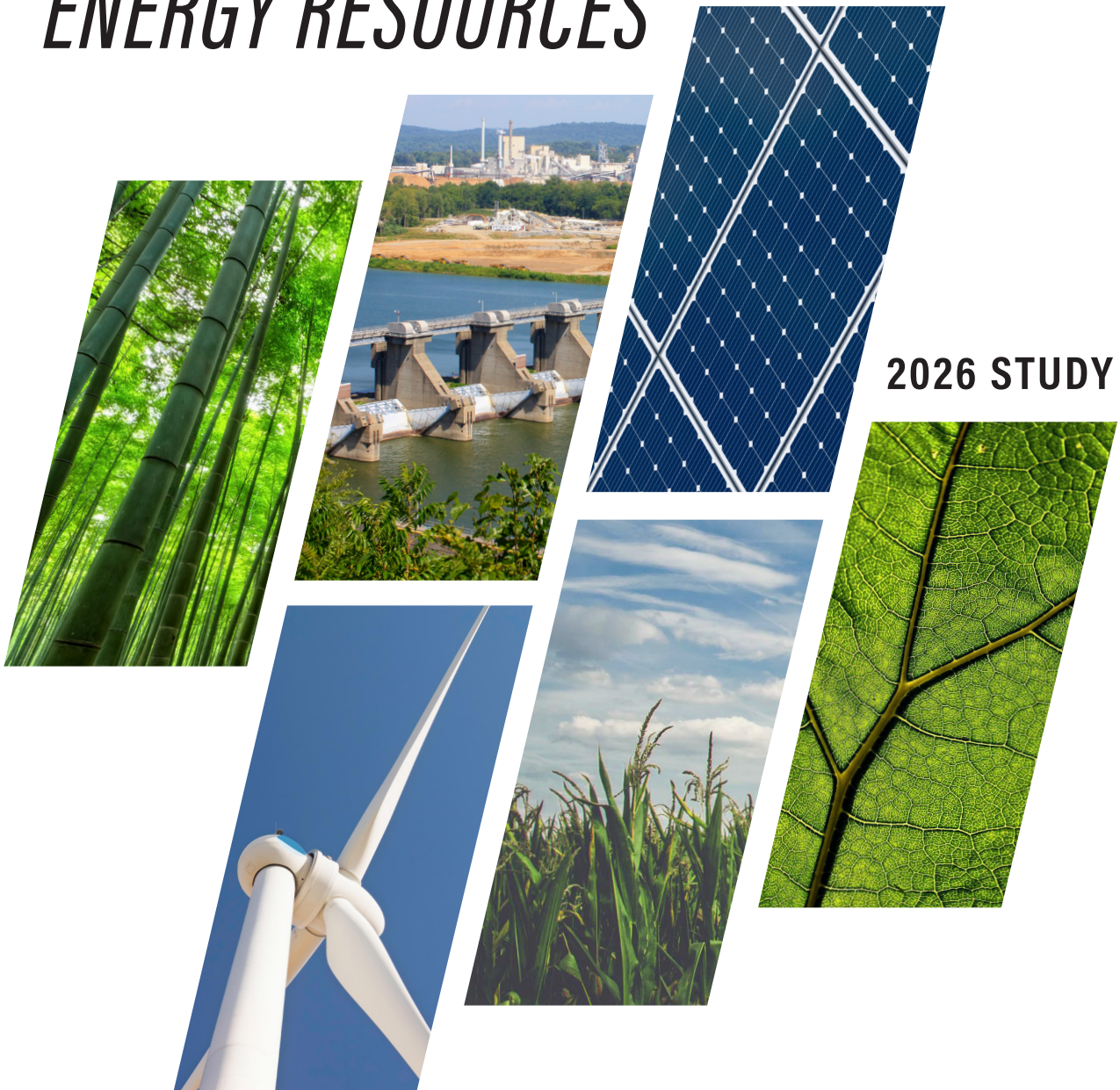


STATE UTILITY FORECASTING GROUP

INDIANA RENEWABLE ENERGY RESOURCES



2026 STUDY



Purdue Policy Research Institute

2026 INDIANA RENEWABLE ENERGY RESOURCES STUDY

State Utility Forecasting Group

Purdue University

West Lafayette, Indiana

Liwei Lu

Tim Phillips

Sunil Maheshwari

Marco Velastegui

Angela Dillworth

September 2026

Table of Contents

List of Figures	iii
List of Tables	vii
Acronyms and Abbreviations	ix
Foreword	xiii
1. Overview	1
1.1 Trends in renewable energy consumption in the United States	1
1.2 Trends in renewable energy consumption in Indiana	6
1.3 Cost of renewable resources	12
1.4 Federal Renewable Energy Incentives.....	16
1.5 References.....	19
2. Energy from Wind.....	21
2.1 Introduction.....	21
2.2 Economics of wind energy.....	23
2.3 State of wind energy nationally	29
2.4 Wind energy in Indiana.....	37
2.5 Incentives for wind energy.....	41
2.6 References.....	44
3. Dedicated Energy Crops.....	49
3.1 Introduction.....	49
3.2 Economics of energy crops.....	54
3.3 State of energy crops nationally.....	58
3.4 Energy crops in Indiana	60
3.5 Incentives for energy crops.....	63
3.6 References.....	66
4. Organic Waste Biomass	71
4.1 Introduction.....	71
4.2 Economics of organic waste biomass	73
4.3 State of organic waste biomass nationally	76
4.4 Organic waste biomass in Indiana	80

4.5 Incentives for organic waste biomass	87
4.6 References.....	91
5. Solar Energy	95
5.1 Introduction.....	95
5.2 Economics of solar technologies	98
5.3 State of solar energy nationally.....	100
5.4 Solar energy in Indiana	103
5.5 Incentives for solar thermal energy.....	104
5.6 References.....	106
6. Photovoltaic Cells.....	109
6.1 Introduction.....	109
6.2 Economics of PV systems.....	112
6.3 State of PV systems nationally	116
6.4 PV systems in Indiana.....	119
6.5 Incentives for PV systems.....	122
6.6 References.....	126
7. Hydropower.....	131
7.1 Introduction.....	131
7.2 Economics of hydropower	135
7.3 State of hydropower nationally	138
7.4 Hydropower in Indiana	142
7.5 Incentives for hydropower	145
7.6 References.....	147
8. Underground Pumped Storage Hydropower	151
8.1 Introduction.....	151
8.2 Economics of underground pumped storage hydropower	153
8.3 State of underground pumped storage hydropower nationally	156
8.4 Underground pumped storage hydropower in Indiana	158
8.5 Incentives for underground pumped storage hydropower	159
8.6 References.....	160

List of Figures

1-1	Renewable energy consumption in the U.S. (1949-2025)	1
1-2	U.S. total energy consumption by source (1949-2025)	2
1-3	U.S. total energy consumption by energy source in 2025	3
1-4	Renewable electricity generation in the U.S. (1949-2025).....	4
1-5	U.S. electricity generation by source (1949-2025)	5
1-6	Net U.S. electricity generation by energy source in 2025	5
1-7	Renewables share of Indiana total energy consumption (1960-2024).....	6
1-8	Renewables share of Indiana electricity generation (1990-2024).....	7
1-9	Wind energy capacity in Indiana	7
1-10	Growth in installed PV capacity in Indiana	9
1-11	Average construction cost of generation installed 2013 to 2024.....	13
1-12	Estimated generating technologies capital costs.....	14
1-13	Estimated generating technologies fixed and variable O&M costs	15
2-1	Horizontal wind turbine configuration.....	21
2-2	Estimated capital costs of various electric generation options	24
2-3	Average construction cost of generators installed from 2013 to 2024 in the U.S.	25
2-4	Installed wind power project costs 1982 to 2024.....	26
2-5	Estimated generating technologies fixed and variable O&M costs	27
2-6	Average O&M costs for available data years	28
2-7	Wholesale energy value of wind.....	29
2-8	U.S. wind capacity growth.....	30
2-9	Renewable portfolio standards across the U.S.....	31
2-10	100-meter U.S. wind resource map.....	34
2-11	Utility-scale wind farm capacity installed in Indiana	37
2-12	Indiana wind speed at 100 meters height.....	39
2-13	Indiana wind speed at 50 meters height.....	40
3-1	Energy crops included in the 2016 Billion-Ton Report.....	51
3-2	Schematic of steps in the bioenergy conversion process	52
3-3	Production of energy crops at various farm-gate prices for select years	55
3-4	Supply curves of potential herbaceous energy crop production for select years under base-case assumptions	55
3-5	Supply curves of potential woody energy crop production for select years under base-case assumptions	56
3-6	Bioenergy crop trial stations	59
3-7	Estimated shares of energy crops and agricultural residues supplied at \$60 per dry ton in 2030.....	61

3-8	Projected production of energy crops at farmgate price of \$70 per dry ton in Indiana for various scenarios in BT23	62
4-1	Supply of potential production from primary crop residues at \$70 per dry short ton (2022\$) under 2023 Billion-Ton Study Mature-market medium assumptions	75
4-2	U.S. renewable energy consumption 1949-2025	76
4-3	Landfill gas projects.....	78
4-4	Renewables share of Indiana total energy consumption (1960-2023).....	81
5-1	The layout of a flat-plate collector.....	95
5-2	A parabolic trough CSP system	96
5-3	A linear Fresnel CSP system.....	97
5-4	A power tower CSP system	97
5-5	A dish/engine CSP system.....	98
5-6	Solar power resource in the U.S.	100
5-7	Solar thermal power capacity installed in the U.S.	101
5-8	Direct normal solar radiation (flat-plate collector) in Indiana	103
6-1	PV cell operation.....	109
6-2	Illustration of a cell, module, panel and array of a PV power plant	110
6-3	Illustration of CPV	111
6-4	Installed price trends among stand-alone PV systems.....	112
6-5	Installed project capital cost of utility-scale PV systems.....	113
6-6	Average construction cost of generation installed in the U.S. (2013-2024).....	113
6-7	Estimated generating technologies capital costs.....	114
6-8	Estimated generating technologies fixed and variable O&M costs	115
6-9	Installed U.S. PV capacity	116
6-10	Renewable portfolio standards and goals	117
6-11	Growth in Installed PV capacity in Indiana.....	119
7-1	Schematic of an impoundment hydropower facility	132
7-2	Schematic of a diversion hydropower facility	132
7-3	Oakdale run-of-river hydropower plant in Carroll County	133
7-4	Micro hydropower facility	133
7-5	Schematic of a PSH facility	134
7-6	Capital cost of new U.S. hydropower plants constructed	135
7-7	Estimated generating technologies fixed and variable O&M costs	137
7-8	Net renewable electricity generation in the U.S. (1949-2025)	138
7-9	Non-powered dams with potential capacity over 1 MW	140
7-10	Renewables share of Indiana net electricity generation (1990-2024).....	143
8-1	Schematic of a pumped storage hydropower plant	152
8-2	Schematic of an underground pumped storage hydropower plant.....	153

8-3	Capital cost of underground pumped storage hydropower plant in an abandoned coal mine in Germany.....	154
8-4	Location of inactive mines in Indiana.....	158

List of Tables

1-1	Operating large-scale Solar farms in Indiana.....	10
1-2	Utility-scale PV projects under construction in Indiana.....	10
1-3	Approved utility-scale PV projects in Indiana not yet under construction.....	11
2-1	Wind resource classification.....	22
2-2	Installed wind power by state at end of 2024	32
2-3	U.S. wind power rankings: top 20 states.....	33
2-4	Offshore wind projects development pipeline	35
2-5	Offshore wind capacity targets and mandates	36
2-6	Indiana wind farms; operating and under construction.....	38
3-1	Integrated biorefinery projects.....	53
3-2	Commercial integrated biorefinery projects	53
3-3	Ethanol plants in Indiana	57
3-4	Average farm-gate cost (\$/dry ton) for producing switchgrass in Indiana	62
3-5	Cost by category for producing corn stover, switchgrass, and miscanthus in Wildcat Creek Watershed.....	63
4-1	Summary of secondary agricultural residues and wastes potential under 2023 Billion-Ton Study Mature-market medium assumptions.....	75
4-2	Summary of animal manures potential under 2023 Billion-Ton Study Mature-market medium assumptions.....	75
4-3	Location of the 75 municipal solid waste-to-energy plants in the U.S.	77
4-4	Top ten states for potential electricity generation from swine and dairy farms.....	79
4-5	Wastewater treatment combined heat and power systems in the U.S.....	80
4-6	Electricity generating plants at Indiana landfills	82
4-7	Wabash Valley Power Association landfill electricity projects.....	82
4-8	Potential electricity generating capacity at Indiana landfills	83
4-9	Operational anaerobic digesters in Indiana.....	84
4-10	Potential electricity generating capacity at Indiana concentrated animal feeding operations	85
4-11	Potential electricity generating capacity at Indiana wastewater treatment plants.....	86
4-12	Estimated agricultural biomass potential in Indiana.....	86
4-13	Estimated forest biomass potential in Indiana	87
4-14	Estimated animal manures potential in Indiana.....	87
5-1	Estimated capital cost of CSP plants in the U.S.	99
5-2	Operating concentrating solar power plants in the U.S.	102
5-3	Concentrating solar power plants in the U.S. that are no longer operating	102

6-1	Operating large-scale solar farms in Indiana	120
6-2	Utility-scale PV projects under construction in Indiana	121
6-3	Approved utility-scale PV projects in Indiana not yet under construction	121
7-1	Initial capital costs of hydropower projects	136
7-2	Ten largest hydropower plants in the U.S.	139
7-3	Top ten U.S. hydropower generating states in 2024	139
7-4	Top ten U.S. hydropower capacity states at the end of 2024	139
7-5	Hydropower potential from NPDs by state	141
7-6	Potential capacity from NPDs owned by the U.S. Army Corps of Engineers	142
7-7	Indiana NPDs with potential capacity over 1 MW	144
7-8	Potential capacity from non-powered dams owned by the U.S. Army Corps of Engineers in Indiana	145

Acronyms and Abbreviations

AC	Alternating current
AD/CVD	Antidumping and Countervailing Duty
AEO	Annual Energy Outlook
AES	AES Indiana (formerly Indianapolis Power and Light)
AgSTAR	A joint program of EPA and USDA that promotes the use of biogas recovery systems to reduce methane emissions from livestock waste
AMP	American Municipal Power
BAU	Business-as-Usual
BETO	Bioenergy Technologies Office
BoS	Balance-of-system
BT23	2023 Billion-Ton Report
Btu	British thermal unit
CAISO	California Independent System Operator
CCS	Carbon capture and sequestration
CEITC	Clean Electricity Investment Tax Credit
CEPTC	Clean Electricity Production Tax Credit
CHP	Combined heat and power
CNG	Compressed natural gas
CO ₂	Carbon dioxide
CPV	Concentrating photovoltaic
CSP	Concentrating solar power
CSPV	Crystalline silicon photovoltaic
DC	Direct current
DNR	Indiana Department of Natural Resources
DOE	U.S. Department of Energy

DSIRE	Database of State Incentives for Renewables & Efficiency
EDG	Excess Distributed Generation
EDPR	EDP Renewables Corporation
EERE	U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FHA	Federal Housing Administration
ft	Foot/feet
ft ³	Cubic feet
GIS	Geographic Information System
GW	Gigawatt
GWh	Gigawatt-hour
IC	Indiana Code
ICCT	International Council on Clean Transportation
IDEM	Indiana Department of Environmental Management
IEA	International Energy Agency
I&M	Indiana Michigan Power
IMPA	Indiana Municipal Power Agency
INL	Idaho National Laboratory
IRA	Inflation Reduction Act of 2022
IREC	Interstate Renewable Energy Council
IRS	Internal Revenue Service
ISO-NE	ISO New England
ITC	Investment Tax Credit

IURC	Indiana Utility Regulatory Commission
KDF	Bioenergy Knowledge Discovery Framework
kW	Kilowatt
kWh	Kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LLC	Limited liability company
LMOP	Landfill Methane Outreach Program
m/s	Meters per second
MACRS	Modified accelerated cost-recovery system
MGD	Million gallons per day
MISO	Midcontinent Independent System Operator
mmBtu	Million British thermal units
MMGY	Million gallons per year
mmscfd	Million standard cubic feet per day
MMTCO ₂ e/yr	Million metric tons of carbon dioxide-equivalent per year
mph	Miles per hour
MSW	Municipal solid waste
MTBE	Methyl tertiary-butyl ether
MW	Megawatt
MWAC	Megawatts alternating current
MWh	Megawatt-hour
NAABB	National Alliance for Advanced Biofuels and Bioproducts
NIPSCO	Northern Indiana Public Service Company
NLR	National Laboratory of the Rockies
NO _x	Nitrogen oxides
NPD	Non-powered dam
NREL	National Renewable Energy Laboratory

NSD	New stream-reach development
NYISO	New York Independent System Operator
O&M	Operation and maintenance
OBBBA	One Big Beautiful Bill Act of 2025
OED	Indiana Office of Energy Development
ORNL	Oak Ridge National Laboratory
PJM	PJM Interconnection
POLYSYS	Policy Analysis System Model
PSH	Pumped Storage Hydropower
PTC	Production Tax Credit
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
RBRH	Regional Biomass Resource Hubs

Foreword

This report represents the twenty-fourth annual study of renewable resources in Indiana performed by the State Utility Forecasting Group. It was prepared to fulfill SUFG’s obligation under Indiana Code § 8-1-8.8 (added in 2002) to “conduct an annual study on the use, availability, and economics of using renewable energy resources in Indiana.” The code was further amended in 2011 and 2022, clarifying the topics to be covered in the report.

The report consists of eight chapters. Chapter one provides an overview of the renewable energy industry in the United States and in Indiana. It discusses trends in the penetration of renewable energy into the energy supply, both nationally and in Indiana. It also discusses the federal incentives in the Inflation Reduction Act of 2022 and, more recently, the One Big Beautiful Bill Act of 2025 for renewable and clean energy resources.

The next seven chapters each cover a specific renewable resource in the following order: energy from wind, dedicated crops grown for energy production, organic biomass waste, solar thermal energy, photovoltaic cells, hydropower, and underground pumped storage hydropower. This last chapter on underground pumped storage hydropower was added to the list in 2022. The chapters are arranged to maintain the format in the previous reports as follows:

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

This report was prepared by the State Utility Forecasting Group. The information contained in it should not be construed as advocating or reflecting any other organization’s views or policy position. For further information, contact SUFG at:

State Utility Forecasting Group
2550 Northwestern Ave.
West Lafayette, IN 47906
Phone: 765-494-4223
e-mail: sufg@purdue.edu
<https://www.purdue.edu/discoverypark/sufg/>

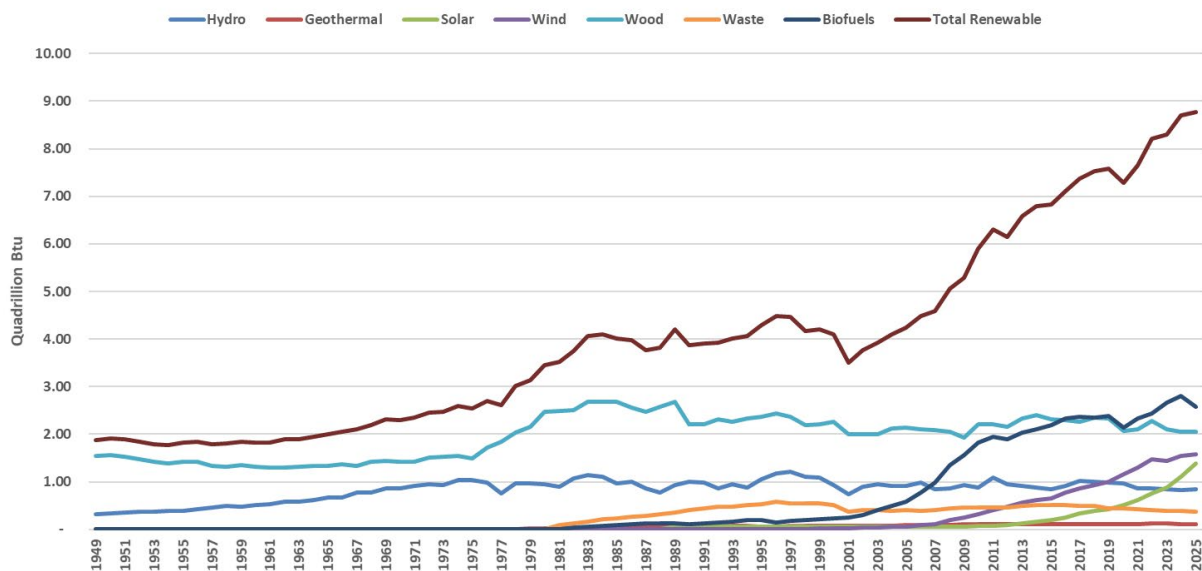
1. Overview

This chapter presents overviews of the trends in renewable energy consumption in the U.S. and in Indiana, the cost of renewable resources, and incentives in the Inflation Reduction Act (IRA) of 2022 and the One Big Beautiful Bill Act (OBBBA) of 2025.

1.1 Trends in renewable energy consumption in the United States

Figure 1-1 shows the amount of renewable energy in quadrillion British thermal units (Btu) consumed in the U.S. from 1949 to 2025 as provided by the U.S. Energy Information Administration (EIA). Until the early 2000s, woody biomass and hydroelectricity were the dominant sources of renewable energy. Since then, biofuels (mainly corn-based ethanol), wind, and solar have grown rapidly as sources of renewable energy, with biofuels becoming the primary source starting in 2016. In 2025, biofuels, wind, and solar combined to account for 63 percent of the 8.8 quadrillion Btu of renewable energy consumed in the U.S., while hydroelectricity and wood accounted for 33 percent. The two main factors that caused the rise in corn ethanol use as a fuel are its use as a replacement for the oxygenating additive methyl tertiary-butyl ether (MTBE) in gasoline, which started being phased out in 2000, and the Federal Renewable Fuel Standard (RFS), first authorized in the 2005 Energy Policy Act and then expanded in 2007, which created mandates for the production of biofuels. Biofuel consumption declined slightly in 2025, primarily because biodiesel and renewable diesel use fell amid uncertainty surrounding federal tax credits and RFS policies, and due to weak blending economics, which reduced demand for biodiesel and renewable diesel [1].

Figure 1-1: Renewable energy consumption in the U.S. (1949-2025) (Data source: EIA [2])



The rapid increase in wind energy began with the introduction of the federal Production Tax Credit (PTC) in 1992 and continued with the enactment of RFSs in several states. The rapid expansion in solar capacity installations is attributed to a combination of state RPS and the federal government's 30 percent Investment Tax Credit (ITC). Renewable energy resources received an additional boost in August 2022 with the enactment of the IRA, which transitioned the legacy PTC and ITC framework toward technology-neutral clean electricity credits under Sections 45Y and 48E for qualifying facilities placed in service after December 31, 2024. Under the IRA, these credits were scheduled to begin phasing out after the later of 2032 or the year in which U.S. electricity-sector greenhouse gas emissions fell to 25 percent of 2022 levels. However, the OBBBA of 2025 established a separate accelerated termination rule for wind and solar incentives. Wind and solar facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the Section 45Y CEPTC or Section 48E CEITC. Facilities that began construction on or before July 4, 2026 are not subject to this accelerated termination rule but remain subject to applicable beginning-of-construction and continuity requirements. Reductions in the cost of constructing wind and solar facilities have also contributed to the growth of these generation types [3, 4].

Despite the rapid growth in energy from renewable resources over the last two decades, as shown in Figure 1-1 above, their contribution remains quite small. Figure 1-2 shows the sources of total energy consumed in the U.S. from 1949 to 2025. In 2025, the share of renewables in total national energy consumption was 8.6 percent. Fossil fuels continue to dominate the energy landscape, contributing 83.8 percent of total energy consumed in 2025. The nuclear energy share was in the same range as that of renewable resources (7.7 percent).

Figure 1-2: U.S. total energy consumption by source (1949-2025) (Data source: EIA [5])

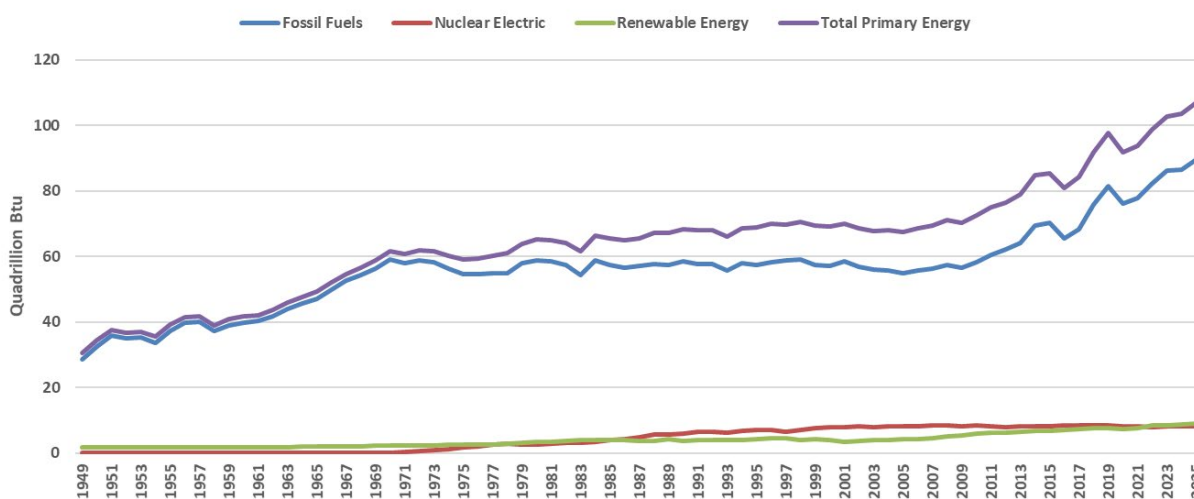


Figure 1-3 shows the contribution of the various energy sources to the total energy consumed in the U.S. in 2025. Petroleum (37 percent) and natural gas (36 percent) remain the largest sources of energy. Coal's share was 9 percent, and the total renewable energy share was also 9 percent.

Among renewable resources, biomass (including wood, biofuels, municipal solid waste, landfill gas, and others) accounted for 56 percent of the total renewable energy. Wind energy's contribution remained at 18 percent of renewable energy in 2025, compared with hydroelectricity's 9 percent. Solar energy's contribution was 16 percent, and geothermal's share stayed at 1 percent.

Figure 1-3: U.S. total energy consumption by energy source in 2025 (Data source: EIA [2, 6])

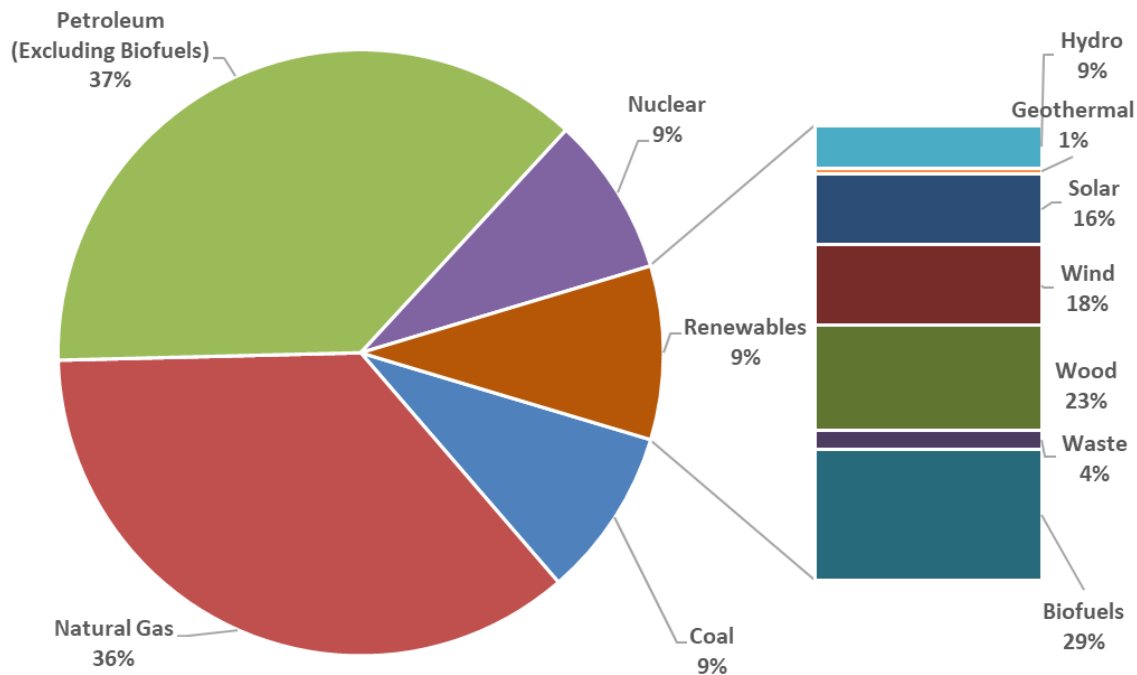
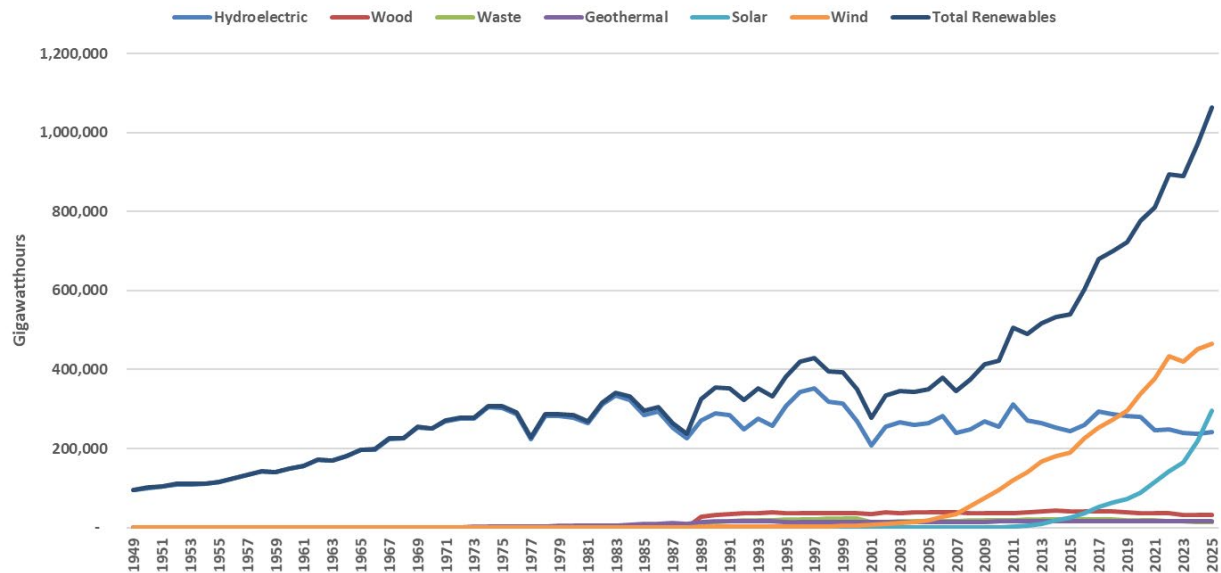


Figure 1-4 shows the growth of renewable resources in electricity generation in the U.S. from 1949 to 2025. Through the late 1980s, hydroelectricity was the sole significant source of renewable electricity generation, after which wood began to gain prominence, contributing approximately 10 percent of annual renewable generation. In the early 2000s, wind energy's share of electricity generation began to rise rapidly. In 2025, wind accounted for 44 percent of renewable electricity generated, marking the seventh year it surpassed hydroelectricity, whose share of total renewable electricity had dropped to 23 percent. Solar electricity generation has risen rapidly in the last ten years, contributing 28 percent of the U.S. renewable electricity generation in 2025. The other sources (geothermal, wood, and waste biomass) contributed a combined total of 6 percent.

Figure 1-4: Renewable electricity generation in the U.S. (1949-2025) (Data source: EIA [7])



Although the amount of electricity generated from renewable resources in the U.S. has increased rapidly over the last 20 years, fossil fuels remain the primary source of electricity. Figure 1-5 shows the amount of electricity generated from all sources from 1949 to 2025, while Figure 1-6 shows the share of electricity generated from various energy sources in the U.S. in 2025. Natural gas, coal, and nuclear energy still account for most electricity generation, jointly accounting for 75 percent in 2025. Renewable resources jointly contributed 24 percent, and petroleum less than half a percent. Among renewable resources, hydroelectricity, wind, and solar played the dominant roles, jointly contributing 95 percent of the renewable electricity generation (44 percent from wind, 28 percent from solar, and 23 percent from hydro). Wood contributed 3 percent, geothermal and waste biomass 1 percent each. As expected, pumped hydroelectricity's net energy contribution was negative.¹

¹ Pumped hydroelectric facilities use electricity from the grid during periods of low demand and price to pump water from a lower reservoir to a higher one. That water is then available to generate electricity during high demand and price periods. Due to evaporation and inefficiencies in the pumping and generating processes, less energy is generated than is used. However, the value of the lost energy is more than compensated because low cost, off-peak electricity is converted to high cost, on-peak electricity.

Figure 1-5: U.S. electricity generation by source (1949-2025) (Data source: EIA [7])

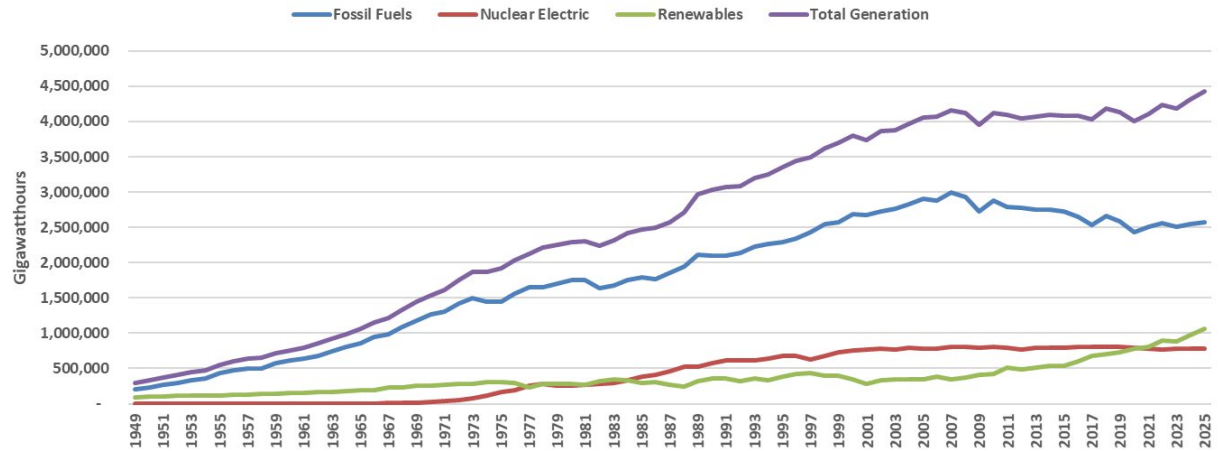
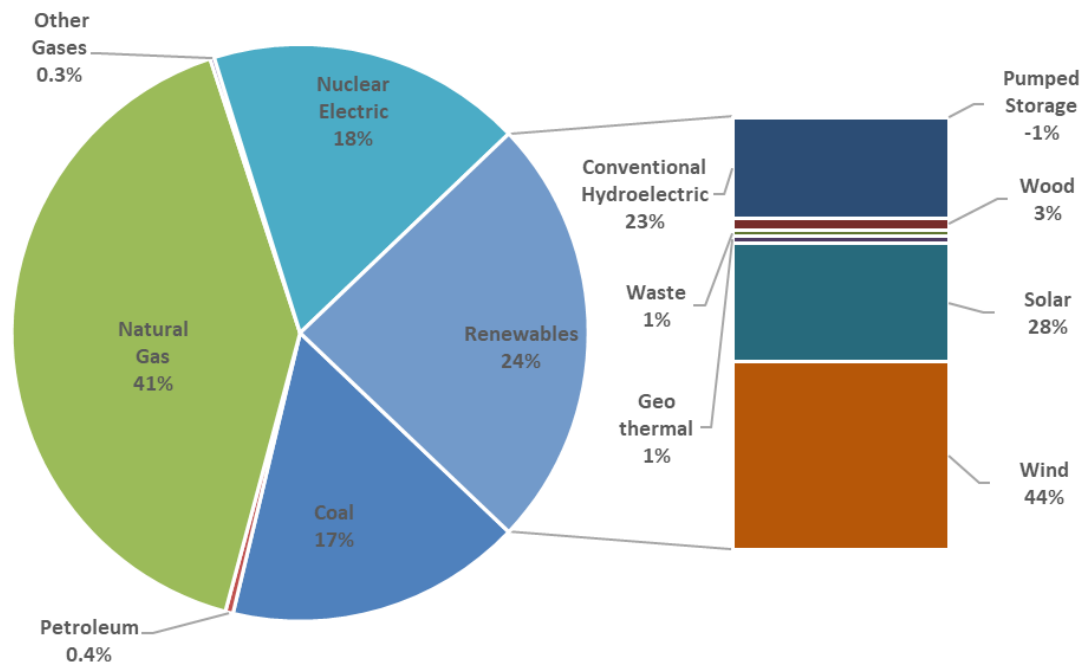


Figure 1-6: Net U.S. electricity generation by energy source in 2025 (Data source: EIA [7])



1.2 Trends in renewable energy consumption in Indiana

Figure 1-7 shows renewable energy consumption in Indiana from 1960 to 2024. In the 1980s, renewable resources accounted for over 3 percent of Indiana's total energy consumption. In the 1990s, the share fell to below 2 percent. Starting in the 2000s, expansions in ethanol and wind increased the share of renewable resources. By 2024, this share had risen to 7.4 percent. Woody biomass had been the main source of renewable energy in Indiana before the 2000s. This has since changed, with biofuels becoming the largest source of renewable energy, supplying 54 percent of the renewable energy consumed in 2024, followed by wind at 19 percent. Wood and waste contributed 18 percent, solar 6 percent, and geothermal 2 percent.

Figure 1-7: Renewables share of Indiana total energy consumption (1960-2024) (Data source: EIA [8])

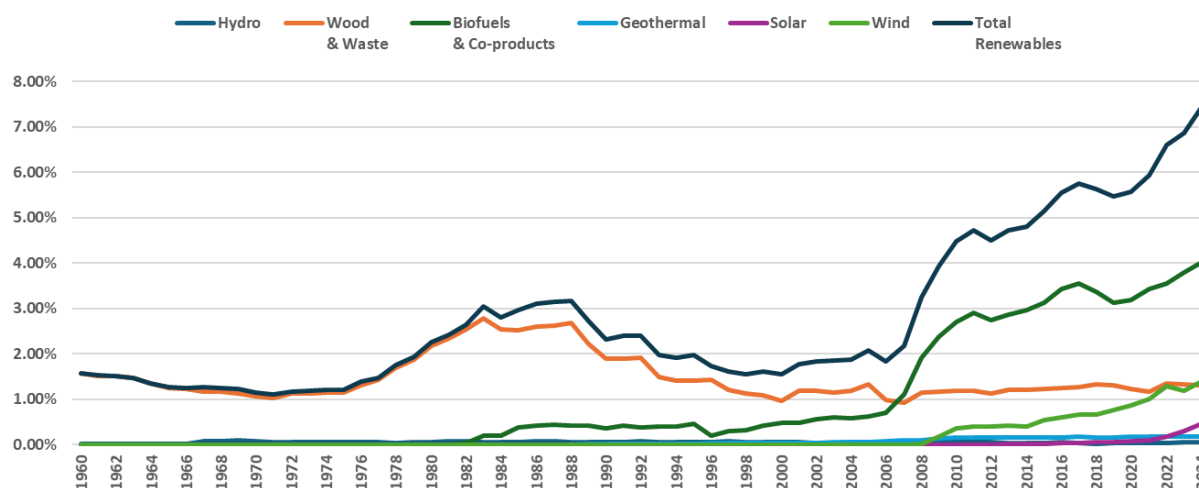
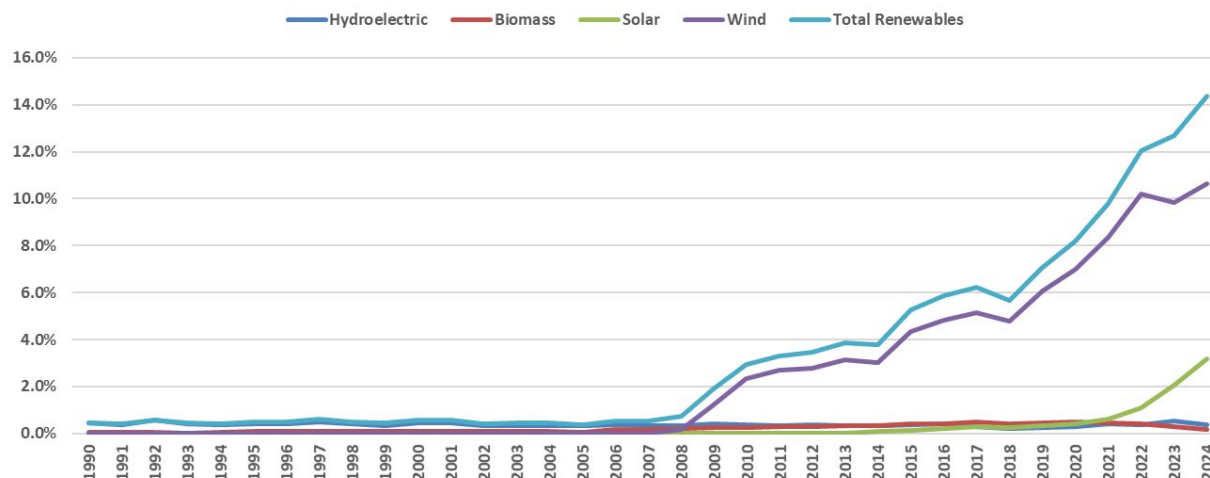


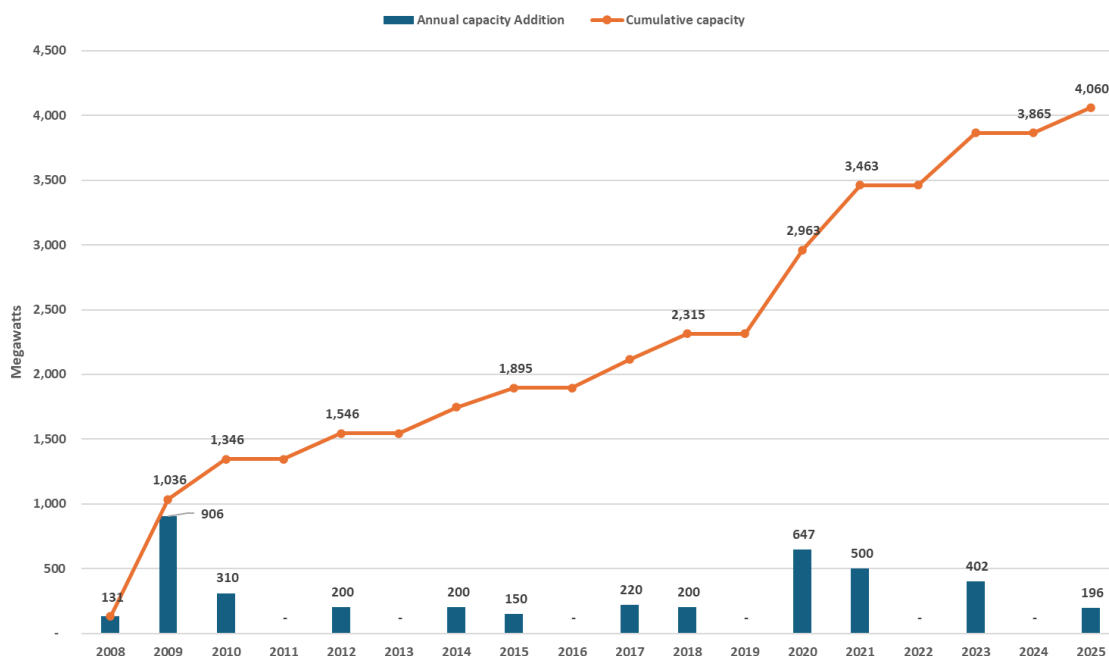
Figure 1-8 shows the contribution of renewable energy to Indiana's net electricity generation from 1990 to 2024. Starting in 2008, the development of utility-scale wind energy projects triggered a swift rise in renewable energy's contribution to Indiana's electricity generation. The renewables share of annual electricity generation rose from 0.5 percent in 2007 to 14.4 percent in 2024. The share of hydroelectricity, which until 2007 was the primary source of renewable electricity, was about 0.4 percent of the net electricity generated in Indiana in 2024. Wind energy has become the dominant source of renewable electricity in Indiana, contributing 74 percent of the renewable electricity generated and 11 percent of the net electricity generated in 2024. Solar generation has grown from virtually none in 2011 to 3,091 GWh in 2024, accounting for 22% of renewable electricity generation and 3% of Indiana's total net generation, making it the second-largest source of electricity from renewable resources after wind.

Figure 1-8: Renewables share of Indiana electricity generation (1990-2024) (Data source: EIA [9])



As shown in Figure 1-9, Indiana’s wind energy capacity has increased steadily since the installation of the first utility-scale wind farm, the 131 MW Benton County wind farm, in 2008. At the end of 2025, the installed utility-scale wind generating capacity stood at 4,060 MW. In addition, two wind farms with a combined capacity of 403 MW were under construction at the time of this report. Utility-scale wind farms consist of multiple wind turbines with a combined capacity of over 100 MW, in contrast to customer-side wind projects, which typically consist of single turbines with a capacity of 1 MW or less.

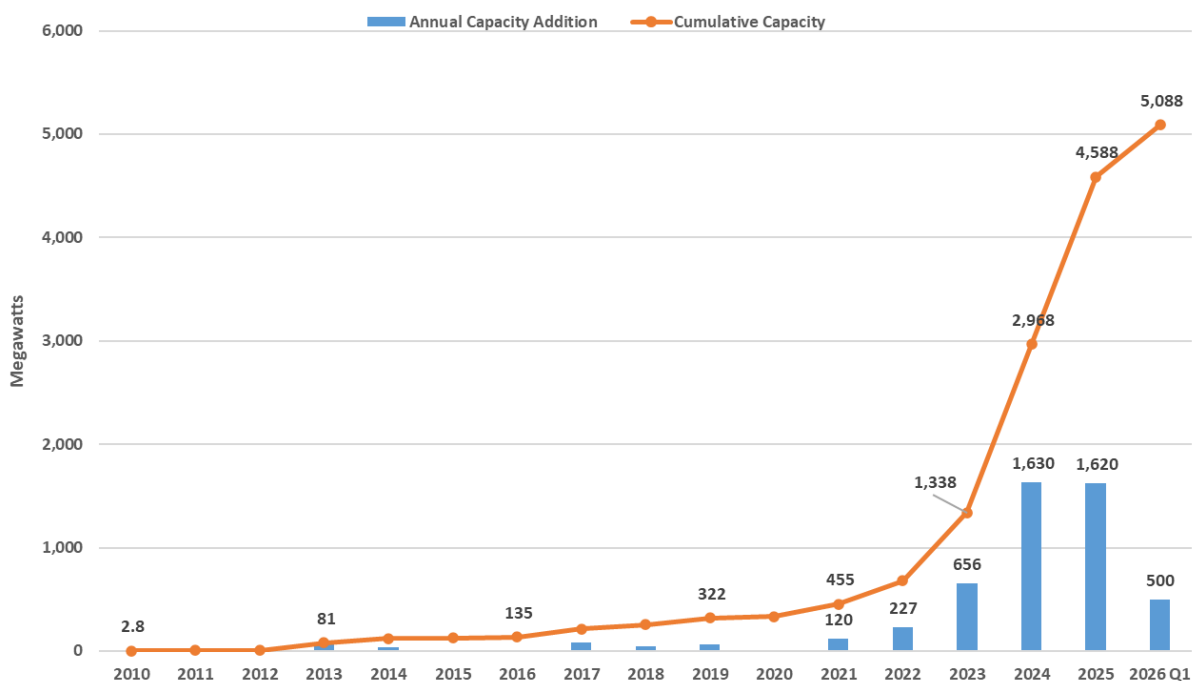
Figure 1-9: Wind energy capacity in Indiana (Data source: IURC [10])



The other renewable resource that has experienced rapid growth in Indiana over the last decade is solar photovoltaic (PV). The installation of multi-megawatt PV power plants began in 2013 in Indianapolis and Northern Indiana. This was made possible by feed-in tariffs introduced by AES Indiana (formerly Indianapolis Power and Light) and Northern Indiana Public Service Company (NIPSCO), which supported notable projects such as the 10 MW solar farm at Indianapolis International Airport. Between 2013 and 2018, a total of 96 MW of PV capacity was installed within the AES service area through these tariffs. At the end of 2024, when the NIPSCO feed-in tariff was discontinued, 22 MW of PV capacity had been interconnected to the NIPSCO system. The other driver for the multimegawatt-sized PV systems was the expansion of the Indiana net metering rule in 2011 to include systems up to 1 MW in capacity. The utilities reported that more than 8,900 customers have installed over 205 MW under Indiana's net metering program [11]. Indiana's net-metering program was closed to new participants after July 1, 2022, under Senate Enrolled Act 309 of 2017, with eligible new customer-side renewable generation compensated under Excess Distributed Generation (EDG) tariffs. Under EDG, excess generation is generally credited at 125 percent of the utility's average annual marginal/wholesale energy price. Since the transition to EDG compensation, approximately 47 MW of renewable energy facilities had been connected through year-end 2024 [11].

With the commissioning of the 200 MW Riverstart Solar Park in Randolph County at the beginning of 2022, the scale of solar farms entered a new phase in which utilities now include utility-scale solar farms as part of their generating portfolio, rather than relying on customer-side net metering and feed-in tariffs as in the previous phase. Utility-scale solar farms have a capacity of 100 MW or more. Figure 1-10 shows the growth in installed PV capacity in Indiana.

Figure 1-10: Growth in installed PV capacity in Indiana (Data source: IURC [10], NREL [12])



By the end of the first quarter of 2026, 22 utility-scale projects with a combined capacity of 4,568 MW had been commissioned in Indiana, bringing the state's total installed solar PV capacity to at least 5,088 MW, compared with 4,588 MW at the end of 2025, as shown in Figure 1-10. This total does not include all customer-side PV capacity, as that data is not currently available. Table 1-1 lists the utility-scale PV projects currently operating in Indiana. Another 7 projects, with a combined capacity of 1,705 MW, were under construction and expected to come online between 2026 and 2028. Table 1-2 lists utility-scale solar farms under construction as of the end of the first quarter of 2026. In addition to the 7 projects under construction, there were a further 30 projects with a total combined capacity of 5,657 MW that had received approval from the IURC but had not yet begun construction. Table 1-3 lists those 30 projects.

Table 1-1: Operating large-scale Solar farms in Indiana (Data source: IURC [10])

Project	County	Developer	Buyer	Capacity (MWac)	In-Service year
Riverstart Solar Park	Randolph	EDPR	Hoosier	200	2021
Dunns Bridge Solar Center Phase I	Jasper	NextEra	NIPSCO	265	2023
Bellflower Solar Project	Rush & Henry	Lightsource	Verizon	153	2023
Indiana Crossroads Solar/Meadow Lake	White	EDPR	NIPSCO	200	2023
Calvary Energy Center	White	NextEra	NIPSCO	200	2024
Dunns Bridge Solar/Storage Phase II	Jasper	NextEra	NIPSCO	435	2024
Hardy Hills Solar	Clinton	Invenergy	AES Indiana	195	2024
Mammoth Solar Phase I (North)	Starke & Pulaski	Doral	AEP	400	2024
Riverstart Solar Park III	Randolph	EDPR	NA*	100	2024
Twin Lakes Solar	White	ENGIE Renewables	Microsoft	150	2024
Honeysuckle Solar	St. Joseph	Lightsource	NA	150	2024
Speedway Solar	Shelby	Ranger Power	Duke	199	2025
Posey Solar	Posey	Arevon	NA	191	2025
Fairbanks Solar Energy Center	Sullivan	Invenergy	NIPSCO	250	2025
Gibson Solar	Gibson	Arevon	NIPSCO	280	2025
Ratts 1 Solar	Pike	Arevon	IMPA	150	2025
Appleseed Solar	Cass	NextEra	NIPSCO	200	2025
Riverstart Solar Park IV	Randolph	EDPR	Undisclosed	150	2025
Crossroads Solar	Fountain	Longroad	Amazon	200	2025
Petersburg Energy Center	Pike	NextEra	AES Indiana	250	2026
Wheatland Solar/IN Solar 1	Knox	Origis Energy	CenterPoint	150	2026
Elkhart County Solar Project	Elkhart	Savion	I&M	100	2026

Total operating 4,568

*NA indicates information is not available.

Table 1-2: Utility-scale PV projects under construction in Indiana (Data source: IURC [10])

Project	County	Developer	Buyer	Capacity (MW _{AC})	Planned In-service Year
Trade Post Solar	Sullivan	Invenergy	A commercial and industrial customer	200	2026
Mammoth Phase II (South)	Pulaski	Doral	Undisclosed	300	2026
Mammoth Phase III (Central)	Pulaski	Doral	Undisclosed	600	2026
Blackford Solar Energy	Blackford	Leeward	NA	150	2026
Emerald Green Solar	Howard	ENGIE	NA	200	2026
Duff Solar Park LLC	Dubois	EDP Renewables	Undisclosed	100	2026
Skycrest Solar	Jay	NA	NA	155	2028

Total under construction 1,705

Table 1-3: Approved utility-scale PV projects in Indiana not yet under construction (Data source: IURC [10])

Project	County	Capacity (MW _{AC})	Planned In-service Year
Elliott Solar	Gibson	200	TBD
Ratts 2 Solar/Blue Jeans Solar	Knox	150	2028
Foundry Works	Lake	200	2027
Crosstrack Solar	Pike	130	2028
Moss Creek Solar	Pulaski	200	2027
Rose Gold Solar	Jay	150	2028
Honey Creek Solar Phase I	White	180	2027
Honey Creek Solar Phase II	White	200	2027
Honey Creek Solar Phase III	White	200	TBD
Rustic Hills Solar	Warrick	100	2028
Sun Chief Solar	Jay	100	2027
Vermillion Rise Solar	Vermillion	185	2027
Cherry Hill Solar Energy	LaGrange	100	2028
Reclamation Solar Energy	Gibson	150	2027
Mayapple Solar	Pulaski	224	2028
Locomotive Solar	Howard	200	2028
Lake Trout Solar	Blackford	245	2028
Merrillville Solar	Lake	58	2028
Crossvine Solar I	Dubois	85	2027
Riverstart Solar Park V	Randolph	100	TBD
Dunns Bridge Solar Phase II	Starke	200	2026
Bluestem Solar Farm	Laporte	250	2027
Rustic Hills Solar	Warrick	100	2028
Dumont Solar	St. Joseph	200	2028
Sullivan County Power	Sullivan	400	2028
Bottlebrush Solar Energy	Pulaski	200	2028
Dolphin Solar	Fountain	700	2029
Bluegrass Creek Solar	Vanderburgh	100	2027
Black Prairie Solar Park	White	200	2027
Worthington Solar	Greene	150	2028

Total approved but not started construction 5,657

Unlike the growth in PV capacity in the 2013-2020 period that was driven by favorable utility incentive rates, the more recent growth of utility-scale PV solar capacity is driven by more fundamental industry-wide issues of the need for replacement capacity for the aging generating fleet, working in combination with the pressure to lower the carbon emissions of the electricity industry.

In addition, the federal government provided significant clean-energy incentives through the IRA of 2022. The IRA extended the legacy ITC and PTC for eligible projects that begin construction before the end of 2024, and created technology-neutral clean electricity credits beginning in 2025. For solar PV, this meant continued eligibility for the legacy ITC and, importantly, new eligibility for the legacy PTC under Section 45, which provides a credit of 1.5 cents/kWh in 1993 dollars, adjusted for inflation, for electricity produced during the first 10 years of operation.

Beginning in 2025, the new Clean Electricity Investment Credit (CEITC) under Section 48E and Clean Electricity Production Credit (CEPTC) under Section 45Y apply to qualifying zero-emissions facilities placed in service after December 31, 2024. Section 48E provides a 30 percent investment tax credit for qualifying projects that meet applicable labor requirements, while Section 45Y provides a production-based credit. Both credits are technology-neutral and therefore broader than the legacy solar ITC/PTC framework, extending eligibility to other non-carbon-emitting technologies, including nuclear. Prior to later amendments, both credits were scheduled to begin phasing out after the later of 2032 or the year in which U.S. electricity-sector greenhouse gas emissions fell to 25 percent of 2022 levels.

The OBBBA, signed into law on July 4, 2025, established an accelerated termination rule for qualifying wind and solar facilities. Wind and solar facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the Section 45Y CEPTC or Section 48E CEITC. Facilities that begin construction on or before July 4, 2026 are not subject to this accelerated termination rule but remain subject to applicable beginning-of-construction and continuity requirements. IRS Notice 2025-42 generally requires applicable wind and solar facilities to use the Physical Work Test to establish that construction began by the July 4, 2026 deadline. The notice also provides a four-calendar-year Continuity Safe Harbor under which the Continuity Requirement is deemed satisfied if a facility is placed in service by the end of the calendar year that is no more than four calendar years after the calendar year in which construction began [4, 13]. A detailed analysis of the CEITC, CEPTC, and other IRA incentives, as well as their modifications under the OBBBA, is provided in Section 1.4 of this report.

1.3 Cost of renewable resources

Figure 1-11 shows the average construction cost of wind and solar PV facilities installed in the U.S. from 2013 to 2024. Also included for comparison is the cost of combustion turbines and combined-cycle power plants installed during the same time period. As shown in the figure, the average construction cost of solar PV fell from approximately \$3,705/kW in 2013 to \$1,561/kW in 2021, a reduction of about 58 percent. Construction costs remained relatively stable during 2021-2023, fluctuating around \$1,600/kW, before increasing to \$1,865/kW in 2024. The average construction cost of onshore wind projects declined substantially from \$1,895/kW in 2013 to \$1,382/kW in 2018. Costs then remained relatively stable between 2018 and 2022, fluctuating between approximately \$1,400/kW and \$1,500/kW, before increasing to \$1,738/kW in 2023 and \$1,882/kW in 2024.

Figure 1-11: Average construction cost of generation installed 2013 to 2024 (Data source: EIA [14])

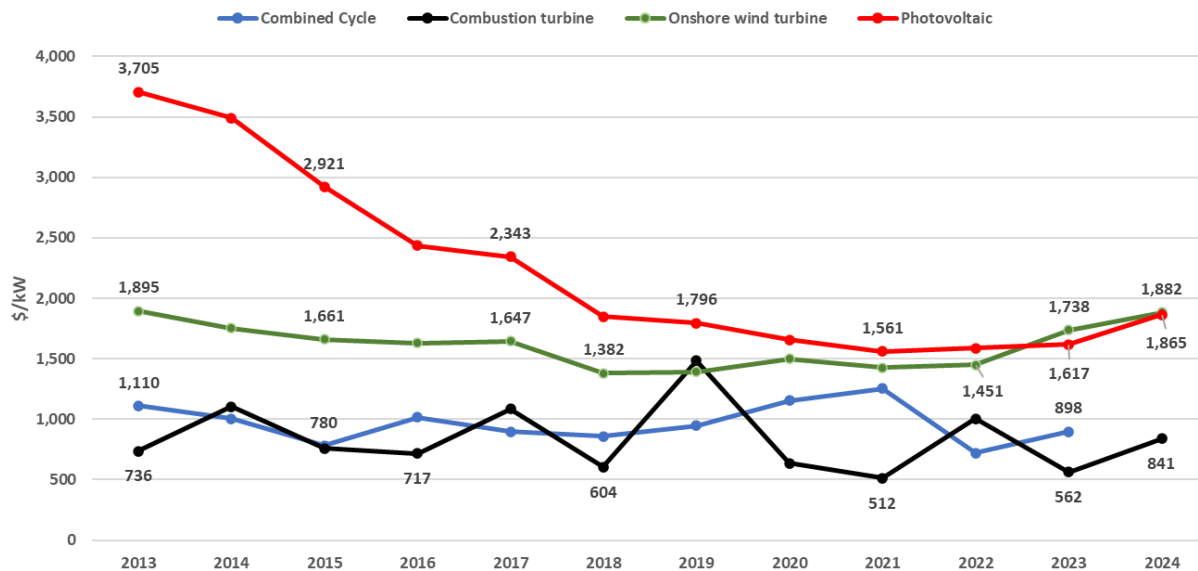


Figure 1-12 shows the estimated cost of future generating plants modeled in the EIA Annual Energy Outlook (AEO) 2026. The capital cost of a PV plant is estimated at \$1,484/kW as compared with \$1,712/kW for an onshore wind power plant.

The EIA's estimated cost of renewable generators remains, for the most part, higher than that of fossil-fuel generators. For example, the capital cost of PV is 37 percent higher than that of a single-shaft combined cycle, 44 percent higher than a multiple-shaft combined cycle, and 28 percent higher than that of an industrial frame combustion turbine.

Figure 1-12: Estimated generating technologies capital costs² (Data source: EIA [15])

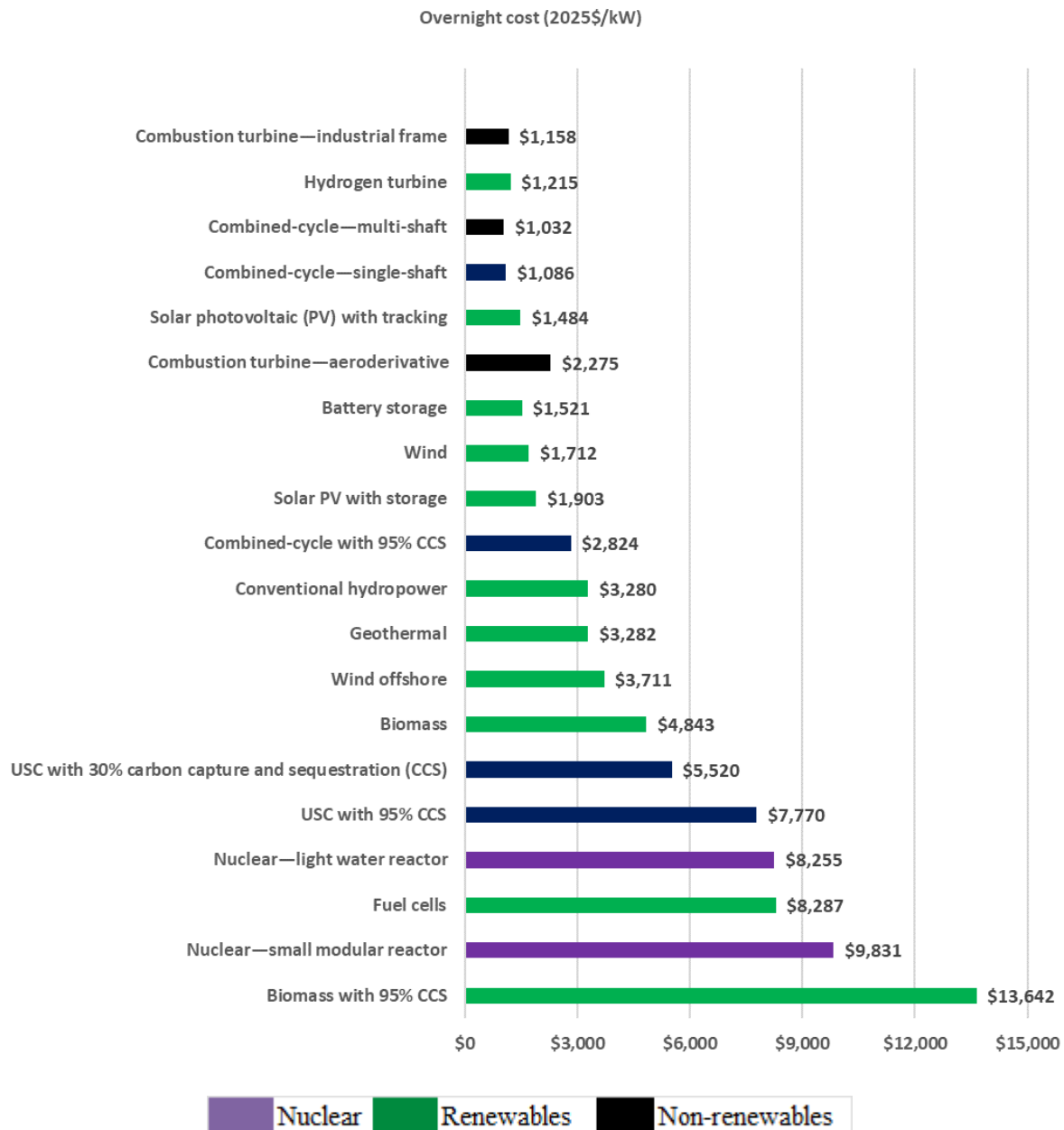
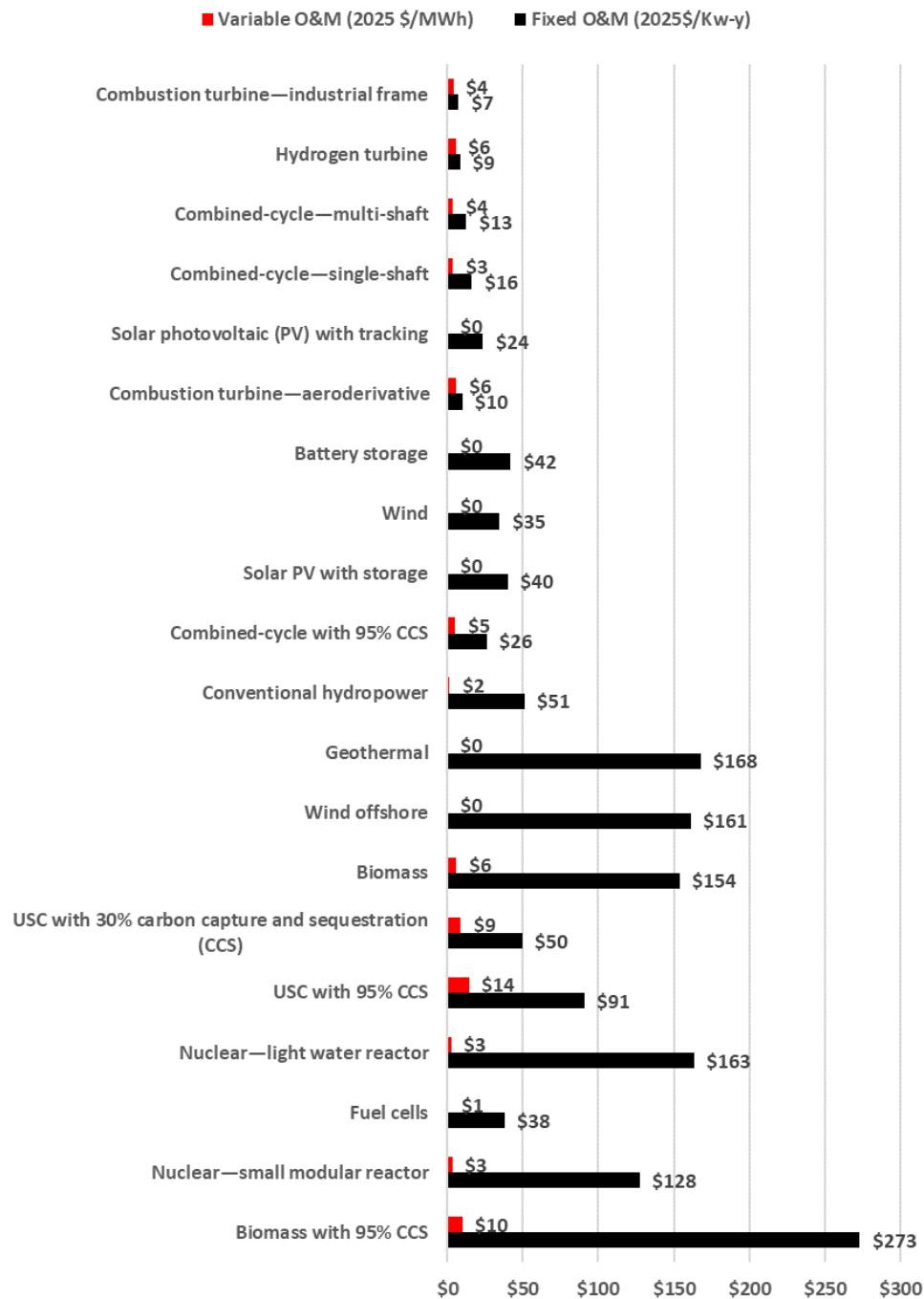


Figure 1-13 shows the EIA-estimated fixed and variable operating and maintenance (O&M) costs for the future generating technologies modeled in the EIA AEO 2026. As shown in the figure, renewable resources do not have a clear advantage over conventional generating technologies in terms of fixed O&M costs. But when it comes to variable O&M costs,

² Overnight capital cost is an estimate of the cost at which a plant could be constructed, assuming that the entire process from planning through completion could be accomplished in a single day. The overnight cost concept is used to avoid the impact of the differences in financing methods chosen by project developers on the estimated costs.

renewable resource generators, except for biomass-based ones, have a clear advantage; renewable generators such as wind and solar have virtually no variable O&M costs.

Figure 1-13: Estimated generating technologies fixed and variable O&M costs (Data source: EIA [15])



1.4 Federal Renewable Energy Incentives

The OBBBA, signed into law on July 4, 2025, modified several clean energy tax credit provisions originally enacted or expanded by the IRA of 2022.

The IRA extended and modified the legacy 30 percent ITC and the 1.5 cents/kWh, inflation-adjusted PTC for eligible projects that began construction before the end of 2024. In addition, it expanded the technologies eligible for the ITC to include stand-alone energy storage equipment, which until then had qualified only if paired with a renewable generating technology such as wind or solar. The IRA also allowed solar facilities to qualify for the legacy Section 45 PTC; prior to the IRA, solar generally qualified for the ITC rather than the PTC. The IRA also created a separate production credit for existing zero-emission nuclear power plants under Section 45U [3, 16].

Beginning in 2025, the IRA replaced the legacy ITC/PTC framework with technology-neutral clean electricity credits: the Clean Electricity Investment Credit (CEITC) under Section 48E and the Clean Electricity Production Credit (CEPTC) under Section 45Y. These credits apply to qualifying zero-emission electricity-generating facilities placed in service after December 31, 2024, including solar, wind, nuclear, geothermal, and hydropower. Section 48E also applies to qualifying energy storage technologies. Under the IRA, these credits were scheduled to begin phasing out after the later of 2032 or the year in which U.S. electricity-sector greenhouse gas emissions fell to 25 percent of 2022 levels.

The OBBBA established an accelerated termination rule for applicable wind and solar facilities. Wind and solar facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the Section 45Y CEPTC or Section 48E CEITC. Facilities that begin construction on or before July 4, 2026 are not subject to this accelerated termination rule but remain subject to applicable beginning-of-construction and continuity requirements. IRS Notice 2025-42 further provides that, for most applicable wind and solar facilities, beginning construction before that deadline must be demonstrated through the Physical Work Test,³ with a four-year continuity safe harbor available if the project is placed in service within four calendar years after the year construction began. The Five Percent Safe Harbor, which generally allows a project to be treated as having begun construction once at least 5 percent of total eligible project costs have been paid or incurred, is generally no longer available for this purpose, except for low-output solar facilities of 1.5 megawatts alternating current (MW AC) or less [17].

³ The Physical Work Test considers construction to have begun when significant physical work starts, rather than when a specified amount of project cost has been spent.

For other qualifying zero-emission technologies, such as nuclear, storage, geothermal, hydropower, and biomass, OBBBA did not impose the accelerated wind-and-solar placed-in-service deadline. These technologies generally remain eligible for the Section 48E CEITC and the Section 45Y CEPTC under the longer phaseout schedule. Under the IRA, the credits were scheduled to begin phasing out after the later of 2032 or the year in which U.S. electricity-sector greenhouse gas emissions fell to 25 percent of 2022 levels; OBBBA removed the emissions-based phaseout trigger and replaced it with a calendar-based phaseout schedule for non-wind/solar technologies. Under this calendar-based phaseout, qualifying facilities that begin construction in 2033 receive 100 percent of the credit; those beginning in 2034 receive 75 percent; those beginning in 2035 receive 50 percent; and those beginning after 2035 receive no credit.

OBBBA did not generally alter the prevailing wage and apprenticeship requirements needed to receive the full-value credits, nor did it eliminate IRA bonus-credit provisions such as the energy community and domestic content adders. For 48E/CEITC, the base credit is 6 percent and increases up to 30 percent for qualifying facilities that meet those labor requirements. For 45Y/CEPTC, the credit starts at a base rate of 0.3 cents/kWh, adjusted for inflation, and increases to 1.5 cents/kWh for qualifying facilities that meet prevailing wage and apprenticeship requirements.

The prevailing wage and apprenticeship requirements are as follows. To qualify for the full-value credits, laborers and mechanics employed by the taxpayer, contractors, and subcontractors in the construction, alteration, or repair of a qualifying facility must generally be paid at least the applicable prevailing wage for their occupation and geographic area. In addition, a specified share of total construction labor hours must be performed by qualified apprentices participating in registered apprenticeship programs.

Bonus tax credits under the IRA are as follows. Projects may qualify for additional tax credits if they meet certain requirements:

- A project meeting the domestic content requirements may receive an additional credit. For investment credits, the bonus generally increases the credit by 10 percentage points when applicable requirements are met; for production credits, it increases the credit amount by 10 percent. To qualify, all structural iron and steel must generally be produced in the United States, and a specified percentage of the cost of manufactured products and components must be attributable to domestically produced materials and components.
- A project located in an energy community may receive an additional 10 percentage points under the investment credit or a 10 percent increase under the production credit. Energy communities include certain brownfield sites, areas with significant historical employment or tax revenue associated with fossil fuels, and census tracts in which a coal mine has closed or a coal-fired generating unit has retired.

- Under the Low-Income Communities Bonus Credit Program, qualifying investment-credit projects may receive an additional 10 percentage points if located in a low-income community or on Indian land.
- Qualifying projects may receive an additional 20 percentage points if they are part of a qualified low-income residential building project or a qualified low-income economic benefit project.
- The low-income communities bonuses apply to eligible investment-credit projects and do not generally apply to production tax credits.

The IRA introduced an elective-pay provision, sometimes referred to as “direct pay,” that allows certain tax-exempt organizations, state and local governments, tribal governments, and other eligible entities to receive the value of qualifying clean-energy tax credits as a direct payment. The IRS treats the credit amount as a tax payment and refunds any resulting overpayment.

The IRA also allows eligible taxpayers to transfer all or part of certain clean-energy tax credits to unrelated third parties in exchange for cash. The cash payment received by the seller is generally not included in taxable income, and the purchaser generally may not deduct the purchase price.

Projects that satisfy the applicable IRS beginning-of-construction requirements may qualify for a four-calendar-year Continuity Safe Harbor. Under this provision, a project is generally deemed to satisfy the continuous-construction or continuous-efforts requirement if it is placed in service no more than four calendar years after the calendar year in which construction began. Projects completed outside the safe-harbor period may still demonstrate continuity based on the relevant facts and circumstances.

The OBBBA introduced new restrictions intended to limit the availability of certain clean-energy tax credits to entities and projects with substantial connections to prohibited foreign entities. These restrictions generally operate in two ways:

- Projects may be disqualified if a prohibited foreign entity provides a level of material assistance through equipment, components, materials, intellectual property, or other project inputs that exceeds applicable statutory thresholds.
- Taxpayers may be disqualified if prohibited foreign entities exercise specified levels of ownership, control, influence, or economic participation in the taxpayer or project.

Prohibited foreign countries generally include China, Russia, Iran, and North Korea. Treasury and the IRS have since issued interim guidance (IRS Notice 2026-15) describing methods for determining material assistance from a prohibited foreign entity, including material assistance cost ratios, interim safe harbors, supplier certification requirements, substantiation requirements, and other compliance procedures, while indicating that more comprehensive regulations will follow [18].

1.5 References

1. EIA. U.S. Renewable Diesel Production and Biodiesel Production Declined in 1Q25. https://www.eia.gov/todayinenergy/detail.php?id=65424&utm_source
2. EIA. Monthly Energy Review Table 10.1 Renewable Energy Production and Consumption by Source. April 2026. <https://www.eia.gov/totalenergy/data/monthly/#renewable>
3. The National Law Review. August 17, 2022. Relief Arrives for Renewable Energy Industry - Inflation Reduction Act of 2022. <https://www.natlawreview.com/article/relief-arrives-renewable-energy-industry-inflation-reduction-act-2022>
4. Sidley Energy Updates. The “One Big Beautiful Bill” Act – Navigating the New Energy Landscape. July 15, 2025. <https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape>
5. EIA. Monthly Energy Review Table 1.1 Primary Energy Overview. April 2026. <https://www.eia.gov/totalenergy/data/monthly/#summary>
6. EIA. Monthly Energy Review Table 1.3 Primary Energy Consumption by Source. April 2026 <https://www.eia.gov/totalenergy/data/monthly/#summary>
7. EIA. Monthly Energy Review Table 7.2a Electricity Net Generation: Total (All Sectors). April 2026. <https://www.eia.gov/totalenergy/data/monthly/#electricity>
8. EIA. State Energy Data System (SEDS) Table CT2. Primary energy consumption estimates, 1960-2024, Indiana <https://www.eia.gov/state/seds/seds-data-complete.php?sid=IN>
https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_use/total/use_tot_INcb.html&sid=IN
9. EIA. EIA-923 Power Plant Operations Report. Net Generation by State by Type of Producer by Energy Source, 1990-2024. <https://www.eia.gov/electricity/data/state/>
10. IURC Renewable Quarterly Report received by July 2026.
11. 2025 IURC Annual Report. July 2025. <https://www.in.gov/iurc/files/2025-IURC-Annual-Report.pdf>
12. NREL. The open PV Project. No longer available, discontinued in 2019 <https://pv-magazine-usa.com/2019/09/19/the-open-pv-project-goes-offline/>
<https://www.nrel.gov/docs/fy16osti/65958.pdf>
13. Norton Rose Fulbright. Project Finance. Effects Of "One Big Beautiful Bill" On Projects. July 10, 2025 <https://www.projectfinance.law/publications/2025/july/effects-of-one-big-beautiful-bill-on-projects/>

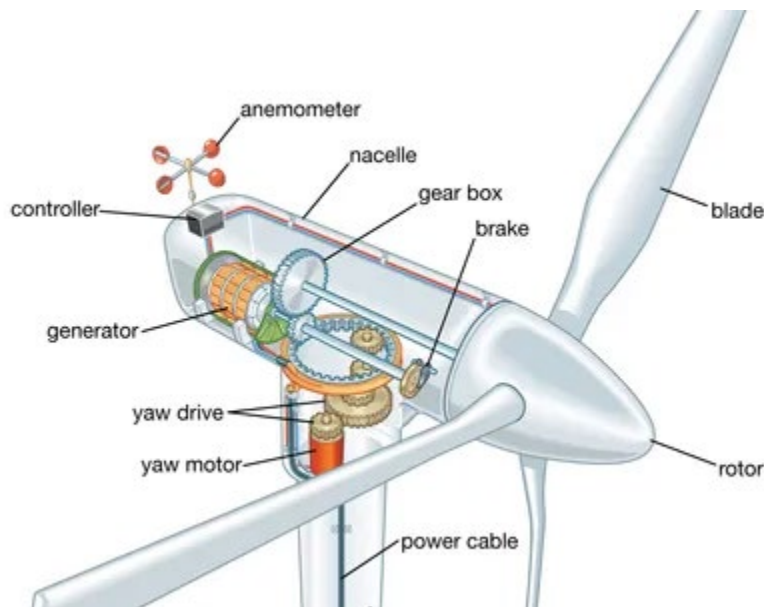
14. EIA. Construction Cost Data for Electric Generators Installed in 2023
<https://www.eia.gov/electricity/generatorcosts/>
15. EIA. Assumptions to the Annual Energy Outlook 2026: Electricity Market Module. April 2026.
https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf
16. DLA Piper Law Firm Publications. August 10, 2022. The clean energy provisions of the Inflation Reduction Act of 2022 - a historic effort to encourage the development of clean energy and reduce carbon emissions.
<https://www.dlapiper.com/en/us/insights/publications/2022/08/the-clean-energy-provisions-of-the-inflation-reduction-act-of-2022/>
17. IRS Notice 2025-42. August 15, 2025.
<https://www.irs.gov/pub/irs-drop/n-25-42.pdf>
18. IRS Notice 2026-15. February 12, 2026.
<https://www.irs.gov/pub/irs-drop/n-26-15.pdf>

2. Energy from Wind

2.1 Introduction

Wind turbines transform the kinetic energy of moving air into mechanical energy, subsequently converting it into electricity through the operation of a generator. There are two main types of wind turbines: vertical and horizontal axis. The horizontal axis turbine with three blades facing into the wind is the most common configuration in modern wind turbines. Vertical wind turbines are more suitable for smaller urban applications where space is limited, and safety is a much greater concern. The horizontal axis wind turbines not only capture more energy per volume of moving air, but they also can be mounted at much greater heights to capture higher wind speeds and less turbulent winds [1]. Figure 2-1 shows the basic parts of a modern horizontal axis wind turbine used for electricity generation.

Figure 2-1: Horizontal wind turbine configuration (Source: Alternative Energy News [2])



Although utility-scale wind farms were not installed in the U.S. until the 1980s, windmills were a source of energy for pumping water on farms and ranches in the 19th century and into the early 20th century. Until the rural electrification efforts of the federal government delivered reliable grid-connected electricity to rural areas, wind-powered generators were a major source of electricity for farms and ranches far removed from the grid. Utility-scale wind farms in the U.S. began in California in the 1980s, with individual wind turbines on the order of 50 – 100 kilowatts (kW). Turbine capacity and wind farm sizes have grown steadily to the point where the two-megawatt (MW) turbine and wind farms with hundreds of MW of capacity are now the norm [3, 4].

Although wind farms' capacities have grown to be comparable to those of fossil fuel-fired generators, the total electricity that can be produced from a wind farm annually is typically much less than the electricity that is available from a fossil fuel-fired power plant with the same nameplate capacity. A baseload coal or nuclear power plant in the U.S. may have an annual capacity factor of over 80 percent, while the capacity factors of wind farms are typically estimated to range between 20 and 40 percent, depending on the average annual wind speed at their location [5].

Wind speeds are important in determining a wind turbine's performance. Generally, annual average wind speeds of greater than 9 miles per hour (mph) are required for small electric wind turbines, whereas utility-scale wind plants require a minimum wind speed of 10 mph. The power available to drive wind turbines is proportional to the cube of the speed of the wind. This implies that a doubling in wind speed leads to an eight-fold increase in power output. According to the National Laboratory of the Rockies (NLR), formerly the National Renewable Energy Laboratory (NREL), the wind resources available in the continental U.S. can be grouped into ten wind classes, as shown in Table 2-1. Wind class 1 is the highest wind resource level, and wind class 10 is the lowest. According to NLR, the moderate wind resource class 4 is the representative resource level for a majority of wind projects installed in the U.S.

Table 2-1: Wind resource classification (Data source: NLR [6])

Wind Class	Wind Speed Range (m/s)	Weighted Average Wind Speed (m/s)
1	> 9.0	9.5
2	8.8 - 9.0	8.9
3	8.6 - 8.8	8.7
4	8.4 - 8.6	8.5
5	8.1 - 8.4	8.2
6	7.6 - 8.1	7.8
7	7.1 - 7.6	7.4
8	6.5 - 7.1	6.8
9	5.9 - 6.5	6.2
10	1.7 - 5.9	5.2

Wind energy's main advantage is that it is a carbon-free, virtually inexhaustible resource. The placement of a wind turbine does not materially diminish the power of the wind; the only limitation is the space available to build wind farms where good-quality wind blows. By the same token, wind has the main disadvantage of being intermittent. That is, the output from a wind farm is determined by the current wind speed and is not under the control of the grid operator. The only control the grid operator can assert is to curtail the wind farm's output from feeding into the grid. This intermittency reduces the wind generator's value at both the operational and system capacity-planning levels. At the capacity planning level, the system

planner needs to know how much energy they can expect from a generator at a future planning date. Since the wind speeds on a particular day many years into the future are unknown, it is difficult to quantify how much power one can expect from the wind farm at any future planning date. Another significant disadvantage of wind energy is that good wind sites tend to be located far from main load centers and from existing transmission lines. Concerns have also been raised about the death of birds and bats flying into wind turbines, the possibility of turbines causing radar interference, and the potential adverse effects of the shadow flicker⁴ on people living in close proximity to the wind turbine.

2.2 Economics of wind energy

Figure 2-2 shows capital cost estimates for electricity-generating plants in Assumptions to the AEO 2026: Electricity Market Module. The national average cost for a land-based wind farm is estimated at \$1,712/kW, while the national average for offshore wind is estimated at \$3,711/kW. In these estimates, EIA observes that the capital cost of wind (and solar) plants varies widely across the United States. The estimated capital cost of wind varies from a low of \$1,516/kW in Midcontinent Independent System Operator/South to a high of \$2,445/kW in New York Independent System Operator Upstate territories. According to the EIA, the locational factors affecting the regional variation in wind plant capital costs include the quality of the wind in the region, proximity to existing transmission lines, access to a road network, and availability of lower-development-cost land.

⁴ Shadow flicker is the pulse of shadows and reflections that are sometimes caused by the moving turbine blades.

Figure 2-2: Estimated capital costs of various electric generation options (Data source: EIA [7])

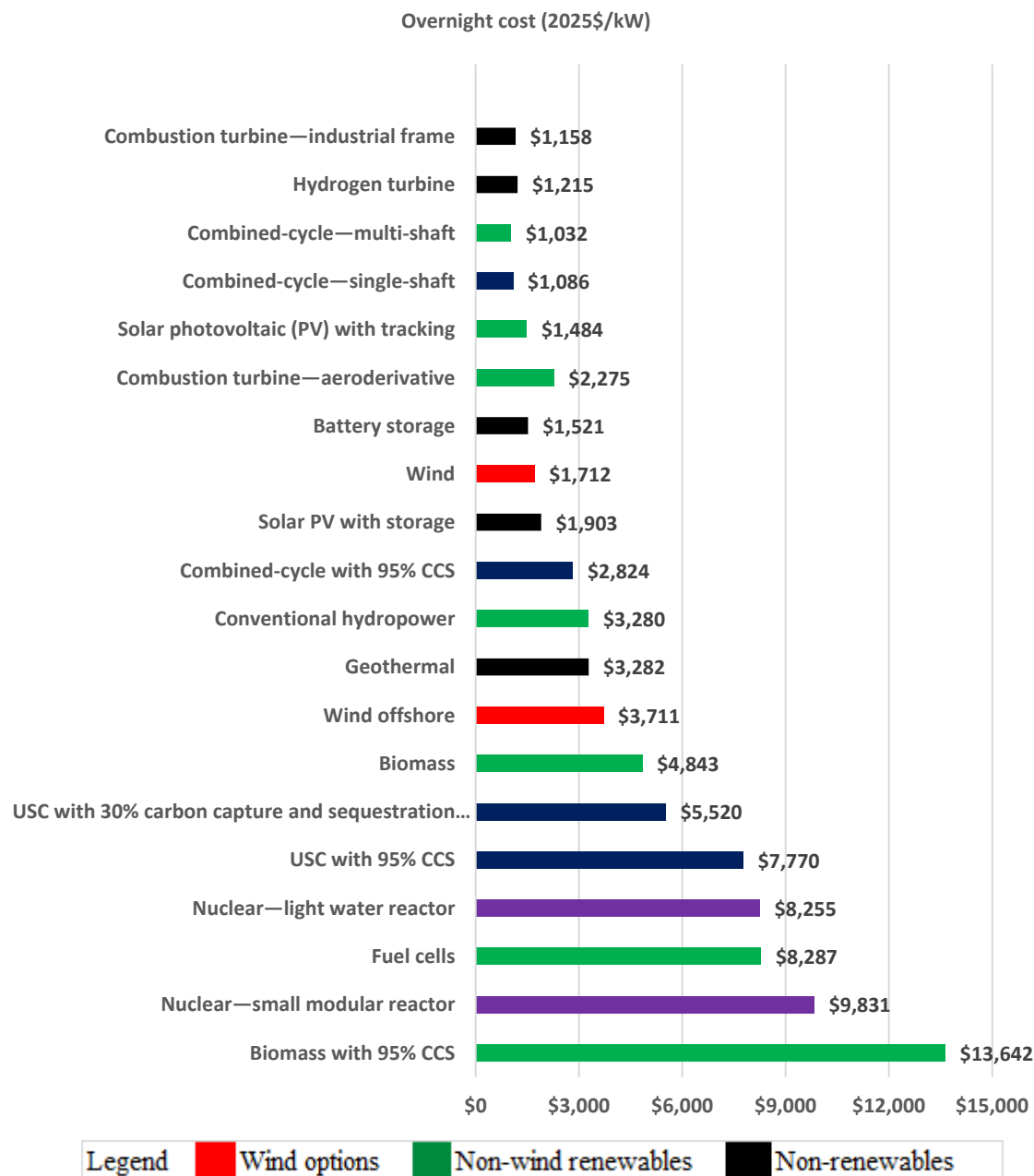


Figure 2-3 shows the capacity-weighted average construction cost for wind and other generation technologies installed in the U.S. from 2013 through 2024. The average construction cost of onshore wind projects declined substantially from \$1,895/kW in 2013 to \$1,382/kW in 2018, a reduction of about 27 percent. Costs then remained relatively stable between 2018 and 2022, fluctuating between approximately \$1,400/kW and \$1,500/kW, before rising to \$1,738/kW in 2023 and \$1,882/kW in 2024.

Figure 2-3: Average construction cost of generators installed from 2013 to 2024 in the U.S. (Data source: EIA [8, 9])

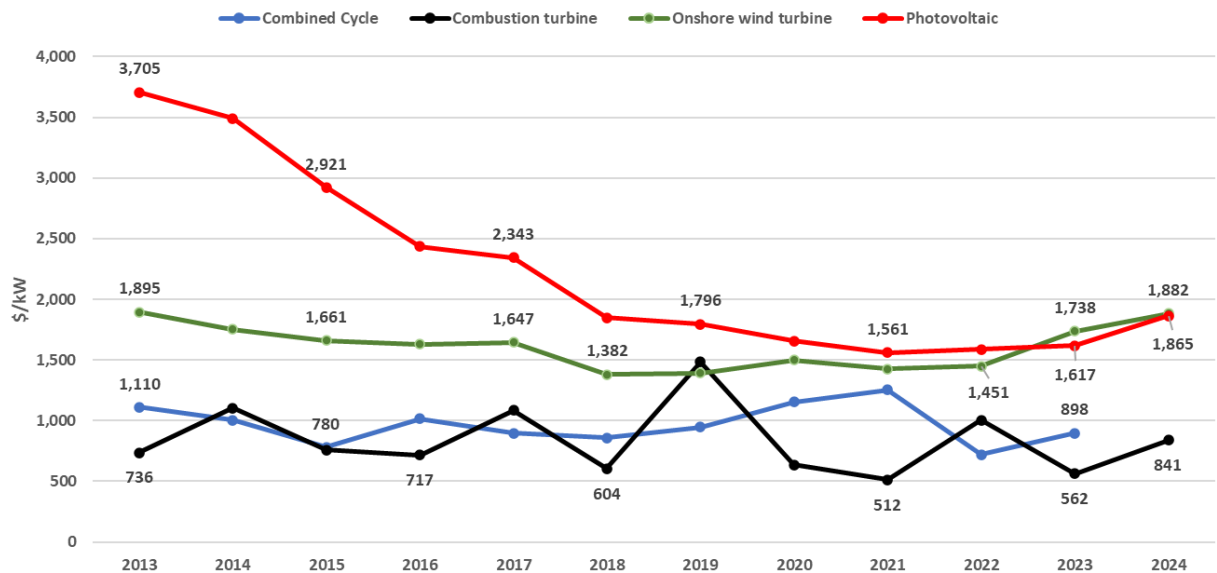


Figure 2-4 shows the trend in installed wind power plant costs for projects from 1982 to 2024, as reported in the 2025 Land-Based Wind Energy Technology Data Update by Lawrence Berkeley National Laboratory (LBNL). The installed cost of wind projects has generally declined over the past four decades. Capacity-weighted average costs fell from more than \$5,000/kW in the early 1980s to about \$2,000/kW by the late 1990s, rose temporarily to around \$3,000/kW during 2008–2011, and then declined to a low around 2022. Costs increased modestly in 2023 and 2024 but remained well below their earlier peaks. The average installed cost of a wind power project was \$1,850/kW in 2024.

Figure 2-4: Installed wind power project costs 1982 to 2024 (Source: LBNL [10])

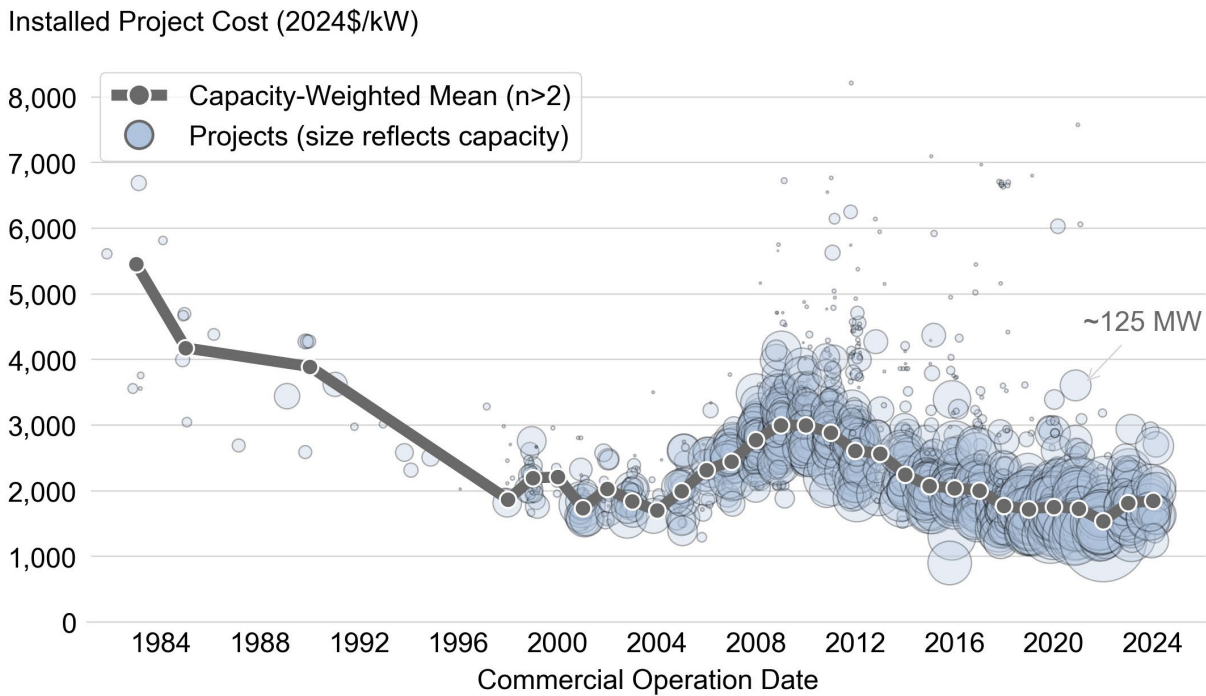


Figure 2-5 shows the operating and maintenance (O&M) costs of electricity-generating plants according to the Assumptions to the AEO 2026: Electricity Market Module. The variable O&M cost is zero for both land-based and offshore wind farms. The fixed O&M cost is estimated at \$35/kW-y for land-based wind farms and \$161/kW-y for offshore wind farms.

Figure 2-5: Estimated generating technologies fixed and variable O&M costs (Data source: EIA [7])

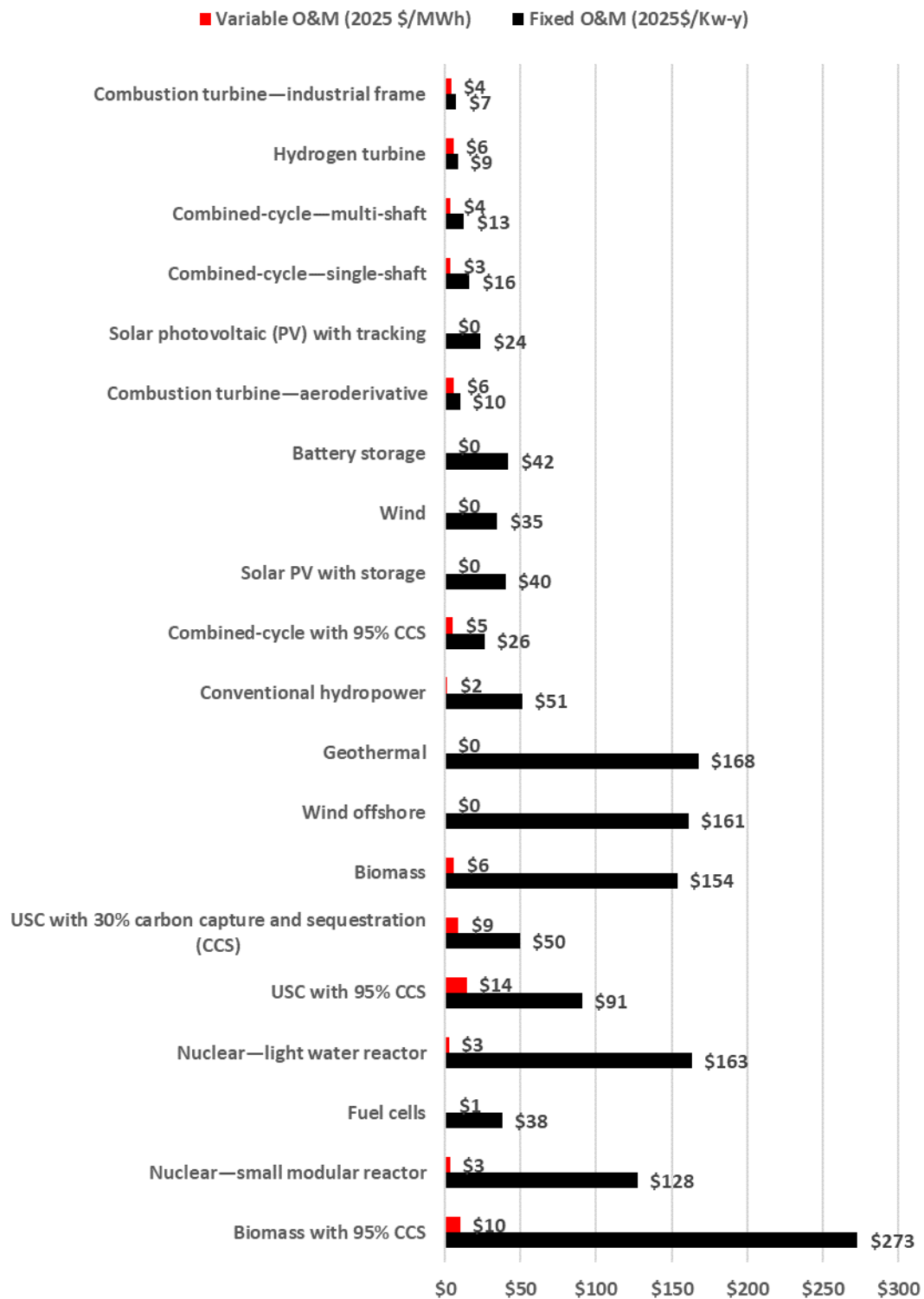


Figure 2-6 from the 2025 Land-Based Wind Energy Technology Data Update shows the median annual O&M costs by commercial operation date. The chart groups projects into four sets by their commissioning date: 1998-2004, 2005-2011, 2012-2018, and 2019-2023. According to LBNL, the O&M cost data shown should be read with caution because consistent O&M data is not readily available, and even where it is, the costs included as O&M may not be consistent across projects. Generally speaking, projects commissioned from 1998 to 2004 have a higher median annual O&M cost than those commissioned between 2019 and 2023.

Figure 2-6: Average O&M costs for available data years (Source: LBNL [10])

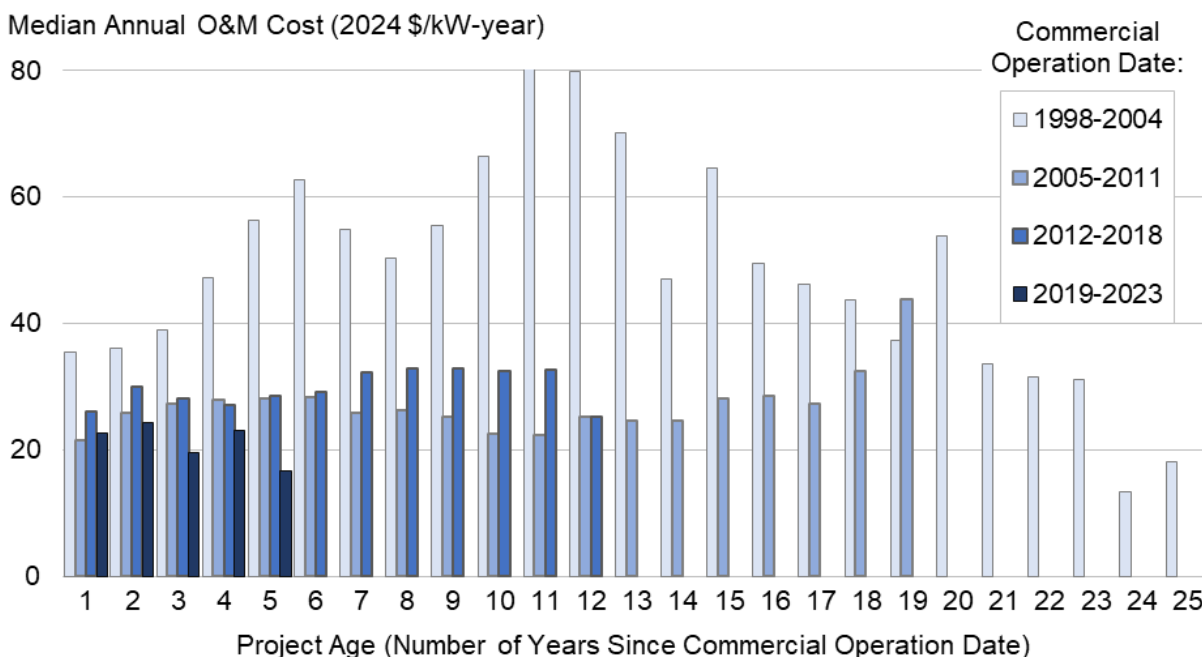
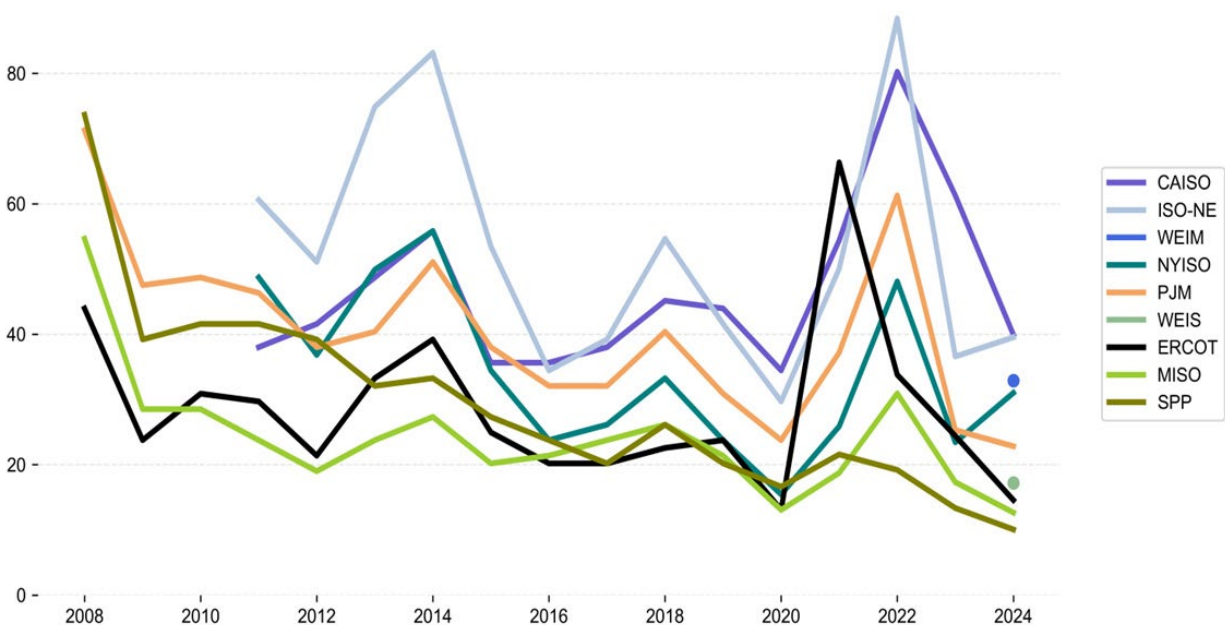


Figure 2-7 compares the wholesale value of wind across seven regional electricity markets. The wholesale market value considers the hourly local wholesale energy price and the hourly wind output, along with the capacity value where available. As shown in the figure, wholesale market values vary substantially by region and year, but most markets show a broadly declining trend from the late 2000s through 2020. Values then rose sharply in 2021-2022 across several regions, with especially large peaks in ISO New England (ISO-NE), the California Independent System Operator (CAISO), PJM Interconnection (PJM), the New York Independent System Operator (NYISO), and the Electric Reliability Council of Texas (ERCOT). The increase was temporary: market values fell markedly in 2023 and remained relatively low in most regions in 2024. In 2024, CAISO and ISO-NE had the highest values at about \$40/MWh, while Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), and ERCOT were among the lowest at roughly \$10-\$15/MWh. Overall, the graph shows considerable regional variation, a pronounced 2021-2022 spike, and a return toward lower values by 2024.

Figure 2-7: Wholesale energy value of wind (Source: LBNL [10])

Wholesale Market Value (2024 \$/MWh)



2.3 State of wind energy nationally

As shown in Figure 2-8, U.S. installed wind energy capacity has increased steadily from 1,512 MW at the end of 1998 to 162,046 MW at the end of 2025. Over that period, wind energy has grown to rival hydroelectricity as the nation's main source of renewable electricity. In 2019, wind energy for the first time overtook hydroelectricity as the largest source of renewable electricity generation in the U.S. The 464,391 GWh of electricity generated by wind in 2025 accounted for 44 percent of renewable generation that year.

In 2024, wind capacity added was 4,033 MW, and in 2025, it increased by 7,635 MW, both significantly below the 2020 high of 17,213 MW. Federal and state incentives, such as federal PTCs and state renewable RPSs, have been crucial in driving U.S. wind industry growth. The substantial fluctuations in annual capacity additions, shown in Figure 2-8, partly result from developers accelerating projects before incentives change or expire. The IRA of 2022 improved policy certainty by extending the legacy PTC through 2024 and introducing the technology-neutral Section 45Y CEPTC starting in 2025. Nonetheless, the OBBBA of 2025 limited wind project eligibility. Wind facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the Section 45Y CEPTC. Facilities that begin construction on or before July 4, 2026 are not subject to this accelerated termination rule but remain subject to applicable beginning-of-construction and continuity requirements. Besides policy changes, factors such as market conditions, permitting, transmission access, and supply

chain issues also influence yearly wind capacity additions.

Figure 2-8: U.S. wind capacity growth (Sources: LBNL [10], DOE [11])

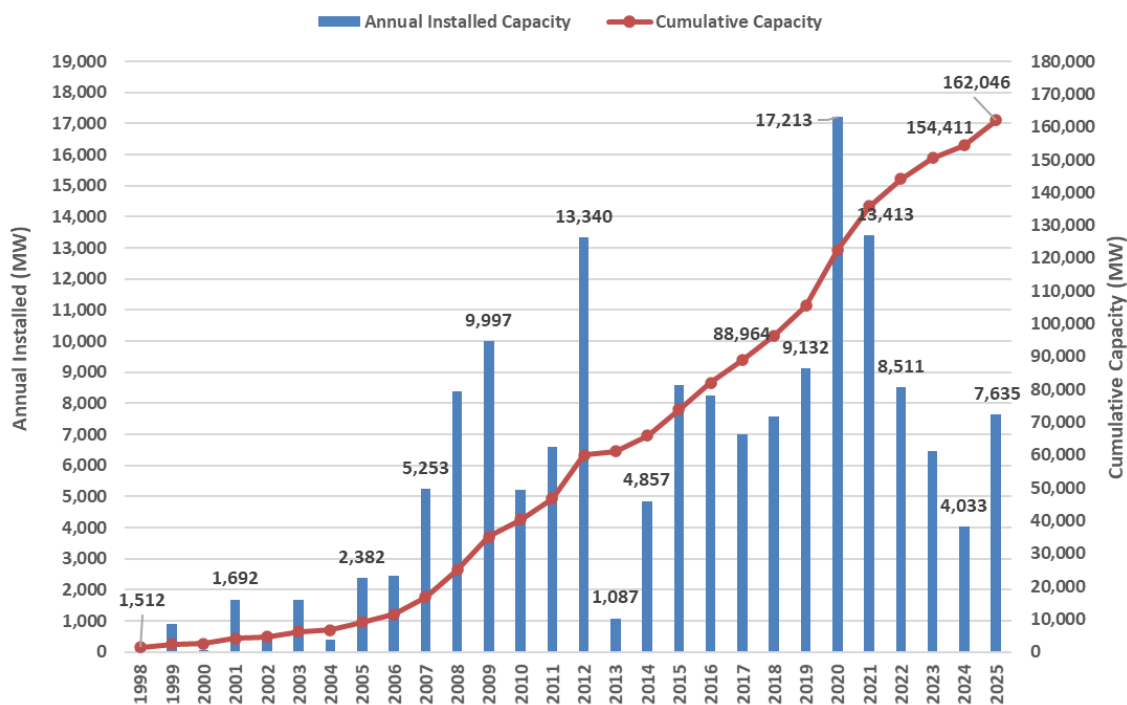


Figure 2-9 is a map showing the states that have enacted some form of renewable or clean energy portfolio standard or set a non-binding goal. Twenty-seven states and Washington, DC, have binding renewable portfolio standards, while six states, including Indiana, have non-binding renewable portfolio goals. Thirteen states have binding clean energy standards, while six states have non-binding clean energy goals. Clean energy standards differ from renewable portfolio standards in that they also include low-carbon resources, such as nuclear energy and coal-bed methane, that are deemed to reduce net greenhouse gas emissions.

Figure 2-9: Renewable portfolio standards across the U.S. (Source: Database of State Incentives for Renewables & Efficiency (DSIRE) [12])

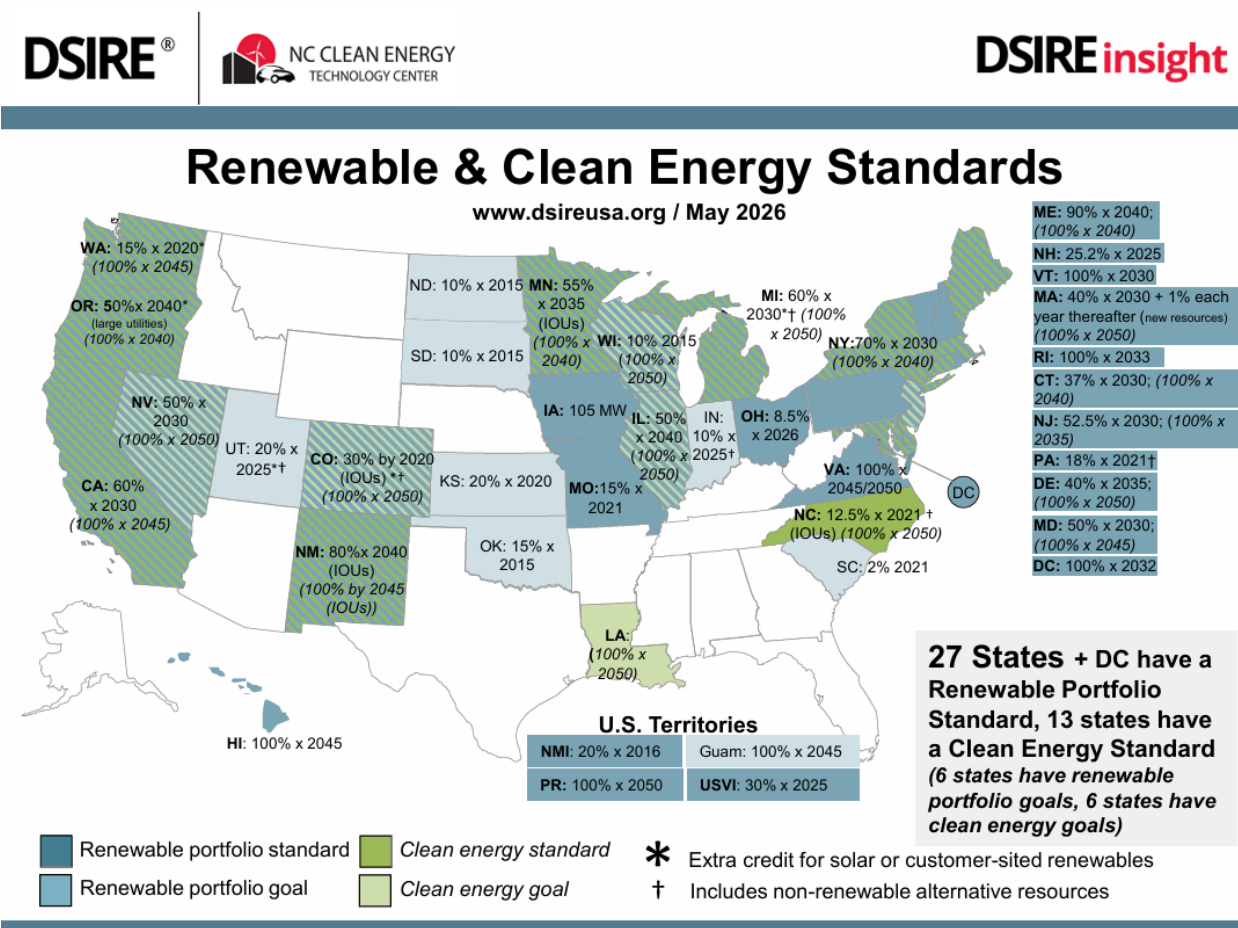


Table 2-2 shows the distribution of the 153,489 MW cumulative capacity of utility-scale wind farms installed in the U.S. by state at the end of 2024. Texas continued to lead with a total capacity of 42,283 MW installed, over three times the installed capacity of its closest follower, Iowa, which had 13,016 MW installed. Oklahoma is third with 12,749 MW installed. Indiana ranked 14th overall with 3,641 MW of wind capacity installed.

Table 2-2: Installed wind power by state at end of 2024 (EIA [13])

Ranking	State	Cumulative Capacity 2024 (MW)		Ranking	State	Cumulative Capacity 2024 (MW)
1	Texas	42,283		27	Wisconsin	826
2	Iowa	13,016		28	North Carolina	397
3	Oklahoma	12,749		29	Utah	390
4	Kansas	9,105		30	Hawaii	233
5	Illinois	7,904		31	New Hampshire	214
6	California	6,487		32	Maryland	190
7	Colorado	5,379		33	Mississippi	185
8	Minnesota	4,972		34	Vermont	151
9	North Dakota	4,529		35	Nevada	150
10	New Mexico	4,429		36	Massachusetts	102
11	Oregon	3,981		37	Rhode Island	78
12	Michigan	3,777		38	Alaska	60
13	Wyoming	3,727		39	Virginia	12
14	Indiana	3,641		40	New Jersey	9
15	Nebraska	3,523		41	Connecticut	5
16	South Dakota	3,457		42	Delaware	2
17	Washington	3,387		43	Tennessee	2
18	New York	2,869		44	Alabama	0
19	Missouri	2,454		45	Arkansas	0
20	Montana	1,898		46	District of Columbia	0
21	Pennsylvania	1,556		47	Florida	0
22	Arizona	1,235		48	Georgia	0
23	Idaho	1,132		49	Kentucky	0
24	Ohio	1,107		50	Louisiana	0
25	Maine	1,033		51	South Carolina	0
26	West Virginia	856		52	Puerto Rico	0
				U.S. Total		153,489

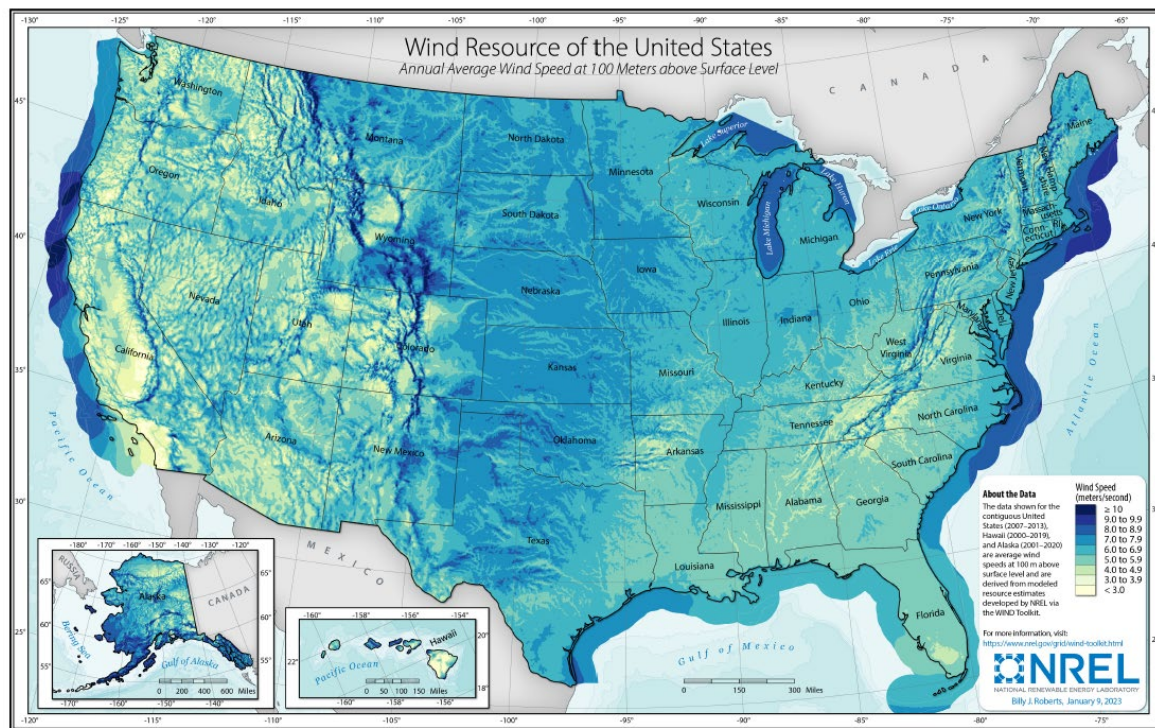
While Texas led in total installed capacity, Iowa led in the share of electricity generated by wind in 2024, at 63 percent. South Dakota followed, with wind contributing 58 percent of electricity generation. Indiana ranked 18th overall in the share of electricity generated by wind in 2024, at 11 percent. Table 2-3 shows the top twenty rankings for wind energy capacity installed and the share of in-state electricity generation from wind in 2024.

Table 2-3: U.S. wind power rankings: top 20 states (LBNL [10], EIA [13, 14])

State	Installed Wind Capacity December 2024 (MW)	State	Wind Share of Electricity Generation 2024
Texas	42,283	Iowa	63%
Iowa	13,016	South Dakota	58%
Oklahoma	12,749	Kansas	52%
Kansas	9,105	Oklahoma	40%
Illinois	7,904	New Mexico	38%
California	6,487	North Dakota	35%
Colorado	5,379	Nebraska	32%
Minnesota	4,972	Colorado	30%
North Dakota	4,529	Minnesota	25%
New Mexico	4,429	Wyoming	22%
Oregon	3,981	Texas	22%
Michigan	3,777	Montana	22%
Wyoming	3,727	Maine	17%
Indiana	3,641	Vermont	16%
Nebraska	3,523	Idaho	15%
South Dakota	3,457	Oregon	15%
Washington	3,387	Illinois	13%
New York	2,869	Indiana	11%
Missouri	2,454	Missouri	10%
Montana	1,898	Washington	9%
U.S. Total	153,489	U.S. Total	10%

The U.S. has significant wind energy potential. NLR estimates the potential onshore wind capacity that could be installed on available windy land areas across the U.S. is approximately 11 million MW, and the annual wind energy that could be generated from this potential capacity is approximately 31 million gigawatt-hours (GWh). This is approximately 6.5 times the 4,760,539 GWh of electricity generated from all sources in the U.S. in 2024 [15, 16]. Figure 2-10 shows the distribution of the wind resource.

Figure 2-10: 100-meter U.S. wind resource map (Source: DOE [17])



As shown in Figure 2-10, there is an abundance of wind energy resources along the U.S. coastlines. Offshore winds tend to be higher in speed and steadier than onshore winds. According to a DOE assessment, the technically feasible capacity of offshore wind in the U.S. is approximately 4,000 GW, which can generate 13,500,000 GWh of electricity annually. This is close to three times the 4,760,539 GWh of electricity generated from all generation resources in the U.S. in 2025 [18].

Although the potential for offshore wind off the coast of the U.S. is high, only three offshore wind projects with a combined capacity of 174 MW had been completed at the end of 2024. They are the 30 MW Block Island Wind Farm off the coast of Rhode Island, commissioned in 2016; the 12 MW Coastal Virginia Offshore Wind project by Dominion Energy, completed in 2020; and the 132 MW South Fork Wind Farm off the coast of New York, commissioned in March 2024. Table 2-4 shows the status of the offshore projects off the coasts of the U.S. as of May 2024 according to the U.S. DOE 2024 Offshore Wind Market Report [19].

Table 2-4: Offshore wind projects development pipeline (Data Source: DOE [19])

Project Pipeline Classification	Classification Definition	East Coast (MW)	Gulf of Mexico (MW)	West Coast (MW)	Total (MW)
Operating	Turbines installed and connected to the grid	174	0	0	174
Under Construction	Major construction initiated	4,097	0	0	4,097
Approved	Approved to start construction	3,378	0	0	3,378
Permitting	Permit applications filed	19,793	0	0	19,793
Site Control	Developer obtained site control	22,870	0	0	22,870
Planning	Formal site control process initiated	20,416	6,638	3,157	30,211
Total		70,728	6,638	3,157	80,523

Several states on the East Coast and California have targets and mandates for major offshore wind farm installations to meet their renewable energy and climate mitigation goals. These include 115,130 MW of goals, 45,730 MW of mandated capacity, and 12,378 MW that had power purchase agreements in place for their generation. The targets and mandates are shown in Tables 2-5. In addition, in 2021 DOE set a goal to install 30 GW of offshore wind generating capacity by 2030 [20, 21].

Table 2-5: Offshore wind capacity targets and mandates (Data Source: DOE [19])

State	Planning Goal		Mandated Procurement		Offtake Contracts Awarded (MW)
	Planning Target (MW)	Planning Target Year	Mandated Capacity (MW)	Target Mandate Year	
California	25,000	2045			
Massachusetts	23,000	2050	5,600	2035	806
New York	20,000	2050	9,000	2035	1,866
New Jersey	11,000	2040	11,000	2,040	5,252
Maryland	8,500	2031	8,500	2,031	1,109
North Carolina	8,000	2040			
Virginia	5,200	2034	5,200	2,034	2,599
Louisiana	5,000	2035			
Maine	3,000	2040	3,000	2040	12
Oregon	3,000	2030			
Connecticut	2,000	2030	2,000	2030	304
Rhode Island	1,430	2030	1,430	2030	430
Total	115,130	2050	45,730	2040	12,378

The construction of the first large-scale offshore wind project in the United States, the 800 MW Vineyard Wind 1 project located approximately 15 miles off the coast of Massachusetts, began following federal approval in 2021. The project reached an important milestone on January 2, 2024, when its first turbine delivered approximately 5 MW of electricity to the New England grid. Construction was temporarily delayed after a turbine blade failure in July 2024, but resumed in January 2025 following federal approval of corrective measures. Vineyard Wind 1 was completed in March 2026, becoming the first commercial-scale offshore wind farm in the United States [22].

In 2023, the momentum of offshore wind development along the U.S. East Coast slowed significantly as several major projects terminated their existing power purchase agreements after inflation, rising interest rates, supply-chain disruptions, and higher equipment costs made the contracted prices financially unviable. These included the 804 MW Park City Wind project off the coast of Connecticut, the 1,232 MW Commonwealth Wind project, and the Mayflower Wind project (now SouthCoast Wind) off the coast of Massachusetts. Although the underlying lease areas remained under development, these contract terminations delayed project deployment and highlighted the financial challenges facing the U.S. offshore wind industry [23].

2.4 Wind energy in Indiana

Since the installation of the first utility-scale wind farm in Benton County in 2008, Indiana's utility-scale wind generating capacity has grown steadily, increasing from 131 MW in 2008 to 4,060 MW at the end of 2025. As of the writing of this report, two wind farms with a combined capacity of 403 MW were under construction in Blackford County. Figure 2-11 shows the utility-scale wind capacity installed in Indiana.

Figure 2-11: Utility-scale wind farm capacity installed in Indiana (Data source: IURC [24], NIPSCO [25]).

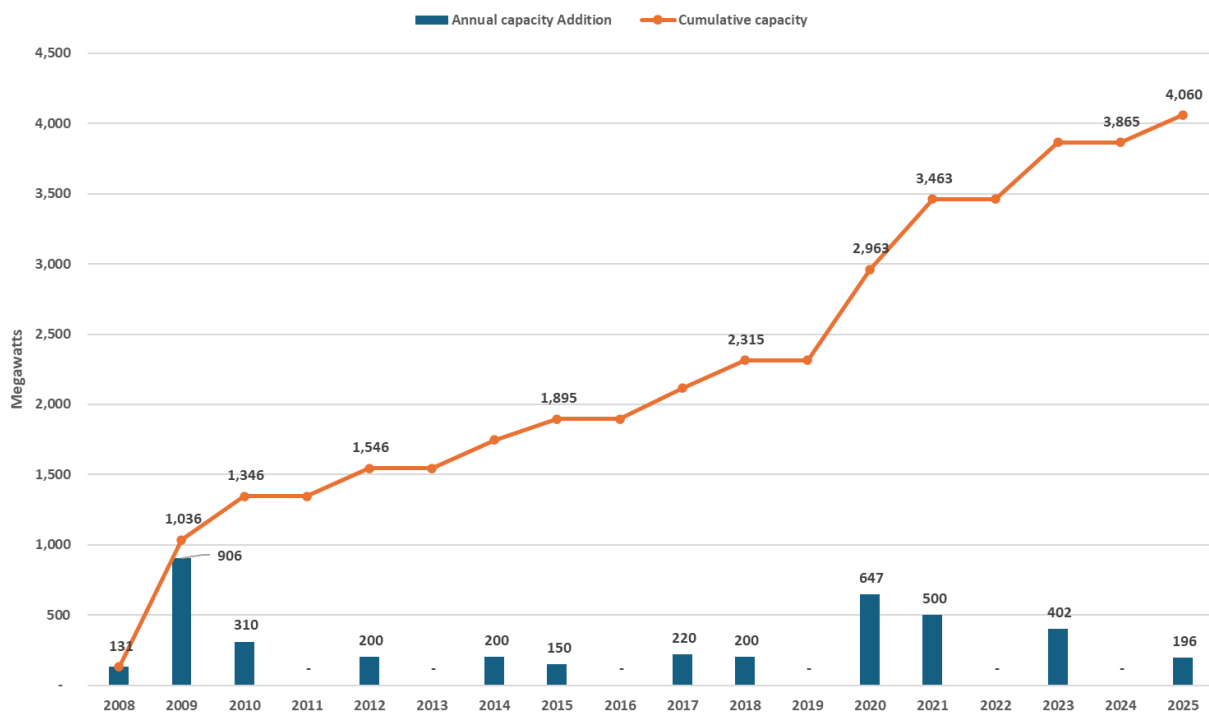


Table 2-6 is a list of utility-scale wind farms operating or under construction in Indiana. As of the writing of this report, there were 23 operational wind farms with a combined capacity of 4,060 MW. Two wind farms with a combined capacity of 403 MW were under construction, and three wind farms with a combined capacity of 500 MW had been approved by the IURC but had not yet started construction at the writing of this report.

Table 2-6: Indiana wind farms; operating and under construction (Data source: IURC [24], NIPSCO [25])

Wind Farm Name	County	Capacity (MW)	In-Service Year
Benton County/Goodland I Wind Farm	Benton	131	2008
Fowler Ridge Wind Farm I	Benton/ Tippecanoe	301	2009
Fowler Ridge Wind Farm II-A	Benton	200	2009
Fowler Ridge Wind Farm III	Benton	99	2009
Hoosier Wind Farm	Benton	106	2009
Meadow Lake Wind Farm I	White	200	2009
Meadow Lake Wind Farm II	White	101	2010
Meadow Lake Wind Farm III	White	110	2010
Meadow Lake Wind Farm IV	White	99	2010
Wildcat Wind Farm I	Madison/Tipton	200	2012
Headwaters Wind Farm I	Randolph	200	2014
Fowler Ridge IV Wind Farm (Amazon Wind Farm Fowler Ridge)	Benton	150	2015
Meadow Lake Wind Farm V	White	100	2017
Bluff Point Wind Farm	Jay/Randolph	120	2017
Meadow Lake Wind Farm VI	Benton	200	2018
Jordan Creek Wind Farm	Benton/Warren	399	2020
Bitter Ridge Wind Farm	Jay	146	2020
Rosewater Wind Farm	White	102	2020
Headwaters II Wind Farm	Randolph	198	2021
Indiana Crossroads Wind Farm	White	302	2021
Sweet Acres Wind Farm	White	202	2023
Indiana Crossroads II Wind Farm	White	200	2023
Carpenter Wind Farm	Jasper	196	2025

Total operating

4,060

Under construction

Prairie Creek Wind	Blackford	203	2027
Blackford Wind Energy	Blackford	200	2027

Figure 2-12 shows the distribution of Indiana wind energy resources at 100 meters, the height at which utility-scale wind turbines typically operate, while Figure 2-13 shows the distribution of the wind resource at 50 meters, a height at which smaller-scale community wind projects operate.

Figure 2-12: Indiana wind speed at 100 meters height (Source: DOE/NLR [26])

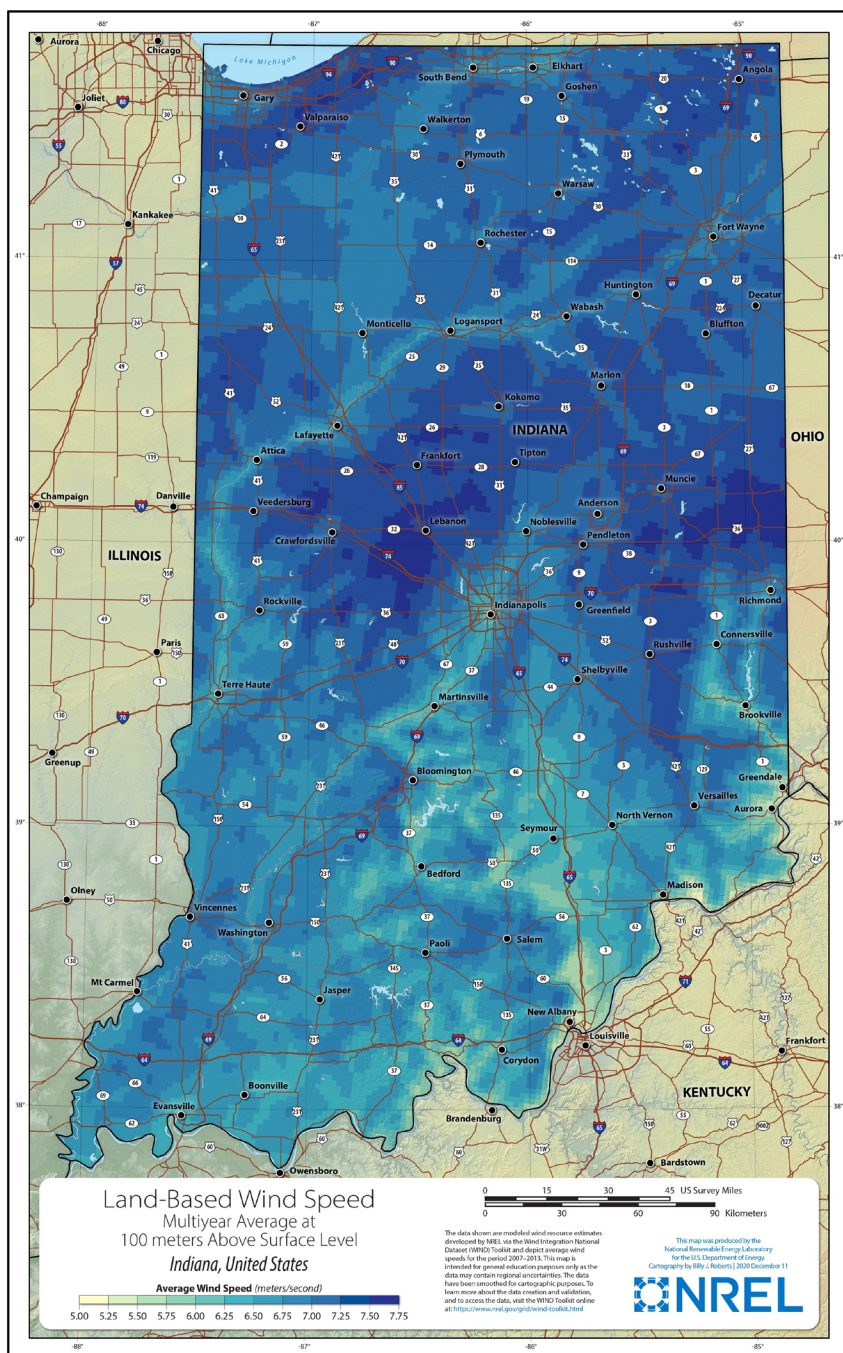
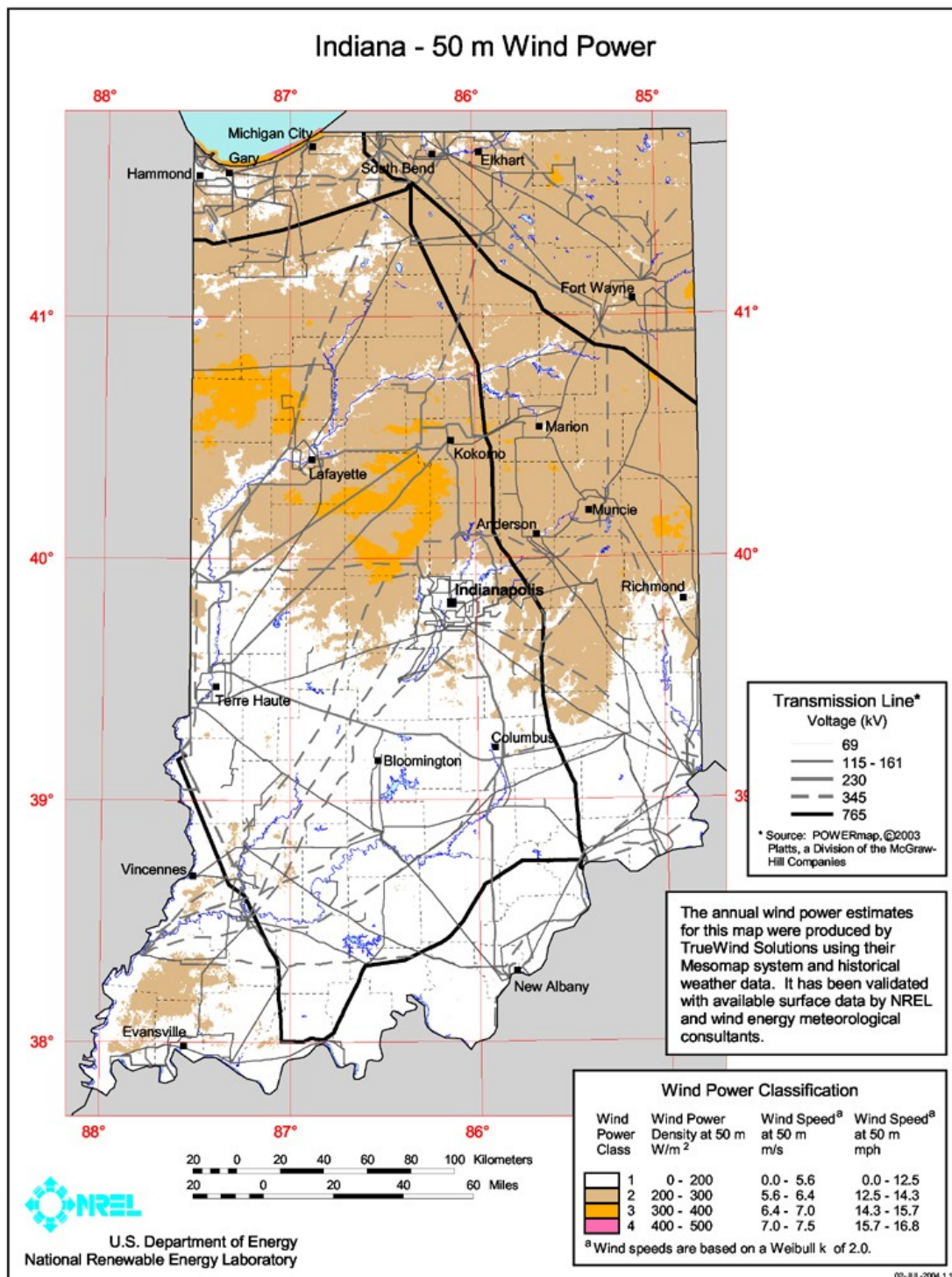


Figure 2-13: Indiana wind speed at 50 meters height (Source: DOE/NREL [26])



With the rapid expansion of utility-scale wind farms in Indiana and across the U.S., resistance has arisen in some communities, leading to the passage of local government ordinances

restricting their installation in some counties. One such local ordinance was passed in Tippecanoe County in May 2019, restricting the maximum height of wind turbines to 140 feet. This effectively bans utility-scale wind farms in the county since the typical utility-scale wind turbine tower ranges anywhere from 300 to 600 feet. Similar restrictive ordinances have been adopted in numerous Indiana counties, reflecting ongoing concerns over visual impacts, noise, setbacks, and land use. In 2022, Indiana enacted default statewide standards for utility-scale wind projects through Public Law 90-2022. The law establishes minimum standards for projects in qualifying "Wind Energy Ready Communities" while allowing local governments to adopt their own wind ordinances in many circumstances. [27, 28].

In April 2023, Senate Enrolled Act 390 (SEA 390) was signed into law to encourage counties and municipalities to adopt regulations that facilitate the development of commercial solar and wind projects. The law established a certification program, administered by the Indiana Office of Energy Development (OED), for Commercial Solar Energy Ready Communities and Wind Energy Ready Communities. To qualify, a community's solar or wind regulations generally must not be more restrictive than Indiana's default statewide standards and must meet additional certification requirements. SEA 390 also authorizes an incentive fund that may provide certified communities with payments of \$1/MWh of electricity generated from qualifying commercial solar or wind projects for up to ten years. However, as of 2026, although the certification program is operational, no incentive funds have been appropriated or made available [29].

2.5 Incentives for wind energy

The following federal and state incentives are available for wind energy projects.

Federal Incentives

- PTC credits wind energy producers with 1.5 cents/kWh in 1993 dollars adjusted by an inflation factor supplied by the IRS for the calendar year. The Inflation Reduction Act of 2022 (IRA) extended the PTC to include projects that begin construction before the end of 2024. To qualify for the full credit, a project must meet the prevailing wage and apprenticeship conditions. Details about the prevailing wage and apprenticeship conditions and other definitions in the IRA are given in Section 1.4 of this report. A project that does not meet the prevailing wage and apprenticeship conditions qualifies only for a credit of 0.3 cents/kWh (1993 dollars). Projects can also qualify for an extra 10 percent credit if they have the specified level of domestic content in the qualified facilities or are located in an energy "community." The percentages given here are percentages of the base 1.5 cents/kWh, inflation adjusted [30, 31].
- CEPTC, established under Section 45Y of the IRA, became effective for qualifying facilities placed in service after December 31, 2024. Unlike the legacy PTC, the CEPTC is

available to all qualifying technologies with zero or negative greenhouse gas emissions. Under the IRA, the credit was scheduled to begin phasing out after the later of 2032 or the year in which U.S. electricity-sector greenhouse gas emissions declined to 25 percent of 2022 levels. The OBBBA subsequently accelerated the termination of the CEPTC for wind and solar facilities. Wind and solar facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the credit. Facilities that begin construction on or before July 4, 2026 are not subject to this accelerated termination rule, but remain subject to applicable beginning-of-construction and continuity requirements. [31, 32].

- CEITC, established under Section 48E of the IRA, also became effective for qualifying facilities placed in service after December 31, 2024. The CEITC allows eligible taxpayers to claim a tax credit generally equal to 30 percent of eligible project costs in lieu of the CEPTC, provided the prevailing wage and apprenticeship requirements are satisfied. As under the CEPTC, the IRA originally scheduled the credit to begin phasing out after the later of 2032 or the achievement of the electricity-sector emissions threshold. The OBBBA subsequently removed the emissions-based trigger, making 2032 the applicable year for the general phaseout, while establishing a separate accelerated termination rule for wind and solar facilities. Wind and solar facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the CEITC. Facilities that begin construction on or before July 4, 2026 are not subject to this accelerated termination rule but remain subject to applicable beginning-of-construction and continuity requirements [31, 32].
- U.S. DOE Title 17 Energy Financing Program (Section 1703 of Title XVII of the Energy Policy Act of 2005) provides loan guarantees for eligible energy projects, including projects that deploy new or significantly improved technologies that are technically proven but not yet widely commercialized in the United States. Eligible technologies include renewable energy technologies such as wind energy [33].
- Modified Accelerated Cost-Recovery System (MACRS) allows businesses to recover investments in qualified renewable energy property through accelerated depreciation deductions. In addition, Congress has periodically authorized bonus depreciation, allowing a portion or all of the investment cost to be deducted in the first year, subject to applicable tax law in effect at the time [34].
- USDA Rural Energy for America Program (REAP) provides financial assistance to agricultural producers and rural small businesses for eligible renewable energy systems and energy-efficiency improvements. Loan guarantees are available on loans covering up to 75 percent of total eligible project costs. Grants may cover up to 50 percent of eligible

project costs for qualifying projects, while other projects are limited to a 25 percent federal grant share. Combined grant and loan-guarantee funding may cover up to 75 percent of total eligible project costs [35].

- High Energy Cost Grant Program, administered by USDA assists eligible rural communities with extremely high household energy costs, defined as exceeding 275 percent of the national average. Eligible projects include the acquisition, construction, or improvement of energy generation, transmission, and distribution facilities, including renewable energy projects [36].
- Federal Renewable Energy Use Statutory Requirement (Section 203 of the Energy Policy Act of 2005, as amended) requires that, to the extent economically feasible and technically practicable, at least 7.5 percent of the electricity consumed by the Federal Government each fiscal year be obtained from renewable energy sources [37].

Indiana Incentives

- SEA 390 of 2023 established a certification program administered by the OED to encourage counties and municipalities to adopt regulations that facilitate commercial solar and wind development. Counties and municipalities may be certified as Commercial Solar Energy Ready Communities or Wind Energy Ready Communities if their ordinances satisfy statutory requirements, including generally not being more restrictive than Indiana's statewide default standards. The Act also authorizes incentive payments of \$1/MWh of electricity generated for up to ten years to certified communities hosting qualifying commercial solar or wind projects, subject to legislative appropriation. As of 2026, the certification program is operational, but no incentive funds have been appropriated. [38].
- Net Metering Rule continues to allow eligible grandfathered utility customers with renewable energy systems having a maximum generating capacity of 1 MW to receive retail-rate credits for excess electricity exported to the grid. Senate Enrolled Act 309 (SEA 309), signed into law in 2017, transitioned Indiana from traditional net metering to the Excess Distributed Generation (EDG) program for new customers after June 30, 2022. Customers with qualifying systems installed before January 1, 2018 continue to receive retail-rate credits until July 1, 2047, while eligible systems installed between January 1, 2018 and June 30, 2022, or until the utility reached the statutory 1.5 percent aggregate-capacity threshold, whichever occurred first, continue to receive retail-rate credits until July 1, 2032 [39, 43].
- EDG Rule, established under Indiana Code 8-1-40 pursuant to SEA 309 (2017), replaced

net metering for new distributed generation customers after June 30, 2022. Under the EDG program, excess electricity exported to the grid is compensated at 125 percent of the utility's average marginal price of electricity during the most recent calendar year [39, 43].

- Renewable Energy Property Tax Deduction previously provided property tax deductions for qualifying solar, wind, hydroelectric, and geothermal energy systems. SEA 1 of 2025 eliminated these deductions effective for assessment dates beginning January 1, 2025 [40].
- Sales and Use Tax Exemption for Electrical Generating Equipment may exempt machinery, tools, equipment, and other tangible personal property that are directly used in the direct production of tangible personal property, including electricity, from Indiana sales and use tax. Equipment used to generate electricity that is directly used in the production of other tangible personal property may also qualify for the manufacturing exemption to the extent that the applicable direct-use requirements are satisfied [12, 44].
- Clean Energy Portfolio Goal established a voluntary goal of obtaining 4 percent of electricity from clean energy sources between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent in 2025, based on 2010 retail sales. The final statutory goal period ended on December 31, 2025, and no additional clean energy portfolio goals are specified beyond 2025. However, financial incentives and cost-recovery mechanisms approved for participating electricity suppliers that achieved the applicable goals may continue beyond 2025 in accordance with the terms of the program and IURC approval [41].
- NIPSCO offers feed-in tariff incentive rates for electricity generated from renewable resources for up to 15 years. The payment for wind turbines between 3kW and 10kW is \$0.2300/kWh and \$0.1380/kWh for wind turbines larger than 10kW up to 200kW. The program is closed to new applicants, although existing contracts remain in effect under their respective agreements [42].

2.6 References

1. The Engineers Post.
<https://www.theengineerspost.com/types-wind-turbine-horizontal-vertical/>
2. Encyclopedia Britannica
<https://cdn.britannica.com/48/121648-050-562F03B0/Components-wind-turbine.jpg>
3. U.S. DOE, EIA. Wind explained: History of wind power.
<https://www.eia.gov/energyexplained/wind/history-of-wind-power.php>
4. U.S. DOE. Wind vision: a new era for wind in the United States.
https://www.energy.gov/sites/prod/files/WindVision_Report_final.pdf

5. Renewable Energy Research Laboratory. University of Massachusetts at Amherst. Wind power: Capacity factor, intermittency, and what happens when the wind doesn't blow? <http://www.leg.state.vt.us/jfo/envy/Wind%20Power%20Fact%20Sheet.pdf>
6. NLR. 2022 annual technology baseline. Land based wind classes. https://atb.nlr.gov/electricity/2022/land-based_wind
7. EIA. Assumptions to the Annual Energy Outlook 2026: Electricity Market Module. April 2026. https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf
8. EIA. Today in Energy, August 17, 2021 <https://www.eia.gov/todayinenergy/detail.php?id=49176>
9. Construction cost data for electric generators installed in 2024 <https://www.eia.gov/electricity/generatorcosts/>
10. LBNL. Land-Based Wind Energy Technology Data Update Figure File: 2025 Edition. <https://emp.lbl.gov/wind-technologies-market-report/>
11. U.S. DOE WINDEXchange. U.S. Installed and Potential Wind Power Capacity and Generation. <https://windexchange.energy.gov/maps-data/321>
12. Database of State Incentives for Renewables & Efficiency (DSIRE). <http://www.dsireusa.org/>
13. EIA. Electric Power Monthly. Proposed Nameplate and Net Summer Capacity by Year, Energy Source, and State (EIA-860). <https://www.eia.gov/electricity/data/state/#electricPowerMonthly>
14. EIA. Electric Power Monthly. Net Generation by State by Type of Producer by Energy Source. 1990-2024. <https://www.eia.gov/electricity/data/state/>
https://www.eia.gov/electricity/data/state/generation_monthly.xlsx
15. U.S. DOE WINDEXchange. Potential wind data. <https://windexchange.energy.gov/maps-data/321>
https://windexchange.energy.gov/files/docs/potential_capacity_and_generation_by_state.xlsx
16. EIA. April 2025 Monthly Energy Review Table 7.2a <https://www.eia.gov/totalenergy/data/monthly/#electricity>
17. U.S. DOE WINDEXchange. Wind energy maps and data. <https://www.energy.gov/cmei/systems/wind-resource-assessment-and-characterization>
18. U.S. DOE. Offshore Wind Research and Development <https://www.energy.gov/eere/wind/offshore-wind-research-and-development>
19. U.S. DOE. Offshore Wind Market Report <https://www.energy.gov/eere/wind/offshore-wind-market-report>

20. U.S. Department of Interior – May 25 2021. Press release. Biden-Harris Administration Advances Offshore Wind in the Pacific.
<https://www.doi.gov/pressreleases/biden-harris-administration-advances-offshore-wind-pacific>
21. U.S. DOE. Offshore Wind Energy Strategies. January, 2022.
<https://www.energy.gov/sites/default/files/2022-01/offshore-wind-energy-strategies-report-january-2022.pdf>
22. WBUR. Vineyard Wind, country's first large-scale offshore wind project, finishes construction.
<https://www.wbur.org/news/2026/03/14/vineyard-wind-construction-complete-massachusetts-offshore-wind>
23. Megawatt Daily. October 3, 2023
24. IURC. July 2026
25. NIPSCO, 2024 Integrated Resource Plan, page 27
<https://www.in.gov/iurc/files/NIPSCO-2024-Integrated-Resource-Plan-Document.pdf>
26. U.S. DOE Office of Energy Efficiency and Renewable Energy. Indiana wind maps & reports.
<https://windexchange.energy.gov/states/in>
100 meters map: <https://windexchange.energy.gov/maps-data/350>
50 meters map: <https://windexchange.energy.gov/maps-data/41>
27. Journal and Courier. May 6, 2019. Wind farms banned in rural Tippecanoe County, as environmentalists grumble.
<https://www.jconline.com/story/news/2019/05/06/wind-farms-banned-rural-tippecanoe-county-environmentalists-grumble/3660870002/>
28. JUSTIA. 2022 Indiana Code Title 8. Utilities and Transportation Article 1. Utilities Generally Chapter 41. Default Standards for Wind Power Devices
<https://law.justia.com/codes/indiana/2022/title-8/article-1/chapter-41/>
29. Indiana Office of Energy Development. Energy Ready Communities Development Center.
<https://www.in.gov/oed/indianas-energy-policy/energy-ready-communities>
30. The National Law Review. August 17, 2022. Relief Arrives for Renewable Energy Industry - Inflation Reduction Act of 2022.
<https://www.natlawreview.com/article/relief-arrives-renewable-energy-industry-inflation-reduction-act-2022>
31. DLA Piper Law Firm Publications. The clean energy provisions of the Inflation Reduction Act of 2022 – a historic effort to encourage the development of clean energy and reduce carbon emissions.
<https://www.dlapiper.com/en/us/insights/publications/2022/08/the-clean-energy-provisions-of-the-inflation-reduction-act-of-2022/>

32. Sidley Energy Updates. The “One Big Beautiful Bill” Act – Navigating the New Energy Landscape. July 15, 2025.
<https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape>
33. U.S. Department of Energy. Program Guidance for the Title 17 Energy Financing Program. May 13, 2026.
<https://www.energy.gov/documents/doe-edf-title-17-energy-financing-program-guidance-2026-05-13>
34. Internal Revenue Service (IRS). Publication 946: How to Depreciate Property (2025). Chapter 4, Modified Accelerated Cost Recovery System (MACRS).
<https://www.irs.gov/publications/p946?a=ecd3e32d-b1e8-49de-8f6a-fee4333c9c61&utm>
35. U.S. Department of Agriculture (USDA) Rural Development. Rural Energy for America Program Renewable Energy Systems & Energy Efficiency Improvement Guaranteed Loans & Grants.
<https://www.rd.usda.gov/programs-services/rural-energy-america-program-renewable-energy-systems-energy-efficiency>
36. U.S. Department of Agriculture, Rural Development, Electric Programs.
<http://www.rd.usda.gov/programs-services/high-energy-cost-grants>
37. U.S. DOE. Federal Renewable Energy Use Statutory Requirement.
<https://www.energy.gov/cmei/femp/federal-renewable-energy-use-statutory-requirement>
38. Indiana Office of Energy Development. Solar and Wind Energy Ready Communities.
<https://www.in.gov/oed/indianas-energy-policy/energy-ready-communities/>
39. Indiana General Assembly. Senate Bill 309.
<https://iga.in.gov/legislative/2017/bills/senate/309#digest-heading>
40. Indiana Department of Local Government Finance. Frequently Asked Questions: 2025 Legislative Overview. June 18, 2025.
<https://www.in.gov/dlgf/files/2025-presentations/250618-FAQ-Webinar-Legislative-Update.pdf>
41. Indiana General Assembly. Indiana Code 8-1-37, Voluntary Clean Energy Portfolio Standard Program, Sections 12–13.
<https://iga.in.gov/laws/2026/ic/titles/8>
42. NIPSCO. Feed-in Tariff
<https://www.nipsco.com/services/renewable-energy-programs/feed-in-tariff>
43. Indiana General Assembly. Indiana Code 8-1-40, Distributed Generation, particularly IC 8-1-40-17.
<https://iga.in.gov/laws/2026/ic/titles/8>
44. Indiana Department of Revenue. Sales and Use Tax Refunds — Manufacturing Exemptions. Accessed 2026.
<https://www.in.gov/dor/i-am-a/business-corp/sales-use-tax-refunds>

3. Dedicated Energy Crops

3.1 Introduction

This section discusses biomass in the form of crops grown exclusively for use as an energy source. This differs from the use of organic waste and residues discussed in Chapter 4 of this report and from bioenergy from dual-use crops such as corn and soybeans, which are currently used to make transportation fuels such as ethanol and biodiesel. Although biomass is already the largest source of renewable energy in the U.S., the energy crops industry is still in its infancy. There are still significant technical and financial hurdles to be overcome before energy crops can be widely used as a commercially viable source of energy [1].

A substantial coordinated research and development effort across the federal government, led by the U.S. Department of Agriculture (USDA) and the U.S. Department of Energy (DOE), has been underway to build a national bioenergy industry with the objective to use non-food biomass to produce fuels, electricity, and other products currently produced using fossil fuels [2].

Biomass is unique among renewable resources in that it can also be used as feedstock to produce liquid transportation fuels and industrial chemicals. This characteristic is the primary motivation behind the research on energy crops and organic waste biomass and the associated conversion technologies. The state of this research effort was detailed in the DOE 2016 Billion-Ton Study update. The crops considered and developed as dedicated energy crops can be grouped into three main categories: perennial grasses, woody crops, and annual crops [3].

Perennial grasses include switchgrass, big bluestem, Indian grass, miscanthus, and sugarcane. Switchgrass, big bluestem, and Indian grass are perennial grasses that are native to North America. They are already grown in a wide range of habitats and climates for pasture, hay production, soil and water conservation, and for wildlife habitat. With proper management they can remain productive for as long as ten years.

The Giant Miscanthus hybrid was developed in Japan and introduced to the U.S. as a landscape plant. The main attraction of Giant Miscanthus as an energy crop is its high level of biomass production. While a great deal of research has been done establishing its potential as an energy crop, there are still barriers to overcome before it can enter large scale commercial production. They include the development of low-cost reliable propagation methods since it is a seedless sterile hybrid. In addition, there is still work to be done to identify varieties suited to given regions of the country.

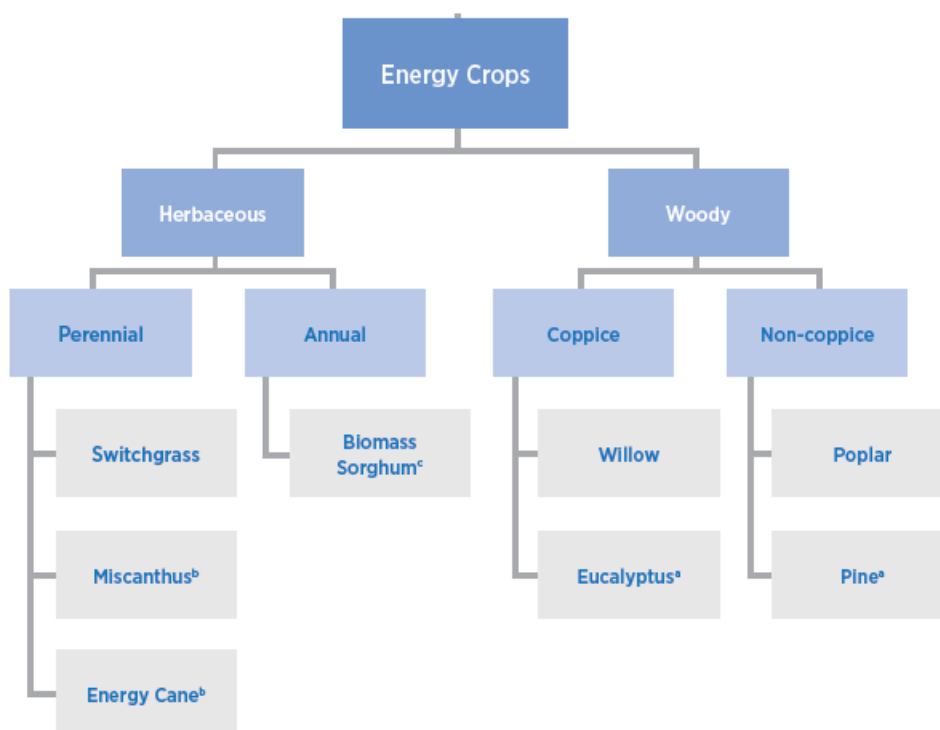
Sugarcane is attractive as an energy crop primarily due to its ability to store sugar in its stem. In addition, sugarcane ethanol is used as a fuel and is recognized to cut greenhouse gas emissions more than any other biofuel. However, sugarcane is a tropical crop and significant research is still needed to develop varieties that do well in temperate climates.

Woody crops being developed as energy crops include poplars, willows, eucalyptus, and southern pines. Poplars are well established trees native to North America. There are already commercial plantations of hybrid poplars (cottonwood) for the production of fiber and biofuels, as well as for environmental remediation. High rates of biomass productivity, ease of propagation and management are cited as factors that make poplar attractive as an energy crop. The characteristics that make willows desirable as an energy crop include high yields, ease of propagation and high energy content. Eucalyptus is being developed for the southern United States where it is grown for lumber. It has been grown commercially for lumber in Florida since the 1960s.

Southern pines are already among the main contributors to bioenergy in the United States. Their bark and the paper-processing byproduct black liquor are used to generate energy in pulp and paper mills. Their ability to grow rapidly across a wide range of sites has made southern pine the most important and widely cultivated timber species in the U.S., primarily for lumber and pulpwood.

The main annual crop being developed as an energy crop is sorghum. According to the DOE Biomass Program, although perennial crops are considered better than annual crops for energy production sustainability purposes, an annual crop serves well as a bridge for a new bioenergy processing facility as it awaits the establishment and full productivity of perennial crops. The factors that make sorghum attractive as an energy crop include its composition (e.g., high in stalk sugar), high yield potential, drought resistance, water use efficiency, established production systems, and potential for genetic improvement [4]. Figure 3-1 shows the energy crops considered under the 2016 Billion-Ton Report.

Figure 3-1: Energy crops included in the 2016 Billion-Ton Report (Source: DOE [3])



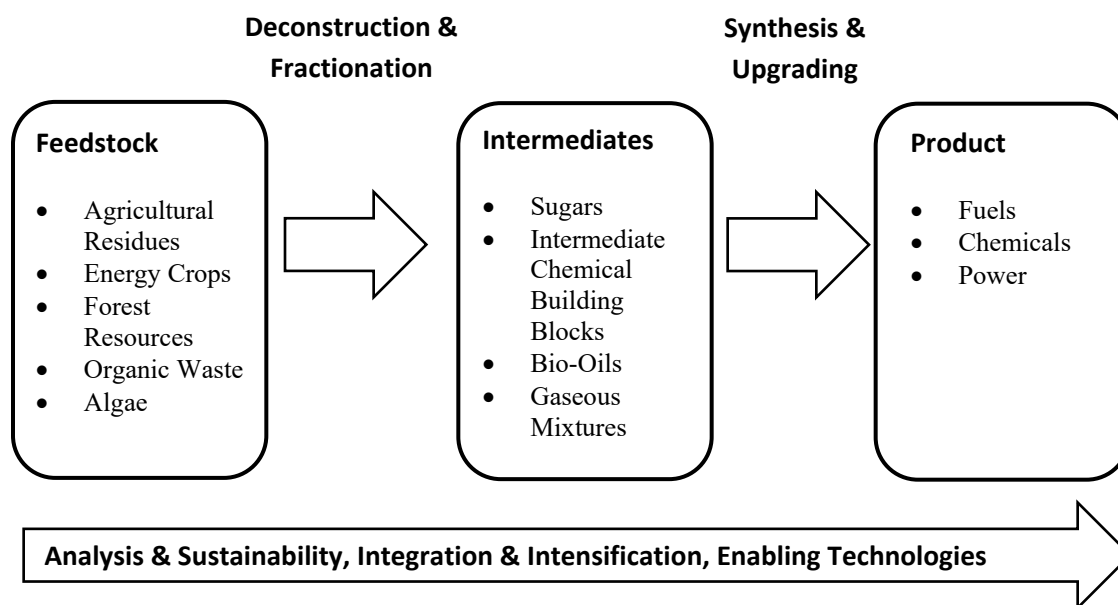
^{a, b, c} These energy crops were studied in more detail in the 2016 Billion-Ton Report than in previous versions of the Billion-Ton Study.

Biomass, including energy crops, can be converted into energy in the following ways:

- In direct combustion, the biomass is burned directly in a boiler to produce steam that can then be used to drive a turbine to generate electricity. Combustion can be done either in a dedicated biomass-only boiler or cofired with other fuels such as coal. Cofiring of biomass in coal boilers has the advantage of lowering the emission of sulfur oxides (SO_x), nitrogen oxides (NO_x), and net lifecycle carbon. However, the widespread application of cofiring with coal has been hindered by the occurrence of alkali deposits that cause slag and corrosion in boiler heat transfer surfaces in the coal boilers [5].
- In biochemical conversion processes, biomass is broken down into fermentable sugars through chemical pretreatment and enzymatic hydrolysis. The resulting sugars are then fermented by microorganisms to produce ethanol and other biofuels [6].
- In thermochemical conversion heat is used to break down the biomass material into intermediate products (synthetic gas) which can then be converted into fuels using heat, pressure and catalysts. Two common thermochemical processes are gasification and pyrolysis. Gasification is a high temperature conversion of solids into a flammable mixture of gases. Pyrolysis is a process of thermal decomposition of biomass at high temperatures in the absence of oxygen into charcoal, bio-oil and synthetic gas [7].

In recognition of the integrated nature of the processes involved in converting biomass to a biofuel or related products, the DOE Bioenergy Technologies Office (BETO) organizes its research funding effort into the following two broad areas in the conversion process - deconstruction and fractionation, and synthesis and upgrading as shown in Figure 3-2 below. The deconstruction and fractionating processes break down biomass, including energy crops, into its component chemicals (sugars, bio-oils, etc.), while the synthesis and upgrading processes take these intermediate component chemicals and convert them into finished products such as fuel and chemicals.

Figure 3-2: Schematic of steps in the bioenergy conversion process (Source: DOE [8])



To take full advantage of the strengths of the different biomass-to-energy conversion processes, the BETO has funded the construction of integrated biorefineries that combine all processes in one plant and produce multiple products. By producing multiple products, the integrated biorefineries, like refineries in the petroleum industry, will be able to take advantage of the differences in feedstocks and intermediate products to maximize the value obtained from the biomass feedstock. As of the writing of this report, there were 85 active DOE-funded integrated biorefinery-related projects spread across the United States working to develop the various bio-processing technologies needed as follows.

Table 3-1: Integrated biorefinery projects (Data source: DOE [9])

Project Scale	Number of Projects
Bench scale	2
Engineering scale	10
Industrial relevant/Pre-pilot	26
Pilot scale	20
Demonstration	15
Commercial	8
Modeling/Analysis	4

At the pilot-scale projects, the technologies developed at the much smaller engineering and pre-pilot scales are verified at a scale of at least one dry metric ton per day before being passed to the demonstration-scale facilities. The demonstration-scale facilities are sized to a scale sufficient to provide data and equipment specifications for the final commercial-level pioneer projects [10]. There are now eight DOE-funded projects that are at the final commercial production scale are listed in Table 3-2.

Table 3-2: Commercial integrated biorefinery projects (Data source: DOE [9])

Company	Location	Feedstock	Conversion Technology	Primary Product
Fulcrum	McCarran, Nevada	Municipal solid waste	Thermo-chemical	Renewable hydrocarbons (jet fuel, diesel)
Red Rock Biofuels	Lakeview, Oregon	Woody biomass	Thermo-chemical	Renewable hydrocarbons
Emerald Biofuels	Plaquemine, Louisiana	Fats; Oils; Greases	Thermo-chemical	Renewable hydrocarbons
INEOS New Planet Bioenergy LLC	Vero Beach, Florida	Municipal Solid Waste; Agricultural Residue	Thermo-chemical	Ethanol
Bluefire	Fulton, Mississippi	Woody Biomass	Biochemical	Ethanol
Rangefuels	Soperton, Georgia	Woody Biomass	Biochemical	Mixed Alcohols
Abengoa	Hugoton, Kansas	Agricultural Residue; Algae; Woody Biomass; Energy Crops; Municipal Solid Waste; Vegetative Waste; Yard Waste	Biochemical	Ethanol
POET	Emmetsburg, Iowa	Agricultural Residue	Biochemical	Ethanol

3.2 Economics of energy crops

The DOE vision of a large-scale bioenergy economy supported by large-scale farming of energy crops and collection of agricultural and forest residues has not yet been realized. This is mainly because the economics of large-scale farming of energy crops are not yet favorable. For such large-scale production of dedicated energy crops to occur, the price of the energy crops will have to be high enough to compete with the current cropland uses, while on the energy industry side, the price must be low enough to compete with traditional fuels currently in use (e.g., petroleum and natural gas). In the 2016 DOE Billion-Ton Report, the U.S. agricultural sector simulation model (POLYSYS) was used to estimate the quantities of the various energy crops that would be produced at various prices. The POLYSYS model is a detailed model of the U.S. agricultural sector that includes crop supply at the county level, national crop demand and prices, national livestock demand and prices, and agricultural income.

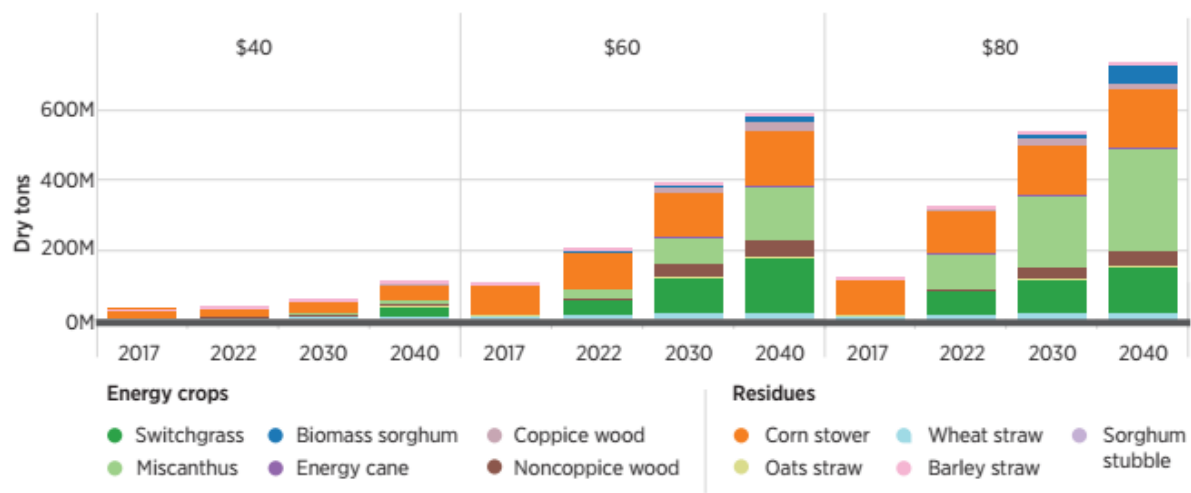
Six types of energy crops are modeled in the POLYSYS simulation for the results presented in the 2016 Billion-Ton Report – three perennial grasses (switchgrass, miscanthus, and energy cane), an annual energy crop (biomass sorghum) and four types of short rotation woody crops, two that are rotated by coppicing⁵ (willow and eucalyptus) and two rotated by other non-coppicing methods (poplar and pine). Switchgrass, miscanthus, and energy cane were modeled for 10-year, 15-year, and 7-year rotations, respectively. Hybrid poplar, pine and eucalyptus were each modeled as growing on an 8-year rotation, and willow was modeled as a coppiced crop over a 32-year period with harvest every 4 years.

Figure 3-3 shows the production of herbaceous and woody energy crops under the 2016 Billion-Ton study base-case scenario⁶ in selected years at various farm-gate prices. At a price of \$40 per dry ton energy crops do not enter the market until 2030. In 2030, they comprise approximately 21 percent of the 59 million tons of biomass offered to the market and 46 percent of the 108 million tons offered in 2040. At \$60, a small amount of biomass from energy crops enters the market in 2022. At this price, 62 percent of the 388 million tons of biomass offered to the market in 2030 is from energy crops, primarily herbaceous energy crops, and 70 percent of the 588 million tons offered to the market in 2040 is from energy crops. When prices increase to \$80 per ton, energy crops dominate the market, supplying 70 percent of the biomass in 2030 and 75 percent in 2040.

⁵ Coppicing is a method of woody crop management that takes advantage of the property that some plants such as willows have where new growth occurs from the stump or roots when the plant is cut down.

⁶ The base-case scenario in the 2016 Billion-Ton Report assumes 1% energy crop yield improvements per year.

Figure 3-3: Production of energy crops at various farm-gate prices for select years (Source: DOE [3])



Figures 3-4 and 3-5 show the total potential availability of herbaceous and woody energy crops expected to be produced in 2022, 2030, and 2040 under the Billion-Ton study base case scenario.

Figure 3-4: Supply curves of potential herbaceous energy crop production for select years under base-case assumptions (Source: DOE [3])

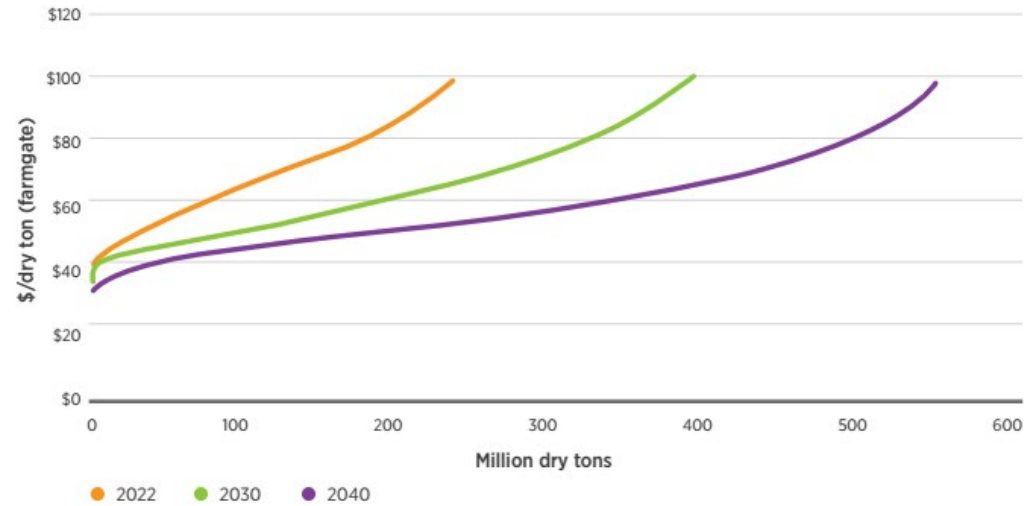
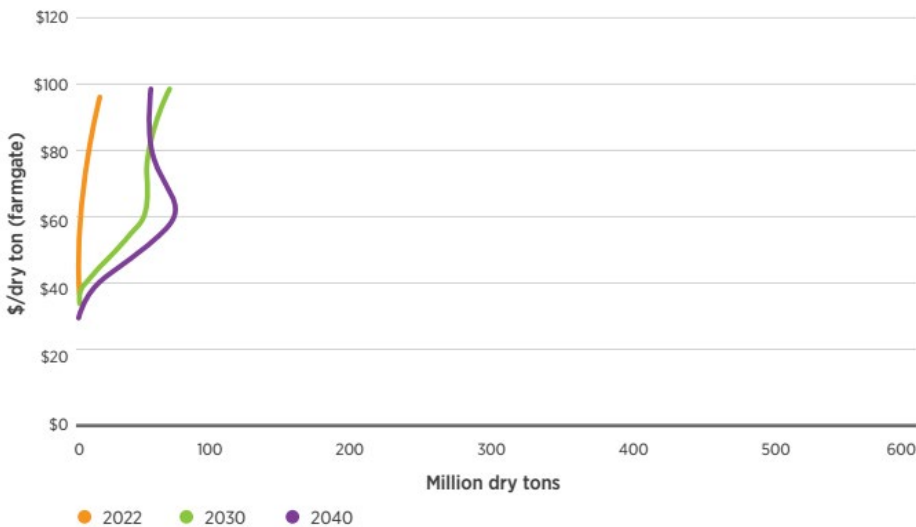


Figure 3-5: Supply curves of potential woody energy crop production for select years under base-case assumptions⁷ (Source: DOE [3])



In addition to the series of Billion-Ton studies, DOE has developed a spatial web-accessible database, the Bioenergy Knowledge Discovery Framework (KDF), which brings together data from the various DOE-supported bioenergy research efforts across the U.S. [11]. The research projects whose data are integrated into the KDF include:

- Biomass Resource Potential research prepared by the Oak Ridge National Laboratory whose results are presented in the 2016 Billion-Ton Update report referenced above,
- The Sun Grant Initiative Resource Assessment project that collects data from the energy crops field trials,
- The Feedstock Supply and Logistics Analysis research being conducted at the Idaho National Laboratory,
- The Microalgae Biofuel Potential project taking place at the Pacific Northwest National Laboratory,
- The Regional Land-Use Change Modeling project based at the Great Lakes Bioenergy Center,
- The International Projects Partnership based at the Oak Ridge National Laboratory that is working to identify areas of biodiversity concern to be avoided when planting energy crops,
- The National Biorefinery Siting Model that seeks to develop a geographical information system (GIS) based biomass supply and biorefinery location model of the U.S., and

⁷ The backward sloping supply curves in 2030 and 2040 show that at high biomass prices it is more profitable for the farmer to grow herbaceous energy crops (shown in Figure 3-4) than woody energy crops.

- The Alternative Fuels and Advanced Vehicles Data Center at the National Renewable Energy Laboratory that is intended to provide interactive maps of alternative fuels infrastructure.

Corn and soybean use for biofuel production.

Although corn and soybeans are not dedicated energy crops but rather mainly grown as food crops, they are included in this section because they currently constitute the largest source of renewable energy in Indiana. Ethanol and diesel biofuels experienced a rapid expansion in the mid-2000s. Before 2007, Indiana's ethanol production capacity consisted of one production plant with a capacity of 100 million gallons per year (MMGY). Since then, the capacity has grown to 1,445 MMGY in fifteen corn ethanol plants. Toward the end of the 2000s, corn ethanol production began to outpace demand because the recession weakened gasoline demand, ending expansion in the ethanol industry. Table 3-3 shows the location and capacities of operating ethanol plants in Indiana. There are currently two operating biodiesel plants in Indiana, the 88 MMGY Dreyfus plant in Clayton, and the 3 MMGY Alternative Solutions Plant in Huntington [12].

Table 3-3: Ethanol plants in Indiana (Data source: Renewable Fuels Association [13])

Company	Location	Capacity (MMGY*)
Cardinal Ethanol LLC	Union City	135
CIE - Marion Distillery	Marion	55
Grain Processing Corp.	Washington	37
Green Plains Mount Vernon LLC	Mount Vernon	90
Harvestone Low Carbon Partners	Rensselaer	60
POET Biorefining - Alexandria LLC	Alexandria	90
POET Biorefining - Cloverdale LLC	Cloverdale	95
POET Biorefining - North Manchester LLC	North Manchester	90
POET Biorefining - Portland LLC	Portland	90
POET Biorefining - Shelbyville LLC	Shelbyville	98
The Andersons Clymers Ethanol LLC	Logansport	140
Valero Renewable Fuels Co. LLC	Bluffton	140
Valero Renewable Fuels Co. LLC	Linden	140
Valero Renewable Fuels Co. LLC	Mount Vernon	100
VERBIO North America Corp.	South Bend	100

*MMGY denotes million gallons per year

The following factors account for the biofuel plant construction in the U.S. since 2005

- The use of corn ethanol as an oxygenating additive in gasoline in place of the chemical methyl tertiary-butyl ether (MTBE). The shift from MTBE was a result of its association with groundwater pollution. The replacement of MTBE was mandated both by states and the 2005 Energy Policy Act [13].
- The renewable fuel standard (RFS), first enacted in 2005 and then expanded in 2007, required that 36 million gallons of renewable fuel (15 billion gallons from corn ethanol and the balance from advanced biofuels) must be blended into gasoline by 2022. Starting in 2014, EPA began revising the annual volume requirements downwards in recognition of the fact that the demand for gasoline was lower than had been anticipated when the blending volumes were set in 2007. Although the minimum volumes of biofuels to be blended into transportation fuels in the RFS were only specified up to 2022, the RFS did not expire at the end of 2022. Beyond 2022, the Energy Independence and Security Act of 2007 mandates the U.S. Environmental Protection Agency (EPA) to set the volumetric minimums. For 2025, the EPA has finalized a total renewable fuel requirement of about 22.3 billion gallons. This consists of conventional biofuel (remains at 15 billion gallons) and the remainder coming from advanced biofuels such as biomass-based diesel and cellulosic biofuel. [14, 15, 16].
- The enactment of the volumetric ethanol excise tax credit (VEETC) in 2004 improved the cost competitiveness of corn ethanol with gasoline and provided long-term protection for corn ethanol producers against price volatility in the transportation fuel market. The VEETC allowed for a 45 cents/gallon tax credit to be given to entities that produce the mixture of gasoline and ethanol. This tax credit expired at the end of 2011 [17].

3.3 State of energy crops nationally

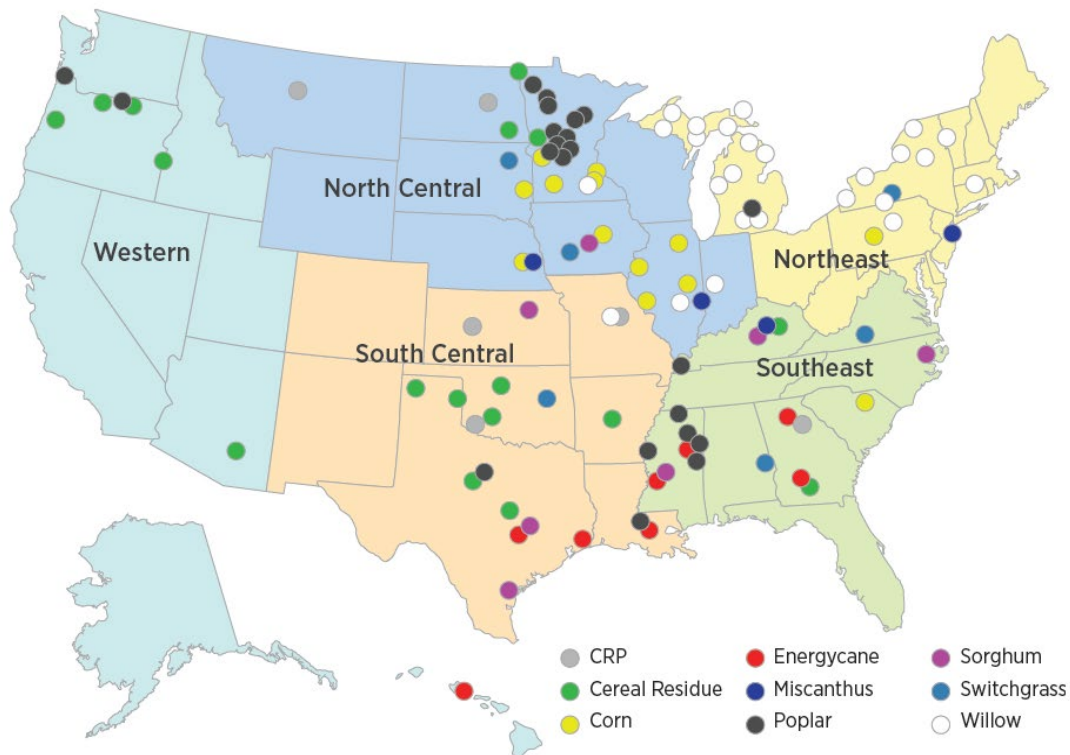
The energy crop industry is still in the early commercialization phase. However, research and development are now well underway under the leadership of the U.S. Department of Energy (DOE) and its partners. These efforts aim to establish a sustainable and commercially viable biomass supply chain that supports the Renewable Fuel Standard (RFS) for transportation biofuels and expands bioenergy applications, including electricity generation and sustainable aviation fuel (SAF).

In particular, the SAF Grand Challenge aims to scale U.S. production of SAF to 3 billion gallons per year by 2030 and 35 billion gallons per year by 2050, which is sufficient to meet projected U.S. aviation fuel demand. However, a key finding in a 2023 review by the International Council on Clean Transportation (ICCT) is that even though the target of 3 billion gallons by 2030 appears feasible, the 2050 target of 35 billion gallons is much more challenging because of constraints on sustainably available biomass, technology, and economics [18].

The DOE has partnered with universities, national laboratories, and the U.S. Department of Agriculture to establish the Regional Biomass Feedstock Partnership. The Partnership has conducted multi-year research, development, and outreach activities at the regional level to

address barriers to building a sustainable bioenergy industry. Between 2008 and 2014, it coordinated field trials for a variety of dedicated energy crops across the country. Figure 3-6 shows the biomass feedstock field trial locations established under this program.

Figure 3-6: Bioenergy crop trial stations (Source: DOE [19])



In addition to the field test sites, the Regional Biomass Feedstock Partnership is also involved in education and outreach efforts to farmers and other stakeholders, preparing them for a future where energy crops become a substantial portion of the agricultural industry. The lead institutions for the five regions in the program are South Dakota State University in the North Central region, Oregon State University in the Western region, Oklahoma State University in the South-Central region, Cornell University in the Northeast, and the University of Tennessee in the Southeast region [20]. At the March 2015 project peer review conference, the following progress was reported on the feedstock research [21]:

- The completion of field trials for seven crop years (2008 to 2014),
- Making the yield and plot treatment data publicly available by uploading it onto the DOE Knowledge Discovery Framework (KDF),
- Collecting soil samples for sustainability analysis at multiple locations, and

- Collecting biomass samples from the field plots and sending them to the Idaho National Laboratory (INL) for composition analysis and archiving in the biomass resource library housed at INL.

The data and analytical results remain accessible through the KDF and INL digital library and continue to serve as key inputs for biomass-supply modeling, feedstock logistics research, and national Billion-Ton resource assessments.

While the original field trials established under the Regional Biomass Feedstock Partnership concluded by 2014 and the final summary reports were issued in 2016, the foundational datasets and lessons learned have informed the DOE's next-generation feedstock programs. In 2024, DOE launched the Regional Biomass Resource Hubs (RBRH) initiative [22] to extend and regionalize feedstock research for purpose-grown energy crops, including perennial grasses, short-rotation woody species, and new oilseed crops such as camelina. These hubs emphasize standardizing data collection, quantifying ecosystem services, improving feedstock quality and logistics, and linking growers directly with biorefineries and SAF producers. In this way, DOE's feedstock research has transitioned from early-stage agronomic trials toward integrated regional supply-chain development that supports national goals for low-carbon fuels and the broader U.S. bioeconomy. Full supply-chain demonstrations and multi-year crop performance results are still forthcoming, as these projects are designed to unfold over the next decade.

3.4 Energy crops in Indiana

The results from the DOE Billion-Ton model show that in the national bioenergy economy, Indiana and other corn-belt states like Iowa and Illinois would mainly be suppliers of biomass in the form of agricultural residues such as corn stover, and only a limited amount of dedicated energy crops. This is because the price that energy crops would have to offer farmers to displace the food crops would be too high for the resulting biofuels to be competitive with petroleum in the transportation sector and traditional fuels such as natural gas in the electricity sector. Figure 3-7 shows the projected pattern of biomass feedstock production by the year 2030 at a biomass farm-gate price of \$60 per dry ton.

Figure 3-7: Estimated shares of energy crops and agricultural residues supplied at \$60 per dry ton in 2030 (Source: DOE [4])

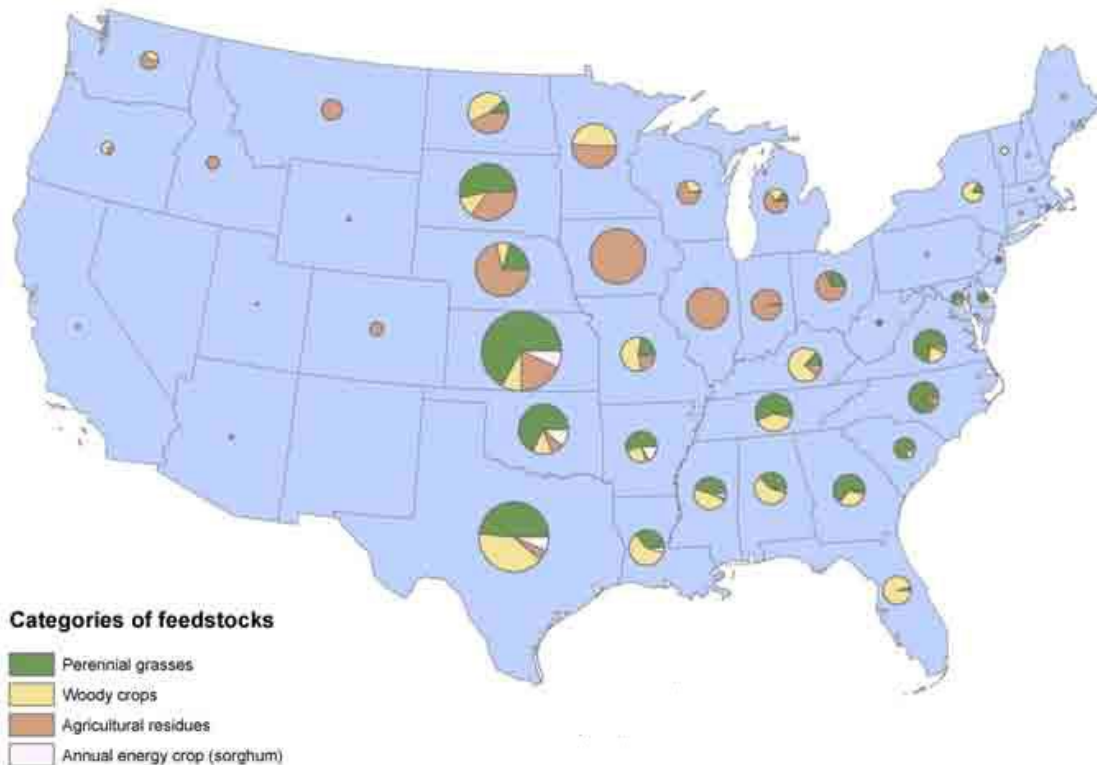
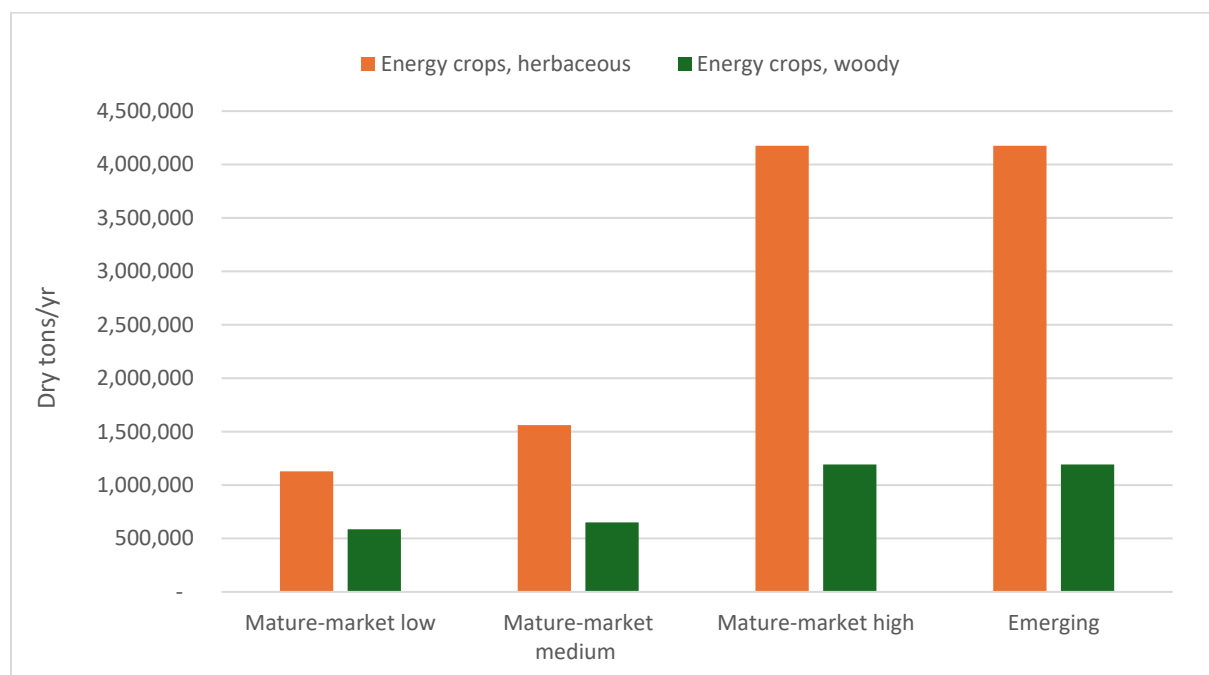


Figure 3-8 presents the projected availability of herbaceous and woody energy crops in Indiana at a farmgate price of \$70 per dry ton, calculated using the 2023 Billion-Ton Report (BT23) [23]. In BT23, the Mature-Market Low, Medium, and High scenarios assume gradually improving crop yields and harvest technologies—from conservative (Low) to moderate (Medium) to aggressive (High) progress. The Emerging scenario goes beyond these assumptions and represents the highest long-term potential if new or still-developing technologies become viable. Under these assumptions, herbaceous energy crops (primarily miscanthus, biomass sorghum, and switchgrass) dominate the state’s dedicated biomass supply, increasing from slightly over 1 million dry tons/yr in the Mature-Market Low scenario to more than 4 million dry tons/yr in both the Mature-Market High and Emerging scenarios. Woody energy crops (primarily willow and poplar) contribute a smaller but meaningful share, rising from 0.6 million dry tons/yr in the Low case to 1.2 million dry tons/yr under the Mature-Market High and Emerging scenarios. In comparison, agricultural residue biomass at \$70 per dry ton is projected to range from 8 million dry tons/yr in the Near-Term scenario to nearly 16 million dry tons/yr under both the Mature-Market High and Emerging scenarios. The Near-Term scenario reflects current or near-current technology and yield levels, assumes only limited improvement beyond today’s practices, and focuses on resources that could be mobilized within the next few years. Dedicated energy crops do not appear at a \$70 per ton price point in the Near-Term scenario.

Figure 3-8: Projected production of energy crops at farmgate price of \$70 per dry ton in Indiana for various scenarios in BT23 (Source: DOE [8])



In a 2011 paper, Brechbill, Tyner and Ileleji of Purdue’s College of Agriculture did a study of the estimated cost of producing switchgrass and harvesting corn stover for the energy industry in Indiana. Table 3-4 shows the average cost of producing switchgrass given in this study [24]. Allen, in his December 2011 master’s thesis, estimated the cost of producing and transporting biomass from woody crops to be between \$43 and \$52 per dry ton [25]

Table 3-4: Average farm-gate cost (\$/dry ton) for producing switchgrass in Indiana (Data source: Brechbill, Tyner & Ileleji [24])

Farm Size (Hectares)	Custom	200	400	600	800
Average Cost (\$/ton)	80.98	69.22	66.23	65.23	64.73

In her 2013 master’s thesis, Song performed an integrated economic and environmental assessment of cellulosic biofuel production, focusing on the Wildcat Creek Watershed. The study evaluated the costs of corn stover, switchgrass, and miscanthus production within the watershed by looking at three cost components: production cost, loading-unloading cost, and hauling cost for each feedstock, as is shown in Table 3-5. A hypothetical biorefinery plant is assumed to be located at the centroid of the watershed, demanding biomass feedstock supply from cropland across the watershed. The nine scenarios shown in Table 3-5 are considered to compare candidate feedstocks and corn stover removal rates [26, 27].

Table 3-5: Cost by category for producing corn stover, switchgrass, and miscanthus in Wildcat Creek Watershed (Data source: Song et al. [27])

Crop Scenario	Production Cost (\$/dry ton)	Loading-unloading (\$/dry ton)	Hauling (\$/dry ton)	Total Cost for Watershed (Million \$)	Unit Cost (\$/dry ton)
Baseline Corn-Soybean	0	0	0	0	0
Continuous Corn with 20% Residue Removal	54.19	5.42	5.37	21.92	64.98
Corn-Soybean with 30% Residue Removal	54.19	5.42	5.37	15.69	64.99
Corn-Soybean with 50% Residue Removal	57.08	5.42	5.37	27.79	67.86
Continuous Corn with 30% Residue Removal	54.19	5.42	5.37	33.03	64.98
Continuous Corn with 50% Residue Removal	56.98	5.42	5.36	57.56	67.75
Switchgrass	106.79	6.88	6.81	204.97	120.47
Switchgrass No Till	106.08	6.88	6.81	203.74	119.77
Miscanthus	92.66	6.88	6.84	350.78	106.37

Although several national and regional studies have been published over the past decade on the economics of dedicated energy crops (e.g., Soldavini, 2017 [28]; Karmel, 2018[29]), no new Indiana-specific cost studies have been produced that update or replace the detailed farm-gate and delivered-cost analyses conducted by Brechbill, Tyner, and Ileleji (2011) and Song (2013). More recent economic research on biomass supply, including the Midwestern and national assessments by Dumortier (2017) [30] and Sesmero et al. (2021) [31], provides valuable context on cost drivers and production feasibility but does not offer Indiana-specific estimates for production, loading, or hauling costs. Consequently, the 2011 and 2013 Purdue studies remain the most current and authoritative sources for detailed biomass production cost information for the state of Indiana.

3.5 Incentives for energy crops

The following incentives have been available to encourage the use of energy crops.

Federal Incentives

- Renewable Electricity Production Tax Credit (PTC) provides a credit for electricity

generated from qualifying closed-loop biomass facilities, including dedicated energy crops, with 1.5 cents/kWh in 1993 dollars adjusted by an inflation factor supplied by the IRS for the calendar year. The PTC was extended by the Inflation Reduction Act of 2022 (IRA) to include projects that began construction before the end of 2024. For a project to qualify for the full credit, it has to meet the prevailing wage and apprenticeship conditions. Details about the prevailing wage and apprenticeship conditions and other definitions in the IRA are provided in Chapter 1.4 of this report. A project that does not meet the prevailing wages and apprenticeship conditions only qualifies for a credit of 0.3 cents/kWh (1993 dollars). Projects can also qualify for an extra 10 percent credit if they have the specified level of domestic content in the power plants or are located in an energy community. The percentages given here are percentages of the base 1.5 cents/kWh (1993 dollars) [32, 33].

- CEPTC, established under Section 45Y of the IRA, became effective for qualifying facilities placed in service after December 31, 2024. Unlike the legacy PTC, the CEPTC is available to all qualifying technologies with zero or negative greenhouse gas emissions. Under the IRA, the credit was scheduled to begin phasing out after the later of 2032 or the year in which U.S. electricity-sector greenhouse gas emissions declined to 25 percent of 2022 levels. The OBBBA accelerated the phaseout only for wind and solar projects. Biomass and other qualifying technologies remain subject to the general CEPTC phase-down schedule beginning after 2032. [33, 34].
- U.S. DOE Title 17 Energy Financing Program (Section 1703 of Title XVII of the Energy Policy Act of 2005) provides loan guarantees for eligible energy projects, including projects that deploy new or significantly improved technologies that are technically proven but not yet widely commercialized in the United States. Eligible technologies include renewable energy technologies [35, 41].
- Modified Accelerated Cost-Recovery System (MACRS) allows businesses to recover investments in qualified renewable energy property through accelerated depreciation deductions. In addition, Congress has periodically authorized bonus depreciation, allowing a portion or all of the investment cost to be deducted in the first year, subject to applicable tax law in effect at the time [43].
- USDA Rural Energy for America Program (REAP) provides financial assistance to agricultural producers and rural small businesses for eligible renewable energy systems and energy-efficiency improvements. Loan guarantees are available on loans covering up to 75 percent of total eligible project costs. Grants may cover up to 50 percent of eligible project costs for qualifying projects, while other projects are limited to a 25 percent federal grant share. Combined grant and loan-guarantee funding may cover up to 75 percent of total

eligible project costs [35, 36].

- High Energy Cost Grant Program, administered by USDA, provides grants to improve energy infrastructure in communities where average residential energy costs are at least 275 percent of the national average. Eligible projects include renewable energy generation, energy storage, transmission and distribution improvements, and energy efficiency measures [37].
- USDA Biorefinery Assistance Program provides loan guarantees for eligible commercial-scale biorefineries, renewable chemical facilities, and renewable fuel projects, subject to program eligibility requirements and statutory funding limits [35].
- Federal Renewable Energy Use Statutory Requirement (Section 203 of the Energy Policy Act of 2005, as amended) requires that, to the extent economically feasible and technically practicable, at least 7.5 percent of the electricity consumed by the Federal Government each fiscal year be obtained from renewable energy sources [35].

Indiana Incentives

- Net Metering Rule continues to allow eligible grandfathered utility customers with renewable energy systems having a maximum generating capacity of 1 MW to receive retail-rate credits for excess electricity exported to the grid. Senate Enrolled Act 309 (SEA 309), signed into law in 2017, transitioned Indiana from traditional net metering to the Excess Distributed Generation (EDG) program for new customers after June 30, 2022. Customers with qualifying systems installed before January 1, 2018 continue to receive retail-rate credits until July 1, 2047, while eligible systems installed between January 1, 2018 and June 30, 2022, or until the utility reached the statutory 1.5 percent aggregate-capacity threshold, whichever occurred first, continue to receive retail-rate credits until July 1, 2032 [38, 42].
- Excess Distributed Generation (EDG) Rule, established under Indiana Code 8-1-40 pursuant to SEA 309 (2017), replaced net metering for new distributed generation customers after June 30, 2022. Under the EDG program, excess electricity exported to the grid is compensated at 125 percent of the utility's average marginal price of electricity during the most recent calendar year [38, 42].
- Clean Energy Portfolio Goal established a voluntary goal of obtaining 4 percent of electricity from clean energy sources between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent in 2025, based on 2010 retail sales. The final statutory goal period ended on December 31, 2025, and no additional clean energy portfolio goals are specified

beyond 2025. However, financial incentives and cost-recovery mechanisms approved for participating electricity suppliers that achieved the applicable goals may continue beyond 2025 in accordance with the terms of the program and IURC approval [35, 40].

- NIPSCO offers feed-in tariff incentive rates for electricity generated from renewable resources for up to 15 years. The payment for biomass projects is negotiated with maximum possible payment set at \$0.0918/kWh. The size of biomass projects eligible for the feed-in tariff is between 100 and 1,000 kW. The program is closed to new applicants, although existing contracts remain in effect under their respective agreements [39].

3.6 References

1. 2023 Billion-Ton Report: An Assessment of U.S. Renewable Carbon Resources. Executive Summary.
<https://www.energy.gov/eere/bioenergy/2023-billion-ton-report-assessment-us-renewable-carbon-resources>.
https://www1.eere.energy.gov/apps/bioenergy/bto-2023-billion-ton-report/assets/pdfs/BETO-2023-Billion-Ton-Report_exec%20summary-1.pdf
2. BR&D. Federal Activities Report on the Bioeconomy.
https://biomassboard.gov/sites/default/files/pdfs/Bioeconomy_Initiative_Implementation_Framework_FINAL.pdf
3. U.S. Department of Energy (DOE). 2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, Volume 1: Economic Availability of Feedstocks. M. H. Langholtz, B. J. Stokes, and L. M. Eaton (Leads), ORNL/TM-2016/160. Oak Ridge National Laboratory, Oak Ridge, TN. 448p. doi:10.2172/1271651
<https://www.energy.gov/eere/bioenergy/downloads/2016-billion-ton-report-advancing-domestic-resources-thriving-bioeconomy>
4. DOE. U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry, 2011. R.D. Perlack and B.J. Stokes (Leads), ORNL/TM-2011/224. Oak Ridge National Laboratory, Oak Ridge, TN. 227p.
https://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf
5. EERE. Biopower technical strategy workshop summary report.
<http://www.energy.gov/eere/bioenergy/downloads/biopower-technical-strategy-workshop-summary-report>
https://www.energy.gov/sites/prod/files/2014/04/f14/biopower_workshop_report_december_2010.pdf
6. U.S. Department of Energy, Bioenergy Technologies Office. Biochemical Conversion: Using Hydrolysis, Fermentation, and Catalysis to Make Fuels and Chemicals.
https://www1.eere.energy.gov/bioenergy/pdfs/biochemical_four_pager.pdf

7. National Renewable Energy Laboratory (NREL). Thermochemical Conversion Capabilities
<https://www.nrel.gov/bioenergy/co2-utilization-economics/thermochemical-conversion-pathway>
8. EERE. Bioenergy Technologies Office Conversion technologies.
<https://www.energy.gov/eere/bioenergy/conversion-technologies>
9. EERE. Integrated biorefineries interactive map
<https://www.energy.gov/eere/bioenergy/integrated-biorefineries>
10. EERE. Integrated biorefineries fact sheet.
<http://www.energy.gov/eere/bioenergy/integrated-biorefineries>
https://www.energy.gov/sites/prod/files/2016/08/f33/ibr_overview_1.pdf
11. EERE. The bioenergy knowledge discovery framework. KDF fact sheet.
https://www.energy.gov/sites/prod/files/2014/03/f14/kdf_fact_sheet.pdf
12. EIA, U.S. Energy Atlas. Biodiesel Plants.
<https://atlas.eia.gov/datasets/eia::biodiesel-plants-1/explore?location=42.020809%2C-84.762005%2C6.00>
13. Renewable Fuels Association
<https://ethanolrfa.org/biorefinery-locations/>
14. EIA. U.S. ethanol production and the Renewable Fuel Standard RIN bank
<http://www.eia.gov/todayinenergy/detail.cfm?id=11551>
15. EPA. Renewable Fuel Standard.
<https://www.epa.gov/renewable-fuel-standard-program/regulations-and-volume-standards-renewable-fuel-standards>
16. International Council on Clean Transportation. How the Renewable Fuel Standard works
http://www.theicct.org/sites/default/files/publications/ICCTBriefing_RFS2_20140211.pdf
17. EERE. Alternative fuels data center. VEETC
<https://afdc.energy.gov/laws/399>
18. International Council on Clean Transportation. Meeting the SAF Grand Challenge: Current and Future Measures to Increase U.S. Sustainable Aviation Fuel Production Capacity
<https://theicct.org/wp-content/uploads/2023/11/ID-37-%E2%80%93SAF-Grand-Challenge-white-paper-letter-40036-v3.pdf>
19. Sun Grant Initiative.
https://sungrantinitiative.tennessee.edu/wp-content/uploads/sites/203/2021/04/regional_feedstock_partnership_summary_report.pdf
20. EERE. DOE Bioenergy Technologies Office. 2015 Project Peer Review.SunGrant/DOERegional Biomass Feedstock Partnership (Award # GO85041; WBS 7.6.2.5).
<https://www.energy.gov/eere/bioenergy/peer-review-2015>
https://www.energy.gov/sites/prod/files/2015/04/f21/terrestrial_feedstocks_owens_7625.pdf

21. EERE. DOE Bioenergy Technologies Office. 2023 Project Peer Review. April 3 – 7 2023. <https://www.energy.gov/eere/bioenergy/2023-project-peer-review>
<https://www.energy.gov/sites/default/files/2023-04/beto-00-project-peer-review-plenary-apr-2023-messner%20.pdf>
22. DOE Bioenergy Technologies Office. Funding Selections for Regional Resource Hubs for Purpose-Grown Energy Crops, 2024. energy.gov announcement
23. DOE. Bioenergy Knowledge Discovery Framework. BT23 Agricultural Download. <https://bioenergykdf.ornl.gov/bt23-agricultural-download>
24. Brechbill, S. Tyner, W. and Ileleji K. The Economics of Biomass Collection and Transportation and Its Supply to Indiana Cellulosic and Electric Utility Facilities. Springer Bioenergy Research. January 2011.
<https://link.springer.com/article/10.1007/s12155-010-9108-0>
25. Allen, B. W. An economic and emissions analysis of electricity generation using biomass feedstock in co-fired and direct fired facilities. Master of Science Thesis, Purdue University August 2011. <https://docs.lib.purdue.edu/dissertations/AAI1502105/>
26. Song, Jingyu. A Spatially Explicit Watershed Scale Optimization of Cellulosic Biofuels Production. Master of Science Thesis, Purdue University December 2013.
<http://docs.lib.purdue.edu/dissertations/AAI1553620/>
27. Song, J., Gramig, B., Cibil, R., and Chaubey, I. 2016. Integrated economic and environmental assessment of cellulosic biofuel production in an agricultural watershed. <https://link.springer.com/article/10.1007%2Fs12155-017-9817-8>
28. Soldavini, J. (2017). Determining switchgrass breakeven prices in a landscape design system. Master's thesis, Purdue University.
29. Karmel, T. (2018). Analyzing the effect of policy, field geometry, and environmental criteria on switchgrass breakeven price in a landscape design system. Master's thesis, Purdue University.
30. Dumortier, J. (2017). "Production and spatial distribution of switchgrass and miscanthus under uncertainty and market risk." *Energy Economics*, 65, 1–13.
31. Sesmero, J. P., Gramig, B. M., & Ruhl, J. B. (2021). "Economic viability and carbon performance of switchgrass for bioenergy under alternative market and policy assumptions." *Energy Policy*, 158, 112–126.
32. The National Law Review. August 17, 2022. Relief Arrives for Renewable Energy Industry - Inflation Reduction Act of 2022. <https://www.natlawreview.com/article/relief-arrives-renewable-energy-industry-inflation-reduction-act-2022>
33. DLA Piper Law Firm Publications. The clean energy provisions of the Inflation Reduction Act of 2022 – a historic effort to encourage the development of clean energy and reduce carbon emissions. <https://www.dlapiper.com/en/us/insights/publications/2022/08/the-clean-energy-provisions-of-the-inflation-reduction-act-of-2022/>

34. Sidley Energy Updates. The “One Big Beautiful Bill” Act – Navigating the New Energy Landscape. July 15, 2025. <https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape>
35. Database of State Incentives for Renewables & Efficiency (DSIRE). <http://www.dsireusa.org/>
36. U.S. Department of Agriculture (USDA) Rural Development. Rural Energy for America Program Renewable Energy Systems & Energy Efficiency Improvement Guaranteed Loans & Grants. <https://www.rd.usda.gov/programs-services/rural-energy-america-program-renewable-energy-systems-energy-efficiency>
37. U.S. Department of Agriculture, Rural Development. Grants. <http://www.rd.usda.gov/programs-services/high-energy-cost-grants>
38. Indiana General Assembly, 2017 Session. Senate Bill 309 <https://iga.in.gov/legislative/2017/bills/senate/309#digest-heading>
39. NIPSCO. Feed-in Tariff. <https://www.nipsco.com/services/renewable-energy-programs/feed-in-tariff>
40. Indiana General Assembly. Indiana Code 8-1-37, Voluntary Clean Energy Portfolio Standard Program, Sections 12–13. <https://iga.in.gov/laws/2026/ic/titles/8>
41. U.S. Department of Energy. Program Guidance for the Title 17 Energy Financing Program. May 13, 2026. <https://www.energy.gov/documents/doe-edf-title-17-energy-financing-program-guidance-2026-05-13>
42. Indiana General Assembly. Indiana Code 8-1-40, Distributed Generation, particularly IC 8-1-40-17. <https://iga.in.gov/laws/2026/ic/titles/8>
43. Internal Revenue Service (IRS). Publication 946: How to Depreciate Property (2025). Chapter 4, Modified Accelerated Cost Recovery System (MACRS). <https://www.irs.gov/publications/p946?a=e3d3e32d-b1e8-49de-8f6a-fee4333c9c61&utm>

4. Organic Waste Biomass

4.1 Introduction

This chapter presents the use of biomass in the form of organic waste and residues as a source of renewable energy, in contrast to the previous chapter (Chapter 3), which presented biomass energy feedstocks in the form of dedicated energy crops. Unlike the dedicated energy crop industry, organic waste biomass has long been, and remains, widely used as a source of renewable energy. Historically, organic waste biomass, mainly wood-derived, has been the leading source of renewable energy consumed in the U.S., until biofuels overtook it as the largest source in 2016. The organic waste biomass in this chapter is separated into two main categories: that currently used as an energy source and that being considered for use in an expanded renewable energy future.

The types of organic waste biomass already in use as energy sources include:

- Residues from the forestry and wood products industry, including material left from logging, residues from the paper and pulp industry, and residues from wood milling,
- Municipal solid waste (MSW), which is the organic portion of the post-consumer waste collected in community garbage collection services,
- Gas extracted from landfills, which is naturally occurring gas resulting from the decomposition of landfill material,
- Livestock manure, mainly from large swine and dairy farms, where it is used to produce gas in biodigesters, and
- Municipal wastewater, or sewage, is used to produce gas in biodigesters.

Organic waste biomass resources that are not yet in large-scale use as energy sources, but are being considered for future use, include:

- Agricultural crop residues, such as stalks, leaves, and other material left in the fields when conventional food crops such as corn are harvested, and
- Aquatic plants, such as algae that have high oil content, can be converted to biofuel such as biodiesel.

Residues from the forestry and wood products industry and municipal solid waste are typically used to produce electricity and heat. These feedstocks are burned in a boiler to produce steam, which is either used directly for heat or to drive a turbine to generate electricity.

Other sources of organic waste-based energy rely on biogas production. Biogas contains a significant percentage of methane and is generated as waste breaks down through natural or managed decay. This is the case for landfill gas, livestock manure, or municipal wastewater processed through anaerobic digestion. Anaerobic digestion involves microorganisms breaking down organic waste in an oxygen-deficient environment, producing biogas that can be burned for energy. Like traditional fossil fuels, biogas can power internal combustion engines or generate electricity via combustion or steam turbines. Converting biogas to energy also prevents methane emissions into the atmosphere. Methane's greenhouse-gas effect is 27 to 30 times greater than carbon dioxides', so using biogas provides an additional environmental benefit [1].

Biomass, including agricultural crop residues, is expected to play a significant role in the U.S. energy supply portfolio in the future. One characteristic that makes biomass a highly attractive renewable energy source is its ability to be converted into both electricity and transportation fuels. Studies, such as the DOE-funded Billion-Ton Study referred to in Chapter 3 of this report, have shown that substantial energy resources in the form of biomass from crop residues could be harvested under appropriate economic conditions. Agricultural residues, unlike dedicated energy crops, have the added advantage that they do not require further cultivation or additional cropland, and therefore present a potential near-term feedstock for the bioenergy industry before a viable dedicated energy crop industry takes root.

Large-scale algae farming is another area under consideration as a potential source of bioenergy. Algae include organisms ranging from microscopic bacteria to giant seaweeds like kelp. They grow quickly using sunlight, water, carbon dioxide, and a few other nutrients to create biomass for energy. Algae offers several advantages as a biofuel feedstock: it produces up to 50 times more biomass per acre than crops like soybeans, can grow on non-arable land using wastewater or saline water, recycles water, nutrients, and carbon dioxide from industrial sources, and is easier to convert into transportation fuels than most other biomass materials [2, 3]. Algae can be grown in open ponds, which are cheaper, but risk contamination, evaporation, and weather issues. Enclosed bioreactors avoid these problems but are much more expensive to build. One potential application of algae is coupling an algal bioreactor with a coal power plant, such that the power plant provides the carbon dioxide needed for algae growth. In this way, a combined benefit of producing bioenergy while reducing carbon dioxide emissions is achieved. Such a project was conducted at Arizona Public Service's Redhawk Power Plant beginning in 2006, using an algae bioreactor to recycle carbon dioxide emissions into algal biomass for biofuel production [4]. Algae energy production is still developing, and the DOE continues to fund research into making it economically and sustainably viable [2, 3].

4.2 Economics of organic waste biomass

Most of the current waste biomass energy is generated and consumed in the paper and pulp industry, where paper and pulp-making byproducts are combusted in combined heat and power plants to supplement the electricity and steam supply to the mills. Several factors have combined to make the use of these residues and byproducts as an energy source economically attractive at pulp and paper mills. They include:

- The burning of the pulp-making residue (black liquor) serves not only to generate energy but also to recover process chemicals,
- The co-location of electricity and steam demand in the paper and pulp mills greatly increases the efficiency of the energy conversion process, and
- The ability to sell excess generation through either the favorable provisions of the Public Utility Regulatory Policies Act (PURPA) of 1978 or through the open transmission access associated with wholesale electricity markets provides a market for those times when the plants' generation exceeds their internal demand.

For municipal solid waste, the need to reduce the amount of material sent to landfills is the primary motivation for building energy conversion facilities. Without this motivation, municipal solid waste power plants would be hard to justify financially, as they are among the most expensive to build and operate. In the 2019 EIA plant cost estimates, the municipal solid waste power plant was listed as having the highest capital cost (\$8,895/kW) among the technologies considered and the highest fixed O&M cost (\$425/kW/yr). EIA has not included MSW power plants that burn solid waste in subsequent annual power plant cost estimates since then [5].

Another waste stream that is currently a major source of renewable energy in Indiana is landfill gas; that is, tapping the methane-rich gas in already established landfills. Unlike municipal solid waste energy conversion facilities that burn solid waste in a boiler to extract energy, landfill gas projects on existing landfills do not need a boiler, since the biogas is a byproduct of decomposing waste. As a result, their capital costs are much lower than those of municipal solid waste energy conversion facilities since they primarily consist of the cost of the combustion engine and generator set.

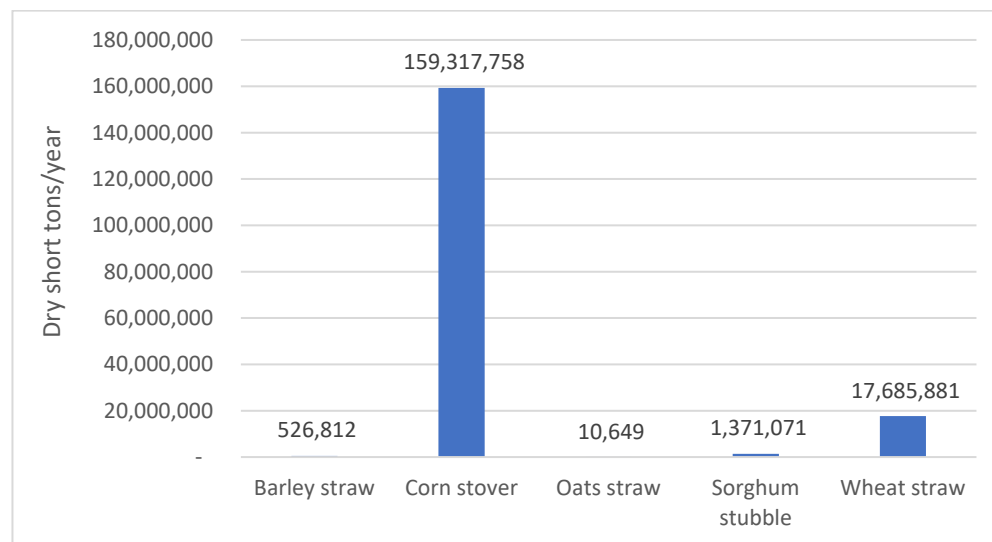
Like landfill gas, other organic waste streams, such as animal waste and municipal wastewater treatment plants, generate methane-rich biogas. Reducing greenhouse gas emissions is a major benefit of converting biogas to energy. In addition, for biogas systems other than landfill gas, energy conversion efficiency, and therefore project economics, can be improved when there is co-located demand for both heat and electricity. This is because anaerobic digesters require heat to maintain the optimal temperatures needed for the microorganisms that decompose the

biomass. Furthermore, in most places, waste treatment is required by local ordinances to maintain the environmental health of the watersheds where these facilities are located.

Agricultural crop residues are not yet being collected at broad commercial scale for bioenergy in most regions. Limited and uncertain profitability for farmers is a key barrier. However, it is expected that biomass, including agricultural crop residues, will play a substantial role in the national effort to diversify the transportation fuel supply away from petroleum. As mentioned in Chapter 3, a significant research and development effort, led by the DOE Bioenergy Technologies Office, has been ongoing since the early 2000s to establish a national bioenergy industry. In 2005, as part of this effort, the USDA and DOE issued a joint report from a study examining the feasibility of using energy from biomass to replace 30 percent of U.S. petroleum consumption by 2030, titled "Biomass Feedstock for a Bioenergy and Bioproducts Industry: the Technical Feasibility of a Billion-Ton Annual Supply" [6]. In 2011, an update to that report and an associated online database of the study's results, the Bioenergy Knowledge Discovery Framework (KDF), were released [7]. The most recent version of the report, the 2023 Billion-Ton Report, presented updated estimates of potential biomass supplies from agricultural lands. Previous versions of the report (2017, 2016, 2011) assessed farmers' ability to respond to new biomass markets using the Policy Analysis System Model (POLYSYS). The latest report incorporates the updated 2023 USDA baseline and provides data on mature-market biomass supplies [8].

Figure 4-1 shows the supply of primary crop residues at \$70 per dry short ton (2022\$) for the mature-market medium scenario of the 2023 Billion-Ton Report. This scenario assumes moderate market demand and supply, using business-as-usual (BAU) projections and a moderate (1%) increase in purpose-grown energy crop yield improvements, alongside current uses. Figure 4-1 indicates that corn stover is by far the largest agricultural residue resource, with an estimated availability of approximately 159.3 million dry short tons per year. Wheat straw represents a much smaller but still notable resource at approximately 17.7 million dry short tons per year, while sorghum stubble, barley straw, and oat straw are available in comparatively limited quantities. Table 4-1 shows the potential supply of secondary agricultural residues and wastes at select prices. In aggregate, availability is estimated at 6.0 million dry tons per year at \$40, 3.5 million dry tons per year at \$48, and 4.1 million dry tons per year at \$60. Table 4-2 shows the potential supply of animal manures. Availability is estimated at 35.9 million dry short tons per year.

Figure 4-1 Supply of potential production from primary crop residues at \$70 per dry short ton (2022\$) under 2023 Billion-Ton Study Mature-market medium assumptions (Source: DOE [8])



Note: Figure 4-1 was created based on data from the 2023 Billion-Ton Study data portal.

Table 4-1 Summary of secondary agricultural residues and wastes potential under 2023 Billion-Ton Study Mature-market medium assumptions (Source: DOE [8])

Waste type	\$40	\$48	\$60
	Dry tons/year		
Cotton field residues			815,052
Cotton gin trash		2,136,109	
Pruning residues, citrus	1,321,342		
Pruning residues, non-citrus	2,805,453		
Pruning residues, tree nuts	1,917,928		
Rice hulls		1,323,201	
Rice straw			3,308,000
Total	6,044,723	3,459,310	4,123,052

Note: Table 4-1 was created based on data from the 2023 Billion-Ton Study data portal.

Table 4-2 Summary of animal manures potential under 2023 Billion-Ton Study Mature-market medium assumptions (Source: DOE [8])

Manure Type	Dry tons/year
Manure, beef	9,503,425
Manure, dairy	16,207,506
Manure, swine	10,172,968
Total	35,883,899

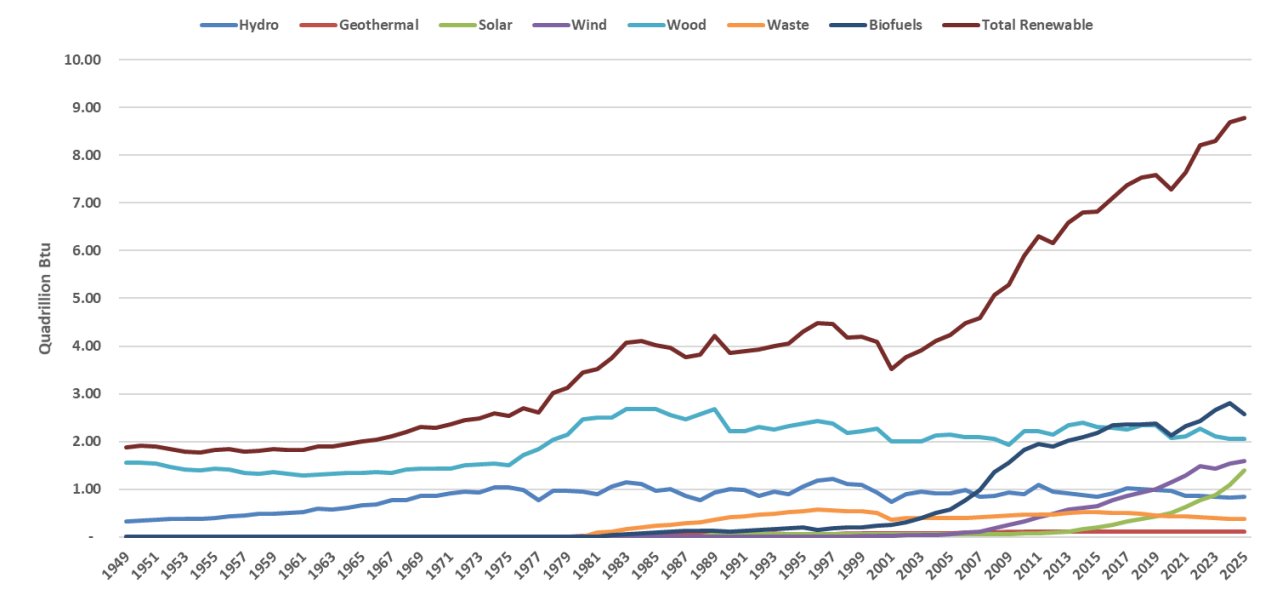
Note: Table 4-2 was created based on data from the 2023 Billion-Ton Study data portal.

Although the concept of using algae for energy production has been proven at the laboratory level, no commercial-scale sustainable production facility has been established yet. In 2009, DOE established the National Alliance for Advanced Biofuels and Bioproducts (NAABB), a consortium of industry, universities, and national laboratories to advance research in various facets of the algal biofuels industry. According to the NAABB final report, the consortium developed and demonstrated, at a pilot level, technology improvements that, when combined, can reduce the cost of producing algal biodiesel from \$240/gallon to \$7.50/gallon. This technology still needs to be applied at a commercial scale [9].

4.3 State of organic waste biomass nationally

Historically, organic waste biomass, and in particular residues from the wood products industry, has been one of the main sources of renewable energy in the U.S. Until recently, as shown in Figure 4-3, wood and wood-derived products were the main sources of renewable energy. Until the rise of wind and biofuels over the last twenty years, wood and wood-derived fuels comprised over half of the renewable energy consumed in the U.S. Recently, wood has been relegated to second place as biofuels have become the largest source of renewable energy. In 2025, wood contributed 23 percent of the renewable energy consumed, behind biofuel energy's 29 percent.

Figure 4-2: U.S. renewable energy consumption 1949-2025 (Data source: EIA [10])



Municipal solid waste, while not as significant as wood as an energy source, contributes to the nation's renewable energy mix. The Energy Recovery Council (ERC) reports that 75 municipal solid waste-to-energy plants operate in 21 states. Of these, 58 generate only electricity, 14 produce both electricity and steam, and 3 produce steam alone. These plants have a combined electricity-generating capacity of 2,534 MW. If the steam from the 18 steam-only and

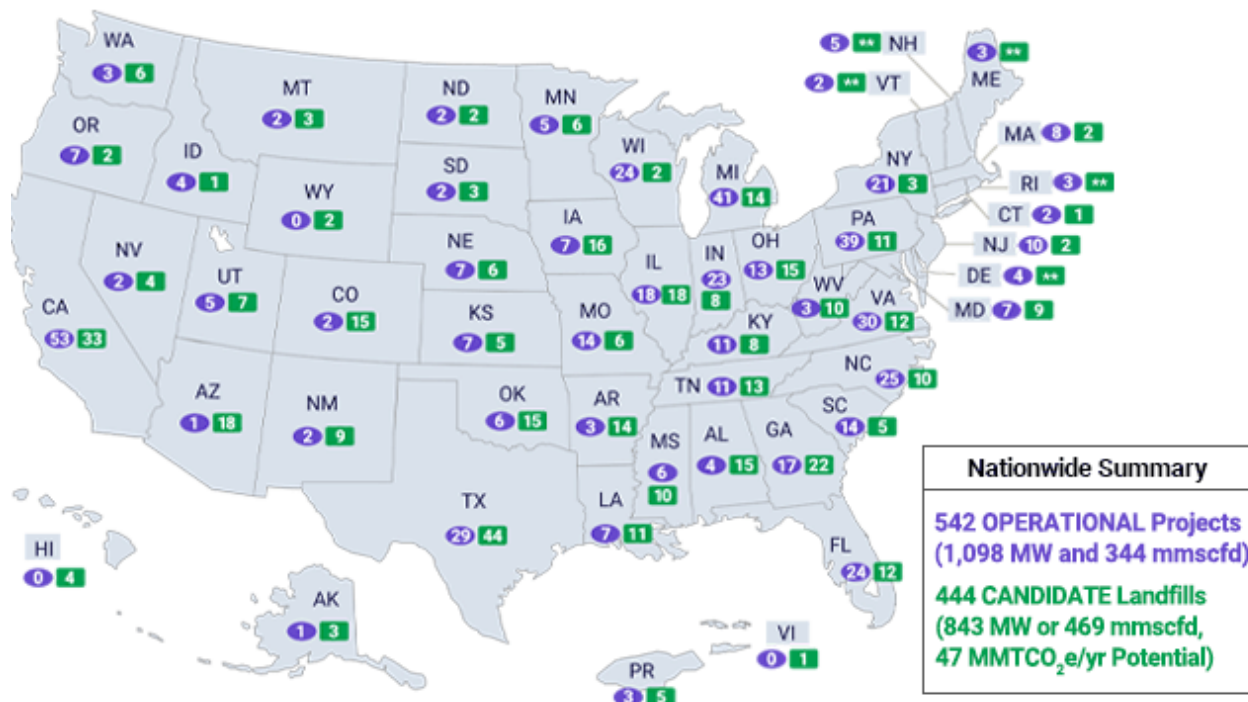
cogenerating plants were converted to electricity, the capacity could increase to 2,725 MW. Table 4-3 shows the locations of these plants, and details about Indiana's sole MSW energy conversion facility are in Chapter 4.4.

Table 4-3: Location of the 75 municipal solid waste-to-energy plants in the U.S. (Data source: Energy Recovery Council [11])

State	Number of facilities	State	Number of facilities	State	Number of facilities
Alabama	1	Maine	3	New York	10
California	2	Maryland	2	Oklahoma	1
Connecticut	5	Massachusetts	7	Oregon	1
Florida	11	Michigan	2	Pennsylvania	6
Hawaii	1	Minnesota	8	Virginia	4
Indiana	1	New Hampshire	1	Washington	1
Iowa	1	New Jersey	5	Wisconsin	2

Another organic waste stream in use as a source of energy is landfill gas. According to the EPA, there were 542 landfills in the U.S. with operational energy conversion projects with a combined capacity of 1,099 MW of electricity generation and 344 million standard cubic feet per day (mmscfd) of gas for thermal energy production. In addition, 444 candidate landfills have the size and capacity necessary to support energy projects. These candidate landfills have the potential to generate 843 MW of electricity or 469 mmscfd of gas for thermal energy conversion. Figure 4-4 shows the location of operational and candidate landfill gas energy projects in the U.S. as of July 2024. Twenty-three of the operational landfills and eight of the candidate landfills are in Indiana [12].

Figure 4-3: Landfill gas projects (Source: EPA [12])



Legend

mmscfd – million standard cubic feet per day

MMTCO₂e/yr – million metric tons of carbon dioxide-equivalent per year

Livestock manure is currently used as an energy source, with 343 anaerobic digester biogas recovery systems operating on livestock farms in the U.S. as of July 2024. The majority of these digesters (247) were on dairy farms, but there were also 39 on swine farms, seven on poultry farms, four on beef cattle farms, five on combined dairy/swine farms, three on combined cattle/swine farms, and one on a mixed cattle/swine/poultry farm [13]. In the 2018 Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities report, the EPA estimated that 8,113 dairy and swine farms could support biogas recovery systems with a combined potential electric generating capacity of 1,667 MW, supplying approximately 16 million MWh of electricity per year. Table 4-4 shows the top states with the potential for electricity generation from livestock farms. Biogas is more readily recovered from swine and dairy farms because the manure at these farms is handled as a wet slurry, which is hospitable to the waste-digesting microorganisms [14].

Table 4-4: Top ten states for potential electricity generation from swine and dairy farms (Source: AgStar [14])

State	Number of Candidate Farms	Methane Emissions Reductions (Thousand Tons)	Methane Production Potential (Billion ft ³ /year)	Energy Generation Potential	
				(1,000 MMBtu/Year)	(1,000 MWh/Year)
Swine Farms					
Iowa	2,174	331	24.30	22,430	2,070
North Carolina	761	192	12.21	11,266	1,040
Minnesota	691	64	7.64	7,052	651
Illinois	345	47	5.45	5,030	464
Indiana	302	34	4.11	3,795	350
Missouri	129	31	3.45	3,183	294
Nebraska	154	27	3.33	3,077	284
Oklahoma	45	49	3.26	3,013	278
Kansas	58	24	2.50	2,311	213
Ohio	226	15	1.73	1,594	147
Remaining 40 states	525	102	9.46	8,733	806
Swine Total:	5,409	915	77	71,484	6,598
Dairy Farms					
California	799	431	32.64	30,125	2,780
Idaho	179	138	11.56	10,668	985
Wisconsin	358	88	9.02	8,323	768
Texas	126	102	7.10	6,553	605
New Mexico	88	83	6.26	5,780	533
Washington	122	54	4.80	4,428	409
Michigan	138	47	4.79	4,420	408
Arizona	56	59	3.84	3,544	327
New York	126	32	3.29	3,033	280
Colorado	58	31	2.72	2,514	232
Remaining 40 states	655	254	22.47	20,737	1,914
Dairy Total:	2,704	1,320	108	100,124	9,241
Overall:	8,113	2,234	186	171,608	15,838

Municipal wastewater is yet another waste stream being used as an energy source and has potential for substantial expansion. According to the EPA 2011 study, there were 104 waste treatment facilities capturing biogas and using it for electricity generation in combined heat and power (CHP) plants, with a total generating capacity of 190 MW. An additional 1,351 facilities had installed anaerobic digesters, but not CHP plants. EPA estimated that if these facilities installed electricity-generating equipment, they could support a further 411 MW of electricity generation and 38,000 mmBtu per day of thermal energy [15]. In addition to the units listed in Table 4-5, State Utility Forecasting Group (SUFG) is aware of two additional electricity-generating plants in Indiana, giving the state a total capacity of 195 kW. More information about these plants is given in Chapter 4.4.

Table 4-5: Wastewater treatment combined heat and power systems in the U.S. (Data source: EPA [15])

State	Number of Sites	Capacity (MW)
AR	1	1.73
AZ	1	0.29
CA	33	62.67
CO	2	7.07
CT	2	0.95
FL	3	13.50
IA	2	3.40
ID	2	0.45
IL	2	4.58
IN	1	0.13
MA	1	18.00
MD	2	3.33
MI	1	0.06
MN	4	7.19

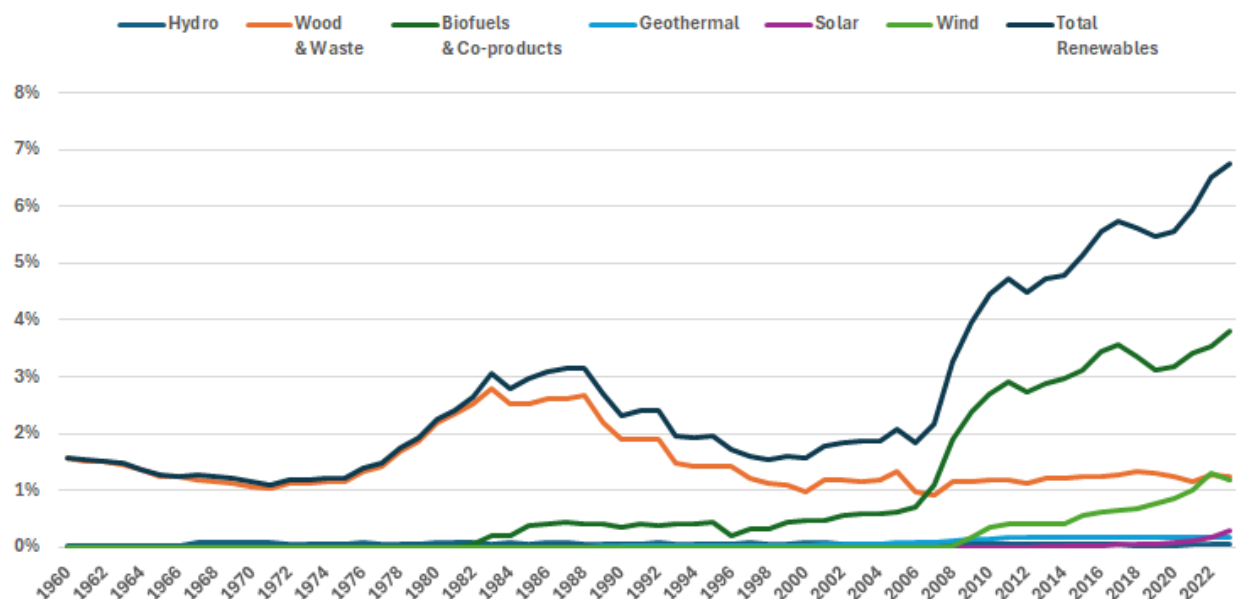
State	Number of Sites	Capacity (MW)
MT	3	1.09
NE	3	5.40
NH	1	0.37
NJ	4	8.72
NY	6	3.01
OH	3	16.29
OR	10	6.42
PA	3	1.99
TX	1	4.20
UT	2	2.65
WA	5	14.18
WI	5	2.02
WY	1	0.03
Total	104	189.8

Although crop residues are not in large-scale use today as a source of energy, they are the most readily available biomass feedstock. In the 2023 update of the Billion-Ton Study, the total amount of agricultural residues projected to be produced at a farm-gate price of \$70 per dry short ton (2022\$) is estimated at 159 million tons of corn stover, 18 million tons of wheat straw, and 2 million tons of barley straw, oats straw and sorghum stubble in total [8].

4.4 Organic waste biomass in Indiana

Organic waste biomass, in particular wood residue and byproducts, has historically been the main source of renewable energy consumed in Indiana, contributing over 80 percent of the renewable energy up to the 1980s and over 60 percent in the 1990s. It was not until the rapid growth in corn ethanol production in the mid-2000s that waste biomass was overtaken by biofuels as the leading source of renewable energy consumed in Indiana. Figure 4-5 shows the contribution of the various renewable resources to the total annual energy consumed in Indiana from 1960 to 2023. The types of industries using wood residue and byproducts include the paper and pulp industry, which has traditionally used the paper-making byproducts for cogeneration of electricity and process heat. In 2023 waste biomass' contribution to Indiana's renewable energy mix ranked second at 18 percent behind biofuels' 56 percent.

Figure 4-4: Renewables share of Indiana total energy consumption (1960-2023) (Data source: EIA [16])



Municipal solid waste is another source of energy from waste biomass in Indiana. For example, the Covanta Energy Corporation’s Indianapolis facility uses municipal solid waste to generate steam for district heating in downtown Indianapolis. The plant processes 703,000 tons of solid waste annually to produce 3.2 billion pounds of steam, which supplies half of the heat energy for the downtown Indianapolis heating loop [17, 18].

The other organic waste biomass that is a significant source of energy in Indiana is landfill gas. According to the EPA Landfill Methane Outreach Program, there are 17 operational landfill gas electricity generating projects in Indiana with a combined 64.3 MW installed generating capacity. Table 4-6 provides a list of operational landfill gas electricity generating plants in Indiana in the EPA database. Wabash Valley Power Association (WVPA), with 48.8 MW listed in the EPA database, is the most active user of landfill gas for electricity generation in Indiana. According to the WVPA website, however, WVPA owns and operates 14 landfill projects with a total of 49.6 MW and contracts for power from one 5.6 MW landfill project. The projects listed on the WVPA website are shown in Table 4-7 [19].

Table 4-6: Electricity generating plants at Indiana landfills (Data source: EPA [20])

Landfill Name	Project Developer	County	Rated Capacity (MW)	End User
Liberty Landfill	WVPA	White	6.4	WVPA
National Serv-All LF		Allen	6.4	General Motors
County Line LF	Aria Energy, LLC; Republic Services, Inc.	Fulton	5.9	NIPSCO
Earthmovers LF	WVPA	Elkhart	4.8	WVPA
Deercroft RDF	WVPA	LaPorte	4	WVPA
Blackfoot Landfill	Energy Systems Group	Pike	3.2	CenterPoint
Deercroft RDF	WVPA	LaPorte	3.2	WVPA
Deercroft RDF	WVPA	LaPorte	3.2	WVPA
Jay County LF	WVPA	Jay	3.2	WVPA
Liberty Landfill	WVPA	White	3.2	WVPA
Liberty Landfill	WVPA	White	3.2	WVPA
Oak Ridge RDF	WVPA	Cass	3.2	WVPA
Prairie View RDF	WVPA	St. Joseph	3.2	WVPA
Prairie View RDF	WVPA	St. Joseph	3.2	WVPA
Twin Bridges RDF	WVPA	Hendricks	3.2	WVPA
Twin Bridges RDF	WVPA	Hendricks	3.2	WVPA
Twin Bridges RDF	WVPA; WM Renewable Energy	Hendricks	3.2	WVPA
Twin Bridges RDF	WVPA	Hendricks	3.2	WVPA
County Line LF	Aria Energy	Fulton	1.6	WVPA

Table 4-7: Wabash Valley Power Association landfill electricity projects (Data source: WVPA [19])

Landfill Name	Capacity (MW)		Landfill Name	Capacity (MW)
Liberty III	6.4		Prairie View II	3.2
Earthmovers	4.8		Deercroft II	3.2
Twin Bridges I	3.2		Liberty I	3.2
Twin Bridges II	3.2		Liberty II	3.2
Twin Bridges III	3.2		Jay County	3.2
Twin Bridges IV	3.2		Oak Ridge	3.2
Prairie View I	3.2		Clinton (Illinois)	3.2
County Line**	5.6			

*County Line project is on a power purchase agreement

Giraldo, in his 2013 master's thesis [21], estimated that 10 other landfills in Indiana had the technical characteristics necessary to support an additional 16.9 MW of electricity generating capacity as shown in Table 4-8.

Table 4-8: Potential electricity generating capacity at Indiana landfills (Data source: Giraldo [21])

Facility Name	Amount of garbage disposed on landfill (tons)	Potential electricity generation capacity (kW)
Clinton County	1,170,254	560
New Paris Pike	1,900,000	870
Decatur Hills	1,363,442	900
Hoosier 2	2,143,024	1,030
Bartholomew County 2	1,468,927	1,170
Medora Sanitary	2,509,000	1,200
Wabash Valley	4,488,770	2,290
County Line	4,694,835	2,400
United Refuse	7,125,327	2,440
Sycamore Ridge	4,579,067	4,060

Another source of biomass fuel used for electricity generation in Indiana is the anaerobic digestion of animal manure. According to the EPA AgSTAR livestock digester database, there are eleven such digesters in Indiana. Five of those digesters use iogas to generate electricity, generating a combined average of 101,072 MWh per year. In four of the farms, the biogas is cleaned and pressurized into transportation fuel quality compressed natural gas (CNG), which can then be used as fuel for the milk transportation trucks, and in one of the projects in Reynolds, Indiana, the gas is purified to high enough purity to where it can be fed into the natural gas pipeline system. In addition to the digesters listed in the EPA AgSTAR database, SUFG is aware of digesters at the Culver Duck Farm in Middlebury, Indiana, that use the by-products from the duck processing plant to generate an average of 9,960 MWh of electricity per year from three generators with a combined 1.2 MW generating capacity. Table 4-9 lists the location and some characteristics of these livestock-based digesters. The potential to expand biogas production from livestock farms in Indiana is substantial, given that Indiana is ranked by the EPA among the top ten, with an estimated potential for producing 3.5 billion cubic feet of biogas per year from livestock manure digesters in 296 farms [14].

Table 4-9: Operational anaerobic digesters in Indiana (Data source: EPA [13])

Project Name	County	Animal Type and Population	Electricity Generated (MWh/yr)	Biogas Generation Estimate (ft³/day)
BioTown Ag, Power Generation	White	Cattle (4,500); Swine (800)	42,000	Cogeneration
Waste No Energy	White	Cattle (300); Swine (4,000)	8,370	408,000 Cogeneration
Curtiss Creek Dairy Digester 1	Jasper	Dairy (12,000)	7,818	120,000 Cogeneration, Compressed natural gas
Homestead Dairy	Marshall	Dairy (2,100)	7,446	Electricity
Hidden View	Jasper	Dairy (4,000)	7,074	Cogeneration
BioTown Ag, RNG	White	Dairy (9,240)		Pipeline gas
Bos Dairy	Jasper	Dairy (3,600)		Compressed natural gas
Curtiss Creek Dairy Digester 2	Jasper	Dairy (4,300)		430,000 Compressed natural gas
Green Cow Power LLC Digester	Elkhart	Dairy (1,500)		907,200 Cogeneration
Herrema Dairy Digester	Jasper	Dairy (5,250)		450,000 Compressed natural gas
Oak Basin Dairy Digester	Jasper	Dairy (3,611)		Pipeline gas
Windy Ridge Dairy Digester	Jasper	Dairy (7,000)		840,000 Compressed natural gas
Culver Duck Farm (processing plant)	Elkhart	Ducks; 18,00 pounds per day of droppings and offal	9,960	Cogeneration
Nature's Methane - Huntington Digester	Huntington	Dairy (4500)		Compressed natural gas

*Data from 2G Energy Corporation [22]

In 2013, it was estimated that 144 concentrated animal feeding operations (CAFOs) had the size and manure handling processes necessary to support an additional 20 MW of electricity generating capacity, as shown in Table 4-10.

Table 4-10: Potential electricity generating capacity at Indiana concentrated animal feeding operations (Data source: Giraldo [21])

Operation type (size in head)	Number of candidate farms	Potential electrical generation capacity per farm (kW)	Potential electrical generation capacity per category (kW)
Dairy (500-999)	17	175	2,975
Dairy (1000-2499)	12	365	4,380
Dairy (2500 or more)	3	1,204	3,612
Hog farrow-to-wean (1000-1999)	4	22	88
Hog farrow-to-wean (2000-4999)	2	53	106
Hog farrow-to-wean (5000 or more)	2	184	368
Hog farrow-to-finish (1000-1999)	14	20	280
Hog farrow-to-finish (2000-4999)	14	43	602
Hog farrow-to-finish (5000 or more)	16	194	3,104
Hog finish only (1000-1999)	18	28	504
Hog finish only (2000-4999)	22	68	1,496
Hog finish only (5000 or more)	14	181	2,534
Hog nursery (1000-1999)	2	12	24
Hog nursery (2000-4999)	3	18	54
Hog nursery (5000 or more)	1	38	38
Total	144		20,165

Another biomass waste stream that is currently in use as a source of energy in Indiana is municipal wastewater. SUFG is aware of a total of 195 kW of electricity generating capacity in wastewater treatment plants (WWTP) in the cities of Jasper (65 kW) and West Lafayette (130 kW). The West Lafayette facility is also equipped to take in food related waste from Purdue University and other local businesses. The electricity produced at the West Lafayette plant supplies approximately 20 percent of the total electricity needs at the plant [23]. It was estimated in 2013 that wastewater treatment plants in 17 Indiana cities had the volume and processing infrastructure necessary to support an additional 11 MW of electricity generating capacity, as shown in Table 4-11.

Table 4-11: Potential electricity generating capacity at Indiana wastewater treatment plants
(Data source: Giraldo [21])

Facility name	Average flow (MGD)	Potential electricity generation capacity (kW)
Noblesville WWTP	5.0	130
Speedway WWTP	5.5	143
Shelbyville WWTP	6.8	177
Elkhart WWTP	8.3	216
J.B. Gifford WWTP	8.5	221
William Edwin Ross WWTP	9.0	234
Anderson WWTP	12.0	312
Mishawaka WWTP	12.0	312
Evansville Eastside WWTP	18.0	468
Muncie WWTP	19.0	494
Lafayette WWTP	20.7	537
Terre Haute WWTP	24.0	624
Hammond WWTP	27.0	702
City of South Bend WWTP	36.0	936
Gary Sanitary District	50.0	1,300
Fort Wayne WPCP	62.0	1,612
Carmel South WWTP	95.0	2,470
Total		10,888

Table 4-12 to Table 4-14 show the amount of agricultural residues and processing waste, forest logging residues and processing waste, and animal manures potentially available for energy production in Indiana according to the 2023 Billion-Ton Study KDF data portal. As can be seen in the tables, the most abundant biomass residues available in Indiana is corn stover, approximately 10.5 million dry short tons per year at an offer price of \$70 per dry short ton (2022\$). Animal manures are the second biggest category, close to 1 million dry short tons per year in total.

Table 4-12: Estimated agricultural biomass potential in Indiana (Data source: DOE [8])

Type	\$40	\$70
	Dry tons/year	
Corn stover		10,493,504
Pruning residues, non-citrus	2,167	
Pruning residues, tree nuts	47	
Wheat straw		14,269
Total	2,214	10,507,773

Note: Table 4-12 was created based on data from the 2023 Billion-Ton Study data portal.

Table 4-13: Estimated forest biomass potential in Indiana (Data source: DOE [8])

Type	Dry tons/year
Hardwood lowland logging residues	59,378
Hardwood processing residues	2,213
Hardwood upland logging residues	1,818
Mixedwood logging residues	1,437
Softwood natural logging residues	569
Softwood planted logging residues	441
Softwood processing residues	64
Total	65,919

Note: Table 4-13 was created based on data from the 2023 Billion-Ton Study data portal.

Table 4-14: Estimated animal manures potential in Indiana (Data source: DOE [8])

Type	Dry tons/year
Manure, beef	37,676
Manure, dairy	302,029
Manure, swine	621,629
Total	961,334

Note: Table 4-14 was created based on data from the 2023 Billion-Ton Study data portal.

4.5 Incentives for organic waste biomass

The following federal and state incentives are available for waste biomass energy projects.

Federal Incentives

- Renewable Electricity Production Tax Credit (PTC) provides an inflation-adjusted production tax credit for electricity generated from qualifying open-loop biomass, landfill gas, and municipal solid waste facilities. The IRA of 2022 extended the legacy PTC to qualifying projects that began construction before January 1, 2025. Projects may also qualify for a 10 percent increase in the credit for meeting domestic content requirements and a separate 10 percent increase for being located in an energy community. For projects beginning construction after December 31, 2024, the legacy PTC was replaced by the technology-neutral Clean Electricity Production Tax Credit (CEPTC) discussed below. Additional details on the PTC are provided in Section 1.4 of this report [24-26].
- Business Energy Investment Tax Credit (ITC) provides an investment tax credit for qualifying renewable energy projects, including eligible biomass projects. Projects that meet the prevailing wage and apprenticeship requirements generally qualify for a credit equal to 30 percent of eligible project costs; otherwise, the base credit is generally 6 percent. Projects may also qualify for bonus credits for meeting domestic content

requirements or being located in an energy community. The Inflation Reduction Act of 2022 extended the legacy ITC to qualifying projects that began construction before January 1, 2025. For qualifying facilities placed in service after December 31, 2024, the legacy ITC was replaced by the technology-neutral Clean Electricity Investment Tax Credit (CEITC) discussed below. Additional details are provided in Section 1.4 of this report [24-26].

- Clean Electricity Production Tax Credit (CEPTC), established under Section 45Y of the IRA, became effective in 2025 and provides a technology-neutral production tax credit for qualifying zero- or negative-emission electricity-generating technologies, including qualifying biomass facilities. Projects that meet the prevailing wage and apprenticeship requirements qualify for the full credit. Unlike wind and solar facilities, qualifying biomass facilities are not subject to the accelerated 2027 termination rule enacted by the OBBBA [26, 27].
- Clean Electricity Investment Tax Credit (CEITC), established under Section 48E of the IRA, became effective in 2025 and provides a technology-neutral investment tax credit for qualifying zero- or negative-emission electricity-generating technologies, including qualifying biomass facilities. Projects that meet the prevailing wage and apprenticeship requirements generally qualify for a credit equal to 30 percent of eligible project costs. Unlike wind and solar facilities, qualifying biomass facilities are not subject to the accelerated 2027 termination rule enacted by the OBBBA [26, 27].
- U.S. DOE Title 17 Energy Financing Program (Section 1703 of Title XVII of the Energy Policy Act of 2005) provides loan guarantees for eligible energy projects, including projects that deploy new or significantly improved technologies that are technically proven but not yet widely commercialized in the United States. Renewable energy systems are among the eligible technology categories [24, 32].
- Modified Accelerated Cost-Recovery System (MACRS) allows businesses to recover investments in qualified renewable energy property through accelerated depreciation deductions. In addition, bonus depreciation may be available under applicable federal tax law [35].
- USDA Rural Energy for America Program (REAP) provides financial assistance to agricultural producers and rural small businesses for eligible renewable energy systems and energy-efficiency improvements. Loan guarantees are available on loans covering up to 75 percent of total eligible project costs. Grants may cover up to 50 percent of eligible project costs for qualifying projects, while other projects are limited to a 25 percent federal grant share. Combined grant and loan-guarantee funding may cover up to 75

percent of total eligible project costs [24, 28].

- High Energy Cost Grant Program administered by USDA assists eligible rural communities with extremely high household energy costs, defined as exceeding 275 percent of the national average. Eligible projects include the acquisition, construction, or improvement of energy generation, transmission, and distribution facilities, including renewable energy projects [29].
- USDA Biorefinery Assistance Program provides loan guarantees for eligible commercial-scale biorefineries, renewable chemical facilities, and renewable fuel projects, with loan guarantees of up to \$250 million, subject to program requirements. [24].
- Federal Renewable Energy Use Statutory Requirement (Section 203 of the Energy Policy Act of 2005, as amended) requires that, to the extent economically feasible and technically practicable, at least 7.5 percent of the electricity consumed by the Federal Government each fiscal year be obtained from renewable energy sources [24].

Indiana Incentives

- Net Metering Rule continues to allow eligible grandfathered utility customers with renewable energy systems having a maximum generating capacity of 1 MW to receive retail-rate credits for excess electricity exported to the grid. Senate Enrolled Act 309 (SEA 309), signed into law in 2017, transitioned Indiana from traditional net metering to the Excess Distributed Generation (EDG) program for new customers after June 30, 2022. Customers with qualifying systems installed before January 1, 2018 continue to receive retail-rate credits until July 1, 2047, while eligible systems installed between January 1, 2018 and June 30, 2022, or until the utility reached the statutory 1.5 percent aggregate-capacity threshold, whichever occurred first, continue to receive retail-rate credits until July 1, 2032 [24, 30].
- Excess Distributed Generation Rule replaced the net metering compensation structure for newer distributed generation systems under Indiana Code 8-1-40 of 2017. Under this rule, customer-sited renewable generation is compensated for exported electricity at a rate equal to 1.25 times the average marginal price of electricity paid by the electricity supplier during the most recent calendar year, rather than the full retail rate provided under net metering. As a result, compensation for excess generation is typically lower than under the legacy net metering framework, reflecting a shift toward a more cost-based valuation of distributed generation [24, 30].
- Sales and Use Tax Exemption for Electrical Generating Equipment may exempt

machinery, tools, equipment, and other tangible personal property that are directly used in the direct production of tangible personal property, including electricity, from Indiana sales and use tax. Equipment used to generate electricity that is directly used in the production of other tangible personal property may also qualify for the manufacturing exemption to the extent that the applicable direct-use requirements are satisfied [24, 33].

- Clean Energy Portfolio Goal established a voluntary goal of obtaining 4 percent of electricity from clean energy sources between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent in 2025, based on 2010 retail sales. The final statutory goal period ended on December 31, 2025, and no additional clean energy portfolio goals are specified beyond 2025. However, financial incentives and cost-recovery mechanisms approved for participating electricity suppliers that achieved the applicable goals may continue beyond 2025 in accordance with the terms of the program and IURC approval [24, 34].
- NIPSCO Feed-in Tariff previously offered incentive rates for electricity generated from renewable resources, including biomass, through long-term power purchase agreements of up to 15 years. For biomass projects, eligible system sizes ranged from 100 kW to 1 MW, with payments negotiated up to a maximum of \$0.0918/kWh. As of 2026, the program is closed to new applicants, although existing contracts remain in effect under their original terms.
- Senate Enrolled Act 240 (2026) (Public Law 126-2026), may further support the development of distributed biogas and waste-based generation by enabling the use of surplus interconnection capacity at existing grid connection points, potentially reducing interconnection costs and timelines.
- Senate Enrolled Act 277 (2026) (Public Law 135-2026), makes broad changes to Indiana’s environmental regulatory framework by increasing flexibility in permitting and reducing certain reporting and compliance requirements under the Indiana Department of Environmental Management (IDEM). These changes may affect the regulatory environment and development timelines for organic waste biomass and biogas projects.
- House Enrolled Act 1368 (2026) (Public Law 161-2026), establishes a state-level regulatory framework for carbon capture and storage and enables Indiana to assume permitting authority for CO₂ sequestration projects. This development introduces an alternative pathway for emissions reduction that may influence investment decisions and the competitive position of organic waste biomass technologies.

4.6 References

1. U.S. Environmental Protection Agency (EPA). Overview of Greenhouse Gases. <https://www.epa.gov/ghgemissions/understanding-global-warming-potentials>
2. DOE Bioenergy Technology Office. National Algal Biofuels Technology Review. June 2016. <https://www.energy.gov/eere/bioenergy/downloads/2016-national-algal-biofuels-technology-review>
https://www.energy.gov/sites/prod/files/2016/06/f33/national_algal_biofuels_technology_review.pdf
3. DOE Bioenergy Technology Office. Algal Biofuels Advanced Algal Systems Fact Sheet. June 2019. <https://www.energy.gov/eere/bioenergy/algal-biofuels>
<https://www.energy.gov/eere/bioenergy/related-links-0>
<https://www.energy.gov/sites/prod/files/2019/06/f63/Advanced%20Algal%20Systems%20Fact%20Sheet.pdf>
4. Arizona Public Service and GreenFuel Technologies Corp. Successfully Recycle Power Plant Flue Gases into Transportation-Grade Biodiesel and Ethanol. November 30, 2006. <https://csrwire.com/press-release/arizona-public-service-and-greenfuel-technologies-corp-successfully-recycle-power-plant-flue-gases-into-transportation-grade-biodiesel-and-ethanol/>
www.greentechmedia.com/articles/read/aps-gets-70.5m-to-feed-captured-carbon-to-algae
5. Energy Information Administration (EIA). Cost and Performance Characteristics of New Generating Technologies, 2019 Annual Energy Outlook. <https://www.eia.gov/outlooks/archive/aeo19/>
6. DOE and U.S. Department of Agriculture (USDA). Biomass as feedstock for a bioenergy and bioproducts industry: the technical feasibility of a billion-ton annual supply. April 2005. https://www1.eere.energy.gov/bioenergy/pdfs/final_billionton_vision_report2.pdf
7. DOE. 2011 U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry. R.D. Perlack and B.J. Stokes (Leads), ORNL/TM-2011/224. Oak Ridge National Laboratory, Oak Ridge, TN. 448p. doi:10.2172/1271651.
https://www.energy.gov/sites/prod/files/2015/01/f19/billion_ton_update_0.pdf
8. Hellwinckel, C., D. de la Torre Ugarte, J. L. Field, and M. Langholtz. 2024. "Chapter 5: Biomass from Agriculture." In 2023 Billion-Ton Report. M. H. Langholtz (Lead). Oak Ridge, TN: Oak Ridge National Laboratory. doi: 10.23720/BT2023/2316171.
<https://www.energy.gov/eere/bioenergy/2023-billion-ton-report-assessment-us-renewable-carbon-resources>
DOE. Bioenergy Knowledge Discovery Framework, Billion-ton 2023 Data Portal.
<https://bioenergykdf.ornl.gov/bt23-data-portal>

9. National Alliance for Advanced Biofuels and Bioproducts (NAABB). Synopsis. Final report. June 2014.
https://www.energy.gov/sites/prod/files/2014/07/f18/naabb_synopsis_report_0.pdf
https://www.energy.gov/sites/prod/files/2014/07/f18/naabb_full_final_report_section_I.pdf
10. EIA. April 2026 Monthly Energy Review Table 10.1
<https://www.eia.gov/totalenergy/data/monthly/#renewable>
11. Energy Recovery Council. 2018 directory of waste-to-energy facilities
<https://wtert.org/2018-directory-of-waste-to-energy-facilities-energy-recovery-council/>
12. EPA. Landfill Methane Outreach Program.
<https://www.epa.gov/lmop/project-and-landfill-data-state>
<https://www.epa.gov/system/files/documents/2024-03/opprjslmopdata-detailed.xlsx>
13. EPA, AgStar. Livestock Anaerobic Digester Database. May 2022.
<https://www.epa.gov/agstar/livestock-anaerobic-digester-database>
<https://www.epa.gov/sites/default/files/2020-10/agstar-livestock-ad-database.xlsx>
14. AgStar. Market opportunities for biogas recovery systems at U.S. livestock facilities.
<https://www.epa.gov/agstar/agstar-market-opportunities-report>
15. EPA Combined Heat and Power Partnership, Opportunities for combined heat and power at wastewater treatment facilities: market analysis and lessons learned from the field.
<https://www.epa.gov/chp/chp-resources>
https://www.epa.gov/sites/default/files/2016-07/documents/opportunities_for_combined_heat_and_power_at_wastewater_treatment_facilities_market_analysis_and_lessons_from_the_field.pdf
16. EIA. State Energy Data System (SEDS): 1960-2023 (complete).
 Table CT2. Primary Energy Consumption Estimates, 1960-2023, Indiana (Trillion Btu)
https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_use/total/use_tot_INcb.html&sid=IN
17. Reworld Sustainable Waste Solutions.
<https://www.reworldwaste.com/where-we-are>
18. The Center for Land Use Interpretation. Indianapolis resource recovery facility, Indiana
<https://clui.org/ludb/site/indianapolis-resource-recovery-facility>
19. Wabash Valley Power Association.
<https://www.wvpa.com/power-supply-diversity/renewable-energy/>
20. EPA. Landfill Methane Outreach Program (LMOP).
<https://www.epa.gov/lmop/landfill-gas-energy-project-data>
<https://www.epa.gov/system/files/documents/2024-03/opprjslmopdata-detailed.xlsx>
21. Juan S. Giraldo. An economic analysis of electricity generation potential from biogas resources in the state of Indiana. Master of Science Thesis, Purdue University 2013.
<https://docs.lib.purdue.edu/dissertations/AAI1544326/>
<https://www.purdue.edu/discoverypark/sufg/wp-content/uploads/2025/04/Juan-Giraldo-Dissertation.pdf>

22. 2G Energy. Culver Ducks Farm Project.
<https://www.2g-energy.com/projects/culver-duck-farms-inc>
https://9102466.fs1.hubspotusercontent-na1.net/hubfs/9102466/2GEnergy_March2022/PDFs/culver_duck_farms.pdf
23. West Lafayette wastewater treatment plant. Presentation to EPA 2021
<https://19january2021snapshot.epa.gov/sites/static/files/2015-09/documents/henderson.pdf>
24. Database of State Incentives for Renewables and Efficiency (DSIRE).
<https://dsireusa.org/>
25. The National Law Review. August 17, 2022. Relief Arrives for Renewable Energy Industry - Inflation Reduction Act of 2022. <https://www.natlawreview.com/article/relief-arrives-renewable-energy-industry-inflation-reduction-act-2022>
26. DLA Piper Law Firm Publications. The clean energy provisions of the Inflation Reduction Act of 2022 – a historic effort to encourage the development of clean energy and reduce carbon emissions. <https://www.dlapiper.com/en/us/insights/publications/2022/08/the-clean-energy-provisions-of-the-inflation-reduction-act-of-2022/>
27. Sidley Energy Updates. The “One Big Beautiful Bill” Act – Navigating the New Energy Landscape. July 15, 2025. <https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape>
28. U.S. Department of Agriculture (USDA) Rural Development. Rural Energy for America Program Renewable Energy Systems & Energy Efficiency Improvement Guaranteed Loans & Grants. <https://www.rd.usda.gov/programs-services/rural-energy-america-program-renewable-energy-systems-energy-efficiency>
29. U.S. Department of Agriculture, Rural Development. Grants.
<https://www.rd.usda.gov/programs-services/high-energy-cost-grants>
30. Indiana General Assembly. Senate Bill 309
<https://iga.in.gov/legislative/2017/bills/senate/309#digest-heading>
31. NIPSCO
<https://www.nipsco.com/services/renewable-energy-programs/feed-in-tariff>
32. U.S. Department of Energy. Program Guidance for the Title 17 Energy Financing Program. May 13, 2026.
<https://www.energy.gov/documents/doe-edf-title-17-energy-financing-program-guidance-2026-05-13>
33. Indiana Department of Revenue. Sales and Use Tax Refunds — Manufacturing Exemptions. Accessed 2026.
<https://www.in.gov/dor/i-am-a/business-corp/sales-use-tax-refunds>
34. Indiana General Assembly. Indiana Code 8-1-37, Voluntary Clean Energy Portfolio Standard Program, Sections 12–13.
<https://iga.in.gov/laws/2026/ic/titles/8>
35. Internal Revenue Service (IRS). Publication 946: How to Depreciate Property (2025). Chapter 4, Modified Accelerated Cost Recovery System (MACRS).
<https://www.irs.gov/publications/p946?a=ecd3e32d-b1e8-49de-8f6a-fee4333c9c61&utm>

5. Solar Energy

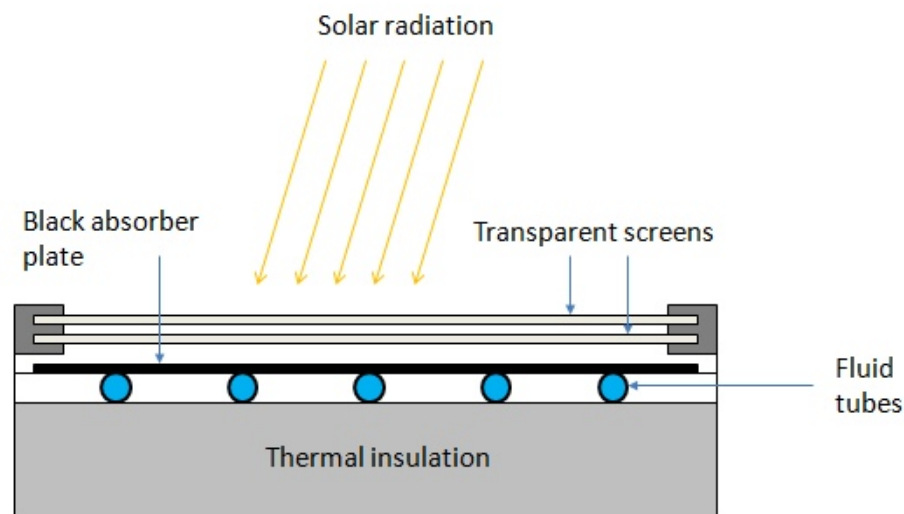
5.1 Introduction

Solar energy is captured and converted into various forms of energy in two main ways: directly to electricity using photovoltaic cells and indirectly using solar thermal conversion technologies. Solar thermal conversion technologies use the sun's energy to heat a fluid, which can then be used to drive an electric generator. The hot fluid can also be used for non-electric purposes, such as heating a building or producing hot water. This report presents the two solar energy conversion methods and their associated technologies, starting with solar thermal conversion in this chapter, followed by photovoltaic cells in the next chapter.

Solar thermal energy is captured using solar collectors, of which there are two main types: concentrating and non-concentrating collectors. Concentrating collectors use mirrors in various configurations to focus solar energy onto a receiver containing a working fluid that transfers heat to a conversion engine. Concentrating collectors are typically used for electricity-generating projects, while non-concentrating collectors are typically used for heating applications such as water and space heating.

The most commonly used non-concentrating collectors are flat-plate designs. Flat-plate collectors consist of a flat-plate absorber, a transparent cover that allows solar energy to pass through while reducing heat loss, a heat-transport fluid flowing through tubes, and a heat insulating backing. Figure 5-1 shows the basic components of a flat-plate collector. Other non-concentrating collectors include evacuated-tube collectors and integral collector-storage systems.

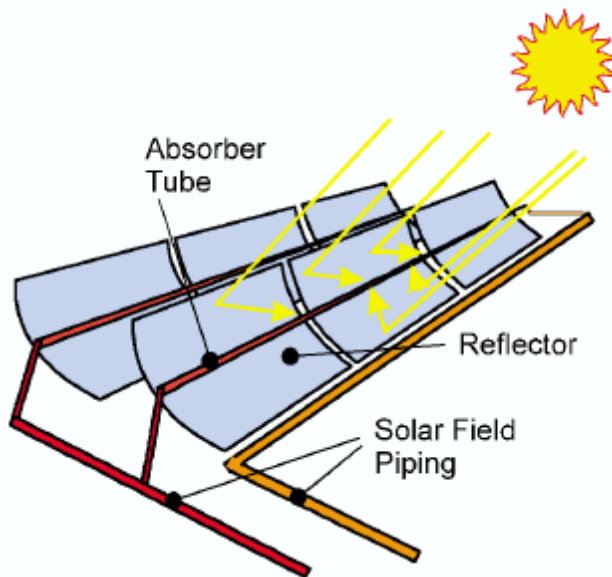
Figure 5-1: The layout of a flat-plate collector (Source: Penn State University [1])



The four main types of thermal concentrating solar power (CSP) systems are parabolic trough, linear Fresnel, solar power tower, and solar dish/engine system.

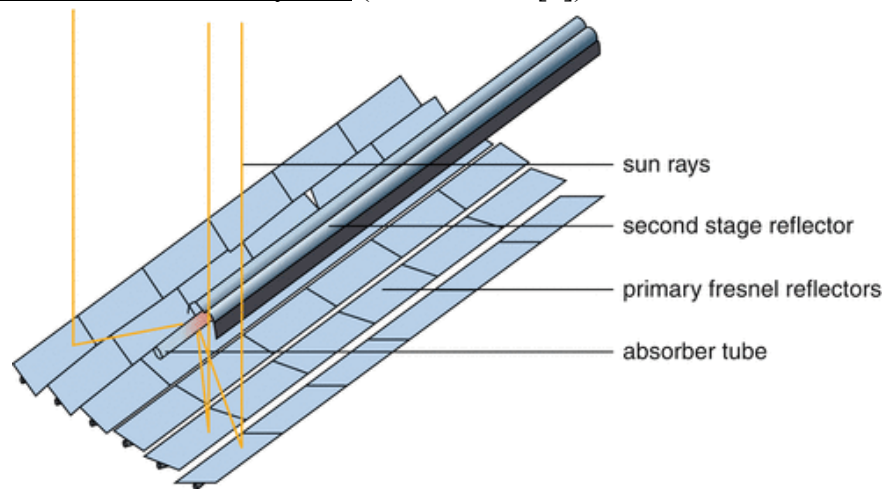
The parabolic trough CSP system is the most developed and widely used CSP technology. It has trough-shaped collectors with a parabolic cross-section and a receiver tube located at the focal line of the trough, as shown in Figure 5-2. A working fluid is used to transport the heat from the receivers to heat exchangers. Trough CSP systems in use for utility-scale electricity generation are typically coupled with a fossil-fuel-fired boiler to supplement the supply of heat when the solar energy collected is not adequate. Trough systems can also be coupled with energy storage equipment to store the hot working fluid, thereby providing the ability for the plant to be dispatched to match system demand.

Figure 5-2: A parabolic trough CSP system (Source: IEA [2])



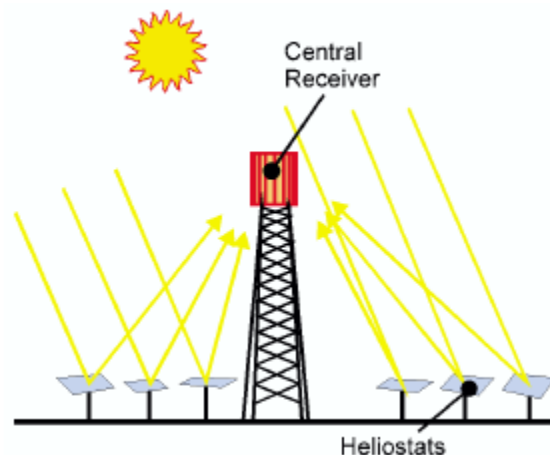
The linear Fresnel CSP system functions a lot like the parabolic trough system. The parabolic trough is replaced with a series of flat or slightly curved mirrors that focus the radiation onto a receiver tube, as shown in Figure 5-3. The receiver tube contains a fluid that is used to carry the reflected sun's heat to the energy conversion equipment. One U.S. example is Tucson Electric Power's 5 MW Sundt Augmentation solar thermal project in Tucson, Arizona, which uses a linear Fresnel-style mirror field to generate steam and boost output at the H. Wilson Sundt Generating Station. [3].

Figure 5-3: A linear Fresnel CSP system (Source: IEA [2])



The power tower CSP system uses flat sun-tracking mirrors to concentrate solar energy on a tower-mounted heat exchanger, as shown in Figure 5-4. This system avoids heat loss during the transport of the working fluid to the central heat exchanger, as in a trough-based CSP system. Power tower CSP systems are typically equipped with molten-salt energy storage tanks at the base of the towers, enabling several hours of energy storage. There are two operational power tower projects in the U.S.: the 377 MW Ivanpah project in the Mojave Desert in California and the 110 MW Crescent Dunes project in Tonopah, Nevada [4].

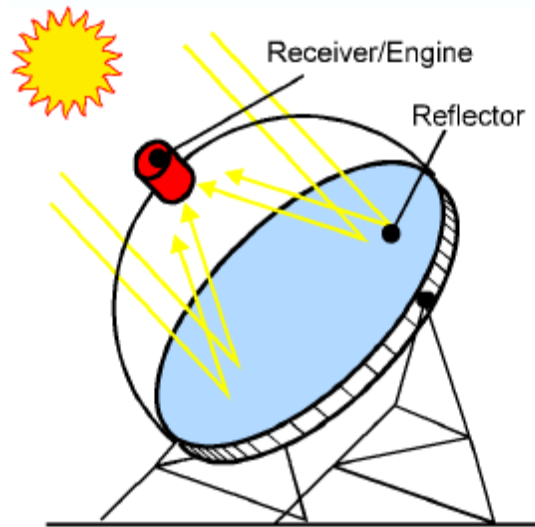
Figure 5-4: A power tower CSP system (Source: IEA [2])



The dish/engine system utilizes a parabolic shaped dish that focuses the sun's rays to a receiver at the focal point of the dish as shown in Figure 5-5. An engine/generator located at the focal point of the dish converts the absorbed heat into electricity. Many of these dish systems may be combined to make a utility-scale power plant. The dish/engine system does not use any cooling water which puts it at an advantage over the other three systems. However, it is the least developed of the three CSP technologies with several challenges to be overcome in the design of

the reflectors and the solar collectors. The two dish/engine CSP plants installed in the U.S. are no longer operational. They are the 1.5 MW Maricopa project in Arizona and the 1.5 MW project at the Tooele Army Depot in Utah [4].

Figure 5-5: A dish/engine CSP system (Source: IEA [2])



5.2 Economics of solar technologies

Table 5-1 shows the overnight capital cost⁸ estimates from the National Laboratory of the Rockies (NLR), previously the National Renewable Energy Laboratory (NREL), for CSP power plants in operation in the U.S. The per-kilowatt cost varies widely, ranging from \$4,385/kW for the Nevada Solar One power plant in Boulder City, Nevada, to \$9,384/kW for the Crescent Dunes Solar power plant in Tonopah, Nevada.

⁸ Overnight capital cost “is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day” [5]. The overnight cost concept is used to avoid the impact of the differences in financing methods chosen by project developers on the estimated costs.

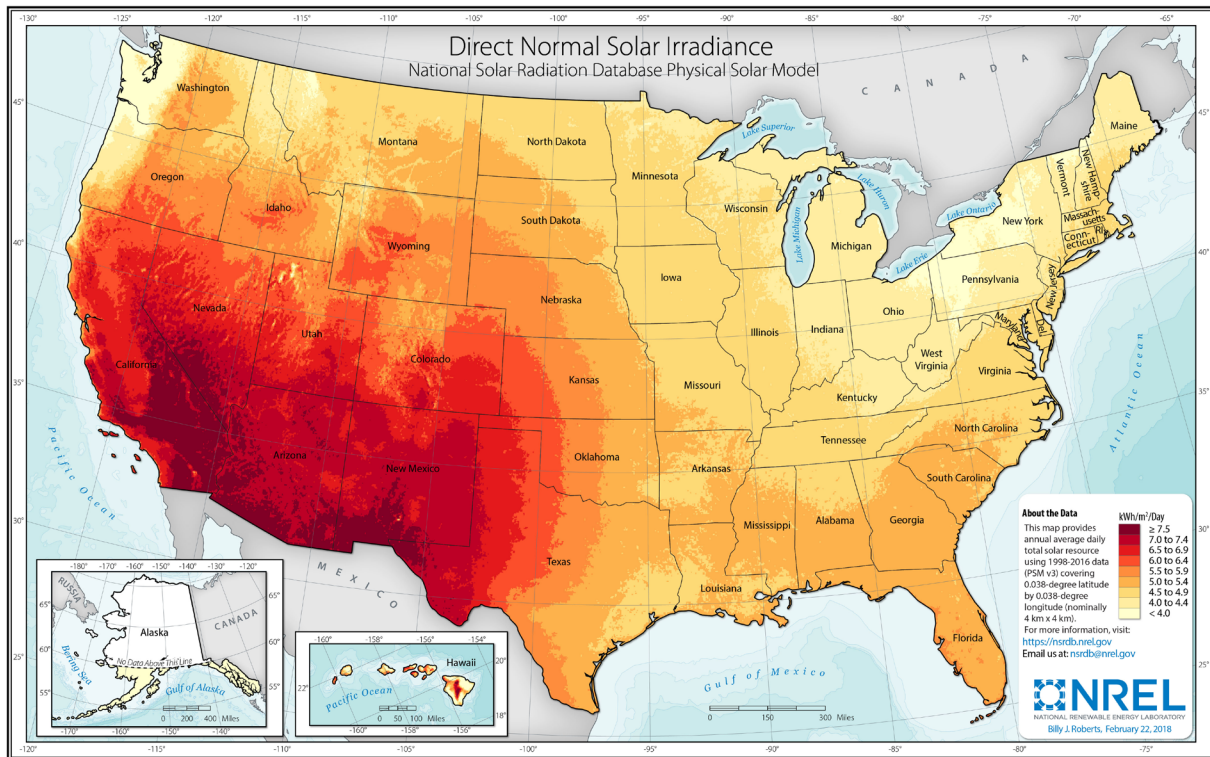
Table 5-1: Estimated capital cost of CSP plants in the U.S. (Data sources NLR [4])

Project Name	Location	Capital Cost (2020\$/kW)	Capacity (MW)	Technology	Thermal Storage (Hours)	Status	Online Date
Crescent Dunes	Tonopah, NV	9,384	110	Power Tower	10	Operational	2015
Solar Electric Generating Station (SEGS) I	Daggett, CA	9,372	13.8	Parabolic Trough	3	Decommissioned	1984
SEGS II	Daggett, CA	9,082	30	Parabolic Trough	None	Decommissioned	1985
Solana	Phoenix, AZ	8,644	250	Parabolic Trough	6	Operational	2013
Martin Next Generation	Indiantown, FL	7,248	75	Hybrid; Trough	None	Operational	2010
SEGS III	Kramer Junction, CA	6,862	30	Parabolic Trough	None	Decommissioned	1985
Ivanpah Solar	Primm, NV	6,207	377	Power Tower	None	Decommissioned	2014
SEGS IV	Kramer Junction, CA	6,100	30	Parabolic Trough	None	Decommissioned	1989
SEGS V	Kramer Junction, CA	6,100	30	Parabolic Trough	None	Decommissioned	1989
SEGS VI	Kramer Junction, CA	6,100	30	Parabolic Trough	None	Decommissioned	1989
SEGS VII	Kramer Junction, CA	6,100	30	Parabolic Trough	None	Decommissioned	1989
Mojave Solar	Harper Dry Lake, CA	6,078	280	Parabolic Trough	None	Operational	2014
Genesis	Blythe, CA	5,171	250	Parabolic Trough	None	Operational	2014
SEGS VIII	Harper Dry Lake, CA	5,158	80	Parabolic Trough	None	Decommissioned	1989
SEGS IX	Harper Dry Lake, CA	4,974	80	Parabolic Trough	None	Operational	1990
Nevada Solar One	Boulder City, NV	4,385	72	Parabolic Trough	0.5	Operational	2007

5.3 State of solar energy nationally

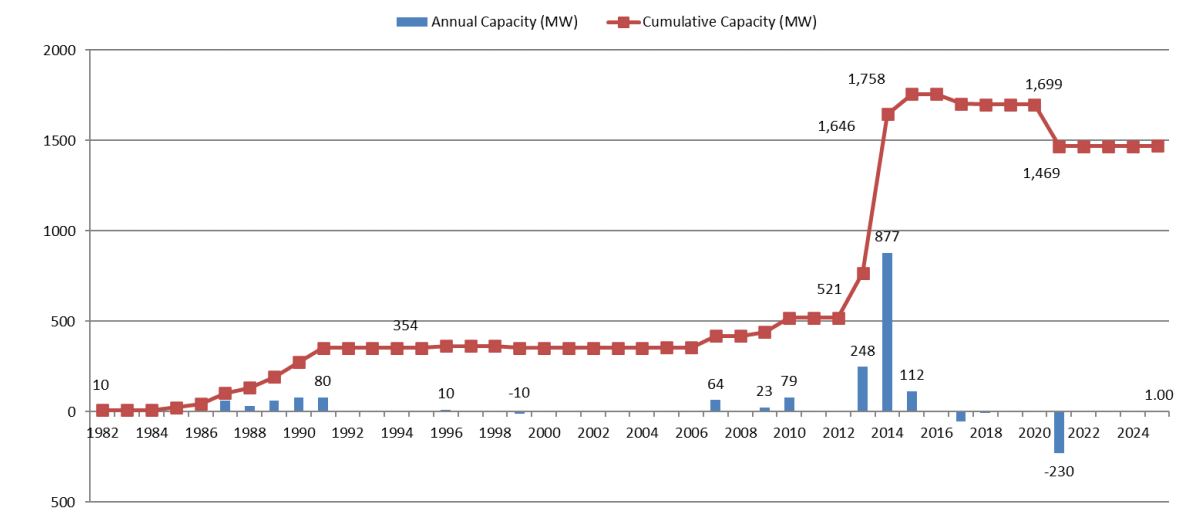
As shown in Figure 5-6, substantial solar resources are available in the U.S., especially in the southwestern region.

Figure 5-6: Solar power resource in the U.S. (Source: NLR [5])



Between 1980 and 2016, U.S. CSP capacity grew in two major waves. The first occurred in the 1980s and early 1990s, driven largely by the multiphase Solar Energy Generating System (SEGS) projects in California, which brought cumulative capacity to about 354 MW. The second wave occurred from 2007 to 2016, when an additional 1,404 MW of CSP capacity came online, raising total U.S. CSP capacity to roughly 1,758 MW. Since 2016, SUFG is not aware of any new commercial-scale CSP projects entering service or being under construction in the United States. However, Sandia National Laboratories' Generation 3 Particle Pilot Plant, a 1-MW pilot-scale power tower project in Albuquerque, New Mexico, was expected to begin generation in. At the same time, approximately 288 MW of older CSP capacity has been retired, including all but 80 MW of the original 354 MW SEGS fleet in California.

Figure 5-7: Solar thermal power capacity installed in the U.S. (Data sources: NLR [4, 6], Solar Energy Industries Association (SEIA) [7], IREC [8])



Five of the largest operating projects, with a combined capacity of 1,282 MW, were completed in 2013-2015. The largest of these is the 377 MW Ivanpah power tower in the Mojave Desert in California. The other four are the 250 MW Solana project near Gila Bend, Arizona; the 250 MW Genesis project in Riverside County, California; the 280 MW Mojave solar project also located in the Mojave Desert of California; and the 110 MW Crescent Dunes project in Tonopah, Nevada. Table 5-2 contains a list of CSP projects in operation in the U.S. as of the writing of this report, while Table 5-3 is a list of installed CSP projects that are no longer operational.

Table 5-2: Operating concentrating solar power plants in the U.S. (Data source: NLR [4, 6])

Project Name	Location	Capacity (MW)	Technology	Year Operational
National Solar Thermal Test Facility	Albuquerque Bernalillo, NM	5	Power Tower	1978
SEGS IX	Harper Lake, CA	80	Parabolic Trough	1990
Nevada Solar One	Boulder City, NV	72	Parabolic Trough	2007
Martin Next Generation	Indiantown, FL	75	Hybrid; Trough	2010
Solana Generating Station	Phoenix, AZ	250	Parabolic Trough	2013
Ivanpah Solar	Primm, NV	377	Power Tower	2014
Mojave Solar Project	Harper Lake, CA	280	Parabolic Trough	2014
Genesis Solar Energy	Blythe, CA	250	Parabolic Trough	2014
Crescent Dunes Solar	Tonopah, NV	110	Power Tower	2015
Stillwater GeoSolar Hybrid	Fallon, NV	2	Parabolic Trough	2015
Generation 3 Particle Pilot Plant Sandia	Albuquerque Bernalillo, NM	1	Power Tower	2025

Table 5-3: Concentrating solar power plants in the U.S. that are no longer operating (Data source: NLR [4, 6])

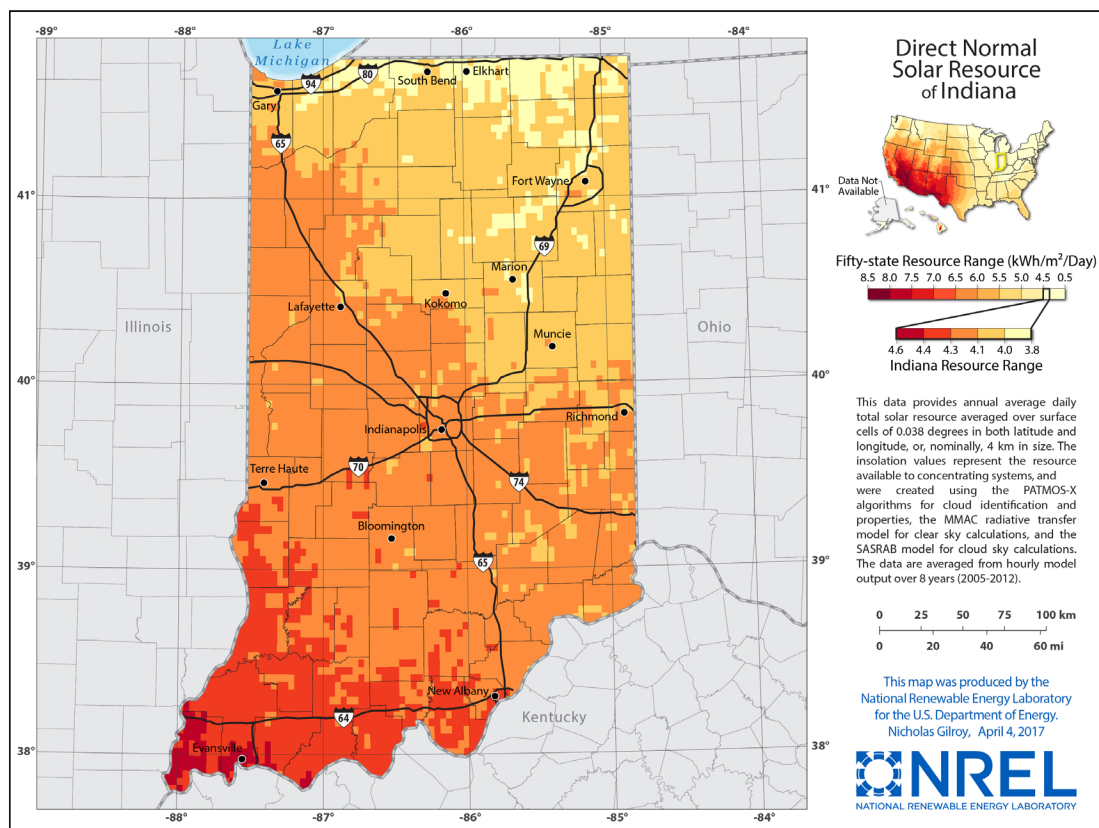
Project Name	State	Generating Capacity (MW)	Technology	Production Start Year
Solar One	CA	10	Power tower	1982
SEGS I	CA	13.8	Parabolic trough	1984
SEGS II	CA	30	Parabolic trough	1985
SEGS III	CA	30	Parabolic trough	1987
SEGS IV	CA	30	Parabolic trough	1989
SEGS V	CA	30	Parabolic trough	1989
SEGS VI	CA	30	Parabolic trough	1989
SEGS VII	CA	30	Parabolic trough	1989
SEGS VIII	CA	80	Parabolic trough	1989
Solar Two	CA	10	Power tower	1995
Saguaro Power Plant	AZ	1	Parabolic trough	2006
Kimberlina Solar Thermal	CA	5	Linear Fresnel reflector	2008
Sierra SunTower	CA	5	Power tower	2009
Holaniku at Keahole Point	HI	2	Parabolic trough	2009
Maricopa Solar Project	AZ	1.5	Dish/Engine	2010
Colorado Integrated Solar	CO	2	Parabolic trough	2010
Tooele Army Depot	UT	1.5	Dish/Engine	2013

5.4 Solar energy in Indiana

As shown in the U.S. solar radiation map (Figure 5-6), Indiana is in a region of the country with comparatively low annual average solar radiation. This, combined with the very high capital cost for CSP power plants compared to other generating technologies, makes Indiana a less-than-ideal location for multi-megawatt CSP plants compared to states such as California, Arizona, Nevada, and Florida. The 1,494 MW of solar thermal power plants currently operating in the U.S. are located in three states as follows: California – 610 MW, Nevada – 559 MW, Arizona – 250 MW and Florida – 75 MW. However, there is some potential for water-heating applications of solar thermal technologies in Indiana.

Figure 5-8 shows the solar radiation available to a flat collector facing south in Indiana. Flat plate collectors are typically used for water heating applications. As can be seen in the figure, the southwestern portion of the state has the highest solar radiation available.

Figure 5-8: Direct normal solar radiation (flat-plate collector) in Indiana (Source: NLR [9])



5.5 Incentives for solar thermal energy

The following incentives are available for solar thermal energy projects:

Federal Incentives

- Business Renewable Energy Investment Tax Credit (ITC) provides an investment tax credit generally equal to 30 percent of eligible project costs for qualifying projects that meet the prevailing wage and apprenticeship requirements; otherwise, the base credit is generally 6 percent. Projects may also qualify for bonus credits for meeting domestic content requirements or being located in an energy community. The IRA extended the legacy ITC to qualifying projects that began construction before January 1, 2025 [10, 11].
- Renewable Electricity Production Tax Credit (PTC) provides a production tax credit of 1.5 cents/kWh, adjusted annually for inflation, for electricity generated from qualifying renewable energy facilities that meet the prevailing wage and apprenticeship requirements. Projects that do not meet these requirements generally qualify for one-fifth of the full credit. Projects may also qualify for a 10 percent increase for meeting domestic content requirements and a separate 10 percent increase for being located in an energy community. The IRA extended the legacy PTC to qualifying projects that began construction before January 1, 2025 [10, 11].
- Clean Electricity Investment Tax Credit (CEITC) is similar to the ITC but is technology-neutral and applies to qualifying zero- or negative-emission electricity-generating technologies. Projects that meet the prevailing wage and apprenticeship requirements generally qualify for a credit equal to 30 percent of eligible project costs. Projects may also qualify for additional bonus credits for meeting domestic content requirements, being located in an energy community, or satisfying applicable low-income-community requirements. For applicable solar facilities, the OBBBA established an accelerated termination rule: facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify [11, 12].
- The Clean Electricity Production Tax Credit (CEPTC) is similar to the PTC but is technology-neutral and applies to qualifying zero- or negative-emission electricity-generating technologies. The credit amount is adjusted annually for inflation, with the credit generally increased fivefold for projects that meet the prevailing wage and apprenticeship requirements. Projects may also qualify for a 10 percent increase for meeting domestic content requirements and a separate 10 percent increase for being located in an energy community. For applicable solar facilities, the OBBBA established an accelerated termination rule: facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify [11, 12].

- U.S. DOE Title 17 Energy Financing Program (Section 1703 of Title XVII of the Energy Policy Act of 2005) provides loan guarantees for eligible energy projects, including projects that deploy new or significantly improved technologies that are technically proven but not yet widely commercialized in the United States. Eligible technologies include renewable energy technologies such as wind energy [13, 17].
- Modified Accelerated Cost-Recovery System (MACRS) allows businesses to recover investments in qualified renewable energy technologies through depreciation deductions [19].
- USDA Rural Energy for America Program (REAP) provides financial assistance to agricultural producers and rural small businesses for eligible renewable energy systems and energy-efficiency improvements. Loan guarantees are available on loans covering up to 75 percent of total eligible project costs. Grants may cover up to 50 percent of eligible project costs for qualifying projects, while other projects are limited to a 25 percent federal grant share. Combined grant and loan-guarantee funding may cover up to 75 percent of total eligible project costs [13, 14].
- USDA High Energy Cost Grant Program administered by USDA assists eligible rural communities with extremely high household energy costs, defined as exceeding 275 percent of the national average. Eligible projects include the acquisition, construction, or improvement of energy generation, transmission, and distribution facilities, including renewable energy projects [15].
- Federal Renewable Energy Use Statutory Requirement (Section 203 of the Energy Policy Act of 2005, as amended) requires that, to the extent economically feasible and technically practicable, at least 7.5 percent of the electricity consumed by the Federal Government each fiscal year be obtained from renewable energy sources [13].

Indiana Incentives

- Renewable Energy Property Tax Exemption provides property tax exemptions for solar water heat, solar space heat, geothermal electric, solar thermal process heat, solar PV, wind (all), hydroelectric, geothermal heat pumps, solar pool heating, wind (small), geothermal direct-use, subject to local assessment practices and specific eligibility criteria. Solar heating and cooling systems are exempt based on out-of-pocket costs, while wind, hydroelectric, geothermal, solar thermal, solar PV, and other solar systems are exempt based on their assessed value [13].
- Sales and Use Tax Exemption for Electrical Generating Equipment may exempt

machinery, tools, equipment, and other tangible personal property that are directly used in the direct production of tangible personal property, including electricity, from Indiana sales and use tax. Equipment used to generate electricity that is directly used in the production of other tangible personal property may also qualify for the manufacturing exemption to the extent that the applicable direct-use requirements are satisfied [13, 18].

- Clean Energy Portfolio Goal established a voluntary goal of obtaining 4 percent of electricity from clean energy sources between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent in 2025, based on 2010 retail sales. The final statutory goal period ended on December 31, 2025, and no additional clean energy portfolio goals are specified beyond 2025. However, financial incentives and cost-recovery mechanisms approved for participating electricity suppliers that achieved the applicable goals may continue beyond 2025 in accordance with the terms of the program and IURC approval [16].

5.6 References

1. Pennsylvania State University. Department of Energy and Mineral Engineering. <https://www.e-education.psu.edu/eme811/node/685>
2. International Energy Agency (IEA). SolarPACES - solar thermal for dispatchable power and solar chemistry network. <http://www.solarpaces.org/how-csp-works/>
3. Tucson Electric Power. Sundt Augmentation (solar thermal). <https://www.tep.com/sundt-augmentation/>
4. National Laboratory of the Rockies (NLR). Concentrating solar projects. <https://solarpaces.nlr.gov/>
5. NLR. Solar maps
<https://www.nlr.gov/gis/solar.html#csp-radiation>
<https://www.nlr.gov/gis/solar-resource-maps>
6. U.S. Energy Information Administration (EIA). Today in Energy, September 20, 2021 <https://www.eia.gov/todayinenergy/detail.php?id=49616>
7. Solar Energy Industries Association (SEIA), Major projects list. August 19, 2014; February 23, 2015; May 28, 2015
<http://www.seia.org/research-resources/major-solar-projects-list>
8. Interstate Renewable Energy Council (IREC). 2013 U.S. solar market trends. <https://irecusa.org/wp-content/uploads/2021/07/IREC-Trends-Report-2013-Web-1-1.pdf>
9. NLR. Direct Normal Solar Radiance of Indiana. NLR April 4, 2017
10. The National Law Review. August 17, 2022. Relief Arrives for Renewable Energy Industry - Inflation Reduction Act of 2022. <https://www.natlawreview.com/article/relief-arrives-renewable-energy-industry-inflation-reduction-act-2022>
11. DLA Piper Law Firm Publications. The clean energy provisions of the Inflation Reduction Act of 2022 – a historic effort to encourage the development of clean energy and reduce

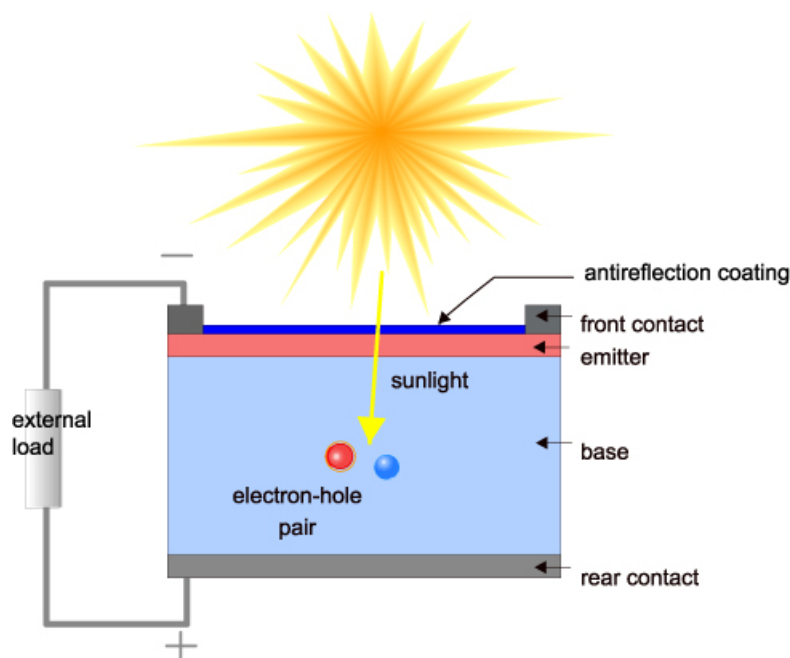
- carbon emissions. <https://www.dlapiper.com/en/us/insights/publications/2022/08/the-clean-energy-provisions-of-the-inflation-reduction-act-of-2022/>
12. Sidley Energy Updates. The “One Big Beautiful Bill” Act – Navigating the New Energy Landscape. July 15, 2025.
<https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape>
 13. Database of State Incentives for Renewables and Efficiency (DSIRE).
<http://www.dsireusa.org/>
 14. U.S. Department of Agriculture (USDA) Rural Development. Rural Energy for America Program Renewable Energy Systems & Energy Efficiency Improvement Guaranteed Loans & Grants. <https://www.rd.usda.gov/programs-services/rural-energy-america-program-renewable-energy-systems-energy-efficiency>
 15. U.S. Department of Agriculture, Rural Development, Electric Programs.
<http://www.rd.usda.gov/programs-services/high-energy-cost-grants>
 16. Indiana General Assembly. Indiana Code 8-1-37, Voluntary Clean Energy Portfolio Standard Program, Sections 12–13.
<https://iga.in.gov/laws/2026/ic/titles/8>
 17. U.S. Department of Energy. Program Guidance for the Title 17 Energy Financing Program. May 13, 2026.
<https://www.energy.gov/documents/doe-edf-title-17-energy-financing-program-guidance-2026-05-13>
 18. Indiana Department of Revenue. Sales and Use Tax Refunds — Manufacturing Exemptions. Accessed 2026.
<https://www.in.gov/dor/i-am-a/business-corp/sales-use-tax-refunds>
 19. Internal Revenue Service (IRS). Publication 946: How to Depreciate Property (2025). Chapter 4, Modified Accelerated Cost Recovery System (MACRS).
<https://www.irs.gov/publications/p946?a=ecd3e32d-b1e8-49de-8f6a-fee4333c9c61&utm>

6. Photovoltaic Cells

6.1 Introduction

Unlike the solar thermal systems discussed in Chapter 5 of this report, photovoltaic (PV) cells convert solar energy directly into electricity without first converting it to heat. In addition, since PV cells use both direct and indirect sunlight, their use is more geographically widespread than solar thermal systems that require access to direct solar radiation. Figure 6-1 shows the layout and functioning of a PV cell. When the photons in sunlight strike the surface of a PV cell, some of them are absorbed. The absorbed photons cause free electrons to migrate in the cell, thus creating “holes.” The resulting charge imbalance between the cell’s front and back surfaces creates a voltage potential. When these two surfaces are connected through an external load, electrical current flows [1].

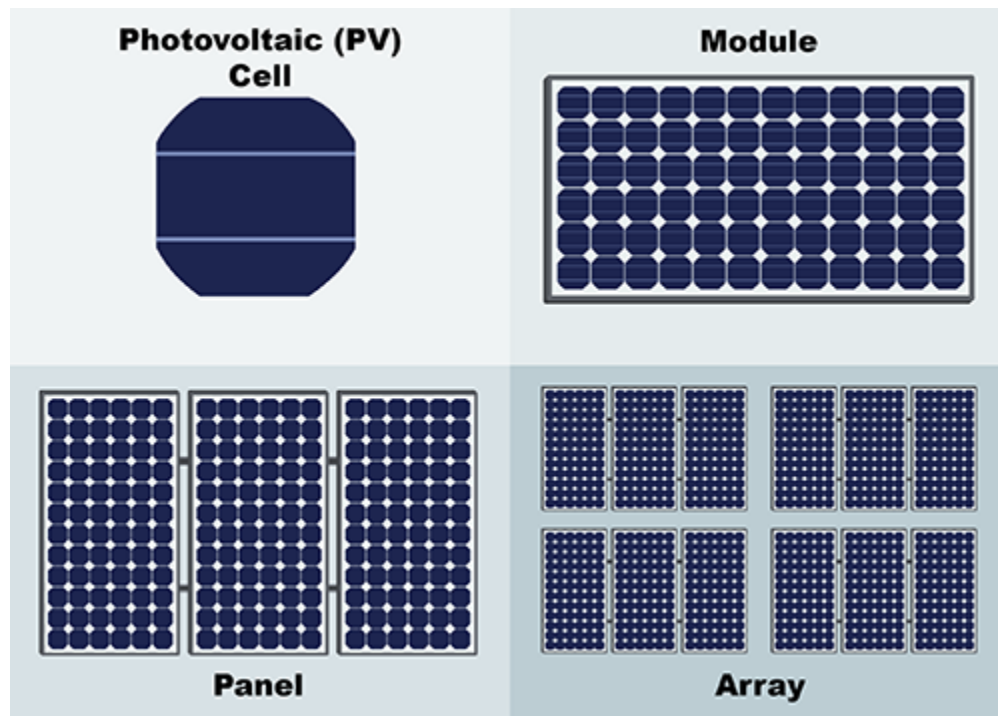
Figure 6-1: PV cell operation (Source: EIA [2])



The PV cell is the basic building block of a PV system. Individual cells range in surface area from smaller than a postage stamp to several inches across with a power output of 1 to 2 watts (W). To increase the power output of the PV unit, the cells are interconnected into a packaged, weather-tight module, typically with a 50-100 W power output as shown in Figure 6-2. Several PV modules are then connected to form a panel. Many of these panels are connected to form the

large-scale multi-megawatt arrays in a modern solar power plant. A complete PV system will include other components such as inverters⁹ and mounting systems [1].

Figure 6-2: Illustration of a cell, module, panel and array of a PV power plant (Source: Florida Solar Energy Center [3])



There are currently three main types of PV cell technologies in commercial use: crystalline silicon, thin-film, and concentrating PV cells. Other PV cells being developed use new materials instead of silicon, including solar dyes, solar inks, and organic polymers. The crystalline silicon photovoltaic cell (CSPV) is the most common PV cell technology and was the first PV technology to be developed. It was developed in the 1950s and was initially used to power satellites and smaller items like watches and electronic calculators. As PV system prices declined, their use spread to other areas, such as highway signs and other facilities remote from the electricity grid. In more recent years, PV power systems have gained application as grid-connected generating resources, with over 216 GW of installed PV capacity in the U.S. at the end of March 2026 [4].

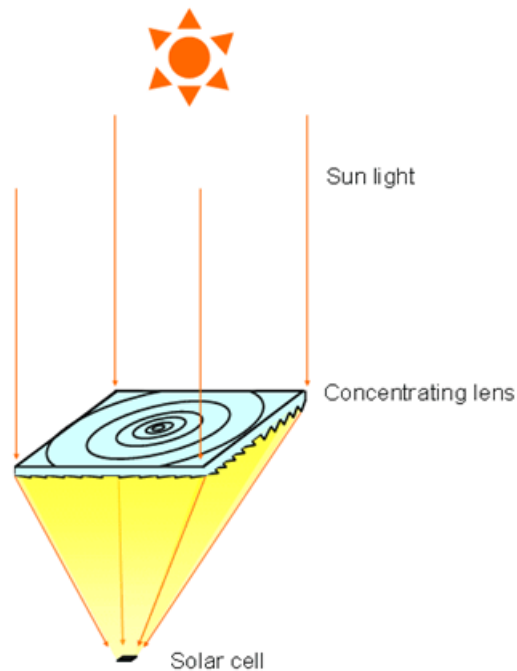
Unlike crystalline silicon cells, thin-film cells are made by depositing thin layers of non-crystalline (amorphous) silicon or other PV material on low-cost substrate material. As a result, thin-film PV cells have a lower cost per unit of area than crystalline silicon cells. However, since they have lower energy conversion efficiency, this cost advantage is reduced by the larger

⁹ Inverters change the direct current (DC) produced by the PV array to alternating current (AC) for household or business use or for injection into the power grid.

surface area required relative to a crystalline silicon PV system with the same power rating. One of the main advantages of thin-film PV cells is that they can be made into flexible panels that can be easily fitted onto building structures such as roofing shingles, facades, and as glazing on skylights.

The third category of PV cell technology in commercial use is the concentrating photovoltaic cell (CPV) technology. CPV systems use optical lenses to focus the sun's rays onto small, high-efficiency PV cells, thus reducing the amount of PV material needed. Unlike other PV technologies, CPV systems require direct sunlight; therefore, their viability is restricted to sunny locations. CPV technology has not had as much commercial success as crystalline silicon PV due to its much higher capital cost, as much as 2.5 to 4 times the cost of crystalline silicon PV technology [5]. Figure 6-3 shows the layout of a CPV cell.

Figure 6-3: Illustration of CPV (Source: Kuraray [6])



According to the U.S. DOE Solar Energy Technologies Office, approximately ninety-five percent of the PV systems sold today are CSPV. They have advantages over other types of solar cells in conversion efficiency, low cost, and long lifetimes. Although thin-film cells have a lower manufacturing cost, their conversion efficiency is lower. CPV cells, although having a high conversion efficiency, are constrained by their more expensive materials, manufacturing processes, and tracking systems. Organic PV cells are still in the research and development stage, with limitations in their efficiency and long-term reliability being significant barriers to their commercial deployment [7, 8].

6.2 Economics of PV systems

Figure 6-4 illustrates trends in the median inflation-adjusted installed prices of host-owned, stand-alone PV systems reported in the LBNL U.S. Distributed Solar and Storage 2025 Data Update for three market segments: residential systems, small non-residential systems (up to 500 kW), and large non-residential systems (0.5–5 MW). As shown in Figure 6-4, inflation-adjusted installed PV system prices have declined by approximately \$9–11/W across all major customer segments over the past two decades, representing a 70–80 percent reduction in real terms. Most of this decline occurred before 2014 and was driven primarily by rapidly falling PV module prices. Since then, installed prices have continued to decline at a more modest pace of approximately \$0.1–0.2/W per year on average, with further reductions driven primarily by decreases in soft costs and other balance-of-system (BoS) costs rather than module prices. Soft costs, including customer acquisition, installation labor, permitting and interconnection, financing fees, taxes, and installer profit, together with other BoS costs, accounted for approximately 80 percent of the median installed price of residential PV systems in 2024 and a somewhat smaller share for non-residential systems. The installed prices shown in Figure 6-4 represent upfront installation costs and do not include any federal, state, or utility financial incentives.

Figure 6-4: Installed price trends among stand-alone PV systems (Source: LBNL [9])

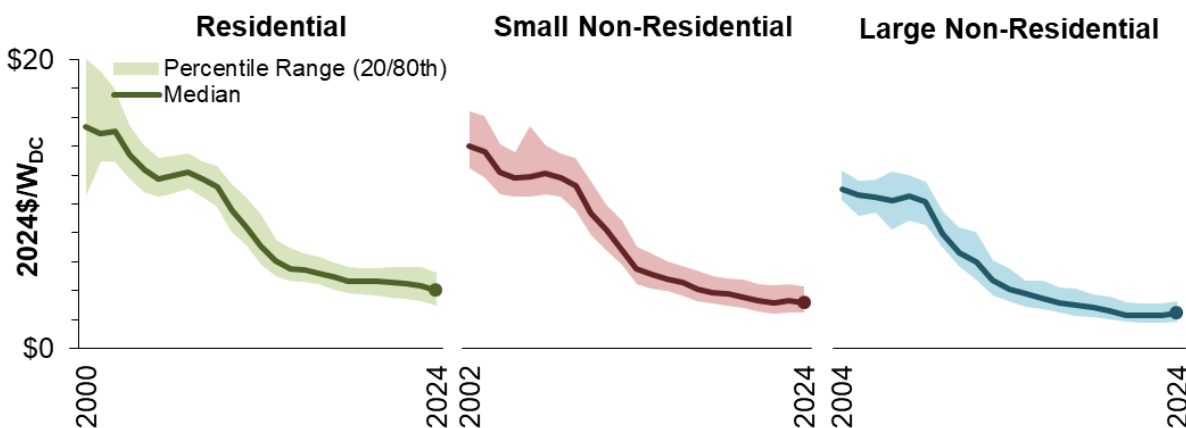


Figure 6-5 shows the installed cost in \$/W for utility-scale PV projects in LBNL’s U.S. Utility-Scale Solar 2025 Data Update, based on the year of the project’s commissioning. As shown in the figure, installed costs for utility-scale PV fell by 73% between 2010 and 2022 but have been flat or slightly increased since then in real dollars. Capacity-weighted means (reflecting the average costs of solar capacity) increased from \$1.59/W_{AC} in 2023 to \$1.61/W_{AC} in 2024.

Figure 6-6 shows the average construction costs of generators installed in the U.S. from 2013 to 2024, according to EIA historical generator cost data released in July 2026. As shown in the figure, the average construction cost fell from approximately \$3,705/kW in 2013 to \$1,561/kW in 2021, a reduction of about 58 percent. Construction costs remained relatively stable during

2021-2023, fluctuating around \$1,600/kW, before increasing to \$1,865/kW in 2024. The data included in the EIA report is for PV systems 1 MW or more installed on the utility side of the meter.

Figure 6-5: Installed project capital cost of utility-scale PV systems (Source: LBNL [10])

Installed Project Capex (2024\$/W_{AC})

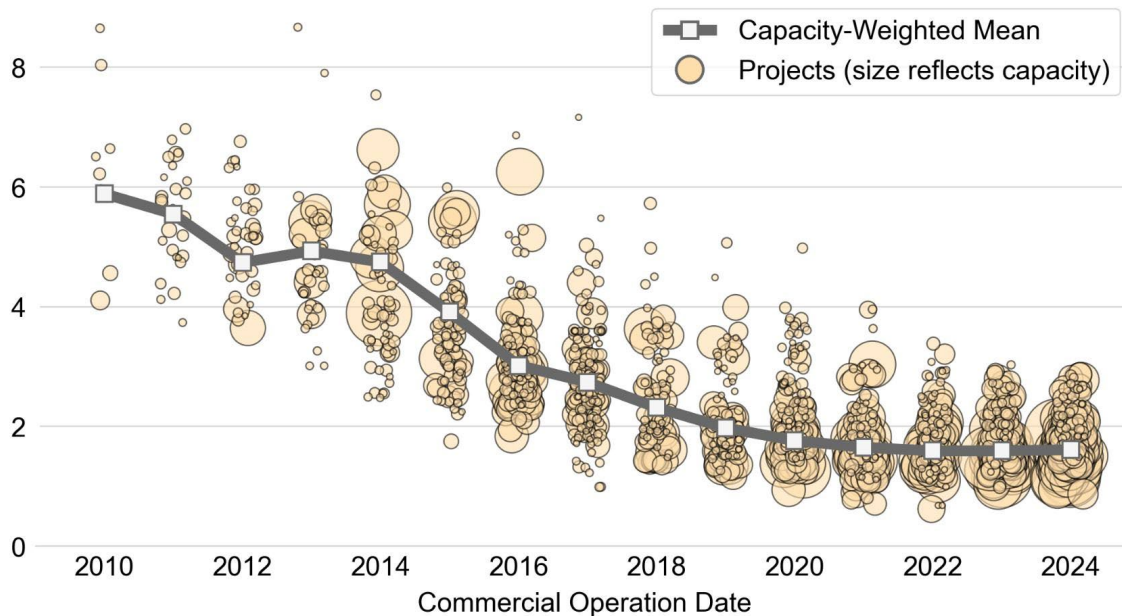


Figure 6-6: Average construction cost of generation installed in the U.S. (2013-2024) (Data source: EIA [11])

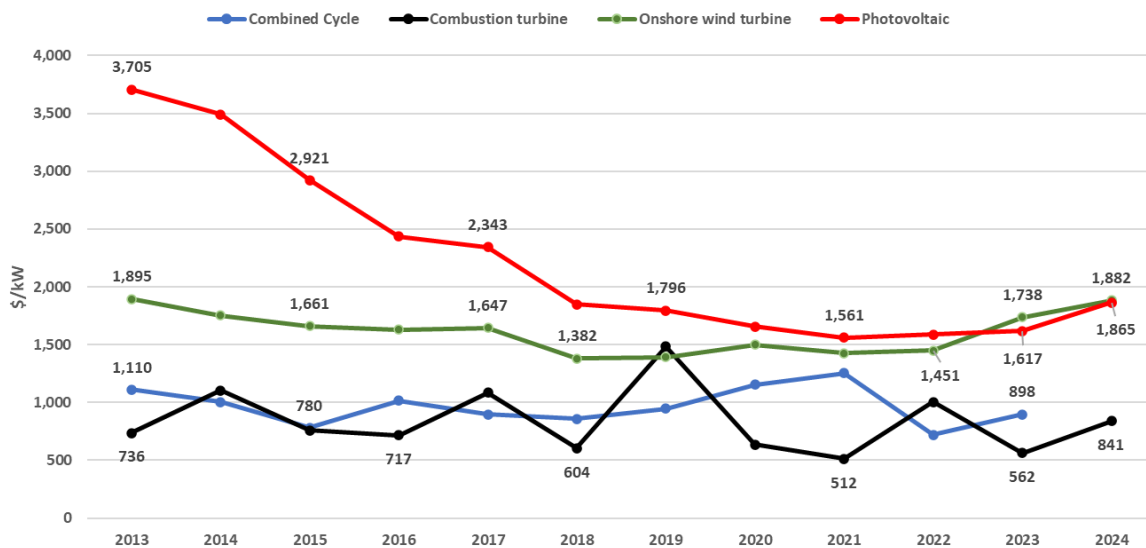


Figure 6-7 shows EIA’s estimate of the capital cost of utility-scale PV electricity generating plants alongside other utility-scale electricity generating technologies in Assumptions to the AEO 2026: Electricity Market Module. The estimated cost of a standalone utility-scale PV plant, that is, one not coupled with battery storage, was \$1,484/kW, and \$1,903/kW for a PV plant coupled with battery storage.

Figure 6-7: Estimated generating technologies capital costs (Data source: EIA [12])

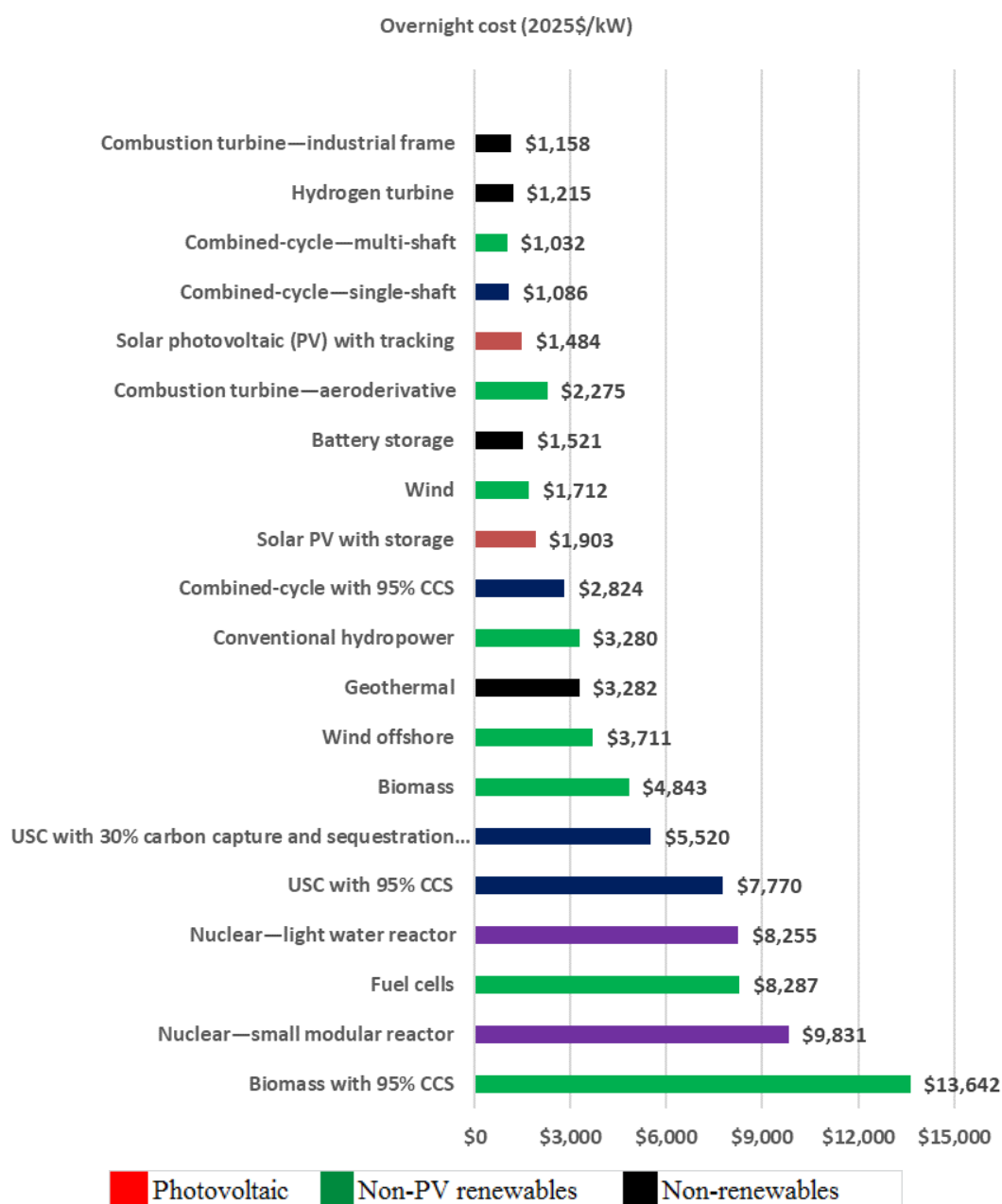
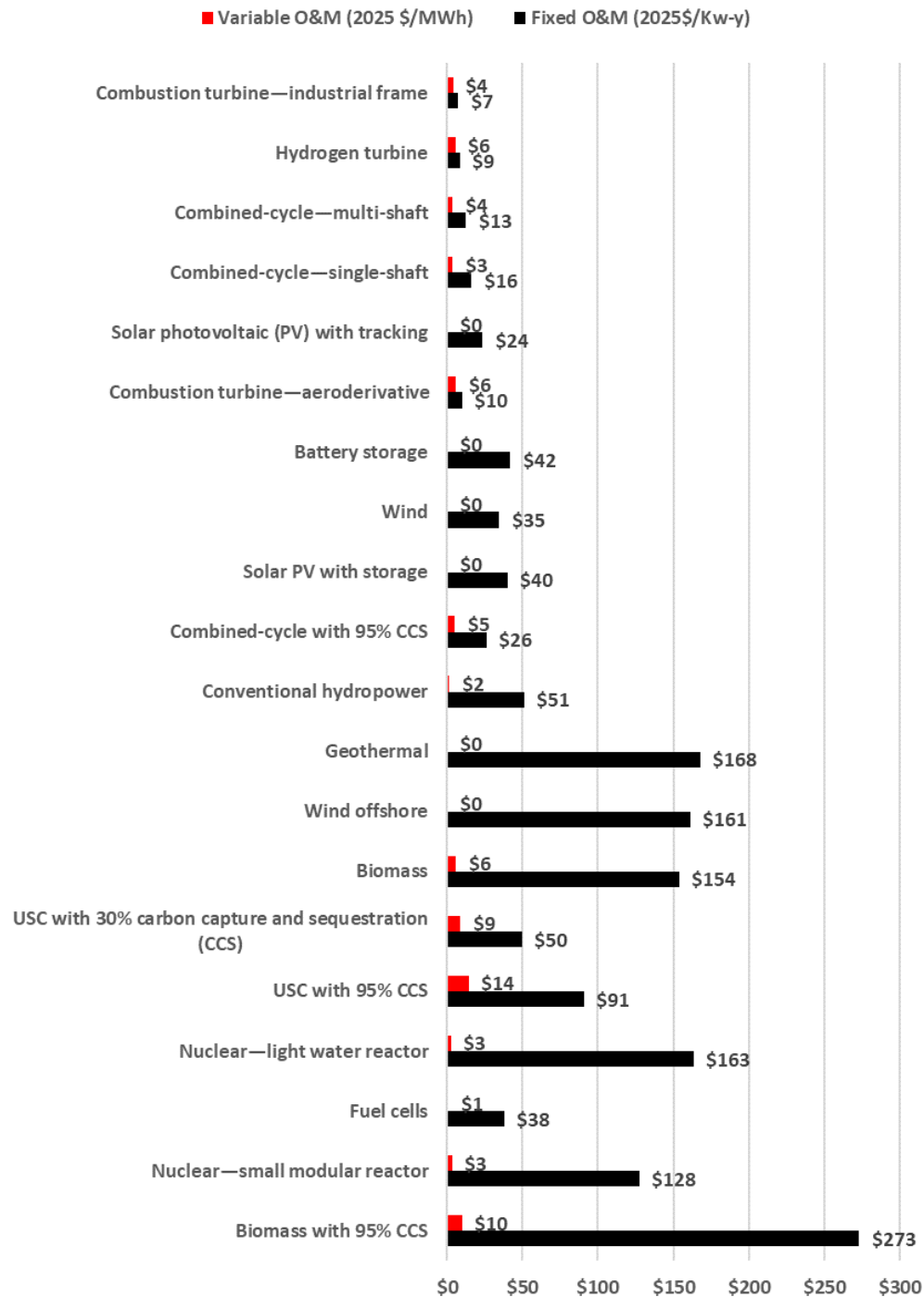


Figure 6-8 shows EIA’s estimated fixed and variable O&M costs for utility-scale PV electricity generating plants alongside other utility-scale electricity generating technologies. The fixed

O&M costs of stand-alone PV power plants are among the lowest of the renewable energy technologies at \$24/kW-y, and there is virtually no variable O&M cost. A PV power plant coupled with battery storage has a higher combined fixed O&M at \$40/kW-y.

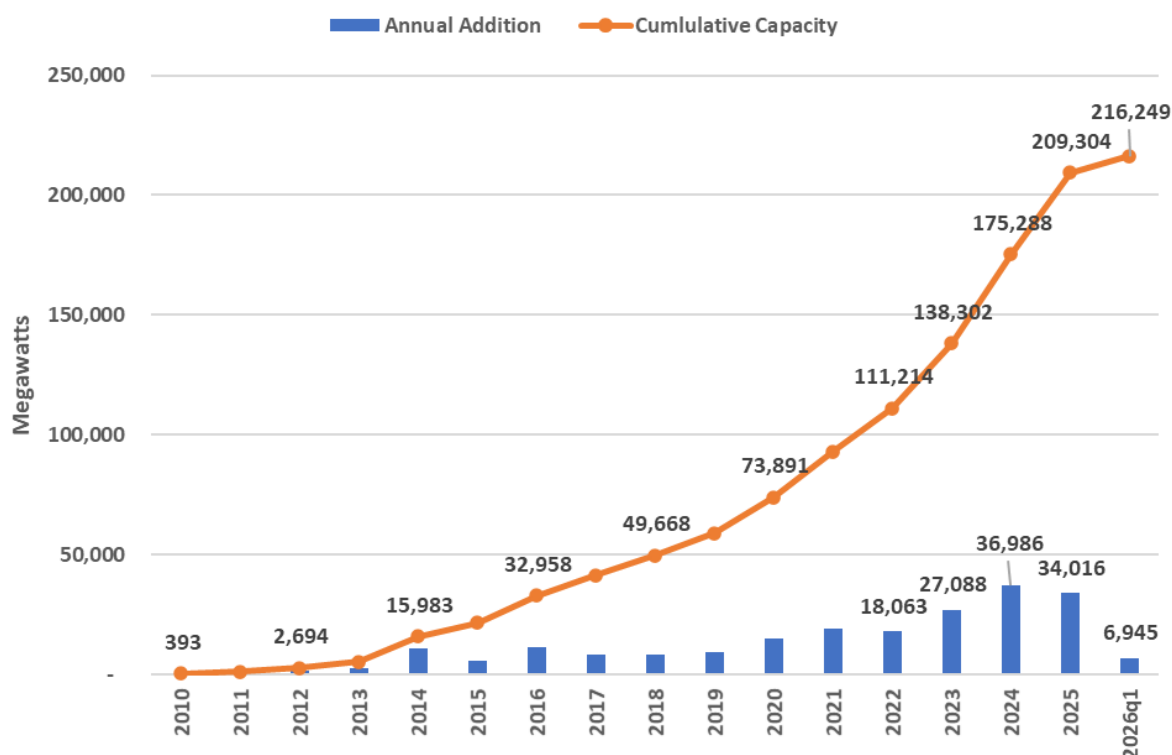
Figure 6-8: Estimated generating technologies fixed and variable O&M costs (Data source: EIA [12])



6.3 State of PV systems nationally

Solar PV generating capacity installed in the U.S. has been increasing steadily in the last twenty years, growing from a mere 393 MW in 2010 to over 216 GW at the end of March 2026. Figure 6-9 shows the annual and cumulative installed capacity of PV systems in the U.S.

Figure 6-9: Installed U.S. PV capacity (Data source: EIA [4, 13])



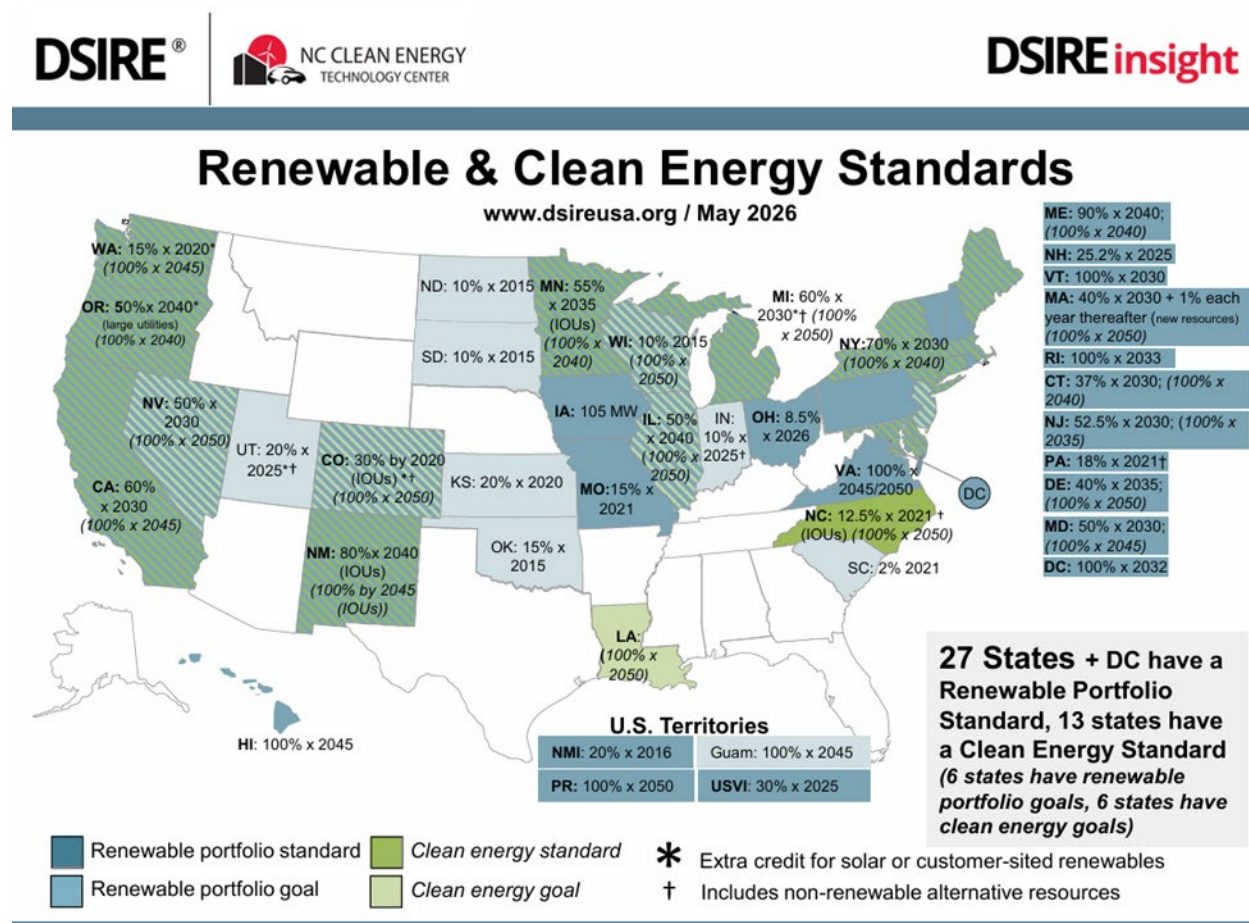
The main factors behind this rapid expansion have been state and federal financial incentives, state RPS with specific provisions for solar technologies, and the declining costs of PV systems. The decline in the cost of PV systems is described in Chapter 6.2 of this report. The thirty percent ITC is generally recognized as one of the most important drivers of the rapid expansion in installed PV capacity in the U.S. The ITC was first enacted into law in the 2005 Energy Policy Act. In 2008, the federal government eliminated the \$2,000 cap on ITC credit for residential customer installations and permitted utilities and companies access to the credit.

The IRA, enacted in August 2022, extended the legacy ITC for projects that began construction before January 1, 2025, while creating the technology-neutral CEITC under Section 48E for qualifying facilities placed in service after December 31, 2024. The IRA also extended the PTC for projects beginning construction before January 1, 2025, and made solar facilities eligible for the PTC. Beginning in 2025, the technology-neutral CEPTC under Section 45Y replaced the legacy PTC for qualifying facilities placed in service after December 31, 2024. Under the IRA,

the CEITC and CEPTC were scheduled to begin phasing out after the later of 2032 or the year in which U.S. electricity-sector greenhouse gas emissions declined to 25 percent of 2022 levels. The OBBBA subsequently removed the emissions-based trigger, making 2032 the applicable year for the general phaseout, while establishing a separate accelerated termination rule for wind and solar facilities. Wind and solar facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the CEITC or CEPTC. Facilities that begin construction on or before July 4, 2026 are not subject to this accelerated termination rule but remain subject to applicable beginning-of-construction and continuity requirements. A more detailed discussion of the CEITC, CEPTC, and other federal renewable energy incentives is provided in Chapter 1 of this report.

As shown in Figure 6-10, 27 states and Washington, DC, have binding renewable portfolio standards, while 6 states, including Indiana, have non-binding renewable portfolio goals. 13 states have binding clean energy standards, while 6 states have non-binding clean energy goals. PV systems are the most common renewable energy technology in use for residential customer-side distributed generation.

Figure 6-10: Renewable portfolio standards and goals (Source: DSIRE [14])



Since January 2018, the United States has imposed Section 201¹⁰ safeguard tariffs on imported CSPV cells and modules. The original four-year safeguard tariff began at 30 percent in 2018 and declined by five percentage points annually. In February 2022, the Biden Administration extended the safeguard measure through February 2026, increased the annual tariff-rate quota for imported solar cells from 2.5 GW to 5.0 GW, and continued the exemption for bifacial modules [15].

In April 2022, the U.S. Department of Commerce initiated circumvention inquiries to determine whether Chinese manufacturers were avoiding existing antidumping and countervailing duty (AD/CVD) orders on Chinese CSPV products by performing minor processing in Cambodia, Malaysia, Thailand, and Vietnam before exporting the products to the United States. In June 2022, President Biden issued a two-year waiver suspending the collection of any additional duties resulting from the circumvention inquiries until June 6, 2024. Commerce issued its final determinations in August 2023, concluding that several manufacturers were circumventing the existing AD/CVD orders [16].

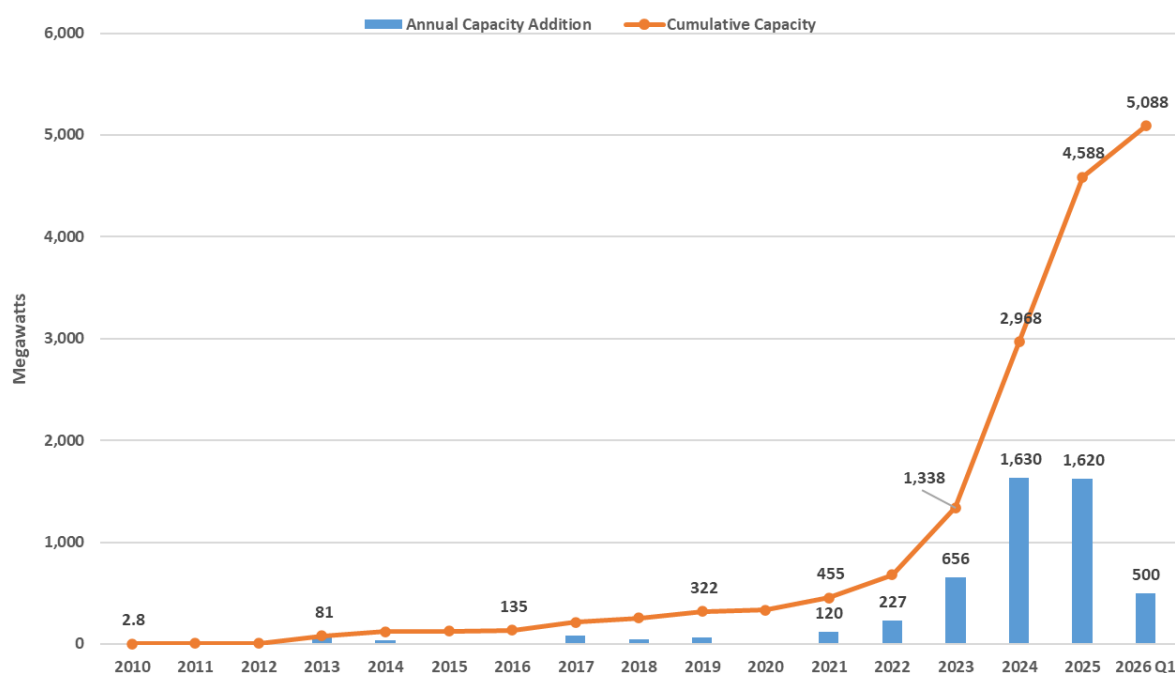
Separately, following completion of the statutory four-year review of the Section 301 tariff actions, the Biden Administration announced in May 2024 that the Section 301 tariff on imports of Chinese solar cells (whether or not assembled into modules) would increase from 25 percent to 50 percent [17]. During the same year, the U.S. Department of Commerce initiated new AD and CVD investigations of CSPV cells and modules imported from Cambodia, Malaysia, Thailand, and Vietnam. Unlike the 2022 circumvention inquiries, these investigations directly examined whether imports from the four Southeast Asian countries were being dumped in the U.S. market and whether the manufacturers were receiving unfair government subsidies. On April 21, 2025, Commerce issued final affirmative AD/CVD determinations, finding that imports from the four countries were being dumped in the U.S. market and that companies in each country were receiving countervailable subsidies, including transnational subsidies provided by the Government of China. Following the U.S. International Trade Commission's affirmative final determination that imports from Malaysia and Vietnam materially injured the domestic industry and imports from Cambodia and Thailand threatened material injury, Commerce issued AD and CVD duty orders establishing company-specific antidumping cash deposit rates and countervailing subsidy rates for imports from Cambodia, Malaysia, Thailand, and Vietnam. The applicable rates vary substantially by company and country [18,19, 20].

¹⁰ Section 201 refers to the safeguard provisions of the Trade Act of 1974 that permit the president to raise tariffs and duties to provide temporary relief to domestic industries facing injury from imports.

6.4 PV systems in Indiana

Like the rest of the U.S., Indiana has seen rapid growth in installed PV capacity over the past twelve years, as shown in Figure 6-11. The installation of multi-megawatt PV power plants began in 2013 in Indianapolis and Northern Indiana. This was enabled by feed-in tariffs introduced by AES Indiana and NIPSCO, which supported notable projects such as the 10 MW solar farm at Indianapolis International Airport. Between 2013 and 2018, a total of 96 MW of PV capacity was installed within the AES service area through these tariffs. At the end of 2024, when the NIPSCO feed-in tariff was discontinued, 22 MW of PV capacity had been interconnected to the NIPSCO system. Another driver of multi-megawatt PV systems was the expansion of Indiana’s net metering rule in 2011 to include systems up to 1 MW in capacity. The utilities reported that more than 8,900 customers have installed over 205 MW under Indiana’s net metering program. Indiana’s net metering program was closed to new participants after July 1, 2022, under Senate Enrolled Act 309 (SEA 309) of 2017, with eligible new customer-side renewable generation compensated under Excess Distributed Generation (EDG) tariffs. Under EDG, excess generation is generally credited at 125 percent of the utility’s average annual marginal/wholesale energy price. Since the transition to EDG compensation, approximately 47 MW of renewable energy facilities had been connected through year-end 2024.

Figure 6-11: Growth in Installed PV capacity in Indiana (Data source: IURC [21, 22], NREL [23])



The start of the second phase of growth in solar PV generating capacity was marked by the construction of the 200 MW Riverstart Solar Park in Randolph County, commissioned at the beginning of 2022. In this new phase, solar farms are much larger and are no longer

interconnected on the customer side of the meter through net metering or feed-in tariffs; instead, utilities are including PV as part of their generation portfolio, either through direct ownership or through long-term power purchase agreements with merchant developers.

Table 6-1: Operating large-scale solar farms in Indiana (Data source: IURC [22])

Project	County	Developer	Buyer	Capacity (MWac)	In-Service year
Riverstart Solar Park	Randolph	EDPR	Hoosier	200	2021
Dunns Bridge Solar Center Phase I	Jasper	NextEra	NIPSCO	265	2023
Bellflower Solar Project	Rush & Henry	Lightsource	Verizon	153	2023
Indiana Crossroads Solar/Meadow Lake	White	EDPR	NIPSCO	200	2023
Cavalry Energy Center	White	NextEra	NIPSCO	200	2024
Dunns Bridge Solar/Storage Phase II	Jasper	NextEra	NIPSCO	435	2024
Hardy Hills Solar	Clinton	Invenergy	AES Indiana	195	2024
Mammoth Solar Phase I (North)	Starke & Pulaski	Doral	AEP	400	2024
Riverstart Solar Park III	Randolph	EDPR	NA	100	2024
Twin Lakes Solar	White	ENGIE Renewables	Microsoft	150	2024
Honeysuckle Solar	St. Joseph	Lightsource	NA	150	2024
Speedway Solar	Shelby	Ranger Power	Duke	199	2025
Posey Solar	Posey	Arevon	CenterPoint	191	2025
Fairbanks Solar Energy Center	Sullivan	Invenergy	NIPSCO	250	2025
Gibson Solar	Gibson	Arevon	NIPSCO	280	2025
Ratts 1 Solar	Pike	Arevon	IMPA	150	2025
Appleseed Solar	Cass	NextEra	NIPSCO	200	2025
Riverstart Solar Park IV	Randolph	EDPR	Undisclosed	150	2025
Crossroads Solar	Fountain	Longroad	Amazon	200	2025
Petersburg Energy Center	Pike	NextEra	AES Indiana	250	2026
Wheatland Solar/IN Solar 1	Knox	Origis Energy	CenterPoint	150	2026
Elkhart County Solar Project	Elkhart	Savion	I&M	100	2026

Total operating 4,568

By the end of the first quarter of 2026, 22 utility-scale projects with a combined capacity of 4,568 MW had been commissioned in Indiana, bringing the state's total installed solar PV capacity to at least 5,088 MW, compared with 4,588 MW at the end of 2025, as shown in Figure 6-11. An additional 7 projects with a combined capacity of 1,705 MW were under construction, with commissioning expected between 2026 and 2028. Table 6-1 lists the 22 utility-scale PV projects currently operating in Indiana, while Table 6-2 lists the 7 projects under construction.

Table 6-2: Utility-scale PV projects under construction in Indiana (Data source: IURC [22])

Project	County	Developer	Buyer	Capacity (MW _{AC})	Planned In-service Year
Trade Post Solar	Sullivan	Invenergy	A commercial C&I customer	200	2026
Mammoth Phase II (South)	Pulaski	Doral	Undisclosed	300	2026
Mammoth Phase III (Central)	Pulaski	Doral	Undisclosed	600	2026
Blackford Solar Energy	Blackford	Leeward	NA	150	2026
Emerald Green Solar	Howard	ENGIE	NA	200	2026
Duff Solar Park LLC	Dubois	EDP Renewables	Undisclosed	100	2026
Skycrest Solar	Jay	NA	NA	155	2028

Total under construction 1,705

Table 6-3: Approved utility-scale PV projects in Indiana not yet under construction (Data source: IURC [22])

Project	County	Capacity (MW _{AC})	Planned In-service Year
Elliott Solar	Gibson	200	TBD
Ratts 2 Solar/Blue Jeans Solar	Knox	150	2028
Foundry Works	Lake	200	2027
Crosstrack Solar	Pike	130	2028
Moss Creek Solar	Pulaski	200	2027
Rose Gold Solar	Jay	150	2028
Honey Creek Solar Phase I	White	180	2027
Honey Creek Solar Phase II	White	200	2027
Honey Creek Solar Phase III	White	200	TBD
Rustic Hills Solar	Warrick	100	2028
Sun Chief Solar	Jay	100	2027
Vermillion Rise Solar	Vermillion	185	2027
Cherry Hill Solar Energy	LaGrange	100	2028
Reclamation Solar Energy	Gibson	150	2027
Mayapple Solar	Pulaski	224	2028
Locomotive Solar	Howard	200	2028
Lake Trout Solar	Blackford	245	2028
Merrillville Solar	Lake	58	2028
Crossvine Solar I	Dubois	85	2027
Riverstart Solar Park V	Randolph	100	TBD
Dunns Bridge Solar Phase II	Starke	200	2026
Bluestem Solar Farm	Laporte	250	2027
Rustic Hills Solar	Warrick	100	2028
Dumont Solar	St. Joseph	200	2028
Sullivan County Power	Sullivan	400	2028
Bottlebrush Solar Energy	Pulaski	200	2028
Dolphin Solar	Fountain	700	2029
Bluegrass Creek Solar	Vanderburgh	100	2027
Black Prairie Solar Park	White	200	2027
Worthington Solar	Greene	150	2028

Total approved but not started construction 5,657

In addition to the 7 projects under construction, there were a further 30 projects with a combined capacity of 5,657 MW that had received approval from the IURC but whose construction had not started. Table 6-3 lists these 30 projects.

Unlike the growth in PV capacity in the 2013-2020 period that was driven by favorable utility incentive rates, the more recent growth of utility-scale PV solar capacity is driven by more fundamental industry-wide issues of the need for replacement capacity for the aging generating fleet, working in combination with the pressure to lower the carbon emissions of the electricity industry.

In addition, the federal government provided significant clean-energy incentives through the IRA of 2022. The IRA extended the legacy ITC and PTC for eligible projects that began construction before the end of 2024, and created technology-neutral clean electricity credits beginning in 2025. For solar PV, this meant continued eligibility for the legacy ITC and, importantly, new eligibility for the legacy PTC under Section 45, which provides a credit of 1.5 cents/kWh in 1993 dollars, adjusted for inflation, for electricity produced during the first 10 years of operation. Beginning in 2025, the new Clean Electricity Investment Credit (CEITC) under Section 48E and Clean Electricity Production Credit (CEPTC) under Section 45Y apply to qualifying zero-emissions facilities placed in service after December 31, 2024. Section 48E provides a 30 percent investment tax credit for qualifying projects that meet applicable labor requirements, while Section 45Y provides a production-based credit. Both credits are technology-neutral and therefore broader than the legacy solar ITC/PTC framework, extending eligibility to other non-carbon-emitting technologies, including nuclear. Prior to later amendments, both credits were scheduled to begin phasing out after the later of 2032 or the year in which U.S. electricity-sector greenhouse gas emissions fell to 25 percent of 2022 levels.

The OBBBA, signed into law on July 4, 2025, accelerated the termination of the CEPTC and CEITC for qualifying wind and solar facilities. Under the amended rules, wind and solar facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the Section 45Y CEPTC or Section 48E CEITC. Facilities that begin construction on or before July 4, 2026 are not subject to this accelerated termination rule but remain subject to applicable beginning-of-construction and continuity requirements. IRS Notice 2025-42 generally requires facilities relying on the July 4, 2026 construction deadline to establish beginning of construction through the Physical Work Test and to maintain a continuous program of construction. The continuity requirement is deemed satisfied under a safe harbor if the facility is placed in service by the end of the fourth calendar year after the calendar year in which construction began.

6.5 Incentives for PV systems

The following federal and state incentives are available for solar PV energy projects.

Federal Incentives

- Business Renewable Energy Investment Tax Credit (ITC) is a corporate investment tax credit that provides up to a 30 percent credit for eligible solar PV projects that began construction before January 1, 2025. To qualify for the full credit, projects must satisfy the prevailing wage and apprenticeship requirements. Projects that do not meet these requirements generally qualify for a base credit of 6 percent. Additional bonus credits are available for projects meeting the domestic content requirements or that are located in an energy community. Certain projects located in qualifying low-income communities or on qualifying low-income residential buildings may also qualify for additional bonus credits. Definitions of these provisions are provided in Section 1.4 of this report. [24, 25].
- Residential Clean Energy Credit (Section 25D) provides homeowners with a tax credit of up to 30 percent of eligible expenditures for residential solar PV systems. Under the OBBBA, the credit is not available for expenditures made after December 31, 2025 [37].
- The Clean Electricity Investment Tax Credit (CEITC), established under Section 48E of the IRA, became effective for qualifying facilities placed in service after December 31, 2024 and provides a technology-neutral investment tax credit for qualifying zero- or negative-emission electricity-generating technologies. Under the IRA, the credit was scheduled to begin phasing out after the later of 2032 or the year in which electricity-sector greenhouse gas emissions fell to 25 percent of their 2022 level. The OBBBA subsequently removed the emissions-based trigger, making 2032 the applicable year for the general phaseout, while establishing a separate accelerated termination rule for wind and solar facilities. Solar facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the CEITC. Facilities that begin construction on or before July 4, 2026 are not subject to this accelerated termination rule but remain subject to applicable beginning-of-construction and continuity requirements [25, 26].
- Renewable Electricity Production Tax Credit (PTC). The IRA extended eligibility for the legacy PTC to qualifying projects that began construction before January 1, 2025 and expanded eligibility to include solar PV projects. The PTC provides a production tax credit of 1.5 cents/kWh, adjusted annually for inflation, for qualifying projects that meet the prevailing wage and apprenticeship requirements; projects that do not meet these requirements generally qualify for one-fifth of the full credit. Projects may also qualify for a 10 percent increase for meeting domestic content requirements and a separate 10 percent increase for being located in an energy community. Additional details are provided in Section 1.4 of this report [24, 25].

- The Clean Electricity Production Tax Credit (CEPTC), established under Section 45Y of the IRA, became effective for qualifying facilities placed in service after December 31, 2024 and provides a technology-neutral production tax credit for qualifying zero- or negative-emission electricity-generating technologies. Under the IRA, the credit was scheduled to begin phasing out after the later of 2032 or the year in which electricity-sector greenhouse gas emissions fell to 25 percent of their 2022 level. The OBBBA subsequently removed the emissions-based trigger, making 2032 the applicable year for the general phaseout, while establishing a separate accelerated termination rule for wind and solar facilities. Solar facilities that begin construction after July 4, 2026 generally must be placed in service by December 31, 2027 to qualify for the CEPTC. Facilities that begin construction on or before July 4, 2026 are not subject to this accelerated termination rule but remain subject to applicable beginning-of-construction and continuity requirements. Projects that meet the prevailing wage and apprenticeship requirements qualify for the full credit. Projects may also qualify for a 10 percent increase for meeting domestic content requirements and a separate 10 percent increase for being located in an energy community. Additional details are provided in Section 1.4 of this report [25, 26].
- U.S. DOE Title 17 Energy Financing Program (Section 1703 of Title XVII of the Energy Policy Act of 2005) provides loan guarantees for eligible energy projects, including projects that deploy new or significantly improved technologies that are technically proven but not yet widely commercialized in the United States [38].
- Modified Accelerated Cost-Recovery System (MACRS) allows businesses to recover investments in qualified renewable energy technologies through accelerated depreciation deductions. In addition to standard MACRS depreciation, qualifying projects may also be eligible for bonus depreciation under applicable federal tax law, subject to the percentage and phase-down schedule in effect for the year the property is placed in service [32].
- USDA Rural Energy for America Program (REAP) provides financial assistance to agricultural producers and rural small businesses for eligible renewable energy systems and energy-efficiency improvements. Loan guarantees are available on loans covering up to 75 percent of total eligible project costs. Grants may cover up to 50 percent of eligible project costs for qualifying projects, while other projects are limited to a 25 percent federal grant share. Combined grant and loan-guarantee funding may cover up to 75 percent of total eligible project costs [27].
- High Energy Cost Grant Program administered by USDA assists eligible rural communities with extremely high household energy costs, defined as exceeding 275 percent of the national average. Eligible projects include the acquisition, construction, or

improvement of energy generation, transmission, and distribution facilities, including renewable energy projects [28].

- Federal Renewable Energy Use Statutory Requirement (Section 203 of the Energy Policy Act of 2005, as amended) requires that, to the extent economically feasible and technically practicable, at least 7.5 percent of the electricity consumed by the Federal Government each fiscal year be obtained from renewable energy sources [33].
- Federal Housing Administration (FHA)-Insured Mortgage Financing for Solar Energy Systems allows eligible homeowners and homebuyers to include the cost of installing a qualifying solar energy system in an FHA-insured mortgage, subject to FHA requirements and applicable financing limits [34].

Indiana Incentives

- Senate Enrolled Act 390 (SEA 390) of 2023 established a certification program administered by the Indiana Office of Energy Development (OED). Counties and municipalities may be certified as Commercial Solar Energy Ready Communities, Wind Energy Ready Communities, or both if their ordinances satisfy statutory requirements, including generally not being more restrictive than Indiana’s default standards. Certified communities may receive incentive payments of \$1/MWh for up to ten years from qualifying projects, subject to available funding. As of 2026, the certification program is operational, but no incentive funds have been appropriated [29].
- Net Metering Rule continues to allow eligible grandfathered utility customers with renewable energy systems having a maximum generating capacity of 1 MW to receive retail-rate credits for excess electricity exported to the grid. Senate Enrolled Act 309 (SEA 309), signed into law in 2017, transitioned Indiana from traditional net metering to the Excess Distributed Generation (EDG) program for new customers after June 30, 2022. Customers with qualifying systems installed before January 1, 2018 continue to receive retail-rate credits until July 1, 2047, while eligible systems installed between January 1, 2018 and June 30, 2022—or until the utility reached the statutory 1.5 percent aggregate-capacity threshold, whichever occurred first—continue to receive retail-rate credits until July 1, 2032 [30, 39].
- EDG Rule, established under Indiana Code 8-1-40 pursuant to SEA 309 (2017), replaced net metering for new distributed generation customers after June 30, 2022. Under the EDG program, excess electricity exported to the grid is compensated at 125 percent of the utility's average marginal price of electricity during the most recent calendar year [30, 39].

- Renewable Energy Property Tax Deduction previously provided property tax deductions for qualifying solar, wind, hydroelectric, and geothermal energy systems. SEA 1 of 2025 eliminated these deductions effective for assessment dates beginning January 1, 2025 [35].
- Solar Easement Law (Indiana Code 32-23-4) permits property owners to voluntarily establish solar easements to protect access to direct sunlight for solar energy systems. A solar easement may specify the dimensions of the easement, restrictions on vegetation or structures that could obstruct sunlight, and terms under which the easement may be revised or terminated [40].
- Sales and Use Tax Exemption for Electrical Generating Equipment may exempt machinery, tools, equipment, and other tangible personal property that are directly used in the direct production of tangible personal property, including electricity, from Indiana sales and use tax. Equipment used to generate electricity that is directly used in the production of other tangible personal property may also qualify for the manufacturing exemption to the extent that the applicable direct-use requirements are satisfied [41].
- Clean Energy Portfolio Goal established a voluntary goal of obtaining 4 percent of electricity from clean energy sources between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent in 2025, based on 2010 retail sales. The final statutory goal period ended on December 31, 2025, and no additional clean energy portfolio goals are specified beyond 2025. However, financial incentives and cost-recovery mechanisms approved for participating electricity suppliers that achieved the applicable goals may continue beyond 2025 in accordance with the terms of the program and IURC approval [36].
- NIPSCO offered purchase contracts for up to 15 years for electricity generated by eligible renewable systems. For solar, the listed rates are \$0.1564/kWh for micro-solar systems from 5 to 10 kW and \$0.1380/kWh for intermediate solar systems above 10 kW through 200 kW. All feed-in-tariff categories are currently closed to new applicants, although existing contracts and tariff provisions may remain in effect [31].

6.6 References

1. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE), Solar Energy Technologies Office. Solar photovoltaic technology basics.
<https://www.energy.gov/eere/solar/articles/solar-photovoltaic-technology-basics>
2. PV Education.org Exchange.
<https://www.pveducation.org/pvcdrom/solar-cell-operation/solar-cell-structure>

3. Florida Solar Energy Center.
http://www.fsec.ucf.edu/en/consumer/solar_Electricity/basics/cells_modules_arrays.htm
4. EIA. Electric Power Monthly June 2026. Table 6.1.A. Estimated Net Summer Solar Photovoltaic Capacity from Utility and Small Scale Facilities (Megawatts)
<https://www.eia.gov/electricity/monthly/>
5. Ennomotive Consulting. The Future of Solar Energy: High Concentrated Photovoltaic (CPV) Cells.
<https://www.ennomotive.com/future-of-solar-energy/>
6. Kuraray Company. News release 2011
<https://www.kuraray.com/news/2011/110422>
7. EERE. Solar Photovoltaic Cell Basics.
<https://www.energy.gov/eere/solar/articles/solar-photovoltaic-cell-basics>
8. EERE. Organic Photovoltaics Research.
<https://www.energy.gov/eere/solar/organic-photovoltaics-research>
9. LBNL. U.S. Distributed Solar and Storage 2025 Data Update. October 2025.
<https://emp.lbl.gov/tracking-the-sun/>
<https://emp.lbl.gov/sites/default/files/2025-10/Distributed%20Solar%20%26%20Storage-2025%20Data%20Update.pdf>
10. LBNL. U.S. Utility-Scale Solar 2025 Data Update. October 2025.
<https://emp.lbl.gov/utility-scale-solar/>
<https://emp.lbl.gov/sites/default/files/202510/Utility%20Scale%20Solar%202025%20Editon%20Slides.pdf>
11. EIA. Construction Cost Data for Electric Generators Installed in 2024
<https://www.eia.gov/electricity/generatorcosts/>
12. EIA. Assumptions to the AEO 2026: Electricity Market Module. April 2026.
https://www.eia.gov/outlooks/aeo/additional_docs.php
https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf
13. EIA. Electric Power Monthly June 2026. Table 6.1.A. Estimated Net Summer Solar Photovoltaic Capacity from Utility and Small-Scale Facilities (Megawatts).
<https://www.eia.gov/electricity/monthly/>
14. Database of State Incentives for Renewables & Efficiency (DSIRE).
<http://www.dsireusa.org/>
15. Office of the United States Trade Representative (USTR). Investigation No. TA-201-75: Crystalline Silicon Photovoltaic Cells (Whether or Not Partially or Fully Assembled into Other Products). Presidential Proclamation 10339, February 4, 2022.
<https://ustr.gov/issue-areas/enforcement/section-201-investigations/investigation-no-ta-201-75-cspv-cells>
16. U.S. Department of Commerce. Department of Commerce Issues Final Determination of Circumvention Inquiries on Solar Cells and Modules from Cambodia, Malaysia, Thailand, and Vietnam. August 18, 2023.

- <https://www.commerce.gov/news/press-releases/2023/08/departments-commerce-issues-final-determination-circumvention-inquiries>
17. USTR. U.S. Trade Representative Katherine Tai to Take Further Action on China Tariffs After Releasing Statutory Four-Year Review. May 14, 2024.
<https://ustr.gov/about-us/policy-offices/press-office/press-releases/2024/may/us-trade-representative-katherine-tai-take-further-action-china-tariffs-after-releasing-statutory>
 18. U.S. Department of Commerce. Commerce Announces Final Antidumping and Countervailing Duty Determinations on Crystalline Silicon Photovoltaic Cells from Cambodia, Malaysia, Thailand, and Vietnam. April 21, 2025.
<https://www.trade.gov/press-release/us-department-commerce-announces-final-determinations-antidumping-and-countervailing>
 19. U.S. International Trade Commission. Crystalline Silicon Photovoltaic Cells, Whether or Not Assembled into Modules, from Cambodia, Malaysia, Thailand, and Vietnam Injure or Threaten U.S. Industry, Says USITC. May 20, 2025.
https://www.usitc.gov/press_room/news_release/2025/er0520_66998.htm
 20. U.S. Department of Commerce, International Trade Administration. 2025. Final Affirmative Determinations in the Antidumping and Countervailing Duty Investigations of Crystalline Silicon Photovoltaic Cells, Whether or Not Assembled into Modules, from Cambodia, Malaysia, Thailand, and Vietnam. April 21, 2025.
<https://www.trade.gov/final-affirmative-determinations-antidumping-and-countervailing-duty-investigations-crystalline>
 21. Indiana Utility Regulatory Commission (IURC). July 2021.
 22. Indiana Utility Regulatory Commission (IURC). July 2026.
 23. NREL. The open PV Project. No longer available, discontinued in 2019
<https://pv-magazine-usa.com/2019/09/19/the-open-pv-project-goes-offline/>
<https://www.nrel.gov/docs/fy16osti/65958.pdf>
 24. The National Law Review. August 17, 2022. Relief Arrives for Renewable Energy Industry - Inflation Reduction Act of 2022.
<https://www.natlawreview.com/article/relief-arrives-renewable-energy-industry-inflation-reduction-act-2022>
 25. DLA Piper Law Firm Publications. The clean energy provisions of the Inflation Reduction Act of 2022 – a historic effort to encourage the development of clean energy and reduce carbon emissions.
<https://www.dlapiper.com/en/us/insights/publications/2022/08/the-clean-energy-provisions-of-the-inflation-reduction-act-of-2022/>
 26. Sidley Energy Updates. The “One Big Beautiful Bill” Act – Navigating the New Energy Landscape. July 15, 2025.
<https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape>

27. U.S. Department of Agriculture (USDA) Rural Development. Rural Energy for America Program Renewable Energy Systems & Energy Efficiency Improvement Guaranteed Loans & Grants.
<https://www.rd.usda.gov/programs-services/rural-energy-america-program-renewable-energy-systems-energy-efficiency>
28. U.S. Department of Agriculture, Rural Development, Electric Programs.
<http://www.rd.usda.gov/programs-services/high-energy-cost-grants>
29. Indiana Office of Energy Development. Solar and Wind Energy Ready Communities.
<https://www.in.gov/oed/indianas-energy-policy/energy-ready-communities/>
30. Indiana General Assembly. Senate Enrolled Act 309
<https://iga.in.gov/legislative/2017/bills/senate/309#digest-heading>
31. NIPSCO. Feed-in Tariff
<https://www.nipsco.com/services/renewable-energy-programs/feed-in-tariff>
32. Internal Revenue Service (IRS). Publication 946: How to Depreciate Property (2025). Chapter 4, Modified Accelerated Cost Recovery System (MACRS).
<https://www.irs.gov/publications/p946?a=ecd3e32d-b1e8-49de-8f6a-fee4333c9c61&utm>
33. U.S. DOE. Federal Renewable Energy Use Statutory Requirement.
<https://www.energy.gov/cmei/femp/federal-renewable-energy-use-statutory-requirement>
34. U.S. Department of Housing and Urban Development, Federal Housing Administration. FHA Connection Single Family Origination – Maximum Mortgage Calculation.
https://entp.hud.gov/sfohlp/fl7203calc-prhlp.cfm?utm_source
35. Indiana Department of Local Government Finance. Frequently Asked Questions: 2025 Legislative Overview. June 18, 2025.
<https://www.in.gov/dlgf/files/2025-presentations/250618-FAQ-Webinar-Legislative-Update.pdf>
36. Indiana General Assembly. Indiana Code 8-1-37, Voluntary Clean Energy Portfolio Standard Program, Sections 12–13.
<https://iga.in.gov/laws/2026/ic/titles/8>
37. Internal Revenue Service. Residential Clean Energy Credit.
<https://www.irs.gov/credits-deductions/residential-clean-energy-credit>
38. U.S. Department of Energy. Program Guidance for the Title 17 Energy Financing Program. May 13, 2026.
<https://www.energy.gov/documents/doe-edf-title-17-energy-financing-program-guidance-2026-05-13>
39. Indiana General Assembly. Indiana Code 8-1-40, Distributed Generation, particularly IC 8-1-40-17.
<https://iga.in.gov/laws/2026/ic/titles/8>
40. Indiana General Assembly. Indiana Code 32-23-4, Solar Easements.
<https://iga.in.gov/laws/2026/ic/titles/32>
41. Indiana Department of Revenue. Sales and Use Tax Refunds — Manufacturing Exemptions. Accessed 2026.
<https://www.in.gov/dor/i-am-a/business-corp/sales-use-tax-refunds>

7. Hydropower

7.1 Introduction

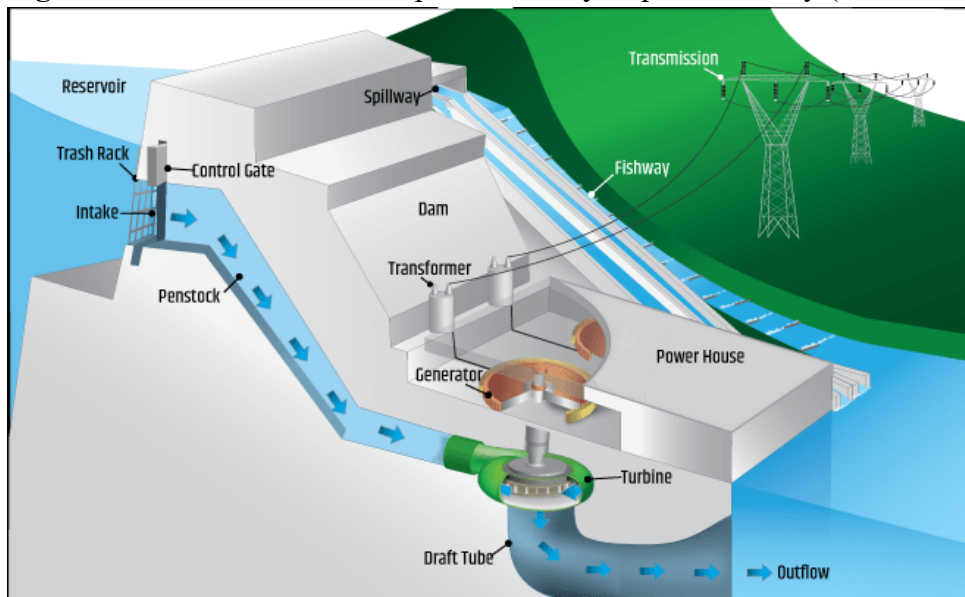
Hydroelectric energy is produced by converting the kinetic energy of falling water into electrical energy. The moving water rotates a turbine, which in turn spins a generator to produce electricity. The harnessing of moving water to perform work has been used for thousands of years, with the Greeks using it to grind wheat more than 2,000 years ago. The evolution of the hydropower turbine began in the mid-1700s in Europe, with the published work of French engineer Bernard Forest de Bélidor. The first use of a water-driven dynamo in the U.S. was in 1880 in Grand Rapids, Michigan, followed closely by Niagara Falls, New York, where hydropower was used to provide street lighting. Unlike modern hydropower plants, these two projects used direct current technology. The first modern alternating current hydropower plant in the world was installed in Appleton, Wisconsin, in 1882. It generated enough electricity to light the inventor's home, the power plant, and one neighboring building [1, 2].

From these beginnings, hydroelectricity quickly became one of the principal sources of electricity in the U.S. At the start of the 20th century, hydropower provided over 30 percent of the electricity generated in the U.S [3]. With the rise of other fuels, such as coal, nuclear, natural gas, wind, and solar, the role of hydroelectricity has dropped steadily, to the point that it supplied less than 6 percent of the total electricity generated in 2025. Starting in 2019, wind energy surpassed hydroelectricity to become the leading source of renewable electricity generation in the United States. In 2025, wind accounted for approximately 44 percent of renewable electricity generation, compared with 23 percent for hydroelectricity. Solar generation has also increased rapidly and accounted for approximately 28 percent in 2025, surpassing hydroelectricity for the first time [4].

There are several types of hydropower facilities in operation. They include impoundment hydropower, diversion, run-of-the-river, micro hydro, and pumped storage.

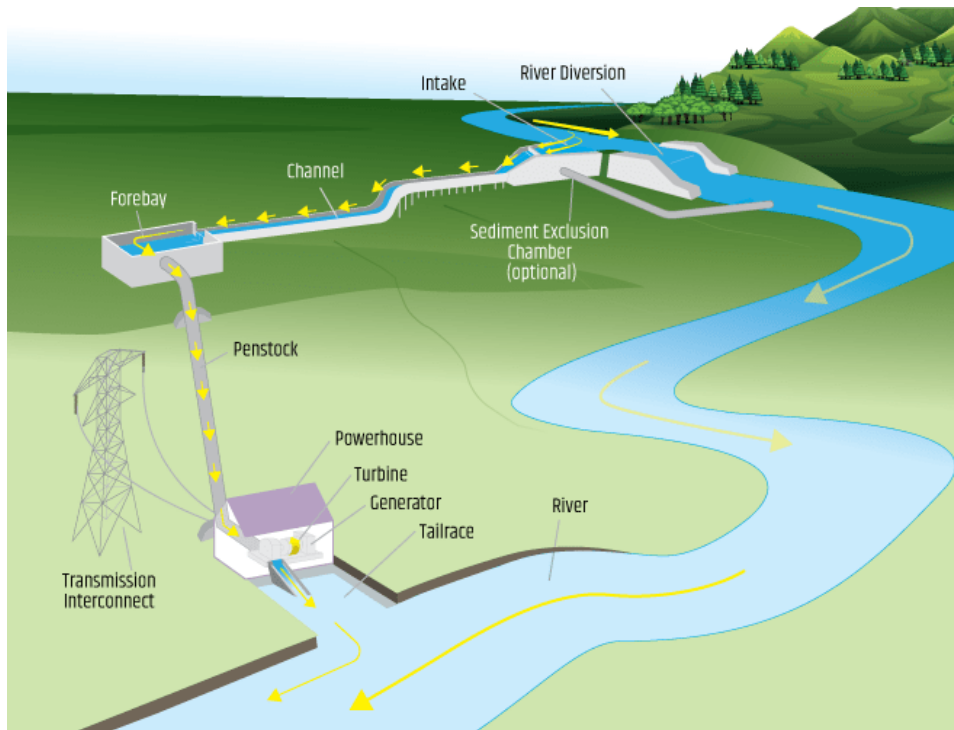
Impoundment hydropower is the most common type of hydropower facility. It stores water in a dam and releases it as needed through turbines to generate electricity. These dams also help with flood control. Figure 7-1 shows the schematic of an impoundment hydropower plant [5].

Figure 7-1: Schematic of an impoundment hydropower facility (Source: DOE [6])



Diversion hydropower facilities channel some of the water from a river through a canal or a pipe. They may require a dam but are less obtrusive than impoundment facilities. Figure 7-2 shows the schematic of a diversion hydropower plant.

Figure 7-2: Schematic of a diversion hydropower facility (Source: DOE [6])



Run-of-river hydropower facilities utilize the natural flow of water of a river and require little to no impoundment. Examples of run-of-river hydropower plants are the NIPSCO-owned Norway and Oakdale hydropower plants on the twin lakes Shafer and Freeman near Monticello. Figure 7-3 is a photograph of the Oakdale run-of-river hydropower plant on Lake Freeman.

Figure 7-3: Oakdale run-of-river hydropower plant in Carroll County (Source: NIPSCO [7])



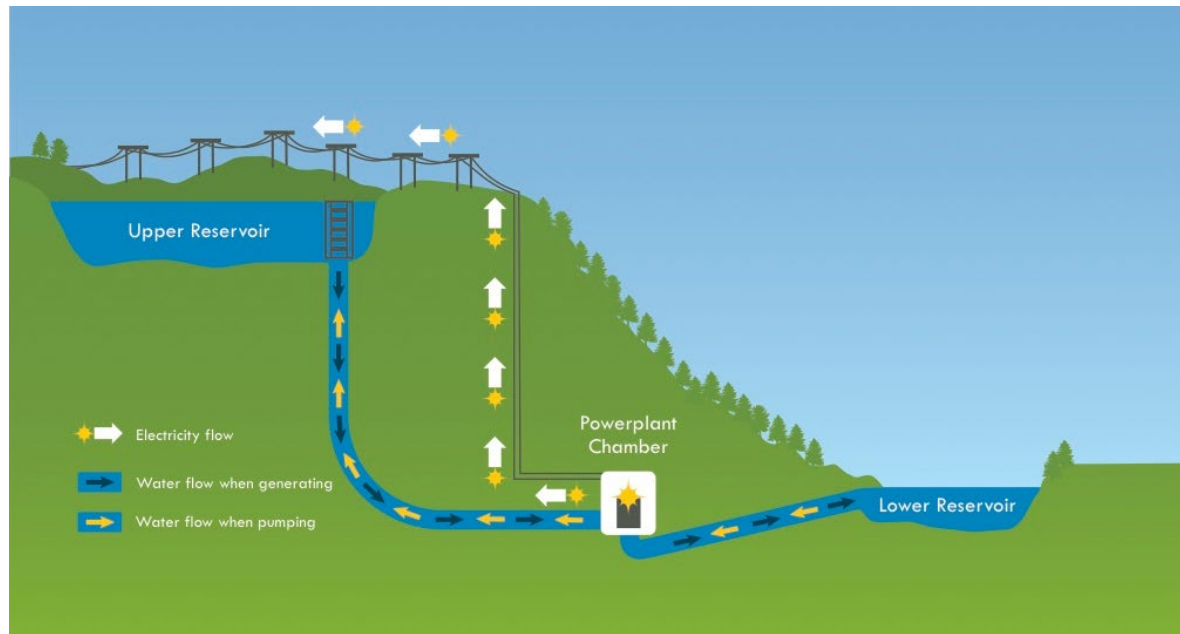
Micro hydropower projects are small sized facilities (about 100 kW or less). They are typically used in remote locations to serve the power needs of a single home or business. Figure 7-4 shows a photograph of a micro hydro power plant manufactured by Suneco Green Energy.

Figure 7-4: Micro hydropower facility (Source: Suneco Green Energy [8])



Pumped storage hydropower (PSH) plants are currently the most common large-scale electric energy storage technology. When electricity demand is low and electricity prices are low, electricity from the grid is used to pump water from a lower reservoir to an upper reservoir. The water is released through the turbines to generate electricity when electricity demand and prices are higher. Figure 7-5 is a schematic of a PSH plant. A more detailed discussion of PSH plants is given in Chapter 8 of this report.

Figure 7-5: Schematic of a PSH facility (Source: DC Thompson and Company [9])



In addition to types of hydropower facilities, there are a variety of turbine technologies that are utilized for hydropower production. The type of turbine is chosen based on its particular application and the height of standing water. There are two main groups of turbines used in hydropower projects –impulse and reaction turbine types. The impulse turbine type uses the velocity of the water, while the reaction turbine uses both the velocity of the water and the pressure drop as the water passes through the turbine. The impulse turbine is more suited to a high head,¹¹ low-flow application, while the reaction turbine is more suited to a lower-head, faster-flow situation [10].

¹¹ Head refers to the vertical distance from the reservoir to the turbine.

7.2 Economics of hydropower

Hydropower projects are very capital-intensive, and costs are highly site-specific. Figure 7-6 shows capital cost ranges for U.S. hydropower projects, expressed in 2021 dollars/kW, from the 2023 DOE U.S. Hydropower Market Report. The projects are grouped into three categories: canals/conduits, non-powered dams (NPD), and new stream-reach development (NSD).

Canal/conduit hydropower projects are constructed on water conveyance conduits built primarily for irrigation or water supply. Non-powered dams are hydropower projects added to dams already in place for other purposes, such as water storage, irrigation, or navigation, while new stream-reach development projects are small-capacity hydropower projects that can be built on streams with minimal environmental impact. Capacity-weighted averages for a sample of 75 U.S. hydropower projects built since 1980 were \$3,955/kW for canal/conduit projects, \$6,096/kW for NPD projects, and \$6,621/kW for NSD projects. Five new projects that began operation since 2020 reported capital costs ranging from \$5,000/kW to \$10,000/kW [11].

Figure 7-6: Capital cost of new U.S. hydropower plants constructed (Source: DOE [11])

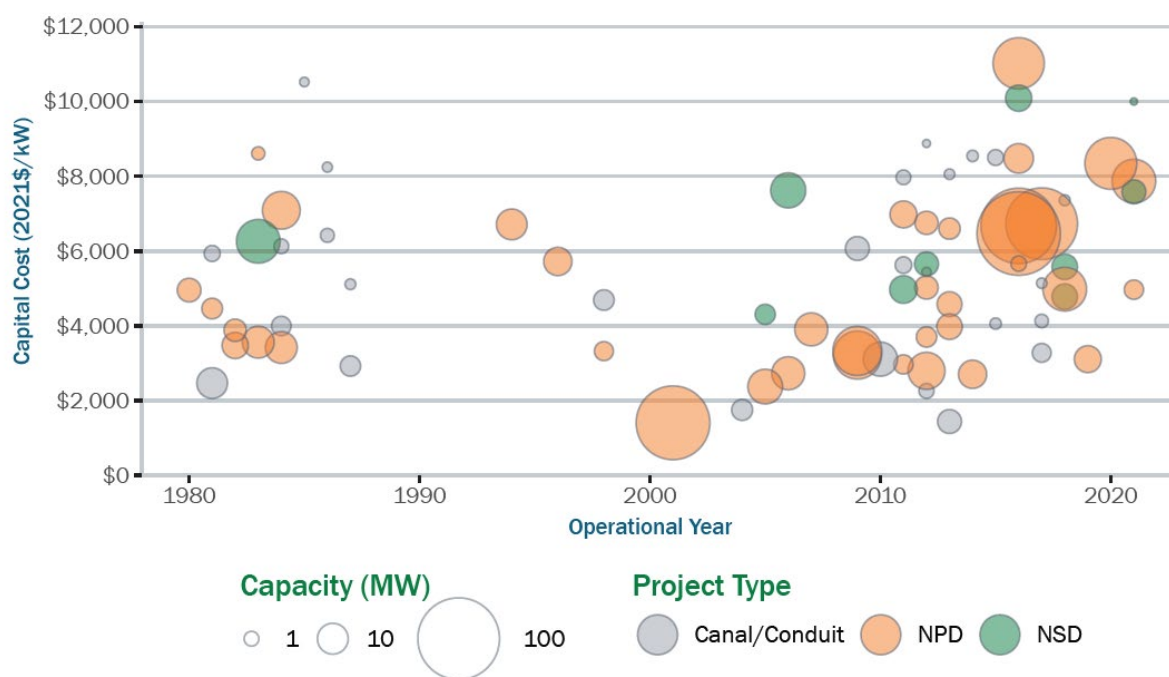


Table 7-1 presents representative capital cost estimates for hydropower projects from several published sources. The reported costs span a wide range, reflecting differences in project type, site characteristics, project scale, and the year of the cost estimate. Among the examples shown, the lowest estimate is \$1,966/kW (2005 dollars) for the Umauma PSH project in Hawaii, while the highest is \$7,889/kW for the Willow Island hydroelectric project developed by American Municipal Power (AMP). The EIA estimate of \$3,280/kW (2025 dollars) lies toward the lower

end of the reported range. Because the estimates are expressed in different base-year dollars, they should not be interpreted as directly comparable without adjusting for inflation.

Table 7-1: Initial capital costs of hydropower projects (Data sources: EIA, Maui Electric Company [12-14])

Project		Time *	Initial Capital Costs (\$/kW) **
EIA estimate		2025	3,280
Hawaii PSH Project (Maui Electric Co.)	Umauma	2005	1,966
	East/West Wailuaiki		3,011
	Big Island		2,432-2,842
	Maui		3,477
American Municipal Power (AMP)	Belleville	1999	2,857
	Cannelton	2009	4,951
	Smithland	2010	6,226
	Meldahl	2010	4,504
	Willow Island	2011	7,889
	Robert C. Byrd	2015	6,250
	Pike Island	NA	7,414

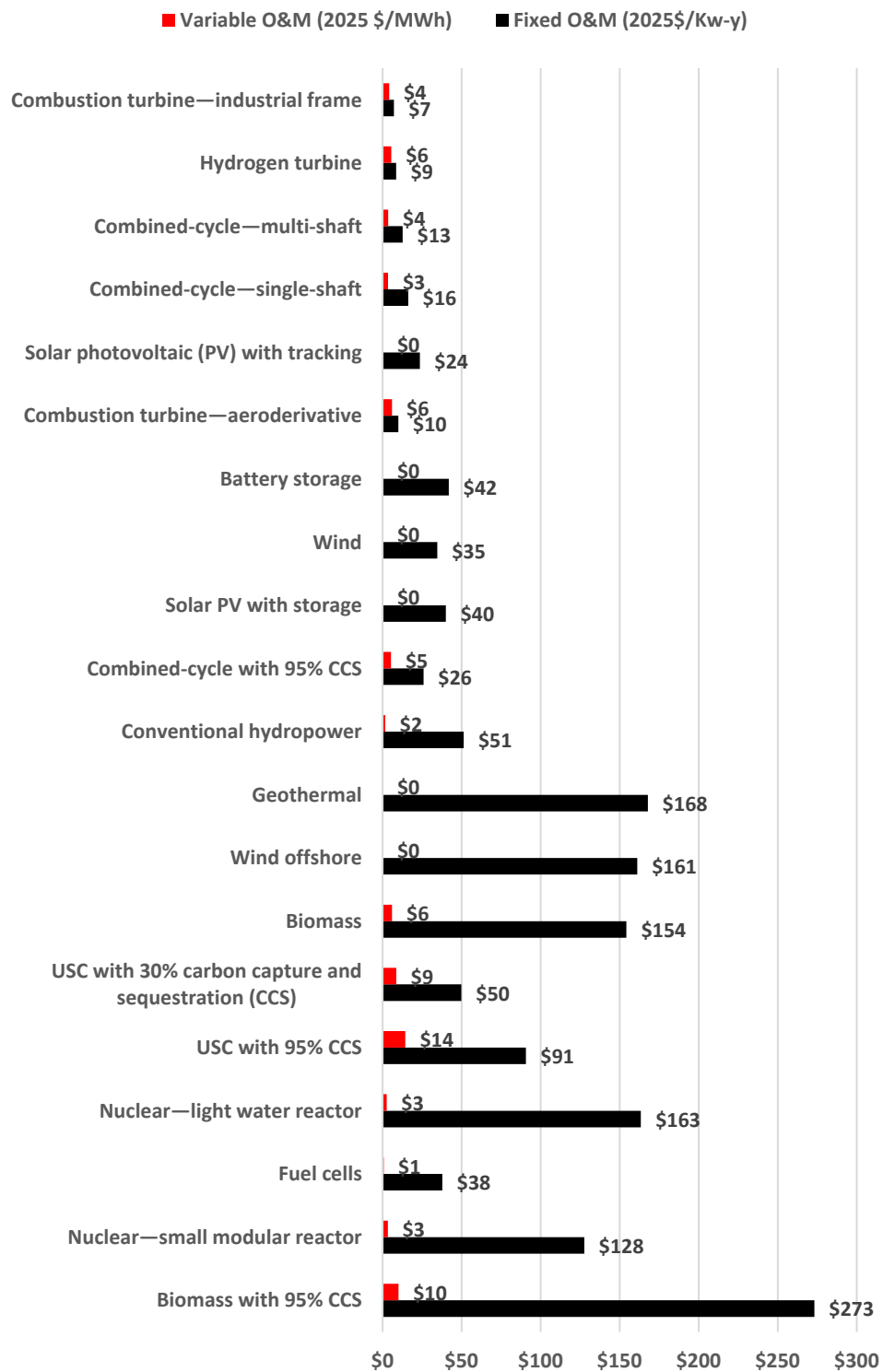
* Time the project's cost estimate was made or the project's expected start date.

** The basis year for the capital cost estimates is 2025 for EIA, and 2005 for the Hawaii PSH project. The basis year for the AMP project cost estimates was not available. The document from which the AMP capital cost estimates were obtained was dated 2011.

Once constructed, hydroelectric power plants have a major cost advantage since, in addition to the free fuel, they have moderately low O&M costs. According to the Assumptions to the AEO 2026: Electricity Market Module, hydroelectric plants have some of the lowest O&M costs among electricity-generating technologies. Figure 7-7 shows the fixed and variable O&M costs of various generating technologies. Hydroelectricity's variable O&M costs are estimated at \$2/MWh, and the fixed O&M cost is \$51/kW-y for a conventional hydroelectric plant.

Impoundment hydropower plants, that is, those with dams that hold substantial amounts of water in a reservoir, have an added advantage over some of the other renewable resources (for example, wind and solar) in that they are dispatchable. That is, the system operator can control the hydropower plant's output to match the system load. In addition, PSH plants can provide cost-effective long-duration, large-scale energy storage where suitable sites are available.

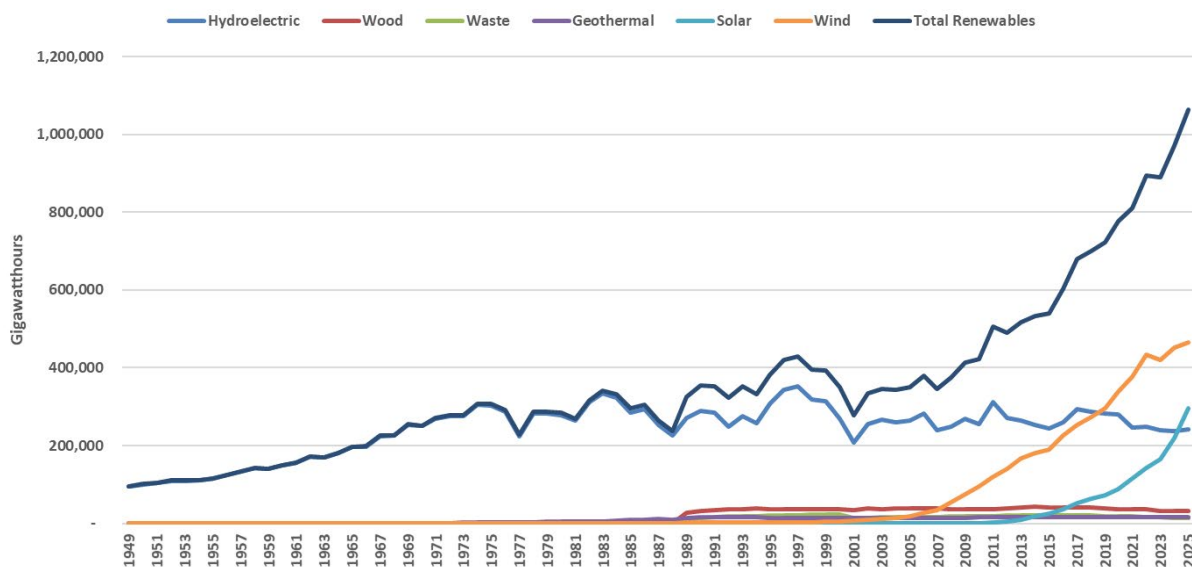
Figure 7-7: Estimated generating technologies fixed and variable O&M costs (Data source: EIA [12])



7.3 State of hydropower nationally

Hydropower has historically been the dominant source of renewable electricity generation in the United States. Figure 7-8 shows annual electricity generation from major renewable energy sources between 1949 and 2025. Hydroelectricity accounted for virtually all renewable electricity generation through the 1960s and still represented about 99 percent of total renewable generation in the early 1970s. Although hydropower generation remained relatively stable over time, its share of renewable generation declined steadily as other renewable technologies expanded. Wind generation grew rapidly beginning in the late 2000s and surpassed hydropower in 2019 to become the largest renewable electricity source. Solar generation also increased rapidly after 2015, reaching 28 percent of total renewable generation by 2025 and surpassing hydropower for the first time. In 2025, wind contributed 44 percent of the renewable electricity while hydroelectricity contributed 23 percent.

Figure 7-8: Net renewable electricity generation in the U.S. (1949-2025) (Data source: EIA [4])



According to the ORNL Existing Hydropower Assets database used in the 2023 U.S. Hydropower Market Report, the U.S. conventional hydropower fleet included 2,252 plants with a total generating capacity of 80.58 GW.¹² The United States has 43 PSH plants with a combined generation capacity of 22 GW and an estimated energy storage capacity of 553 GWh [11]. Table 7-2 is a list of the ten largest hydropower plants in the U.S.

¹² Nameplate capacity value from ORNL Existing Hydropower Assets (EHA) Plant Database 2023, including hydropower plants in Puerto Rico.

Table 7-2: Ten largest hydropower plants in the U.S. (Data sources: EIA [15])

Plant Name	River	State	Nameplate Capacity (MW)	Year of completion
Grand Coulee	Columbia	Washington	6,809	1941-1984
Bath County*	Little Back Creek	Virginia	2,862	1985
Chief Joseph	Columbia	Washington	2,456	1955-1979
Robert Moses - Niagara	Niagara	New York	2,429	1961-1962
John Day	Columbia	Oregon	2,160	1968-1971
Hoover	Colorado	Arizona/Nevada	2,079	1936-1961
Ludington*	Lake Michigan	Michigan	1,979	1973
The Dalles	Columbia	Oregon	1,820	1957-1973
Raccoon Mountain*	Tennessee River	Tennessee	1,714	1978-1979
Castaic*	California Aqueduct	California	1,682	1972-1978

*Pumped hydropower stations

Table 7-3 shows the top ten hydro states ranked by their conventional hydroelectricity output in 2024, and Table 7-4 shows the top ten hydro states ranked by installed conventional hydro capacity at the end of 2024. 60 percent of the conventional hydroelectricity generation in 2024 was from the top four states of Washington, California, New York, and Oregon, and 56 percent of the nameplate hydroelectric capacity in the U.S. in 2024 was in the top four states of Washington, California, Oregon, and New York.

Table 7-3: Top ten U.S. hydropower generating states in 2024 (Data source: EIA [16])

State	2024 Generation (GWh)	Percent of U.S. generation	State	2024 Generation (GWh)	Percent of U.S. generation
Washington	60,736	25%	Idaho	9,150	4%
California	29,454	12%	Tennessee	8,911	4%
New York	27,945	12%	Alabama	8,357	3%
Oregon	26,933	11%	Arizona	5,314	2%
Montana	9,220	4%	North Carolina	4,829	2%

Table 7-4: Top ten U.S. hydropower capacity states at the end of 2024 (Data source: EIA [17])

State	2024 Nameplate Capacity (MW)	Percent of U.S. Hydro Capacity	State	2024 Nameplate Capacity (MW)	Percent of U.S. Hydro Capacity
Washington	21,409	27%	Arizona	2,720	3%
California	10,014	13%	Idaho	2,696	3%
Oregon	8,360	10%	Montana	2,682	3%
New York	4,683	6%	Tennessee	2,504	3%
Alabama	3,318	4%	Georgia	1,962	2%

In 2012, DOE released an assessment of the hydropower potential available at hydro sites that had dams already in place, but no power generation equipment installed. According to DOE,

there were a total of 80,000 such non-powered dams (NPDs) providing services such as navigation, water supply, and recreation. The combined electricity generating potential at these sites was assessed at 12 GW. Figure 7-9 shows the location of the NPDs with a hydropower potential greater than 1 MW. Table 7-5 shows the hydropower potential from NPDs for the states in the contiguous U.S.

Figure 7-9: Non-powered dams with potential capacity over 1 MW (Source: DOE [18])

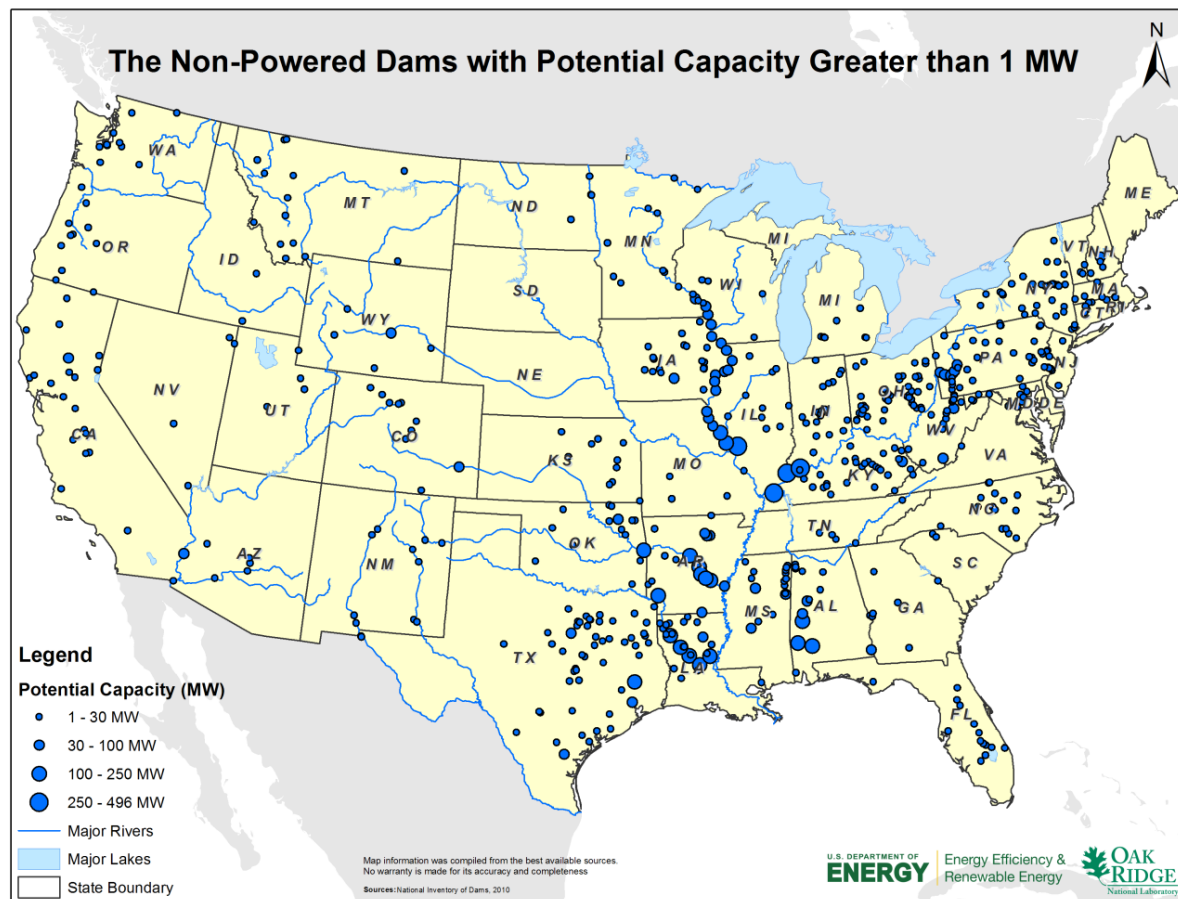


Table 7-5: Hydropower potential from NPDs by state (Data source: DOE [18])

State	Potential Capacity (MW)	State	Potential Capacity (MW)
Illinois	1269	Kansas	92
Kentucky	1253	Montana	88
Arkansas	1136	Washington	85
Alabama	922	Arizona	80
Louisiana	857	Connecticut	68
Pennsylvania	679	Massachusetts	67
Texas	658	New Hampshire	63
Missouri	489	Virginia	50
Indiana	454	Maryland	48
Iowa	427	Michigan	48
Oklahoma	339	Wyoming	45
New York	295	Tennessee	40
Ohio	288	Utah	40
Mississippi	271	South Carolina	38
Wisconsin	245	New Jersey	33
West Virginia	210	North Dakota	31
California	195	Maine	19
Minnesota	186	Vermont	17
Florida	173	Nevada	16
Colorado	172	Rhode Island	13
North Carolina	167	Idaho	12
Georgia	144	South Dakota	12
Oregon	116	Nebraska	7
New Mexico	103	Delaware	3

Since then, DOE and Oak Ridge National Laboratory have refined the assessment using improved hydrologic data, updated dam inventories, and physics-based generation models. The latest HydroSource dataset, released in 2024 and revised in 2025, evaluates 2,616 NPDs with at least 100 kW of theoretical potential and estimates nearly 4 GW of technical capacity at these sites based on historical streamflow, hydraulic head, and turbine performance. In parallel, DOE has developed the NPD HYDRO decision-support tool to help utilities and developers identify and prioritize the most promising retrofit opportunities by considering technical, economic, environmental, community, and grid-related factors. These more recent studies shift the emphasis from estimating the total national resource to identifying the NPDs with the greatest practical development potential [19].

Building on DOE's 2012 national assessment, the U.S. Army Corps of Engineers (USACE) conducted a more detailed assessment of the 419 USACE-owned and -operated NPDs identified in the DOE study. The 2013 USACE Hydropower Resource Assessment at Non-Powered USACE Sites initially identified 236 sites with at least 1 MW of potential hydropower capacity and, after excluding sites with an existing Federal Energy Regulatory Commission (FERC) license or obvious hindrances to hydropower development, selected 223 sites for further

evaluation. The study used more detailed hydraulic-head and flow data available to estimate potential generating capacity, annual generation, development costs, and economic feasibility. Table 7-6 shows the distribution of these 223 sites among USACE divisions.

Table 7-6: Potential capacity from NPDs owned by the U.S. Army Corps of Engineers (Data source: USACE [20])

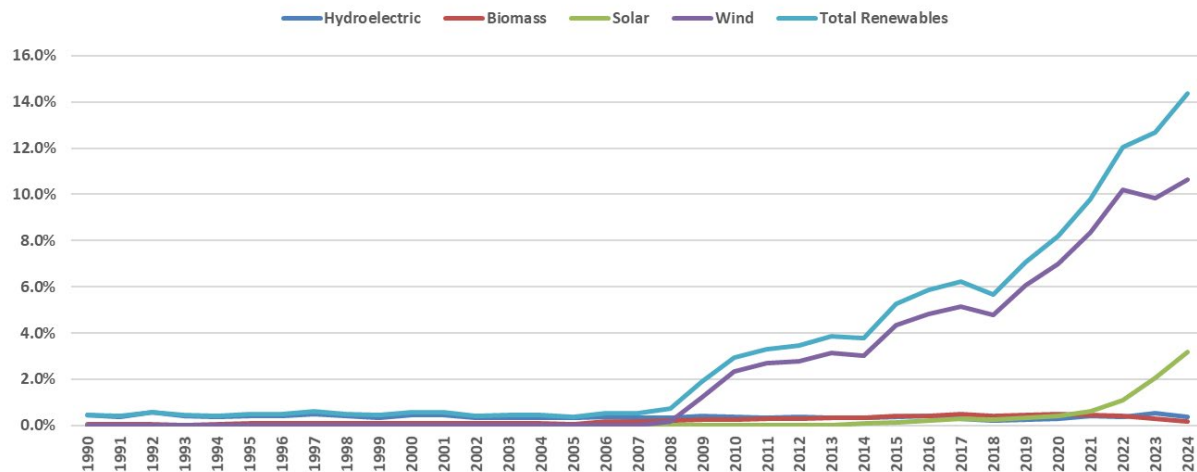
U.S. Army Corps of Engineers Region	Number of Technically Feasible Projects	Potential Capacity (MW)	Economically Feasible Capacity (MW)
Great Lakes & Ohio River	71	1,962	898
Mississippi Valley	50	1,568	940
Southwestern	39	288	63
North Atlantic	21	349	51
South Atlantic	19	672	325
Northwestern	12	116	113
South Pacific	11	1,302	429
Total	223	6,256	2,819

In April 2014, DOE released another assessment of hydropower potential focused on undeveloped stream reaches: rivers and streams without any existing dams (either hydropower plants or NPDs). The total hydropower potential in these rivers and streams is estimated at 84.7 GW, capable of generating 460,000 GWh of electricity per year [21, 22]. Although DOE has not subsequently published a national stream-reach resource assessment, subsequent DOE and ORNL research has investigated standard modular hydropower technologies as a potentially more economical and environmentally compatible approach for developing the many small and low-head sites identified in the undeveloped stream-reach resource [23].

7.4 Hydropower in Indiana

Until the commissioning of the first wind farms in Indiana in 2008, hydroelectricity was the largest source of renewable electricity generation in the state, as shown in Figure 7-10. However, hydropower has consistently accounted for less than 1 percent of Indiana’s total electricity generation throughout the period shown and contributed only 0.4 percent in 2024. Hydropower now represents a relatively small share of Indiana’s renewable generating capacity. At the end of 2024, Indiana had only 107.5 MW of installed hydropower capacity [17], compared with 4,060 MW of utility-scale wind capacity by the end of 2025 [15]. Solar capacity has expanded even more rapidly, reaching 5,088 MW by the end of the first quarter of 2026 [15]. Thus, both wind and solar capacity now substantially exceed hydropower capacity in Indiana.

Figure 7-10: Renewables share of Indiana net electricity generation (1990-2024) (Data source: EIA [24])



The 2012 DOE national assessment of hydropower potential from NPDs, referred to in the preceding section of this report, estimated that Indiana had a total hydropower potential of 454 MW from existing NPDs. Table 7-7 lists the dams in Indiana with potential hydropower development greater than 1 MW. The capacity of the two dams on the Ohio River is allocated equally between Indiana and Kentucky.

Table 7-7: Indiana NPDs with potential capacity over 1 MW (Data source: DOE [18])

Dam Name	County	City	River	Hydroelectric Potential (MW)
John T. Myers locks & dams	Posey	Mt. Vernon	Ohio River	395
Newburgh locks and dams	Henderson	Newburgh	Ohio River	319
Mississinewa Lake dam	Miami	Peru	Mississinewa River	14
J. Edward Roush Lake dam	Huntington	Huntington	Wabash River	9
Salamonie Lake dam	Wabash	Lagro	Salamonie River	9
Brookville Lake dam	Franklin	Brookville	White Water River (East fork)	8
Monroe Lake dam	Monroe	Guthrie	Salt Creek	8
White River dam	Marion	Indianapolis	White River	3
Patoka Lake dam	Dubois	Jasper	Patoka River	3
Cagles Mill Lake dam	Putman	Bowling Green	Mill Creek	2
Cecil M. Harden Lake dam	Parke	Mansfield	Raccoon Creek	2
Ball Band dam	St. Joseph	Mishawaka	St. Joseph River	2
Seymour Water Co. dam	Jackson	Seymour	White Water River (East fork)	2
Eagles Creek Reservoir dam	Marion	Clermont	Eagle Creek	2
West fork White River dam	Morgan	Martinsville	White River	2
Harding St. power plant dam	Marion	Indianapolis	White River	2
Versailles State Park dam	Ripley	Versailles	Laughery Creek	1.4
Emerichsville dam	Marion	Indianapolis	White River	1.3
Broad Ripple dam	Marion	Indianapolis	White River	1.3
Geist Reservoir dam	Marion	Indianapolis	Fall Creek	1.3
Cedarville dam	Allen	Cedarville	St. Joseph River	1.3
HFIgureosey dam	Allen	Fort Wayne	Maumee River	1.2

The 2013 U.S. Army Corps of Engineers hydropower study, referred to earlier, estimates that eleven NPDs owned and operated by the U.S. Army Corps of Engineers in Indiana have the potential for economically feasible hydropower development, as shown in Table 7-8. Their total estimated capacity is 352 MW and 1,291 GWh per year.

Table 7-8: Potential capacity from non-powered dams owned by the U.S. Army Corps of Engineers in Indiana (Data source: USACE [20])

Name of Dam	Estimated Capacity (MW)	Estimated Annual Generation (MWh)	Average Head (Feet)	Average Flow (ft ³ /s)
John T. Myers locks & dam	115	731,882	16	158,807
Newburgh locks & dam	97	371,585	14	137,799
Brookville lake dam	32	36,507	122	500
Mississinewa lake dam	26	33,508	76	816
Salamonie lake dam	23	24,435	78	559
J. Edward Roush lake dam	18	16,584	40	673
Cagles mill lake dam	11	14,930	56	378
Monroe lake dam	10	17,416	55	535
Cecil M Harden lake dam	7	9,404	70	234
Green river lock & dam 1	6	27,815	8	11,135
Patoka lake dam	5	7,119	57	216
Total	352	1,291,185		

The 2014 DOE assessment of hydropower potential in rivers and streams without dams estimated that Indiana has the potential for 581 MW of hydropower capacity capable of generating over 3,000 GWh of electricity per year [21].

American Municipal Power (AMP), a wholesale electricity supplier to municipal utilities in Ohio, Pennsylvania, Michigan, Virginia, Kentucky, and West Virginia, developed a series of run-of-the-river hydroelectric projects along the Ohio River. Three of the projects, the 105 MW Meldahl, the 44 MW Willow Island, and the 88 MW Cannelton projects, were completed in 2016, while the 76 MW Smithland project was completed in 2017. The Cannelton project is located on the Indiana/Kentucky section of the river [25].

The University of Notre Dame's 2.5 MW hydroelectric project on the Saint Joseph River in South Bend was completed and started generating electricity in May 2022. Notre Dame and the City of South Bend have had an agreement since 2016 for the University to construct the hydroelectric project as part of improvements for the Seitz Park in downtown South Bend where the hydroelectric project is located [26, 27].

7.5 Incentives for hydropower

The following federal and state incentives are available for hydropower projects.

Federal Incentives

- Clean Electricity Investment Tax Credit (CEITC), enacted by the IRA of 2022, provides an investment tax credit for qualified electricity-generating facilities with zero or

negative greenhouse gas emissions, including qualifying hydropower facilities, that are placed in service after 2024. Projects that satisfy the prevailing wage and apprenticeship requirements generally qualify for a credit equal to 30 percent of qualified investment. Unlike wind and solar facilities, hydropower facilities are not subject to the accelerated 2027 termination provisions enacted by the One Big Beautiful Bill Act of 2025 (OBBBA) [28, 29].

- Clean Electricity Production Tax Credit (CEPTC) provides a production tax credit for electricity generated by qualified facilities with zero or negative greenhouse gas emissions, including qualifying hydropower facilities, that are placed in service after 2024. Projects meeting the prevailing wage and apprenticeship requirements qualify for the full credit rate, which is adjusted annually for inflation. Unlike wind and solar facilities, hydropower facilities are not subject to the accelerated 2027 termination provisions enacted by the OBBBA of 2025 [28, 29].
- U.S. DOE Title 17 Energy Financing Program (Section 1703 of Title XVII of the Energy Policy Act of 2005) provides loan guarantees for eligible energy projects, including projects that deploy new or significantly improved technologies that are technically proven but not yet widely commercialized in the United States. Eligible technologies include renewable energy technologies such as hydropower [30].
- USDA Rural Energy for America Program (REAP) provides financial assistance to agricultural producers and rural small businesses for eligible renewable energy systems and energy-efficiency improvements. Loan guarantees are available on loans covering up to 75 percent of total eligible project costs. Grants may cover up to 50 percent of eligible project costs for qualifying projects, while other projects are limited to a 25 percent federal grant share. Combined grant and loan-guarantee funding may cover up to 75 percent of total eligible project costs [31].
- High Energy Cost Grant Program administered by USDA assists eligible rural communities with extremely high household energy costs, defined as exceeding 275 percent of the national average. Eligible projects include the acquisition, construction, or improvement of energy generation, transmission, and distribution facilities, including renewable energy projects [32].
- Federal Renewable Energy Use Statutory Requirement (Section 203 of the Energy Policy Act of 2005, as amended) requires that, to the extent economically feasible and technically practicable, at least 7.5 percent of the electricity consumed annually by the federal government be obtained from renewable energy sources. For hydropower, qualifying renewable energy includes new hydroelectric generation capacity resulting

from efficiency improvements or additions of new capacity at existing hydroelectric projects [34].

Indiana Incentives

- Net Metering Rule continues to apply to eligible grandfathered customer-generators with renewable energy facilities having a maximum capacity of 1 MW. SEA 309, enacted in 2017, phased out traditional retail-rate net metering for new customers and established transition periods for existing participants. Eligible systems installed before January 1, 2018 may continue receiving net-metering treatment until July 1, 2047, while certain systems installed after December 31, 2017 may continue receiving net-metering treatment until July 1, 2032 [33].
- Excess Distributed Generation Rule established under Indiana Code 8-1-40 pursuant to SEA 309 (2017), replaced net metering for new distributed generation customers after June 30, 2022. Under the EDG program, excess electricity exported to the grid is compensated at 125 percent of the utility's average marginal price of electricity during the most recent calendar year [33].
- Renewable Energy Property Tax Deduction previously provided property tax deductions for qualifying solar, wind, hydroelectric, and geothermal energy systems. SEA 1 of 2025 eliminated these deductions effective for assessment dates beginning January 1, 2025 [35].
- Clean Energy Portfolio Goal established a voluntary goal of obtaining 4 percent of electricity from clean energy sources between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent in 2025, based on 2010 retail sales. The final statutory goal period ended on December 31, 2025, and no additional clean energy portfolio goals are specified beyond 2025. However, financial incentives and cost-recovery mechanisms approved for participating electricity suppliers that achieved the applicable goals may continue beyond 2025 in accordance with the terms of the program and IURC approval [36].

7.6 References

1. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE). History of hydropower. <http://energy.gov/eere/water/history-hydropower>
2. National Park Service. <https://www.nps.gov/articles/5-the-origins-of-hydroelectric-power.htm>
3. U.S. Department of the Interior, Bureau of Reclamation. The history of hydropower development in the United States. <http://www.usbr.gov/power/edu/history.html>

4. Energy Information Administration (EIA). Electricity Net Generation. April 2026 Monthly Energy Review, Table 7.2a.
<https://www.eia.gov/totalenergy/data/monthly/#electricity>
5. EERE. Hydropower: Setting our course for our energy future.
<http://www.nrel.gov/docs/fy04osti/34916.pdf>
6. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE). Types of hydropower plants. <https://www.energy.gov/eere/water/types-hydropower-plants>
7. NIPSCO. About NIPSCO's hydroelectric plants.
<https://www.nipsco.com/our-company/about-us/hydro-power>
8. Suneco Green Energy
<https://www.sunecochina.com/micro-hydro-power-kits.htm>
9. DC Thompson and Company.
<https://www.thecourier.co.uk/fp/business/business-news/320720/low-carbon-economy-worth-10-7-billion/>
10. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE). Types of hydropower turbines.
<https://energy.gov/eere/water/types-hydropower-turbines>
11. U.S. Department of Energy, Water Power Technologies Office. 2023 U.S. Hydropower Market Report. 2023.
<https://www.energy.gov/cmei/water/hydropower-market-reports>
12. U.S. Energy Information Administration (EIA). Assumptions to the Annual Energy Outlook 2026: Electricity Market Module. Table 3. April 2026.
https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf
13. Maui Electric Company, Ltd. Hawaii pumped storage hydroelectric project: Advisory group meeting, November 1, 2005.
14. AMP. Organization and generation project overview, June 2011.
15. EIA. Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860). June 2026.
<https://www.eia.gov/electricity/data/eia860m/>
https://www.eia.gov/electricity/data/eia860m/xls/june_generator2026.xlsx
16. EIA. Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923) 1990-2024.
<https://www.eia.gov/electricity/data/state/>
https://www.eia.gov/electricity/data/state/annual_generation_state.xls
17. EIA. Historical State Data. Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860) 1990-2024.
<https://www.eia.gov/electricity/data/state/>
https://www.eia.gov/electricity/data/state/existcapacity_annual.xlsx
18. DOE. An Assessment of Energy Potential at Non-Powered Dams in the United States.
https://www.energy.gov/sites/default/files/2013/12/f5/npd_report_0.pdf

19. Hansen, C.H., Gallego Calderon, J.F., Bastidas Pacheco, C.J., Davis, C., Mendadhala, R., and Russell, G. Technical Potential for Hydropower Capacity at Non-powered Dams. HydroSource, Oak Ridge National Laboratory. Published October 3, 2024; revised June 25, 2025.
https://doi.org/10.21951/HydroCapacity_NPD/2570407
20. U.S. Army Corps of Engineers. Hydropower resource assessment at non-powered USACE sites, final report. July 2013.
<https://www.hydro.org/wp-content/uploads/2014/01/Army-Corps-NPD-Assessment.pdf>
21. Kao, S.-C., et al. New Stream-Reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. Oak Ridge National Laboratory, U.S. Department of Energy, 2014.
<https://hydrosorce.ornl.gov/publications/new-stream-reach-development-a-comprehensive-assessment-of-hydropower-energy-potential-in-the-united-states/>
22. U.S. Department of Energy, Water Power Program. New Stream-Reach Hydropower Development. April 2014.
<https://www.energy.gov/sites/prod/files/2014/04/f15/New%20Stream-Reach%20Development%20Potential%20April%202014.pdf>
23. Oak Ridge National Laboratory (ORNL). Standard Modular Hydropower. U.S. Department of Energy, Water Power Technologies Office.
<https://www.ornl.gov/project/standard-modular-hydropower>
24. EIA. 1990-2024 Net Generation by State by Type of Producer by Energy Source.
<https://www.eia.gov/electricity/data/state/>
https://www.eia.gov/electricity/data/state/annual_generation_state.xls
25. American Municipal Power (AMP). Hydroelectric power
<http://www.amppartners.org/generation/hydro>
26. University of Notre Dame.
<https://facilities.nd.edu/projects/current-major-projects/hydroelectric-plant/>
27. Notre Dame News September 12, 2022.
Notre Dame clean energy projects earn Partners for Clean Air Award
<https://news.nd.edu/news/notre-dame-dedicates-new-hydro-facility-along-st-joseph-river-in-south-bend/>
28. DLA Piper Law Firm Publications. The clean energy provisions of the Inflation Reduction Act of 2022 – a historic effort to encourage the development of clean energy and reduce carbon emissions. <https://www.dlapiper.com/en/us/insights/publications/2022/08/the-clean-energy-provisions-of-the-inflation-reduction-act-of-2022/>
29. Sidley Energy Updates. The “One Big Beautiful Bill” Act – Navigating the New Energy Landscape. July 15, 2025. <https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape>

30. U.S. Department of Energy. Program Guidance for the Title 17 Energy Financing Program. May 13, 2026.
<https://www.energy.gov/documents/doe-edf-title-17-energy-financing-program-guidance-2026-05-13>
31. U.S. Department of Agriculture (USDA) Rural Development. Rural Energy for America Program Renewable Energy Systems & Energy Efficiency Improvement Guaranteed Loans & Grants. <https://www.rd.usda.gov/programs-services/rural-energy-america-program-renewable-energy-systems-energy-efficiency>
32. U.S. Department of Agriculture, Rural Development. High Energy Cost Grants. https://www.rd.usda.gov/programs-services/electric-programs/high-energy-cost-grants?utm_source=chatgpt.com
33. Indiana General Assembly. Indiana Code 8-1-40, Distributed Generation, particularly IC 8-1-40-17.
<https://iga.in.gov/laws/2026/ic/titles/8>
34. U.S. DOE. Federal Renewable Energy Use Statutory Requirement.
<https://www.energy.gov/cmei/femp/federal-renewable-energy-use-statutory-requirement>
35. Indiana Department of Local Government Finance. Frequently Asked Questions: 2025 Legislative Overview. June 18, 2025.
<https://www.in.gov/dlgf/files/2025-presentations/250618-FAQ-Webinar-Legislative-Update.pdf>
36. Indiana General Assembly. Indiana Code 8-1-37, Voluntary Clean Energy Portfolio Standard Program, Sections 12–13.
<https://iga.in.gov/laws/2026/ic/titles/8>

8. Underground Pumped Storage Hydropower

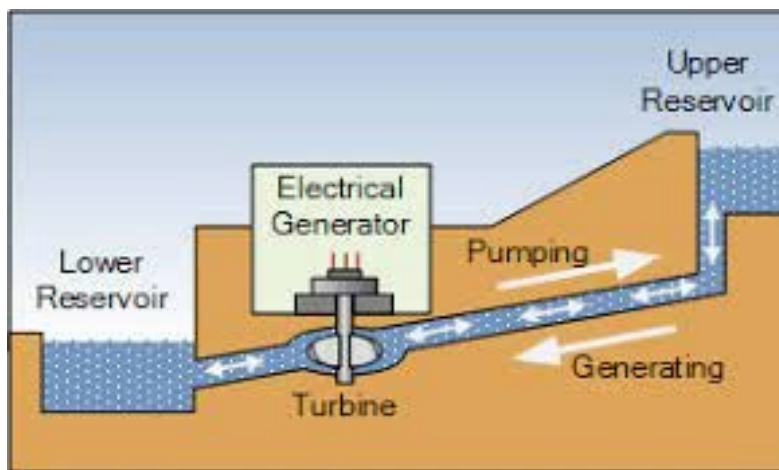
8.1 Introduction

An underground pumped storage hydropower plant is a type of pumped storage hydropower plant in which at least one reservoir, usually the lower one, is located underground. This reservoir can be an artificially constructed cavern, an abandoned mine, or any other underground chamber capable of holding water without leaks. In some designs, it has been proposed to put both reservoirs underground to further reduce the power plant's surface footprint.

Although there have been many feasibility studies, a recent surge in interest, and several proposals to build underground pumped storage hydropower plants worldwide, SUFG is not aware of any commercial underground pumped storage hydropower plant in operation anywhere in the world as of the writing of this report. However, at least one proposed underground pumped storage project appears to be moving toward construction: Zero Terrain's Paldiski project in Estonia, described as a 500 MW underground pumped hydro energy storage facility using newly built underground reservoirs. Public project materials and industry reporting indicated that construction was expected to begin in 2025, with the project targeted to become operational by 2032 [1]. However, publicly available information reviewed in 2026 does not confirm that full construction has begun; Global Energy Monitor's Global Hydropower Tracker continues to list the Paldiski project as being in pre-construction [2].

In contrast, conventional surface-level pumped-storage hydropower plants have been operating for decades in the U.S. and around the world. Pumped storage hydropower remains the dominant utility-scale energy storage technology by energy capacity, although its share has declined as battery storage deployment has grown rapidly. DOE's 2023 Hydropower Market Report indicated that the 43 pumped storage hydropower plants in the United States had an estimated energy storage capacity of 553 GWh and accounted for 96 percent of U.S. utility-scale energy storage capacity in 2022 [3]. DOE's current pumped storage hydropower webpage, citing the 2024 edition of the Hydropower Market Report, indicates that pumped storage hydropower plants account for approximately 88 percent of U.S. utility-scale energy storage [4]. The basic structure of a pumped storage hydropower plant consists of two water reservoirs at differing heights, as shown in Figure 8-1. As mentioned earlier, the more common arrangement in existing pumped-storage hydroelectric power plants is for both reservoirs to be surface-level lakes at differing elevations.

Figure 8-1: Schematic of a pumped storage hydropower plant (Source: Alternative Energy Tutorials [5])

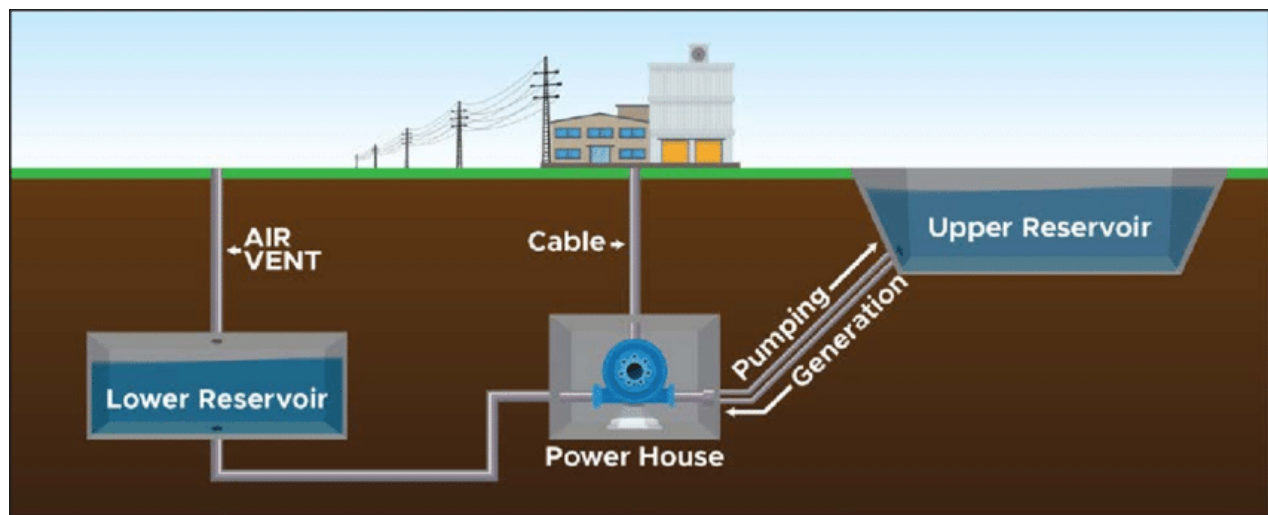


During periods of low electricity demand, grid electricity is used to pump water from the lower to the upper reservoir. Then, during times of high electricity demand, this water is released through a turbine to the lower reservoir to generate electricity. An example of a pumped storage power plant near Indiana is the 1,979-MW Ludington Pumped Storage Hydropower plant in Ludington, Michigan. In this pumped storage plant, Lake Michigan is used as the lower reservoir, while the upper reservoir is a man-made lake at the elevated plateau above the lake shore [6, 7].

The main motivator behind the impetus to build underground pumped-storage hydropower plants is that conventional pumped-storage hydropower plants require the availability of land layout (topography) with significant elevation differences. Sites with this type of topography have, for the most part, been exhausted in the U.S., and where they exist, proposals to flood large tracts of land to create reservoirs face fierce public resistance. Underground pumped storage hydropower technology overcomes this siting constraint by placing one or both reservoirs underground. Further, since the power rating of a hydropower plant is proportional to the height through which the water falls before encountering the turbines, given a fixed reservoir volume, one can reduce the size of the upper-surface reservoir by increasing the depth at which the lower reservoir is excavated. This can be done at a reasonable cost because the excavation cost of the reservoir does not increase proportionally with increasing depth [8].

Figure 8-2 is the schematic of a typical underground pumped storage hydropower plant where only one of the reservoirs, the lower one, is underground, in a specially constructed cavern or in an abandoned mine.

Figure 8-2: Schematic of an underground pumped storage hydropower plant (Source: ResearchGate [9])



In some conventional pumped storage hydropower plants, the power plant equipment (turbines and transformers, pressure pipes, etc.) is placed underground. This arrangement, however, does not constitute an underground pumped storage hydropower plant, as discussed in this report; one of the two reservoirs must be placed underground for a pumped storage hydropower plant to be considered underground [8].

8.2 Economics of underground pumped storage hydropower

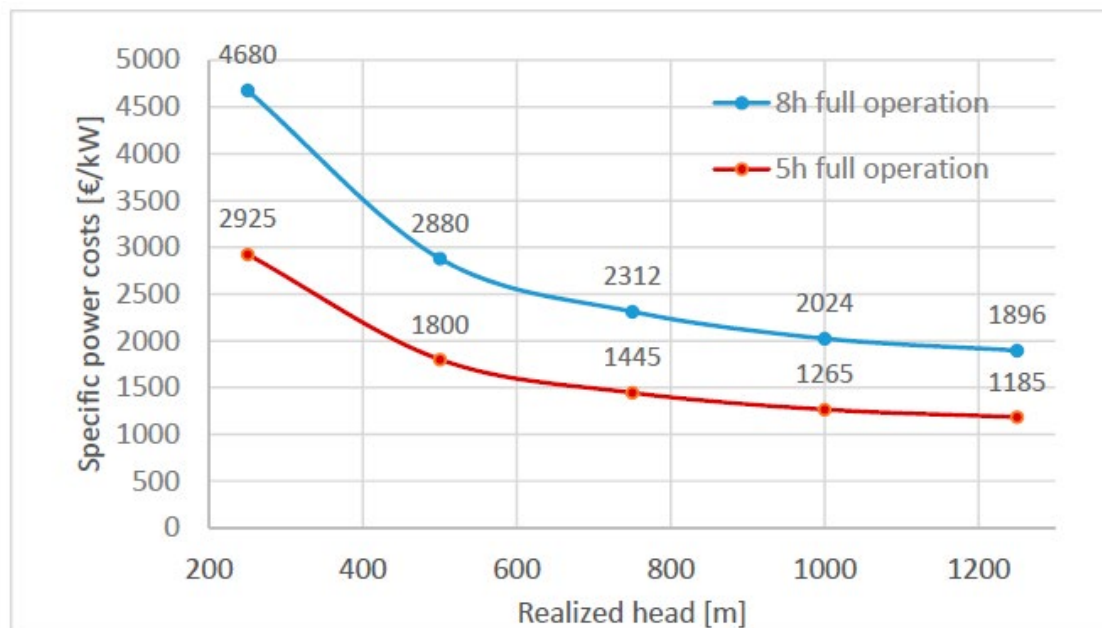
Many studies in the U.S. and elsewhere have established that underground pumped storage hydropower is both technically viable and, at least in modeling studies, an economical technology for large-scale energy storage for the electrical grid [8, 10]. Most of the feasibility studies done for underground pumped hydropower in the U.S. in the 1980s were focused on building the power plants with man-made underground reservoirs as close to the demand centers (cities) as possible, with the only limitation being the presence of the required hard impervious rock formations that could hold water without leaking. The use of abandoned mines for the lower reservoir has received more attention in recent years as more coal mines are made available by the move towards less carbon-intensive energy.

The cost of building underground pumped storage hydropower plants using abandoned mines is very site specific and depends on how well fitted the caverns in the abandoned mines are to hold the water and the power plant equipment. A few of those studies found in the literature, and their cost estimates, are presented below.

Reinhard Madlener and Jan Martin Specht (2013, 2020) published a paper that presents the results of an economic analysis evaluating the feasibility of constructing pumped storage hydropower plants utilizing the numerous abandoned deep coal mines in Germany's Ruhr region. Although this study is cited in literature as one of the most rigorous techno-economic analysis of underground pumped storage hydropower plants using abandoned coal mines, the authors make a point to emphasize that there are numerous uncertainties in the data and assumptions made in the study and much more needs to be done to get a more accurate estimate of the costs and potential profitability of underground pumped storage hydropower plants in underground mines [8].

Figure 8-3 shows the capital cost of a 2,500 MWh underground pumped storage hydropower plant in Euros (€) per kW as a function of the realized head¹³ of water. The realized head is determined by the depth of the mine at which the lower reservoir is constructed. For example, for a lower reservoir placement resulting in a 1,000-meter head, the capital cost is €1,265/kW for a 5-hour discharge turbine and €2,024/kW for an 8-hour discharge turbine. At an exchange rate of 0.87 euros to a U.S. dollar, this capital cost converts to \$1,460/kW for a 5-hour discharge power plant and \$2,919/kW for an 8-hour discharge power plant. The paper used a 0.87 euro-to-dollar conversion rate.

Figure 8-3: Capital cost of underground pumped storage hydropower plant in an abandoned coal mine in Germany (Source: Madlener et al. [8])



¹³ The head (also known as the hydraulic head) is a measure of the energy available in a water column at the inlet to the turbine. In a pumped storage hydropower plant, it is proportional to the height difference between the upper and the lower reservoirs.

R Alvarado Montero, T. Wortberg, J. Binias, and A. Nieman (2016) build upon the earlier study by Madlener and Specht, which was based on a generic mine in the Ruhr region of Germany, by conducting a detailed technical and economic assessment of constructing an underground pumped storage power plant at the Prosper-Haniel mine, located in the same Ruhr region. This study brings into even clearer focus the wide range of potential costs. Even when one narrows it down to one mine, the cost will vary widely depending on how much of the mine infrastructure is usable and how much additional work (excavation, etc.) is needed to house the reservoir, pump house, etc .

In the case of the Prosper-Haniel mine, the capital cost of the power plant was estimated to range from a low of €760/kW to a high of €2,750/kW, depending on how much of the mine's tunnel system was usable for water storage. Using the 0.87 euros to a dollar exchange rate explained earlier, this translates to a low cost of \$877/kW and a high cost of \$3,173/kW. In the lowest cost option, the existing open tunnels in the mine are assumed usable, while in the high-cost case, only the mine shafts are deemed usable, and new tunnels have to be excavated to hold the water as the lower reservoir [11].

Peter Schubert, Afshin Izadian, and JW Wheeler published a paper in October 2019 that is the only study based on abandoned coal mines in Indiana. The study proposes a modular underground pumped storage hydropower plant design that can be scaled to fit different mine sizes. The conceptual power plant used for cost estimates is a 200 MW, 1400 MWh (7-hour discharge) plant with the lower reservoir at a depth that provides a 400-foot water head.

A unique design feature of this power plant is the use of hydraulic wind turbines to supplement the pumping of water from the lower to the upper reservoir. A hydraulic wind turbine differs from the more common electricity-generating wind turbines in that instead of a turbine-generator, the rotors in a hydraulic turbine drive a hydraulic pump, which can then be used to drive a water pump. The authors estimated the cost of this power plant at \$1,494/kW [12].

Roman Sidortsov, Shardul Tiwari, Timothy Scarlett, Ana Dyreson, and David Watkins of Michigan Technological University, in a draft technical report written in 2021, detail a study of repurposing the decommissioned metal mines (not coal) generally in the U.S., with a specific case study involving the use of a decommissioned copper mine in the Upper Peninsula of Michigan.

Their preliminary results estimated that the chosen mine, the Mather B mine in Negaunee, Michigan had the technical and economic feasibility to house an underground pumped storage hydropower plant in either of the two configurations: in a daily cycling configuration with a power capacity of 295 MW and an energy storage capacity of 1,666 MWh, or in a long-term

(seasonal) storage configuration with a power capacity of 73 MW and an energy storage capacity of 52,188 MWh. Their estimated capital cost for the facility in the Mather B mine is \$1,340/kW.

The study further concluded that the United States had metal mines with the potential to host 285 GW of partially underground pumped storage hydropower plants or 137 GW fully underground UPS hydropower plants operating in a daily cycling mode with an energy storage capacity of 564,441 GWh or 271,040 GWh for partial or fully underground pumped storage hydropower plants, respectively. In comparison, the existing U.S. pumped storage hydropower fleet consists of 43 operating plants, all of which use conventional surface-level reservoirs rather than underground reservoirs. DOE hydropower market materials indicate that the fleet has approximately 22 GW of installed power capacity and an estimated energy storage capacity of 553 GWh. U.S. utility-scale battery storage power capacity exceeded 26 GW in 2024, surpassing pumped storage hydropower by power capacity, but battery systems still provide much less total energy storage duration than the pumped storage hydropower fleet. [3, 13, 14, 15].

8.3 State of underground pumped storage hydropower nationally

Several technical and feasibility studies have been conducted, demonstrating the technical viability of underground pumped storage hydropower plants. The cost and the uncertainty associated with a new technology have been too high a barrier to surmount thus far [16].

There was a flurry of activity in the 1970s and 1980s in the U.S. around the concept of building underground pumped hydropower plants including feasibility studies conducted by utilities such as Commonwealth Edison and Potomac Electric Company. The state of the research in that period is summarized in a 1984 U. S. Department of Energy (DOE) report [10]. During this period, the focus was not on using abandoned mines but rather the excavation of underground reservoirs at locations close to cities where the load was located, where they would serve to complement base-load nuclear generation and were considered more economical than running coal-fired power plants on cycling duty. Some of the more prominent studies in that period include.

The Potomac Electric Power Study (1981) was considered the most comprehensive and rigorous techno-economic and feasibility analysis conducted during that period, according to the 1984 DOE report. The design specification was for a 2,000 MW, 10-hour discharge (20,000 MWh) underground pumped storage in close proximity to Washington, D.C., with a 5,000-foot operating head. Seismological studies were done, and a site with the appropriate rock formation to host the underground reservoir was identified in Maryland, 20 miles North of Washington, D.C., and 20 miles Southwest of Baltimore, Maryland. Like the other proposed underground projects in this period, Potomac Electric Power did not proceed with the project.

The Commonwealth Edison Study (1975-1981) proposed a 3,000 MW underground pumped storage facility near Chicago, capable of a 10-hour discharge (30,000 MWh) to support the company's nuclear and coal power plants. Seismic studies were done, and a site with the appropriate rock formation to host the lower reservoir was identified in Northwest Illinois, within the Commonwealth Edison service territory. This project was suspended when a revised load forecast set back substantially the date the capacity would be needed.

More recently, the attention of the underground pumped storage industry globally has focused on the use of abandoned underground mines. Much more investigation has been going on in Europe than in the U.S. The major studies outside the U.S. encountered in literature include

- The 2013 (revised in 2020) Madlener et al techno-economic study of the potential for using underground coal mines in the Ruhr region of Germany [8]
- The 2016 Alvarado et al. study of one of the mines, the Prosper-Haniel mine in the Ruhr region of Germany (200 MW) [11]
- The 2017 Menendez et al study of the use of mines in the Asturian Central Coal Basin in northern Spain [17]

Despite this heightened interest and studies in Europe, none of these projects has proceeded to make any substantial progress toward implementation.

In the U.S., most proposed underground pumped storage hydropower projects using abandoned mines focus on abandoned open-pit mines, with none progressing beyond preliminary FERC permits. Examples include:

The 1,000 MW Riverbank Wiscasset project (2009) proposed using the site of the decommissioned Maine Yankee Nuclear Power Plant, utilizing tidal water for the upper reservoir and a subterranean cavern for the lower. Although attractive to the community, it remained at the permitting stage [18,19].

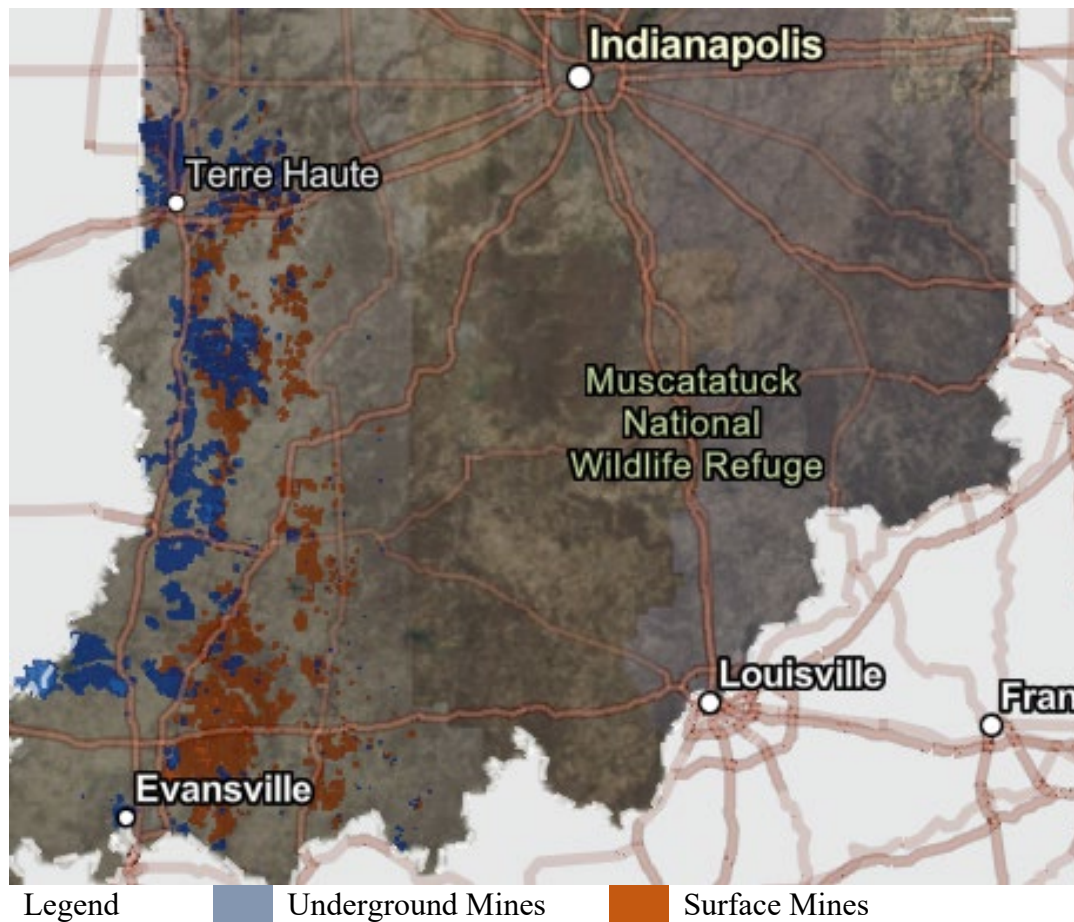
The Elmhurst Quarry project (2011) planned to use a previously operational quarry and underground mine for flood control and power storage, with a 709 MWh capacity. It received a preliminary permit but did not advance [20,21].

The Mineville Energy Storage Project in New York, initially proposed as a closed-loop system in a decommissioned mine, progressed further, with a FERC license application filed in 2015 and a draft environmental impact statement issued in 2019. However, it did not move to construction following the denial of water quality certification, although recent proposals indicate ongoing interest [22].

8.4 Underground pumped storage hydropower in Indiana

Indiana has many surface and underground coal mines that are no longer active. Based on SUFG's download of the Indiana Department of Natural Resources (DNR) CMIS GIS datasets, the data include 1,702 underground mine records and 2,787 surface mine records representing documented inactive coal mine locations in Indiana [23]. Figure 8-4 shows the location of these mines as downloaded from the DNR Coal Mine Information System.

Figure 8-4: Location of inactive mines in Indiana (Source: DNR [23])



Each of these mines has the potential to host an underground pumped storage hydropower plant. Further investigation would need to be done on the suitability of each individual mine, including the condition of the chambers, the depth, the location relative to transmission lines, etc.

Peter Schubert, Afshin Izadian, and JW Wheeler, in their paper referred to earlier in this chapter, presents the cost estimate of a conceptual underground pumped storage hydropower plant that could be located in one of the many underground mines in Indiana. A modular power plant with

the capacity to generate 200 MW for 7 hours (1,400 MWh) and a water head of 400 feet is modeled in the paper [12].

8.5 Incentives for underground pumped storage hydropower

No incentives or mandates specific to underground pumped storage hydropower plants exist currently in the U.S. or in Indiana, but since pumped storage hydropower is a form of hydropower, incentives where hydropower qualifies may also be applicable for underground pumped storage hydropower.

Federal Incentives

- Clean Electricity Investment Tax Credit (CEITC) established under Section 48E of the IRA, became effective in 2025 and provides an investment tax credit for qualifying clean electricity facilities and energy storage technologies, including pumped-storage hydropower. Projects that satisfy the prevailing wage and apprenticeship requirements generally qualify for a credit equal to 30 percent of qualified investment. Unlike wind and solar facilities, qualifying pumped-storage projects are not subject to the accelerated 2027 termination rule. Projects may also qualify for applicable bonus credits, including domestic content and energy-community bonuses [24, 25, 29].
- Clean Electricity Production Tax Credit (CEPTC) under Section 45Y provides an inflation-adjusted production tax credit for electricity generated by qualifying zero- or negative-emission facilities placed in service after December 31, 2024. A qualifying hydropower generating facility associated with a pumped-storage project may be eligible if it satisfies the Section 45Y requirements. Unlike wind and solar facilities, qualifying hydropower facilities are not subject to the accelerated 2027 termination rule [24, 25].
- U.S. DOE Title 17 Energy Financing Program (Section 1703 of Title XVII of the Energy Policy Act of 2005) provides loan guarantees for eligible energy projects, including projects that deploy new or significantly improved technologies that are technically proven but not yet widely commercialized in the United States [28].

Indiana Incentives

- Clean Energy Portfolio Goal established a voluntary goal of obtaining 4 percent of electricity from clean energy sources between 2013 and 2018, 7 percent between 2019 and 2024, and 10 percent in 2025, based on 2010 retail sales. The final statutory goal period ended on December 31, 2025, and no additional clean energy portfolio goals are specified beyond 2025. However, financial incentives and cost-recovery mechanisms approved for

participating electricity suppliers that achieved the applicable goals may continue beyond 2025 in accordance with the terms of the program and IURC approval [26, 27].

- Indiana Clean Energy Project Incentives provide financial incentives for qualifying clean energy projects found by the IURC to be just and reasonable, including incentives for eligible renewable energy resource projects, subject to applicable statutory requirements and Commission approval. Underground pumped-storage hydropower using abandoned coal mines, abandoned quarries, or other suitable sites in Indiana is expressly identified as a clean energy resource under Indiana law [30, 31].

8.6 References

1. Energy-Storage News, “Estonia backs 500MW pumped hydro project to integrate wind,” February 4, 2025
<https://www.energy-storage.news/estonia-backs-500mw-pumped-hydro-project-to-integrate-wind/>
2. Global Energy Monitor, “Zero Terrain Hydroelectric Plant,” Global Hydropower Tracker, accessed May 2026.
https://www.gem.wiki/Zero_Terrain_hydroelectric_plant?
3. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Water Power Technologies Office. 2023 U.S. Hydropower Market Report.
<https://www.energy.gov/sites/default/files/2023-09/U.S.%20Hydropower%20Market%20Report%202023%20Edition.pdf>
4. U.S. Department of Energy, “Pumped Storage Hydropower,” Hydropower and Hydrokinetic Office, citing the 2024 edition of the Hydropower Market Report.
<https://www.energy.gov/cmei/water/pumped-storage-hydropower>
5. Alternative Energy Tutorials
<https://www.alternative-energy-tutorials.com/hydro-energy/pumped-hydro-storage.html>
6. Consumer Energy. Ludington Relicensing.
<https://www.consumersenergy.com/company/electric-generation/renewables/hydroelectric/pumped-storage-hydro-electricity/ludington-relicensing>
<https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/Hydro/ludington-hydro-review.ashx>
7. EIA. Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860). May 2025
<https://www.eia.gov/electricity/data/eia860m/>
https://www.eia.gov/electricity/data/eia860m/xls/april_generator2025.xlsx
8. Reinhard Madlener, Jan Martin Specht. An Exploratory Economic Analysis of Underground Pumped-Storage Hydro Power Plants in Abandoned Deep Coal Mines. MDPI Energies Journal. October 2020.
<https://ntnuopen.ntnu.no/ntnu-xmlui/handle/11250/2732203>

9. James Saulsbury. ResearchGate
https://www.researchgate.net/figure/Conceptual-diagram-of-an-underground-pumped-storage-hydropower-project-Source-Based-on_fig5_340716067
10. R.D. Allen, T.J. Doherty, L.D. Kannberg. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. Office of Scientific and Technical Information. Underground pumped hydroelectric storage. July 1994.
<https://www.osti.gov/biblio/6517343>
<https://www.osti.gov/servlets/purl/6517343>
11. R Alvarado Montero, T. Wortberg, J. Binias and A Nieman. Integrated Assessment of Underground Pumped-Storage Facilities using Existing Coal Mine Infrastructure.
https://www.researchgate.net/publication/305872758_Integrated_assessment_of_underground_pumped-storage_facilities_using_existing_coal_mine_infrastructure
12. Peter J Schubert, Afshin Izadian, JW Wheeler. Abandoned Mine Voids for Pumped Storage Hydro. Juniper Publishers. October 17, 2019.
<https://juniperpublishers.com/imst/IMST.MS.ID.555563.php>
13. Roman Sidortsov, Shardul Tiwari, Timothy Scarlett, Ana Dyreson & David Watkins. Michigan Technological University. PUSHing for Storage. A Case for Repurposing Decommissioned Mines for Pumped Underground Storage Hydro (PUSH) in the United States. Draft Technical Report. October 2021.
<https://www.ketl.info/post/push-report-released>
14. Michigan Technological University. Inclined to Innovate, Old Mines Inspire a new Energy Landscape. The Michigan Tech Magazine, Volume 59, Spring 2023. pages 36-42
15. U.S. Energy Information Administration, “U.S. battery capacity increased 66% in 2024,” Today in Energy, March 12, 2025, based on EIA’s January 2025 Preliminary Monthly Electric Generator Inventory.
<https://www.eia.gov/todayinenergy/detail.php?id=64705&utm>
16. Catalina R. Matos, Julio F. Carneiro, Patricia P. Silva. Overview of large-scale underground energy storage technologies for integration of renewable energies and criteria for reservoir identification. Elsevier Journal of Energy Storage. Volume 21, pages 241-258, February 2019.
<https://www.sciencedirect.com/science/article/abs/pii/S2352152X18301919>
17. Javier Menéndez, Jorge Loredo , J. Manuel Fernandez, Mónica Galdo. Underground Pumped-Storage Hydro Power Plants with Mine Water in Abandoned Coal Mines
https://www.imwa.info/docs/imwa_2017/IMWA2017_Menendez_6.pdf
18. International Water Power and Dam Construction Magazine. Investigating Aquabank. January 2010. <https://www.waterpowermagazine.com/features/featureinvestigating-aquabank/>
19. Lincoln County News. January 31, 2009. Riverbank Power Receives Warm Local Reception. <https://lcnme.com/currentnews/riverbank-power-receives-warm-local-reception/>

20. Factor This Power Engineering. Pumped Storage: Investigating Development of the Elmhurst Quarry Project. December 2012.
<https://www.renewableenergyworld.com/energy-storage/pumped-storage/pumped-storage-investigating-development-of-the-elmhurst-quarry-project/>
21. Anthony Charlton, Thomas Haag. Renewable Energy World.
Pumped Storage: Investigating Development of the Elmhurst Quarry Project
<https://www.renewableenergyworld.com/energy-storage/pumped-storage/pumped-storage-investigating-development-of-the-elmhurst-quarry-project/#:~:text=EQPS%20is%20being%20developed%20by%20Dupage%20County,%20Ill.,being%20used%20as%20a%20critical%20flood%20storage%20resource.>
22. Federal Energy Regulatory Commission, “FERC Staff Issues Draft Environmental Impact Statement for the Mineville Energy Storage Project (P-12635-002),” June 18, 2019.
https://www.ferc.gov/ferc-staff-issues-draft-environmental-impact-statement-mineville-energy-storage-project-p-12635-002?utm_source=
23. Indiana Department of Natural Resources. Coal Mine Information System.
<https://www.in.gov/dnr/reclamation/abandoned-mines/coal-mine-information-system/>
24. DLA Piper Law Firm Publications. The clean energy provisions of the Inflation Reduction Act of 2022 – a historic effort to encourage the development of clean energy and reduce carbon emissions. <https://www.dlapiper.com/en/us/insights/publications/2022/08/the-clean-energy-provisions-of-the-inflation-reduction-act-of-2022/>
25. Sidley Energy Updates. The “One Big Beautiful Bill” Act – Navigating the New Energy Landscape. July 15, 2025. <https://www.sidley.com/en/insights/newsupdates/2025/07/the-one-big-beautiful-bill-act-navigating-the-new-energy-landscape>
26. Database of State Incentives for Renewables and Efficiency (DSIRE).
<http://www.dsireusa.org/>
27. Indiana General Assembly. Indiana Code 8-1-37, Voluntary Clean Energy Portfolio Standard Program, Sections 12–13.
<https://iga.in.gov/laws/2026/ic/titles/8>
28. U.S. Department of Energy. Program Guidance for the Title 17 Energy Financing Program. May 13, 2026.
<https://www.energy.gov/documents/doe-edf-title-17-energy-financing-program-guidance-2026-05-13>
29. U.S. Department of the Treasury and Internal Revenue Service. Section 45Y Clean Electricity Production Credit and Section 48E Clean Electricity Investment Credit, Final Regulations, T.D. 10024. Internal Revenue Bulletin 2025-12, March 17, 2025.
https://www.irs.gov/irb/2025-12_IRB
30. Indiana General Assembly. Indiana Code 8-1-8.8-11, Incentives for Clean Energy Projects.
<https://law.justia.com/codes/indiana/title-8/article-1/chapter-8-8/section-8-1-8-8-11/>
31. Indiana General Assembly. Indiana Code 8-1-37-4, Clean Energy Resource, particularly IC 8-1-37-4(a)(22).
<https://law.justia.com/codes/indiana/title-8/article-1/chapter-37/section-8-1-37-4/>