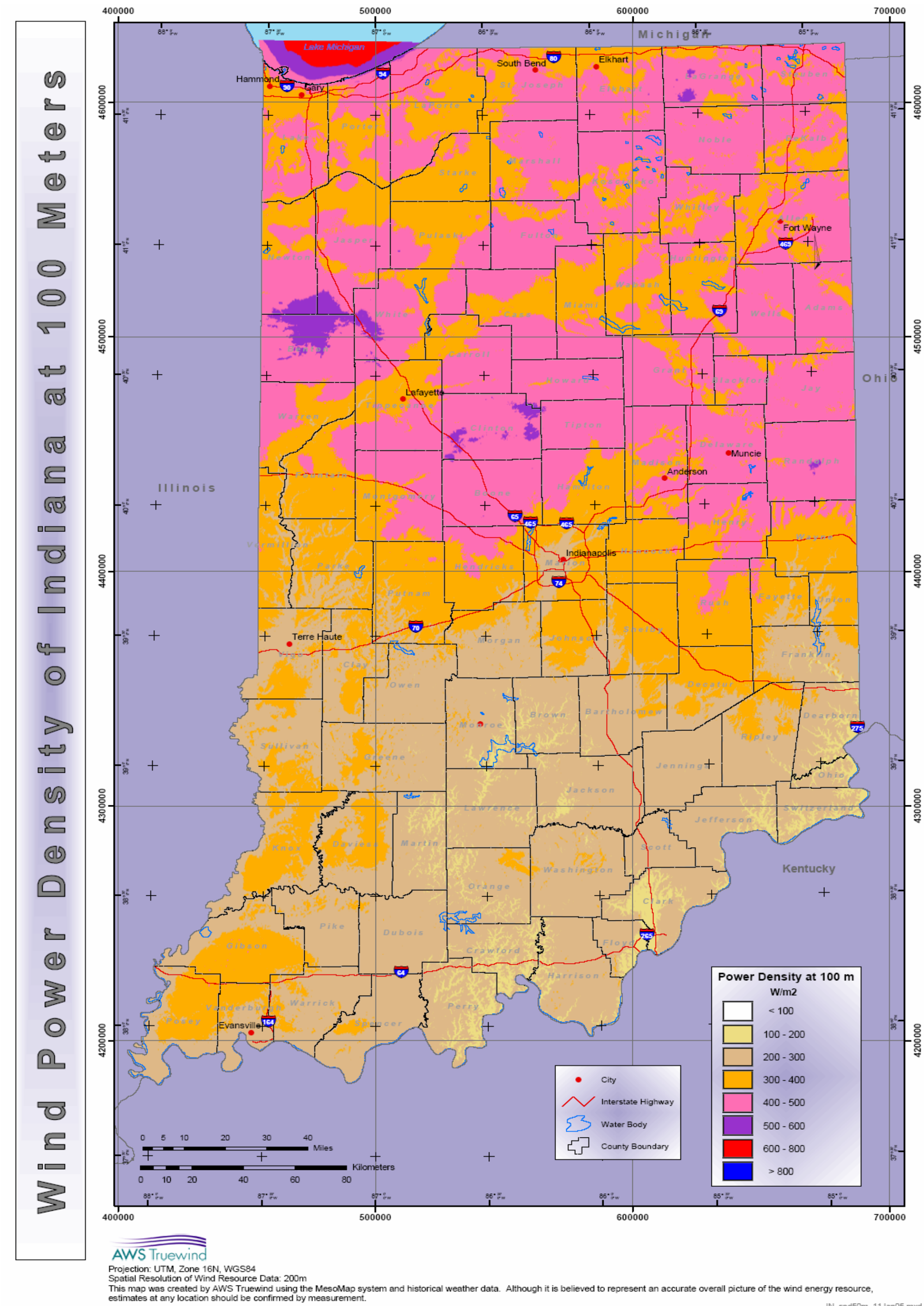


Figure 2-13: Indiana wind power resource map (2005) (Source: **AWS** TrueWind)

Station Name	Annual		Winter		Spring		Summer		Autumn	
	Speed (m/s)	PD (w/m^2)	Speed (m/s)	PD (w/m^2)	Speed (m/s)	PD (w/m^2)	Speed (m/s)	PD (w/m^2)	Speed (m/s)	PD (w/m^2)
BUNKER HILL	3.6	72#	4.3	102#	4.3	104#	2.5	29#	3.3	58#
COLUMBUS	3.7	77	4.3	101	4.3	109	2.8	38	3.4	64
COLUMBUS	3.3	58%	3.8	73%	4	83%	2.6	30%	3	47%
EVANSVILLE	4.1	95	4.8	126	4.7	133	3.2	46	3.7	77
EVANSVILLE	3.4	58	4	80	4	79	2.7	29	3.1	46
FT. WAYNE	3.8	78	4.3	106	4.2	93	2.9	34	3.6	71
FT. WAYNE	5.2	158	5.6	186	5.9	225	4.2	81	5	145
FT. WAYNE	4.6	117	5.3	168	5.1	146	3.8	62	4.2	90
GOSHEN	4.5	126	5.4	176	5.2	167	3.6	65	4.3	116
INDIANAPOLIS	5	146	5.6	189	5.7	205	3.9	68	4.7	127
INDIANAPOLIS	4	76	4.6	105	4.5	98	3.3	40	3.8	59
SOUTH BEND	4.9	132	5.3	160	5.5	175	4	69	4.8	122
SOUTH BEND	4.6	110	5.3	158	5.1	142	3.8	62	4.2	85
TERRE HAUTE	4	94	4.7	132	4.7	138	2.9	36	3.6	74
TERRE HAUTE	4.3	106	5	138	5.4	167	3.1	44	3.9	72
W. LAFAYETTE	5.1	166#	6	235#	5.7	209#	3.9	73#	4.8	144#

Annual or seasonal mean wind power with the # (or %) symbol may be as much as 20 percent in error because climatic mean air temperatures were used to calculate the hourly (or 3-hourly) wind power values that went into the calculation of the mean value.

Table 2-3: Wind measurements within Indiana (Source: National Climatic Data Center)

Small-scale wind turbines that do not require higher wind speeds could be used within the state for remote power applications[4], but their high production costs in comparison with the low electricity costs available within Indiana do not make them economically attractive. EERE Indiana Consumer's Guide for small wind electric system stated that a typical home wind system costs approximately $32,000 (10 kW) while a comparable photovoltaic (PV) system would cost over $80,000 [14]. In order to improve the cost effectiveness of wind energy the Federal and state governments have implemented several incentives for wind power development within Indiana [12]. These are:

- Renewable Electricity Production Tax Credit (PTC) which credits wind energy producers 1.9 cents/kWh during the first ten years of operation. The PTC originally covered wind and biomass and has been expanded in the Energy Policy Act of 2005 and its expiration extended through December 31, 2007 [6].
- Renewable Energy Systems Exemption provides property tax exemptions for the entire renewable energy device and affiliated equipment.
- Renewable Energy Production Incentive (REPI) provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Eligible projects must have commenced operations between October 1, 1993 and September 30, 2003. Qualifying facilities are eligible for annual incentive payments of 1.5 cents/kWh for the first ten year period of their 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, as well as the reauthorization for fiscal years 2006 thought 2026.
- Distributed Generation Grant Program offers awards of up to $30,000 to commercial, industrial, and government entities to "install and study alternatives to central generation" (wind energy falls under one of these alternatives).
- Alternative Power and Energy Grant Program offers grants of up to $30,000 to enable businesses and institutions to "install and study alternative and renewable energy system applications (wind energy is an acceptable technology).
- Conservation Security Program (CSP) Production Incentive: Enacted in March 2005, this program provides financial and technical assistance to promote the conservation and improvement of soil, water, air, and other conservation proposed on tribal and private working land. Eligible producers receive $2.50 per 100 kWh of electricity generated by new wind, solar, geothermal, and methane-to-energy systems (up to $45,000 per year for 10 years).
- Green Pricing Program is an initiative offered by some utilities that gives consumers the option to purchase power produced from renewable energy sources at some premium.
- Net Energy Credit: Facilities generating less than 1000 kWh per month from renewable sources are eligible to sell the excess electricity to the utility. Facilities generating more than 1000 kWh per month need to request permission to sell the excess electricity to the utility.
- Net metering rule: Solar, wind and hydroelectric facilities with a maximum capacity of 10 kW are qualified for net metering under this September 2004 rule

[4] As in the 10 kW installation in Fort Wayne owned by the American Electric Power Co., Inc. [18]

where the net excess generation is credited to the customer in the next billing cycle.

- 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 [23]. These credits can be sold on the national market.
- Modified Accelerated Cost-Recovery System (MACRS): This program allows businesses to recover investments in solar, wind and geothermal property through depreciation deductions.

Figure 2-14 shows the importance of incentives[5], wind speed, and electricity prices in the economic viability of small-scale wind systems [5]. As incentives are added, wind speed increases, or electric rates increase, the time needed to recover the cost of installation decreases. Figure 2-15 shows the locations that have incentives for small residential wind installations.

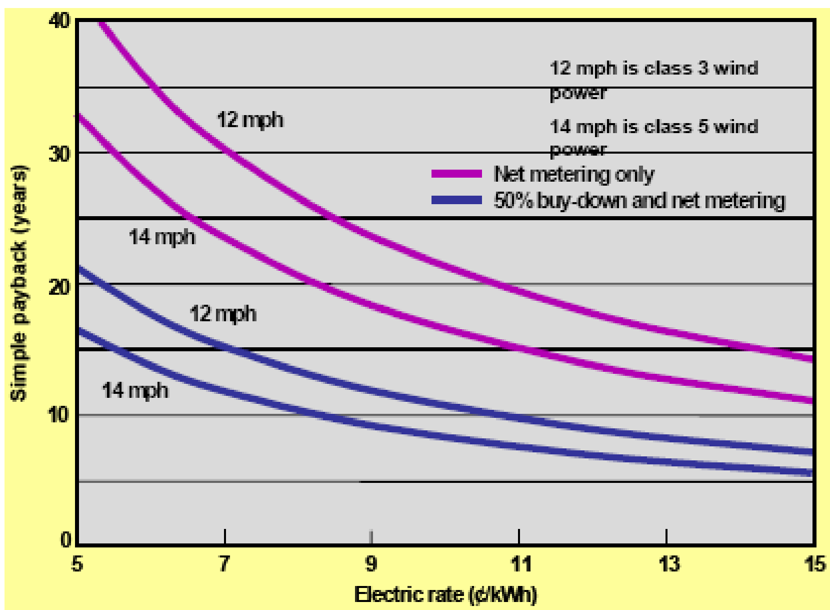


Figure 2-14: Economic payback for small wind systems (Source: DOE)

[5] A buy-down is a subsidy or grant that covers a portion of the purchase cost.

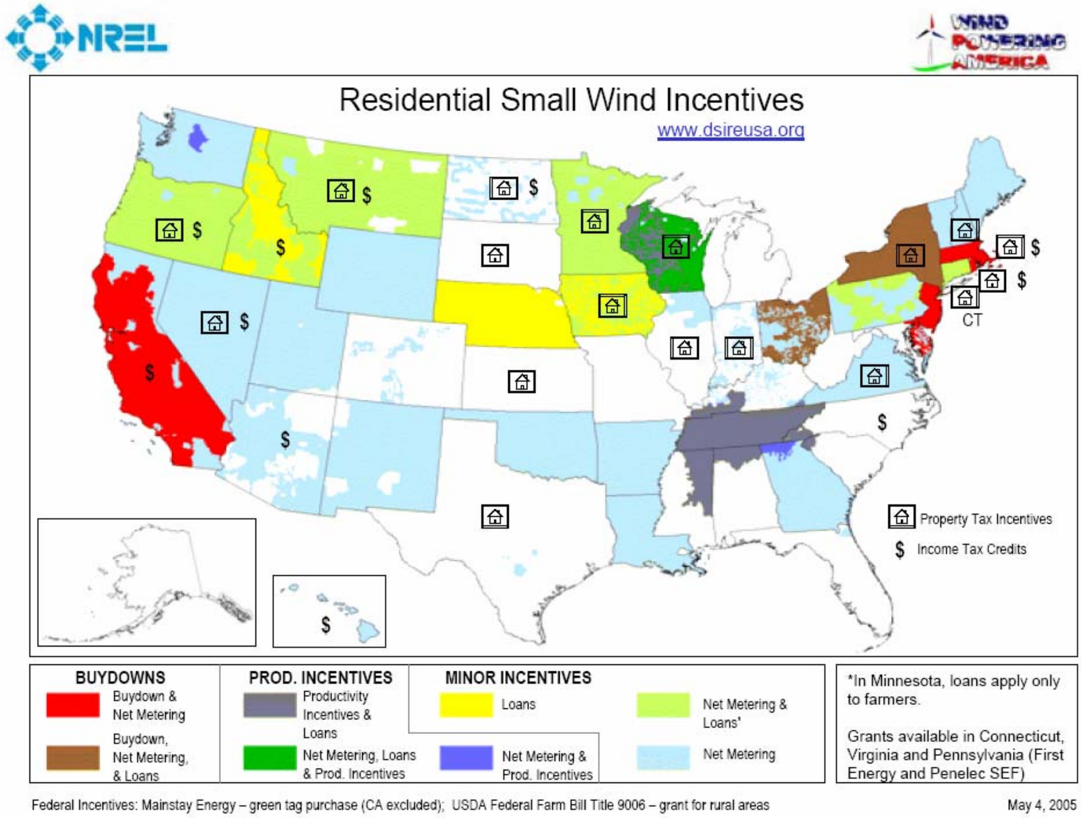


Figure 2-15: Residential small wind incentives (Source: DOE Wind Powering America)

2.5 References

1. http://www.awea.org/
2. http://www1.eere.energy.gov/windandhydro/printable_versions/wind_animation.ml
3. http://www.windustry.org/images/TurbineScale.jpg
4. EIA, United States Department of Energy, "Renewable Energy Trends 2000: Issues and Trends," Feb 2000.
5. http://www.eere.energy.gov/windpoweringamerica/pdfs/wpa/wpa_update.pdf
6. Energy Policy Act 2005
7. U. S. Department of State, Congressional Report Service, Agriculture-Based Renewable Energy Production. Updated May 18, 2006 http://fpc.state.gov/documents/organization/68294.pdf
8. http://www.eia.doe.gov/
9. Office of Energy Efficiency and Renewable Energy, Wind and hydrogen technologies program, Wind energy multi year program plan for 2005-2010, November 2004. http://www.nrel.gov/wind_meetings/2003_imp_meeting/pdfs/wind_prog_mypp_15Nov2004.pdf
10. F. Sissine, Congressional Research Service, "Renewable Energy Policy: Tax Credit, Budget, and Regulatory Issues," July 2006
11. Union of Concerned Scientists, http://www.ucsusa.org/
12. http://www.dsireusa.org

13. http://www.eere.energy.gov/windandhydro/windpoweringamerica/wind_installed_capacity.asp
14. http://www.eere.energy.gov/windandhydro/windpoweringamerica/pdfs/small_wind/small_wind_in.pdf
15. Indiana Office of Energy & Defense Development. http://www.in.gov/energy/technologies/windpower1-1-14speed100mcap.pdf
16. AWS TrueWind http://www.awstruewind.com/inner/windmaps/maps/NorthAmerica/UnitedStates/Indiana/IN_pwr100m_22March2004.pdf
17. http://www.nrel.gov/analysis/repis/online_reports.asp
18. AEP Corporation, http://www.aep.com/environmental/renewables/wind/fortwayne.htm
19. Cinergy/PSI, http://www.cinergy.com/sustainability/04/env_improvement.htm
20. http://www.enxco.com/
21. Megawatt Daily, June 19, 2006. http://www.platt.com
22. Megawatt Daily, August 16, 2006. http://www.platt.com
23. http://www.in.gov/idem/energycredit/ecreditfct.pdf

3. Dedicated Crops Grown for Energy Production (Energy Crops)

3.1 Introduction

The Oak Ridge National Laboratory (ORNL) defines energy crops as "perennial grasses and trees produced with traditional agricultural practices and used to produce electricity, liquid fuels, and chemicals" [1]. Energy crops are just one of the possible forms of biomass. DOE [2] defines biomass as "any organic matter available on a renewable basis, including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, aquatic plants, animal wastes, municipal wastes, and other waste materials."

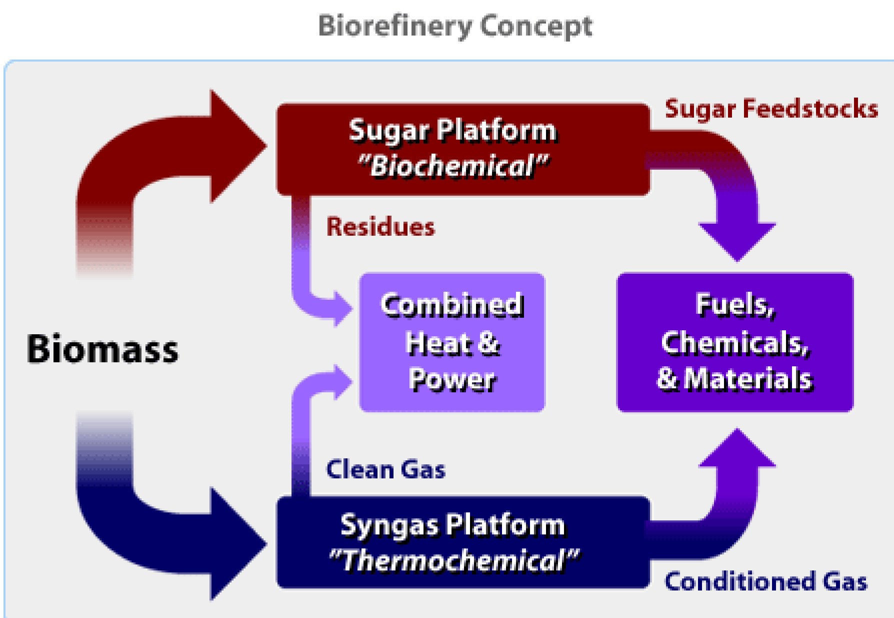
Energy derived from biomass supplies or "bioenergy" can occur in several possible ways.

- Biomass direct combustion: This is the simplest conversion process when the biomass energy is converted into heat energy. The heat can be used to produce steam which in turn can be used in the electricity generation industry. This direct combustion, however, leads to large levels of ash production.
- Biomass cofiring: This conversion process involves mixing the biomass source with existing fossil fuels (typically coal or oil) prior to combustion. The mix could either take place outside or inside the boiler. This is the most popular method utilized in the electricity generation industries that utilize biomass. This is because the biomass supply reduces the nitrogen oxide, sulfur dioxide and carbon dioxide emissions without significant losses in energy efficiency. This allows the energy in biomass to be converted to electricity with the high efficiency (in the 33-37 percent range) of a modern coal-fired power plant. Typically five to ten percent of the input fuel is biomass [3].
- Chemical conversion: Biomass can be used to produce liquid fuels (biofuels) such as ethanol and biodiesel. While they can each be used as alternative fuels, both are more frequently used as additives to conventional fuels to reduce toxic air emissions and improve performance.
- Biomass gasification: This involves a two-step thermochemical process of converting biomass or coal into either a gaseous or liquid fuel in high temperature reactors. Thermal gasification converts approximately 65-70 percent of available energy from the biomass into gases that could be used in gas turbines to generate electricity.
- Pyrolysis: Research is being conducted on a smoky-colored, sticky liquid that forms when biomass is heated in the absence of oxygen. Called pyrolysis oil, this liquid can be burned like petroleum to generate electricity. Unlike direct combustion, cofiring, and gasification, this technology is not yet in the marketplace [4].

Bioenergy constituted 4 percent of the total energy consumed and 47 percent of the total renewable energy consumed in the U. S. in 2004 [4]. Of the 2.7773 quadrillion British thermal units (Btu) supplied by biomass in 2002, 1.705 (around 61 percent) quadrillion

Btu (quads) were consumed in the industrial sector, 0.515 quads were consumed in the electricity sector and 0.313 quads were consumed in the residential sector [5]. A total of 0.156 quads were consumed in the transportation sector in the form of ethanol. The majority of the consumption in the industrial sector is cogeneration that takes place at the pulp and paper plants. Here the wood residues from the manufacturing process are combusted to produce steam and electricity [6]. Residential consumption occurs primarily in the form of wood burning fireplaces and stoves.

The biorefinery concept involves integrating biomass conversion processes and equipment to produce fuels, power and chemicals from biomass. The NREL biorefinery concept is built on two different platforms; the sugar platform based on biochemical conversion processes (fermentation of sugar) and syngas platform based on thermochemical conversion processes (gasification of biomass). The value added of a biorefinery lies on the advantage of maximizing the value derived from the different biomass stocks. The NREL Biomass Program is currently working on six major biorefinery projects [7].



<u>Figure 3-1:</u> <u>The biorefinery concept</u> (Source: NREL)

The primary sources of biomass for electricity generation are landfill gas and municipal solid waste, which account for approximately 70 percent of biomass electricity generation [5]. A complete overview of organic waste biomass is presented in Section 4 of this report.

Agricultural, forest, and municipal solid wastes are valuable short-term bioenergy resources, but do not provide the same long term advantages as energy crops [8]. Energy crops are not being commercially grown in the United States at present although a few demonstration projects are underway with DOE funding in Iowa and New York [6]. The Bioenergy Feedstock Development Program at ORNL has identified hybrid poplars, hybrid willows, and switchgrass as having the greatest potential for dedicated energy use over a wide geographic range [8].

Switchgrass falls under the category of herbaceous energy crops. These energy crops are perennials that are harvested annually after taking two to three years to reach full productivity. A 2005 study by McLaughlin and Kszos in multiple locations in the U. S. reported a current average annual yield from switchgrass clones of 4.2 to 10.2 dry tons per acre, with the most common average among the sample between 5.5 and 8 dry tons per acre [9]. The hybrid poplar and hybrid willow are short rotation, fast growing hardwood trees. They are harvested within five to eight years after planting [2]. The comparative chemical characteristics between the relevant energy crops and the conventional fossil fuels are shown in Table 3-1 [10].

Fuel Source	Heating Value (Gigajoule/ton)	Ash (percent)	Sulfur (percent)
Switchgrass	18.3	4.5-5.8	0.12
Hybrid Poplar/Willow	19	0.5-1.5	0.03
Coal (Low Rank)	15-19	5-20	1-3
Coal (High Rank)	27-30	1-10	0.5-1.5
Oil	42-45	0.5-1.5	0.2-1.2

Table 3-1: Comparative chemical characteristics of energy crops and fossil fuels (Source: ORNL)

In today's direct-fired biomass power plants, generation costs are about 9 cents/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as 5 cents/kWh. In cofiring applications, modifications to the coal plant can have payback periods of 2-3 years [11].

3.2 Economics of energy crops

The economic feasibility of energy crops is a function of many factors. First, the price of the energy crop is crucial. If the price is too high, the energy crop will not be able to compete with other energy sources, such as fossil fuels. On the other hand, if the price is too low, the producer will use the land for other, more profitable uses, such as planting corn or soybeans. A second factor is the set of environmental regulations that fuel users operate under, which may make energy crops more attractive. A third factor is the cost of transporting the energy crop to the consumer. Unlike other renewable resources, energy crops must be harvested and transported instead of used locally. A final factor is the existence of government subsidies, such as those used in the ethanol industry. These factors are discussed in more detail in the following sections.

3.3 State of energy crops nationally

Energy crops can be grown on most of the more than 368 million acres classified as cropland in the nation, as shown in Figure 3-2 from the Natural Resources Conservation

Service (NRCS) of the U. S. Department of Agriculture (USDA) [8]. Overall, the nation's cropland acreage declined from 420 million acres in 1982 to 368 million acres in 2003, a decrease of about 12 percent. Figure 3-3 shows the estimated biomass production potential nationally [12]. A subset of these lands is defined as prime farmland – those lands with the best combination of physical and chemical characteristics for producing food, fiber, energy crops and other vegetation. Energy crops offer many environmental advantages when produced on erosive lands or lands that are otherwise limited for conventional crop production.

In 1979, Purdue University published a comprehensive report titled, "The Potential of Producing Energy from Agriculture," for the Office of Technology Assessment within the U. S. Congress [13]. The report analyzed the technological, resource and environmental constraints to producing energy from agricultural crops and residues. The report concluded that there would likely be government incentives or mandates required to stimulate widespread production and conversion of biomass to energy. The EERE Biomass Program, multi year 2004 -2008 report concludes that "*Energy production from biomass calls for a complete rethinking of farming in America, and it may involve dramatic changes in agriculture that may take some time bring about*" [14].

The primary barrier to the commercial development of energy crops is the high cost of the feedstock relative to the cost of fossil fuels. The high costs are driven by competition with other crops that could be produced on the land. The price of the energy crop needs to be high enough to entice producers to grow the energy crop rather than other crops, including those whose prices are Federally subsidized. Also, some have argued that the true environmental costs of burning fossil fuels are not charged to the entity using the fuel [3].

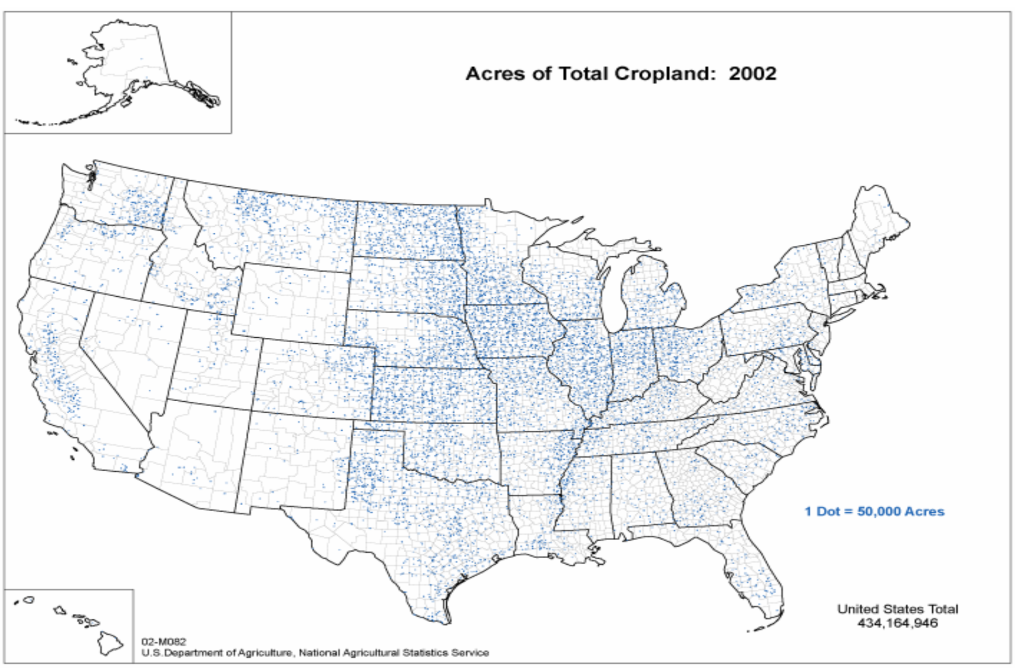


Figure 3-2: Cropland distribution in the U. S. (Source: NRCS)

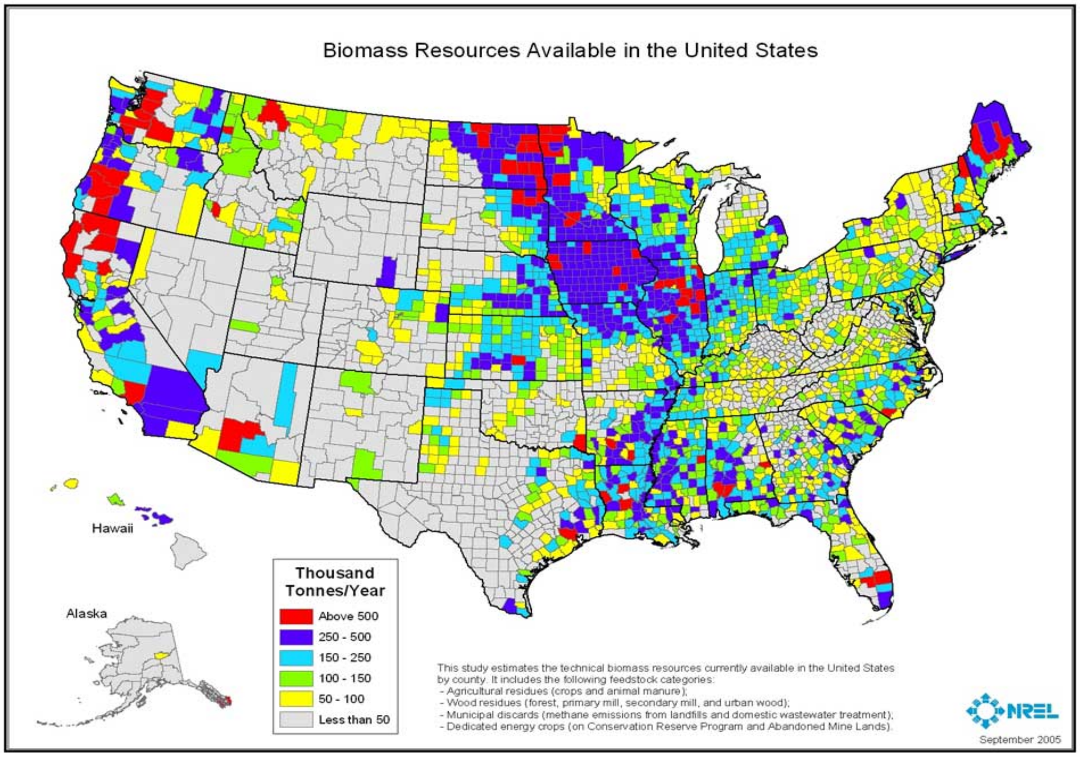
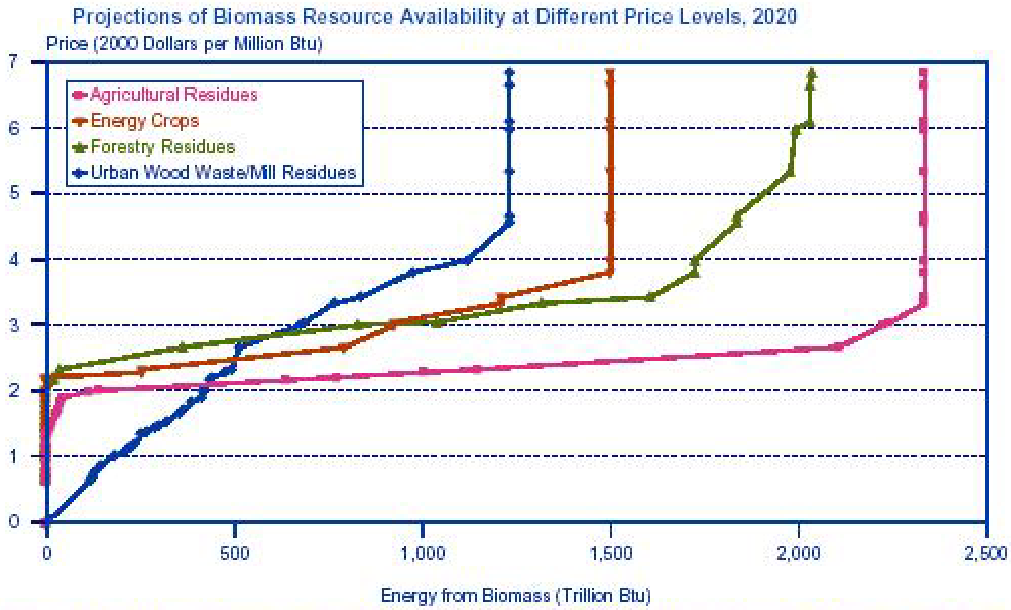


Figure 3-3: Biomass resources available in the U. S. (Source: NREL)

The Energy Information Administration, a division of DOE, published a report titled, *Biomass for Energy Generation*, by Zia Haq [6]. This report focused on the expected biomass energy supply (including energy crop supply) in 2020. It utilized an agricultural sector model called POLYSYS (Policy Analysis System), which was developed by ORNL to estimate the possible future supplies. Traditionally this software was used for estimating commodities crops supply; therefore to evaluate the economic potential of bioenergy crops, several modifications to the POLYSIS model were made [15]. The estimated national supply curve for biomass and energy crops produced by POLYSYS for the year 2020 is shown in Figure 3-4. Other modeling tools used for estimating feedstock supplies developed by ORNL are; ORIBAS, BIOCOST and databases ORRECL [14].

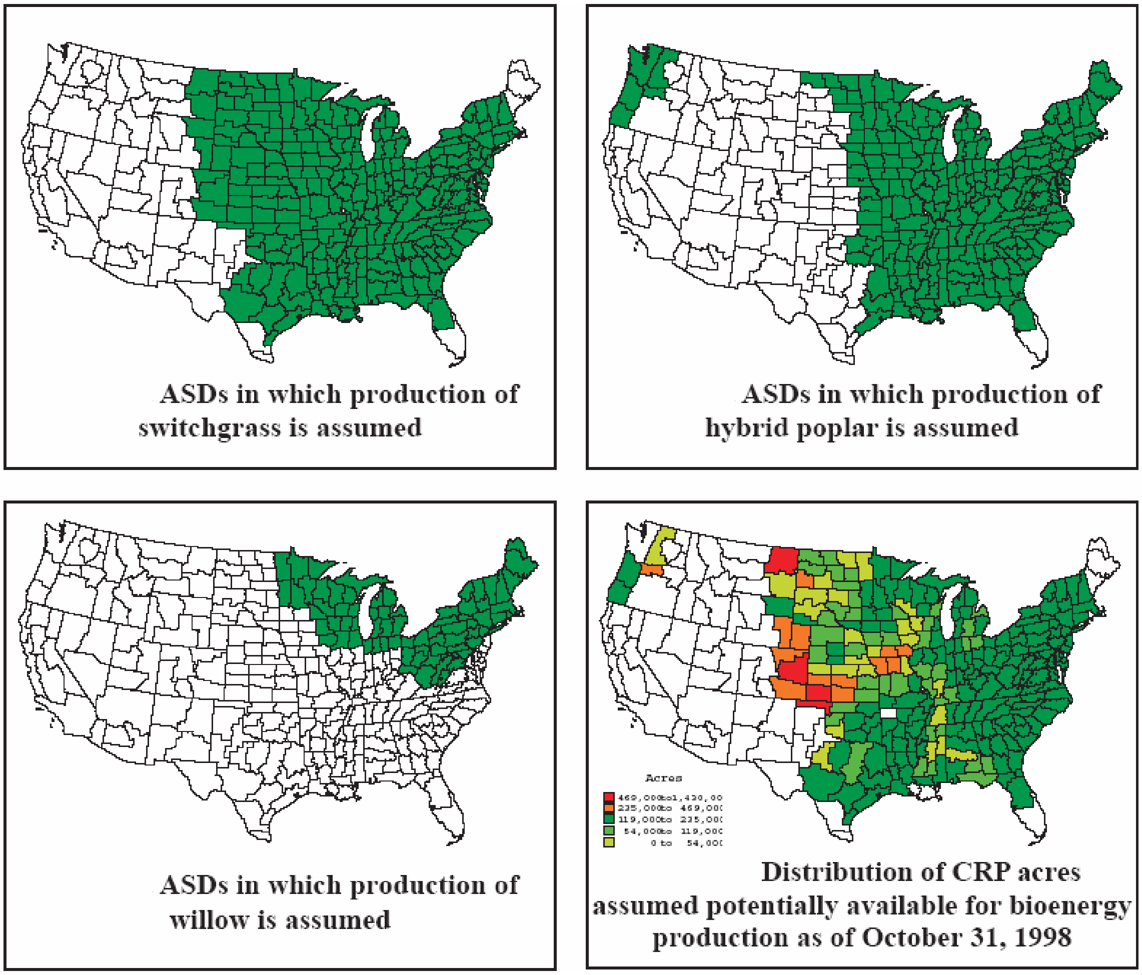
Figure 3-4 indicates that energy crops will be supplied into the market when the average price (in 2000 dollars) exceeds \$2.10/million Btu. In comparison, the average price of coal to electric utilities in 2005 was \$1.52/million Btu [16]. Therefore, the use of energy crops could represent an increased cost to the electric utilities.



Sources: A.F. Turhollow and S.M. Cohn, *Data and Sources of Biomass Supply*, unpublished report (Oak Ridge, TN: Oak Ridge National Laboratory, January 1994); M. Walsh et al., *Biomass Feedstock Availability in the United States: 1999 State Level Analysis* (Oak Ridge, TN: Oak Ridge National Laboratory, April 1999, updated January 2000), web site http://bioenergy.ornl.gov/resourcedata; M. Walsh et al., "The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture" (Oak Ridge, TN: Oak Ridge National Laboratory, May 2000), web site http://bioenergy.ornl.gov/papers/wagin/index.html; and Antares Group, Inc., *Biomass Residue Supply Curves for the United States (Update)*, Report for the U.S. Department of Energy and the National Renewable Energy Laboratory (June 1999).

Figure 3-4: POLYSYS estimated biomass supply curve for year 2020 (Source: EIA)

ORNL uses POLYSYS to estimate the quantities of energy crops that could be produced at various prices in the future. The POLYSYS model assumes that irrigation of energy crops would be a huge economic penalty and thus excludes the Western Plains due to the natural rain gradient in the U. S. Also the Rocky Mountain region is excluded as it is assumed to be an unsuitable climate in which to produce energy crops. The assumed yields of energy crops were lowest in the Northern Plains and highest in the heart of the Corn Belt. The hybrid poplar production was assumed to occur in the Pacific Northwest, Southern and Northern regions, while willow production was assumed to only occur in the Northern region due to limited research being conducted for the potential growth outside that area. The production assumptions used by ORNL are shown in Figure 3-5. The final panel in Figure 3-5 shows the acreage in the Conservation Reserve Program (CRP) that is assumed potentially available for bioenergy. These and further assumptions ORNL used with the POLYSYS model are discussed in ORNL's *The Economic Impacts of Bioenergy Crop Production on U. S. Agriculture* [15].



<u>Figure 3-5:</u> <u>POLYSYS assumed Agricultural Statistical Districts (ASDs) for energy crop production</u> (Source: USDA)

The energy crop yield assumptions that have been used for the POLYSYS model are illustrated in Table 3-2. According to *Biomass for Electricity Generation* [6],

> *The variation in yields is due to differences in weather and soil conditions across the country. The lowest yields are assumed to be in the Northern Plains and the highest in the heart of the corn belt, as is the pattern observed with traditional crops. In addition, POLYSYS assumes that different varieties of switchgrass, hybrid poplar, and willow are produced in different parts of the country, with different yield assumptions. Energy crop production costs are estimated using the same full-cost accounting approach that is used by USDA to estimate the cost of producing conventional crops. The approach includes both fixed costs (such as equipment) and variable costs (such as labor, fuel, seed, and fertilizers).*
>
> *Switchgrass stands are assumed to remain in production for 10 years before replanting, to be harvested annually, and to be delivered as large round bales. The plants can regenerate, and the same plant can continue to produce*

switchgrass for up to 10 years. It is assumed that new switchgrass varieties will have been developed after 10 years, and that it will be financially beneficial to plow under the existing switchgrass stand and replant with a new variety. Once established, a switchgrass field could be maintained in perpetuity, but the advantages of new, higher yield varieties would warrant periodic replanting.

Hybrid poplars are assumed to be planted at spacings of 8 feet by 10 feet (545 trees per acre) and to be harvested after 6, 8, and 10 years of growth in the Pacific Northwest, southern United States, and northern United States, respectively. Harvesting is assumed to be by custom operation, and the product is assumed to be delivered as whole tree chips.

Willow production is assumed only in the northern United States. Willows can technically be grown throughout the entire eastern United States, but limited research has been done for areas outside the Northeast and North Central regions. Willows are produced in a coppice system with a replant every 22 years. They are planted in 2 x 3 double rows (6,200 trees per acre) with first harvest in year 4 and subsequent harvests every 3 years for a total of 7 harvests. Willow is delivered as whole tree chips.

In terms of product quality, hybrid poplar and willow contain about 45 to 50 percent moisture when harvested. The trees would typically be fed into a wood chipper, which generally would provide chips between 0.5 and 1 inch square and less than 0.25 inch thick. Switchgrass is harvested at about 15 percent moisture, baled, and generally ground in a tub grinder before use.

Energy Crop	Land Currently Planted with Major Crops	Idle and Pasture Land
Switchgrass	2.0 to 6.7	1.7 to 5.7
Hybrid poplar	3.25 to 6.0	2.8 to 5.1
Willow	3.15 to 5.8	2.7 to 4.9

Table 3-2: Energy crop yield assumptions for the POLYSYS model (dry tons per acre per year) (Source: EIA) [6]

The USDA and DOE conducted a joint study, using the POLYSYS model, to determine the potential of producing biomass energy crops [17]. The results indicated that an estimated 188 million dry tons (2.9 quadrillion Btu) of biomass could be available annually at delivered prices of less than $50/dry ton ($2.88/million Btu) by the year 2008. The analysis includes all cropland suitable for the production of energy crops that is currently planted to traditional crops, idled, in pasture, or in the CRP. It is estimated that 42 million acres of cropland (about 10 percent of all cropland acres) could be converted to energy crop production including 16.9 million CRP acres that are identified as being potentially available for bioenergy crop production. The last graph in Figure 3-5 shows that CRP acres could become a significant source of biomass crops, decreasing the impact of competition with traditional crops [15]. Harvest of CRP acres will require a significant change in the current laws and should be structured in a way that maintains the environmental benefits of the program. The estimated quantities represent the maximum that could be produced at a profit greater than that which could be earned through existing uses. Farmer adoption of new crops is based on several factors. Greater profitability will encourage, but not necessarily ensure, the adoption of a new crop.

Energy crop yields will increase over time as will traditional crop yields. The interplay of demand for food, feed, and fiber with traditional crop yields, and crop production costs will determine the number of acres allocated to traditional crop production. International demand for food, feed, and fiber is expected to increase in the future.

Another factor that will impact the amount of land available for energy crops is the conversion of cropland to other uses, especially to developed land. Figure 3-6 shows the distribution of land in the lower 48 states in millions of acres in various years according to the National Resources Inventory by NRCS [18]. Note that the CRP did not exist until 1985.

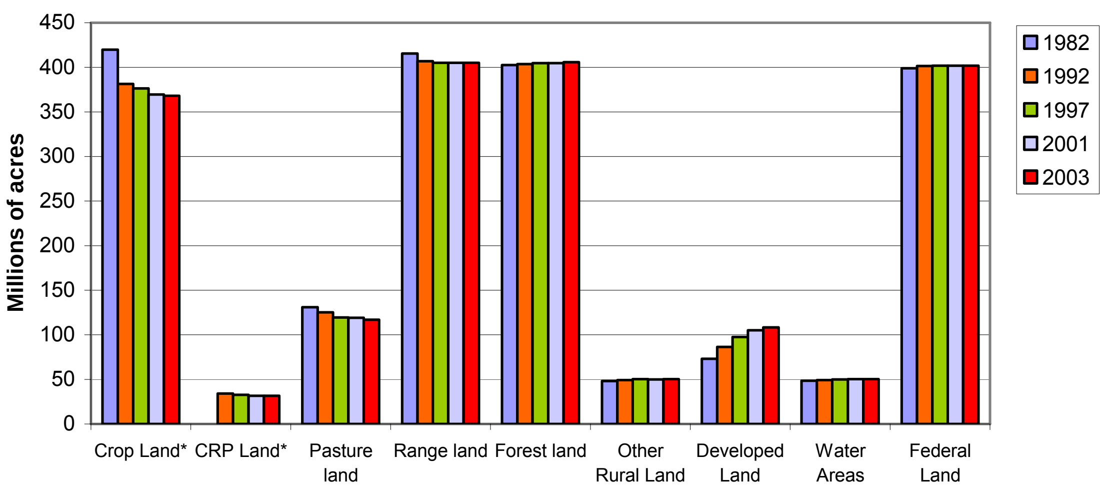


Figure 3-6: Land use in the contiguous United States (Source: NRCS)

Biotechnology is expected to substantially increase crop yields in the future, although studies (such as those by the Office of Technology Assessment and by the Resource Conservation Act assessments) indicate that the largest increases in yields will likely occur after 2020. Potential quantities of energy crops could increase in the near future, but increases may be more due to increasing yields per acre than from increasing acres. Opportunities to tailor biomass energy crops to serve multiple purposes have not been considered in this analysis.

3.4 Energy crops in Indiana

It has been estimated that 27.1 billion kWh of electricity could be generated using renewable biomass fuels in Indiana [19]. These biomass resource supply figures are based on estimates for five general categories of biomass: urban residues, mill residues, forest residues, agricultural residues, and energy crops. Of these potential biomass supplies, most forest residues, agricultural residues, and energy crops are not presently economic for energy use. New tax credits or incentives, increased monetary valuation of environmental benefits, or sustained high prices for fossil fuels could make these fuel sources more economic in the future [19].

While Indiana has a huge potential for energy crops, it is unlikely that farmers will utilize prime farmland for an uncertain return on energy crops. It is more likely that marginal lands[6] will be used [3]. Switchgrass has been identified as the most effective energy crop for most of the Midwest including Indiana [3, 20]. The following reasons were used to justify this claim [3]:

- It is native to most of the Midwest;
- It does not require much input after planting, therefore less soil disturbance;
- With less soil disturbance there is less chance of soil erosion;
- Harvest usually occurs from September to October prior to the harvest of corn and soybeans; and
- Machinery required for switchgrass is similar to that used for hay or silage harvest.

According to GIS-based estimates, the total switchgrass yield for Indiana using all agricultural land would be 90 million tons/year, giving an energy production potential of 1.54 quads/year [3]. Obviously, not all land would be used for switchgrass production but this does illustrate the huge potential available within Indiana. The central region of the state has the highest potential for switchgrass production because of favorable soils and a high percentage of agricultural lands. The southern region has the least potential and the northern region has a fairly high potential.

The joint USDA and DOE study [17] estimated that the annual cumulative production level of energy crops in Indiana would be as shown in Table 3-3.

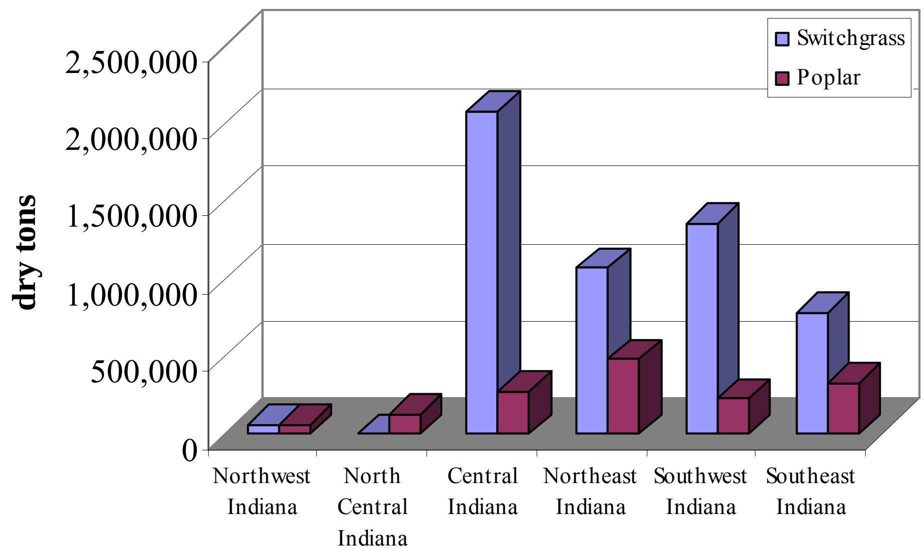
State	**< $30/dry ton ($1.73/million Btu) delivered**	**< $40/dry ton ($2.31/million Btu) delivered**	**< $50/dry ton ($2.88/million Btu) delivered**
Indiana	0	418,042	5,026,234

Table 3-3: Estimated annual cumulative energy crop quantities (dry tons), by delivered price (1997 dollars) for Indiana (Source: ORNL)

The ORNL estimated the production of energy crops; switchgrass and poplar within Indiana based on the assumption of farm gate feedstock price of $40-50/dry ton [7]. These estimations are USDA baseline 2001, and production of each crop is fixed at levels predicted for 2014 by USDA-OCE. Figure 3-7 shows that central Indiana has the highest potential for switchgrass production [21]. The northeast and southeast regions of Indiana

[6] Marginal lands include highly erodable land, CRP land and reclaimed surface mined lands.

have the highest potential for hybrid poplar production. As can be seen from the figure, Indiana has a higher potential for production of switchgrass than it has for hybrid poplar.



Northwest Indiana; Jasper, La Porte, Lake, Newton, Porter, Pulaski, Starke.
North Central Indiana; Elkhart, Fulton, Kosciusko, Marshall, St. Joseph, Cass, Miami, Wabash.
Central Indiana; Boone, Hamilton, Hancock, Hendricks, Madison, Marion, Shelby, Delaware, Henry, Randolph, Wayne, Benton, Carroll, Clinton, Fountain, Montgomery, Tippecanoe, Warren, White, Johnson, Monroe, Morgan, Clay, Howard, Owen, Parke, Putnam, Tipton, Vermillion, Vigo.
Northeast Indiana; Adams, Allen, Blackford, De Kalb, Grant, Huntington, Jay, Lagrange, Noble, Steuben, Wells, Whitley
Southwest Indiana; Lawrence, Crawford, Daviess, Dubois, Gibson, Greene, Knox, Martin, Orange, Perry, Pike, Posey, Spencer, Sullivan, Vanderburgh, Warrick.
Southeast Indiana; Brown, Bartholomew, Dearborn, Fayette, Floyd, Franklin, Jennings, Ohio, Ripley, Rush, Scott, Switzerland, Union, Washington, Clark, Harrison, Decatur, Jackson, Jefferson.

Figure 3-7: Estimated annual potential production of switchgrass and hybrid poplar (dry tons) for Indiana, USDA baseline 2001 (Source: ORNL, data provided by Dr. Wallace Tyner, Purdue University)

Government support is seen as crucial for the development of energy crops as a viable energy source within Indiana [13]. First, if CRP lands are to be utilized to grow energy crops, some government approval would be required as these lands were set aside for conservation purposes. Second, since farmers would only utilize farmland to grow energy crops if they yield profits at least as great as the traditional crops that they replaced, high feedstock prices for electric utilities could be expected. Furthermore, Indiana is a source of low cost coal that is the dominant fuel for electricity production in the state. Thus, the government would need to provide incentives for farmers or electricity generators that use energy crops in order to help make them more competitive. The following incentives have been available to assist in the use of energy crops [22].

- Renewable Electricity Production Tax Credit: is a per kWh tax credit for electricity generated by qualified energy resources that provides producers 1.9

cents/kWh during the first ten years of operation. The PTC originally covered wind and biomass and has been expanded in the Energy Policy Act of 2005 and its expiration extended through December 31, 2007.

- Renewable Energy Systems and Energy Efficiency Improvements Program: Section 9006 of the 2002 Farm Bill requires the USDA to create a program to make direct loans, loan guarantees, and grants to agricultural producers and rural small businesses to purchase renewable-energy systems and make energy-efficiency improvements. This program is known as the Renewable Energy Systems and Energy Efficiency Improvements Program. The USDA has implemented this program through a Notice of Funds Availability (NOFA) for each of the last four years. The latest round of funding was made available in February 2006. Part of the funding, $11.385 million, is available immediately for competitive grants. Approximately $176.5 million in guaranteed loan authority is also available. Renewable-energy grants range from $2,500 to $500,000 and may not exceed 25 percent of an eligible project's cost.
- Value-Added Producer Grant Program: The application period for year 2006 closed on March 31, 2006. Funding decisions were scheduled to be made by August 31, 2006. Last year, a total of $14.3 million in grants was allocated from USDA to support the development of value-added agriculture business ventures. Value-Added Producer Grants are available to independent producers, agricultural producer groups, farmer or rancher cooperatives, and majority-controlled producer-based business ventures seeking funding. Grant awards for fiscal year 2005 supported energy generated on-farm through the use of agricultural commodities, wind power, water power or solar power. The maximum award per grant was $100,000 for planning grants and $150,000 for working capital grants. Matching funds of at least 50 percent were required.
- Distributed Generation Grant Program: offers awards of up to $30,000 to commercial, industrial, and government entities to "install and study alternatives to central generation" (biomass falls under one of these alternatives).
- Alternative Power and Energy Grant Program: offers grants of up to $30,000 to enable businesses and institutions to "install and study alternative and renewable energy system applications" (biomass is an acceptable technology).
- Energy Education and Demonstration Grant Program: This program makes small-scale grants for projects that demonstrate applications of energy efficiency and renewable energy technologies for businesses, public and non-profit institutions, schools, and local governments.
- Energy Efficiency and Renewable Energy (EERE) Set-Aside: Indiana's Energy Efficiency and Renewable Energy Set-Aside is a joint effort of the Indiana Energy and Recycling Office (ERO) and the Indiana Office of Air Quality (OAQ) that offers potential financial incentives to large-scale energy-efficiency projects and renewable-energy projects that significantly reduce NO_x emissions.
- Renewable Energy Production Incentive: The REPI provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Eligible electric production facilities include publicly-owned electric utilities, rural electric cooperatives, and local or state governments that sell the project's electricity to someone else. Eligible projects had to

commence operations between October 1, 1993 and September 30, 2003. Qualifying facilities are eligible for annual incentive payments of 1.5 cents/kWh (1993 dollars and indexed for inflation) for the first ten year period of their operation, subject to the availability of annual appropriations in each Federal fiscal year of operation. The period for payment under this program ends with fiscal year 2013.

- Net Energy Credit: Facilities generating less than 1000 kWh per month from renewable sources are eligible to sell the excess electricity to the utility. Facilities generating more than 1000 kWh per month need to request permission to sell the excess electricity to the utility.
- 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 [23]. These credits can be sold on the national market.

Government aid could also assist in offsetting the renovation costs of conventional fossil-fueled stations wanting to include some energy crops as an input. It has been stated that converting a coal-fired station to cofire with biomass will result in an incremental cost of approximately 1 to 2 cents/kWh and if the biomass was gasified then the resulting incremental cost would be approximately 7 cents/kWh [24]. Further biotechnology developments in energy crops and improvements in energy conversion technology would also assist in the development of energy crops within Indiana.

Corn use for ethanol production

Another crop being used for energy purposes in Indiana and nationally is corn. Although corn is not a dedicated energy crop, its rapid increase for use as gasoline additive is significant. The increase in the use of corn-based ethanol as a gasoline additive can be attributed to a number of factors, including the substitution of ethanol as a gasoline oxygenating additive in place of the chemical additive MTBE which has been associated with ground water pollution [25] and the renewable fuel standard (RFS) included in the 2005 Energy Policy Act [26]. The RFS mandates the use of renewable fuel beginning with 4 billion gallons per year in 2006, and expanding to 7.5 billion of gallons by 2012. A number of tax incentives have also contributed to the increased investment in ethanol plants. They include the streamlining of the volumetric ethanol tax credit (VEETC) process and the raising of the cutoff level for small producers tax credit from 30 million gallons per year to 60 million gallons per year. The streamlined VEETC allows for a 51 cents/gallon tax credit to be refunded within 20 days of blending the ethanol with gasoline [27]. Indiana has also recently enacted a tax incentive package that includes increasing the maximum amount of credits for biodiesel production, biodiesel blending and ethanol production from 20 to 50 million dollars and a 10 cents/gallon sales tax deduction for retail sales of the ethanol blend E85. Table 3-4 shows the ethanol plants existing and proposed in Indiana. The capacity in Table 3-4 is in units of million gallons per year (MGY).

Indiana Ethanol Plants

	City	County	Capacity MGY	Type	Built	Cost Million$	Approximate Announce	Ground Breaking
Operating Plants								
New Energy Corp.	South Bend	St. Joe	102	Dry	1980			
Under Construction (RFA)*								
AS Alliances Biofuels, LLC-Cargill	Linden	Montgomery	100	Dry		$125		January 2006
Iroquois Bio-Energy Company, LLC	Rensselaer	Jasper	40	Dry		$66		August 2005
Central Indiana Ethanol, LLC	Marion	Grant	45	Dry				Nov. 2005
The Andersons Clymers Ethanol, LLC	Clymers	Cass	110	Dry				March 2006
Proposed or Announced								
Putnam Ethanol, LLC	Cloverdale	Putnam	60	Wet		$120	6/29/05	June 2005
Hartford Energy LLC	Hartford City	Blackford	63	Wet		$150	9/18/05	IDEM* Air Permits (Feb, 2006)
Indiana Ethanol, LLC		Randolph	50	Dry		$80 - $130	10/1/05	50 to 100 million gallons
Rush Renewable Energy, LLC		Rush	60	Dry		$82	12/19/05	
Maize AgriProducts		Benton	50	Dry			2/2/06	
Louis Dreyfus Group	Claypool	Kosciusko	100	Dry			3/8/06	
The Andersons, Inc.	Dunkirk	Jay	100	Dry			4/7/06	Air Permit Filing (4/6/06)
Indiana Renewable Fuels, LLC	Near "Couty Line Landfill"	Fulton	100	Dry			4/21/06	
AS Alliances Biofuels, LLC-Cargill	Tipton	Tipton	100	Dry			5/1/06	
Central States	Montpelier	Jay	110	Dry			5/2/06	
Cardinal Ethanol	Harrisville	Randolph	100	Dry		$150	5/4/06	05/06: Began Selling Shares to Public
Premier Ethanol, LLC (Broin Companies)	Portland	Jay	120	Dry			6/1/06	June 2006
Morning State Energy	Pitsburo	Hendricks	100	Dry			6/6/06	
AS Alliances Biofuels, LLC-Cargill	Mt Vernon	Posey	100	Dry			6/13/06	

*According to Renewable Fuels Association
http://www.ethanolrfa.org/industry/locations/

This information is not official. It is from local newspapers and other sources believed to be accurate. However, there may be discrepancies for a number of reasons.
** Indiana Department of Environmental Management*
Updated: June 2006.

Table 3-4: Operating, under construction and proposed ethanol plants in Indiana (Source: Dr. Christopher Hurt, Purdue University)

3.5 References

1. http://bioenergy.ornl.gov/pubs/resource_data.html
2. http://www.eere.energy.gov/RE/bio_resources.html
3. H. Brown, J. Elfin, D. Fergusin and J. Vann, "Connecting Biomass Producers with Users: Biomass Production on Marginal Lands," Nov 2002.
4. http://www.eere.energy.gov/biomass/biomass_today.html
5. http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/table7.html
6. Zia Haq, "Biomass for Electricity Generation," Energy Information Administration, U. S. Department of Energy.
7. http://www.nrel.gov/biomass/biorefinery.html
8. http://www.nrcs.usda.gov/technical/land/nri03/nri03landuse-mrb.html
9. http://feedstockreview.ornl.gov/pdf/billion_ton_vision.pdf
10. http://bioenergy.ornl.gov/papers/misc/biochar_factsheet.html
11. http://www.eere.energy.gov/biopower/basics/index.htm
12. http://www.nrel.gov/gis/images/biomass.jpg
13. W. Tyner, et al., "The Potential of Producing Energy from Agriculture," Purdue University, 1979.
14. http://www.nrel.gov/docs/fy05osti/36999.pdf
15. http://apacweb.ag.utk.edu/ppap/pp03/bio/AER816BioenergyReportTotal.pdf
16. http://www.eia.doe.gov/cneaf/electricity/epm/chap4.pdf
17. http://bioenergy.ornl.gov/resourcedata/index.html
18. http://www.nrcs.usda.gov/technical/land/nri03/nri03landuse-mrb.html
19. http://www.eere.energy.gov/state_energy/tech_biomass.cfm?state=IN
20. Environmental Law and Policy Center, "Repowering the Midwest: The Clean Energy Development plan for the Heartland," 2001.
21. ORNL, Indiana's Counties energy crops estimates. Data provided by Dr. Wallace Tyner (2006).
22. http://www.dsireusa.org/
23. http://www.in.gov/idem/energycredit/ecreditfct.pdf
24. http://www.energyfoundation.org/documents/Bioenergy.pdf
25. http://www.eia.doe.gov/oiaf/aeo/
26. Energy Policy Act of 2005

4. Organic Waste Biomass

4.1 Introduction

Organic waste biomass can be divided into five subcategories [1]:

- Agriculture crop residues: Crop residues include biomass, primarily stalks and leaves, not harvested or removed from the fields in commercial use. Examples include corn stover (stalks, leaves, husks and cobs), wheat straw, and rice straw. With approximately 80 million acres of corn planted annually, corn stover is expected to become a major biomass resource for bioenergy applications.
- Forestry residues: Forestry residues include biomass not harvested or removed from logging sites in commercial hardwood and softwood stands as well as material resulting from forest management operations, such as pre-commercial thinnings and removal of dead and dying trees.
- Municipal solid waste (MSW): Residential, commercial, and institutional post-consumer wastes contain a significant proportion of plant derived organic material that constitutes a renewable energy resource. Waste paper, cardboard, wood waste and yard wastes are examples of biomass resources in municipal wastes.
- Biomass processing residues: All processing of biomass yields byproducts and waste streams collectively called residues, which have significant energy potential. Residues are simple to use because they have already been collected. For example, processing of wood for products or pulp produces sawdust and collection of bark, branches and leaves/needles.
- Animal wastes: Farms and animal processing operations create animal wastes that constitute a complex source of organic materials with environmental consequences. These wastes can be used to make many products, including energy.

As discussed in Section 3, biomass can be converted to energy in one of several ways[7]:

- Biomass direct combustion
- Biomass cofiring
- Chemical conversion
- Biomass gasification

A more detailed treatment of the capture of energy from organic biomass waste streams, including livestock manure, landfills and wastewater treatment plants, is given in the appendices at the end of this report.

There are varying levels of efficiency for plants using each of the above-mentioned biomass conversion technologies. Typical efficiency ranges are from 20 to 24 percent for direct combustion, 33 to 35 percent for biomass cofiring and 35 to 45 percent for gasification [2].

---

[7] These terms are explained fully in Section 3.

According to DOE, the U. S. can produce nearly 1 billion dry tons of biomass annually and still continue to meet food, feed, and export demands. This projection includes 428 million dry tons of annual crop residues, 377 million dry tons of perennial crops, 87 million dry tons of grains used for biofuels, and 106 million dry tons of animal manures, process residues, and other miscellaneous feedstock. Important assumptions that were made include the following [3]:

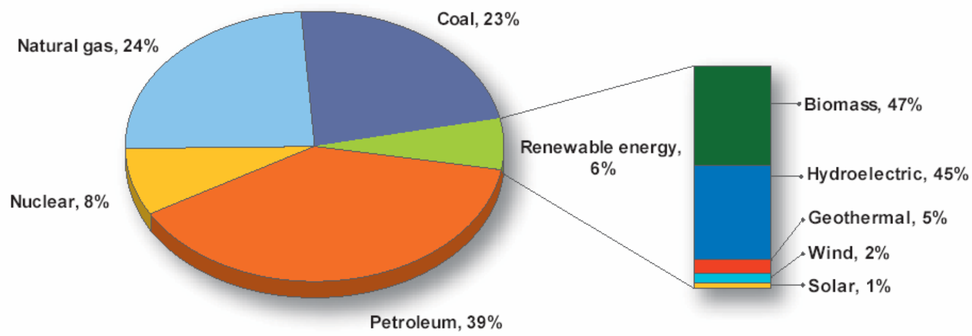
- *Yields of corn, wheat, and other small grains were increased by 50 percent;*
- *The residue-to-grain ratio for soybeans was increased to 2:1;*
- *Harvest technology was capable of recovering 75 percent of annual crop residues;*
- *All cropland was managed with no-till methods;*
- *55 million acres of cropland, idle cropland, and cropland pasture were dedicated to the production of perennial bioenergy crops;*
- *All manure in excess of that which can be applied on-farm for soil improvement under anticipated EPA [Environmental Protection Agency] restrictions were used for biofuel; and*
- *All other available residues were utilized.*

Furthermore, according to EIA [4], bioenergy constituted 6 percent of the total energy consumed in the U. S. and 47 percent of the total renewable energy consumed in the U. S. in 2004, making it the single largest renewable energy source, recently surpassing hydropower (Figure 4-1). More than 50 percent of this biomass comes from wood residues and pulping liquors generated by the forest products industry [5]. During 2004, biomass accounted for approximately [6]:

- 14 percent of renewably generated electricity,
- 97 percent of industrial renewable energy use,
- 81 percent of residential renewable energy use, and
- 84 percent of commercial renewable energy use.

The primary sources of biomass for non-cogeneration electricity are landfill gas and municipal solid waste. Together, they account for over 61 percent of biomass electricity generation by electric utilities and independent power producers [4]. Furthermore, the primary sources for industrial sector biomass electricity generation in 2003 were black liquor, a byproduct of the paper making process and wood/wood waste solids, which accounted for 63 percent and 32 percent of the sector's total, respectively [4].

EIA's long term forecast of energy supply and prices, *Annual Energy Outlook 2006*, shows that biomass will continue to be the largest renewable source for electricity generation as shown in Figure 4-2. By year 2030, it is estimated that electricity generation from biomass will increase from 0.9 percent of total generation in 2004 to 1.7 percent by the end of 2030. That increase will come primarily due an increase in biomass co-firing and dedicated power plants [7].



Biomass Consumption	Million dry tons/year
Forest products industry	
Wood residues	44
Pulping liquors	52
Urban wood and food & other process residues	35
Fuelwood (residential/commercial & electric utilities)	35
Biofuels	18
Bioproducts	6
Total	**190**

- Forestlands and agricultural lands contribute 190 million dry tons of biomass - 3% of America's current energy consumption.

Source: EIA, 2004a & b

Figure 4-1: Summary of biomass resource consumption (Source: EIA)

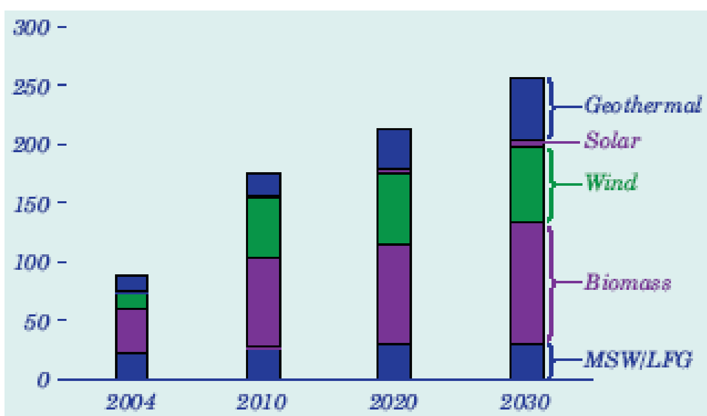


Figure 4-2: Nonhydroelectric renewable electricity generation by energy source, 2004-2030 (billion kWh) (Source: EIA)

The energy content in the various organic waste biomass fuels vary as shown in Table 4-1 [8].

Fuel Type	Heat Content	Units
Agricultural Byproducts	8.248	Million Btu/Short Ton
Digester Gas	0.619	Million Btu/Thousand Cubic Feet
Landfill Gas	0.490	Million Btu/Thousand Cubic Feet
Municipal Solid Waste	9.945	Million Btu/Short Ton
Paper Pellets	13.029	Million Btu/Short Ton
Peat	8.000	Million Btu/Short Ton
Railroad Ties	12.618	Million Btu/Short Ton
Sludge Waste	7.512	Million Btu/Short Ton
Sludge Wood	10.071	Million Btu/Short Ton
Solid Byproducts	25.830	Million Btu/Short Ton
Spent Sulfite Liquor	12.720	Million Btu/Short Ton
Tires	26.865	Million Btu/Short Ton
Utility Poles	12.500	Million Btu/Short Ton
Waste Alcohol	3.800	Million Btu/Barrel
Wood/Wood Waste	9.961	Million Btu/Short Ton
Source: Energy Information Administration, Form EIA-860B (1999), "Annual Electric Generator Report – Non-utility 1999."		

Table 4-1: Average heat content of selected biomass fuels (Source: EIA)

4.2 Economics of organic waste biomass-fired generation

Cofiring with biomass fuels utilizes existing power plant infrastructure to minimize costs while maximizing environmental and economic benefits [5]. Typical cofiring applications utilize 5 to 10 percent biomass as the input fuel mix. To allow for cofiring, some conversion of the existing fuel supply system in the station is required. It has been stated that the payback period of this capital investment could be as low as two years if low cost biomass is used [9].

The following excerpt was extracted from DOE's website [9]:

> *A typical existing coal fueled power plant produces power for about 2.3 cents/kWh. Cofiring inexpensive biomass fuels can reduce this cost to 2.1 cents/kWh. In today's direct-fired biomass power plants, generation costs are about 9 cents/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as 5 cents/kWh. For comparison, a new combined-cycle power plant using natural gas can generate electricity for about 4 to 5 cents/kWh at today's gas prices.*
>
> *For biomass to be economical as a power plant fuel, transportation distances from the resource supply to the power generation point must be minimized, with the maximum economically feasible distance being less than 100 miles. The most economical conditions exist when the energy use is located at the site where the biomass residue is generated (i.e., at a paper mill, sawmill, or sugar mill).*

Modular biopower generation technologies under development by the U. S. Department of Energy (DOE) and industry partners will minimize fuel transportation distances by locating small-scale power plants at biomass supply sites.

4.3 State of organic waste biomass-fired generation nationally

In 2004, the total biomass-based generation capacity in the U. S. was 9,709 MW [10]. Of this installed capacity 5,891 MW was dedicated to generation from wood and wood wastes (mostly by pulp and paper mills), 3,319 MW was attributed to generation capacity from MSW and landfill gas supplies, and the remainder used various other sources such as agricultural byproducts. There are currently about 39 million tons of unused economically viable annual biomass supplies available in the nation [9]. This translates to about 7,500 MW of additional generation capacity. Figure 4-3 shows the current biomass availability in the U. S. According to the DOE Biomass Program [11],

Biomass Program analysts estimate that 512 million dry tons of biomass equivalent to 8.09 quads of primary energy could initially be available at less than $50/dry ton delivered. Of this, 36.8 million dry tons (0.63 Quads) of urban wood wastes were available in 1999. In the wood, paper, and forestry industrial sectors, they estimate that 90.5 million dry tons (1.5 Quads) of primary mill residues were available in 1999 and 45 million dry tons (0.76 Quads) of forest residues were available at a delivered price of less than $50/dry ton. An estimated 150.7 million dry tons (2.3 Quads) of agricultural residues (corn stover and wheat straw) would be available annually.

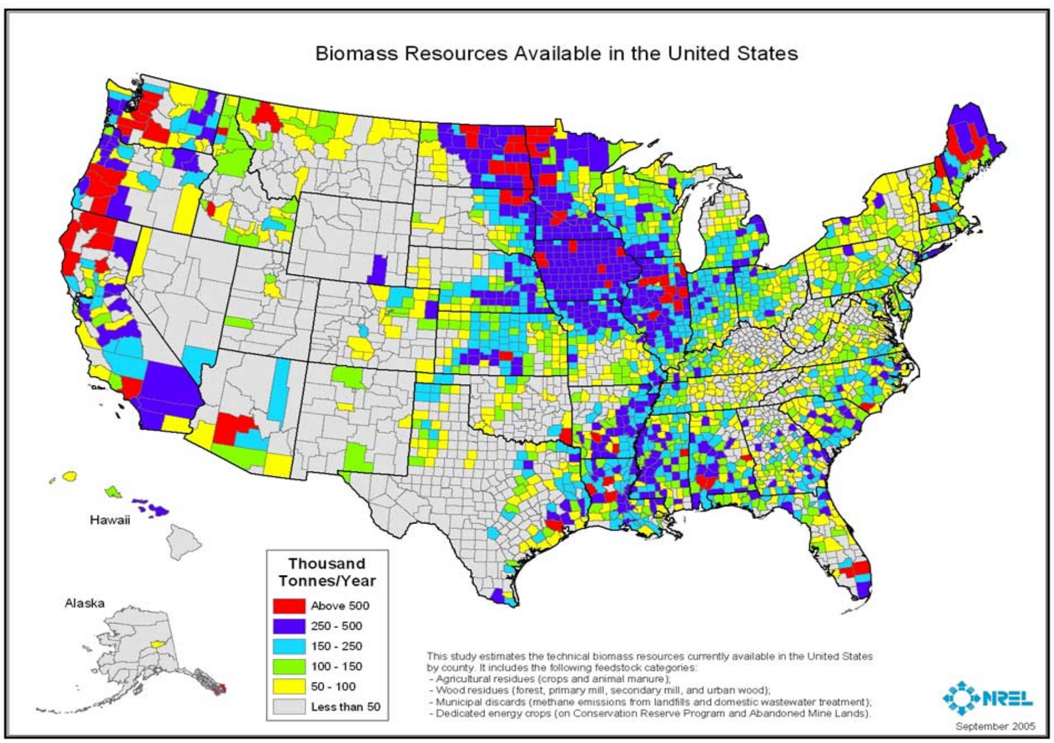


Figure 4-3: Biomass resources available in the U. S. (Source: NREL)

There are several generation projects throughout the U. S. that have implemented biomass gasification or are in the process of researching its use with the aid of DOE funding [12]:

- McNiel Generation Station, Burlington, Vermont: This station which has a generating capacity of 50 MW, utilizes waste wood from nearby forestry operations as its feedstock. It operated traditionally as a wood combustion facility but added a low pressure wood gasifier where the gas produced is fed directly into the boiler. This addition has led to an increase in capacity of 12 MW.
- Emery Recycling, Salt Lake City, Utah: Integrated gasification and fuel cells that use segregated municipal solid waste, animal waste and agricultural residues are being tested.
- Sebesta Bloomberg, Roseville, Minnesota: It has begun a project on an atmospheric gasifier with gas turbine at a malting factory which uses barley residues and corn stover as the feedstock.
- Alliant Energy, Lansing, Iowa: Corn stover is used as the feedstock in a combined-cycle concept being developed that involves a fluidized-bed-pyrolyzer.
- United Technologies Research Center, East Hartford, Connecticut: Project testing has begun using clean wood residues and natural gas as feedstocks.
- Carolina Power and Light, Raleigh, North Carolina: Biomass gasification process to supply utility boilers using clean wood residues is being developed.

There are currently several commercially operational stations throughout the U. S. that cofire biomass with traditional fossil fuels to generate electricity. These are shown in Table 4-2 [12].

U.S. Power Plants Currently Co-firing with Biomass

Facility Name	Company Name	City/County	State	Capacity (Megawatts)	Heat Input from Biomass (Percent of Total)
6th Street	Alliant Energy	Cedar Rapids	IA	85	7.7
Bay Front	Xcel Energy, Inc.	Ashland	WI	76	40.3
Colbert	TVA	Tuscumbia	AL	190	1.5
Gadsden 2	Alabama Power Co.	Gadsden	AL	70	<1.0
Greenridge	AES	Dresden	NY	161	6.8
C. D. McIntosh, Jr.	City of Lakeland	Polk	FL	350	<1.0
Tacoma Steam Plant	Tacoma Public Utilities	Tacoma	WA	35	44.0
Willow Island 2	Allegheny Power	Pleasants	WV	188	1.2
Yates 6 and 7	Georgia Power	Newnan	GA	150	<1.0

Sources: Personal communication with Evan Hughes, Electric Power Research Institute, Kevin Comer, Antares Group, Inc., Douglas Boylan, Southern Company Services, Inc., and Hugh Messer, City of Tacoma; Energy Information Administration, 2000 data from Form EIA-759 and Form EIA-767; corporate web sites; and G. Wiltsee, *Lessons Learned from Existing Biomass Power Plants*, NREL/SR-570-26946 (Golden, CO: National Renewable Energy Laboratory, February 2000), web site www.nrel.gov/docs/fy00osti/26946.pdf.

Table 4-2: List of current biomass projects in the U. S. (Source: Haq)

In most of the cofiring operations listed above the input mix of biomass is less that 10 percent except for the Bay Front station and the Tacoma Steam Plant. The Bay Front station can generate electricity using coal, wood, rubber and natural gas [12]. It was found that cofiring caused excessive ash and slag and therefore over time it was found that it was better to operate the two units on coal during heavy loads and on biomass during light loads thus the high average biomass input. The Tacoma Steam Plant can cofire wood, refuse-derived fuel and coal. The plant runs only as many hours as necessary to burn the refuse-derived fuels that it receives [12]. A listing of other pilot projects can be found on DOE's website [13].

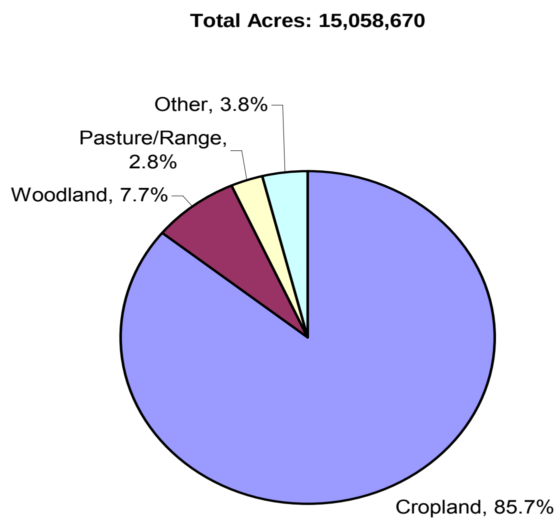
Despite all the benefits offered by biomass gasification, there are a variety of technical barriers to its implementation as well. For example, the raw gases from biomass systems may not meet the strict quality standards for downstream fuel or chemical synthesis catalysts. Thus, extra gas cleaning and conditioning technologies must be developed at a price that is economically feasible. Moreover, effective process control is needed at biomass gasification plants. Emissions at target levels with varying loads, fuel properties, and atmospheric conditions must be monitored with sensors and a variety of other analytical instruments. As with all new process technologies, demonstrating sustained integrated performance that meets technical, environmental and safety requirements at sufficiently large scale is essential to supporting commercialization [14]. There is interest in improving biomass gasification technology in the future, especially by combining gasification systems with fuel cell systems. These systems will have reduced air emissions and will become more competitive economically as the cost of fuel cells and biomass gasifiers come down [15].

In 2004, DOE and USDA funded 22 projects with $25,480,628 to further the Biomass Research and Development Initiative. Including the cost sharing of the private sector partners, the total value of the projects is nearly $38 million. The funds will be used for biomass research, development and demonstration projects [16]. A complete listing of the sponsored projects can be found on the Energy Efficiency and Renewable Energy website [17].

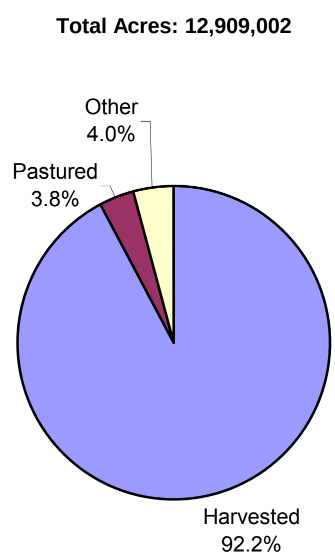
4.4 Organic waste biomass in Indiana

In 2003, Indiana's total state generation of electric energy was 124,888 GWh. However, only 0.4 percent of the energy generation was renewable. Moreover, only 0.1 percent of the total energy generated came from biomass sources [18]. The reason for this low contribution is mainly due to the availability of low-cost fuels (coal) in the state, thus leading to generation predominantly from fossil-fueled stations [19].

Indiana has a large agricultural residue biomass resource potential, as shown in Figures 4-4, 4-5 [20] and 4-6. It is estimated that over 16 million dry tons of agricultural residues, mainly from corn stover, are available each year within Indiana [21]. However, there are potential problems associated with residue removal [22]. First, the removal of agricultural residues will increase the likelihood of soil erosion and thus the removal will depend on the soil type and slope of the land. Second, farmers would incur costs when removing and transporting the residues. The farmers would only be willing to incur these costs if there were a stable market for the residues. The transportation distance is seen as a crucial factor in the cost of residues for generating plants. The estimated feasible transportation distance for these residues is stated as 100 miles [9]. However, the low cost of coal within Indiana will further tighten this bound.



<u>Figure 4-4:</u> <u>Indiana land use in 2002</u> (Source: USDA)



<u>Figure 4-5:</u> <u>Indiana cropland use in 2002</u> (Source: USDA)

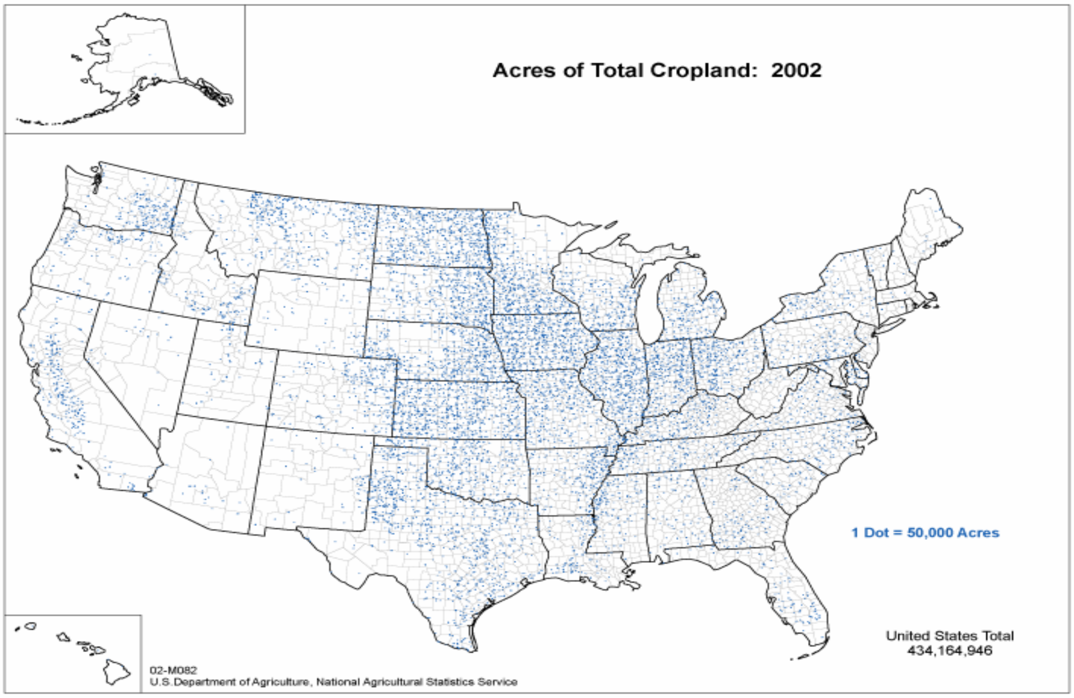


Figure 4-6: Cropland distribution in the U. S. (Source: NRCS [23])

An estimated 27,100 GWh of electricity could be generated using renewable biomass fuels in Indiana. This is enough electricity to fully supply the annual needs of 2,706,000 average homes, or 100 percent of the residential electricity use in Indiana. These biomass resource supply figures are based on estimates for five general categories of biomass: urban residues, mill residues, forest residues, agricultural residues, and energy crops [24].

Wood is the most commonly used biomass fuel for heat and power while MSW and landfill gas are the most common biomass fuels for electricity generation. The most economic sources of wood fuels are usually urban residues and mill residues. Urban residues used for power generation consist mainly of chips and grindings of clean, non-hazardous wood from construction activities, woody yard and right-of-way trimmings, and discarded wood products such as waste pallets and crates. Mill residues, such as sawdust, bark, and wood scraps from paper, lumber, and furniture manufacturing operations are typically very clean and can be used as fuel by a wide range of biomass energy systems. The estimated supplies of urban and mill residues available for energy uses in Indiana are respectively, 470,000 and 28,000 dry tons per year [21].

Overall, Indiana's greatest potential for biomass is corn stover. Crop residues production in the state is significantly higher than the rest of biomass sources; such as logging residue, other removal residue, fuel treatment thinnings (from timberlands), mill residue and urban wood residues. Annual production of biomass in Indiana is estimated in Figure 4-7. Estimations on crop residues were made based on two types of planting system; tillage and no till which is a form of conservation tillage. Biomass production potential is much greater when no till farming is practiced. Central Indiana has the higher potential of producing crop residues as shown in Figure 4-8, accounting for the 45 percent of the total production of Indiana. The northwest, north central and northeast regions also produce significant amount of crop residues accounting for 18 percent, 14 percent and 13 percent, respectively [21].

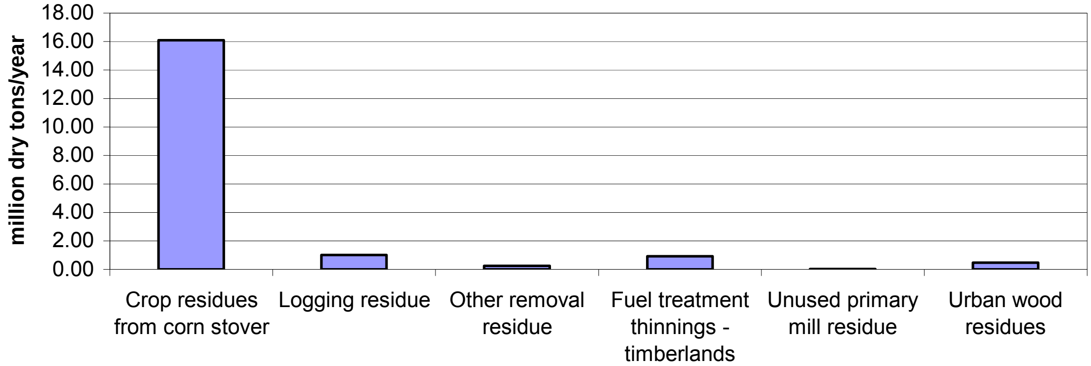
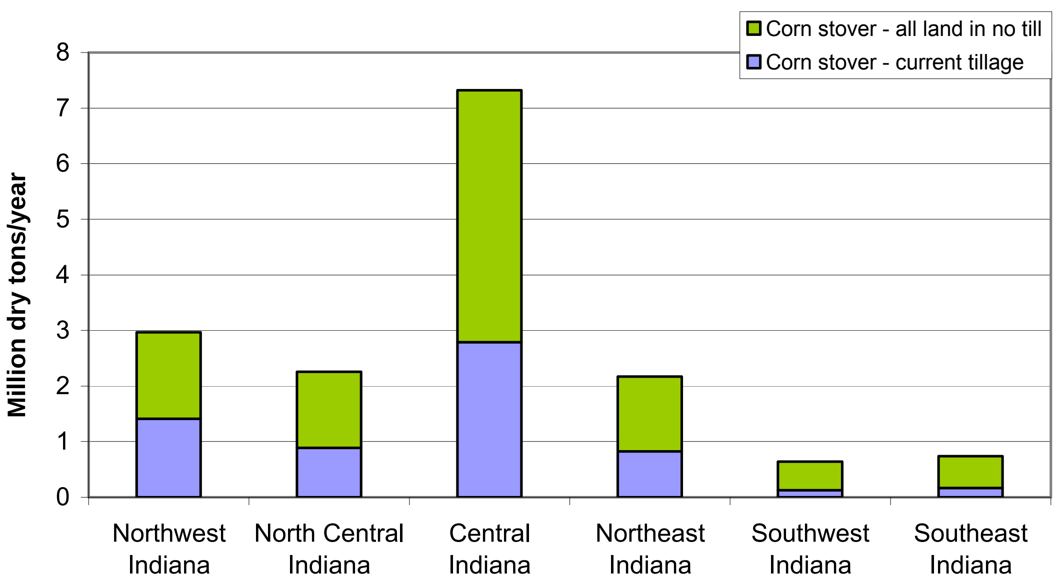


Figure 4-7: Estimated biomass production in Indiana (Source: ORNL, courtesy Dr. W. Tyner, Purdue University)



Northwest Indiana; Jasper, La Porte, Lake, Newton, Porter, Pulaski, Starke.
North Central Indiana; Elkhart, Fulton, Kosciusko, Marshall, St. Joseph, Cass, Miami, Wabash.
Central Indiana; Boone, Hamilton, Hancock, Hendricks, Madison, Marion, Shelby, Delaware, Henry, Randolph, Wayne, Benton, Carroll, Clinton, Fountain, Montgomery, Tippecanoe, Warren, White, Johnson, Monroe, Morgan, Clay, Howard, Owen, Parke, Putnam, Tipton, Vermillion, Vigo.
Northeast Indiana; Adams, Allen, Blackford, De Kalb, Grant, Huntington, Jay, Lagrange, Noble, Steuben, Wells, Whitley
Southwest Indiana; Lawrence, Crawford, Daviess, Dubois, Gibson, Greene, Knox, Martin, Orange, Perry, Pike, Posey, Spencer, Sullivan, Vanderburgh, Warrick.
Southeast Indiana; Brown, Bartholomew, Dearborn, Fayette, Floyd, Franklin, Jennings, Ohio, Ripley, Rush, Scott, Switzerland, Union, Washington, Clark, Harrison, Decatur, Jackson, Jefferson.

Figure 4-8: Estimated production of crop residues from corn stover in Indiana (Source: ORNL, courtesy Dr. Wallace Tyner, Purdue University)

In a March 2004 presentation of the DOE office of the biomass program [25], the Northern Indiana Public Service Company (NIPSCO) in Hammond was reported as having conducted biomass cofiring tests at two of its coal-fired power plants: Michigan City Station (425 MW) in Michigan City and Bailey Station (160 MW) in Chesterton. The biomass fuel tested was urban wood waste. The tests were conducted with biomass input fuel mix for the Michigan City station at 6.5 percent and 5 percent for Bailey Station. Both of these cofiring tests revealed reductions in the levels of nitrogen oxides, sulfur dioxide and carbon dioxide emissions. DOE assisted NIPSCO in sharing the costs.

As mentioned previously, MSW/land fill gas is the main biomass fuel used for electricity generation in Indiana. The most active user of this organic waste biomass for electricity generation is Wabash Valley Power Association (WVPA). WVPA owns four landfill gas units in Hendricks, Cass, Jay and White counties and purchases the output of three other units in Indiana. WVPA has a total of 22.4 MW of waste biomass capacity. Another user of biogas for electricity generation is the Fair Oaks Dairy in northwest Indiana. A 700 kW generating facility utilizing animal manure as a fuel produces electricity to supplement the daily farms electricity needs [26].

Several factors are seen as crucial in determining whether organic waste biomass will have a major role in the electricity generation sector. These include:

- <u>Government support for biomass:</u> Government support is needed to help make biomass resources more competitive with coal. This support could be in the form of grants for converting plants or tax credits for energy production from cofiring plants. The government might also need to provide tax incentives to farmers for the supplying of the agricultural residues. This would help reduce the cost of the input biomass fuels. All of these incentives are consistent with the government's energy policy of cleaner and more diversified energy sources. Several incentives are offered by both the Federal and state governments as explained in Section 3.
- <u>Stable growing market:</u> This is important from both the supply and demand sides. In Indiana, where the predominant organic waste biomass supply would be from agricultural residues, the farmers who would be responsible for this supply will incur costs in the removal and transportation of the residues. This process might only be feasible if the farmer has some certainty of receiving a profit. A stable, growing demand market is required for this. From the demand side, the electricity generators would need assurance of stable supply prices in order to minimize risk. Since the residue supply will likely be from many suppliers (unlike the coal supply), the input price stability is important for generator operations.
- <u>Improved conversion technology:</u> Research is being conducted on the various conversion processes for organic waste biomass. The improved efficiency of the conversion process along with the benefits of reduced emissions would greatly help the cause of organic waste biomass as a fuel for electricity generation.

4.5 References

1. http://www.eere.energy.gov/RE/bio_resources.html
2. http://www.eere.energy.gov/state_energy/technology_overview.cfm?techid=3
3. http://feedstockreview.ornl.gov/pdf/billion_ton_vision.pdf
4. http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/rentrends04.html
5. http://devafdc.nrel.gov/pdfs/florida_crops_fs_3_28_02.pdf
6. http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/table02.pdf
7. http://www.eia.doe.gov/oiaf/aeo/index.html
8. http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/tableb6.html
9. http://www.eere.energy.gov/states/alternatives/biomass.cfm
10. http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/table12.html
11. http://www.eere.energy.gov/biomass/biomass_feedstocks.html
12. Zia Haq, "Biomass for Electricity Generation," Energy Information Administration, U. S. Department of Energy.
13. http://www.eere.energy.gov/biopower/projects/index.htm
14. http://www.eere.energy.gov/biomass/large_scale_gasification.html
15. http://www1.eere.energy.gov/biomass/electrical_power.html
16. http://www.energy.gov/
17. http://www.bioproducts-bioenergy.gov/pdfs/Joint%20SolicitationTotalSelectedProposals.pdf
18. http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/rea.pdf
19. http://www.eere.energy.gov/state_energy/states_currfuelmix.cfm?state=IN
20. http://www.nass.usda.gov/census/census02/volume1/INVolume104.pdf
21. ORNL, Indiana's Counties energy crops estimates. Data provided by Dr. Wallace Tyner (2006).
22. W. Tyner, et al., "The Potential of Producing Energy from Agriculture," Purdue University, 1979.
23. http://www.nrcs.usda.gov/technical/land/
24. http://www.eere.energy.gov/state_energy/tech_biomass.cfm?state=IN
25. http://www.bioproducts-bioenergy.gov/pdfs/PGCofiring.pdf
26. J.M. Kramer, "Agricultural biogas casebook", Sept 2002.

5. Solar Energy

5.1 Introduction

Solar energy entails using the energy from the sun to generate electricity, provide hot water, and to heat, cool, and light buildings [1]. The solar energy can be converted either directly or indirectly into other forms of energy, such as heat or electricity.

Solar thermal energy is usually captured using a solar-energy collector. These collectors could either have fixed or variable orientation and could either be concentrating or non-concentrating. Variable orientation collectors track the position of the sun during the day whereas the fixed orientation collectors remain static. In the non-concentrating collectors, the collector[8] area is roughly equal to the absorber[9] area, whereas in concentrating collectors the collector area is greater[10] than the absorber area [2].

The fixed flat-plate collectors (non-concentrating) are usually used in applications that have low temperature requirements (200^{o}F), such as heating swimming pools, heating water for domestic use and spatial heating for buildings. There are many flat-plate collector designs but generally all consist of (1) a flat-plate absorber, which intercepts and absorbs the solar energy, (2) a transparent cover(s) 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.

Variable orientation, concentrating collectors are usually utilized in higher energy requirement applications, such as solar thermal power plants where they use the sun's rays to heat a fluid, from which heat transfer systems may be used to produce steam, which in turn is used together with a turbine-generator set to generate electricity.

There are three main types of solar thermal power systems in use or under development. These are the parabolic trough, solar power tower, and solar dish [2, 3], which are illustrated in Figure 5-1.

- The parabolic trough system has collectors that are parabolic in shape with the receiver system located at the focal point of the parabola. A working fluid is then used to transport the heat from the receiver systems to heat exchangers. This system is the most mature of the solar thermal technologies with commercial production in California's Mojave Desert. The main advantage of the system is its compatibility with large engines. On the other hand, it has the disadvantage of operating at low temperature, which reduces the efficiency of the heat transfer. Current systems range from 350 MW to a newer small scale 1 MW.

---

[8] This is the area that intercepts the solar radiation.
[9] This is the area that absorbs the radiation.
[10] Sometimes several hundred times greater.

- The solar power tower system utilizes thousands of flat sun-tracking heliostats (mirrors) that concentrate the solar energy on a tower-mounted heat exchanger (receiver). This system avoids the heat loss during transportation of the working fluid to the central heat exchanger. Solar power tower systems are unique among solar electric technologies in their ability to efficiently store solar energy and dispatch electricity to the grid when needed — even at night or during cloudy weather [4]. There are two 10 MW facilities located in the U. S. near Barstow, California.

- The solar dish system utilizes concentrating solar collectors that concentrate the energy at the focal point of the dish. The concentration ratio achieved with the solar dish system is much higher than that obtained with the solar trough system. The heat generated from a solar dish system is converted to mechanical energy by heating the working fluid that was compressed when cold. The heated compressed working fluid is then expanded through a turbine or piston to produce work. The engine is coupled to an electric generator to convert the mechanical power to electric power. This system provides the highest optical efficiency of all the concentrating solar systems.

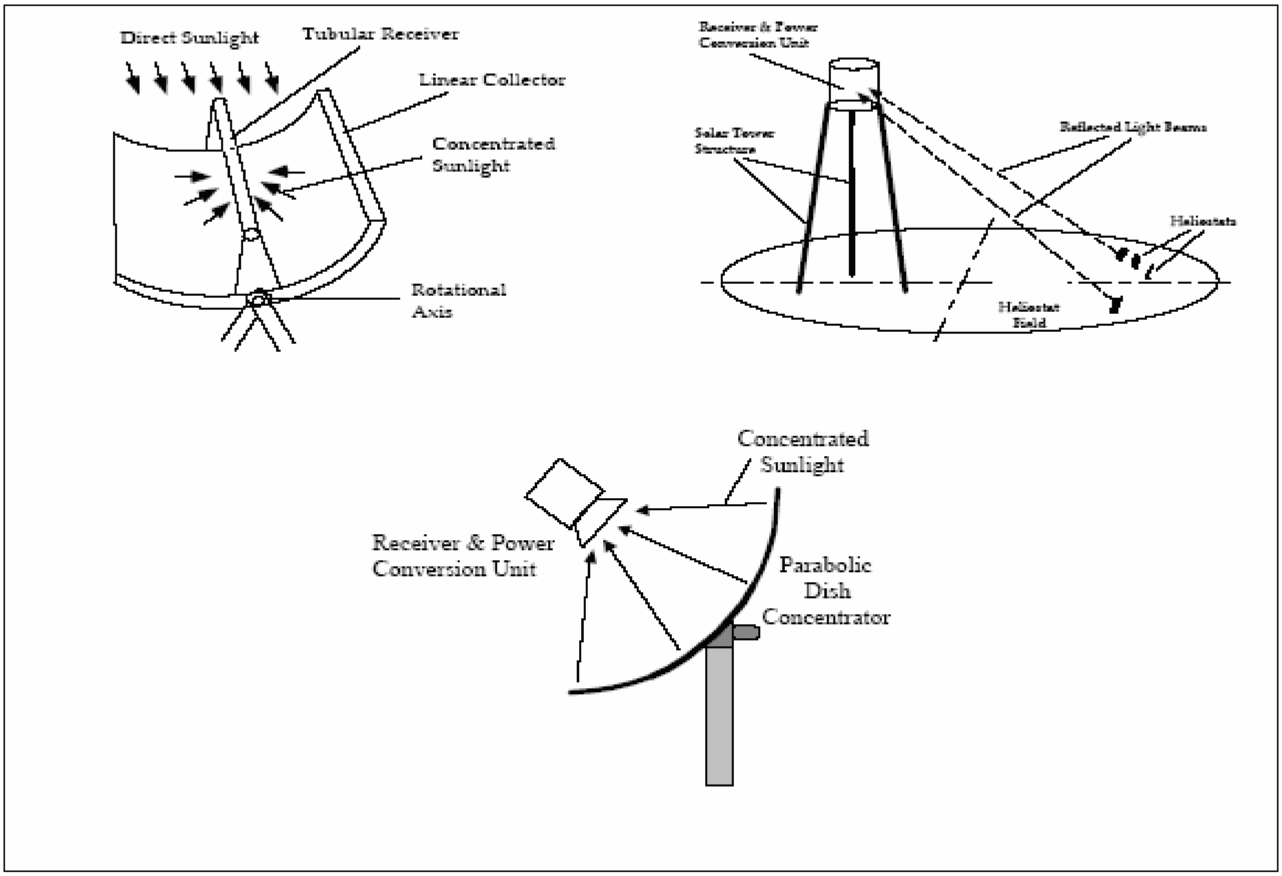


Figure 5-1: Solar concentrator technologies (Source: DOE)

Table 5-1 illustrates further differences between the three types of solar thermal technologies [5].

	Parabolic Trough	Power Tower	Dish/Engine
Size	30-320 MW*	10-200 MW*	5-25 kW*
Operating Temperature (ºC/ºF)	390/734	565/1,049	750/1,382
Annual Capacity Factor	23-50%*	20-77%*	25%
Peak Efficiency	20%(d)	23%(p)	29.4%(d)
Net Annual Efficiency	11(d')-16%*	7(d')-20%*	12-25%*(p)
Commercial Status	Commercially Available	Scale-up Demonstration	Prototype Demonstration
Technology Development Risk	Low	Medium	High
Storage Available	Limited	Yes	Battery
Hybrid Designs	Yes	Yes	Yes
Cost			
$\$/m^2$	630-275*	475-200*	3,100-320*
\$/W	4.0-2.7*	4.4-2.5*	12.6-1.3*
$\$/W_p$ †	4.0-1.3*	2.4-0.9*	12.6-1.1*

* Values indicate changes over the 1997-2030 time frame.

† $\$/W_p$ removes the effect of thermal storage (or hybridization for dish/engine). See discussion of thermal storage in the power tower TC and footnotes in Table 4.

(p) = predicted; (d) = demonstrated; (d') = has been demonstrated, out years are predicted values

Table 5-1: Characteristics of solar thermal electric power systems (Source: DOE)

Moreover, researchers are working with utilities on experimental hybrid power towers that run on solar energy and natural gas. A similar solar/fossil fuel hybrid is being developed for dish/engine systems. The advantage offered by hybrid systems is that they could run continuously independent of the weather conditions.

Like all other renewable technologies, solar thermal energy has distinct advantages and disadvantages. The major advantages include:

- It is a free and inexhaustible resource;
- It helps diversify the portfolio of resources, thus reducing the potential impacts of events affecting other fuel sources, such as price increases;
- It reduces the reliance on imported fuels;
- Energy can be stored in the form of heat and dispatched when needed;
- It is a modular and scalable technology; and
- It is a source of clean, quiet, non-polluting energy (no emissions or chemical waste).

However, there are some disadvantages of solar thermal energy, namely:

- Solar is an intermittent source of energy (i.e., a cloudy day can greatly reduce output); and
- It has high equipment costs when compared to traditional technologies.

5.2 Economics of solar thermal technologies

Current installed cost of parabolic through systems is approximately $3000/kW. Efforts are being made to reduce this cost to $2000/kW. Present estimates for large scale facility (above 50 MW) costs are around $3000/kW. A recent study suggests that costs could be significantly reduced by at least $500/kW. New developments made in materials for high temperature performance can also lead to an increase in efficiency. Estimated costs of large scale (above 50 MW) dish/Stirling facility are approximately $2500/kW. However, current costs based on several demonstration systems could be three to four times higher as indicated in the *Solar Energy Utilization Report*, DOE 2005. Future research and development could potentially reduce cost by more than $500/kW [3].

On the other hand, energy costs for current large-scale (above 10 MW) concentrating solar power technologies are in the range of 9 cents/kWh to 12 cents/kWh. The hybrid systems which utilize solar technology together with conventional fuels have a cost of around 8 cents/kWh. It is forecast that within the next few decades the advancements in technology would reduce the cost of large-scale solar power to around 5 cents/kWh [6]. Table 5-2 shows the forecast costs of energy from the solar thermal technologies in areas with high solar resources [7]. The currently most cost effective concentrating solar power technology is the parabolic trough systems for large-scale solar electric power systems [8].

		Levelized COE *(constant 1997 cents/kWh)*				
Technology	Configuration	1997	2000	2010	2020	2030
Dispatchable Technologies						
Solar Thermal	Power Tower	--	13.6*	5.2	4.2	4.2
	Parabolic Trough	17.3	11.8	7.6	7.2	6.8
	Dish Engine -- Hybrid	--	17.9	6.1	5.5	5.2
Intermittent Technologies						
Solar Thermal	Dish Engine (solar-only configuration)	134.3	26.8	7.2	6.4	5.9

* COE is only for the solar portion of the year 2000 hybrid plant configuration.

Table 5-2: Comparative costs of different solar thermal technologies (Source: Sandia National Laboratories)

Table 5-3 presents a comparison of solar electricity prices by the Solarbuzz Company [9] for the 12 month period running from July 2000 to June 2001. "*The table compares the solar electricity prices with US Government Statistics on US Electric Utility average Revenue per Kilowatt hour by Sector.*"

Cents per kWhr	average electric-utility revenue	Residential Solar electricity price index	average electric-utility revenue	Commerical Solar electricity Price Index	average electric-utility revenue	Industrial solar electricity price index
	Residential		Commercial		Industrial	
2000						
July	8.63	39.85	7.58	29.62	4.76	21.50
August	8.64	39.45	7.68	29.42	4.85	21.34
September	8.5	39.41	7.49	29.3	4.69	21.26
October	8.47	39.53	7.45	29.46	4.57	21.38
November	8.19	39.26	7.15	29.18	4.37	21.18
December	7.79	40.09	7.25	29.74	4.64	21.58
2001						
January	7.73	40.57	7.6	30.02	4.96	21.74
February	8.03	40.45	7.55	29.9	5.09	21.66
March	8.19	40.45	7.51	29.86	4.9	21.62
April	8.42	40.69	7.58	30.06	4.92	21.78
May	8.57	40.57	7.48	30.02	4.93	21.74
June	8.82	40.63	7.84	30.03	5.16	21.76

Table 5-3: Solar electricity price index vs. U. S. electricity tariff price index (Source: Solarbuzz Company [9])

The residential price index is based upon a standard 2 kW peak system, roof retrofit mounted. It is assumed to be connected to the electricity grid and has battery back up to allow it to operate during times of electricity downtime. The commercial price index is based on a 50 kW ground mounted solar system, which is connected to the electricity grid. It is assumed to provide distributed energy and excludes any back up power. Finally, the industrial price index is based on a 500 kW flat roof mounted solar system, suitable on large buildings. It is assumed to be connected to the electricity grid and excludes back up power [9].

5.3 State of solar energy nationally

The generation from solar energy was about 1 percent of the total renewable energy generated in 2004. The U. S. market showed 27 percent growth in demand for solar energy in 2004 compared to 17 percent in the previous year [10]. The CSP industry has shown to be a potentially viable source of renewable energy in the U. S. The industry is constituted by companies who design, sell, own, and/or operate energy systems and power plants based on the concentration of solar energy.

Figures 5-2 and 5-3 show the annual solar radiation in the U.S for different collector categories. Figure 5-2 shows the annual average solar radiation with a fixed, flat-plate, collector orientation fixed at its latitude whereas Figures 5-3 shows the annual average solar radiation for tracking, concentrating collectors [11]. The flat-plate collector's ability to use indirect or diffuse light allows it to outperform the concentrating collectors in areas where there is less direct sunlight. Conversely, the concentrating collector works better in regions with more intense sunlight. For example, the average solar radiation for a flat-plate is about 500 Watthours per square meter (Wh/sq m) more than for a concentrating collector, while concentrating collectors pick up about 1000 more Wh/sq m in the Mojave Desert region of California. In addition, Figure 5-4 illustrates the solar radiation in each state [12]. The amount of solar radiation that each state is subjected to greatly impacts the cost and profit of implementing solar technologies [13].

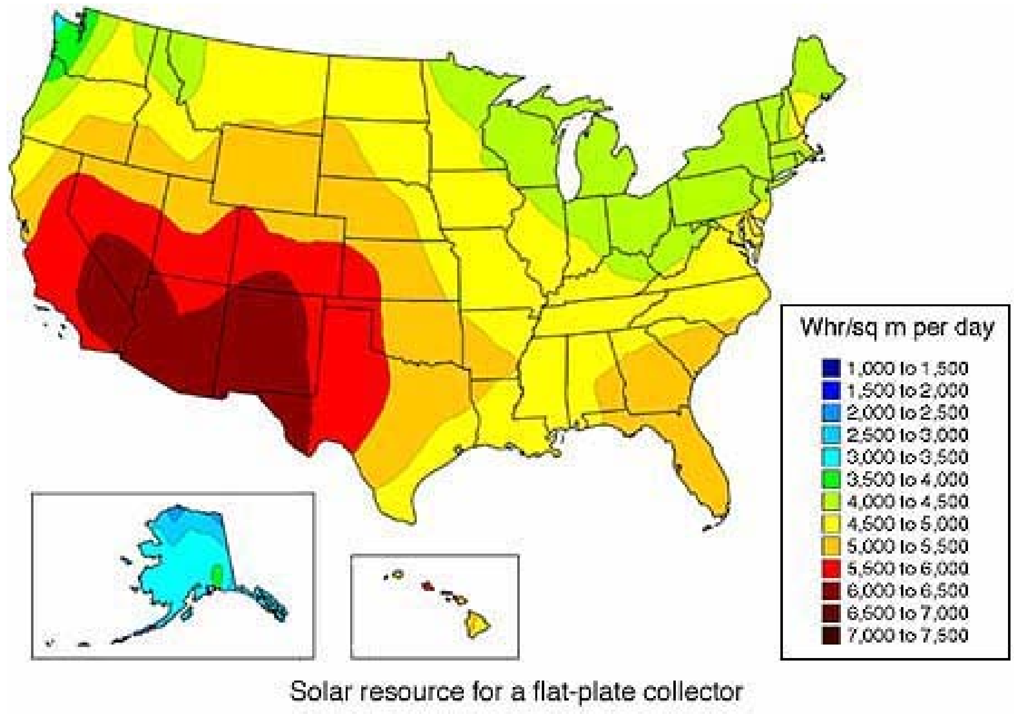


Figure 5-2: Annual average solar radiation for a flat-plate collector (Source: DOE)

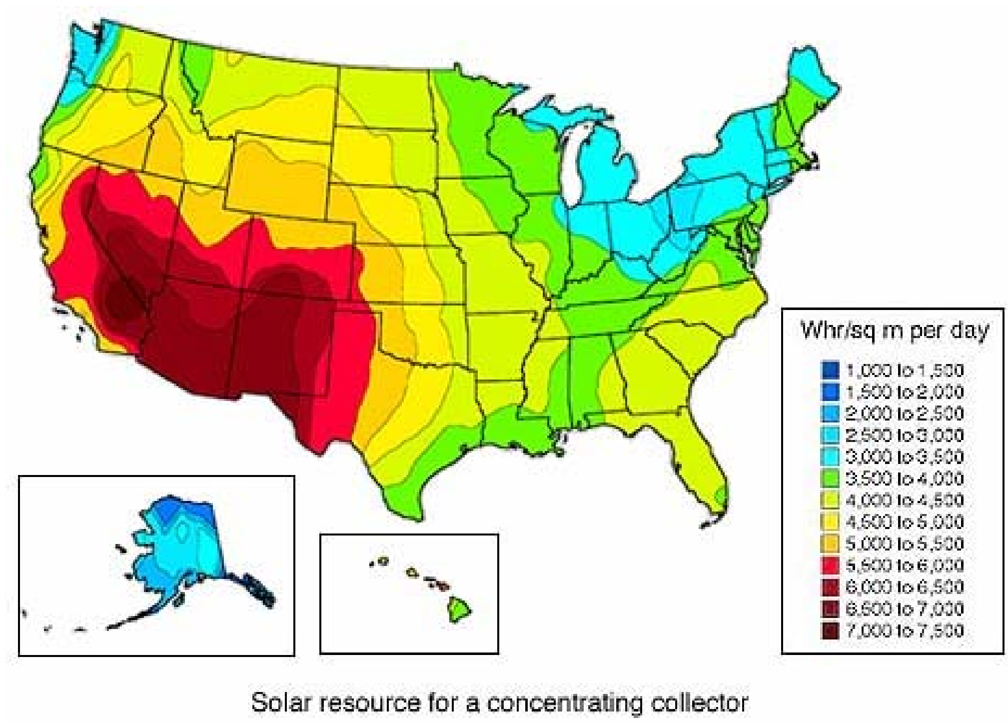


Figure 5-3: Annual average solar radiation for a concentrating collector (Source: DOE)

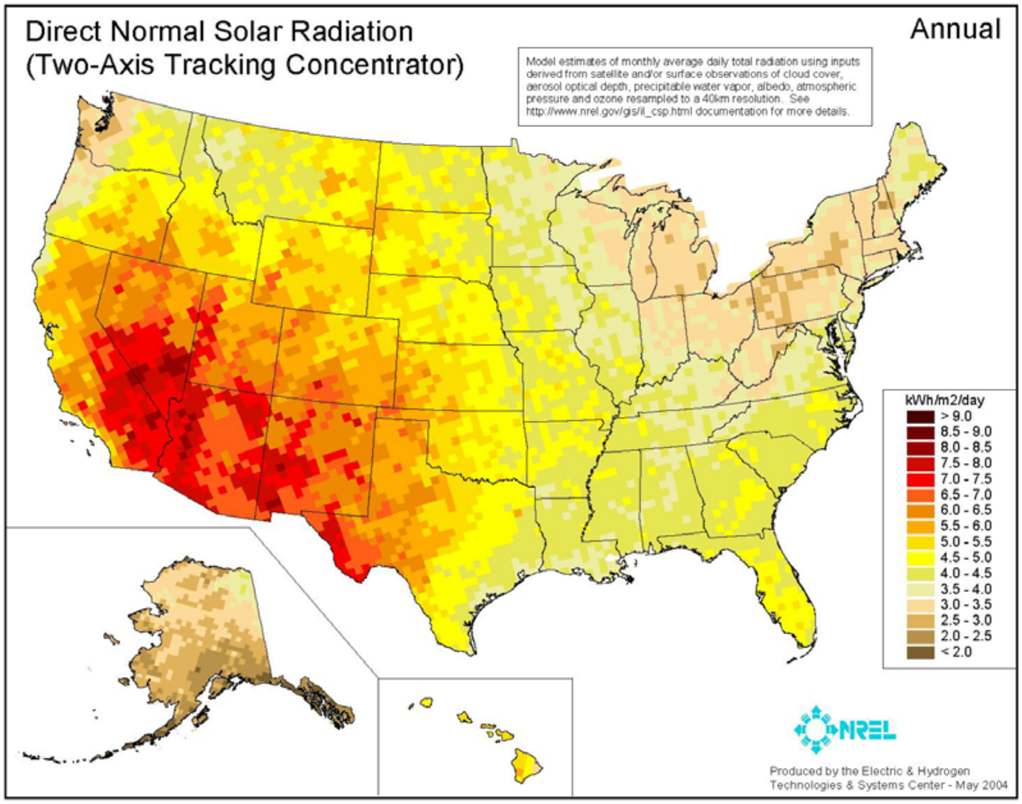


Figure 5-4: Direct normal solar radiation (two-axis solar concentrator) (Source: NREL)

These maps clearly illustrate the potential for solar power in the southwestern parts of the U. S. There are currently several solar projects in this area [14]. In the California Mojave Desert lies the largest grid connected solar project in the nation. It is a parabolic trough system and has an installed capacity of around 360 MW. This is over 95 percent of the total solar power capacity in the U. S. It is a hybrid station which also has natural gas as an input to assist the system during periods of low levels of solar energy. The system is mainly used as a peaking station as the system peak in the area is largely driven by air conditioning loads that coincide with the maximum output of the facility.

The other major solar project is in Barstow, California where the Solar Two Power Tower is located. The Solar Two facility is a continuation of the Solar One facility with modifications made to the heat transfer systems. The Solar One facility used oil as the transfer fluid whereas the Solar Two facility uses molten salt. The facility consists of 1,818 heliostats and a total generating capacity of 10 MW. The goal of the Solar Two facility was to validate solar power generation using molten salt for thermal energy transport and storage and to show that the technology is viable for dispatchable power. The project was successful in that it met all of its objectives. The cost of the project was $58 million, which was shared by industry and utility ($32 million) and DOE ($26 million) [15]. Furthermore, key U. S. industry participants in the project have begun a commercial solar power tower project in Spain. They are actively seeking U. S. customers for domestic plants [12].

There are currently many projects in the Southwest investigating the long term use of solar dish systems [16]. In December 2005, a new CSP plant began to operate in Arizona which produces enough power for 200 homes. Meanwhile, a 64 MW CSP plant is being assembled in Boulder City, Nevada with a capacity to produce power for 11,000 homes. This plant, which has an extension of 300 acres, will be the largest installation of its kind since 1990. Both plants are using the parabolic trough system [8].

Current developments in the solar industry include [17]:

- President's Advanced Energy Initiative and the 2007 Budget: proposes a new $148 million budget for Solar America Initiative (SAI), which is an increase of $65 million compared to fiscal year 2006 budget. SAI is responsible for accelerating the development of advanced solar electric technologies, including photovoltaics and concentrating solar power systems. SAI's goal is to make solar energy cost competitive with other sources of renewable electricity by 2015 [18].
- The 1000-MW Initiative: NREL, working through SunLab, is supporting DOE's goal to install 1,000 MW of new concentrating solar power systems in the southwestern U. S. by 2010. This level of deployment, combined with research and development to reduce technology component costs, could help reduce concentrating solar power electricity costs to 7 cents/kWh. At this cost, concentrating solar power can compete effectively in the Southwest's energy markets.
- USA Trough Initiative: Through the USA Trough Initiative, NREL is supporting the DOE's efforts to expand U. S. industry involvement and competitiveness in worldwide parabolic-trough development activities. This includes helping to advance the state of parabolic-trough technology from a U. S. knowledge base.
- Parabolic-Trough Solar Field Technology: NREL is working to develop less costly and more efficient parabolic-trough solar field technology. This involves improving the structure of parabolic-trough concentrators, receivers and mirrors, and increasing the manufacturing of these components. Through NREL's development and testing, the next generation of parabolic-trough concentrators is quickly evolving. NREL is focused on optimizing the structure of the current steel/thick-glass concentrators and increasing the concentrator size.
- Advanced Optical Materials for Concentrating Solar Power: NREL is working to develop durable, low-cost optical materials for concentrating solar power systems. These optical materials-which reflect, absorb, and transmit solar energy - play a fundamental role in the overall cost and efficiency of all concentrating solar power systems. Today, the solar collectors used in concentrating solar power systems account for approximately 50 percent of the total capital cost of power plants. The solar reflector costs for these systems represent about 30 percent of the collector cost. To reduce the costs of solar collectors, NREL focuses on improving the stability of selective coatings at higher temperatures for use on optical materials.
- Parabolic-Trough Systems Integration: NREL is developing system integration software tools for evaluating parabolic-trough technologies and assessing

concentrating solar power program activities. This includes models for evaluating:
    - Collector optics and thermal performance
    - Plant process design and integration tools
    - Annual performance and economic assessment
    - Capital and operation and maintenance costs.
- Parabolic-Trough Solar Power Plant Technology: NREL continues to evaluate and develop opportunities for improving the cost effectiveness of parabolic-trough concentrating solar power plants. They are primarily working to integrate parabolic-trough technology into Rankine cycle power plants - the power plants of choice because of their efficiency. Their work also encompasses projects to reduce power plant and solar-field operation and maintenance (O&M) costs by:
    - Scaling up plant size
    - Increasing capacity factor
    - Improving receiver and mirror reliability, and mirror-washing techniques
    - Developing improved automation and control systems
    - Developing O&M data integration and tracking systems.
- Parabolic-Trough Thermal Energy Storage Technology: NREL is working to develop efficient and lower cost thermal energy storage technologies for parabolic-trough concentrating solar power systems. Improved thermal energy storage is needed to:
    - Increase solar plant capacity factors above 25 percent
    - Increase dispatchability of solar power
    - Help reduce the cost of solar electricity.

  Parabolic-trough technology currently has one thermal energy storage option - a two-tank, indirect, molten-salt system. The system uses different heat transfer fluids for the solar field and for storage. Therefore, it requires a heat exchanger. It has a unit cost of $30-$40/kW.

The total domestic shipments of solar thermal collectors were 14.11 million square feet in 2004 [19]. This represents an increase from 11.44 million square feet in the previous year. The majority of shipments were low-temperature type collectors (96 percent) while medium-temperature collectors represented 4 percent of total shipments. Nearly all low temperature solar thermal collectors shipped in 2004 were used for the heating of swimming pools. Medium-temperature collectors were used primarily for water heating applications. Florida and California were the top destinations of solar thermal collectors, accounting for more than half of all domestic shipments. Figure 5-5 illustrates the top states for domestic shipments of solar thermal collectors in 2004.

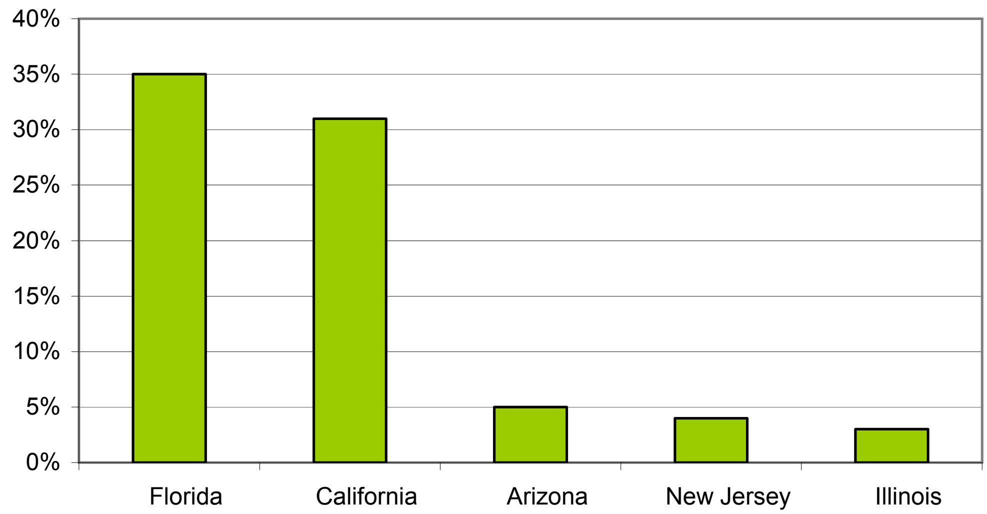


Figure 5-5: Top domestic destinations for solar thermal collectors in 2004 (Source: EIA)

5.4 Solar energy in Indiana

Indiana has relatively little potential for grid-connected solar projects like those in California [11] because of the lack of annual solar radiation, as shown in Figures 5-2 and 5-3. There is, however, some potential (more so in the southern part of the state) for water (swimming pool and domestic) and building heating using flat-plate collectors. Figure 5-6 shows the solar collection potential for both flat plate and concentrating collectors. As can be seen from the figure, the flat-plate collector performs better than the concentrating collector for many northern states.

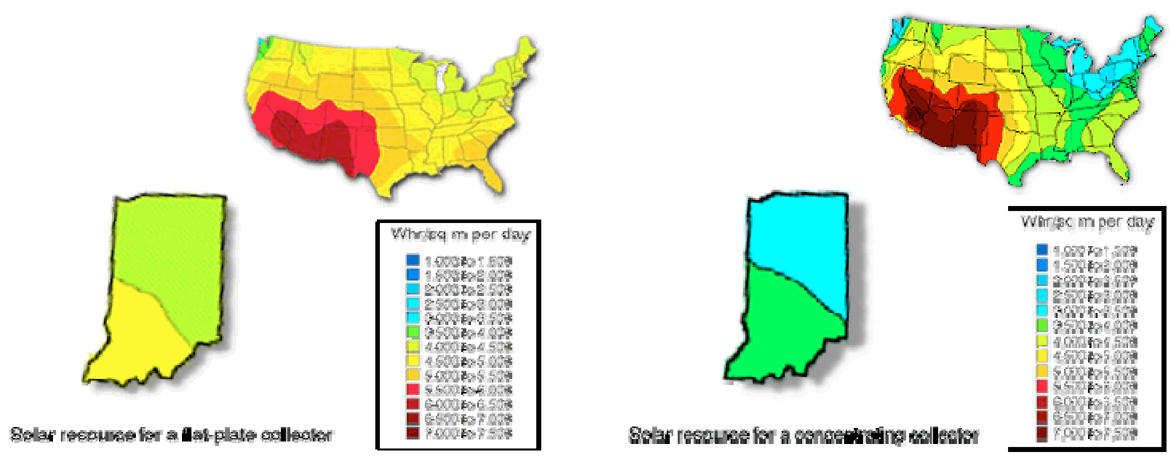


Figure 5-6: Solar thermal energy potential in Indiana by type of collector (Source: EIA)

Figure 5-7 is a map made by NREL that represents

> *The states with largest commercial solar market potential as measured by the Breakeven Turnkey Costs (BTC) using data developed by NREL. The BTC represents the cost at which investments in commercial solar equipment will breakeven over the life of the equipment. Measured this way, higher breakeven costs represent markets with the highest potential. The BTC takes into account the cost of equipment, the amount of sunlight, electricity prices, and any financial incentives available for solar equipment with the state. As shown in the map, four states (MT, HI, WI, and NJ) have the highest potential for commercial solar as measured by BTC* [20].

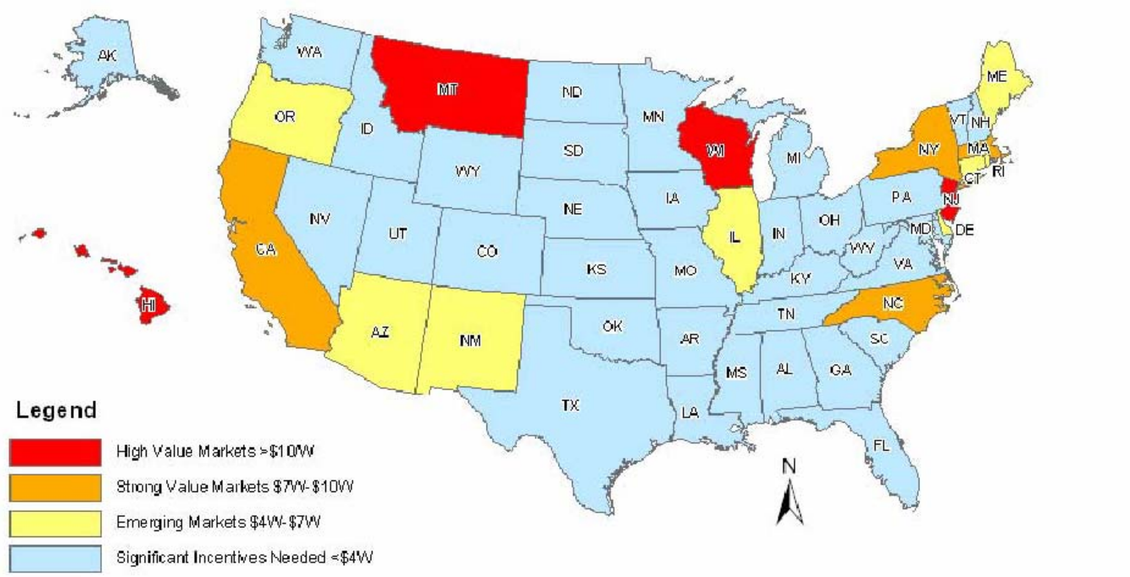


Figure 5-7: Breakeven turnkey costs for commercial solar by state (Source: NREL)

The actual viability of installing solar energy water heating within Indiana would depend on the microclimate of the area of concern. The typical initial cost of the solar water heating system is about $1,500 to $3,000 and the typical payback period is between 4 to 8 years [21].

There is currently an initiative being pursued by DOE's Solar Building Program where the aim is to displace some 0.17 percent of the total energy consumption with the aid of solar water heating, space heating and cooling [22]. DOE's Million Solar Roofs program is also aimed at increasing the number of buildings using solar power for their water and space heating and cooling needs. The goal is to have one million buildings using this technology by 2010. This is not limited to thermal solar but also includes photovoltaics.

The following incentives [23] could help with the introduction of solar energy within Indiana:

- Business investment tax credit: Energy Policy Act 2005 provides a 30 percent tax credit for business investment in solar energy systems (thermal non-power and power uses) installed before January 1, 2008. This credit has no expiration dates and it increased significantly from the 10 percent tax credit provided previously [24].
- Million Solar Roofs Initiative: DOE's Million Solar Roofs program is also aimed at increasing the number of buildings using solar power (thermal and PV) for their water and space heating and cooling needs. The goal is to have one million buildings using this technology by 2010.
- Renewable Electricity Production Credit: The Renewable Electricity Production Tax Credit is a per kilowatt-hour tax credit for electricity generated by qualified energy resources. It provides a tax credit of 1.9 cents/kWh, adjusted annually for inflation, for wind, solar, closed-loop biomass and geothermal. The tax credit was modified by the Energy Policy Act of 2005 and extended through December 31, 2007.
- Renewable Energy Systems Exemption: provides property tax exemptions for active solar equipment used for heating and cooling.
- Alternative Power and Energy Grant Program: offers grants of up to $30,000 to enable businesses and institutions to "install and study alternative and renewable energy system applications" (solar thermal is an acceptable technology).
- Green Pricing Program: is an initiative offered by some utilities that gives consumers the option to purchase power produced from renewable energy sources at some premium.
- Net Energy Credit: Facilities generating less than 1000 kWh per month from renewable sources are eligible to sell the excess electricity to the utility. Facilities generating more than 1000 kWh per month need to request permission to sell the excess electricity to the utility.
- Net metering rule: Solar, wind and hydroelectric facilities with a maximum capacity of 10 kW are under this September 2004 rule qualified for net metering where the net excess generation is credited to the customer in the next billing cycle.
- Emissions Credits: Electricity generators that do not NO_x and that displace utility generation are eligible to receive NO_x emissions credits under the Indiana Clean Energy Credit Program [25]. These credits can be sold on the national market.
- Solar and Geothermal Business Energy Tax Credit: The U. S. Federal government offers a 10 percent tax credit to businesses that invest in or purchase solar or geothermal energy property in the United States. The tax credit is limited to $25,000 per year, plus 25 percent of the total tax remaining after the credit is taken. Remaining credit may be carried back to the three preceding years and then carried forward for 15 years.
- Renewable Energy Systems and Energy Efficiency Improvements Program: Solar facilities are eligible for renewable-energy grants range from $2,500 to $500,000. The grants may not exceed 25 percent of an eligible project's cost.
- Tax Exempt Financing for Green Buildings: The "American Jobs Creation Act of 2004", signed into law on October 22, 2004, authorizes $2 billion in tax-exempt

bond financing for green buildings, brownfield redevelopment, and sustainable design projects.

- Residential Energy Conservation Subsidy Exclusion: According to Section 136 of the IRS Code, energy conservation subsidies provided by public utilities, either directly or indirectly, are nontaxable: "Gross income shall not include the value of any subsidy provided (directly or indirectly) by a public utility to a customer for the purchase or installation of any energy conservation measure."
- Conservation Security Program (CSP): The 2005 CSP sign-up includes a renewable-energy component. Eligible producers will receive $2.50 per 100 kWh of electricity generated by new wind, solar, geothermal and methane-to-energy systems. Payments of up to $45,000 per year will be made using three tiers of conservation contracts, with a maximum payment period of 10 years.
- Modified Accelerated Cost-Recovery System: Under this program, businesses can 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 is five years.

The reduction in cost of low temperature solar thermal technology together with Federal and State incentives and programs would be essential to increase the use of solar thermal energy within Indiana.

5.5 References

1. http://www.eere.energy.gov/RE/solar_basics.html
2. http://www.eia.doe.gov/kids/renewable/solar.html#Solar%20Dish
3. http://www.sc.doe.gov/bes/reports/files/SEU_rpt.pdf
4. http://www.energylan.sandia.gov/sunlab/overview.htm
5. http://www.eere.energy.gov/power/pdfs/solar_overview.pdf
6. http://www.energylan.sandia.gov/sunlab/overview.htm
7. http://www.energylan.sandia.gov/sunlab/PDFs/financials.pdf
8. http://www.nrel.gov/features/07-06_deliver_clean.html
9. http://www.solarbuzz.com/Solarprices.htm
10. http://www.solarbuzz.com/FastFactsIndustry.htm
11. http://www.eere.energy.gov/state_energy/tech_solar.cfm?state=IN
12. http://www.eere.energy.gov/solar/cfm/faqs/third_level.cfm/name=Concentrating%20 Solar%20Power/cat=Applications
13. http://www.nrel.gov/gis/images/us_csp_annual_may2004.jpg
14. http://www.energylan.sandia.gov/sunlab/documents.htm
15. http://www.energylan.sandia.gov/sunlab/Snapshot/STFUTURE.HTM
16. http://www.energylan.sandia.gov/sunlab/projects.htm
17. http://www.nrel.gov/csp/trough_sys_integ.html
18. http://www1.eere.energy.gov/solar/solar_america/
19. http://www.eia.doe.gov/cneaf/solar.renewables/page/solarthermal/solarthermal.html

20. ECONorthwest Corporation, for National Renewable Energy Laboratory, Commercial solar energy market potential study, February 2004. http://www.econw.com/pdf/comm_solar04.pdf
21. http://www.eere.energy.gov/erec/factsheets/solrwatr.html
22. http://www.eere.energy.gov/solarbuildings/market.html
23. http://www.dsireusa.org
24. http://www.eia.doe.gov/oiaf/aeo/
25. http://www.in.gov/idem/energycredit/ecreditfct.pdf

6. Photovoltaic Cells

6.1 Introduction

PV cells allow the conversion of photons in sunlight into electricity. The photovoltaic cell is a non-mechanical device constructed from semiconductor material (see Figure 6-1). When the photons in light strike the surface of a photovoltaic cell, the photon may be reflected, pass through or be absorbed by the cell. The absorbed photons cause free electrons to migrate thus causing "holes." The front surface of the photovoltaic cell is made more receptive to these migrating electrons. 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].

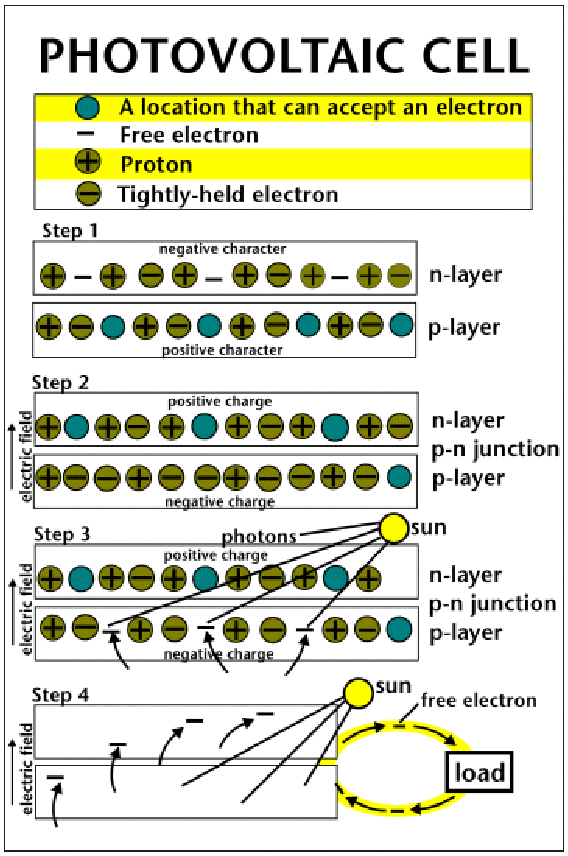


Figure 6-1: Photovoltaic cell operation (Source: EIA)

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. About 10 modules make up an array and about

10 to 20 arrays are enough to supply power to a house [2]. Hundreds of arrays could be connected together for larger power applications. The performance of PV units depend upon sunlight, the more sunlight the better the performance. Figure 6-2 illustrates how cells can combine to make a module and modules combined to make an array [3].

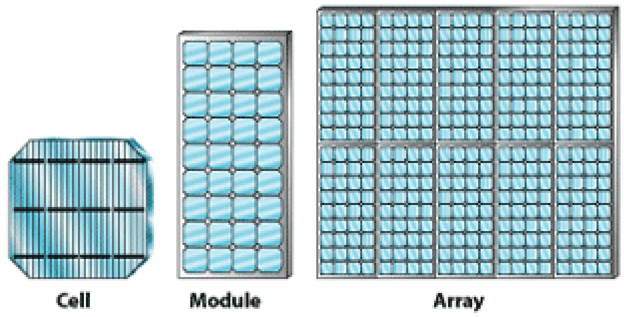


Figure 6-2: Illustration of a cell, module and array of a PV system (Source: EERE)

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.

There are currently three major types of PV cells: crystalline silicon-based, thin film-based and concentrator-based. Silicon PV cells, the most common, typically cost more than thin film cells but are more efficient. Efficiency ranges of 12 to 15 percent are normal with SunPower Corporation recently announcing the development of a silicon-based cell that achieves 21.5 percent efficiency [4]. Thin-film cells have a normal efficiency of 7 percent with a reported high of 10.7 percent [4]. Concentrator cells and modules utilize a lens to gather and converge sunlight onto the cell or module surface [5].

"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, allowing them to capture more sunlight over the course of a day. Some PV cells are designed to operate with concentrated sunlight, and a lens is used to focus the sunlight onto the cells. This approach has both advantages and disadvantages compared with flat-plate PV arrays. The main idea is to use very little of the expensive semiconducting PV material while collecting as much sunlight as possible. The lenses cannot use diffuse sunlight, but must be pointed directly at the sun. Therefore, the use of concentrating collectors is limited to the sunniest parts of the country.

NREL is continuing to further research and develop concentrating photovoltaic (CPV) technology as an alternative to dish/Stirling engine system that uses mirrors to concentrate the solar radiation. According to NREL,

> *Concentrating photovoltaic systems use lenses or mirrors to concentrate sunlight onto high-efficiency solar cells. These solar cells are typically more expensive than conventional cells used for flat-plate photovoltaic systems. However, the*

concentration decreases the required cell area while also increasing the cell efficiency. Concentrating photovoltaic technology offers the following advantages:

- *Potential for solar cell efficiencies greater than 40 percent*
- *No moving parts*
- *No intervening heat transfer surface*
- *Near-ambient temperature operation*
- *No thermal mass, fast response*
- *Reduction in costs of cells relative to optics*
- *Scalable to a range of sizes.*

The high cost of advanced, high-efficiency solar cells requires the use of concentrated sunlight for systems to achieve a cost-effective comparison with both the cost of concentrator optics and other solar power options. NREL has recently focused on the development of multi-cell packages (dense arrays) to improve overall performance, improve cooling, and install reliable prototype systems [6].

Figure 6-3 represents the historical progress of the best reported solar cell efficiencies to date. The major PV systems are included in the graph; single-crystal silicon, thin films, multiple-junction concentrator cells, and emerging technologies such as dye-sensitized nanocrystalline titanium oxide cells and cells based on organic compounds. As can be seen in the graph, the experimental concentrator based PV cells reported the highest efficiency levels, approximately 40 percent [7].

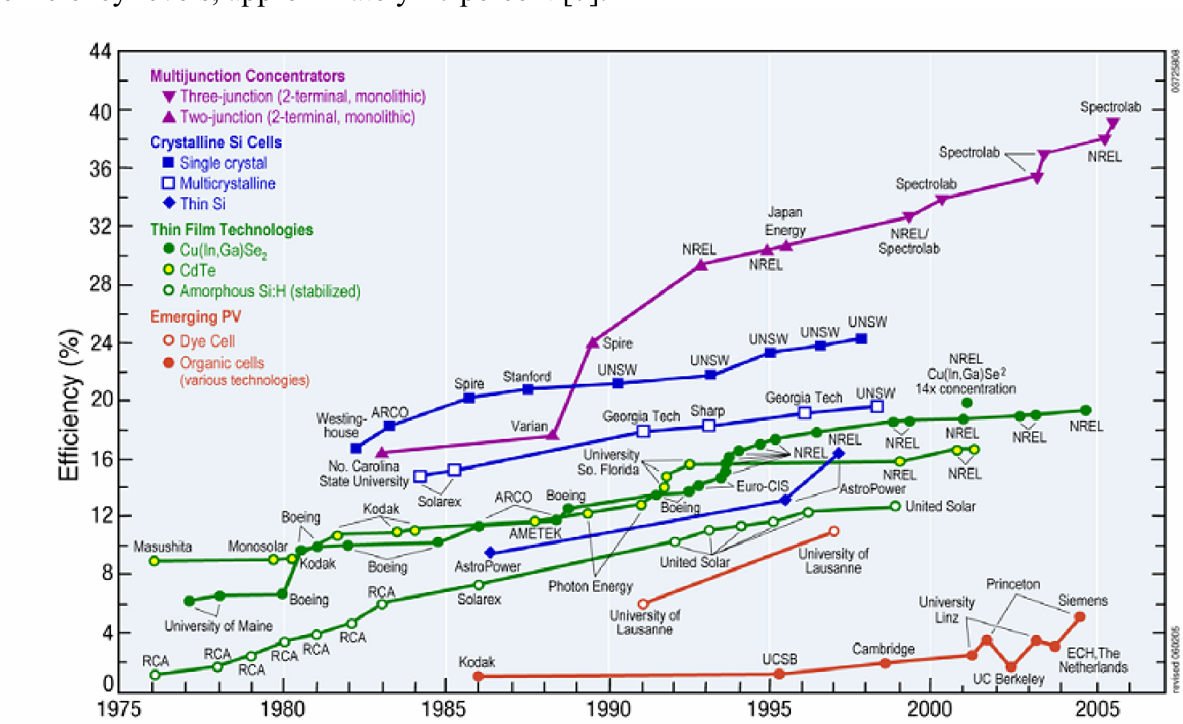


Figure 6-3: Improvements in solar cell efficiency, by system, from 1976 to 2004
(Source: DOE)

In addition, 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 photoelectrochemical cells, which produce hydrogen directly from water in the presence of sunlight [8].

The main advantages to using PV systems are [9]:

- For PV systems, the conversion from sunlight to electricity is direct so no bulky mechanical generator systems are required, leading to high system reliability;
- Sunlight is a free and inexhaustible resource;
- The lack of moving parts[11] results in lower maintenance costs;
- There are no emissions (by-products) from PV systems;
- The modular nature of PV systems (PV arrays) allow for variable output power configurations; and
- PV systems are usually located close to the load site, reducing the amount of transmission capacity (lines and substations) needed to be constructed.

The main disadvantages to using PV systems are:

- The sun is an intermittent source of energy (i.e., a cloudy day can greatly reduce output); and
- It has high equipment costs when compared to traditional technologies.

Despite the intermittent nature of sunlight, PV has added potential as a supplier of electricity during periods of peak demand, since it produces more electricity during sunny days when air conditioning loads are the greatest. It is at a relative disadvantage in providing continuous baseload power since the supply is intermittent and variable. Thus, other fuels or storage devices might be required to ensure a reliable supply during periods of low solar radiation.

6.2 Economics of PV systems

A key goal of researchers is to make PV technologies cost competitive by increasing the conversion efficiency of the PV systems. Higher efficiency directly impacts the overall electricity costs since higher efficiency cells will produce more electrical energy per unit of cell area. Another important factor that will contribute to reduce capital cost is the utilization of less expensive materials when manufacturing the PV systems [7].

[11] There are no moving parts for fixed-orientation PV units and minimal slow-moving parts for tracking PV units.

The cost of PV installation depends on the installation size and the degree to which it utilizes standard off-the-shelf components [10]. The capital costs range from $5/watt for bulk orders of small standardized systems to around $11/watt for small, one-of-a-kind grid connected PV systems [2, 10]. The recent trend in PV module prices is shown in Figure 6-4 [11]. From August 2001 to April 2004, PV prices dropped by 16 percent. Moreover, overall photovoltaic prices have declined on average 4 percent per year over the past 15 years. The recent leveling of prices is believed to be due to increased demand as well as increased conversion efficiencies and manufacturing economies of scale. As production increases in response to the higher demand, prices are expected to continue to fall. In fact, the U. S. market showed 27 percent growth for solar energy demand in 2004 compared to 17 percent in the previous year. These figures serve to promote the economic viability of PV systems in the future [12].

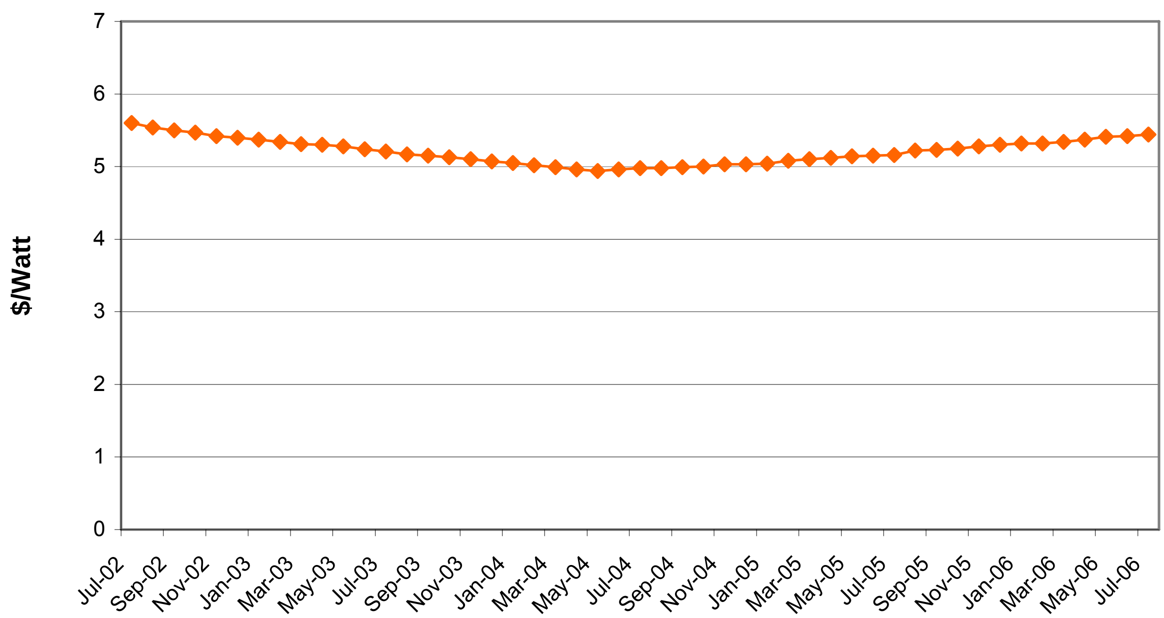


Figure 6-4: Historical PV module prices (Source: Solarbuzz)

Figure 6-5 shows the so called 80 percent learning curve, that for every doubling of the total cumulative production of PV modules worldwide; the price has dropped by approximately 20 percent. DOE's projected learning curve beyond 2003 is between 70 and 90 percent.

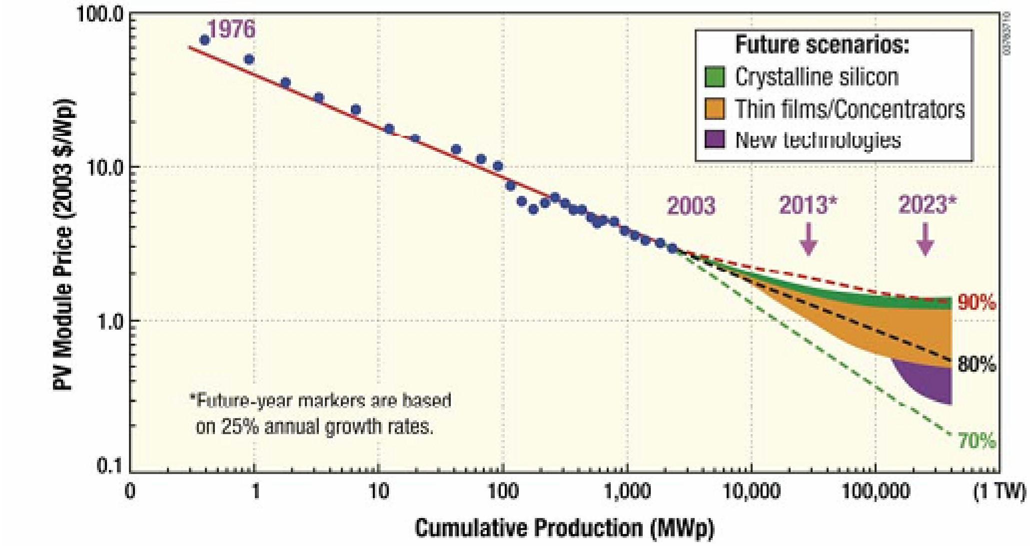


Figure 6-5: Learning curve for PV production (Source: DOE)

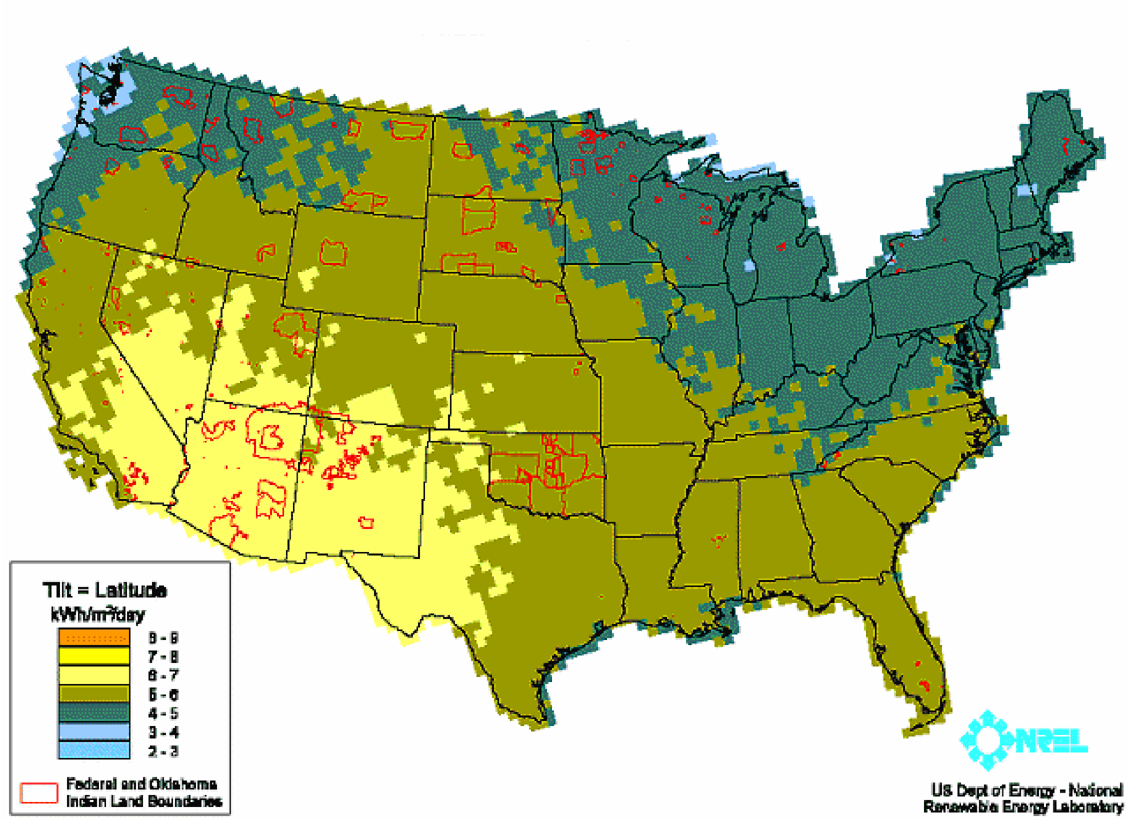
The O&M costs for PV systems are very low. The estimates for these O&M costs currently range from about 0.5 cents/kWh to 0.63 cents/kWh [10, 15]. These low O&M costs lead to levelized PV energy costs ranging from about 20 cents/kWh to 50 cents/kWh [2, 10, 14]. At these prices, PV may be cost effective for residential customers located farther than a quarter of a mile from the nearest utility line [14] because of the relatively high costs of distribution line construction. The energy costs of PV systems are expected to decline in the future to below 20 cents/kWh in 2020 [10, 15].

Another factor affecting the economics of photovoltaic cell is the typically low conversion efficiencies. According to the NREL PV program, a typical commercial PV solar cell efficiency is 15 percent. The improvement of these efficiencies while holding down the capital cost is one of the goals of DOE's solar energy research program [16].

6.3 State of PV systems nationally

Figure 6-6 shows the solar photovoltaic resource potential for the U. S. [17]. The southwestern U. S. has the highest solar resources in the country for both the flat plate and the concentrating PV systems, while the northeastern section of the country has the worst solar resources. Accordingly, California leads the nation in the amount of PV capacity installed. According to NREL's REPiS, California had 48.5 MW of grid-connected PV capacity at the end of 2002, with another 74.5 MW planned. Arizona was second with 9.5 MW of installed PV capacity [19].

At present, the majority of the PV market lies in off-grid applications (e.g., telecommunications and transportation construction signage); however, there is an increase in the number of PV systems being used in the residential sector [18]. Off-grid applications are especially suited to PV systems as usually high levels of reliability and low levels of maintenance are required, while the high cost of grid connection would make the PV system economically advantageous [2, 20].



<u>Figure 6-6:</u> <u>Solar photovoltaic resource potential</u> (Source: NREL)

In 1998, a study was carried out by EIA [21] to determine the trends in the U. S. photovoltaic industry. The report divided the national PV market into several niche markets that accounted for 15 MW of the 1998 domestic shipments. These markets were labeled and described as follows [21]:

- <u>Building Integrated Photovoltaics (BIPV):</u> These are PV arrays mounted on building roofs or facades. For residential buildings, analyses have assumed BIPV capacities of 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 set, battery, and photovoltaic generation capacity for off-grid remote cabins.
- <u>Non-BIPV Electricity Generation (grid interactive and remote):</u> This includes distributed generation (e.g., stand-alone PV systems or hybrid systems including diesel generators, battery storage, and other renewable technologies), water pumping and power for irrigation systems, and power for cathodic protection. The U. S. Coast Guard has installed over 20,000 PV-powered navigational aids (e.g., warning buoys and shore markers) since 1984.
- <u>Communications:</u> 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.

EIA currently tracks the shipments[12] of PV systems within the nation [20]. These domestic shipments provide an indication of the status of the PV market. Table 6-1 shows the total annual shipments, domestic shipments, imports and exports of PV cells in the U. S.

Year	Total photovoltaic cells and modules shipment (kilowatts)	Domestic photovoltaic cells and modules (kilowatts)	Imported photovoltaic cells and modules (kilowatts)	Exported photovoltaic cells and modules (kilowatts)
1995	31,059	11,188	1,337	19,871
1996	35,464	13,016	1,864	22,448
1997	46,354	12,561	1,853	33,793
1998	50,562	15,069	1,931	35,493
1999	76,787	21,225	4,784	55,562
2000	88,221	19,838	8,821	68,382
2001	97,666	36,310	10,204	61,356
2002	112,090	45,313	7,297	66,778
2003	109,357	48,664	9,731	60,693
2004 [P]	181,116	78,346	47,703	102,770
Total	**828,676**	**301,530**	**95,525**	**527,146**
P - preliminary				

Table 6-1: Total annual shipments, domestic shipments, imports and exports of PV cells and modules in the U. S. (Source: EIA)

As can be seen from Table 6-1, the total use of PV systems is increasing in the U. S. During 2004 domestic demand for PV systems increased significantly, by 61 percent compared to year 2003. Imports also increased significantly from 9,731 kW in 2003 to 47,703 kW in 2004. This increase could be related to the increase in the domestic demand. Electricity generation is currently the largest end-use application of PV systems (grid interactive and remote) with communications and transportation coming in second and third respectively. However, an important amount of U. S. shipments of PV cells and modules are exported, which accounted for the 56.7 percent of the total shipments in 2004, continuing an increasing trend [20].

[12] The reason for keeping track of shipments rather that energy produced could be because of the large number of off-grid PV applications.

The PV industry has shown growth during 2004. Production of PV cells and modules increased from 103 MW in 2003 to 138.7 MW in 2004. The leading company was Shell Solar (62 MW), followed by General Electric (25 MW) [22].

The following programs in the Midwest are extracted from the International Energy Agency of major PV programs in the United States [23].

> ***Illinois:*** *Led by the strong "Brightfields" program in Chicago (where abandoned factories (Brownfields) are converted to photovoltaic manufacturing plants (owned and operated by Spire Corporation) or installed photovoltaic systems. The state of Illinois passed the largest subsidy in the United States for photovoltaic systems, \$6.00/W_p. Over 1 MW of photovoltaic systems was installed in Illinois in 2003* [23].
>
> ***Ohio:*** *A primary objective in Ohio is support for 50 schools to have photovoltaic systems/training modules installed on public schools* [23].

The national PV Roadmap [24] provides a guide to building the domestic PV industry. One of the objectives stated in the roadmap is that PV grid applications should increase such that 10 percent of the national peak generation capacity should be met with PV systems by 2030. The cumulative installed capacity in 2020 is expected to be 15 GW. It is expected that of the 2020 PV installations, 50 percent of the applications will be in alternating current (AC), distributed, capacity generation (remote, off-grid power for applications including cabins, village power, and communications), 33 percent in direct current (DC) and AC value applications (consumer products such as cell phones, calculators, and camping equipment), and 17 percent in AC grid (wholesale) generation (grid-connected systems including BIPV systems) [21, 24]. The forecast end-user price in the roadmap is between \$3/watt and \$4/watt by 2010 [24].

Distributors have identified markets where photovoltaic power is cost-effective now, without subsidies [15]. Examples include: (1) rural telephones and highway call boxes, (2) remote data acquisition for both land-based and offshore operations in the oil and gas industries, (3) message boards or warning signals on streets and highways, and (4) off-grid remote cabins, as part of a hybrid power system including batteries. In the longer term, it will take a combination of wholesale system price below \$3/watt and large volume dealers for PV to be cost-effective in the residential grid-connected market. PV installed system costs must fall to a range where they are competitive with current retail electric rates of 8 to 12 cents/kWh in the residential market and 6 to 7 cents/kWh in the commercial market.

Federal incentives such as the Million Solar Roofs (MSR) initiative are aimed at increasing the amount of grid-connected PV systems. The MSR program neither directs nor controls the activities of the state and community partnerships, nor does it provide funding to design, purchase or install solar systems. Instead, MSR brings together the capabilities of the Federal government with key national businesses and organizations, and focuses them on building a strong market for solar energy applications on buildings. MSR partnerships apply annually for DOE grant funding. The grants sponsor a variety of activities in conjunction with state and local resources, including [25]:

> *1) Work with local and regional home builders to include solar energy systems in new homes;*
> *2) Work with local lending institutions to develop financing options for solar energy systems;*
> *3) Develop and implement marketing and consumer education plans and workshops;*
> *4) Work with local officials to develop standard building codes and practices for solar installations;*
> *5) Develop training programs for inspectors and installers.*

In 2001, 34 partners were awarded $1.5 million for development and implementation activities [25]. Further state driven programs and initiatives such as the "Green" power programs where consumers are willing to pay a premium for clean energy (e.g., PV) would further help increase the use of PV systems [21].

Figure 6-7 shows the growth of installed PV power installations in the United States over the ten year period from 1992 to 2004 segregated by market sector [23]. The U. S. PV installation in 2004 increased 36.5 percent compared to the previous year, from 63 MW in 2003 to 86 MW in 2004. The growth came mainly from the grid-connected sector, which increased by 67.6 percent compared to 2003 (from 37 MW in 2003 to 62 MW in 2004) [22]. Furthermore, in 2005 a total of 80 MW was installed in the U. S. grid connected market. According to the 2006 annual report issued by Solarbuzz, the U. S. grid connected PV market will reach an annual installation rate of 290 MW by 2010 [26].

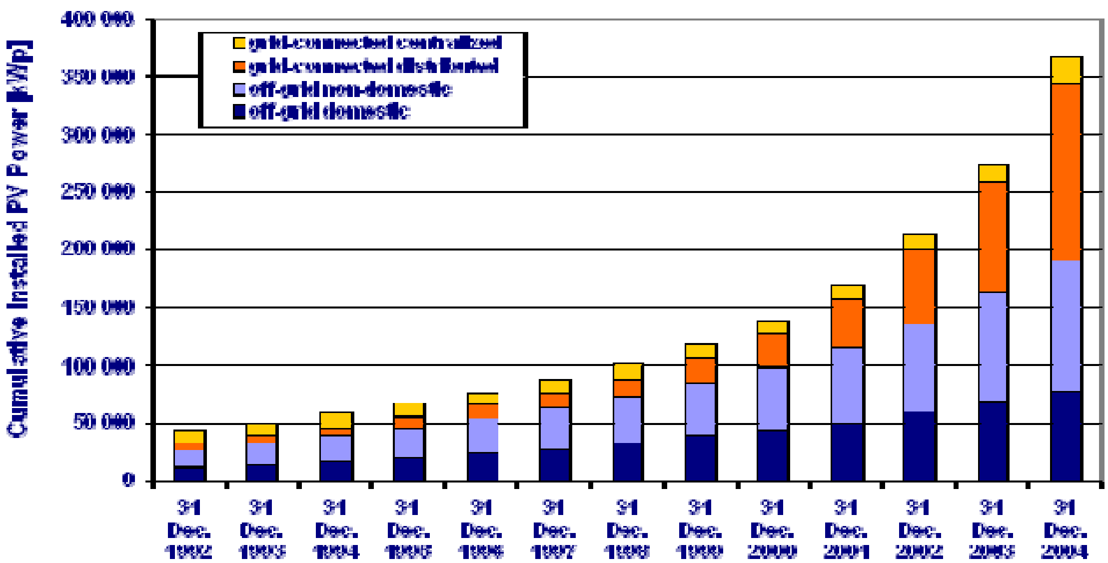


Figure 6-7: Cumulative installed PV power in the U. S. by sub-market (Source: International Energy Agency)

Figure 6-8 details the breakdown of nationwide PV installations in 2004 by state and utility. As can be inferred from the chart, PV installations in PG&E's territory accounted for approximately 27 percent of the national market. The second largest market segment was commercialized systems into the same Northern Californian utility's territory [27].

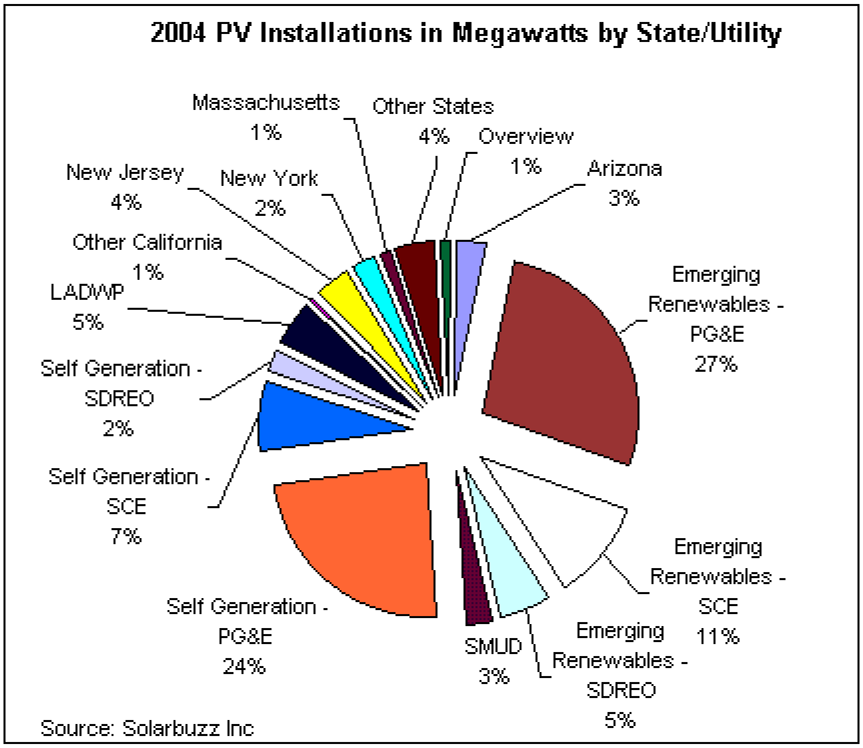


Figure 6-8: PV installations by state and utility (Source: Solarbuzz)[13]

As of May 2005, there is approximately $516 million in funding lined up against prospective PV projects that have yet to be installed. Additionally, another $558 million of identified PV projects are waiting in queue to receive funding [27].

6.4 PV systems in Indiana

While Indiana does not have excellent solar resources, there is some potential for fixed, flat-plate PV systems. As of 2002, Indiana had grid-connected photovoltaic installations with a total installed capacity of 21.8 kW at several locations within the state [19, 28], as shown in Table 6-2. These range from providing electricity to schools and other commercial buildings to residential applications.

[13] LADWP – Los Angeles Department of Water & Power; PG&E – Pacific Gas & Electric; SDREO – San Diego Regional Energy Office; SMUD – Sacramento Municipal Utility District; SCE – Southern California Edison

Location	Fuel Type	Plant Name	Capacity (kW)
Fort Wayne	Solar	American Electric Power	0.8
Lafayette	Solar	Commercial	3.6
Lafayette	Solar	IBEW	5.6
Fort Wayne	Solar	MSR School	1.0
Indianapolis	Solar	Orchard School	1.2
	Solar	PV installation in Indiana	1.0
	Solar	Residential Installation in Indiana	3.6
Fort Wayne	Solar	Science Central	1.0
Buffalo	Solar	Residential Installation	4.0

Table 6-2: Grid-connected PV systems in Indiana (Source: DOE)

In addition, six schools installed PV systems in the Cinergy-PSI, now Duke Energy, service territory in 2003 and two additional schools installed PV systems in 2004. PSI Energy also contracted with Altair Energy and the NEED Project to provide an educational program for these schools. Also, two residential homes in PSI Energy's service territory installed PV systems in 2004 in addition to four homes that installed PV systems in 2003. The eight schools currently participating in the program are [29]:

- Carmel High School
- Greenwood Middle School
- Doe Creek Middle School
- Rushville High School
- New Albany High School
- West Lafayette High School
- Clay City Junior/Senior High School
- North Manchester High School

In Indianapolis in 2001, BP Amoco opened the first of its BP Connect stores in the U. S. The store incorporates thin film PV collectors in the canopy over the fuel islands to produce electricity for use on site [30]. In addition, an 8 kW PV array has been operating at the Duke Energy field office in Bloomington since September 2004 [31].

The remote locations of farming residences in the state of Indiana make the PV alternative more attractive. The high installation costs are offset by little or no operating costs, since there is no fuel required[14] and there are no moving parts. Energy from PV systems currently ranges from 20 cents/kWh to 50 cents/kWh [2]. Although this is high for grid connected consumers, it may be acceptable for remote consumers and applications where grid connection is too expensive or where diesel generators are too expensive and unreliable.

[14] Besides the energy from the sun.

The relatively low solar resource (Figure 6-6) in Indiana combined with the availability of low cost energy from coal results in the breakeven cost being one of the lowest nationally. Figure 6-9 shows Indiana ranked thirty-fifth nationally for residential PV breakeven cost in a list led by such states as Hawaii, California and Arizona.

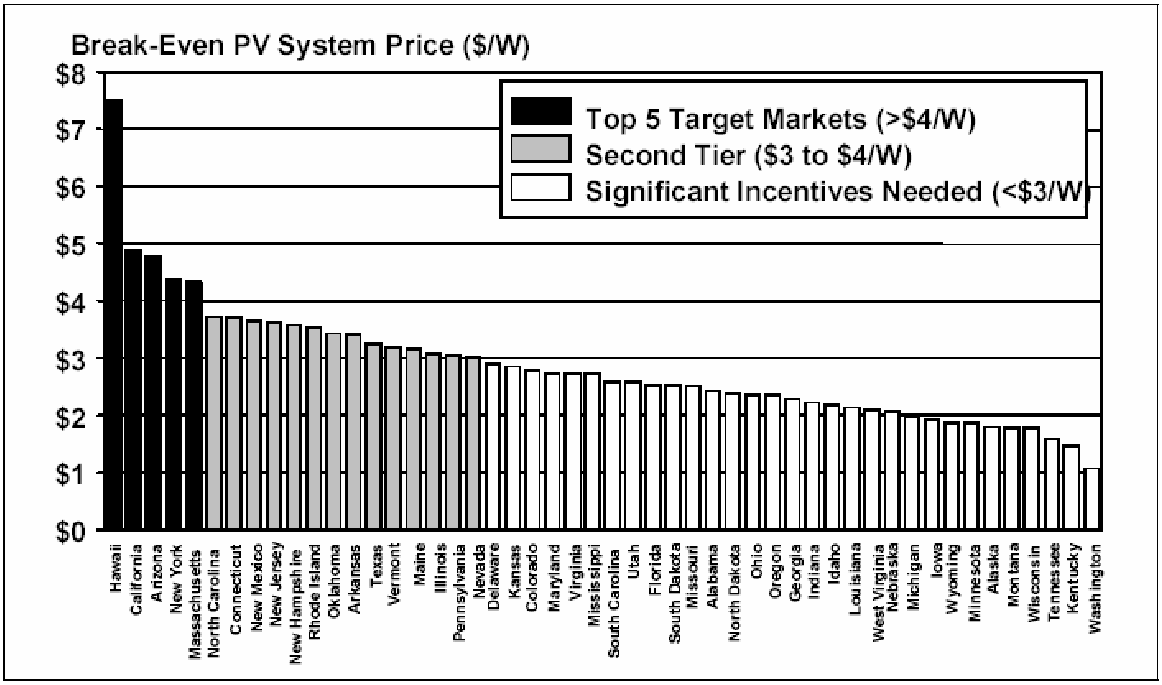


Figure 6-9: State-by-state ranking of PV residential breakeven turnkey cost (Source: NREL [32])

Thus, for grid-connected PV systems to become competitive within Indiana, Federal and State government incentives are required. The forecast cost of PV systems is between $3 and $4/W by 2010 [24] but this is still above the breakeven costs of entry of PV systems within Indiana. There are several Federal, State and Utility incentives available to PV systems [8]. They include[15]:

Federal Incentives:

- Million Solar Roofs Initiative: DOE's Million Solar Roofs program is aimed at increasing the number of buildings using solar power (thermal and PV) for their water and space heating and cooling needs. The goal is to have one million buildings using this technology by 2010.
- President's Advanced Energy Initiative and the 2007 Budget: proposes a new $148 million budget for SAI, which is an increase of $65 million compared to fiscal year 2006 budget. SAI is responsible for accelerating the development of advanced solar electric technologies, including photovoltaics and concentrating solar power systems. SAI's goal is to make solar energy cost competitive with other sources of renewable electricity by 2015 [32].

[15] These initiatives are also discussed in Section 5.4.

- Renewable Electricity Production Credit: The Renewable Electricity Production Tax Credit is a per kilowatt-hour tax credit for electricity generated by qualified energy resources. It provides a tax credit of 1.9 cents/kWh, adjusted annually for inflation, for wind, solar, closed-loop biomass and geothermal. The tax credit was modified by the Energy Policy Act of 2005 and extended through December 31, 2007.
- Residential Energy Conservation Subsidy Exclusion: According to Section 136 of the IRS Code, energy conservation subsidies provided by public utilities, either directly or indirectly, are nontaxable: "*Gross income shall not include the value of any subsidy provided (directly or indirectly) by a public utility to a customer for the purchase or installation of any energy conservation measure*."
- Modified Accelerated Cost-Recovery System: Under this program, businesses can 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 50 years, over which the property may be depreciated. For solar, wind and geothermal property placed in service after 1986, the current MACRS property class is five years.
- Solar and Geothermal Business Energy Tax Credit: The U. S. Federal government offers a 10 percent tax credit to businesses that invest in or purchase solar or geothermal energy property in the U. S. The tax credit is limited to $25,000 per year, plus 25 percent of the total tax remaining after the credit is taken. Remaining credit may be carried back to the three preceding years and then carried forward for 15 years.
- Tax Exempt Financing for Green Buildings: The "American Jobs Creation Act of 2004", signed into law on October 22, 2004, authorizes $2 billion in tax-exempt bond financing for green buildings, brownfield redevelopment, and sustainable design projects.
- Renewable Energy Systems and Energy Efficiency Improvements Program: Solar Facilities are eligible for renewable-energy grants range from $2,500 to $500,000. The grants may not exceed 25 percent of an eligible project's cost.

State Incentives:

- Distributed Generation Grant Program: offers awards of up to $30,000 to commercial, industrial, and government entities to "install and study alternatives to central generation" (PV falls under one of these alternatives).
- Alternative Power and Energy Grant Program: offers grants of up to $30,000 to enable businesses and institutions to "install and study alternative and renewable energy system applications (PV is an acceptable technology).
- Net Energy Credit: Facilities generating less than 1000 kWh per month from renewable sources are eligible to sell the excess electricity to the utility. Facilities generating more than 1000 kWh per month need to request permission to sell the excess electricity to the utility.
- Net Metering Rule: Solar, wind and hydroelectric facilities with a maximum capacity of 10 kW are under this September 2004 rule qualified for net metering where the net excess generation is credited to the customer in the next billing cycle.

- Energy Education and Demonstration Grant Program: This program makes small-scale grants for projects that demonstrate applications of energy efficiency and renewable energy technologies for businesses, public and non-profit institutions, schools and local governments. A maximum of $30,000 may be awarded.
- Energy Efficiency and Renewable Energy Set-Aside: This program is a joint effort of the Indiana Energy and Recycling Office and the Indiana Office of Air Quality that offers potential financial incentives to large-scale energy-efficiency projects and renewable-energy projects that significantly reduce NO_x.
- 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 [32]. These credits can be sold on the national market.

Utility programs:

- Green Pricing Program: is an initiative offered by some utilities that give consumers the option to purchase power produced from renewable energy sources at some premium [35].

6.5 References

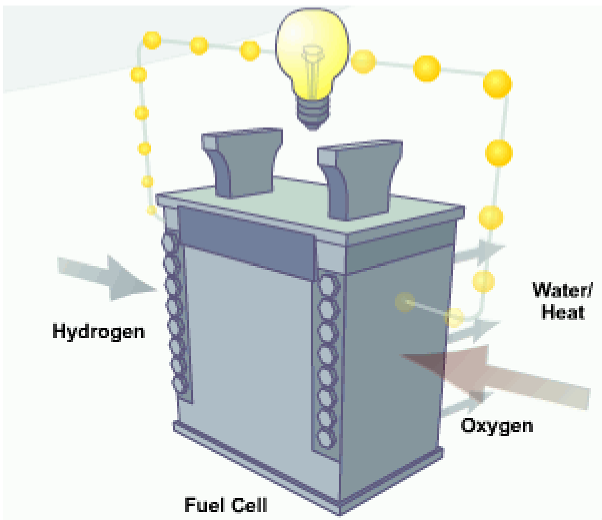
1. http://www.eia.doe.gov/kids/energyfacts/sources/renewable/solar.html
2. http://www.eere.energy.gov/state_energy/technology_overview.cfm?techid=1
3. http://www1.eere.energy.gov/solar/pv_systems.html
4. http://www.eere.energy.gov/solar/cfml/news_detail.cfm/news_id=6712
5. http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/chapter2.html
6. http://www.nrel.gov/csp/concentrating_pv.html
7. http://www.sc.doe.gov/bes/reports/files/SEU_rpt.pdf
8. http://www.dsireusa.org/
9. http://www.eere.energy.gov/solar/photovoltaics.html
10. Environmental Law and Policy Center, "Repowering the Midwest: The Clean Energy Development plan for the Heartland," 2001.
11. http://www.solarbuzz.com/ModulePrices.htm
12. http://www.solarbuzz.com/FastFactsIndustry.htm
13. http://www.eere.energy.gov/power/pdfs/pv_overview.pdf
14. http://www.eere.energy.gov/pv/pvmenu.cgi?site=pv&idx=1&body=aboutpv.html
15. http://www.energylan.sandia.gov/sunlab/PDFs/financials.pdf
16. http://www.nrel.gov/clean_energy/photovoltaic.html
17. http://www.eia.doe.gov/cneaf/solar.renewables/ilands/fig11.html
18. http://www.eere.energy.gov/state_energy/tech_solar.cfm?state=IN
19. http://www.nrel.gov
20. http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/rea.pdf
21. http://www.eia.doe.gov/cneaf/solar.renewables/rea_issues/solar.html
22. http://www.oja-services.nl/iea-pvps/nsr04/usa.htm
23. International Energy Agency, Country information U. S. A. http://www.oja-services.nl/iea-pvps/countries/usa/
24. http://www.sandia.gov/pv/docs/PVRMPV_Road_Map.htm
25. http://www.millionsolarroofs.org/articles/static/1/1023898520_1023713795.html

26. http://www.solarbuzz.com/USGridConnect2006.htm
27. http://www.solarbuzz.com/USGridConnect2005.htm
28. http://www.eere.energy.gov/state_energy/opfacbytech.cfm?state=IN
29. http://www.irecusa.org/articles/static/1/1065806275_989930621.html
30. http://www.bp.com/genericarticle.do?categoryId=120&contentId=2001318
31. http://www.cinergy.com/sustainability/04/env_improvement.htm
32. Richard Perez and Howard Wenger, For the National Renewable Energy Laboratory, Final report on photovoltaic valuation, December 1998.
33. http://www1.eere.energy.gov/solar/solar_america/
34. http://www.in.gov/idem/energycredit/ecreditfct.pdf
35. http://www.epa.gov/greenpower/locator/in.htm

7. Fuel Cells

7.1 Introduction

A fuel cell converts chemical potential energy to electrical energy similar to a battery except that it does not "run down" or require charging but will produce energy as long as fuel is supplied [1]. The basic fuel cell consists of two electrodes encompassing an electrolyte as in the polymer electrolyte membrane (PEM) fuel cell in Figure 7-1.



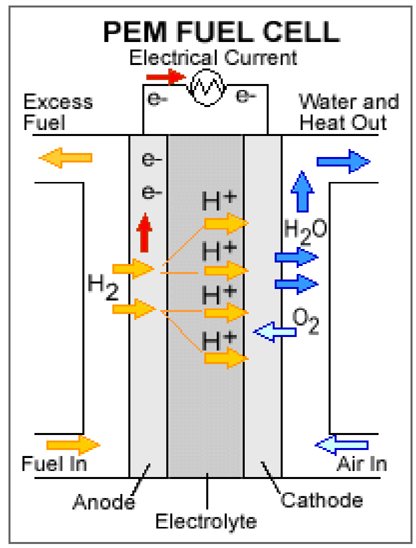


Figure 7-1: Schematic of basic fuel cell operation (Source: EERE)

Hydrogen (H) is fed into the anode and oxygen (or air) enters the fuel cell through the cathode. The hydrogen atom releases its electron (e^-) with the aid of a catalyst in the anode and the proton (H^+) and electron pursue separate paths before rejoining at the cathode. The proton passes through the electrolyte whereas the electron flows through an external electric circuit (electric current). The proton, electron and oxygen are rejoined at the cathode to produce water as the exhaust emission [1].

Fuel cells are classified primarily by the kind of electrolyte they employ. This in turn determines the chemical reactions that take place in the cell, the catalysts required for the chemical reaction, the temperature range in which the cell will operate, the fuel required, and a variety of other factors. Taken together, these characteristics affect the applications for which these cells are most suitable. Listed below are several types of fuel cells currently under development, each with its own advantages, limitations, and potential applications [2].

- Polymer Electrolyte Membrane Fuel Cells (PEMFCs): These fuel cells (also known as proton exchange membrane fuel cells) deliver high power density and offer advantages of low weight and volume, compared to most other fuel cells. PEMFCs require only hydrogen, oxygen, and water to operate and are used primarily for transportation applications. However, the costs associated with utilizing a catalyst to separate the hydrogen's electrons and protons coupled with the space required for hydrogen storage prevent the use of these fuel cells in vehicles.

- Direct Methanol Fuel Cells (DMFCs): These fuel cells are powered by pure methanol, which is mixed with steam and consequently fed to the fuel cell anode. Direct methanol fuel cells do not have the fuel storage problems that are prevalent in most hydrogen-based fuel cells because methanol has a higher density than hydrogen. However, this technology is relatively new and research is still being conducted on its efficacy and economic viability.
- Alkaline Fuel Cells (AFCs): These fuel cells use potassium hydroxide and water as the electrolyte. Conventional high-temperature AFCs operate between 100°C and 250°C. However, newer designs operate between 23°C to 70°C. AFCs' performance is dependent upon the rate at which chemical reactions take place in the cell. They have demonstrated efficiencies of approximately 60 percent in space applications. In order to effectively compete in commercial markets, AFCs will have to become more cost-effective. AFC stacks have been proven to maintain stable operation for more than 8,000 operating hours. However, to be economically viable in large-scale utility applications, these fuel cells must reach operating times exceeding 40,000 hours.
- Phosphoric Acid Fuel Cells (PAFCs): These fuel cells use liquid phosphoric acid as an electrolyte and porous carbon electrodes containing a platinum catalyst. PAFCs are one of the most mature cell types and the first to be used commercially, with over 200 units currently in use. These types of fuel cells are typically used for stationary power generation, but some PAFCs have been used to power large vehicles such as city buses. In addition, they are typically 85 percent efficient when used for the cogeneration of electricity and heat, but only 37-42 percent efficient at generating electricity alone. A typical phosphoric acid fuel cell costs between $4,000 and $4,500 per kilowatt.
- Molten Carbonate Fuel Cells (MCFCs): These fuel cells are being developed for natural gas and coal-based power plants for electric utility, industrial, and military applications. MCFCs utilize an electrolyte composed of a molten carbonate salt mixture and operate at temperatures of 650°C. MCFCs can reach efficiencies of approximately 60 percent. When the waste heat is captured and used, efficiency levels can reach 85 percent. The primary disadvantage of MCFC technology is durability. The high temperatures at which these cells operate and the corrosive electrolyte used reduce cell life.
- Solid Oxide Fuel Cells (SOFCs): SOFCs use a hard ceramic compound as the electrolyte. They are expected to be around 50-60 percent efficient at converting fuel to electricity. In applications designed to capture and utilize the system's waste heat (co-generation), overall fuel use efficiencies could top 80-85 percent. SOFCs operate at temperatures of approximately 1,000°C, which can result in slow startups and increased thermal shielding to retain heat and protect personnel.
- Regenerative Fuel Cells (RFCs): RFCs produce electricity from hydrogen and oxygen and generate heat and water as byproducts. However, RFC systems are capable of utilizing energy from solar power or other sources to divide the excess

water into oxygen and hydrogen fuel – a process known as “electrolysis.” This technology is still being developed by NASA and others.

The five basic fuel cell types that are currently being pursued by manufacturers are listed in Table 7-1. Currently the PAFC is commercially available. The PEMFC seems to be most suitable for small-scale distributed applications (e.g., building cogeneration systems for homes and businesses) and the higher temperature SOFCs and MCFCs might be suitable for larger-scale utility applications because of their high efficiencies[16] [3]. Table 7-1 and 7-2 illustrates the efficiency levels of the various fuel cell technologies [4].

Fuel Cell Type	Electrolyte	Operating Temperature	Applications	Advantages	Disadvantages
Polymer Electrolyte membrane (PEM)	Solid organic polymer poly-perfluorosulfonic acid	60–100°C 140–212°F	• electric utility • portable power • transportation	• Solid electrolyte reduces corrosion & management problems • Low temperature • Quick start-up	• Low temperature requires expensive catalysts • High sensitivity to fuel impurities
Alkaline (AFC)	Aqueous solution of potassium hydroxide soaked in a matrix	90–100°C 194–212°F	• military • space	• Cathode reaction faster in alkaline electrolyte so high performance	• Expensive removal of CO_2 from fuel and air streams required
Phosphoric Acid (PAFC)	Liquid phosphoric acid soaked in a matrix	175–200°C 347–392°F	• electric utility • transportation	• Up to 85% efficiency in cogeneration of electricity and heat • Can use impure H_2 as fuel	• Requires platinum catalyst • Low current and power • Large size/weight
Molten Carbonate (MCFC)	Liquid solution of lithium, sodium, and/or potassium carbonates, soaked in a matrix	600–1000°C 1112–1832°F	• electric utility	• High efficiency • Fuel flexibility • Can use a variety of catalysts	• High temperature enhances corrosion and breakdown of cell components
Solid Oxide (SOFC)	Solid zirconium oxide to which a small amount of yttria is added	600–1000°C 1112–1832°F	• electric utility	• High efficiency • Fuel flexibility • Can use a variety of catalysts • Solid electrolyte reduces corrosion & management problems • Low temperature • Quick start-up	• High temperature enhances breakdown of cell components

Table 7-1: Comparison of fuel cell technologies (Source: EERE)

Fuel Cell Type	Operating Temperature	Efficiency
PEFC/PEMFC	~80°C	~45%
PAFC	~100–220°C	~37-42%
MCFC	~600–700°C	>70%
SOFC	~600–1000°C	>70%
AFC	~200°	~60%

Table 7-2: Operating temperatures and efficiency levels for fuel cells (Source: Fuelcells.org)

[16] The efficiencies of fuel cells are increased through the reuse of high temperature “waste” heat.

There are five main attractive features of fuel cell technology [3]:

- High generation efficiencies exceeding 80 percent;
- Virtual elimination of most energy-related air pollutants;
- Modularity that enables fuel cells to be used in a wider variety of applications of differing energy requirements
- Lack of moving parts (chemical process); therefore there is less noise and less maintenance than conventional generation technologies (turbine-generator sets); and
- Fuel cells have longer operating times than batteries. Doubling the operating time only requires the doubling of the amount of fuel, not the capacity of the unit.

There are some drawbacks to using fuel cells, mostly the high capital cost of fuel cells and fuel extraction [1]. Although the fuel cells run on hydrogen, the most plentiful gas in the universe, hydrogen is never found alone in nature. Therefore, efficient methods of extracting hydrogen in large quantities are required. Currently, hydrogen is more expensive that other energy sources such as coal, oil or natural gas [1]. Researchers are working on improving "fuel reformers" to extract hydrogen from fossil fuels[17] (natural gas) or water. In addition, DOE is working to achieve a $3.00 per gallon of gasoline equivalent at the station by 2008 and $1.50 per gallon of gasoline equivalent by 2010 [1]. Using fossil fuels is seen as a commercial short-term solution whereas the electrolysis of water from solar or wind energy is seen as a more appropriate long-term solution for obtaining hydrogen for fuel cells. Fuel cells currently have a significant drawback in that economically viable technology and infrastructure for the production, transportation, distribution, and storage of hydrogen is not yet available [3].

Fuel cells have many potential applications ranging from powering motor vehicles to providing primary (or backup) power for homes and industries (stationary applications) [5]. While there are several different types of fuel cells technologies available, the PEMFCs are most commonly found in most prototype fuel cell cars and buses. SOFCs are being tested on cars and trucks with traditional power trains as "auxiliary power units," which will ease their transition into the automotive market. To date, more than 50 vehicles have been demonstrated using fuel cell technology [1].

Stationary fuel cells are used for backup power, power for remote locations, stand-alone power plants, distributed generation and co-generation systems. They are beneficial because they provide extremely reliable power, are modular in nature, are capable of utilizing different fuels, and are environmentally preferable to traditional power generation technologies. The first commercially available fuel cell power plants, produced by the UTC Fuel Cells, created less than 20 grams of pollutants per MWh, compared to over 11,388 grams per MWh for an average U. S. fossil fueled plant. A typical residential fuel cell system consists of three main components [1]:

---

[17] Although fossil fuels could be used, since the extraction of the hydrogen is via a chemical process and not by combustion, less pollutants are released.

- Hydrogen Fuel Reformer: This unit allows the extraction of hydrogen from the hydrogen-rich fuel, e.g., natural gas;
- Fuel Cell Stack: Converts the hydrogen and oxygen from air into electricity, water vapor and heat; and
- Power Conditioner: Converts DC from the fuel cell to AC for use by residential appliances.

Fuel cells have also been extensively used in landfill/wastewater treatment plants. The hydrogen for these fuel cells is extracted from the methane gas produced in the landfills. Fuel cells operating at wastewater treatment facilities effectively reduce emissions of methane, carbon dioxide, and other pollutants that contribute to global warming. The New York Power Authority's (NYPA) fuel cell system in Yonkers, New York generates about 1.6 million kilowatt-hours of electricity a year, and in that time releases only 72 pounds of air emissions into the environment. Average fossil fuel power plants generating the same amount of electricity generally produce more than 41,000 pounds of air pollutants [1]. The Northeast Regional Biomass program has completed a study on the feasibility of using bio-based fuels with stationary fuel cell technologies [6]. The results show that this is technically feasible for providing a source of clean, renewable electricity over the long-term. Fuel cells can have a variety of applications as shown in Figure 7-2 [7].

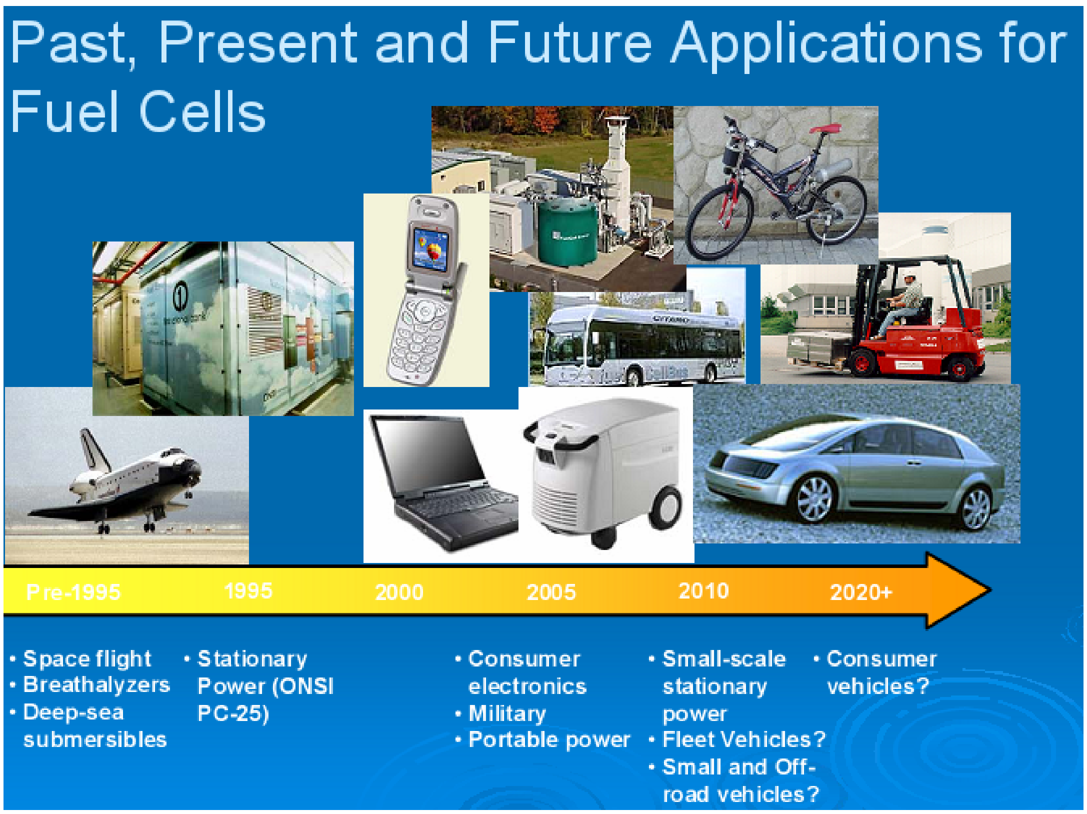


Figure 7-2: Fuel cell applications (Source: www.fuelcells.org)

7.2 Economics of fuel cells

The currently available PAFCs units cost around $3,000/kW [1, 3]. These units are only produced in 200 kW sizes that are suitable for larger power applications. This is in comparison to the cost for a typical automotive internal combustion engine power plant of approximately $25-$35/kW [5]. Several companies are currently researching the production of smaller scale (2 to 4 kW) fuel cell units for residential use.

Fuel Cell Technologies (FCT) estimates that the cost of residential fuel cell units will drop to between $500/kW and $1000/kW once commercial production begins [1]. The expected payback period for the residential fuel cell units is forecast to be around 4 years [1]. According to DOE, the price of fuel cells needs to fall to the $400/kW to $750/kW range for them to be commercially viable. For transportation applications, a fuel cell system needs to cost $30/kW for the technology to be competitive [8].

Hydrogen can be produced from a variety of resources such as fossil, nuclear and renewables [9]. Hydrogen has potential benefits for U. S. energy security, environmental quality, energy efficiency and economic competitiveness. However, there are still some barriers to overcome in order to make hydrogen price competitive, such as development of fuel cell vehicles, stationary fuel cells, and also development of a hydrogen fueling infrastructure. Figure 7-3 shows the U. S. hydrogen facilities [10].

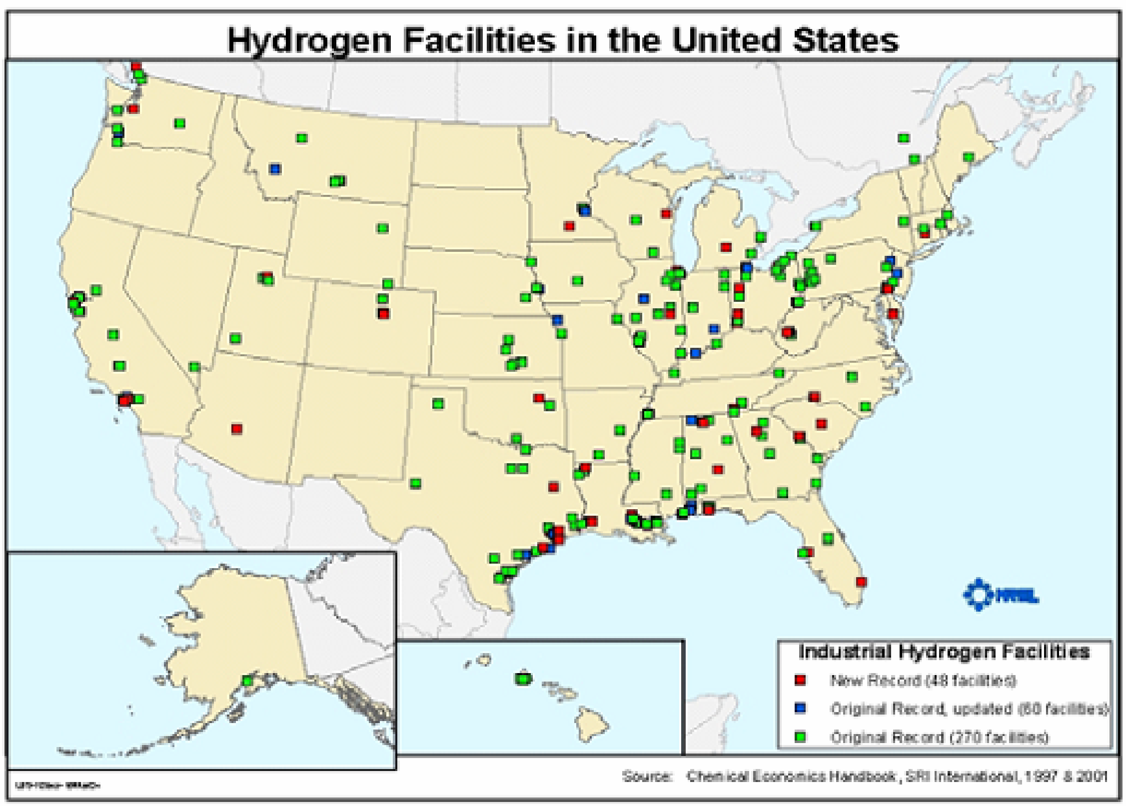


Figure 7-3: Hydrogen facilities in the U. S. (Source: NREL)

7.3 State of fuel cells nationally

Fuel cells are currently in service at over 150 landfills and wastewater treatment plants in the United States. A few of these projects include [1]:

- Groton Landfill (Connecticut): Installed fuel cell in 1996. This plant produces about 600,000 kWh of electricity per year.
- Yonkers Wastewater Treatment Plant (New York): Installed fuel cell in 1997 and produces over 1.6 million kWh/year.
- City of Portland (Oregon): Installed fuel cell that utilizes anaerobic digester gas from a wastewater facility. It generates 1.5 million kWh/year and reduces the electricity bill of the treatment plant by $102,000/year.

In addition to landfill/wastewater plant applications, there are also several stationary fuel cell demonstration projects throughout the country. Some of these are [11]:

- Chugach Electric Association (Anchorage, Alaska): Installed 1 MW (5x200 kW) fuel cell system at the U. S. Postal Service's Anchorage mail handling facility. The system runs on natural gas and provides primary power for the facility as well as half of the hot water needed for heating (co-generation). The excess electricity flows back onto the grid.
- Town of South Windsor Fuel Cell Project (Connecticut): Installed a natural gas powered 200 kW fuel cell system. This unit provides heat and electricity to the local high school. It is also used as an education center for fuel cells.
- Department of Defense Fuel Cell Demonstration Program: This began in the mid-1990s to advance the use of fuel cells at DOD installations. Currently fuel cells are located at about 30 sites throughout the Armed Services providing primary and or back-up electrical power and heat.

These demonstration projects are seen as critical to market acceptance of fuel cells as well as validate the reliability of the product in real life situations [5].

A variety of other projects are also currently being undertaken throughout the nation. Some of the more notable ones are referenced below [1]:

- DaimlerChrysler (California): DaimlerChrysler has provided the University of California at Los Angeles with two F-Cell fuel cell vehicles. UCLA has formed the Hydrogen Engineering Research Consortium (HERC), whose goal is to accelerate the onset of the hydrogen economy through the development and demonstration of technologies for the production, storage, transportation and use of hydrogen.
- Cellex Power Products, Inc. (Missouri): Cellex Power Products, Inc. has completed its Alpha hydrogen fuel cell product field trials at the logistics subsidiary of Wal-Mart Stores, Inc. They had four fuel cell power units in operation at a Wal-Mart food distribution center demonstrating the operational

benefits to Wal-Mart when powering their fleet of pallet trucks. The fuel cell units ran successfully and were capable of being refueled with compressed hydrogen in one minute.

- Sierra Nevada Brewing Company (California): California Governor Schwarzenegger dedicated a 1 MW fuel cell power plant at Sierra Nevada Brewing Company. The power plant consists of four 250 kW Direct Fuel Cell power plants from FuelCell Energy, Inc. The waste heat from the fuel cell is harvested in the form of steam and used for the brewing process as well as other heating operations.
- IdaTech, LLC: IdaTech, LLC has entered into a new contract with the U. S. Army to continue the development of a portable fuel cell system for military applications. The agreement involves research into the enhancement of its 250 watt, integrated, portable fuel cell systems for use in tactical military operations on domestic bases and to provide quiet, rechargeable power over an extended period of time during training.

As stated in Section 7.2, the commercial availability of fuel cells is currently limited to larger power applications (200 kW). Smaller residential-type fuel cells are being researched and commercial production of these units is expected soon with General Motors and Toyota exploring the stationary fuel cell market [1, 3]. GE Fuel Cell Systems (GEFCS) is building a network of regional distributors to market, install and service its residential fuel cell. GEFCS have already signed distributors in New Jersey, Michigan, Illinois, Indiana, New York City and Long Island [1].

To promote the commercialization of fuel cells for power generation, *Fuel Cells and Hydrogen: The Path Forward* recommended that Congress should enact a tax credit program beginning in 2003 and continuing to 2007. This would credit purchasers of fuel cell systems that provide power to businesses and residential property one-third the cost of the equipment or $1000/kW, whichever is less. It is also recommended that an additional 10 percent tax credit be available for residences, businesses or commercial properties that utilize fuel cells for both heat and power [5].

Currently the 15 states shown in Figure 7-4 and Washington D.C allow the use of hydrogen/fuel cells in meeting their renewable portfolio standards. The states of Washington, Oregon, California, Idaho, New Mexico, Iowa, Michigan, New York, Maryland, Massachusetts, Delaware and Montana provide tax incentives or rebates for power generation from stationary fuel cells [12].

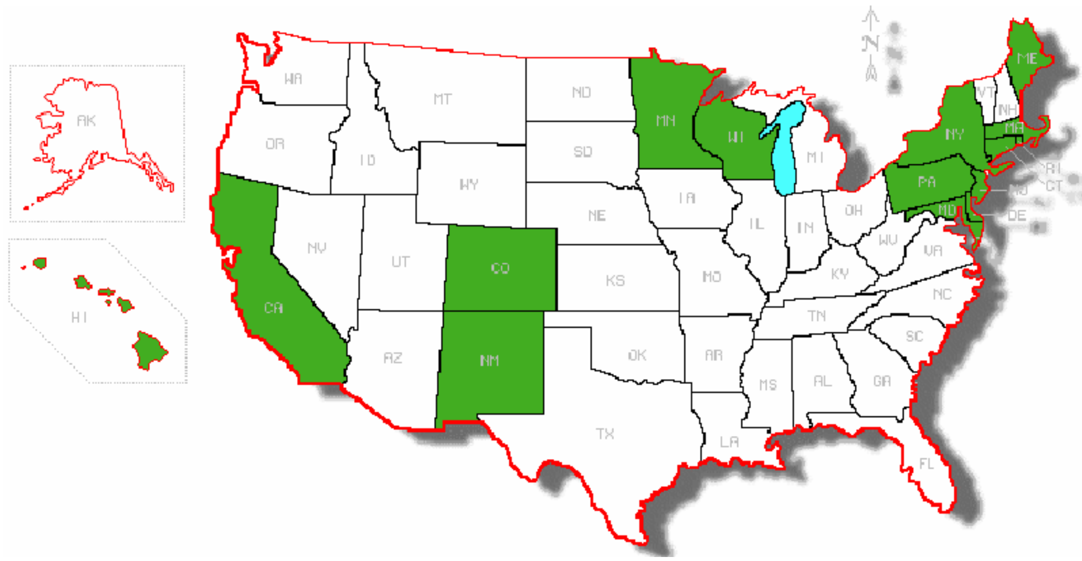


Figure 7-4: Renewable portfolio standards that include H2/fuel cells (Source: www.fuelcells.org)

7.4 Fuel cells in Indiana

In September of 1999, Cinergy Technology, Inc. installed a 250 kW stationary generator at the Crane Naval Surface Warfare Center. This was the first 250 kW PEM fuel cell generator in the world to enter field testing and provided valuable information concerning the viability of fuel cells during its two-year evaluation period. In March 2004, the U. S. Navy installed a PEM-powered refueler at Crane [1].

In July 2004, FuelCell Energy of Danbury, CT completed construction of a 2 MW fuel cell installation at the Wabash River coal gasification site near Terre Haute. This installation is designed to run on gasified coal, or syngas, from the nearby gasification facility. Partial funding for the project was obtained from DOE's Clean Coal Technologies Program.

In general, fuel cells are quite expensive but the cost per kW is expected to decrease as the commercial production of smaller residential-type units begins [1, 3]. Once this occurs there is expected to be an increase in the number of fuel cell installations in the Midwestern states although the assumed numbers are small [3]. The following factors will determine the extent of the market penetration by fuel cells within Indiana:

- The cost of electricity from fossil fuel plants and alternative renewable sources;
- The market cost of fuel cell units;
- The cost of fuel for the fuel cell units (e.g., natural gas); and
- The extent of Federal and state incentives.

In 2004, Indiana had the fifth cheapest average retail electricity prices in the nation [13]. The low cost of electricity in Indiana might provide a barrier to entry for the emerging fuel cell technologies and other renewable sources.

The commercial production of fuel cells would lead to reductions in the unit costs thus making them more competitive to both grid and off-grid applications. The signing of the distribution rights of GEFCS's fuel cells within Indiana is further indication that there would be an active promotion of fuel cell usage within the state. In *Repowering the Midwest: The Clean Energy Development plan for the Heartland*, the Environmental Law and Policy Center assumed that a small number of fuel cells would be installed in each Midwestern state but acknowledged that this was a pessimistic view and did not take into account the promising near-term market for smaller-scale distributed fuel cells [3].

The current short-term viability of fuel cells is seen as using existing natural gas supplies to extract hydrogen for the fuel cell[18] [1, 3]. Figure 7-5 shows the average annual residential price of natural gas in the nation and within Indiana [14]. The cost of natural gas within Indiana is slightly below the national average but not enough so as to give Indiana a significant advantage in terms of costs.

Certain farms within Indiana where biogas supplies are available (e.g., dairies) might benefit from the reduced costs of fuel cells in the future. The biogas could be used to supply hydrogen to the fuel cell thus reducing the electricity requirements of the facility and reducing costs. Net metering rules that allow the sale of excess electricity sent back to the grid could also aid the facility. Landfill and wastewater treatment plants within the state also could utilize the methane produced to supply hydrogen to the fuel cell.

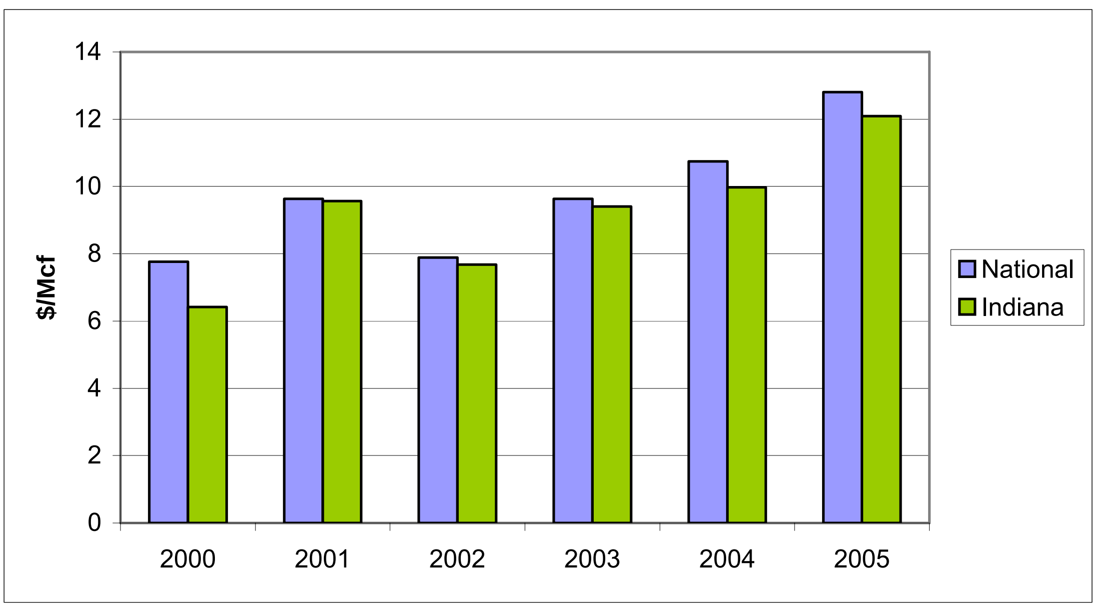


Figure 7-5: National and Indiana residential natural gas prices (Source: EIA)

[18] This would occur in the fuel reformer module of the fuel cell unit.

Government incentives are seen as critical in terms of commercializing the use of fuel cells in stationary power applications, particularly when commercial availability is in its infancy [1, 5]. The tax credit proposed in [5] would help in this regard.

There are some Federal incentives that play an important role in developing the fuel cell industry:

- Business investments tax credit: The 2005 Energy Policy Act includes a business investments tax credit of 30 percent for fuel cells and 10 percent for microturbines. The credits are available in 2006 and 2007; the amount depends on the technology purchased [15].
- Hydrogen Fuel Initiative: was launched President George W. Bush in 2002 to pursue the promise of hydrogen. The initiative requires DOE to invest $1.7 billion over five years in research and development of advanced hybrid vehicle components, fuel cells, and hydrogen infrastructure technologies [10].

Further state incentives could also assist the introduction of fuel cells within Indiana. These include [16]:

- Distributed Generation Grant Program: offers awards of up to $30,000 to commercial, industrial, and government entities to "install and study alternatives to central generation" (fuel cells fall under one of these alternatives).
- Alternative Power and Energy Grant Program: offers grants of up to $30,000 to enable businesses and institutions to "install and study alternative and renewable energy system applications" (fuel cells are an acceptable technology if powered by a renewable source).
- Net Energy Credit: Facilities generating less than 1000 kWh per month from renewable sources are eligible to sell the excess electricity to the utility. Facilities generating more than 1000 kWh per month need to request permission to sell the excess electricity to the utility.
- 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 [17]. These credits can be sold on the national market.
- Energy Efficiency and Renewable Energy Set-Aside: This program is a joint effort of the Indiana Energy and Recycling Office and the Indiana Office of Air Quality that offers potential financial incentives to large-scale energy-efficiency projects and renewable-energy projects that significantly reduce NO_x.
- Renewable Energy Systems and Energy Efficiency Improvement Program: The USDA has implemented this program through a NOFA for each of the last three years. The latest round of funding, totaling $22.8 million, was made available in March 2005. Half ($11.4 million) of this sum was available immediately for competitive grants. Renewable energy grants range from $2,500 to $500,000 and may not exceed 25 percent of an eligible project's cost.
- Tax-Exempt Financing for Green Buildings, Renewable Energy and Brownfield Redevelopment: The American Jobs Creation Act of 2004" (HR 4520), signed

into law on October 22, 2004, authorizes $2 billion in tax-exempt bond financing for green buildings, brownfield redevelopment, and sustainable design projects. Tax-exempt financing allows a project developer to borrow money at a lower interest rate because the buyers of the bonds will not have to pay Federal income taxes on interest earned. The savings from tax-exempt financing must then be used to offset the costs of sustainable design and/or renewable energy technologies.

A wider variety of fuel cells will be available commercially in the near future. The impact of fuel cells on the profile of Indiana's renewable electricity generation sector depends to a large extent of the price of the units, the efficiency of the units and the government (Federal and State) incentives in commercializing this technology for stationary applications.

7.5 References

1. http://www.fuelcells.org/
2. http://www.eere.energy.gov/hydrogenandfuelcells/fuelcells/fc_types.html
3. Environmental Law and Policy Center, "Repowering the Midwest: The Clean Energy Development plan for the Heartland", 2001.
4. http://www.eere.energy.gov/hydrogenandfuelcells/fuelcells/pdfs/fc_comparison_chart.pdf
5. http://www.fuelcellpath.org/full%20feb%202003.pdf
6. www.nrbp.org/pdfs/pub31.pdf
7. http://www.fuelcells.org/info/MIT.pdf
8. http://www.eere.energy.gov/hydrogenandfuelcells/fuelcells/fc_challenges.html
9. http://www1.eere.energy.gov/hydrogenandfuelcells/mypp/pdfs/production.pdf
10. http://www.nrel.gov/docs/fy05osti/37903.pdf
11. http://www.eere.energy.gov/hydrogenandfuelcells/fuelcells/stationary_power.html
12. http://www.fuelcells.org/info/Ohio.pdf
13. http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html
14. http://www.eia.doe.gov/cneaf/electricity/st_profiles/indiana.pdf
15. http://www.eia.doe.gov/oiaf/aeo/index.html
16. http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm
17. http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=IN

8. Hydropower from Existing Dams

8.1 Introduction

Hydroelectric energy is produced by converting the kinetic energy of falling water to 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. These are [2, 3]:

- Impoundment hydropower: This facility uses a dam to store the water. Water is then released through the turbines to meet electricity demand or to maintain a desired reservoir level. Figure 8-1 from the Idaho National Engineering and Environmental Laboratory (INEL) shows a schematic of this type of facility.
- Pumped storage: Water is pumped from a lower reservoir to an upper reservoir when electricity demand is low and 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 within the natural range of the river requiring little or no impoundment. Run-of-river plants can be designed for large flow rates with low head (the elevation difference between water level and turbine) 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 would typically be used in remote locations to satisfy a single home or business.

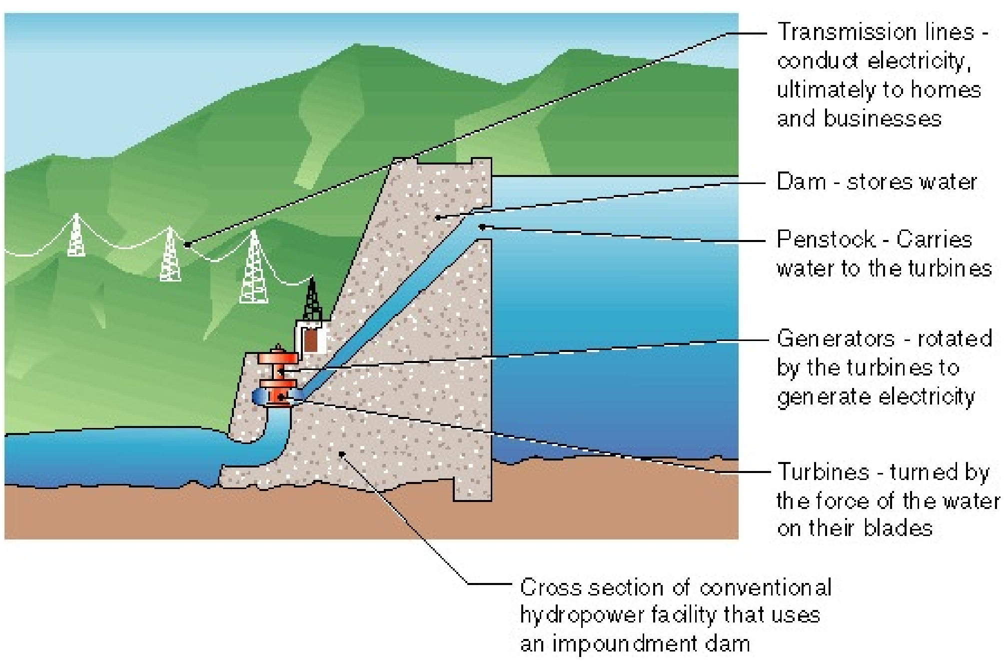


Figure 8-1: Schematic of impoundment hydropower facility (Source: INEL)

In addition, there are a variety of turbine technologies that are utilized for hydropower. 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 [4]:

- 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 fixed vanes (usually 9). 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 from 10 feet to 2,000 feet of head 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 from 10 feet to 300 feet of head and can be as large as 100 MW.

Hydropower is a renewable resource that has many benefits, including [1]:

- Hydropower is a clean, renewable and reliable source of energy.
- Current hydropower turbines are capable of converting 90 percent of the available energy to electricity. This is more efficient than any other form of generation.
- Hydroelectric facilities have very short startup and shutdown times, making them an operationally flexible asset. This characteristic is even more desirable in competitive electricity markets.
- Impoundment hydropower is generally available as needed since engineers can control the flow of the water through the turbines to produce electricity on demand [5].

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 [5]. As a primary purpose, electricity production constitutes only 2 percent of the uses of U. S. dams as shown in Figure 8-2 [6].

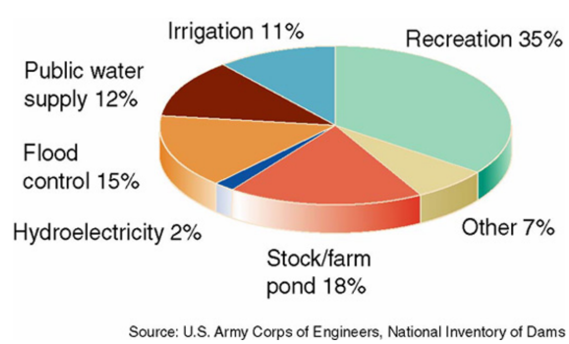


Figure 8-2: Primarily purposes or benefits of U. S. dams (Source: U. S. Army Corps of Engineers)

The supply of electricity from hydroelectric facilities can be quite sensitive to the amount of precipitation in the watershed supplying the hydro facility. There have also been some concerns raised about the environmental impact of hydroelectric facilities, including [7]:

- The blockage of upstream fish passage.
- Fish injury and mortality from passage through the turbine.
- Changes in the quality and quantity of water released below dams and diversions.

Other factors may act as deterrents to potential (and continuation of existing) hydropower projects. This includes the increasingly costly and uncertain process of licensing (relicensing) hydropower projects. It was stated that through 2017 about 32 GW of hydroelectric capacity needs to go through Federal licensing which is estimated to cost more than $2.7 billion (2001 dollars) for processing [1]. It was also stated the typical time taken for obtaining a new license varies from 8 to 10 years.

8.2 Economics of hydropower

An obstacle to large hydropower projects is the large up-front capital costs [1]. Even with these large capital costs, hydropower is extremely competitive over the project lifetime with initial capital costs of $1,700-$2,300/kW and levelized production costs of around 2.4 cents/kWh [2]. Typically the useful life of a hydroelectric facility exceeds 50 years [3]. Figures 8-2 and 8-3 illustrate the competitiveness of hydropower with respect to other generator plant types.

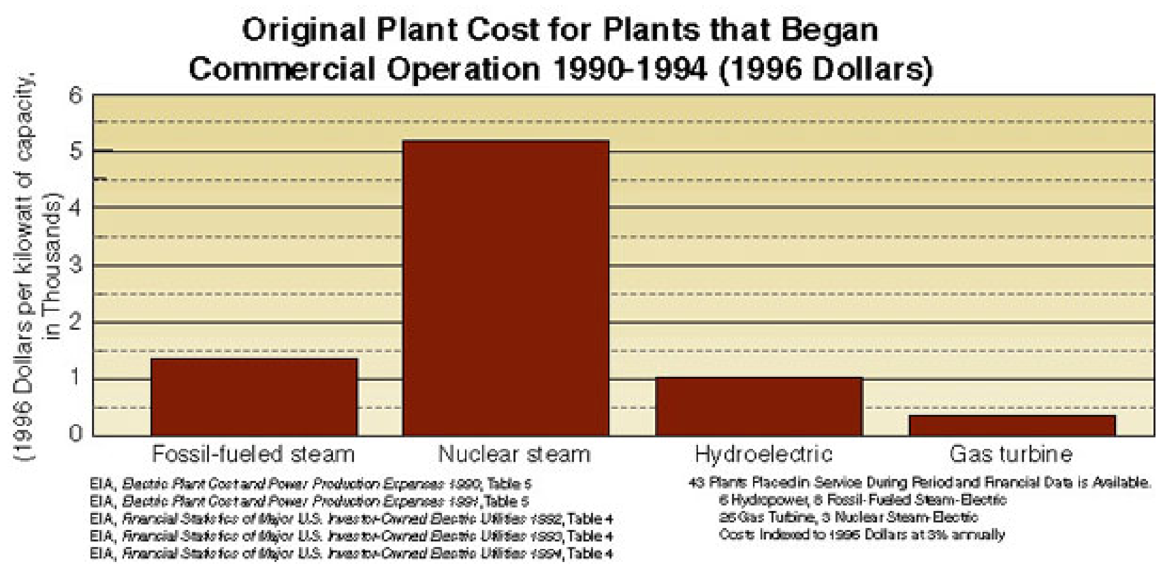


Figure 8-3: Plant costs per unit installed capacity (Source: INEL)

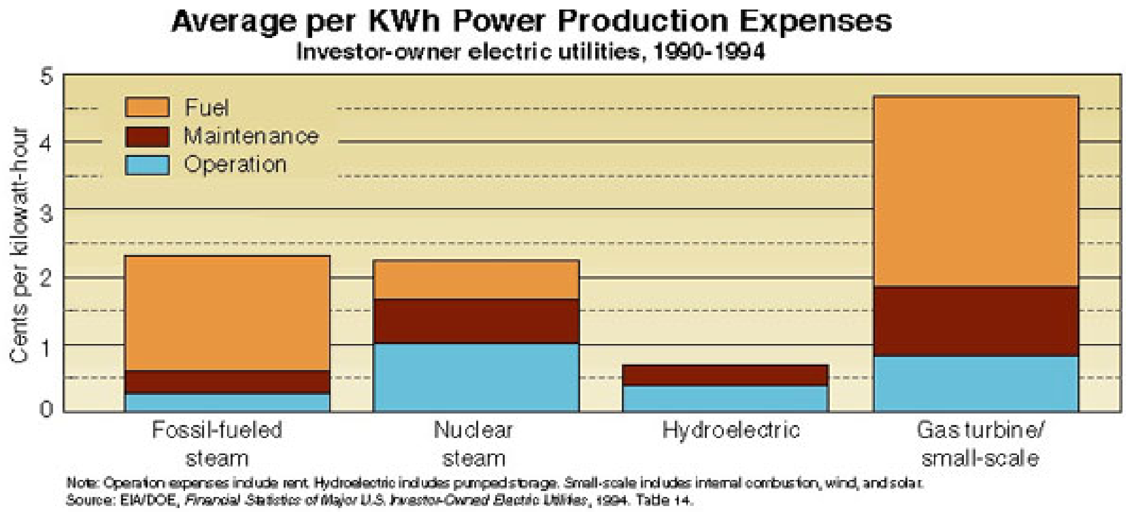


Figure 8-4: Average production costs of various types of generating plants (Source: INEL)

8.3 State of hydropower nationally

In 2004, the U. S. consumed 6.117 quads of renewable energy. Of this, 2.725 quads (44.5 percent) were from conventional hydroelectric energy [8]. In 2004, hydroelectric generation capacity[19] constituted about 6.5 percent of the total generation capacity [10]. The total net summer (including pumped storage) installed hydroelectric generation capacity during 2004 in the U. S. was 98.4 GW [9, 11]. The states of Washington, California and Oregon account for 52.5 percent of the total electricity generation from hydropower with Washington having the most capacity [12]. Table 8-1 shows the top 10 states in hydropower capacity [13].

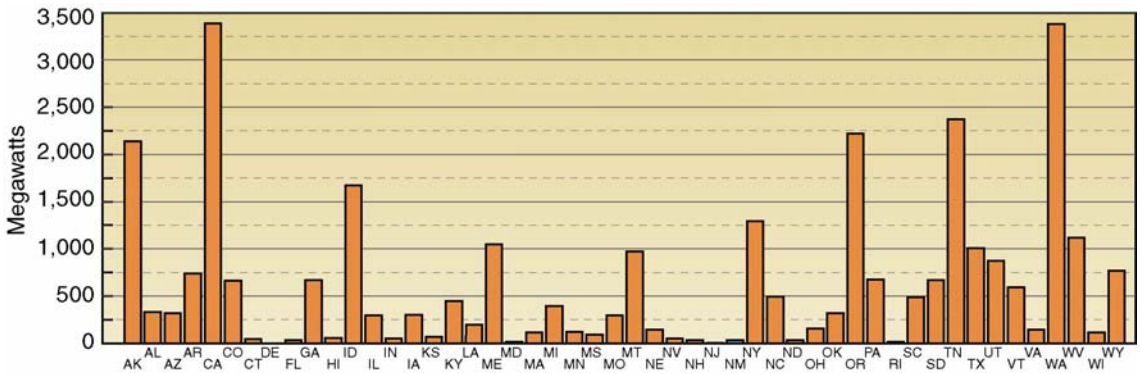
1. Washington	21,464		6. Montana	2,717
2. California	10,364		7. Arizona	2,703
3. Oregon	9,089		8. Idaho	2,665
4. New York	4,094		9. Tennessee	2,513
5. Alabama	3,002		10. Georgia	2,325

Table 8-1: U. S. top ten states in hydropower capacity (MW) – 2004 (Source: National Hydropower Association)

In 1998 DOE published a report assessing the resources for hydropower in the country [14]. The DOE Hydropower Program developed a computer model, Hydropower Evaluation Software (HES) which utilizes environmental, legal and institutional attributes to help assess the potential for domestic undeveloped hydropower capacity. HES identified 5,677 sites in this study with a total undeveloped capacity of 30 GW [14]. Of this amount, 57 percent (17.052 GW) are at sites with some type of existing dam or impoundment but with no power generation. Another 14 percent (4.326 GW) exists at

[19] This is excluding pump storage schemes.

projects that already have hydropower generation but are not developed to their full potential and only 8.5 GW (28 percent) of the potential would require the construction of new dams [1]. Therefore the potential for hydropower from existing dams is about 21.378 GW. The breakdown of the state-by-state contribution to the total 30 GW identified by HES is shown in Figure 8-5.



Source: Hydroelectric Power Resources Assessment database (FERC) and Hydropower Evaluation Software (INEEL). DOE has modeled the undeveloped conventional hydropower potential in the United States. This does not include developed capacity. Various state agencies have reviewed the modeled results and provided input. The 50-state undeveloped conventional hydropower potential is approximately 30,000 MW. The model includes environmental, legal, and institutional constraints to development.

Figure 8-5: State breakdown of potential hydropower capacity (Source: INEL)

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 [6].

Although there are substantial undeveloped resources for hydropower, its share of the nation's total generation is predicted to decline through 2020 with almost no new hydropower capacity additions during this time [7]. The reason for this is due to a combination of environmental issues, regulatory complexities and pressures, and changes in economics [7]. Due to environmental concerns, the most currently viable of the available hydropower potential is the 4.3 GW of "incremental" capacity available at existing hydropower facilities. Improvements in turbine design to minimize environmental impacts and Federal and State government incentives could help further develop the potential hydropower projects from existing dams.

Currently, DOE is conducting research into technologies that will enable existing hydropower projects to generate more electricity with less environmental impact. Their main objectives are to develop new turbine systems with improved overall performance, develop new methods to optimize hydropower operations, and to conduct research to improve the effectiveness of the environmental mitigation practices required at hydropower projects. Together, these advances in hydropower technology will reduce the cost of implementation and help smooth the hydropower integration process [15].

The Consumer Energy Council of America (CECA) recommends that Congress act to fully implement the incentives for hydropower production and research and development contained in the Energy Policy Act of 2005. CECA suggests that Congress should extend the placed-in service date for the Section 45 production tax credit for hydropower to 2015 and also expand the credit to include hydropower development at non-hydropower dams. Special attention should also be given to the development of small hydropower facilities and emerging hydropower technologies [16].

8.4 Hydropower from existing dams in Indiana

Hydroelectric energy contributed only 0.3 percent (443.7 GWh) of the total electricity generated in the Indiana in 2004, as shown in Figure 8-6. Indiana has 91.4 MW of hydroelectric generation capacity, which makes up about 0.3 percent of the state's total generation capacity [17, 18]. In 2001, the total hydroelectric generation in Indiana was 571 GWh (0.4 percent of total state generation). Thus it can be seen that hydropower currently plays a very small role in Indiana's generation mix.

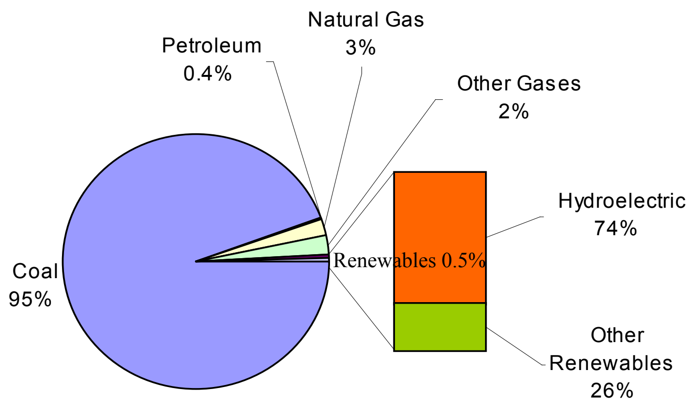


Figure 8-6: Contribution of various generation sources to total electricity generated in Indiana - 2004 (Source: EIA)

In 1995 a report was published for DOE which assessed the potential hydropower resources[20] available in Indiana [19]. The results of this study indicated a total of 30 sites[21] that were identified within Indiana and assessed, using HES, as potential undeveloped hydropower sources. Table 8-2 shows a breakdown of these identified sites.

The following key[22] was used to indicate the status of the potential hydropower site [19]:

- With Power: Developed hydropower site with current power generation, but the total hydropower potential has not been fully developed.
- W/O Power: This is a developed site without current hydropower generation. The site has some type of developed impoundment (dam) or diversion structure but no power generating capability.

[20] Undeveloped pumped-storage hydropower potential was not included.
[21] A complete list of these projects is given in [19].
[22] In terms of the hydropower potential projects relevant for this report, only the first two (With Power and W/O Power) categories are of interest.

- Undeveloped: This site does not have power generating capability nor any impoundment or diversion structure.

	Number of projects	Identified potential (MW)	HES-modeled potential (MW)
With Power	3	15.9	8.0
W/O Power	24	50.8	33.7
Undeveloped	3	16.7	1.7
State Total	30	83.5	43.4

Table 8-2: Undeveloped hydropower potential in Indiana (Source: Francfort)

From Table 8-2 it can be seen that the HES-modeled potential projects were much less than the identified potential. This was particularly apparent in the undeveloped projects where environmental and legislative constraints made these potential projects less viable. In terms of projects with existing dams (or diversion structures) a total of 41.7 MW of potential capacity was available within Indiana (at 27 sites). The majority of the potential projects within Indiana have capacities below 1 MW [19]. This would imply predominantly smaller hydropower and microhydro projects.

All of the identified projects were located within the five major river basins. The Wabash River Basin was seen as having the most undeveloped hydropower potential (about 23 MW) of the Indiana river basins [19].

The viability of these projects could be increased with Federal and State government incentives. The current incentives for hydropower within Indiana include [8]:

- Renewable Energy Systems Exemption: provides property tax exemptions for the entire renewable energy device and affiliated equipment.
- Alternative Power and Energy Grant Program: offers grants of up to $30,000 to enable businesses and institutions to "install and study alternative and renewable energy system applications (hydropower is an acceptable technology).
- Green Pricing Program: is an initiative offered by some utilities that gives consumers the option to purchase power produced from renewable energy sources at some premium.
- Net metering rule: Solar, wind and hydroelectric facilities with a maximum capacity of 10 kW are under this September 2004 rule qualified for net metering where the net excess generation is credited to the customer in the next billing cycle.
- Energy Efficiency and Renewable Energy Set-Aside: This program is a join effort of the Indiana Energy and Recycling Office and the Indiana Office of Air Quality that offers potential financial incentives to large-scale energy-efficiency projects and renewable-energy projects that significantly reduce NO_x emissions.
- Renewable Electricity Production Tax Credit: This program is a per kilowatt-hour tax credit for electricity generated by qualified energy sources. The initiative was recently renewed in August of 2005 and provides a tax credit of 0.9 cents/kWh for

electricity generated from hydropower. This credit was extended once again trough December 31, 2007.

- Renewable Energy Systems and Energy Efficiency Improvements: The USDA makes direct loans and grants to agricultural producers that purchase renewable-energy systems and make energy-efficiency improvements. The USDA has implemented this program through a NOFA for each of the last three years. The latest round of funding, totaling $11.3 million was made available in February 2006.
- Value Added Producer Grant Program: The USDA awards grants to support the development of value-added agriculture business ventures. A total of $19.47 million in grants was allocated for the fiscal year 2006 [20].

8.5 References

1. National Hydropower Association,
   http://www.hydro.org
2. Idaho National Engineering and Environmental Laboratory,
   http://hydropower.inel.gov
3. www.eere.energy.gov/power/consumer/tech_hydropower.html
4. http://www.eere.energy.gov/RE/hydropower.html
5. http://www1.eere.energy.gov/windandhydro/hydro_ad.html
6. http://www.nrel.gov/docs/fy04osti/34916.pdf
7. DOE Hydropower Program Annual Report – 2002
8. http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/table1.html
9. U. S. Department of Interior, Bureau of Reclamation,
   http://www.usbr.gov/power/edu/hydrole.html
10. http://www.eia.doe.gov/cneaf/electricity/epa/figes2.html
11. http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html
12. http://www.eia.doe.gov/cneaf/electricity/epm/table1_12b.html
13. http://www.hydro.org/Hydro_Facts/Fact_Sheets/113.cfm#_ftn2
14. http://hydropower.inel.gov/resourceassessment/pdfs/doeid-10430.pdf
15. http://www.eere.energy.gov/windandhydro/hydro_advtech.html
16. http://www.hydro.org/searchable_files/filemanager/CECAReport2006Final.pdf
17. http://www.eia.doe.gov/cneaf/electricity/st_profiles/indiana/in.html
18. http://www.nrel.gov/
19. J.E. Francfort, "U. S. Hydropower Resource Assessment for Indiana," DOE/ID-10430(IN), Dec. 1995.
20. http://www.rurdev.usda.gov/GA/vadg.htm

Appendices: Biogas from Waste Streams

There are currently three main organic waste streams from which biogas is captured. They are livestock manure, landfills and wastewater treatment plants. A fourth potential source of energy-bearing gas is the gasification of organic biomass, often from wood and wood waste, into synthesis gas (syngas).

Biomass gasification is not included in these appendices since the gasification technologies still have technical hurdles to overcome before they can be scaled up for commercialization and large scale production. DOE's Biomass Program has a detailed list of these technical hurdles.

The large of amount of organic waste biomass in use today is not converted to biogas, but rather burned directly to fire boilers either as biomass only or co-fired with coal. Section 4 of the main report more broadly covers the various uses of biomass as a source of energy.

These appendices focus strictly of the recovery of energy in the form of biogas from the three organic waste streams – livestock manure, landfills and wastewater treatment facilities. The three sections of this report are

- Appendix A – Livestock manure
- Appendix B – Landfill gas
- Appendix C – Wastewater treatment

Each of the three appendices are organized similarly to the chapters in the main report with an introductory section, a section on the economics of the technology, the state of the technology nationally, a section on the application of the technology in Indiana and a list of references.

Appendix A: Biogas from Livestock Waste

A.1 Introduction

Most of the biogas recovery from farm-based waste streams in the U. S. occurs in dairy and swine farms, since the biogas recovery systems currently in use are designed to work with manure in the form of liquid, slurry, or semi-solid state. Manure management in this form is more prevalent in dairy and swine farms while other livestock sectors manage their manure primarily in solid forms. In addition, the frequent collection of manure in confined dairy and swine farms (weekly or more frequently) minimizes the loss of the organic biodegradable material that is be converted to biogas. In contrast, other animal farms, such as poultry and beef, typically collect the manure no more than three or four times per year [1].

This biogas is composed of mostly methane (60-70 percent by volume), which is the energy containing component, carbon dioxide (30-40 percent) and small amounts of hydrogen sulfide, ammonia and water vapor [1-3]. This means that the energy content of biogas less than that of natural gas, which is nearly pure methane. In addition, the non-methane gases have to be removed before the biogas can be sold outside the farm as a pipeline quality energy product.

In addition to the value of energy from methane, the process of capturing methane from livestock waste has a number benefits. These environmental and waste-management benefits are cited as adequate justification for the installation of biogas capture facilities with the potential for energy, thereby adding economic benefit to what would otherwise be a sunk cost.

- Odor control: Odor control is cited as one of the main benefits of a biogas recovery system.
- Nutrient management flexibility: Manure that has been through the biogas recovery process has improved nutrient availability and reduced acidity. This makes it more valuable for application on farm fields as a substitute for commercial fertilizer. The reduced odor also gives farmers added flexibility as to the times they can field apply the treated manure.
- Improved water quality: The digestion process, which typically involves heating, destroys most of the disease-causing bacteria in the effluent, thereby reducing the risk of these bacteria entering streams and other surface waters. In addition, the biogas conversion process reduces the chemical oxygen demand of the effluent and therefore the potential for harm to aquatic ecosystems.
- Greenhouse gas reduction: When livestock manure is stored in conventional tanks, storage ponds or lagoons, the methane gas produced is released into the atmosphere adding to the accumulation of greenhouse gases. The methane, which is a far more potent greenhouse gas than carbon dioxide is captured in a biogas conversion process. Methane is estimated to have 21 times as much heat trapping capacity as carbon dioxide [1, 4].

A.2 Economics of biogas recovery from livestock waste

The most common process for biogas recovery from waste streams is the anaerobic digestion process. It consists of the controlled breakdown of organic wastes by two sets of bacteria in an oxygen deficient environment. Acid-forming bacteria convert the organic waste to simple organic acids; these acids are in turn converted into biogas by methane-forming bacteria. The three most common designs of biogas recovery systems in the U. S. are plug-flow digesters, complete mix digesters and unheated covered lagoons. Of the biogas recovery systems operating or under construction in the U. S. in 2005, 51 percent were plug flow digesters, 26 percent complete mix digesters and 13 percent unheated covered lagoons. The remainder consisted of heated covered lagoons, two stage mix digesters and attached media type digesters [1]. Plug flow digesters are the most common in use in Indiana.

Unheated covered lagoons are the simplest and least costly of the digester types, but they are not viable in colder climates such as in Indiana. The plug flow digester consists of a long, narrow heated tank with a cover. Its concrete walls and the energy needed to heat it make the plug flow digester more expensive than the unheated covered lagoon. It is, however, less costly to maintain than the complete mix digester because it has no need for an externally powered mixer. The complete mix digester consists of an enclosed heated tank with a mechanical, hydraulic, or gas mixing system. Complete mix digesters work especially well when the manure is diluted with wastewater such as from the milking center of a dairy farm [1].

Table A-1 gives the average amount of biogas and energy from manure as estimated by the North Carolina Cooperative Extension Service [3]. Dairy cows lead with an average 47 cubic feet (ft^3) of biogas per animal per day, followed by beef feeders at 28 ft^3 per animal per day. These productivity numbers are used in Section A.4 to estimate the total potential for biogas and electricity from animal manure in Indiana.

	Animal weight (lbs)	**Biogas production** (ft^3/head/day)	**Gross energy content*** (Btu/head/day)	**Net energy content**** (Btu/head/day)	**Electricity***** (kWh/head/year)
Dairy Cow	1400	46.4	27,800	18,000	385
Beef Feeder	800	27.6	16,600	10,700	230
Market Hog	135	3.9	2,300	1,500	32
Poultry Layer	4	0.29	180	110	2.5

*assuming 60 percent methane
**assuming 35 percent of energy is put back into digester
***assuming 20 percent combined generating efficiency

Table A-1: Energy potential from livestock waste (Source: North Carolina Cooperative Extension Service) [3]

Table A-2 shows the cost range estimate by EPA's AgSTAR program [2]. The cost does not include the annual operating and maintenance cost. As can be seen from the table, the costs of the digesters have a wide range since they are highly site specific.

	Cost range ($/1,000lbs live animal weight)
Covered lagoon digesters with open storage ponds	150-400
Heated digesters (i.e., complete mix and plug flow) with open storage tanks	200-400
Aerated lagoons with open storage ponds*	200-450
Separate treatment lagoons and storage ponds (2-cell systems)	200-400
Combined treatment lagoons and storage ponds	200-400
Storage ponds and tanks	50-500
* add an additional $35-50 per 1,000 lbs per year for aerated lagoons energy requirements	

Table A-2: Cost of various manure management options (Source: EPA AgSTAR [2])

According to the 2004 update of the *Agricultural Casebook* put forward by the Great Lakes Regional Biomass Energy Project [4], the total cost of installing and bringing to operation the biogas recovery systems in the region for which data was available varied from a low of $70,000 for an anaerobic lagoon in the Baldwin dairy in Wisconsin to a high of $1.526 million in the New Horizons dairy in Illinois. The equivalent cost per head for dairy operations varied from a low of $417 to a high of $763 for systems that included energy generation and from $57 to $78 for farms with open lagoon systems without energy generation equipment. These facilities flared the biogas they produced rather than generate electricity with it. Table A-3 details the cost and funding sources for the 12 farms featured in the Regional Biomass Project 2004 study.

The generation of electricity from livestock waste biogas has not worked very smoothly, with a number of engine-generators having been de-rated from their nameplate capacity. If the hydrogen sulfide in the biogas gets into the engine it causes corrosion and solid particles in the biogas have been known to clog valves and gauges.

Farm Name	Total Cost to Make Operational	Cost Comments and Details	Total Cost per Head (and per AU [a]) (Grant Funds Included)
Apex Pork	$152,300	$66,700 for cover and gas collection equipment, $85,600 for boiler and gas handling equipment	$18 ($46) swine – based on current herd of 8,300 (3,320 AU)
Baldwin Dairy	$70,000	costs are for lagoon cover and gas collection equipment only	$57 ($45) based on design capacity of 1,100 (1,540 AU)
Double S Dairy	$500,000 (digester only)	engine-generator set costs were not available (paid by Alliant Energy)	$500 ($357) digester only – based on design capacity of 1,000 (1,400 AU)
Emerald Dairy	$125,000	costs are for lagoon cover and gas collection equipment only	$78 ($60) based on current population of 1,600 (2,080 AU)
Gordondale Farms	$520,000	digester cost $230,000, energy generation cost (Alliant Energy) $290,000	$650 ($464) digester $288, energy generation $362 and grid connection – based on design capacity of 800 (1,120 AU)
Haubenschild Farms	$355,000	owner set it up with extra wiring, plumbing and thicker walls for contingencies and experiments. Owner paid $77,500, and got $150,000 no-interest loan from MN Dept. of Agriculture, $50,000 grant from MN Dept. of Commerce, $37,500 grant from MN Office of Environmental Assistance, $40,000 AgStar in-kind services.	$444 ($317) based on design capacity of 800 cows (1,120 AU)
Herrema Dairy	na	na	na
Maple Leaf Farms	$804,000	$534,000 (digester cost converted to 2002 dollars) + $270,000 energy generation equipment costs. Got $65,000 from WI Dept. of Administration (toward the $270,000 cost)	$1.6 ($161) duck – based on current population of 500,000 (5,000 AU)
New Horizons	$1.526M	received grants totaling $226,000 from IL Dept. of Commerce and Community Affairs, and Division of Energy and Conservation	$763 ($545) based on design capacity of 2,000 (2,800 AU)
Stencil Farm	$500,000	na	$417 ($298) based on design capacity of 1,200 (1,680 AU)
Tinedale Farms	na	system involved a lot of R&D resulting in high costs	na
Top Deck Holsteins	$501,500	Iowa DNR and NRCS contributed $157,900, Alliant Energy paid $250,000 for the energy generation equipment and to connect the system to the grid, and Top Deck paid $93,600 for the digester	$743 ($548) based on current herd size of 675 (915 AU)

[a] Animal units (AU) are calculated using Wisconsin Department of Natural Resources conversion factors as follows: milking cows = 1.4; cattle = 1.0; swine = 0.4; duck = 0.01. Dairy estimates may include both dairy cows and dry cattle. AU numbers used here represent animals feeding the digester only.

Table A-3: Cost of agricultural biogas recovery systems (Source: Great Lakes Regional Biomass Project) [4]

A.3 State of biogas recovery from livestock waste nationally

According to a report titled *Market Opportunities for Biogas Recovery Systems* issued by EPA's AgSTAR program, there were about 100 biogas recovery systems in operation or under construction in 2005. The EPA estimates that biogas recovery systems were technically feasible in a total of approximately 2,600 dairy and 4,300 swine farms in the country. These biogas recovery systems have a total potential electricity generating capacity of 722 MW and the potential to generate over six million Megawatthour (MWh) of electrical energy per year. Table A-4 shows the distribution of this capacity between dairies and swine farms [1].

Animal Sector	Number of Candidate Farms	Electricity Generating Potential (MW)	Electricity Generating Potential (MWh)
Swine	4,300	363	3,184,000
Dairy	2,600	359	3,148,000
Total	6,900	722	6,332,000

Table A-4: Market opportunities for biogas recovery systems at animal feeding operations (Source: EPA AgSTAR) [1]

According to the market opportunities report quoted above, there is potential for profitability in approximately 6,000 of the 6,900 dairies and swine farms referred to in Table A-4. These farms are the larger ones, i.e., dairies with more than 500 animals and swine farms with more than 2,000 animals which use liquid or slurry manure handling systems and which collect the manure frequently.

As can be seen in Table A-5, Indiana is ranked 7th nationwide for potential for methane generation from swine farms. According to the EPA AgSTAR program [1], Indiana swine farms have the potential to produce at a profit 2.2 million cubic feet per year of methane, which can in turn be used to generate approximately 145 GWh of electric energy per year. This amounts to approximately 0.1 percent of Indiana's annual electric energy requirements. The top ten states listed account for 85 percent of the national methane from swine farms potential. The top two states, North Carolina and Iowa, each account for 20 percent of the national potential [1].

Indiana does not rank among the top ten states for profitable methane production potential from dairies. The top ten states listed Table A-5 account for 80 percent of the national potential for methane from dairies, with California accounting for 40 percent of the national potential [1].

State	Number of Candidate Farms	Methane Emissions Reduction (000 Tons)	Methane Production Potential (million ft^3/year)	Electricity Generation Potential (000 MWh/year)
SWINE FARMS				
NORTH CAROLINA	1,179	247	11.5	766
IOWA	1,022	126	10.2	677
MINNESOTA	429	40	3.5	234
OKLAHOMA	52	54	2.9	196
ILLINOIS	267	36	2.8	184
MISSOURI	200	53	2.7	177
INDIANA	234	28	2.2	145
NEBRASKA	148	25	2.0	134
KANSAS	91	29	1.6	109
TEXAS	13	21	1.1	75
Remaining 40 States	646	113	7.3	487
Subtotal	**4,281**	**773**	**48**	**3,184**
DAIRY FARMS				
CALIFORNIA	963	263	18.1	1203
IDAHO	185	61	4.0	267
NEW MEXICO	123	62	3.9	259
TEXAS	149	32	2.3	154
WISCONSIN	175	8	2.1	138
NEW YORK	157	6	2.0	132
ARIZONA	73	35	1.9	126
WASHINGTON	122	22	1.9	126
MICHIGAN	72	6	1.9	73
MINNESOTA	60	3	0.7	46
Remaining 40 States	544	75	9.4	624
Subtotal	**2,623**	**573**	**48**	**3,148**
U.S. Total	**6,904**	**1,346**	**96**	**6,332**

Table A-5: Top ten states for electricity production from swine and dairy (Source: EPA AgSTAR) [1]

A.4 Biogas recovery from livestock waste in Indiana

According to AgSTAR, there are currently 3 farms with biogas recovery operations in Indiana. All three are large scale dairies in Jasper County. They are the Boss Dairy Number 4, the Fair Oaks Dairy, and the Herrema Dairy. Some of their characteristics are given in Table A-6.

If all the manure from all the cattle (dairy and beef), swine and poultry layers in Indiana was fed into anaerobic digesters it would produce 12.5 billion cubic feet (Bcf) of biogas per year. Assuming a 60 percent methane composition, the 12.5 Bcf of biogas production potential translates to 7.5 Bcf of methane production potential. Further, assuming energy content of 1,000 British thermal units (Btu) per cubic foot for methane, the 7.5 Bcf of methane translates to 4,900,000 million British thermal units (mmBtu) of energy. This is 1 percent of the approximately 500,000,000 mmBtu annual natural gas consumption in Indiana. Table A-7 shows the assumptions and calculations used to arrive at these numbers.

	Boss Dairy No. 4	**Fair Oaks**	**Herrema Dairy (formerly Boss)**
Animals feeding digester	3,400	3,500	3,750
Type and number of digesters	Two phase mixed plug-flow loop (x2)	Combined phase vertical plug-flow (x4)	Two phase mixed plug-flow loop (x2)
Design temperature	100°F (mesophilic)	95-98°F (mesophilic)	100°F (mesophilic)
Year built	2004	2004	2002
Digester Designer	Steve Dvorak, GHD	Dennis Burke, EEC	Steve Dvorak, GHD
Heat used for	Digester, water	Digester	Digester, hope to heat barn and alleyway
Electricity generation	2 Waukesha 350kW synchronous engine-generator sets	2 Waukesha 375kW induction engine-generator sets	2 Hess 350kW induction engine-generator sets
Electricity use	Designed to work independent of grid. Plan to use it to replace grid electricity	Electricity used onsite and some wheeled through utility system to other Fair Oaks facility. Biogas supplemented with natural gas as needed to keep engines running at full capacity	Engine-generator sets have had frequent breakdowns and been unable to reach rated capacity (expected to have replacement engines from manufacturer)
System cost	$1,000,000 for digesters $700,000 for generation equipment (rough approximation)	$5,000,000 spent considered on the high side. A more reasonable estimate would be approximately $1000/cow	Not available

Table A-6: Characteristics of the three operating animal waste based digesters in Indiana (Source: EPA AgSTAR [1] and site visit)

	Dairy Cows	Beef Feeders	Hogs	Poultry	Total per day	Total per year
Biogas potential[1] (ft^3/head/day)	46.4	27.6	3.9	0.3		
Numbers of animals in Indiana	143,000[2]	227,000[2]	3,200,000[3]	30,715,000[2]		
Total Biogas (thousand ft^3/day)	6,635	6,265	12,480	8,907	**34,288**	**12,523,600**
Total Methane[4] (thousand ft^3/day)	3,981	3,759	7,488	5,344	**20,573**	**7,514,160**
Net methane[5] (energy) (mmBtu/day)	2,588	2,443	4,867	3,474	**13,372**	**4,884,204**

[1]The biogas productivity number are from North Carolina State University Extension Service
[2]Cattle and poultry inventory from National Agricultural Statistical Service website
[3]Hog inventory from Indiana Pork Producers Association website
[4]Assuming biogas is 60 percent methane
[5]Assuming 35 percent of energy goes to heating the digester

Table A-7: Biogas potential from Indiana livestock

As shown in Table A-8, if the 4,900,000 mmBtu of methane from animal manure is used to generate electricity it would result in 325,000 MWh of electrical energy. This is approximately 0.3 percent of Indiana's annual electrical energy requirements.

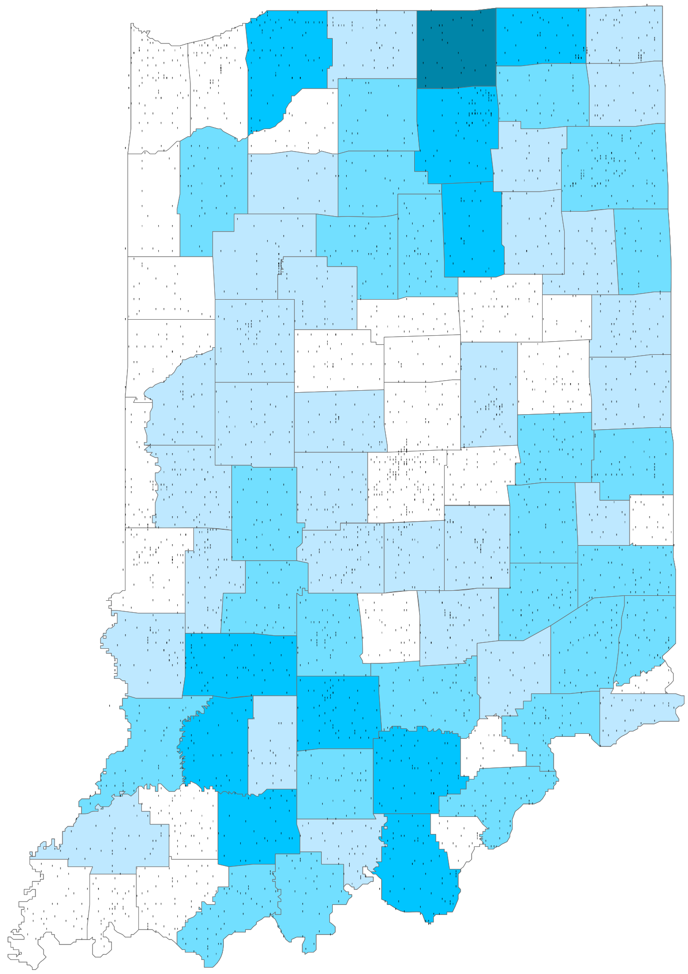
	Dairy Cows	Beef Feeders	Hogs	Poultry	Total
Biogas potential (ft^3/head/day)	46.4	27.6	3.9	0.3	
Electricity potential[1] kWh/head/day	1.2	0.7	0.1	0.01	
Numbers of animals in Indiana	143,000	227,000	3,200,000	30,715,000	
Total Electricity (MWh/day)	173	163	324	232	**891**
Total Electricity (MWh/year)	63,011	59,497	118,516	84,589	**325,614**

[1]A heat rate of 15,000 BTU/kWh as reported in an AgSTAR demonstration farm (Haubenschild) is used

Table A-8: Electrical energy potential from Indiana livestock

Figures A-1, A-2, A-3 shows the estimated biogas potential in Indiana per county from cattle, swine, and poultry.

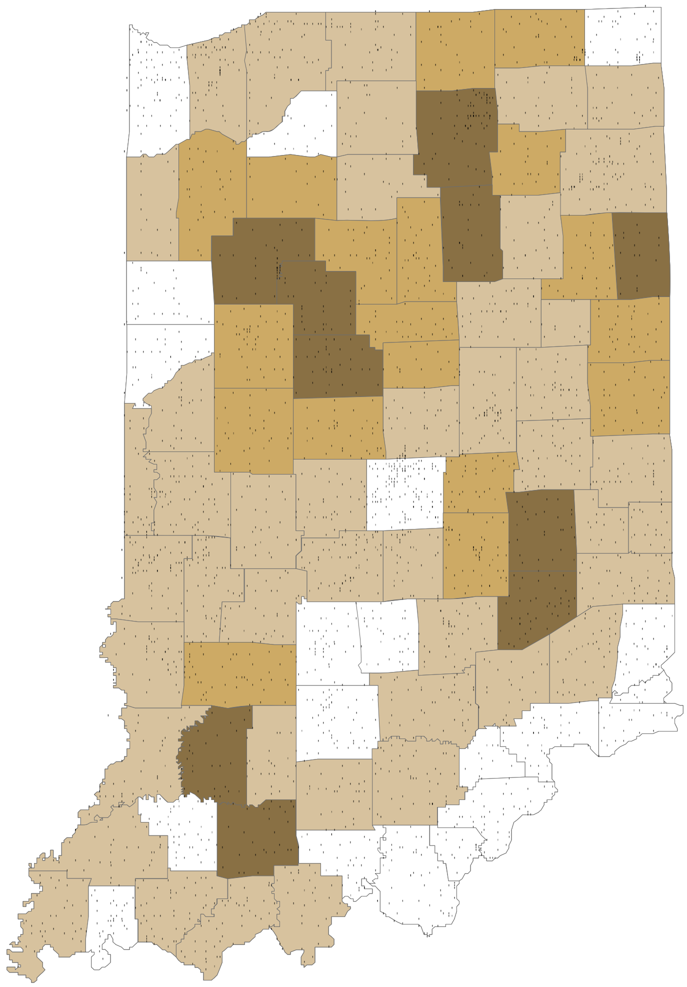
Cattle concentration



	number of cows	mmBTU methane
	5,000	54.7
	5,001-10,000	54.7-109.4
	10,001-20,000	109.4-218.8
	20,001-40,000	218.8-437.5
	> 40,000	> 437.5

Figure A-1: Cattle energy potential (Source: Dr. Klein Ileleji and Abhijith Mukunda, Purdue University [5])

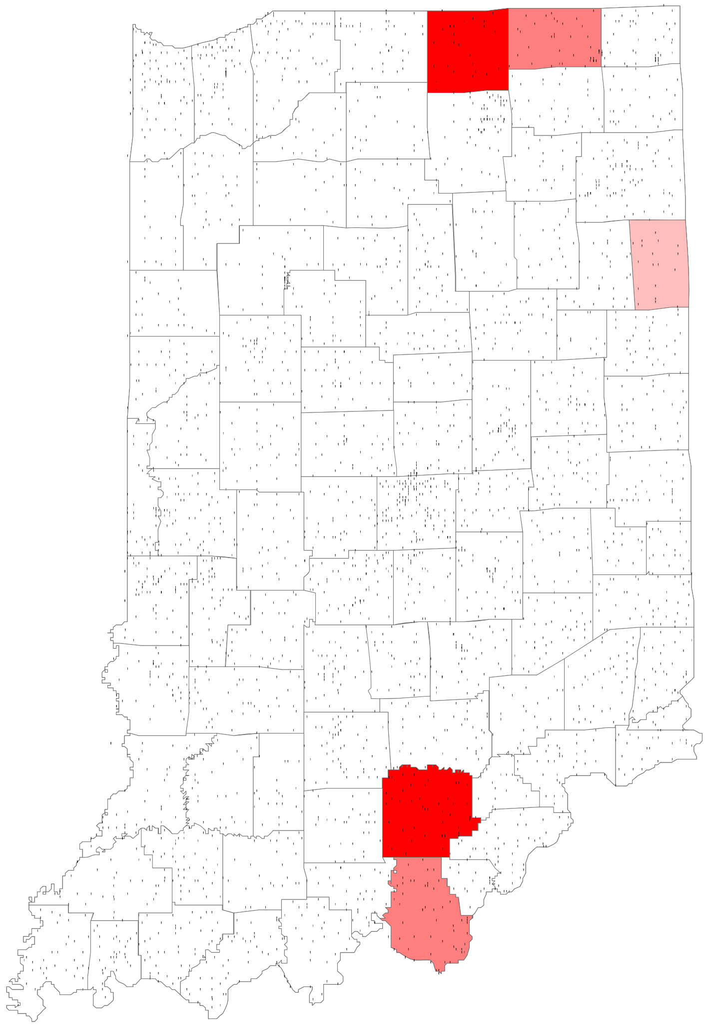
Hog Concentration



	Number of pigs	mmBTU methane
	10,000	22.5
	10,001-50,000	22.5-112.5
	50,001-100,000	112.5-224.9
	> 100,000	> 224.9

Figure A-2: Swine energy potential (Source: Dr. Klein Ileleji and Abhijith Mukunda, Purdue University [5])

Chicken Concentration



	Number of chicken	mmBTU methane
	500,000	42
	500,001 – 2 million	42 – 168
	2 million -3.3 million	168 – 277
	> 3.3 million	> 277

Figure A-3: Poultry energy potential (Source: Dr. Klein Ileleji and Abhijith Mukunda, Purdue University [5])

The biogas available from livestock farms is currently limited by anaerobic digesters in use in the U. S. being only able to process manure in liquid, slurry, or semi-solid state. This restricts biogas recovery through anaerobic digesters to mostly dairy and swine farms [1]. Also, as mentioned in Section A.3, the EPA AgSTAR estimates that energy capture is likely to be more profitable in the larger farms with over 500 head of cattle or over 2,000 head of swine. These sizes of farms are approximately the size of farms that are regulated by the Indiana Department of Environmental Management as concentrated animal feeding operations (CAFO) [6]. Figure A-5 shows the location all the CAFO farms in Indiana.

One method that has been proposed to improve the economies of scale and therefore enable biogas recovery from smaller scale animal operations, is the installation of a centralized digester serving several farms. Such a centralized facility is being implemented, with DOE funding, in Port Tillamook Bay, Oregon [4]. Several issues regarding this business model constrain its widespread use. They include the added cost of transporting the manure from the farms, the quality control of the composition of the manure from different farms and perhaps most important of all, the possibility of transporting disease causing pathogens from one farm to another via the manure collection process.

Another factor raised by the by practitioners in the digester industry in Indiana is the low price offered by the local electric utilities for the excess electricity sold to the grid. The price offered by the utilities was lower than the retail rate and not sufficient to justify investment in the full complement of generating equipment needed to fully utilize the biogas potential of the digesters. The net effect was that some biogas was still being flared whenever there was an increase in the digester biogas production or when the generator was not operational. The ideal set up would be the purchase of an extra generator set that would serve both as a reliability backup and also would be put to use during digester production spikes.

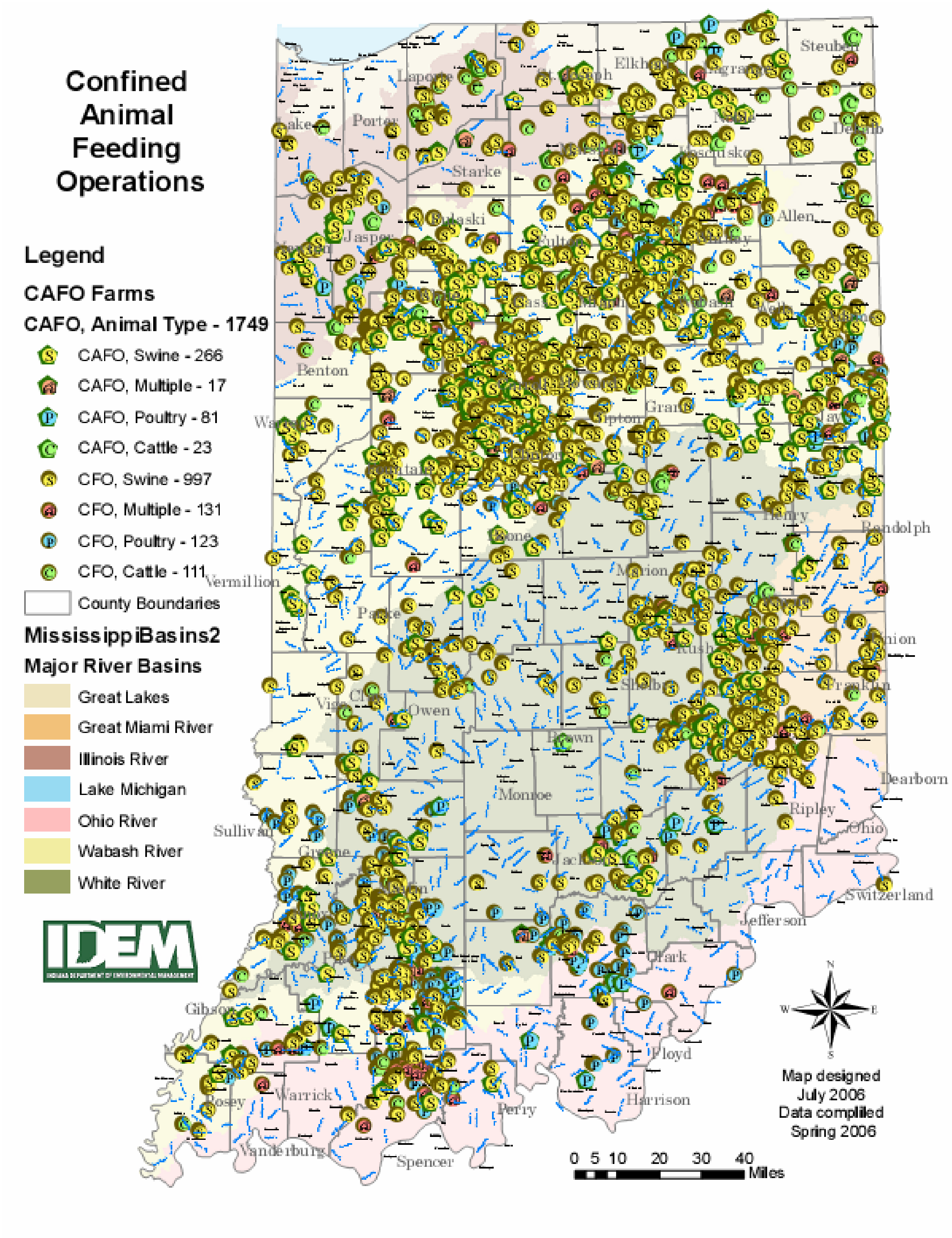


Figure A-4: Animal feeding operations in Indiana (Source: IDEM [7])

A.5 References

1. U. S. Environmental Protection Agency, The AgSTAR Program, "Market Opportunities for Biogas Recovery Systems A Guide to Identifying Candidates for On-Farm and Centralized Systems," EPA-430-8-06-004, 2006.
2. U. S. Environmental Protection Agency, The AgSTAR Program, "Managing Manure With Biogas Recovery Systems. Improved Performance at Competitive Costs," EPA-430-F-02-004, Winter 2002.
3. Barker, James C., North Carolina Cooperative Extension Service, "Methane fuel gas from livestock wastes – a summary," updated March 2001. http://www.bae.ncsu.edu/programs/extension/publicat/wqwm/ebae071_80.html
4. Kramer, Joseph M., Resource Strategies Inc., "Agricultural Biogas Casebook – 2004 update," September 2004.
5. Ileleji, Klein E.; Mukunda, Abhijith; Purdue University Department of Agricultural Engineering, "Production potential of on-farm energy from livestock waste in Indiana."
6. Russel, David; Indiana Department of Environmental Management, Indiana confined feeding operations feeding operations permit program, presentation at methane recovery from farm and food processing waste workshop, Peru, IN, June 6 2006.
7. Indiana Department of Environmental Management, map of Indiana confined feeding operations feeding operations, provided by IDEM staff.

Appendix B: Biogas from Landfill Gases

B.1 Introduction

The oxygen deprived conditions in a municipal solid waste facility provides the conditions necessary for anaerobic digestion of the organic matter in the waste to be converted to biogas. This results in a landfill gas composed of approximately 50 percent methane and 50 percent carbon dioxide. Left on its own the carbon dioxide in landfill gas will likely leach out of the landfill because it is soluble in water while the methane which is less soluble in water and lighter than air will likely migrate into the atmosphere [1].

According to the EPA's Landfill Methane Outreach Program (LMOP), landfills containing municipal solid waste constitute the largest (34 percent in 2003) source of human-induced methane emissions in the United States. Since methane is a potent greenhouse gas, there is a significant incentive to capture it and stop it from leaking into the atmosphere. Converting this methane to energy provides an economic benefit to this environmental task [1].

In recognition of the significant contribution of landfill methane emission, the LMOP was launched in 1994 to promote the capture and use of landfill gas as a viable source of energy. The "*LMOP forms partnerships with communities, landfill owners, utilities, power marketers, states, project developers, tribes, and non-profit organizations to overcome barriers to project development by helping them assess project feasibility, find financing, and market the benefits of project development to the community*" [1].

Like other biogases, landfill gas can be used directly for heating and other such purposes or can be converted to electricity. Electricity generation from landfill comprises about two-thirds of the currently operational landfill to energy projects in the U. S. As shown in Figure B-1, internal combustion engines are the predominant technology in use for electricity generation in landfill gas operations. Other technologies in use in order of their frequency are gas turbines, microturbines and steam turbines. Other technologies still in developmental stage include Stirling and organic Rankine cycle engines and fuel cells. The remaining one-third of landfill to energy projects in the U. S. use the landfill gas directly to provide heat for such applications as spaceheat, process heat or evaporation of the leachate in the landfill. The distribution of direct energy use technologies is shown in Figure B-2. Other potential uses of landfill gas include treating it to produce pipeline quality gas for feeding into the natural gas pipeline system and compressed natural gas for vehicle fuel.

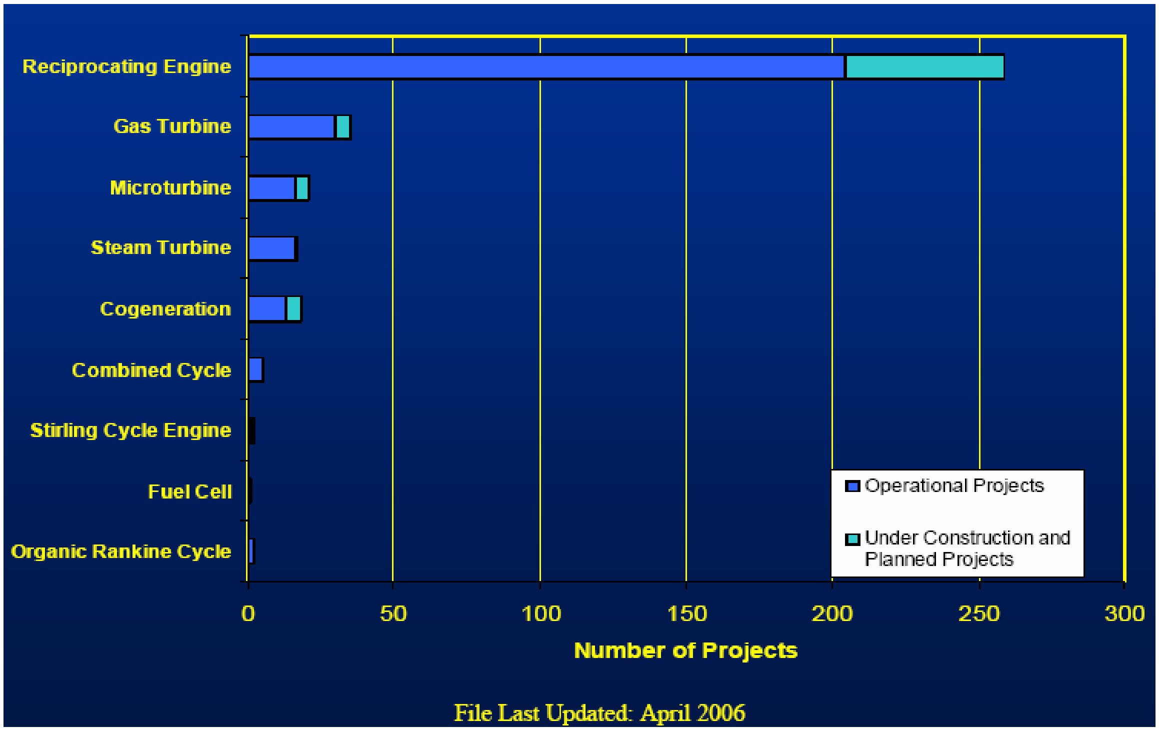


Figure B-1: Technology trends: electricity generating from landfill gas (Source: EPA LMOP) [1]

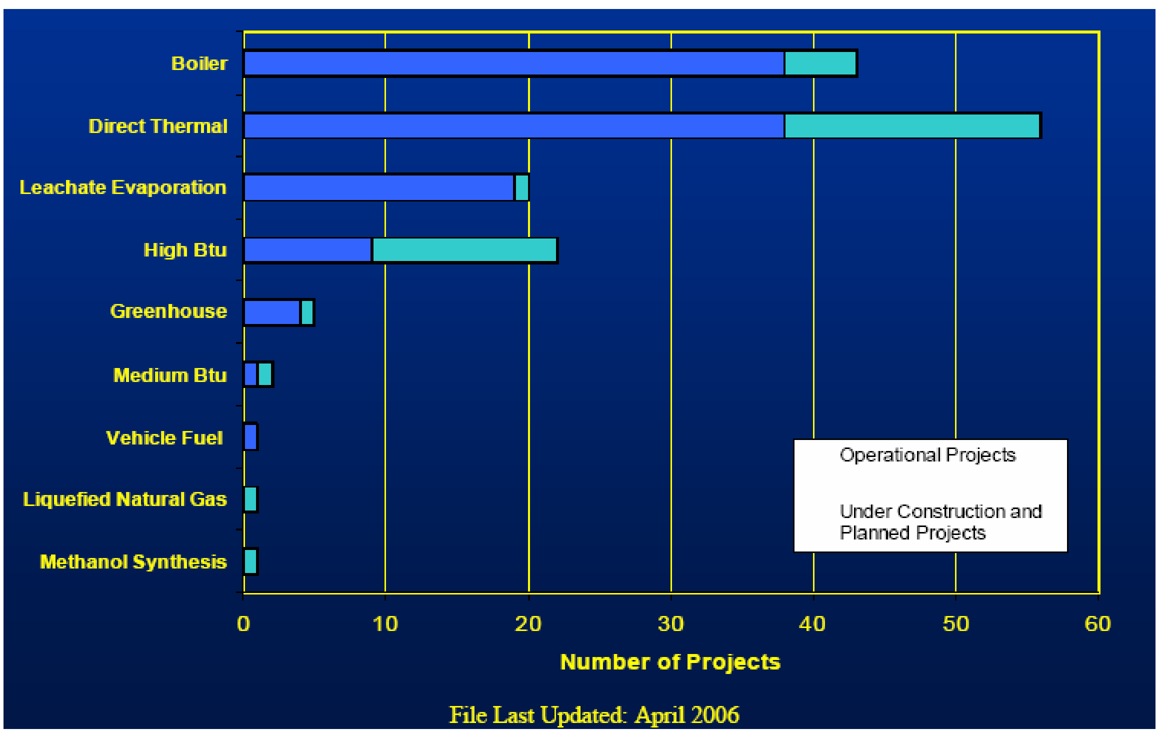


Figure B-2: Technology trends: direct-use landfill gas projects (Source: EPA LMOP) [1]

B.2 Economics of landfill gas energy capture

Table B-1 compares the total levelized cost of energy (LCOE) of landfill gas with other renewable resources. As can be seen in the table landfill gas at 4.6 cents/kWh compares very favorably with wind energy's 4.8 cents/kWh, especially considering that the LCOE calculation for landfill gas does not include the Federal production tax credit.

	Wind		Solar Photovoltaic		Geothermal	Landfill Gas
Vintage	2005	2015	2005	2015	(all vintages)	(all vintages)
All In Capital ($/kW)	**1,199**	**1,141**	**3,075**	**2,661**	**2,536**	**1,268**
Plant Costs	980	925	2,733	2,346	2,229	1,044
Interconnection Cost	141	141	141	141	141	141
Interest During Construction (7% = 6% Interest + 1% Bank Fees)	78	75	201	174	166	83
Total O&M	**25.50**	**25.50**	**10.00**	**10.00**	**127.62**	**166.05**
Fixed O&M ($/kw/yr)	25.50	25.50	10.00	10.00	120.00	47.00
Variable O&M ($/kw/yr)	0.00	0.00	0.00	0.00	7.62	119.05
Capacity Factor	**32.0%**	**36.5%**	**30%**	**30%**	**87%**	**90%**
Reserve Margin Contribution	20%	20%	50%	50%	100%	100%
Capital Charge Rate	12%	12%	12%	12%	11%	15%
Levelized Average All-In Generation Cost ($/MWh)	**59.16**	**49.71**	**140.71**	**122.28**	**54.34**	45.67
Levelized Production Tax Credit ($/MWh)	10.71	10.71	0.00	0.00	0.00	0.00
Tax Adjusted Levelized Generation Cost ($/MWh)	**48.45**	**39.00**	**140.71**	**122.28**	**54.34**	45.67

Table B-1: Total levelized cost of various generating technologies (Source: EPA LMOP) [1]

B.3 State of landfill gas energy projects nationally

According to LMOP, *as of December 2005, approximately 395 landfill gas (LFG) energy projects were operational in the United States. These 395 projects generate approximately 9 billion kilowatt-hours of electricity per year and deliver just over 200 million cubic feet per day of LFG to direct-use applications. EPA estimates that approximately 600 additional landfills present attractive opportunities for project development* [1]. Figure B-3 shows the distribution of these energy projects**.**

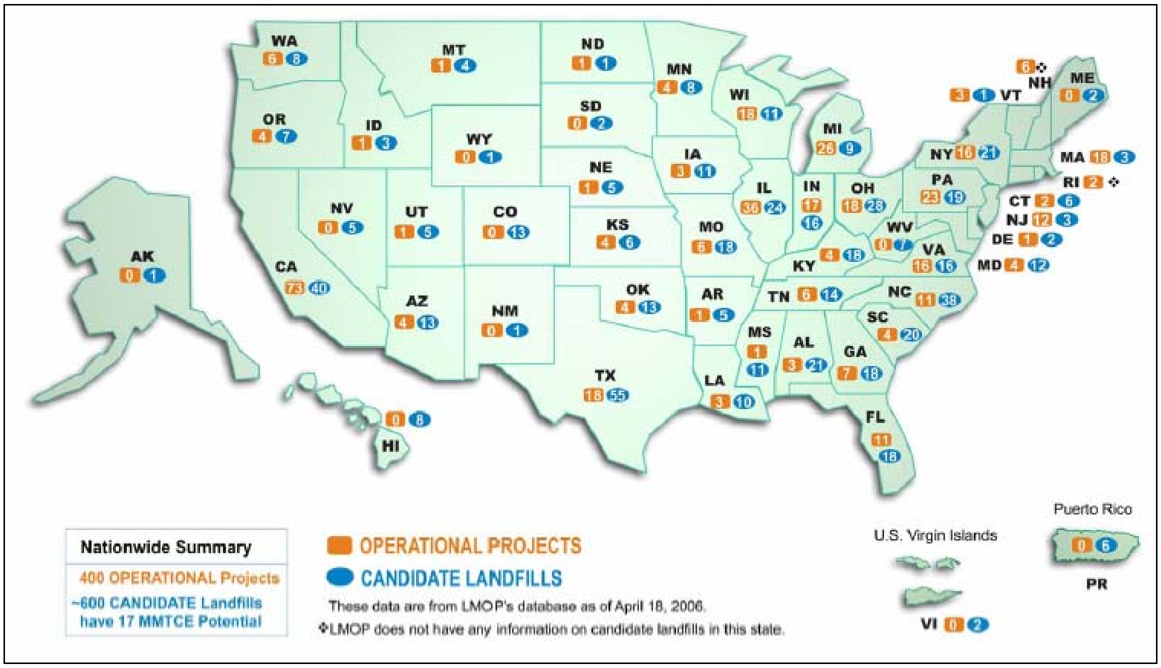


Figure B-3: Current and potential landfill gas energy projects (Source: EPA LMOP) [1]

B.4 Landfill gas energy projects in Indiana

According to the EPA LMOP, there are 17 landfill energy projects in Indiana. Table B-2 shows the characteristics of these seventeen projects. Eleven out of the seventeen projects have electricity generation and the remaining six operational landfill energy projects in Indiana use the landfill gas directly without converting it to electricity.

Six of the eleven landfill-to-electricity projects in Indiana are operated by Wabash Valley Power Association (WVPA), with a capacity listed by the LMOP as 18.4 MW. One project, the Twin Bridges II landfill in Danville is also operated by WVPA and is not listed by the LMOP [2]. When this capacity is included, the total electricity generating capacity operated by WVPA comes to 21 MW. This comprises over 60 percent of Indiana's 33 MW of landfill-based electricity generating capacity.

The other 12 operational landfill energy projects listed for Indiana by the EPA LMOP do not convert the biogas to electricity, but use it directly for such things as firing boilers, direct thermal use, in greenhouses, leachate evaporation, etc.

Sixteen landfills with 44 million tons of waste in Indiana are listed as candidate landfill energy projects in the EPA LMOP while an additional 63 landfills with 37 million tons of waste are listed as having potential for landfill energy projects. Table B-3 shows the characteristics of the sixteen "candidate" landfills.

Landfill Name	Landfill City	Landfill County	Waste In Place (tons)	Landfill Owner Organization	Project Developer Organization	LFGE Utilization Type (Direct-Use vs. Electricity)	LFGE Project Type	MW Capacity	LFG Flow to Project (mmscfd)
Wheeler RDF	Hobart	Porter	6,692,406	Waste Management, Inc.	Bio Energy Partners	Electricity	Reciprocating Engine	2.4	
Laidlaw South LF	Indianapolis	Marion	5,903,986	Republic Services, Inc.	Gas Recovery Systems, LLC	Electricity	Reciprocating Engine	4.4	
South Side Landfill	Indianapolis	Marion	15,000,000	Balkema	Granger Electric/Energy	Electricity	Gas Turbine	5.0	0.800
South Side Landfill	Indianapolis	Marion	15,000,000	Balkema	Granger Electric/Energy, Indianapolis Power & Light Company	Electricity	Microturbine	0.0	0.200
Oak Ridge RDF	Logansport	Cass	3,930,000	Indiana Waste Systems	Wabash Valley Power	Electricity	Reciprocating Engine	3.2	
Deercroft RDF	Michigan City	La Porte	10,196,460	Waste Management, Inc.	Wabash Valley Power	Electricity	Reciprocating Engine	2.4	
Jay County LF	Portland	Jay	1,770,714	Waste Management, Inc.	Wabash Valley Power	Electricity	Reciprocating Engine	3.2	
Liberty Landfill	Monticello	White	6,022,000	Waste Management, Inc.	Wabash Valley Power	Electricity	Reciprocating Engine	3.2	
Prairie View LF	Wyatt	St. Joseph	5,425,098	Waste Management, Inc.	Wabash Valley Power	Electricity	Reciprocating Engine	3.2	
Twin Bridges RDF	Danville	Hendricks	5,336,140	Waste Management, Inc.	Wabash Valley Power	Electricity	Reciprocating Engine	3.2	
Laubscher Meadows LF	Evansville	Vanderburgh	5,000,000	Allied Waste Services		Electricity	Reciprocating Engine	0.2	0.144
South Side Landfill	Indianapolis	Marion	15,000,000	Balkema	Granger Electric/Energy	Direct	Greenhouse		0.300
South Side Landfill	Indianapolis	Marion	15,000,000	Balkema	Granger Electric/Energy	Direct	Boiler		2.400
Randolph Farms LF	Modoc	Randolph	3,454,330	Randolph Farms, Inc.	Randolph Farms, Inc.	Direct	Greenhouse		
Earthmovers LF	Elkhart	Elkhart	4,091,598	Waste Management, Inc.	Shaw Environmental, Inc.	Direct	Leachate Evaporation		
Liberty Landfill	Monticello	White	6,022,000	Waste Management, Inc.	Shaw Environmental, Inc.	Direct	Leachate Evaporation		0.003
MacBeth Road Landfill	Fort Wayne	Allen	9,115,011	Republic Services, Inc.	Toro Energy, Inc.	Direct	Boiler		2.520

Table B-2: Operational Indiana landfill energy projects (Source: EPA LMOP) [1]

Landfill Name	City	County	Waste In Place (tons)	Year Opened	Closure Year	Owner Organization
Caldwell LF	Morristown	Shelby	2,437,688	1975	1997	Caldwell's Gravel Company
Clark-Floyd LF	Clarksville	Clark	4,033,944	1973		Clark Floyd Landfill Corp.
County Line LF	Argos	Fulton	2,628,000	1983	2054	Allied Waste Services
Elkhart County - CR 7 LF	Goshen	Elkhart	2,624,888	1978	2014	Elkhart County, IN
Hayes Landfill, Inc.		Henry	1,801,536	1975	2001	Hayes Landfill, Inc.
Medora Landfill	Medora	Jackson	1,594,000	1971	2005	Rumpke Waste, Inc.
New Paris Pike LF	Richmond	Wayne	1,900,000	1968	2021	Richmond Sanitary District
Northside LF		Boone	3,712,324	1975	1991	Landfill Owner
Onyx Blackfoot LF	Winslow	Pike	1,021,300	1988	2030	Onyx Waste Services, Inc.
Rumpke (Uniontown)	Crothersville	Jackson	1,639,263	1975	1993	Rumpke Waste, Inc.
Rumpke-Milan LF		Ripley	1,538,482	1975	1995	Rumpke Waste, Inc.
Sycamore Ridge Landfill	Pimento	Vigo	595,000	2003		Republic Services, Inc.
United Refuse LF	Fort Wayne	Allen	7,125,327	1970	2005	National Serv-All, Inc.
Victory Environmental Services Landfill	Terre Haute	Vigo	5,000,000	1990	2003	Republic Services, Inc.
Wabash Valley LF	Wabash	Wabash	4,488,770	1975	2018	Republic Services, Inc.
Worthington LF	Worthington	Greene	2,115,000	1982	2015	Republic Services, Inc.

Table B-3: Candidate Indiana landfill energy projects (Source: EPA LMOP) [1]

Using the data in the LMOP database, SUFG estimates a total potential for methane (natural gas equivalent) of 3.4 Bcf per year from Indiana landfills as follows:

- The current 7 operational landfills in Indiana that report using landfill gas directly in the LMOP database average a productivity of 12.6 million tons of waste in place to produce a million cubic feet (mmcf) of landfill gas per day.
- At this average productivity, the 233 million tons in the 98 Indiana landfills listed in the LMOP database can be estimated to have the potential to produce 18.5 mmcf/day of landfill gas.
- Assuming landfill gas is 50 percent methane, the annual methane production from the 98 landfills is 3.4 Bcf.
- With an assumed energy content of 1,000 Btu per cubic, the 3.4 Bcf of methane from Indiana's landfills listed in the LMOP database works out to 3,400,000 mmBtu of energy. This amount of energy is equivalent to 0.7 percent of the approximately 500,000,000 mmBtu of natural gas consumed in Indiana annually.

SUFG also estimates that Indiana landfills can support 88 MW of electricity generating capacity as follows:

- The current 11 landfills with installed electric generating average about 2.6 tons in place for each installed MW.
- The total waste in place in the 98 landfills in Indiana listed in the LMOP is approximately 233 million tons.
- At an average of 2.6 million tons per MW installed this results in a total 88 MW generating capacity.

The distribution of landfill and other solid waste disposal facilities in Indiana is shown in Figure B-4 [3]. Overlaid on the map supplied by the Indiana Department of Environmental Management (IDEM) is the location of the nine landfills that processed nearly three quarters of Indiana's municipal solid waste in 2005. Figure B-5 shows the distribution of disposal of waste at municipal solid waste landfills [4]. These large landfills would form prime candidates for landfill gas energy projects. They are the Newton County Landfill in Newton County; the County Line Landfill in Fulton County; the Sycamore Ridge Landfill in Vigo County; the South Side Landfill in Indianapolis; the Twin Bridges Facility in Hendricks County; the National Serv-All Landfill in Allen County; the Liberty Landfill in White County; the Laubscher Meadows Landfill in Evansville; and the Wabash Valley Landfill in Wabash County.

There are energy projects already operational in five of these landfills: the Liberty Landfill in White County; the Laubscher Meadows Landfill in Evansville; the South Side Landfill in Indianapolis; and the Twin Bridges Facility in Hendricks County.

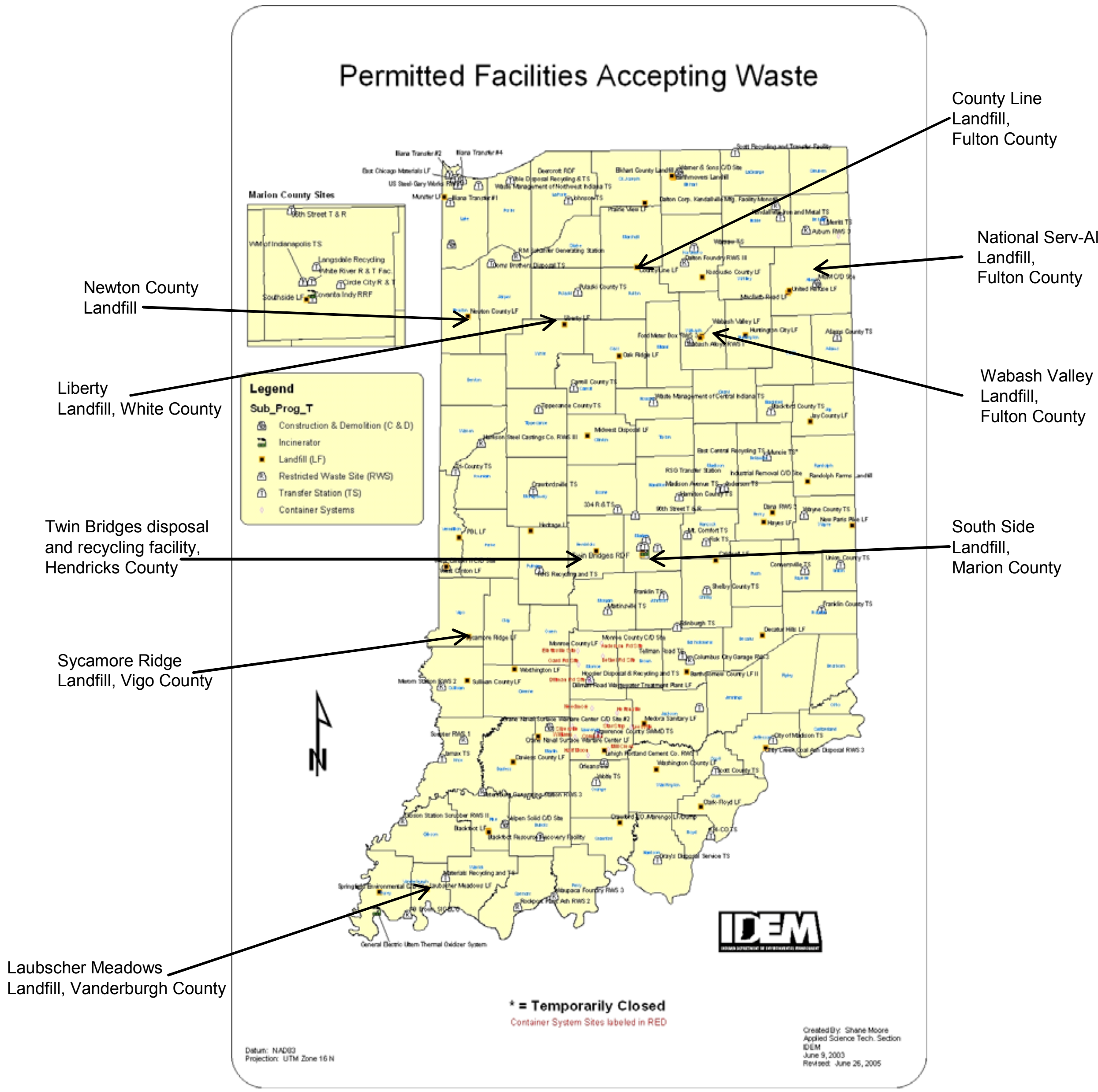


Figure B-4: The location of solid waste disposal facilities in Indiana with the top nine landfills in 2005 (Source: IDEM)

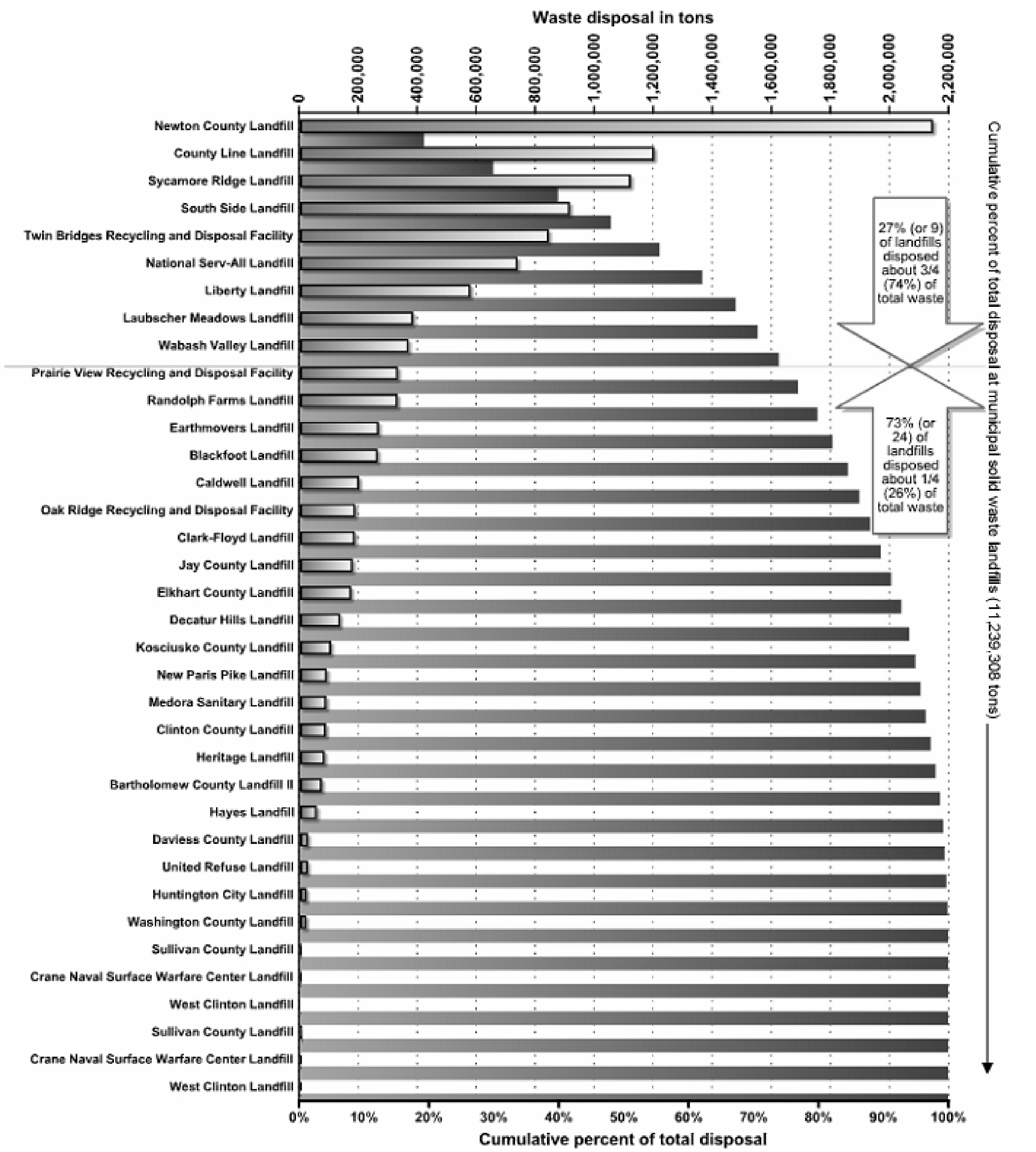


Figure B-5: Distribution of disposal of waste at municipal solid waste landfills during 2005 (Source: IDEM) [4]

B.5 References

1. United States Environmental Protection Agency, Landfill Methane Outreach Program, http://www.epa.gov/lmop/
2. Wabash Valley Power Association, http://www.wvpa.com/our_powerplants.aspx
3. Indiana Department of Environmental Management, Permitted facilities accepting waste. Map and list supplied by IDEM staff.
4. Indiana Department of Environmental Management, 2005 summary of Indiana solid waste data. http://www.in.gov/idem/programs/land/sw/papers.html#reports

Appendix C: Biogas from Wastewater Treatment Facilities

C.1 Introduction

As in other waste streams (animal manure and landfills), biogas is a byproduct of anaerobic decomposition of sludge waste at wastewater treatment plants. The methane content in this biogas is about the same as in landfill gas (50 percent), which is lower than biogas from livestock manure digesters (60 – 70 percent). The remaining 50 percent of the biogas is mostly carbon dioxide and small amounts of other compounds such hydrogen sulfide, siloxanes, and water vapor. The composition of biogas from wastewater treatment varies greatly among wastewater treatment plants because of the varying composition of the effluent in different communities. This, in addition to the scarcity of literature on wastewater treatment energy projects, makes it difficult to estimate the total potential of energy conversion from wastewater treatment facilities. In wastewater treatment facilities where anaerobic digestion is already part of the process, the methane gas is essentially a free fuel and is in most cases already in use to some degree to supplement the sludge heating requirements in the plants.

The economic viability of adding an electric generator depends on the price of electricity, which helps explain the large concentration of wastewater combined heat and power (CHP) installations in such high electricity cost states such as California. The economics of installing an electric generator are less attractive in a state with relatively low electricity prices such as Indiana.

C.2 Economics of wastewater energy projects

The typical costs of technologies used for electricity generation from biogas from anaerobic digesters in wastewater plants (also in livestock manure or landfills) are shown in Table C-1. The lowest capital cost technology is the combustion turbine, but its relatively large size makes it unsuitable for most wastewater treatment plants, where most of the power plants are in the multiple kW range.

	Size Range (kW)	Installed Cost ($/kW)
Reciprocating Engine	75 – 5,000	1,000 – 1,700
Microturbine	30 – 300	1,800 – 3,000
Combustion Turbine	> 1,000	900 – 2,100
Stirling Engine	55	1,500 – 2,000[a]
Fuel Cell	200	4,000 – 5,000

[a] assuming $300-$500/Kw installation cost for Stirling engines

Table C-1: Capital cost of generating technologies (Source: Resource Dynamics Corporation) [1]

In wastewater treatment facilities already using the anaerobic digestion process, the cost of the digesters have already been incurred. Therefore, the cost of electricity will be primarily the recovery of the capital cost of the electricity generating equipment. Using the capital cost given by the resource Dynamics Corporation and shown in Table C-1, SUFG estimates the cost of electricity associated with the various generator technologies to be as shown in Table C-2. The estimates assume a 5 year pay back period and 80 percent capacity factor[23] for the power plant. Although the cost of electricity will change depending on the assumptions made on capacity factor and cost of capital, the cost associated with generating electricity using the internal combustion engine or a gas turbine compares quite favorably with the average cost of generating on the grid.

	Levelized cost of electricity (cents/kWh)
Reciprocating Engine	4 – 9
Microturbine	7 – 12
Combustion Turbine	4 – 8
Stirling Engine	5 – 7
Fuel Cell	13 – 18

Table C-2: Levelized cost of electricity from wastewater treatment facilities

C.3 State of wastewater energy projects nationally

According to the EPA Combined Heat and Power Partnership [2], there are wastewater generating systems in 23 states representing 176 MW of generating capacity, with California and Oregon leading in the number of generating systems with 18 and 10 sites, respectively.

[23] Capacity factor is the ratio, expressed as a percentage, of the operating load of an electric power generating system for a period of time to the capacity rating of the system during that period. A system that is not used has a capacity factor of 0 percent, while a system used at full capacity all the time has a capacity factor of 100 percent.

Figure C-1: Wastewater treatment plants with electricity generation (Source: EPA CHP) [3]

C.4 Wastewater energy projects in Indiana

SUFG is aware of one electricity generating project in operation in Indiana. This is in the wastewater treatment works in Jasper in Dubois County. It consists of a combined heat and power, internal combustion engine rated for 65 kW. From its various cooling systems approximately 3,000 Btu/hour of waste heat is captured and used to supplement the plants heating needs. The plant has been operating since 1994 and, according to the staff at the plant, has performed very well with significant savings. Figures C-2 and C-3 illustrate some of the aspects of the biogas energy system at the Jasper Wastewater treatment facility. The biogas is captured from the anaerobic digester as shown in Figure C-2. The air-based inflatable bladder on top of the digester is used to maintain the biogas at a constant pressure. This constant pressure is vital for the optimal performance of the generator.

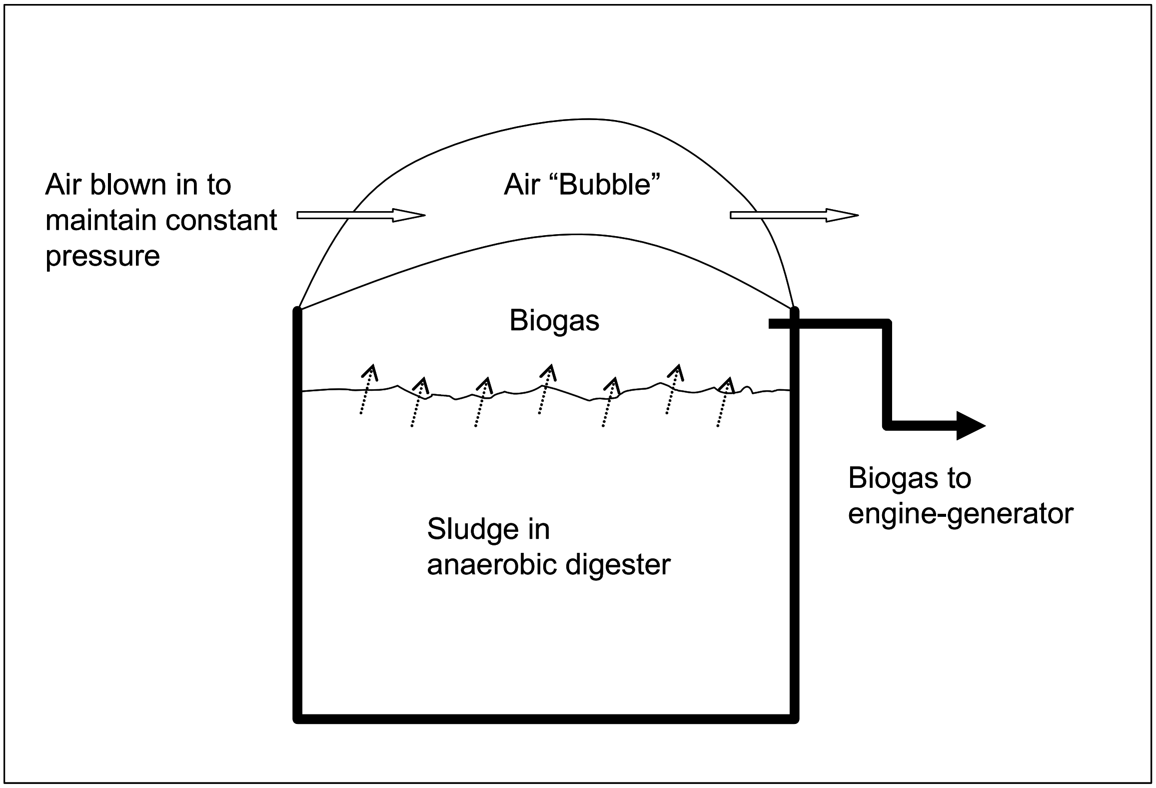


Figure C-2: Inflatable bladder system at Jasper wastewater treatment works

In addition to the inflatable bladder, a supplemental supply of natural gas is provided to keep the engine running optimally in those moments when the biogas pressure drops below the engine specifications. A pressure operated valve is used to automatically switch the fuel supply to natural gas whenever the pressure falls too low and to switch back to the digester biogas when the biogas pressure is returns to a sufficient level.

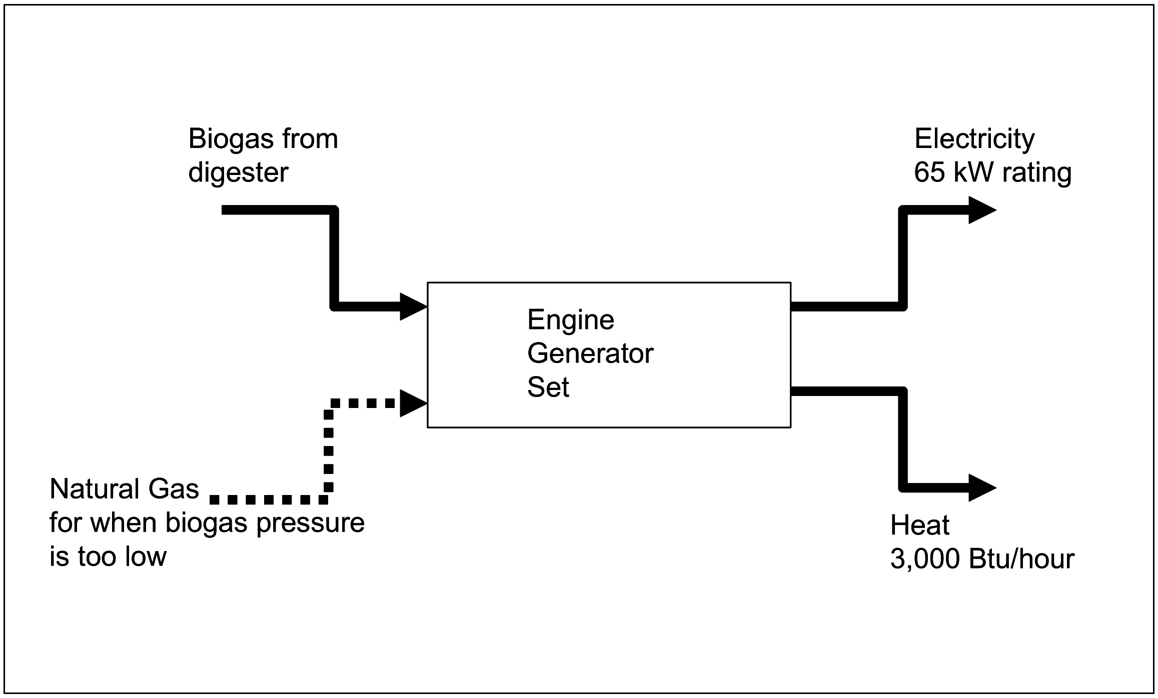


Figure C-3: Co-generation system at Jasper wastewater treatment works

At the time of the installation of the Jasper project in 1994, the capital cost of the engine generator set was approximately $750/kW. Assuming a 5 year payback period and an 80 percent capacity factor, this translates to a levelized cost of 2.1 cents/kWh. The maintenance cost of the unit was approximately 1.9 cents/kWh, for a total levelized cost of electricity of 4 cents/kWh. An additional $6,000 was incurred later in the project for the installation of a power factor correction unit. The staff at the Jasper wastewater treatment facility estimated that the savings considering only the avoided cost of utility electricity was almost $10,000. If the approximately 3,000 Btu/hour heat captured from the engine were included, the savings would be higher.

SUFG is aware of two other cities considering the possibility of adding electricity generation equipment to their waste water treatment facilities. The city of West Lafayette made an announcement to that effect in April 2006, and there are reports that the city of Reynolds under the Bio-Town USA project is planning on teaming up with the neighboring cities of Monticello and Monon to build a joint wastewater to energy project.

In the absence of more accurate estimates in literature, SUFG estimates the potential for energy conversion from wastewater treatment facilities as follows. According to approximate "rules of thumb" in a report by the Federal Energy Management Program (FEMP) [4], a typical wastewater treatment plant processes 1 million gallon per day of wastewater for every 10,000 in population and anaerobic digesters are generally used when the wastewater flow is greater than 3 million gallon per day. From these two generalizations, it is assumed that anaerobic digesters are most likely to be found in Indiana in cities with a population greater than 30,000. Further, FEMP estimates that each million gallon per day of wastewater processed can support up to 35 kW of electricity generating capacity.

According to population estimates by the Indiana Business Research Center (IBRC) at Indiana University, there were 28 cities in Indiana with a projected population of greater than 30,000 as of July 1, 2005 [5]. The total population in these cities at that time was estimated to be 2.4 million. The 28 Indiana cities and their estimated population in July 2005 are shown in Table C-3.

Geographic Area	**Population estimate July 1 2005**
Indianapolis (balance)	784,118
Fort Wayne	223,341
Evansville	115,918
South Bend	105,262
Gary	98,715
Hammond	79,217
Bloomington	69,017
Muncie	66,164
Lafayette	60,459
Carmel	59,243
Anderson	57,500
Fishers town	57,220
Terre Haute	56,893
Elkhart	52,270
Mishawaka	48,497
Kokomo	46,178
Greenwood	42,236
Lawrence	40,959
Columbus	39,380
Noblesville	38,825
Richmond	37,560
New Albany	36,772
Portage	35,687
Michigan City	32,205
Merrillville town	31,525
Goshen	31,269
East Chicago	30,946
Marion	30,644

Table C-3: Indiana cities with a population greater than 30,000 in 2005 (Source: IBRC)

At 100 gallons per individual this results in 240 million gallons per day of wastewater for the 28 cities combined. At 35 kW for each million gallons per day of wastewater processed, the total electricity generating potential from these 28 cities from wastewater treatment plants is approximately 8.4 MW.

According to the Indiana Department of Environmental Management (IDEM) there are a total of 856 permitted sanitary wastewater treatment facilities comprised of 466 owned by municipalities, 48 by the state and 342 semi-publicly owned. There are 113 facilities with greater than one million gallons of day of wastewater. Figure C-4 shows the location of all sanitary wastewater facilities in Indiana [6].

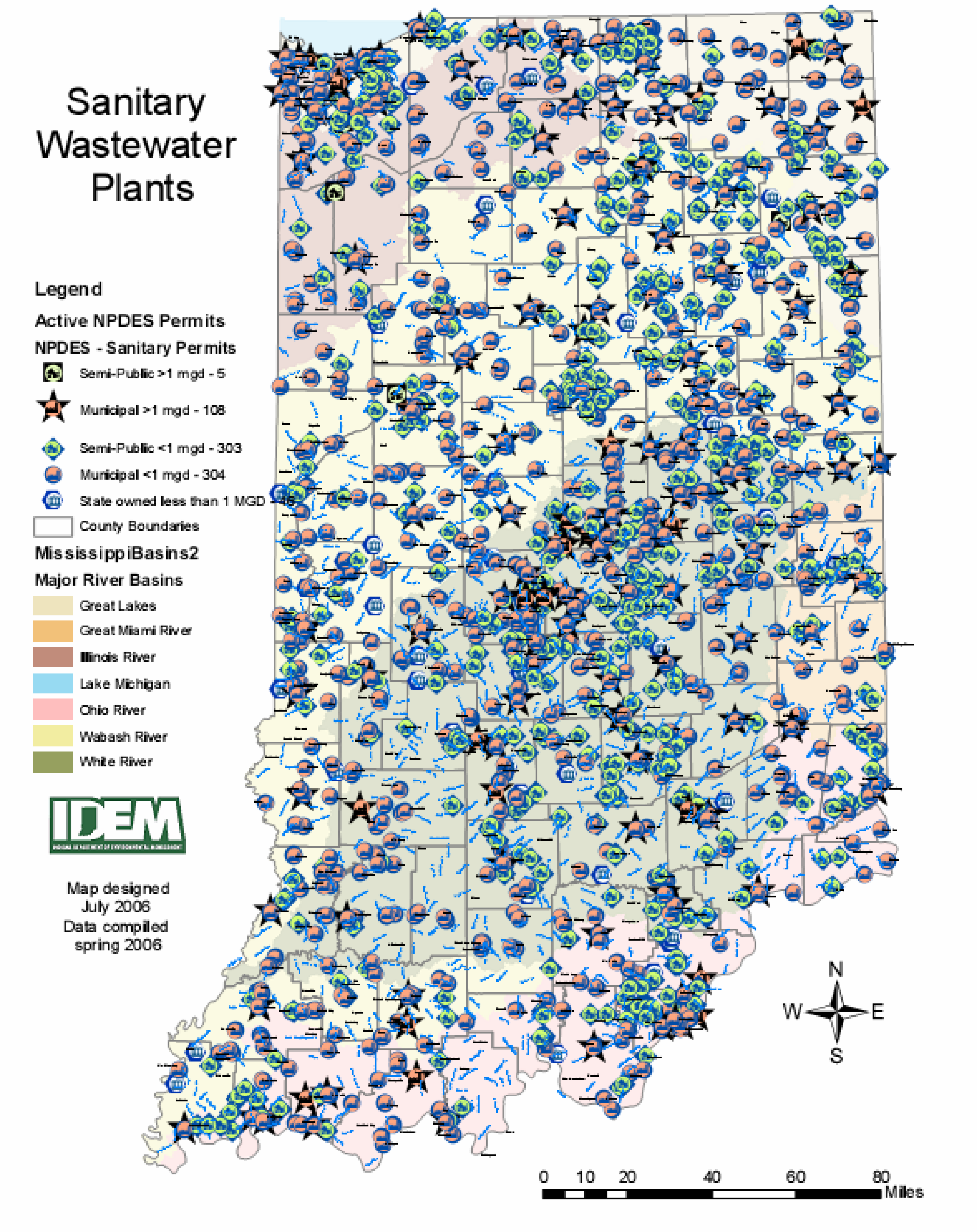


Figure C-4: Location of wastewater treatment facilities in Indiana (Source: IDEM)

One should be aware though that this estimate is a very rough estimate. The energy potential from wastewater varies greatly from city to city depending on such things as the source of the wastewater (residential, industrial, etc.) and the travel time of the wastewater before it gets to the treatment facility. In general, each treatment facility is unique in terms of the combination of flow patterns and physical characteristics of its wastewater, which provides a barrier to standardized design and operation of wastewater to energy projects.

C.5 References

1. Lemar, Paul Jr., Resource Dynamics Corporation, “CHP systems for landfills and wastewater treatment plants,” presentation at the CHP and Bioenergy for Landfills and Wastewater Treatment Plants workshop, hosted by the Intermountain CHP Center, Salt Lake City, Utah, August 11, 2005. http://www.intermountainchp.org/events/landfills/default.htm
2. U. S. Environmental Protection Agency, Combined Heat and Power partnership, http://www.epa.gov/CHP/project_resources/wastewater.htm
3. Crossman, Kim, U. S. Environmental Protection Agency, Combined Heat and Power partnership, “Benefits of CHP and clean distributed generation,” presentation at the CHP and Bioenergy for Landfills and Wastewater Treatment Plants workshop, hosted by the Intermountain CHP Center, Salt Lake City, Utah, August 11, 2005. http://www.intermountainchp.org/events/landfills/default.htm
4. U. S. Department of Energy, Federal Energy Management Program, Wastewater treatment gas to energy for Federal facilities. http://www1.eere.energy.gov/femp/financing/superespcs_biomass.html
5. Indiana Business Research Center, Kelley School of Business , Indiana University STATS Indiana, http://www.stats.indiana.edu/pop_totals_topic_page.html
6. Indiana Department of Environmental Management, Sanitary wastewater plants map, supplied by IDEM staff.