United States Government Accountability Office

Report to Congressional Requesters

April 2015

ELECTRICITY GENERATION PROJECTS

Additional Data Could Improve Understanding of the Effectiveness of Tax Expenditures

Accessible Version

GAO-15-302

GAO Highlights

Highlights of GAO-15-302, a report to congressional requesters

Why GAO Did This Study

The states and the federal government have supported the development of electricity generation projects in a variety of ways. In recent years, state and federal supports have been targeted toward renewable energy sources, such as solar and wind, although there have been some supports for projects using traditional sources—natural gas, coal, and nuclear.

GAO was asked to examine state and federal supports for the development of utility-scale electricity generation projects—power plants with generating capacities of at least 1 MW that are connected to the grid and intend to sell electricity—for fiscal years 2004 through 2013. This report (1) identifies key state supports for these projects; (2) examines key federal support provided through outlays, loan programs, and tax expenditures for these projects; and (3) examines how state and federal supports affect the development of new renewable projects. GAO analyzed relevant legislation, agency outlay and loan program data, and interviewed stakeholders, including project developers and experts. GAO also surveyed state regulatory commissions about state policies. In addition, GAO modeled the impact of reducing federal tax expenditures on project finances.

What GAO Recommends

Congress should consider directing IRS to (1) collect and report project-level data from all taxpayers who claim the ITC and (2) collect and report similar data for taxpayers who claim the PTC.

DOE, Treasury, and USDA did not provide formal comments in response to a draft of this report.

View GAO-15-302. For more information, contact Frank Rusco at (202) 512-3841 or RuscoF@gao.gov.

April 2015

ELECTRICITY GENERATION PROJECTS

Additional Data Could Improve Understanding of the Effectiveness of Tax Expenditures

What GAO Found

Key state supports, in the form of state policies, aided the development of utility-scale electricity generation projects—particularly renewable ones—in most states, for fiscal years 2004 through 2013. For example, most states have a renewable portfolio standard (RPS) mandating that retail service providers obtain a specific amount of the electricity they sell from renewable energy sources, which creates additional demand for renewable energy. In addition, most states supported new renewable and traditional projects through regulatory policies that set electricity prices, which allowed utilities to recover the costs of building new projects or purchasing electricity from them.

Federal financial supports aided the development of new projects, but limited data hinder an understanding of the effectiveness of tax expenditures. From fiscal year 2004 through 2013, programs at the Departments of Agriculture (USDA), Energy (DOE), and the Treasury (Treasury) provided supports including outlays, loan programs, and tax expenditures. For example, one Treasury program provided payments in lieu of tax credits and accounted for almost all of the $16.8 billion in outlays that supported 29,000 megawatts (MW) of new renewable generating capacity. Tax expenditures accounted for an estimated $13.7 billion in forgone revenue to the federal government for renewable projects and $1.4 billion for traditional projects. The two largest tax expenditures GAO examined—the Investment Tax Credit (ITC) and the Production Tax Credit (PTC)—supported renewable projects and accounted for $11.5 billion in forgone revenue. However, the total generating capacity they supported is unknown because the Internal Revenue Service (IRS) is not required to collect project-level data from all taxpayers claiming the ITC or report the data it does collect, nor is it required to collect project-level data for the PTC. IRS officials stated that IRS is unlikely to collect additional data on these tax credits unless it is directed to do so. Since 1994, GAO has encouraged greater scrutiny of tax expenditures, including data collection. Without project-level data on the ITC and PTC, Congress cannot evaluate their effectiveness as it considers whether to reauthorize or extend them.

Developers combined state and federal supports to finance renewable projects, and reducing these supports would likely reduce development of such projects. Demand created by state RPSs allowed developers of renewable projects to obtain power purchase agreements (PPA)—long-term contracts to sell power at specific prices. Federal supports, in turn, lowered developers' costs to build renewable projects, which allowed them to offer lower PPA prices than they otherwise could have. According to most stakeholders, these lower prices were then passed on to retail customers. Overall, if the level of support is reduced, fewer projects would likely be built. For example, GAO's modeling suggests that reducing the ITC or eliminating the PTC would likely reduce the number of renewable projects built because developers' returns would decline unless PPA prices increased to compensate for the reduction in federal support. The extent to which development would decrease depends on how states respond to reduced federal support and the associated increase in prices. For example, many states limit the amount retail prices could increase, limiting PPA price increases, which could reduce development.

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Abbreviations

accelerated depreciation for renewable energy property	Accelerated Depreciation Recovery Periods for Specific Energy Property: Renewable Energy
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables and Efficiency
IRR	internal rates of return
IRS	Internal Revenue Service
ITC	Energy Investment Credit, also known as the Investment Tax Credit
JCT	Joint Committee on Taxation
MW	megawatt
NREL	National Renewable Energy Laboratory
payments-in-lieu-of-tax-credits program	Payments for Specified Energy Property in Lieu of Tax Credits
PPA	power purchase agreement
PTC	Energy Production Credit, also known as the Production Tax Credit
Recovery Act	American Recovery and Reinvestment Act of 2009
RPG	renewable portfolio goal
RPS	renewable portfolio standard
SAM	System Advisor Model
Treasury	U.S. Department of the Treasury
USDA	U.S. Department of Agriculture

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April 28, 2015

The Honorable Lisa Murkowski
Chairman
Committee on Energy and Natural Resources
United States Senate

The Honorable Randy Weber
Chairman
Subcommittee on Energy
Committee on Science, Space and Technology
House of Representatives

The Honorable Cynthia Lummis
House of Representatives

The economic productivity and high standard of living of the United States depend, in part, on the availability of affordable electricity to power homes, businesses, and industries. Historically, the vast majority of electricity generation has come from power plants that use traditional fuel sources—including coal, natural gas, and nuclear.[1] More recently, renewable energy sources such as wind and solar have provided a small but growing percentage of electricity generation.[2] From 2004 through 2013, around 500 traditional and nearly 2,000 renewable utility-scale electricity generation projects—power plants with generating capacities of at least 1 megawatt (MW) that are connected to the grid and intend to sell electricity[3]—were built in the United States.[4,5] State governments and the

[1]Nuclear energy comes from uranium that is mined and processed into nuclear fuel that then undergoes nuclear fission in a nuclear reactor to produce heat, which is converted into electricity using steam turbine technology.

[2]According to the U.S. Energy Information Administration's methodology for reporting data on renewable energy sources, these sources include biomass, which is organic material from plants and animals and includes liquid biofuels (such as ethanol and biodiesel), wood, and waste (such as municipal solid waste and agricultural by-products); hydroelectric power; geothermal; wind; and solar.

[3]We developed the term "utility-scale electricity generation projects" and definition for the purposes of this report.

[4]GAO analysis of SNL Financial data of power plants with generating capacities of at least 1 megawatt.

federal government—through the U.S. Department of Agriculture (USDA), U.S. Department of Energy (DOE), and U.S. Department of the Treasury (Treasury)—have supported the development of utility-scale electricity generation projects in a variety of ways, including by providing financial assistance directly to developers and through other means such as tax credits. In recent years, a growing share of this support has been directed at renewable projects.

You asked us to examine state and federal supports for utility-scale electricity generation projects.[6] For fiscal year 2004 through 2013, this report (1) identifies key state supports for these projects; (2) examines key federal supports provided through outlays, loan programs, and tax expenditures for these projects; and (3) examines how state and federal supports affect the development of new renewable projects and how reducing federal supports may affect such development.

To identify key state supports, examine key federal supports, and examine how these supports affect the development of new renewable projects, we held semistructured interviews with nearly 50 stakeholders, including project developers and owners; attorneys and experts who specialize in project finance; industry trade associations; nongovernmental organizations; banks that provide or arrange project financing; investor-owned utilities, municipally-owned utilities, and electric cooperatives; and state energy agencies. We began our interviews with agency officials, representatives from industry trade associations, and project developers known to have received federal support to build projects. We then used the "snowball sampling" technique and selected stakeholders to interview who had experience or knowledge related to our objectives.[7] Because this was a nonprobability sample, information these stakeholders provided is not generalizable beyond the stakeholders we interviewed. For additional information on our methodology for conducting

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[5]Generating capacity is measured in megawatts and refers to the maximum capability of a unit to produce electricity.

[6]This request was originally made by the Ranking Member of the Senate Committee on Energy and Natural Resources, Senator Lisa Murkowski, who is now the chairman of that committee; Representative Cynthia Lummis; and former Representative Paul Broun, M.D.

[7]In snowball sampling, the unit of analysis is a person. This methodology begins with an initial list of cases, and asks each person interviewed to refer the interviewer to additional cognizant persons. The group of referred cases (or "snowball") grows larger and then narrows as a group of individuals are identified frequently.

interviews, see appendix I. See appendix II for a list of stakeholders we interviewed.

To identify state supports for the development of these projects, we interviewed officials from five state regulatory agencies and sent a web-based survey to all 50 states, the District of Columbia, and five U.S. territories.[8] Of these, 46 states and three U.S. territories responded to our survey for an 88 percent response rate.[9] For further information on how we conducted our survey, see appendix I. For a copy of our survey, see appendix III.

To examine key federal supports for these projects, we reviewed relevant legislation, agency data, and agency documents, and interviewed officials at DOE, Treasury, and USDA. We also collected and analyzed agency data on outlays and loan guarantees that supported these projects for fiscal years 2004 through 2013. In addition, we compiled estimates of forgone revenue from tax expenditures calculated by Treasury and the Joint Committee on Taxation to estimate the cost to the government of supporting these projects.[10] To assess the reliability of these data sets, we reviewed available documentation on the collection of and methods that were used in calculating the estimates. From this review, we found some limitations, but determined that the data were sufficiently reliable for the purposes of this report.

To examine how state and federal supports affect the development of projects, we conducted semistructured interviews with nearly 50 stakeholders, as noted above. We also modeled project finances for

[8]The five U.S. territories we surveyed were American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the U.S. Virgin Islands.

[9]Not all respondents answered every question in our survey and as a result, the denominator of the aggregated responses differs from question to question. For example, states without renewable portfolio standards or renewable portfolio goals did not answer questions related to these standards and goals. Where appropriate, we have indicated throughout the report both the numerator and denominator related to specific survey responses.

[10]Tax expenditures are provisions of federal tax laws that (1) allow a special exclusion, exemption, or deduction from gross income or (2) provide a special credit, preferential tax rate, or deferral of tax liability. Tax expenditures result in revenue losses for the federal government, which forgoes some of the tax revenues that it would have otherwise collected.

hypothetical solar photovoltaic[11] and wind projects using the DOE's National Renewable Energy Laboratory's (NREL) System Advisor Model.[12] For information on our analysis, see appendix VIII.

We conducted this performance audit from August 2013 to April 2015 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

This section describes (1) utility-scale electricity generation in the United States, (2) federal and state regulation of electricity markets, and (3) federal actions that have supported utility-scale electricity generation projects.

Utility-Scale Electricity Generation in the United States

Developers of utility-scale electricity generation projects build new projects to meet the growing electricity demands of U.S. retail customers.[13] Developers include: (1) utilities that build projects to serve their own retail customers and (2) nonutilities, which includes both developers that build and sell projects and independent power producers that build and own projects and then sell the electricity generated by the project. In the later case, the independent power producers sell electricity to utilities or other retail service providers—entities that compete with each other to provide electricity to retail customers by offering electricity plans with differing prices, terms, and incentives. Developers are either for-profit or nonprofit entities. For-profit developers include investor-

[11]Solar cells, also known as photovoltaic cells, convert sunlight directly into electricity. Photovoltaic technologies are used in a variety of applications. They can be found on residential and commercial rooftops to power homes and businesses; utility companies use them for large power stations, and they power space satellites, calculators, and watches.

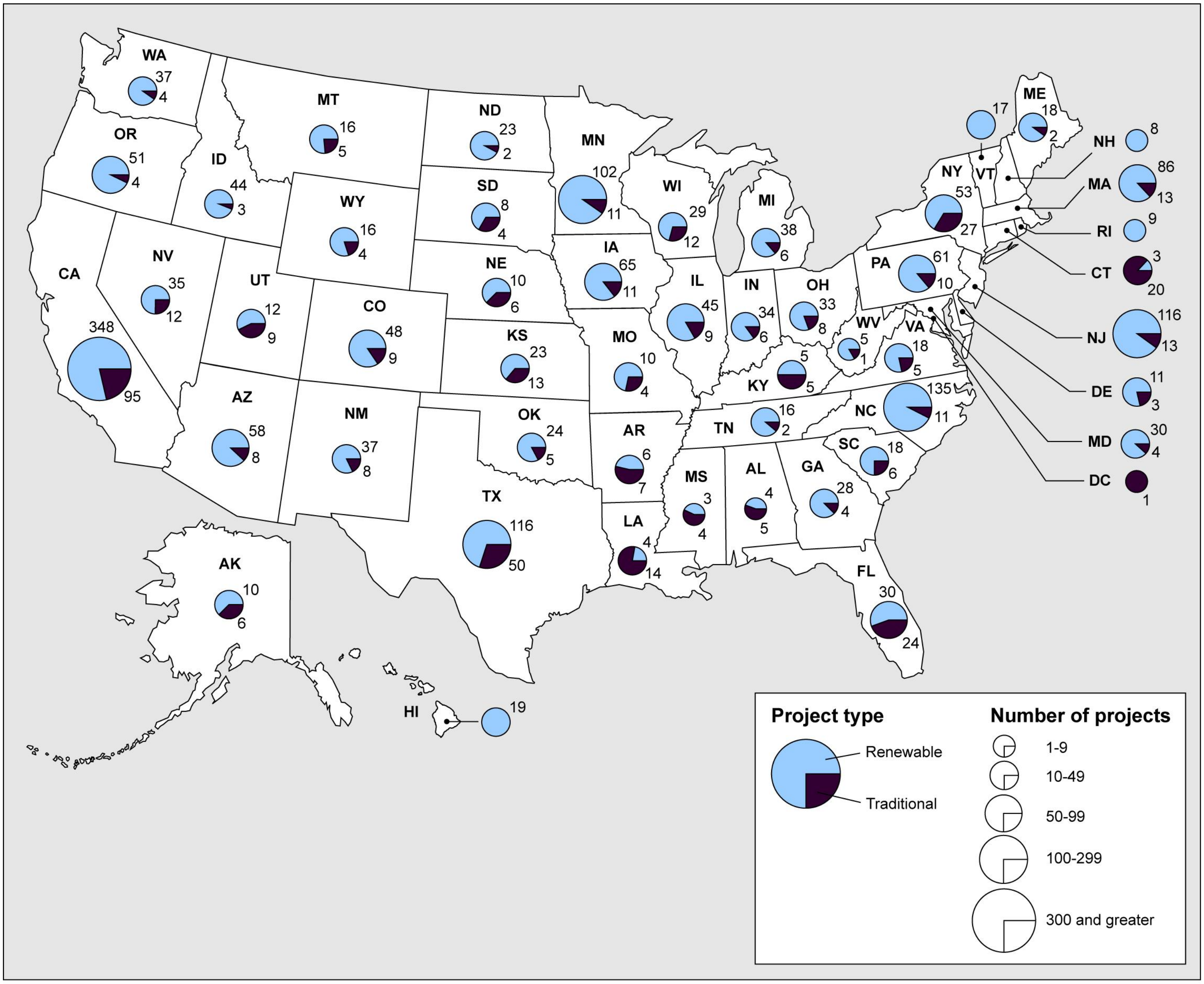
[12]NREL's System Advisor Model is a performance and financial model designed to facilitate decision making for people involved in the renewable energy industry. As of January 30, 2015, the model was publicly available at https://sam.nrel.gov/.

[13]Consumers of retail electricity are often referred to as ratepayers, retail consumers, or retail customers. For the purposes of this report, we refer to them as retail customers.

owned utilities—which serve 75 percent of the U.S. population—that are owned by private investors and provide the services of a utility, and independent power producers. Nonprofit developers include municipally-owned utilities and electric cooperatives.

Across the United States, the development of new renewable and traditional utility-scale electricity generation projects varied by state from 2004 through 2013 (see fig. 1).

Figure 1: Number and Type of New Utility-Scale Electricity Generation Projects, 2004-2013



Sources: GAO analysis of SNL Financial data; Map Resources (map). | GAO-15-302

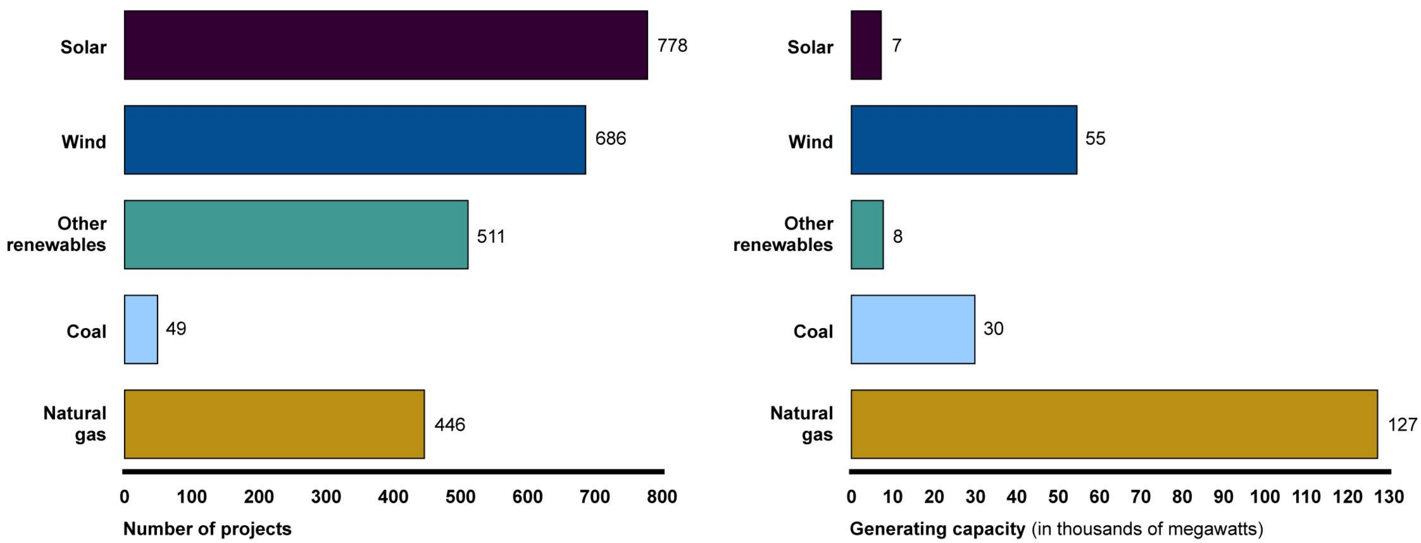
Notes:

Utility-scale electricity generation projects are power plants with generating capacities of at least 1 megawatt that are connected to the grid and intend to sell electricity to retail customers or retail service providers. Generating capacity is measured in megawatts and refers to the maximum capability of a unit to produce electricity.

Renewable projects include the following energy sources: biomass, geothermal, hydropower, solar, and wind. Traditional projects include coal and natural gas projects. No new nuclear generating capacity came online from 2004 through 2013.

From 2004 through 2013, around 2,000 new renewable and about 500 new traditional utility-scale electricity generation projects were built in the United States. However, according to our analysis of SNL Financial data, renewable projects were significantly smaller than traditional ones. For example, utility-scale solar projects averaged about 10 MW of generating capacity, whereas gas projects averaged 285 MW of generating capacity. Specifically, renewable projects added about 69,000 MW of new generating capacity, and traditional projects added about 157,000 MW of new generating capacity (see fig. 2).[14]

Figure 2: Number and Type of New Utility-Scale Electricity Generation Projects and Added Generating Capacity, 2004-2013



Source: GAO analysis of SNL Financial data. | GAO-15-302

Notes:

Utility-scale electricity generation projects are power plants with generating capacities of at least 1 megawatt that are connected to the grid and intend to sell electricity to retail customers or retail service providers. Generating capacity is measured in megawatts and refers to the maximum capability of a unit to produce electricity.

[14]GAO analysis of SNL Financial data. Calculations of generating capacity added from 2004 to 2013 do not reflect any reductions in capacity, for example, from plant closures during the same period.

Other renewable energy sources include the following: biomass, geothermal, and hydropower. No new nuclear generating capacity came online from 2004 through 2013.

Calculations of generating capacity added from 2004 through 2013 do not reflect any reductions in capacity, for example, from plant closures during the same period.

Federal and State Regulation of Electricity Markets

The electricity industry has historically been characterized by investor-owned utilities that were integrated and provided the four functions of electricity service—generation, transmission, distribution, and system operations—to all retail customers in a specified area. These integrated utilities were allowed to operate in monopoly service territories, but the rates they could charge retail customers were regulated by state regulatory commissions, often called public utility commissions. These commissions were charged with ensuring that, in the absence of competition, the services these integrated utilities provided were adequate, and the rates they charged were reasonable and compensated them for approved costs they incurred. In most states, this regulatory approach continues. These states are referred to as traditionally regulated.

During the last 2 decades, some states and the federal government have taken steps to restructure traditionally regulated electricity markets with the goal of increasing competition. Broadly speaking, these efforts by the states have resulted in areas where electricity generation and distribution services are no longer integrated. These are referred to as restructured states. Utilities in restructured states still generally provide transmission, distribution, and system operations to retail customers in their service areas, but they do not own all the generation facilities in those areas. In restructured states, retail customers may purchase electricity from any qualified retail service provider, and the price for electricity is determined largely by supply and demand. The responsibility for regulating electricity in these states is divided between states and the federal government. States continue to regulate the provision of electricity service by retail service providers, and the Federal Energy Regulatory Commission oversees electricity that is traded in wholesale markets prior to being sold to retail customers.

Federal Support of Utility-Scale Electricity Generation Projects

The federal government's support of the development of utility-scale electricity generation projects generally falls into the following three categories:

- *Providing funds*: The federal government provides funds through outlays such as grants or incentive payments that directly cover some of the developer's project costs. These outlays do not need to be repaid and, therefore, represent a direct cost to the government.[15]

- *Assuming risk*: The federal government assumes risk and potential costs associated with risk in a number of ways, including by making direct loans and by guaranteeing loans.[16] When making direct loans, the federal government disburses funds to nonfederal borrowers under contracts requiring the repayment of such funds either with or without interest. When making loan guarantees, the federal government provides a guarantee, insurance, or other pledge regarding the payment of all or a part of the principal or interest on any debt obligation of a nonfederal borrower to a lender. For both loans and loan guarantees, the cost to the government is estimated using the credit subsidy cost—the cost to the government, in net present value terms, over the entire period the loans are outstanding to cover interest subsidies, defaults, and delinquencies (not including administrative costs).[17]
- *Forgoing revenues*: The federal government may choose to forgo certain revenues through various measures in the tax code, broadly known as tax expenditures.[18] Tax expenditures are tax provisions—including tax deductions and credits—that are exceptions to the normal structure of income tax requirements necessary to collect federal revenue. Tax expenditures can have the same effects on the federal budget as spending programs—namely that the government has less money available to use for other purposes.[19]

As we have previously reported, some of these federal supports may be combined, resulting in support from multiple programs going to the same

[15]See appendixes V and VI for information on federal supports for utility-scale electricity generation projects, including outlays.

[16]See appendixes V and VI for information on federal supports for utility-scale electricity generation projects, including loan programs.

[17]Under the Federal Credit Reform Act of 1990, with certain limited exceptions, new direct loan and loan guarantee commitments may be made only to the extent that new budget authority to cover their costs, including credit subsidy costs, is provided in advance through appropriations.

[18]See appendixes V and VI for information on federal supports for utility-scale electricity generation projects, including tax expenditures.

[19]For more information, see GAO's Key Issues web page on tax expenditures, http://www.gao.gov/key_issues/tax_expenditures/issue_summary.

recipient for the development of a single project.[20] For example, in the last decade, project developers may have combined the support of more than one tax expenditure with grants or loan guarantees from DOE or USDA.

Key State Supports Aided the Development of Electricity Generation Projects

Key state supports, in the form of state policies, aided the development of utility-scale electricity generation projects—particularly renewable energy projects—for fiscal years 2004 through 2013. For example, most states have a renewable portfolio standard (RPS) that mandates that retail service providers obtain a certain percentage or amount of the electricity they sell from renewable energy sources, which helped create additional demand for renewable energy, according to many stakeholders we interviewed. In addition, most states remain traditionally regulated, and regulatory policies in these states provided important state-level support for renewable or traditional projects by allowing regulated utilities to recover costs incurred while purchasing power from existing electricity generation facilities or building new generating capacity themselves. Respondents to our survey of state regulatory commissions and some stakeholders cited other state supports for new renewable energy projects, such as state implementation of the Public Utility Regulatory Policies Act of 1978, and state tax incentives including property tax exemptions and tax credits.

RPSs Provided Important State-Level Support by Mandating the Purchase or Generation of Renewable Energy

According to many stakeholders we interviewed and most respondents to our survey of state regulatory commissions, state RPSs provided important state-level support for new renewable projects built by utilities and independent power producers from 2004 through 2013 (see app. II for a list of stakeholders we interviewed and app. III for a copy of our survey).[21] Of the regulatory commissions that answered our survey questions about the importance of state-level supports, 17 of 19 (89 percent) responded that RPSs were either very or extremely important for renewable projects built by utilities, and 21 of 24 (88 percent) responded that RPSs were either very or extremely important for renewable projects

[20]GAO, *Wind Energy: Additional Actions Could Help Ensure Effective Use of Federal Financial Support,* GAO-13-136, (Washington, D.C.: Mar 11, 2013).

[21]Survey respondents completed our survey from August through September of 2014. Therefore, the survey data we are reporting were accurate as of September 22, 2014, when the survey closed.

built by independent power producers.[22] According to many stakeholders we interviewed, RPSs provided important support because they mandated the purchase or generation of electricity from renewable energy sources, which helped create additional demand for renewable energy. As of September 2014, 30 states and the District of Columbia had established RPSs, and an additional 8 states had established a voluntary or nonbinding renewable portfolio goal (RPG).[23,24]

The characteristics of state RPSs and RPGs varied by state. For example,

- Timelines for meeting RPSs or RPGs and the amounts of electricity required to be obtained from renewable energy sources varied, according to survey respondents. For example, Michigan's RPS required retail service providers to generate 10 percent of the electricity they sold from renewable energy sources by 2015. In contrast, Hawaii's RPS required utilities to obtain 40 percent of the electricity they sell from renewable energy sources by 2030.
- Types of entities subject to RPSs and RPGs also varied. For example, 14 state regulatory commissions confirmed that their RPSs or RPGs applied specifically to investor-owned utilities. Another commission in a restructured state noted that the state's RPS did not apply to utilities; instead, it applied to the retail suppliers that provided electricity in utilities' service areas.
- Types of energy sources that could satisfy RPSs or RPGs also varied. For example, the California Energy Commission's guidebook on RPS

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[22]Even though independent power producers are not always subject to state RPSs, utilities may use power they purchase from independent power producers to meet state RPSs. In some states, utilities may also meet RPSs by purchasing renewable energy certificates, which represent the environmental and other nonpower attributes of renewable energy products. Although renewable energy certificates are created at the point of electricity generation, utilities may, in some cases, purchase renewable energy certificates without purchasing the electricity associated with the renewable energy certificates.

[23]This information is derived from our survey of state regulatory commissions and data from the publicly available Database of State Incentives for Renewable Energy (DSIRE), which is funded by DOE and others. When providing their survey responses, state regulatory commissions confirmed data from DSIRE. We did not examine DSIRE data or underlying state RPS or RPG legislation.

[24]According to survey respondents and data from DSIRE, U.S. territories also have RPSs and RPGs. For example, Puerto Rico, Northern Mariana Islands, and the U.S. Virgin Islands have RPSs, and American Samoa and Guam have RPGs.

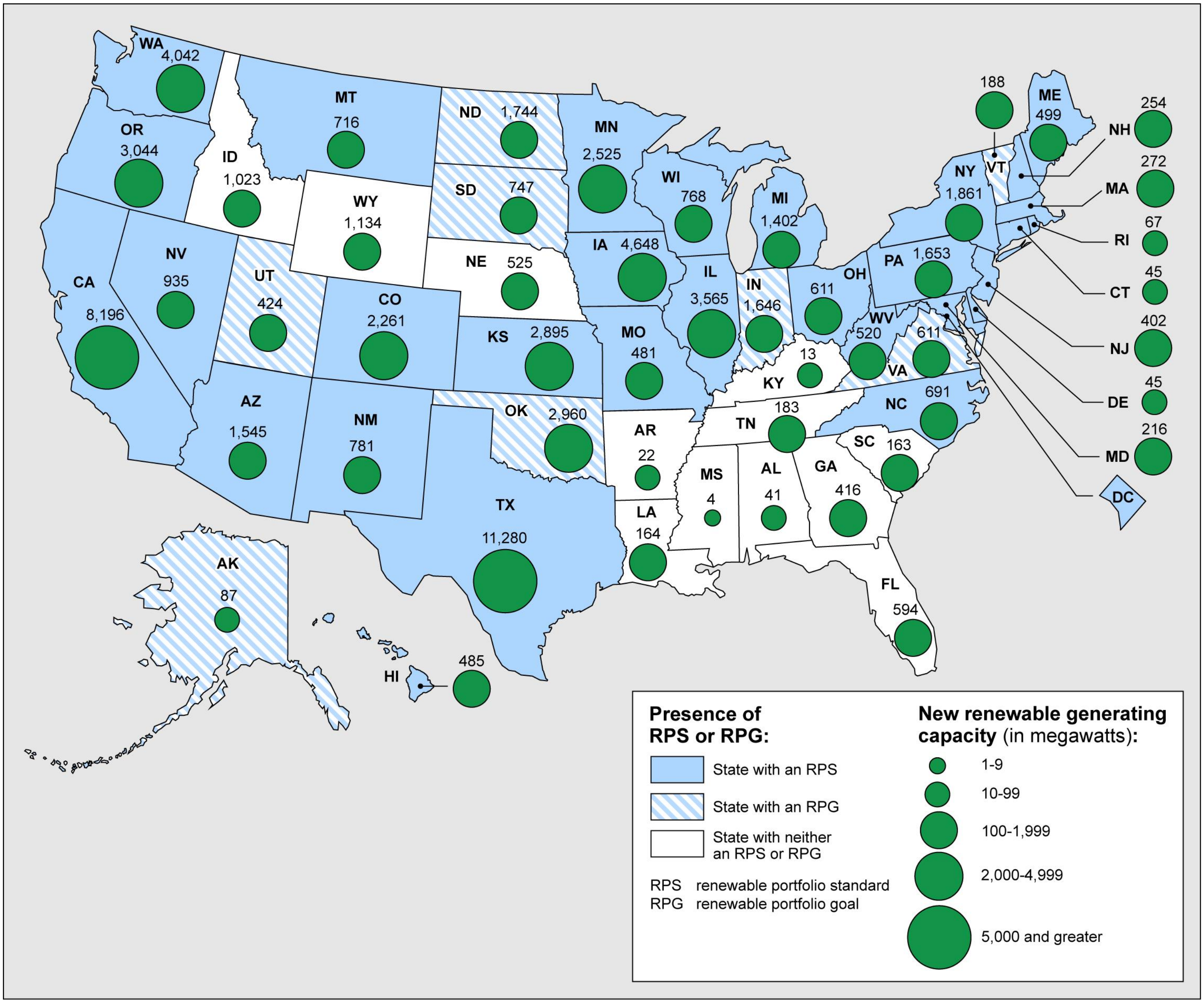
eligibility identifies a variety of renewable energy sources—such as solar photovoltaic, wind, and biomass—that can satisfy California's RPS. In contrast, under Pennsylvania law, the state's RPS allows "alternative energy sources" to satisfy the RPS and defines alternative to include waste coal and coal mine methane. Additionally, some state RPSs include provisions that require a certain percentage of the electricity generated or produced to be derived from specific types of renewable energy. For example, according to Lawrence Berkeley National Laboratory, 17 states plus the District of Columbia have special provisions encouraging solar or other energy sources.[25]

See appendix IV for additional information about individual state RPSs and RPGs.

In addition to creating additional demand for renewable energy, state RPSs and RPGs were an important factor in determining where projects were built. More specifically, our analysis of utility-scale electricity generation project data and responses to our survey found that 91 percent of new renewable projects from 2004 through 2013 were built in states with RPSs or RPGs, and that these projects accounted for 94 percent of new renewable generating capacity. Several stakeholders explained that state RPSs made it possible for developers to secure power purchase agreements (PPA)—contracts in which a utility agrees to purchase power, generally over a term of 20 to 25 years. In addition, most stakeholders said that PPAs were essential to moving a project forward because they provided the developer and potential investors an expectation of stable revenue for projects. See figure 3 for additional information about where new renewable generating capacity was added from 2004 through 2013.

[25] G. Barbose, *State RPS Policies and Solar Energy: Impacts, Experiences, Challenges, and Lessons Learned*, Lawrence Berkeley National Laboratory webinar (Nov 21, 2013).

Figure 3: Renewable Generating Capacity Added From 2004 Through 2013 in States with and without a Renewable Portfolio Standard (RPS) or Renewable Portfolio Goal (RPG)



Sources: GAO survey of state regulatory commissions, SNL Financial, and the Database of State Incentives for Renewables & Efficiency; Map Resources (map). | GAO-15-302

Notes:

RPSs typically require retail service providers to obtain a percentage or amount of electricity from renewable energy sources. RPGs establish voluntary or nonbinding goals.

Generating capacity is measured in megawatts and refers to the maximum capability of a unit to produce electricity.

Renewable generating capacity includes the following energy sources: biomass, geothermal, hydropower, solar, and wind.

Regulatory Policies in Most States Provided Important State-Level Support by Allowing Utilities to Recover Costs for New Renewable or Traditional Projects

Most states remain traditionally regulated, and regulatory policies in these states provided important state-level support by allowing regulated utilities to recover costs incurred while purchasing power from existing renewable or traditional electricity generation facilities or building new generating capacity themselves.[26] Specifically, 29 of 46 (63 percent) respondents to our survey reported that regulatory commissions regulated the electricity generation services provided by investor-owned utilities (see app. V for more detail about what states reported about their regulatory status). As previously discussed, in these states, state regulatory commissions set retail customers' electricity rates to compensate regulated utilities for the costs they incur serving these customers—including expenses incurred while purchasing power or building new electricity generation capacity.[27] Of the 19 traditionally regulated states that answered a survey question about the importance of commission-approved rates of return for building new traditional projects, 17 (90 percent) reported that they were either very or extremely important. In addition, of the 22 traditionally regulated states that answered a survey question about the importance of commission-approved rates of return for building new renewable projects, 19 (86 percent), reported that they were very or extremely important. In addition, according to at least 36 regulatory commissions we surveyed, utilities subject to this type of regulation did not build projects from fiscal year 2004 through 2013 without seeking approval to recover their costs and earn a return on their investments.[28] All 29 regulatory commissions in traditionally regulated states also reported that, when utilities purchased power for fiscal years 2004 through 2013, the utility was allowed to recover associated costs by passing these costs on to retail customers.

[26]Utilities may also be able to obtain recovery of their investment and a return on the utility-scale electricity generation projects they purchase.

[27]Commission-approved rates of return generally are not available in restructured states. In these states, developers of utility-scale electricity generation projects recover their costs and earn returns through sales made in competitive markets.

[28]The survey question that addressed this issue was subdivided into seven subparts—one for each fuel type (i.e., coal, natural gas, nuclear, hydropower, solar, wind, and biomass.) Not all regulatory commissions responded to all subparts of the question. Therefore, the denominators for each of the subparts varied.

Other State Supports Aided the Development of Renewable Projects

State regulators and some stakeholders cited other state supports for the development of new renewable projects for fiscal years 2004 through 2013.[29] For example, in some cases, state regulatory commissions allowed regulated utilities to offer their retail customers "green power"—the option to purchase renewably produced electricity to meet their electricity needs. According to DOE, in 2012, the most recent year for which data were available, more than 860 traditionally regulated utilities, which served more than half of all U.S. retail customers, offered such an option.

Another state policy that supported the development of new renewable projects was state implementation of the Public Utility Regulatory Policies Act of 1978.[30] Specifically, 17 of 21 of the regulatory commissions that answered one of our survey questions about how developers earned revenues reported that developers earned revenues through PPAs obtained as a result of state implementation of the Public Utility Regulatory Policies Act.

Finally, several stakeholders also told us that state tax incentives, such as property tax exemptions and tax credits, were helpful for developing new renewable projects. For example, some solar developers have used the New Mexico Renewable Energy Production Tax Credit, which allows companies that generate electricity from solar energy to receive a tax credit ranging from $0.015 to $0.04 per kilowatt-hour over a 10-year period. The program also provides a tax credit against corporate income taxes of $0.01 per kilowatt-hour for companies that generate electricity from wind or biomass.

[29]During this review, state regulators and stakeholders identified a variety of state-level supports for renewable projects. The examples cited in this report do not represent an exhaustive list of all possible state-level supports.

[30]Pub. L. No. 95–617, 92 Stat. 3117 (Nov. 9, 1978). Congress passed the Public Utility Regulatory Policies Act of 1978 to, among other goals, conserve energy and optimize the efficiency of power. To meet these goals, states establish an "avoided cost" threshold below which electric utilities would be required to buy power from certain facilities, including renewable energy facilities. The avoided cost represents the cost utilities would have incurred if they had obtained power through other means, such as building the facilities themselves or buying them. The Public Utility Regulatory Policies Act of 1978 was amended by the Energy Policy Act of 2005 to eliminate the mandatory purchase requirement if a qualifying facility has nondiscriminatory access to competitive markets.

Federal Financial Supports Aided the Development of New Electricity Generating Capacity, but Limited Data on Tax Expenditures Hinders an Understanding of their Effectiveness

For fiscal years 2004 through 2013, programs at DOE, Treasury, and USDA aided the development of new electricity generating capacity through outlays, loan programs, and tax expenditures. Most of this support was directed at renewable projects, with federal support for traditional projects largely directed toward reducing the cost of fuel rather than the development of new projects.[31] As shown in table 1, one program—Treasury's temporary Payments for Specified Energy Property in Lieu of Tax Credits (payments-in-lieu-of-tax-credits program)—accounted for most of the $16.8 billion in total outlays, which supported over 29,000 MW of new generating capacity. Federal loan programs accounted for an estimated $1.2 billion in credit subsidy costs that supported nearly 10,000 MW of new generating capacity. Federal tax expenditures—which reduce a taxpayer's tax liability by providing, for example, credits toward or deferrals of tax liability[32]—accounted for an estimated $15.1 billion in forgone revenue to the government,[33] but limited data hinder an understanding of their contributions to new generating capacity and ultimately, their effectiveness.

[31]For more information on all federal supports for energy production and consumption, see GAO, *Energy Policy: Information on Federal and Other Factors Influencing U.S. Energy Production and Consumption from 2000 through 2013*, GAO-14-836 (Washington, D.C.: Sept. 30, 2014).

[32]Tax expenditures result in revenue losses for the federal government, which forgoes some of the tax revenues that it would have otherwise collected. Tax expenditure estimates do not incorporate any behavioral responses and thus do not reflect the exact amount of revenue that would be gained if a specific tax expenditure were repealed. In addition, while sufficiently reliable as a gauge of general magnitude, summing individual tax expenditures' revenue loss estimates does not take into account interactions between individual provisions. Tax expenditure estimates are calculated by Treasury, which reports its estimates in the President's budget, and by Joint Committee on Taxation (JCT). For additional details on how these revenue losses were calculated, see appendix I.

[33]In this report, we use the term "forgone revenue" to mean revenue that would have accrued to the federal government had the tax expenditure or other incentive not been provided for in the law.

Table 1: Federal Financial Support for Utility-Scale Electricity Generation Projects (Dollars in millions)

Support type	Number of federal programs	Number of projects supported	Generating capacity added (in megawatts)	Financial support in fiscal years 2004-2013
Outlays - Department of the Treasury's Payments for Specified Energy Property in Lieu of Tax Credits	1	1,073	28,309	$16,570
Outlays - Other[a,b]	7	128	1,022	$241
Loan programs[a]	6	70	9,748	$1,216
Tax expenditures	7	Unknown	Unknown	$15,090[c]

Source: GAO analysis of Treasury, Joint Committee on Taxation, Office of Management and Budget's Public Budget Database and other agency data. | GAO-15-302

Notes: Utility-scale electricity generation projects are power plants with generating capacities of at least 1 megawatt that are connected to the grid and intend to sell electricity to retail customers or retail service providers. Generating capacity is measured in megawatts and refers to the maximum capability of a unit to produce electricity.

Projects may receive more than one type of federal financial support; therefore, the total number of projects supported and megawatts added by outlays, loan programs, and tax expenditures noted above exceeds the total projects supported or megawatts added using federal financial supports.

[a]For some of the U.S. Department of Agriculture's (USDA) loan programs and one of its outlay programs, we estimated generating capacity added from USDA data on projected generation. See appendix VI for additional information on how we developed these estimates.

bTwo Internal Revenue Service (IRS) programs included in this category could have supported activities other than the construction of utility-scale electricity generation projects, and IRS did not have data on how many utility-scale electricity generation projects were supported. Therefore, the number of projects supported and generating capacity added reported here do not include the projects supported by these IRS programs. See appendixes VI and VII for additional information on these programs.

cWhile sufficiently reliable as a gauge of general magnitude, summing individual tax expenditures' revenue loss estimates does not take into account interactions between individual provisions.

Treasury's Temporary Payments-in-Lieu-of-Tax-Credits Program Accounted for Most of the $16.8 Billion in Outlays That Supported Over 29,000 MW of Generating Capacity

In total, $16.8 billion in outlays supported over 29,000 MW of new generating capacity through eight federal programs, and Treasury's temporary payments-in-lieu-of-tax-credits program accounted for 99 percent of the total outlays. Treasury's program was enacted in the American Recovery and Reinvestment Act of 2009 (Recovery Act),[34] and provided cash payments of up to 30 percent of the total eligible costs of qualifying renewable energy facilities.[35,36] These cash payments were available in lieu of the Energy Investment Credit, also known as the Investment Tax Credit (ITC) or the Energy Production Credit, also known as the Production Tax Credit (PTC).[37,38] During the first 5 years of Treasury's program, developers of 1,073 utility-scale electricity generation projects developed 28,309 MW of generating capacity across the United

[34]American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5, § 1603, 123 Stat. 115, 364 (Feb. 19, 2009). Many stakeholders noted that federal supports—particularly Treasury's payments-in-lieu-of-tax-credits program—provided by the Recovery Act were important after the Recovery Act passed because the availability of private capital to finance projects was scarce during the recession.

[35]Cash payments were awarded to for-profit, taxpaying entities. Nonprofits such as municipally-owned utilities and electric cooperatives did not qualify because they are exempt from federal taxes and are not eligible for the tax credits that these payments were provided in lieu of.

[36]Qualifying energy facilities include: wind, solar, fuel cells, closed-loop and open-loop biomass, geothermal, qualified hydropower, landfill gas, trash, microturbines, marine and hydrokinetic, combined heat and power, and geothermal heat pumps.

[37]The ITC, PTC, and Treasury's payments in lieu of tax credits cannot be combined for a specific project; however, a taxpayer can benefit from all three simultaneously for different projects.

[38]Initially, Treasury's payments-in-lieu-of-tax-credits program provided cash payments for renewable energy projects placed in service in 2009 or 2010. The program was extended for 1 year as part of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Pub. L. No. 111–312, §707, 124 Stat. 3296, 3312 (Dec. 17, 2010)). For energy projects placed in service after 2011, applications must have been submitted to the Treasury before October 1, 2012.

States, according to the data submitted by developers in their applications for payments in lieu of tax credits.[39,40]

In addition to Treasury's program, seven other federal programs at DOE, Treasury, and USDA, supported 128 projects for fiscal years 2004 through 2013 through grants, incentive payments, or other mechanisms, for a total of $241 million in additional federal outlays. For example, USDA's Rural Energy for America Program provides outlays in the form of grants to farmers, ranchers, and small businesses in rural areas to assist with purchasing and installing renewable energy systems.[41] These grants supported 50 projects that added 139 MW of electric generating capacity for total outlays of nearly $16 million.

DOE's outlay program that supported the greatest number of projects was its now-discontinued Renewable Energy Production Incentive program, which provided production-based cash payments to nonprofit owners of qualified renewable energy projects for 10 years after the project was placed in service. According to DOE officials, this program was designed to provide incentives for entities that do not pay income taxes—such as electric cooperatives and municipally-owned utilities—similar to those provided to for-profit developers through the PTC. Unlike the PTC, this

[39]Not all projects that received support through Treasury's payments-in-lieu-of-tax-credits program were for utility-scale electricity generation projects therefore, these data reflect only a subset of projects that received Treasury payments in lieu of tax credits.

[40]The deadline for submitting applications for Treasury's payments-in-lieu-of-tax-credits program was October 1, 2012 but, according to agency officials, because the payment is not awarded until the project is placed in service, which can take a year or longer, not all approved payments have been paid. Therefore, while the program is now expired for new applicants, according to agency officials, payment determinations are still being made and the program is still active. For those projects not yet placed in service as of October 1, 2012, applicants must update their initial application to a converted application after the project has been placed in service in order to be eligible for a payment in lieu of tax credits. Payment determinations are not made until after the project is placed in service, and the applicant submits a converted application. According to a Treasury official, as of the close of fiscal year 2013, an additional 1,275 utility-scale projects have submitted preliminary applications for an additional $7.5 billion in payments. The official noted, however, that Treasury does not expect that all of the projects for which a preliminary application was received will ultimately be placed in service.

[41]USDA's Rural Energy for America Program also offers loan guarantees.

program was subject to annual appropriations by Congress.[42,43] The Renewable Energy Production Incentive program provided $26 million in incentive payments to 59 projects with 704 MW of generating capacity but, according to agency officials, was discontinued in 2010. Projects that received support through federal outlays may have also received support through loan programs or tax expenditures. See appendixes VI and VII for program descriptions and outlays for all federal programs.

Federal Loan Programs Provided Support at an Estimated Cost of $1.2 Billion for Nearly 10,000 MW of New Generating Capacity

Six federal loan programs—providing both direct loans and loan guarantees—at DOE and USDA accounted for an estimated $1.2 billion in credit subsidy costs that supported 70 projects for a total of 9,748 MW of new generating capacity. DOE administered two of the six loan programs that were authorized to support the development of projects for fiscal years 2004 through 2013, but only one DOE loan program actually awarded loan guarantees for utility-scale electricity generation projects during this timeframe. Specifically,

- DOE's loan guarantee program for innovative technologies was authorized to support the development of these projects, but did not award loan guarantees to any utility-scale electricity generation projects during these years.[44]
- DOE's now-expired Recovery Act loan guarantee program—which supported both innovative and commercial technologies—authorized loans for 21 utility-scale electricity generation projects with 3,976 MW of generating capacity and is estimated to have provided over $1.2 billion in federal support through payments of credit subsidy costs as

[42]While the PTC itself was not subject to annual appropriations or limits on taxpayer claims, the PTC has been subject to periodic expirations and congressional consideration to extend it. In contrast, many tax expenditures are not subject to congressional reauthorization.

[43]According to DOE officials, electricity producers initially received 1.5 cents per kilowatt-hour, but over time, capacity grew while annual federal funding remained stagnant. According to agency officials, the Renewable Energy Production Incentive program was formally discontinued in 2010. Near the end of the program, due to funding constraints, there was no guarantee that electricity producers would get any reimbursement for production, even if they qualified to receive it.

[44]Section 1703 of Title XVII of Energy Policy Act of 2005, Pub. L. No. 109-58 119 Stat. 1036 (Aug. 8, 2005), authorizes DOE to support innovative clean energy technologies that avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases.

of the close of fiscal year 2013.[45,46] (For an explanation of how the credit subsidy costs for DOE's loan guarantees were calculated, see app. I.) Under the Recovery Act loan guarantee program, the credit subsidy cost was paid with appropriated funds, whereas under the loan guarantee program for innovative technologies, borrowers generally had to pay for their own credit subsidy costs.[47]

USDA administered four programs that provided either loans or loan guarantees for both traditional and renewable projects for fiscal years 2004 through 2013, and earned revenues for the government. In aggregate, USDA's loan programs resulted in a negative credit subsidy cost—that is, they yielded revenue rather than incurring a cost to the government—of $14 million. According to a USDA official, this is because USDA's Direct and Guaranteed Electric Loans program had a low rate of default and earned revenues from borrowers' annual fees and interest. This program, which provided both loans and loan guarantees to establish and improve electric service in rural areas, supported 32 projects that added 5,714 MW in new generating capacity.[48,49] The other three loan programs at USDA supported 17 projects and added 58 MW of additional generating capacity. Projects that received support through federal loan programs might also have received support through outlays,

[45]Section 1705 of Title XVII of the Energy Policy Act of 2005 was added by the American Recovery and Reinvestment Recovery Act, Pub. L. No. 111-5, 123 Stat. 115 (Feb. 17, 2009). In addition to supporting certain renewable energy systems, DOE's Section 1705 program also provided loan guarantees for electric power transmission systems and leading edge biofuels. To be eligible, these projects were required to be located in the United States and to commence construction no later than September 30, 2011, among other qualifications.

[46]According to DOE officials, one other loan guarantee for a utility-scale electricity generation project closed, but was not subsequently funded. Therefore, that loan guarantee is not included in the 21 projects listed here.

[47]Under the 2011 Continuing Resolution to fund the federal government, after fiscal year 2010 appropriations had expired but before the 2012 budget was authorized, a small amount of appropriated credit subsidy was provided for loan guarantees for renewable energy and energy efficiency projects under Section 1703.

[48]This program supported 31 loan guarantees and 1 direct loan for utility-scale electricity generation projects. In addition to supporting new generation facilities, the program also provides loans for distribution and transmission facilities.

[49]According to agency officials, USDA's Rural Electric Program offers several types of direct loans and also has authority to guarantee private loans. These activities are described in this report as USDA's Direct and Guaranteed Electric Loans program.

including Treasury’s payments in lieu of tax credits, or tax expenditures. See appendixes VI and VII for program descriptions and credit subsidy costs for all federal loan programs.

Federal Tax Expenditures Accounted for an Estimated $15.1 Billion in Forgone Revenue, but IRS Does Not Collect Key Data on the Two Largest Tax Expenditures

Seven tax expenditures administered by the Internal Revenue Service (IRS) at Treasury accounted for an estimated $15.1 billion in forgone revenue for fiscal years 2004 through 2013,[50] but IRS does not collect or report key data on the two largest tax expenditures supporting new utility-scale electricity generation projects.[51,52] Tax expenditures supported the development of both renewable and traditional projects, and the majority

[50]Estimates from Treasury and the JCT were not available for all years from 2004 to 2013 for all tax expenditures supporting these projects. See appendix VI for tax expenditure estimates.

[51]In order to realize the full benefit of tax expenditures, a taxpayer must have sufficient taxable income to use the credits or depreciation deductions over the period of years they are provided. In some cases, the taxpayer may not realize their full benefits because, for example, they may be required to pay the Alternative Minimum Tax due to the use of the credits and deductions. Similarly, for the energy tax credits that are claimed as part of a general business tax credit, the total credit can reduce current-year tax liability but is not refundable and, therefore, requires sufficient taxable income to be used; however, unused general business credits may be carried back 1 year and forward 20 years. Benefits provided through tax expenditures may be shared, for example among business partners, as long as the entities meet conditions established by the IRS such as how long the entity claiming the credit retains an ownership interest in the facility.

[52]For-profit developers are generally subject to federal income taxation and, therefore, may use federal tax expenditures to reduce their federal income tax liability. By contrast, nonprofit developers such as electric cooperatives and municipally-owned utilities are exempt from federal taxes and, therefore, cannot benefit from most tax expenditures. According to IRS officials, nonprofit developers can, however, use tax-advantaged bonds, which provide a tax benefit to the bondholder and reduce the net interest expense to the developer of financing a project.

of the forgone revenue (91 percent) supported renewable projects.[53] Of the seven tax expenditures, the following four accounted for nearly 97 percent of the forgone revenue ($14.6 billion):[54]

- *PTC*. The PTC accounted for an estimated $8.1 billion in forgone revenue and, as of the end of 2013, provided an income tax credit of 2.3 cents per kilowatt-hour for energy produced from wind and certain other renewable energy sources. Since it was first made available in 1992, the PTC has expired and been extended by Congress six times—in 1999, 2001, 2003, 2012, 2013, and 2014. Most recently, the PTC was extended for certain qualified facilities for projects that began construction before January 1, 2015.[55] Because the credit is taken over a 10-year period once a project is placed in service, the PTC will continue to result in forgone revenue for years to come.
- *ITC*. The ITC accounted for an estimated $3.4 billion in forgone revenue, and it provided an income tax credit up to 30 percent for the development of certain renewable projects.[56] Developers of certain qualifying facilities could choose to take the ITC in lieu of the PTC if the project met certain criteria;[57] however, developers could not claim

[53]Of the $15.1 billion in forgone revenue through tax expenditures, an estimated $13.7 billion supported renewable projects, and an additional $1.4 billion supported traditional projects. For more information on all federal supports for energy production and consumption, including supports for both renewable and traditional projects, see GAO-14-836.

[54]Of the three remaining tax expenditures, two supported the development of renewable projects, and one supported the development of traditional projects. Specifically, the Credit for Holding Clean Renewable Energy Bonds and the Credit for Holding Qualified Energy Conservation Bonds supported the development of renewable projects and were estimated to have accounted for a total of $480 million in forgone revenue. The Advanced Nuclear Power Production Credit permits developers to claim a credit for electricity that is produced at an advanced nuclear power facility. This credit has not been claimed to date because no new nuclear power facilities have been placed in service since the credit became available. See appendixes VI and VII for program descriptions and details on estimates of forgone revenue for all federal tax expenditures.

[55]The Tax Increase Prevention Act of 2014, Pub. L. No. 113-295, title I, § 155 (Dec. 19, 2014). The December 31, 2014 begun construction deadline extension applied only to the following qualified facilities: wind, biomass, geothermal, landfill gas, trash, hydropower, and marine/hydrokinetic.

[56]The investment tax credit also provides a tax credit for geothermal systems, fuel cells, microturbines, and combined heat and power.

[57]For facilities that began construction before December 31, 2014, taxpayers could elect to claim the ITC for property that otherwise would have qualified for the PTC.

both tax credits for the same project. The ITC was first established in 1978 at 10 percent of eligible investment costs and was temporarily increased in 2005 to 30 percent for solar and certain other technologies.[58] Subsequent legislation extended the ITC at 30 percent for these technologies through December 31, 2016.[59] After December 31, 2016, the ITC is scheduled to return to 10 percent of eligible investment costs for solar projects.

- *Accelerated Depreciation for Renewable Energy Property*. Accelerated Depreciation Recovery Periods for Specific Energy Property: Renewable Energy (accelerated depreciation for renewable energy property) accounted for an estimated $1.7 billion in forgone revenue. This provision is similar to accelerated depreciation provisions available for a wide range of investments in other sectors.[60] Accelerated depreciation for renewable energy property allows developers of certain renewable energy properties to deduct larger amounts from their taxable income sooner than they would normally be able to do under the straight-line depreciation method.[61,62]

[58]The Energy Tax Act of 1978, Pub. L. No. 95-618, §301, 92 Stat. 3174, 3195 (Nov. 9, 1978), and the Energy Policy Act of 2005, Pub. L. No. 109-58, tit. XIII, §1337, 119 Stat. 1036, 1038 (Aug. 8, 2005).

[59]The Tax Relief and Health Care Act of 2006, Pub. L. No. 109-432, div. A, tit. II, §207, 120 Stat. 2922, 2945 (Dec. 20, 2006), and the Emergency Economic Stabilization Act of 2008, Pub. L. No. 110-343, div. B, tit. I, §103, 122 Stat. 3765, 3811 (Oct. 3, 2008), respectively.

[60]Accelerated Depreciation for Renewable Energy Property is a component of the Modified Accelerated Cost Recovery System, which allows taxpayers to recover the capitalized cost of most business and investment property over a specified life by annual deductions on the taxpayer's return. Capitalized costs are costs that are expended or treated as an item of a capital nature. A capitalized amount is not deductible as a current expense and must be included in the basis of property. The Modified Accelerated Cost Recovery System is not specific to utility-scale electricity generating projects, rather, it covers a broad range of properties including agricultural equipment, office machinery, taxis, and certain livestock. It establishes various time frames ranging from 3 to 50 years over which the property may be depreciated.

[61]The Modified Accelerated Cost Recovery System provides for a variety of methods and periods for depreciating long-lasting assets for tax purposes. For example, straight-line depreciation refers to an accounting treatment in which the rate of depreciation in an asset's value is assumed to be constant over a specified period of time.

Specifically it allows them to recover investments by deducting the cost of the investment from their taxable income over a 5-year period. Unlike the ITC and PTC, which have expiration dates and have been subject to congressional review as part of efforts to expand, extend, or reauthorize them, accelerated depreciation for energy property—like other accelerated depreciation provisions—does not have a specific expiration date and, as such, is not subject to periodic review by Congress.

- *Credit for Investment in Clean Coal Facilities*. This credit for traditional fuel sources is estimated to have accounted for $1.4 billion in forgone revenue to support the development of clean coal projects. The credit provides up to 30 percent of qualified investments in clean coal facilities greater than 400 MW in size.[63] Unlike the ITC, PTC, and accelerated depreciation for renewable energy property—for which all eligible taxpayers may claim the tax expenditure—the Credit for Investment in Clean Coal Facilities is subject to a specified amount authorized by Congress. As such, developers must submit an application that includes a description of the project, the project's financing structure, and the proposed technology to apply for the credit. According to IRS officials, DOE's NREL reviewed the applications to determine whether the projects met the required technical criteria, and then made recommendations to IRS about whether the projects should receive an allocation of the tax credit. According to IRS officials, 12 awards have been made for projects included in our scope, and 4 of those projects had been placed in service as of September 2014. Additionally, according to the officials, further allocations of the credit are available. IRS announced a 2015 reallocation round on March 9, 2015 and the agency plans to send acceptance letters by April 30, 2015.

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[62]Reducing tax liability earlier provides a benefit to the taxpayer because of the time value of money—having a lower tax payment today is worth more to the taxpayer than having the lower payment in the future. In addition to the existing 5-year accelerated depreciation allowed for these properties, 2008 legislation and subsequent laws temporarily granted a 50 percent first-year depreciation, commonly referred to as bonus depreciation, which is currently limited to properties placed in service before January 1, 2015. This allowed businesses to deduct 50 percent of the depreciable basis of a broad set of tangible properties, including renewable energy facilities, from their taxable income in the first year after they were acquired. Several stakeholders noted that the first-year bonus depreciation was an important federal support for these projects; however, some noted that developers had to have large enough taxable burdens to use bonus depreciation.

[63]Pub. L. No. 109-58, tit. XIII, §1307, 119 Stat. 594, 999 (Aug. 8, 2005). Section 48B, also authorized in §1307 of the Energy Policy Act of 2005, was added to provide tax credits to qualifying gasification projects; however, these types of projects do not fall within the scope of this report.

Projects that received support through federal tax expenditures may also have received support through outlay or loan programs. See appendixes VI and VII for program descriptions and details on estimates of forgone revenue for all federal tax expenditures that supported the development of utility-scale electricity generation projects.

While some project-level data are collected for the projects supported through outlays, loan programs, and the Credit for Investment in Clean Coal Facilities,[64] basic information such as projects supported or MW of generating capacity added is not collected or available about the ITC and PTC. The ITC and PTC—which accounted for an estimated $11.5 billion in forgone revenue from 2004 to 2013—are the two largest tax expenditures supporting these projects and in the past 5 years, the estimated forgone revenues from them have more than tripled from $870 million to $2.8 billion. Key information is not available because the IRS does not collect certain project-level data, such as the total generating capacity added. Specifically,

- For the ITC, the IRS requires all developers to report the total amount of the credit they are claiming for all eligible projects aggregated as a single line item; therefore, the IRS does not know the total number of projects for which an individual developer is claiming the credit.[65] Developers who were eligible for the PTC but instead elected to claim the ITC must also submit supporting documentation that includes project-level data, such as the generating capacity and technology of each specific facility for which they are claiming the credit;[66] however, the IRS does not require such project-level information from developers eligible only for the ITC. Consistent with the Internal Revenue Code, in general, the IRS is not allowed to make individual taxpayer information available for analysis, but IRS can and does

[64]According to agency officials, some project-level data are collected on the applications for the Credit for Investment in Clean Coal Facilities; however, these data are not available for analysis.

[65]Taxpayers report the ITC they claim on IRS Form 3468.

[66]The requirement to submit supporting documentation applies only to taxpayers who claim the ITC in lieu of the PTC under section 48(a)(5). The requirement does not apply to other qualifying property in section 48.

make available certain aggregated data. However, IRS does not make available the project-level data it collects for the ITC.[67]

- For the PTC, as with the ITC, the IRS requires all developers to report the total amount of the credit they are claiming for all eligible projects aggregated by technology as a single line item; therefore, the IRS does not know the total number of projects for which an individual developer is claiming the PTC.[68] Unlike the ITC, the IRS requires developers to report the technology type (e.g. wind, geothermal, solar) for which they are claiming the PTC. IRS does not require developers to submit any project-level data, such as generating capacity, when they claim the PTC.

The IRS is not required to collect or evaluate data other than those which are required for administration of the tax code unless it is legislatively mandated to collect additional information. IRS officials stated that, given a number of factors, IRS is unlikely to collect additional information on these tax expenditures without being directed to do so by Congress. IRS has not evaluated the costs of collecting these data. As we have previously found, collecting additional data to identify users and specific properties would require changes in IRS forms and information processing procedures.[69] To some extent, the increasing number of taxpayers filing electronically could make it easier for IRS to collect additional data without expensive transcription costs. In considering additional data requirements, it is important that Congress weigh the need for more information with IRS's other priorities because such requirements likely would increase, to some degree, the administrative costs for IRS and the compliance burden on taxpayers. If policymakers conclude that additional data would facilitate examining a particular tax expenditure, additional considerations on what data are needed, who should provide the data, who should collect the data, how to collect the

[67]Section 6103 of the Internal Revenue Code requires confidentiality of returns and return information and limits the types of information IRS can share with these external parties. One way IRS makes tax expenditure data available to external parties, such as the public and other government agencies, is through its Statistics of Income Division, which reports some taxpayer data in the aggregate, so as to protect the confidentiality of individual taxpayers.

[68]Taxpayers report the PTC they claim on IRS Form 8835.

[69]GAO, *Community Development: Limited Information on the Use and Effectiveness of Tax Expenditures Could Be Mitigated through Congressional Attention,* GAO-12-262 (Washington, D.C.: Feb. 29, 2012).

data, what it would cost to collect the data, and whether the benefits of collecting additional data warrant the cost of doing so would be important.

Nonetheless, since 1994, we have encouraged greater scrutiny of tax expenditures to help policymakers make more informed decisions about using such mechanisms as a means of supporting policies. For example, since 1994, we have found that substantial revenues are forgone through tax expenditures, yet policymakers have had few opportunities to make explicit comparisons or evaluate trade-offs between tax expenditures and federal spending programs.[70] Based on these and other findings, we recommended that Congress explore opportunities to exercise more scrutiny over indirect spending through tax expenditures, and Congress took action by subjecting certain tax expenditures to closer examination. In addition, in 2005, we found that tax expenditures may not always be efficient, effective, or equitable and, consequently, we concluded that information on tax expenditures could help policymakers make more informed decisions as they adapt current policies in light of fiscal challenges and other overarching trends.[71,72] We also concluded that reviews of tax expenditures could help establish whether these programs are relevant to today's needs and, if so, how well tax expenditures have worked to achieve specific objectives and whether the benefits from particular tax expenditures are greater than their costs.

We have also previously concluded that limited data about specific tax expenditures can hinder analysis of their effectiveness. For example, in 2008, we determined that the data the IRS collected were insufficient for examining efforts to use a tax expenditure to encourage economic

[70]GAO, *Tax Policy: Tax Expenditures Deserve More Scrutiny*, GAO/GGD/AIMD-94-122 (Washington, D.C.: June 3, 1994).

[71]GAO, *Government Performance and Accountability: Tax Expenditures Represent a Substantial Federal Commitment and Need to Be Reexamined*, GAO-05-690 (Washington, D.C.: Sept. 23, 2005).

[72]In this report, we made four recommendations to the Treasury and the Office of Management and Budget. To address our recommendation to develop clear and consistent guidance to Executive Branch agencies on how to incorporate tax expenditures in strategic plans, annual performance plans, and performance and accountability reports, the Office of Management and Budget updated Circular A-11 in July 2013 to direct agencies to identify tax expenditures that contribute to each of their strategic objectives. This guidance, if properly implemented, should position the Office of Management and Budget and the agencies to more broadly identify how tax expenditures contribute to each agency's overall performance.

development on Indian reservations.[73] As a result, we suggested that Congress consider requiring IRS to collect additional information about the tax expenditure. Similarly, in examining a broad range of tax expenditures in 2013, we concluded that it was becoming more pressing to determine whether tax expenditures were achieving specific objectives.[74]

Additionally, the Government Performance and Results Act Modernization Act of 2010 established a framework for providing a more crosscutting and integrated approach to focusing on results and improving government performance.[75] This act makes clear that tax expenditures are to be included in identifying the range of federal agencies and activities that contribute to crosscutting goals, and guidance from the Office of Management and Budget directs agencies to do so for their agency priority goals. Such information can be used to inform congressional decisions about authorizing or reauthorizing provisions in the tax code.

In requesting this report, Congress asked us to evaluate federal supports for the development of utility-scale electricity generation projects, for example, by providing information about how many projects were built, the technologies supported, and the amount of generating capacity added. The absence of project-level data for the ITC and PTC—such as is available for projects that took Treasury's payments in lieu of these tax credits—precluded us from examining and providing this information. Without it, Congress and others do not have basic information about what has been supported, including how many projects used these tax expenditures or how much generating capacity was added. According to the Congressional Research Service, the ITC and PTC were designed to encourage the commercialization of renewable energy technologies.[76,77]

[73]GAO, *Tax Expenditures: Available Data Are Insufficient to Determine the Use and Impact of Indian Reservation Depreciation,* GAO-08-731 (Washington, D.C.: June 26, 2008).

[74]GAO, *Tax Expenditures: IRS Data Available for Evaluations Are Limited*, GAO-13-479 (Washington, D.C. Apr 30, 2013).

[75]Pub. L. No. 111-352, 124 Stat. 3866 (Jan. 4, 2011).

[76]Congressional Research Service, Committee Print on Tax Expenditures (Washington, D.C.: Dec. 21, 2012).

[77]The ITC and PTC are codified at 26 U.S.C. § 48 and 26 U.S.C. § 45, respectively.

Basic information is required for any evaluation of these tax credits, such as determining whether or not they were effective at encouraging development of new renewable projects.

Developers Combined State and Federal Supports to Finance Renewable Projects, and Reducing State or Federal Supports Would Likely Reduce Development of These Projects

Developers combined state and federal supports to secure financing for renewable projects, and these supports reduced the price paid for renewable electricity by retail customers. Reducing state or federal supports would likely reduce the development of renewable projects unless PPA prices increased to compensate for the reduction in federal support.

Developers Combined State and Federal Supports to Finance Projects, and Federal Supports Reduced the Price of Renewable Electricity

Debt and Equity

Project financing through private markets generally takes two forms—debt and equity. Similar to a home mortgage, debt is incurred when a developer borrows funds with prescribed repayment terms—such as an interest rate and a specified number of payments. The lender has no ownership in the property but may be able to take over the property if the borrower does not make payments as agreed. In addition, in the event of a bankruptcy or other loan default, the lender typically has the first right to any assets. Equity is invested funds that give the investor an ownership interest in the operations and assets of a business and a right to a portion of any income remaining after payment of operating costs and payments on debt. The investor is not entitled to repayment if the project fails. Because investors consider debt to be less risky than equity, it is typically the cheaper form of private financing. However, lenders typically will not lend the total costs of a project and they often place limits on the amount of money they will lend by limiting the amount of the payment on the loan to a specified percentage of the expected income of the project.

Sources: GAO and project finance literature. | GAO-15-302

Developers combined state and federal supports to finance renewable projects. As previously noted, state supports in the form of RPSs and RPGs mandated that retail service providers obtain a certain percentage or amount of the electricity they sell from renewable sources. These supports created additional demand for electricity from renewable sources. Retail service providers comply with this requirement by either generating their own electricity from renewable sources or by purchasing this electricity from a third party, such as an independent power producer. To purchase renewable electricity, retail service providers often issue solicitations seeking bids for PPAs—long-term contracts in which the retail service provider agrees to purchase power and which provides the developer with an expectation of stable revenue. In response to these solicitations, developers bid for these PPAs. Once bids are selected and developers are awarded PPAs, developers generally then attempt to secure debt and equity to finance their projects through private markets. In seeking project financing, developers combine the value of the revenues guaranteed in their PPAs and the value of the federal supports to secure favorable financing terms.

Tax Equity Partnerships

In several cases, developers of renewable projects had to enter into complex financial partnerships—tax equity partnerships—to use certain tax expenditures. For example, the use of tax expenditures like the Investment Tax Credit and Production Tax Credit required developers' tax liability to equal or exceed the value of the tax expenditure. Developers with substantial corporate profits generally had enough tax liability to be able to directly use these tax expenditures. However, developers with lower tax liability had to enter into arrangements known as tax equity partnerships with third parties—usually large financial institutions, such as investment banks—that had sufficient tax liability in order to use tax expenditures. Under these partnerships, the third party typically provided equity for the project in exchange for the right to use nearly all of the tax benefits and receive a share of the project revenues. According to stakeholders, the partnerships typically incurred legal, administrative, and other transaction costs that reduced the value of tax expenditures to the developers' projects by 10 to 30 percent. Nonetheless, some stakeholders reported that tax equity partnerships were critical for projects to move forward.

Sources: GAO and project finance literature. | GAO-15-302

Federal supports reduced the price of renewable electricity for retail customers by reducing the cost to the developers to build projects in two key ways. First, some federal loan programs reduced the cost of capital—i.e., the funds necessary to build the projects. For example, some stakeholders said USDA loan programs offered lower interest rates than were available through the capital markets, which lowered the overall cost of borrowing. Second, federal tax expenditures and payments allowed developers to recover some of their costs. For example, the ITC allowed developers to recover up to 30 percent of eligible project costs for solar and other qualifying renewable energy facilities by reducing the amount of taxes they owed. However, many stakeholders noted that, in some cases, developers needed to enter into complex financial partnerships—tax equity partnerships—to utilize federal tax expenditures, which reduced the value of the federal support to the developer. According to several stakeholders, the amount that developers can bid for a PPA depends on how much federal support the project expects to receive; therefore, these supports allowed developers to offer lower prices in their PPAs than they otherwise could have. These lower prices were then passed on to retail customers. In this way, these supports can be thought of as reducing the price of electricity that retail customers pay.

Reducing State or Federal Supports Would Likely Reduce the Development of Renewable Projects

Reducing state or federal supports would likely reduce the development of renewable projects. To understand the effects of changes to federal tax expenditures, we modeled hypothetical utility-scale solar photovoltaic and wind projects and found that reducing or eliminating the ITC or PTC would likely reduce the number of renewable projects built because either developers' returns would decline or PPA prices would increase.[78] For our analysis, we held investor rates of return—which stakeholders typically refer to as the internal rate of return—constant. We modeled the two projects with variations in the levels of the ITC—at 10 and 30 percent—and PTC—with no PTC and with the PTC at $0.023 per kilowatt-hour.[79]

Our modeling suggests that reducing or eliminating federal financial supports could result in substantially reduced returns for developers, which could reduce the number of new renewable utility-scale electricity generation projects built.[80] For example, in the case of the solar project, we found that with a reduced ITC and constant PPA prices, the

[78]We used NREL's System Advisor Model and modeled each project under three different project finance structures—one in which the project has a single owner and two others that relied on tax equity partnerships in order to use available tax expenditures. These two other structures are referred to as "partnership flip" structures because nearly all of the revenues are initially provided to the tax equity partner until they receive a specified rate of return and, thereafter, switch (or flip) to the owner or developer. In the all equity partnership flip, the project is funded with equity contributions from the two partners—the developer and the tax equity investor—without debt. In the leveraged partnership flip, the project is funded with debt and a large equity investment by a tax equity investor, while the developer typically makes only a small equity investment. When modeling the hypothetical projects, we made decisions on project size, location, project costs, and internal rates of return based on information available in energy and project finance literature and on information provided in our interviews with stakeholders, including project developers and finance experts. For additional details on our analysis, see appendix VIII.

[79]We modeled two projects—one utility-scale solar photovoltaic project and one utility-scale wind project. Utility-scale photovoltaic solar projects are eligible to take the ITC. We modeled the ITC at its current value of 30 percent of investment costs, as well as at 10 percent of investment costs—the amount it is scheduled to reduce to in 2017 for these types of projects. Utility-scale wind projects that were under construction by the end of 2014 are eligible for the ITC but are more likely to take the PTC. Therefore, we modeled a wind project with the PTC starting at $0.023 per kilowatt hour—the level at which the credit was available for eligible projects at the end of 2013. We also modeled the same wind project without the PTC, as the PTC expired at the end of 2014. See appendix VIII for more information on the modeling.

[80]To conduct these analyses, we held the tax equity investors' rates of return constant for the solar photovoltaic and wind projects. These target rates of return were developed based on discussions with stakeholders. We did not analyze the effect of other potential changes on prices or returns, for example, we did not model the possibility that the cost of purchasing equipment such as solar panels or wind turbines could change. For our analysis, we specified a baseline rate of return of 10 percent for the developer in two of the project finance structures. For the third, we used the target rate of return of 10 percent as the discount rate, and used SAM to calculate specified developer returns in net present value. The rate of return values and other model parameters were developed based on discussions with stakeholders regarding typical target rates of return, development fees, and other factors. See appendix VIII for additional information on our analysis.

developer's returns could decrease by as much as 76 percent (see table 2). Likewise, for the wind project, we found that without the PTC, the developer's returns could decrease by 68 to 109 percent—in other words, in the extreme case, the developer would lose money by developing the project. Our modeling results are consistent with the effects of past expirations of the PTC. As we have previously found, in the years following the PTC's expiration, new additions of wind capacity fell dramatically.[81]

Table 2: Changes in Developer Returns as a Result of Reduced or Eliminated Federal Support

Project type	Decrease in developer returns
Solar photovoltaic (100 megawatts)	39-76%
Wind (150 megawatts)	68-109%

Source: GAO analysis of the National Renewable Energy Laboratory's System Advisor Model results. | GAO-15-302

Notes:

We modeled two hypothetical projects—one utility-scale solar photovoltaic project and one utility-scale wind project. The solar photovoltaic project was modeled with a 10 percent and 30 percent Investment Tax Credit, and the wind project was modeled both with and without a 2.3 cent/kilowatt-hour Production Tax Credit. Both projects were modeled with accelerated depreciation for renewable energy property.

We modeled these projects using three project finance structures—one in which the project has a single owner and two others that relied on financial partnerships in order to use available tax expenditures. We held investor rates of return constant, and modeled the two projects with variations in the levels of the Investment Tax Credit and Production Tax Credit. For our analysis, we specified a baseline rate of return of 10 percent for the developer in two of the project finance structures. For the third, we used the target rate of return of 10 percent as the discount rate, and used SAM to calculate specified developer returns in net present value. The rate of return values and other model parameters were developed based on discussions with stakeholders regarding typical target rates of return, development fees, and other factors. See appendix VIII for additional information on our analysis.

For the results shown here, we held electricity prices in power purchase agreements constant to understand the relationship between changes in federal tax expenditures on developers' rates of return. A power purchase agreement is a contract in which a retail service provider agrees to purchase power from a developer's project, generally over a term of 20 to 25 years.

Alternatively, we found that if we held the developer's returns constant, a reduction or elimination of federal supports could mean that, for future projects to remain viable, electricity prices in PPAs would have to

[81] GAO-13-136.

increase.[82] Specifically, for the solar project with the lower ITC, we found that the electricity prices in PPAs would need to increase by 20 to 27 percent if developers were to maintain their returns. For wind projects without the PTC, we found that electricity prices would need to increase by 32 to 62 percent if developers were to maintain their returns (see table 3).[83,84]

Table 3: Percent Increase in Power Purchase Agreement Prices as a Result of Reduced or Eliminated Federal Support

Project type	Percent of price increase
Solar photovoltaic (100 megawatts)	20-27%
Wind (150 megawatts)	32-62%

Source: GAO analysis of the National Renewable Energy Laboratory's System Advisor Model results. | GAO-15-302

Notes:

A power purchase agreement is a contract in which a retail service provider agrees to purchase power from a developer's project, generally over a term of 20 to 25 years.

We modeled two hypothetical projects—one utility-scale solar photovoltaic project and one utility-scale wind project. The solar photovoltaic project was modeled with a 10 percent and 30 percent Investment Tax Credit, and the wind project was modeled both with and without a 2.3 cent/kilowatt-hour Production Tax Credit. Both projects were modeled with accelerated depreciation for renewable energy property.

[82]For our analysis, we held the developer's rate of return at 10 percent for two of the three project finance structures. For the third, in which the developer primarily uses debt to finance their portion of the project and makes only a small equity contribution, we used the target rate of return of 10 percent as the discount rate, and used SAM to calculate specified developer returns in net present value. See appendix VIII for additional information on our analysis.

[83]Our results were generally consistent across the three project finance structures we modeled. It is important to note that our results are a function of the analysis that we performed, namely staying within each project finance structure we examined and either holding the power purchase agreement price constant and allowing the developer return to vary, or holding the developer rate of return constant and allowing the power purchase agreement price to vary. For more information on our methodology and the results of our modeling, see appendix VIII.

[84]Many variables could affect electricity prices in power purchase agreements and investor and developer returns, beyond those we examined. For example, in our analysis we only examined the impacts of changes in available federal supports on specific project finance structures currently being used in the industry, such as tax equity partnership flips. It is possible that changes in federal support could result in changes in the types of project finance structures, and that the market could shift away from the use of tax equity partnerships. In our modeling, we do not characterize the changes in the power purchase agreements or developer returns as predictions of what will happen to electricity prices for retail customers or to potential investments in and returns from utility-scale renewable energy projects.

We modeled these projects using three project finance structures—one in which the project has a single owner and two others that relied on financial partnerships in order to use available tax expenditures. We held investor rates of return constant, and modeled the two projects with variations in the levels of the Investment Tax Credit and Production Tax Credit. The range in the percent of price increase in the PPA represents the range in results depending on the project finance structure modeled.

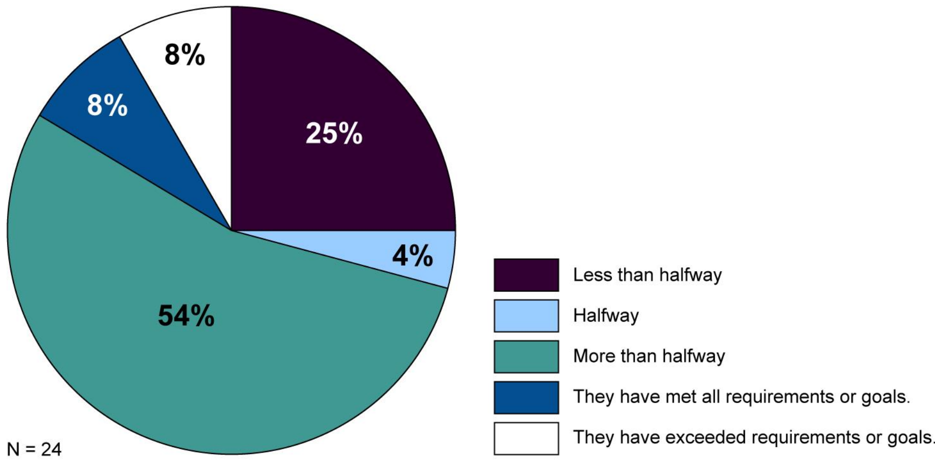
For the results shown here, we held the developer's returns constant within each project finance structure to understand the relationship between changes in federal tax expenditures on electricity prices in power purchase agreements.

Placed in a broader context, because PPA prices are determined through negotiations between developers and retail service providers, the willingness of these providers and state regulators to agree to higher prices will likely constrain the ability of developers to maintain their returns. If expected returns from renewable energy projects are reduced past a certain point, developers may seek alternative investments, either in the energy sector or elsewhere. Collectively, the constraints faced by developers with reduced or eliminated federal supports would likely lead to a reduction in the level of investment in new renewable utility-scale electricity generation projects.

The extent to which development of renewable projects would decrease depends on, among other factors, how states respond to the effects of reduced federal supports. Specifically, reducing federal supports would reduce developers' returns unless PPA prices increased to compensate for the reduction in federal support.[85] The amount PPA prices could increase may be constrained by how close states are to completing their RPSs. Four of the 24 state regulatory commissions that responded to our survey question about progress made by investor-owned utilities toward completing their RPSs reported that they have either met or exceeded their RPSs (see fig. 4). In these states, if PPA prices were to increase beyond the prices available for other sources of electricity, renewable development would likely decline because investor-owned utilities would not be required to purchase the more expensive renewable electricity. However, assuming that RPSs remain the same in the 20 states that reported not having met their RPSs, investor-owned utilities will need to obtain additional renewable capacity even if the price to do so increases.

[85]Developers might also be willing to accept lower returns for their projects to compensate for some or all of the reduction in federal support.

Figure 4: Progress Made by Investor-Owned Utilities toward Completing Their State's Renewable Portfolio Standard (RPS)



Source: GAO survey of state regulatory commissions. | GAO-15-302

Notes:

Percentages in figure do not add to 100 due to rounding.

RPSs typically require retail service providers to obtain a percentage or amount of electricity from renewable energy sources.

Twenty-seven regulatory commissions reported that their state had an RPS. Of those, 24 answered our question about the progress made by investor-owned utilities toward completing their state's RPS.

The amount PPA prices could increase may also be constrained by state cost-containment mechanisms. Cost-containment mechanisms are sometimes included in state RPS legislation to limit costs associated with RPS compliance. For example, some RPSs allow state regulatory commissions to freeze or delay RPS requirements if purchasing additional renewable energy forces retail prices to exceed a threshold deemed excessive. Of the 27 states that reported having an RPS in our survey, 18 reported having cost-containment mechanisms in place, and 8 reported having no such mechanism.[86] Looking forward, however, some states may revise or implement cost-containment mechanisms if prices of renewable electricity increase. Some stakeholders noted that, in the

[86]In addition to the 27 states that reported having an RPS in our survey, 3 additional states plus the District of Columbia have RPSs; however, these 3 states and the District of Columbia did not respond to our survey. One state that reported having an RPS in our survey of state regulatory commissions did not answer our question about cost-containment mechanisms.

absence of federal supports, developers would continue to build renewable projects to meet existing RPSs even if doing so increased electricity prices for retail customers, unless states had existing cost-containment mechanisms or implemented new ones.

Conclusions

The federal government has demonstrated a commitment to supporting the development of utility-scale electricity generation projects through a variety of federal programs. While agencies collect data on projects supported through outlays, loan programs, and some tax expenditures, including the Credit for Investment in Clean Coal Facilities, the IRS does not collect such data for the ITC or PTC—the two largest tax expenditures supporting new utility-scale electricity generation projects. The ITC and PTC have increased sharply in recent years—resulting in billions of dollars in forgone revenue to the government—and will continue to represent significant forgone revenue for years to come. Since 1994, our body of work on tax expenditures has encouraged greater scrutiny of tax expenditures to help policymakers make more informed decisions. Specifically, we have concluded that more data on tax expenditures would allow policymakers to compare and evaluate trade-offs between tax expenditures and outlays and loan programs. Data currently available on outlays and loan programs allow policymakers to understand how many projects and megawatts of new generating capacity were added with federal support, thus allowing for an understanding of how effective the programs were at encouraging the development of renewable projects. However, because basic information on the ITC and PTC are not available, it will be difficult for Congress to evaluate the effectiveness of these tax credits or compare them with outlay or loan programs as it considers reauthorizing or extending them.

Matters for Congressional Consideration

If Congress wishes to evaluate the effectiveness of the ITC and the PTC as incentives for the development of renewable utility-scale electricity generation projects as it considers proposals to extend the ITC or reauthorize the PTC, it should consider directing the Commissioner of Internal Revenue to take the following two actions:

- Provide Congress with project-level data currently collected from taxpayers who claim the ITC in lieu of the PTC—such as the number of projects for which they are claiming the credit, the technology of the projects taking the credit, and the total generating capacity added—and make such data available for analysis. Additionally, take steps to collect and report the same data from all taxpayers claiming the ITC.

- Take steps to collect project-level data from taxpayers claiming the PTC—such as the number of projects for which they are claiming the credit, the technology of the projects taking the credit, and the total generating capacity—and make these data available for analysis.

Agency Comments and Our Evaluation

We provided a draft of this report to DOE, Treasury, and USDA for review and comment. None of the agencies provided formal comments. Treasury provided technical comments, which we integrated as appropriate.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of the report to the appropriate congressional committees, the Secretaries of Agriculture, Energy, and the Treasury, the Commissioner of Internal Revenue, and other interested parties. In addition, this report will be available at no charge on the GAO website at http://www.gao.gov.

If you or your staff have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff members who made significant contributions to this report are listed in appendix IX.

Frank Rusco
Director, Natural Resources and Environment

Appendix I: Objectives, Scope, and Methodology

This report examines supports for utility-scale electricity generation projects for fiscal years 2004 through 2013.[1] Our objectives were to: (1) identify key state supports for these projects; (2) examine key federal financial supports provided through outlays, loan programs, and tax expenditures for these projects; and (3) examine how state and federal supports affect the development of new renewable projects and how reducing federal supports may affect such development.

To identify key state supports, examine federal supports, and examine how these supports affect the development of new renewable projects, we interviewed officials at the U.S. Department of Energy (DOE), U.S. Department of the Treasury (Treasury) and U.S. Department of Agriculture (USDA); representatives from industry trade associations; and project developers known to have received federal support to build projects. We then used the “snowball sampling” technique and selected stakeholders to interview who had experience or knowledge related to our objectives.[2] We conducted semistructured interviews with nearly 50 stakeholders including project developers and owners; attorneys and experts who specialize in project finance; industry trade associations; nongovernmental organizations; banks that provide and arrange equity and debt financing; investor-owned utilities, municipally-owned utilities, and electric cooperatives; state energy agencies; and an independent system operator. Because this was a nonprobability sample, the information these stakeholders provided cannot be generalized to other stakeholders but provided valuable insights. See appendix II for a list of stakeholders we interviewed. To identify the number of utility-scale electricity generating projects constructed and the generating capacity added from 2004 through 2013, we analyzed data from the SNL Financial database. To assess the reliability of these data, we interviewed a knowledgeable individual at SNL Financial and reviewed existing information about the system. From this review, we determined that the data were sufficiently reliable for the purposes of this report.

[1]For the purposes of this report, we defined utility-scale electricity generation projects as power plants with capacities of at least 1 megawatt (MW) that are connected to the grid and intend to sell electricity. We chose 1 MW as our threshold because this is the smallest size project for which the U.S. Energy Information Agency collects data.

[2]In snowball sampling, the unit of analysis is a person. This methodology begins with an initial list of cases, and asks each person interviewed to refer the interviewer to additional cognizant persons. The group of referred cases (or “snowball”) grows larger and then narrows as a group of individuals are identified frequently.

To further examine state and federal supports that aided the development of these projects, we sent a Web-based survey to officials at state regulatory agencies in all 50 states, the District of Columbia, and five U.S. territories.[3] Of those we contacted, 46 states and three U.S. territories responded, for a response rate of 88 percent.[4] We asked survey respondents about: (1) regulatory commission responsibilities; (2) the role of the regulatory process in supporting construction of new utility-scale electricity generation projects; (3) the importance of federal and state supports relative to broader market conditions; (4) federal supports for new utility-scale electricity generation projects; (5) state supports for new utility-scale electricity generation projects; and (6) renewable portfolio standards and goals.

We solicited comments on an initial draft of our survey from knowledgeable officials at five state regulatory agencies and at the National Association of Regulatory Utility Commissioners—the national association representing state public service commissioners. We conducted pretests with them to ensure that (1) the questions were clear and unambiguous, (2) terminology was used correctly, (3) the questionnaire did not place an undue burden on survey respondents, (4) the information could feasibly be obtained, and (5) the survey was comprehensive and unbiased. We chose to pretest with five states that had renewable portfolio standards, as well as some that were traditionally regulated and some with restructured electricity markets. We conducted two pretests in person and four over the telephone. We revised the content and format of the survey as appropriate after each pretest based on the feedback we received.

We developed and administered the Web-based survey through a secure server. When we completed the final survey questions and format, we sent an e-mail on July 31, 2014, announcing the survey to the regulatory commissions in all 50 states, the District of Columbia, and five U.S.

[3]The five U.S. territories included: American Samoa, Guam, Northern Mariana Islands, Puerto Rico, and the U.S. Virgin Islands.

[4]The denominator of the aggregated responses differs from question to question. For example, states without renewable portfolio standards or renewable portfolio goals did not answer questions related to these state supports, and as a result, those blocks of questions have denominators less than 46. Additionally, in some cases, respondents choose not to answer all questions. Where appropriate, throughout the report, we have indicated both the numerator and denominator related to specific survey responses.

territories.[5] On August 6, 2014, we notified them via e-mail that the survey was available online and provided unique passwords and usernames. We sent follow-up e-mail messages on August 14, 2014, and again on August 20, 2014, to those who had not yet responded. We then contacted all remaining nonrespondents by telephone. We sent a final e-mail that was copied to the regulatory commission's chairperson on September 8, 2014 stating that we were extending the deadline for submission to September 12, 2014. The questionnaire was available online until September 22, 2014. We sent follow-up e-mails to officials at 14 state regulatory officials to clarify data about states' renewable portfolio standards and regulatory responsibilities. We made some changes to the renewable portfolio standards data collected as a result of these conversations. As noted, surveys were completed by 46 states and three U.S. territories, for a response rate of 88 percent.[6,7] Because this was not a sample survey, it has no sampling errors. However, the practical difficulties of conducting any survey may introduce errors, commonly referred to as nonsampling errors. For example, difficulties in interpreting a particular question, sources of information available to respondents, or entering data into the survey or analyzing them can introduce unwanted variability into the survey results. We took steps in developing the survey, collecting the data, and analyzing them to minimize such nonsampling error—including using a social science survey specialist to help design and pretest the survey in collaboration with GAO staff who had subject matter expertise. When we analyzed the data, an independent analyst checked all computer programs. Since this was a Web-based survey, respondents entered their answers directly into the electronic questionnaire,

[5]America Samoa was notified about the survey on September 17, 2014, and completed its survey before the final deadline.

[6]The states that responded to our survey include: Alabama, Alaska, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin and Wyoming. The territories that responded to our survey include: American Samoa, Northern Mariana Islands and Puerto Rico.

[7]For the four states, and the District of Columbia, that did not complete the survey, we used data in the Database of State Incentives for Renewables and Efficiency, which is funded by DOE and others, to determine whether they had renewable portfolio standards or goals.

eliminating the need to key data into a database, thereby minimizing error. For a copy of our survey, see appendix III.

To examine key federal supports for these projects, we reviewed relevant legislation, previous GAO reports, and agency documents, and we interviewed agency officials. Using our previous reports, we compiled a list of federal supports for these projects, and during our interviews with stakeholders we asked which of the supports were key to the development of projects. The federal programs described in this report reflect those supports that stakeholders considered key for the development of new utility-scale electricity generation projects. We also collected and analyzed agency data on outlays, loan programs, and tax expenditures that supported these projects from fiscal year 2004 through 2013 as follows:[8]

- *Outlays*: We collected and analyzed data on outlays, projects and generating capacity added from USDA, DOE, and Treasury. To assess the reliability of these data, we interviewed individuals with knowledge of them. From this review, we determined that the data were sufficiently reliable for the purposes of this report.

- *Loan programs:* We also collected and reviewed data from DOE and USDA on loan programs, projects, and generating capacity added. We used two methodologies to calculate the cost to the government of loan programs supporting these projects:
    - For DOE's two loan guarantee programs, we collected net lifetime credit subsidy reestimates, including interest, for all the loan guarantees within our scope—those that supported projects of 1 megawatt (MW) or greater that were connected to the grid with the intent to sell electricity—as of the close of fiscal year 2013. Because only a subset of the loans in DOE's portfolio is within our scope, our estimates will not match the estimates found in the fiscal year 2014 *Federal Credit Supplement* to the *Budget of the U.S. Government*. We added that net lifetime credit subsidy

[8]Tax expenditures are reductions in federal tax liabilities that result from provisions of the federal tax laws that (1) allow a special exclusion, exemption, or deduction from gross income or (2) provide a special credit, preferential tax rate, or deferral of tax liability. Tax expenditures result in revenue losses for the federal government, which forgoes some of the tax revenues that it would have otherwise collected, while the taxpayers that take advantage of the tax expenditures pay lower taxes than they would otherwise have to pay. See also GAO-05-690.

reestimate to the original credit subsidy estimate to calculate the estimated cost to the government of the loan guarantee as of the close of fiscal year 2013. We then summed those estimates to calculate the total cost of DOE's loan guarantee programs. To assess the reliability of these data, we interviewed agency officials, verified our calculations with agency officials, and made changes as appropriate. From this review, we determined the data were sufficiently reliable for the purposes of this report and agency officials concurred with our results.

- For USDA's loan programs, we used USDA's net lifetime credit subsidy factor reestimates, including interest, for each loan cohort (all loans guaranteed within a fiscal year) from the fiscal year 2014 *Federal Credit Supplement* to the *Budget of the U.S. Government*, and applied the reestimated credit subsidy factor to each individual loan. Only a subset of the loans in USDA's portfolio is within our scope, therefore, our estimates will not match the estimates found in the fiscal year 2014 *Federal Credit Supplement* to the *Budget of the U.S. Government*. Because USDA does not calculate estimates on a loan-by-loan basis but does so on a cohort basis, applying a cohort's subsidy factor to only those loans included in our scope represents an estimate of the expected cost to the government. To assess the reliability of these data, we interviewed agency officials, verified our calculations with agency officials, and made changes as appropriate. From this review, we determined the data were sufficiently reliable for the purposes of our report and agency officials concurred with our results.

- *Tax expenditures*: We compiled estimates of forgone revenue to the government from energy-related tax expenditures calculated by Treasury and the congressional Joint Committee on Taxation (JCT) to estimate the cost to the government of supporting these projects. Both Treasury and JCT estimate the revenue loss associated with each tax provision they have identified as a tax expenditure. Treasury's list is included in the President's annual budget submission; JCT issues annual tax expenditure estimates as a stand-alone product. Both organizations calculate a tax expenditure as the difference between tax liability under current law and what the tax liability would be if the provision were eliminated and the item were treated as it would be under a "normal" income tax. Revenue loss estimates do not incorporate any behavioral responses and thus do not reflect the exact amount of revenue that would be gained if a specific tax expenditure were repealed. In general, the tax expenditure lists that Treasury and JCT publish are similar, although these lists differ somewhat in the number of tax expenditures reported and the estimated revenue losses for particular expenditures. Specifically, we used the most recent tax expenditure estimates for fiscal years 2004 to 2013 developed by Treasury and reported by Office of Management and Budget in the *Budget of the U.S. Government* for fiscal years 2006 to 2015. Similarly, we used the most recent tax expenditures estimates developed by JCT and reported in their *Estimates of Federal Tax Expenditures* reports for fiscal years 2004 to 2012. For fiscal year 2013 data, we used estimates from the 2012 JCT report, which reflect the provisions in federal tax law enacted through January 2, 2013. Although we present the tax expenditure estimates in aggregate, and the sums are reliable as a gauge of general magnitude, they do not take into account interactions between individual provisions. To assess the reliability of these data sets, we reviewed available documentation on the collection of and methods that were used in calculating the estimates. From this review, we found some limitations but determined that they were sufficiently reliable for the purposes of this report.

We did not analyze federal supports related to electricity end use or consumption, such as those designed to promote energy efficiency and conservation or to provide low-income energy assistance. In addition, because our scope was limited to supports for the construction of new utility-scale electricity generation projects, we did not collect data on possible electricity-related research and development funding by federal agencies, nor did we examine other financial structures, such as master limited partnerships, real estate investment trusts, or yield cos, which could have been used for the development of these projects.

To examine how state and federal support affect the development of projects, we conducted semistructured interviews with nearly 50 stakeholders, as noted above. We also modeled typical project finance structures—as identified by stakeholders—for hypothetical solar photovoltaic and wind projects using the DOE's National Renewable Energy Laboratory's (NREL) System Advisor Model.[9] For information on our analysis, see appendix VIII.

We conducted this performance audit from August 2013 to April 2015 in accordance with generally accepted government auditing standards.

[9]As of January 30, 2015, NREL's System Advisor Model was publicly available at https://sam.nrel.gov/.

Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Appendix II: Stakeholders Interviewed by GAO

Type of stakeholder	Organization
For-profit developers: Utilities and independent power producers[a]	Caithness Energy
	Evergreen Clean Energy, LLC
	Exelon Generation Co.
	Finley BioEnergy LLC
	First Solar, Inc.
	First Wind
	Iberdrola Renewables
	MidAmerican Renewables, LLC
	NextEra Energy Resources, LLC
	NRG Energy
	Pacific Gas and Electric Company
	PacifiCorp
	Southern California Edison
	Southern Company
Nonprofit developers: Electric cooperatives and municipally-owned utilities	American Municipal Power, Inc.
	Associated Electric Cooperative Inc.
	Brazos Electric Cooperative, Inc.
	Oglethorpe Power Corporation
	Vineland Municipal Electric Utility
Industry trade associations	America's Natural Gas Alliance
	American Public Power Association
	American Wind Energy Association
	Biomass Power Association
	Edison Electric Institute
	Geothermal Energy Association
	Independent Energy Producers Association
	National Hydropower Association
	National Rural Electric Cooperative Association
	Solar Energy Industries Association
Nongovernmental organizations	American Council on Renewable Energy
	Climate Policy Initiative
	National Association of Regulatory Utility Commissioners
	Solar Electric Power Association
Law firms, attorneys, and consultants	Akin Gump Strauss Hauer & Feld LLP
	Birch Tree Capital, LLC

Type of stakeholder	Organization
	Chadbourne & Parke LLP
	Latham & Watkins LLP
	Martin Klepper
	Mintz Levin Cohn Ferris Glovsky and Popeo PC
	Orrick, Herrington & Sutcliffe LLP
	Stoel Rives LLP
Stakeholders that provided debt financing and tax equity	Citi
	JPMorgan Capital Corporation
	Morgan Stanley
	National Rural Utilities Cooperative Finance Corporation
Independent system operator	California Independent System Operator Corporation
State agencies	California Energy Commission
	Oregon Department of Energy

Source: GAO | GAO-15-302

Note: In addition to the stakeholders listed above, GAO interviewed one stakeholder who wished to remain anonymous.

aDuring our interviews with representatives at utilities, we interviewed some primarily in their role as a utility and others primarily about their role as a developer.

Appendix III: GAO Survey of State Regulatory Commissions

The contents of this appendix represent an approximation of how survey respondents viewed GAO's survey online. In addition to the answer options provided, all survey respondents had the option to report "No answer" to each of the questions contained in this survey. Please see appendix I for additional information about how the GAO administered this survey.

SURVEY OF STATE REGULATORY COMMISSIONS ABOUT UTILITY-SCALE ELECTRICITY GENERATION PROJECTS

NOTE: text of survey form available upon request. (pages 51 to 83)

Background

The U.S. Government Accountability Office (GAO) is an independent, legislative branch agency that assists the U.S. Congress in evaluating federal programs. We have been asked to provide Congress with information about how the federal government and states have supported new utility-scale electricity generation projects from fiscal years (FY) 2004 to 2013.

As part of this review, we are gathering information from state regulatory commissions on a variety of topics, including state regulatory processes, state renewable portfolio standards and goals, and other state-level supports.

Your participation in this survey is critical to providing Congress complete and balanced information about how state activities, including regulatory oversight, affect the construction of utility-scale electricity generation projects.

Definitions

For the purposes of this survey, utility-scale electricity generation projects are projects that:

1. Have a total generator nameplate capacity (i.e. the sum for generators at a single site) of 1 megawatt or greater;
2. Are connected to the grid; and
3. Intend to sell the electricity they produce.

We are not including distributed generation projects, such as rooftop solar projects, in the scope of this review.

Instructions

This survey should be completed by cognizant officials at your state's regulatory commission. As appropriate, please feel free to share this survey with officials who are knowledgeable about the questions in order to submit the most accurate answers.

We estimate that it will take you 60 minutes to complete this survey, and you can save your responses and return to the survey later if needed. Most of our questions ask for your overall impressions of, or opinions about, factors that have affected or may affect the development of new utility-scale electricity generation projects in your state. The questions are generally short and may be answered by checking a box next to the appropriate response. Most questions also allow you to provide additional comments.

The survey was designed such that you should not have to conduct significant research to answer questions—much of this information should be readily known by commission staff. If you are not sure about any of the answers, respond with "don't know/not sure."

Please complete all questions and submit the survey electronically no later than two weeks from today.

If you are unsure of how to respond to a question, please contact Mary Koenen at koenenm@gao.gov or 202-512-9373 or Tanya Doriss at dorisst@gao.gov or 303- 572-7336 for assistance.

Thank you very much for your assistance.

Appendix IV: Additional Information about State and U.S. Territory Renewable Portfolio Standards and Renewable Portfolio Goals

The tables in this appendix reflect answers provided by officials from state regulatory commissions to survey questions about their state's renewable portfolio standard (RPS) or renewable portfolio goal (RPG). Table 4 reflects answers for states and table 5 reflects answers for U.S. territories. States and territories that did not participate in our survey are not included in these tables.

Table 4: Additional Information about States with a Renewable Portfolio Standard (RPS) or Renewable Portfolio Goal (RPG), as of September 2014

State	Type	Year	Final RPS or RPG	Entities subject to RPS/RPG	Unbundled renewable energy certificates allowed?[a]	Geographic requirements?[b]	Notes
Alaska	RPG	2025	50%	State government	No answer provided	No answer provided	Renewable and alternative energy allowed
California	RPS	2020	33%	Electric utilities	Yes	No	Not applicable
Colorado	RPS	2020	30%	IOUs[c]	Yes	No	Not applicable
	RPS	2020	20%	Coops[d] serving 100,000 or > meters	Yes	No	Not applicable
	RPS	2020	10%	Coops serving < 100,000 meters; MOUs[e] serving > 40,000 customers	Yes	No	Not applicable
Connecticut*	RPS	2020	At least 23%	Electric suppliers	Yes	No	Not applicable
Delaware	RPS	2025	25%	Retail electricity suppliers	Yes	No	Not applicable
Hawaii	RPS	2030	40%	Electric utilities	No	No	Not applicable
Illinois	RPS	2025	25%	IOUs and alternative retail electric suppliers	Yes	Yes	Not applicable
Indiana	RPG	2025	10%	Participating IOUs	Yes	Yes	10% refers to 10% of the electricity they supplied in 2010
Iowa*	RPS	No date provided	105 megawatts (MW)	IOUs	No	No	Not applicable
Maine	RPS	2017	At least 10%	Electricity suppliers	Yes	Yes	Must be new renewable energy
	RPS	2017	Additional 30%	Electricity suppliers	Yes	Yes	Existing renewable sources or certain energy efficient resources allowed

State	Type	Year	Final RPS or RPG	Entities subject to RPS/RPG	Unbundled renewable energy certificates allowed?[a]	Geographic requirements?[b]	Notes
Massachusetts	RPS	2020	At least 15%	Retail electricity suppliers	Yes	No	Not applicable
	RPS	Every year after 2020	Additional 1%	Retail electricity suppliers	Yes	No	Not applicable
Michigan	RPS	2015	10%	Retail electricity suppliers	Yes	Yes	Not applicable
	RPS	2015	Additional 1,100 MW	State's two largest IOUs	Yes	Yes	Must be new renewable energy.
Minnesota	RPS	2020	31.50%	Xcel Energy	No	No	Not applicable
	RPS	2025	26.50%	IOUs other than Xcel Energy	No	No	Not applicable
	RPS	2025	25%	Publically-owned utilities (including coops and MOUs)	No	No	Not applicable
Missouri	RPS	2020	10%	IOUs	Yes	No	Not applicable
	RPS	After 2020	15%	IOUs	Yes	No	Not applicable
Montana	RPS	2015	15%	Public utilities and competitive electricity suppliers serving > 50 customers	Yes	Yes	Not applicable
Nevada*	RPS	2025	At least 25%	NV Energy	Yes	Yes	Not applicable
New Hampshire	RPS	2025	24.80%	Electricity suppliers other than MOUs	Yes	Yes	Not applicable
New Jersey	RPS	2021	23.85%	Electricity suppliers serving retail customers	Yes	No[f]	Not applicable
New Mexico	RPS	2020	20%	IOUs	Yes	Yes	Not applicable
	RPS	2020	10%	Rural coops	Yes	Yes	Not applicable
New York	RPS	2015	29%	State government	No answer provided[a]	No answer provided	Not applicable
North Carolina	RPS	2021	12.50%	IOUs	Yes	No	Not applicable
	RPS	2018	10%	MOUs and coops	Yes	No	Not applicable
North Dakota*	RPG	2015	10%	Retail electricity providers	No answer provided	No answer provided	Renewable or recycled energy allowed.
Ohio	RPS	2027	12.50%	IOUs	Yes	Yes	Not applicable

State	Type	Year	Final RPS or RPG	Entities subject to RPS/RPG	Unbundled renewable energy certificates allowed?[a]	Geographic requirements?[b]	Notes
Oklahoma*	RPG	2015	15%	Electric utilities	No	No	Programs to reduce energy use overall as well as during peak hours can meet up to 25% of this goal.
Oregon	RPS	2025	25%	Large utilities	Yes	Yes	Not applicable
	RPS	2025	5 to 10%	Smaller utilities	Yes	Yes	Not applicable
Pennsylvania	RPS	2020	18%	Retail electricity suppliers (including distribution companies and electric generation suppliers)	Yes	No	Alternative energy (e.g., new and existing renewable energy) allowed.
Rhode Island	RPS	2019	14.50%	Retail electricity providers	Yes	Yes	Providers include nonregulated power producers and distribution companies
South Dakota	RPG	2015	10%	Retail electricity providers in state	Yes	No	Renewable or recycled energy allowed.
Texas*	RPS	2015	5,880 MW	Retail suppliers of electricity	Yes	No	Must be new renewable capacity
	RPG	2015	500 MW	Retail suppliers of electricity	Yes	No	Suppliers will aim to add nonwind renewable capacity
	RPG	2025	10,000 MW	Retail suppliers of electricity	Yes	No	Not applicable
Utah	RPG	2025	20%	IOUs, MOUs and coops	Yes	“Don’t Know” answer provided	Utilities must derive 20% of their 2025 adjusted retail electric sales—to the extent that it is cost effective to do so.
Vermont	Goal	2032	75%	Electric utilities	Yes	No	This goal will start at 55% in 2017 and rise 4% every three years until 2032.

State	Type	Year	Final RPS or RPG	Entities subject to RPS/RPG	Unbundled renewable energy certificates allowed?[a]	Geographic requirements?[b]	Notes
Virginia	RPG	2025	15%	Participating IOUs	Yes	Yes	15% refers to 15% of base year 2007 sales.
Washington	RPS	2020	At least 15%	Qualifying utilities	Yes	Yes	Must come from new renewable energy.
West Virginia	RPS	2025	25%	IOUs with > 30,000 residential customers	Yes	"Don't Know" answer provided	Alternative or renewable energy allowed.
Wisconsin	RPS	2015	At least 10%	IOUs and coops	No	No	Not applicable

Legend: * indicates that this state reported that it has completed its RPS or RPG.

Source: GAO survey of state regulatory commissions. | GAO-15-302

Notes: Four other states (Arizona, Maryland, Kansas and Washington D.C.) have RPSs. However, because our survey of state regulatory commissions is the source for the data in this table, states that did not respond to our survey are not included in this table.

aData in this column reflect survey respondents' answers to the following question: "Are utilities in your state allowed to satisfy your state's RPS requirements or RPG goals with unbundled renewable energy certificates?"

bData in this column reflect survey respondents' answers about whether any portion of the renewable energy associated with renewable energy certificates must be deliverable to or generated at any specific locations (e.g., states).

cThe term "IOU" refers to investor-owned utilities.

dThe term "coop" refers to electric cooperatives.

eThe term "MOU" refers to municipally-owned utilities.

fSince this respondent did not answer both related survey questions, this information only reflects the state's generation requirements.

Table 5: Additional Information about U.S. Territories with a Renewable Portfolio Standard (RPS) or Renewable Portfolio Goal (RPG), as of September 2014

Territory	Type	Year	Final RPS or RPG	Entities subject to RPS/RPG	Unbundled renewable energy certificates allowed?[a]	Geographic requirements?[b]	Notes
American Samoa	RPG	TBD	100%	American Samoa Power Authority	No	No	Not applicable
Northern Mariana Islands	RPS	2014	80%	Commonwealth Utilities Corporation	No	No	Not applicable
Puerto Rico	RPS	2035	20%	Retail electricity providers	Yes	Yes	Eligible "green energy" sources can include renewable or alternative renewable energy.

Source: GAO survey of state regulatory commissions. | GAO-15-302

Notes: Two other U.S. territories (U.S. Virgin Islands and Guam) have either an RPS or RPG. However, because our survey of state regulatory commissions is the source for the data in this table, territories that did not respond to our survey are not included in this table.

aData in this column reflect survey respondents' answers to the following question: "Are utilities in your state allowed to satisfy your state's RPS requirements or RPG goals with unbundled renewable energy certificates?"

bData in this column reflect survey respondents' answers about whether any portion of the renewable energy associated with renewable energy certificates must be deliverable to or generated at any specific locations (e.g., states).

Appendix V: Types of Utilities for Which Regulatory Commissions Regulate Electricity Generation Services

Tables 6 and 7 in this appendix reflect survey respondents' answers to questions about whether regulatory commissions regulate retail rates for electricity generation services provided by investor-owned utilities, municipally-owned utilities, and electric cooperatives in their states or territories. States and territories that did not participate in our survey are not included in these tables. For more information about how we administered our survey, see appendix I.

Table 6: Types of Utilities for Which State Regulatory Commissions Regulate Electricity Generation Services

State	Investor-owned utilities	Municipally-owned utilities	Electric cooperatives
Alabama	Yes	No	No
Alaska	Yes	"Other" answer provided	Yes
Arkansas	Yes	No	Yes
California	*	No	No
Colorado	Yes	No	No
Connecticut	No	No	No
Delaware	*	No	No
Florida	Yes	No	No
Georgia	Yes	No	No
Hawaii	Yes	No	Yes
Illinois	*	No	No
Indiana	Yes	"Other" answer provided	No
Iowa	Yes	No	"Other" answer provided
Kentucky	Yes	No	Yes
Louisiana	Yes	No	Yes
Maine	*	"Other" answer provided	No
Massachusetts	*	No	No
Michigan	No answer available[a,b]	No	"Other" answer provided
Minnesota	Yes	No	"Other" answer provided
Mississippi	Yes	"Other" answer provided	No
Missouri	Yes	No	No
Montana	Yes	No	No

State	Investor-owned utilities	Municipally-owned utilities	Electric cooperatives
Nebraska	No answer available[a,c]	No	No
Nevada	Yes	No	No
New Hampshire	No answer available[a,d]	No	No
New Jersey	*	No	No
New Mexico	Yes	No	Yes
New York	*	No answer provided	No answer provided
North Carolina	Yes	No	No
North Dakota	Yes	No	No
Ohio	*	No	No
Oklahoma	Yes	No	Yes
Oregon	No answer available[a,e]	No	No
Pennsylvania	*	No	No
Rhode Island	*	Yes	"Other" answer provided
South Carolina	Yes	No	No
South Dakota	Yes	No	No
Tennessee	No	No	No
Texas	No answer available[a,f]	"Other" answer provided	No
Utah	Yes	No	No
Vermont	Yes	Yes	Yes
Virginia	Yes	No	Yes
Washington	Yes	No	No
West Virginia	Yes	"Other" answer provided	Yes
Wisconsin	Yes	Yes	No
Wyoming	Yes	No	No

Legend: * indicates that this state reported that electricity generation services provided by investor-owned utilities in this state are restructured.

Source: GAO survey of state and territory regulatory commissions | GAO-15-302

Notes: Unless otherwise noted, the data in this table reflect survey respondents' answers to questions about whether regulatory commissions regulate retail rates for electricity generation services provided by investor-owned utilities (IOU), municipally-owned utilities, and electric cooperatives in their states. States that did not participate in our survey are not included in this table.

[a]If respondents did not report "no" in the question that preceded this one, they would not have had the opportunity to respond to this question. Therefore, no answer was available in this instance.

[b]In the question that preceded this one about whether the electricity generation services provided by IOUs are restructured, respondents noted that in Michigan, unbundled retail sales of electric generation from the two largest utilities are generally limited to 10% of the utility's load.

[c]In the question that preceded this one about whether the electricity generation services provided by IOUs are restructured, respondents noted that the Nebraska Public Service Commission does not regulate electricity generation services provided by IOUs.

[d]In the question that preceded this one about whether the electricity generation services provided by IOUs are restructured, respondents noted that New Hampshire restructured its electric industry in the late 1990s and opened its markets to retail choice in 2001; however, the state's largest electric company retained its fossil-hydro ownership, and those assets are priced in an unbundled bill on a cost-of-service basis.

[e]In the question that preceded this one about whether electricity generation services provided by IOUs are restructured, respondents noted that such services are not restructured for residential service in Oregon, but they are for nonresidential service.

[f]In the question that preceded this one about whether electricity generation services provided by IOUs are restructured, respondents noted that IOUs in the Electric Reliability Council of Texas are restructured, but utilities outside of the Electric Reliability Council of Texas are not.

Table 7: Types of Utilities for Which Regulatory Commissions Regulate Electricity Generation Services in U.S. Territories

U.S. territory	Investor-owned utilities	Municipally-owned utilities	Electric cooperatives
American Samoa	No answer available[a,b]	"Other" answer provided	"Other" answer provided
Northern Mariana Islands	Yes	Yes	"Other" answer provided
Puerto Rico	No answer available[a,c]	Yes	"Other" answer provided

Source: GAO survey of state and territory regulatory commissions. | GAO-15-302

Notes: The data in this table reflect survey respondents' answers to questions about whether regulatory commissions regulate retail rates for electricity generation services provided by investor-owned utilities (IOU), municipally-owned utilities, and electric cooperatives in their territories. Territories that did not participate in our survey are not included in this table.

[a]If respondents did not report "no" in the question that preceded this one, they would not have had the opportunity to respond to this question. Therefore, no answer was available in this instance.

[b]In the question that preceded this one about whether the electricity generation services provided by IOUs are restructured, respondents noted that there are no IOUs in American Samoa.

[c]In the question that preceded this one about whether the electricity generation services provided by IOUs are restructured, respondents noted that there are no IOUs in Puerto Rico.

Appendix VI: Outlays, Loan Programs, and Estimates of Tax Expenditures That Supported Utility-Scale Electricity Generation Projects

Table 8 in this appendix reflects outlays that supported utility-scale electricity generation projects for fiscal years 2004 to 2013. Table 9 reflects the estimated cost to the government of loan programs that supported these projects during this same time period. Table 10 reflects the estimated cost of tax expenditures for these projects during this same time period.

Table 8: Outlays That Supported Utility-Scale Electricity Generation Projects Greater Than 1MW (Fiscal Years 2004-2013) (Dollars in millions)

Agency	Program	Projects supported	Total megawatts added	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
U.S. Department of Agriculture	*Rural Business-Cooperative Service*													
	Rural Energy for America Program Grants[a]	50	139	$ -	$7.2	$1.5	$0.3	$0.7	$1.3	$2.5	$1.5	$0.5	$0.02	$15.5
U.S. Department of Energy	*Office of Energy Efficiency and Renewable Energy*													
	Energy Efficiency and Conservation Block Grant Program[b]	5	30	-	-	-	-	-	6.4	-	-	-	-	6.4
	Renewable Energy Production Incentive	59	704	3.4	4.6	4.5	4.7	4.4	4.4	-	-	-	-	25.9
	State Energy Program[b]	13	144	-	-	-	-	-	71.7	-	-	-	-	71.7
	Tribal Energy Program[c]	1	5	-	-	-	-	-	-	0.04	-	-	-	0.04
U.S. Department of the Treasury	*Office of Domestic Finance*													
	Payments for Specified Energy Property in Lieu of Tax Credits (Section 1603)	1,073	28,309	-	-	-	-	-	1,047.6	3,988.0	3,051.5	3,986.5	4,495.9	16,569.5
	Internal Revenue Service													
	Direct Payment in Lieu of a Credit for Holding New Clean Renewable Energy Bonds[d]	Unknown	Unknown	-	-	-	-	-	-	-	11.0	20.0	29.0	60.0
	Direct Payment in Lieu of a Credit for Holding Qualified Energy Conservation Bonds[d]	Unknown	Unknown	-	-	-	-	-	-	-	9.0	23.0	29.0	61.0
	Total	**1, 201**	**29,331**	**$3.4**	**$11.8**	**$6.0**	**$5.0**	**$5.1**	**$1,131.4**	**$3,990.5**	**$3,073.0**	**$4,030.0**	**$4,553.9**	**$16,810.1**

Sources: GAO analysis of agency data and Office of Management and Budget's Public Budget Database. | GAO-15-302

Notes: The agency data represent only those projects greater than 1 megawatt (MW) in size, and therefore, may represent only a portion of the projects supported through these programs.

Outlays may not add up to the total outlays due to rounding.

The following programs provided grants: Energy Efficiency and Conservation Block Grant Program, State Energy Program, Tribal Energy Program and Rural Energy for America Program. Payments for Specified Energy Property in Lieu of Tax Credits (Section 1603) provided payments in lieu of the Investment Tax Credit and Production Tax Credit. The Renewable Energy Production Incentive provided incentive payments. The direct payments in lieu of a credit for Holding New Clean Renewable Energy Bonds and Qualified Energy Conservation bonds were direct payment tax expenditures.

[a]USDA's Rural Business-Cooperative Service collects information on projected generation (in kilowatt-hours) and does not collect information on generating capacity (in kilowatts or MW). In order to report similar information across all programs, we had to estimate generating capacity from the projected generation, using a number of assumptions: (1) 1MW = 8,760,000 kilowatt-hours; (2) an average capacity factor of 70 percent for anaerobic digestors; (3) an average capacity factor of 20 percent for solar; and (4) an average capacity factor of 30 percent for wind.

[b]According to agency officials, this program funding was provided by a one-time American Recovery and Reinvestment Act of 2009 appropriation.

[c]According to an agency official, as of July 18, 2014, the recipient of a $1.2 million grant in fiscal year 2010 had expended only $35,649.77 of the total grant award. The outlays for the grant are shown here in the grant award year, but may have been expended in later years. The grant recipient may continue to expend the remainder of the grant in future years.

[d]We did not receive data from the Internal Revenue Service on the number of utility-scale electricity generation projects supported by these direct payments in lieu of credits for holding bonds because activities other than the construction of utility-scale electricity generation projects are eligible for these payments, and IRS did not have data by project supported. However, IRS reported that some or all of the 254 direct pay bond issues for these two programs could have supported utility-scale electricity generation projects. Therefore, the number of projects supported and MW added through these programs are unknown. According to IRS officials, in general, tax-advantaged bonds, including direct payments in lieu of tax credits for holding bonds, reduce the net interest expense to the developer of financing projects. For example, for these direct payments in lieu of tax credits for holding bonds, bond issuers could elect to receive a direct payment equivalent to and in lieu of the amount of the tax credit that would otherwise go to a bondholder. This option helped tax-exempt entities finance projects because it provided an incentive for investors to purchase the bonds since their returns would not depend upon having sufficient taxable income to utilize a tax credit. Not all tax-advantaged bonds that could have supported utility-scale electricity generation projects are included in this report. For example, both regular tax-exempt governmental bonds and private activity bonds could have supported these projects but are excluded, because these bonds can be used for a wide range of purposes and are not directed specifically at supporting utility-scale electricity generation projects.

Table 9: Estimated Cost to the Government of Loan Programs That Supported Utility-Scale Electricity Generation Projects Greater Than 1MW (Fiscal Years 2004-2013) Dollars in millions

Agency	Program	Projects supported	Total megawatts added	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
U.S. Department of Agriculture	*Rural Business-Cooperative Service*[a]													
	Business and Industry Guaranteed Loan Program	1	4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.6	$ -	$0.6
	Rural Energy for America Program Guaranteed Loans	15	51	-	-	-	-	0.1	0.5	3.2	0.1	0.3	2.4	6.7
	Biorefinery, Renewable Chemical, and Biobased Product Manufacturing Assistance Program (formerly the Biorefinery Assistance Program)[b]	1	3	-	-	-	-	-	-	-	4.8	-	-	4.8
	Rural Utilities Service													
	Direct and Guaranteed Electric Loans[c,d]	32	5,714	(16.0)	(18.8)	(16.5)	-	40.3	4.5	(16.3)	32.2	(29.5)	(6.3)	(26.3)
U.S. Department of Energy	*Loan Programs Office*													
	Title XVII Section 1703 Loan Guarantee Program	0	0	-	-	-	-	-	-	-	-	-	-	-
	Title XVII Section 1705 Loan Guarantee Program[e,f,g]	21	3,976	-	-	-	-	-	-	27.7	1,203.1	-	-	1,230.8
	Total	**70**	**9,748**	**$(16.0)**	**$(18.8)**	**$(16.5)**	**$ -**	**$40.3**	**$5.0**	**$14.6**	**$1,240.2**	**$(28.6)**	**$(3.9)**	**$1,216.4**

Sources: GAO analysis of agency data. | GAO-15-302

Notes: These data represent only those projects greater than 1 megawatt (MW) in size, and therefore, may represent only a portion of the projects supported through these programs.

Dollars may not add up to the total due to rounding.

aUSDA’s Rural Business-Cooperative Service collects information on projected generation (in kilowatt-hours) and does not collect information on generating capacity (in kilowatts or MW). In order to report similar information across all programs, we had to estimate generating capacity from the projected generation, using a number of assumptions: (1) 1MW = 8,760,000 kilowatt-hours; (2) an average capacity factor of 70 percent for anaerobic digestors; (3) an average capacity factor of 20 percent for solar; and (4) an average capacity factor of 30 percent for wind.

bThe Agricultural Act of 2014, which passed in February 2014, renamed the Biorefinery Assistance Program the Biorefinery, Renewable Chemical, and Biobased Product Manufacturing Assistance Program.

cAccording to agency officials, credit subsidy costs for USDA's Rural Business-Cooperative Service and Rural Utilities Service are calculated for an entire loan cohort and not for individual loans. Since not all loans in each loan cohort are included in these data, the cost to the government shown here represents the best estimate, given the loan guarantee amount and credit subsidy reestimate for the loan cohort for a given loan.

dOf the 32 projects supported by this program, 31 were loan guarantees and 1 was a direct loan. According to agency officials, USDA's Rural Electric Program offers several types of direct loans and also has authority to guarantee private loans. These activities are described in this report as USDA's Direct and Guaranteed Electric Loans program.

eAccording to agency officials, DOE's Loan Programs Office reestimates the credit subsidy calculations for loans and loan guarantees in its portfolio on an annual basis in support of the Office of Management and Budget's preparation of the President's Budget and submits the reestimates to the Office of Management and Budget in late November. Reestimate data is also utilized in the preparation of DOE's annual financial statement and is calculated as of fiscal year end (September 30). For most loans, the reestimate data for the financial statement is identical to the data prepared for the Office of Management and Budget in the budget process. Any differences between these credit subsidy calculations reflect such factors as actual cash flow activity and changes in perceived transaction risk that occurred after the financial statement reestimates and before the budget submission.

fLifetime reestimates used to calculate the total cost to the government were provided by DOE's Loan Programs Office. The reestimates are those used in the federal credit supplement, but because some borrowers are outside the scope of this review and are therefore excluded from this table, the numbers shown here may not match to the numbers reflected in the federal credit supplement.

gAccording to an agency official at DOE's Loan Programs Office, the office updates their reestimates for actual activity between fiscal year end and November to include in the credit supplement. Consequently, some borrower amounts may differ between the close of the fiscal year and what is reflected in the credit supplement to the President's budget.

Table 10: Estimated Cost of Tax Expenditures That Supported Utility-Scale Electricity Generation Projects Greater Than 1MW (Fiscal Years 2004-2013) Dollars in millions (U.S. Department of the Treasury - *Internal Revenue Service)*

Program	Projects supported	Total megawatts added	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Accelerated Depreciation Recovery Periods for Specific Energy Property: Renewable Energy[a,b,c]	Unknown	Unknown	$-	$ -	$ -	$ -	$200	$300	$300	$300	$300	$300	$1,700
Credit for Investment in Clean Coal Facilities[d]	Unknown	Unknown	-	-	-	30	30	180	240	370	360	170	1,380
Advanced Nuclear Power Production Credit	Unknown	Unknown	-	-	-	-	-	-	-	-	-	-	-
Investment Tax Credit (ITC) (also known as Energy Investment Credit)[e]	Unknown	Unknown	-	-	-	-	30	230	100	560	920	1,560	3,400
Production Tax Credit (PTC) (also known as the Energy Production Credit)[f]	Unknown	Unknown	330	220	470	380	840	380	1,370	1,410	1,480	1,250	8,130
Credit for Holding Clean Renewable Energy Bonds[g] and Credit for Holding New Clean Renewable Energy Bonds	Unknown	Unknown	-	-	20	20	40	70	70	70	70	70	430

Program	Projects supported	Total megawatts added	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Credit for Holding Qualified Energy Conservation Bonds[g]	Unknown	Unknown	-	-	-	-	-	-	-	10	20	20	50
Total	**—**	**—**	**$330**	**$220**	**$490**	**$430**	**$1,140**	**$1,160**	**$2,080**	**$2,720**	**$3,150**	**$3,370**	**$15,090**

Sources: GAO analysis of Treasury and Joint Committee on Taxation data. | GAO-15-302

Notes: Treasury tax expenditure estimates come from the President's budget unless otherwise specified. Tax expenditure estimates do not incorporate any behavioral responses and thus do not reflect the exact amount of revenue that would be gained if a specific tax expenditure were eliminated. In addition, summing individual tax expenditures' revenue loss estimates does not take into account interactions between individual provisions.

Unless otherwise noted, all revenue loss estimates are for corporations only.

aThe revenue loss estimate is reported by the Joint Committee on Taxation (JCT) only. Treasury and JCT use different (1) income tax baselines, (2) de minimis amounts (which is the minimum revenue loss threshold for Treasury and JCT to report a tax expenditure), and (3) economic and technical assumptions. For more information on how Treasury and JCT estimate revenue loss, see appendix III in GAO-05-690.

bThe Accelerated Depreciation Recovery Periods for Specific Energy Property: Renewable Energy, may include revenue losses associated with combined heat and power and microturbines. The JCT generally classifies as tax expenditures cost recovery allowances that are more favorable than those provided under the alternative depreciation system (Internal Revenue Code Section 168(g)), which provides for straight-line recovery over tax lives that are longer than those permitted under the accelerated system. Accelerated depreciation, in effect, reduces the cost of acquiring energy properties by allowing businesses to deduct larger amounts from their taxable income sooner than they would be able to do under straight-line depreciation. Reducing tax liability earlier provides a benefit to the taxpayer because of the time value of money—having a lower tax payment today is worth more to the taxpayer than having the lower payment in the future.

cDepreciation—a normal business expense under an income tax system—is an annual deduction from income that allows taxpayers to recover the cost or other basis of certain property used in a business or other income-producing activity over the useful life of the property. In addition to the existing 5-year accelerated depreciation allowed for wind and other properties, 2008 legislation and subsequent laws have temporarily granted a 50 percent first-year bonus depreciation, currently in effect for properties placed in service before January 1, 2015. This allows businesses to deduct 50 percent of the depreciable basis of a broad set of tangible properties, including wind and other renewable energy facilities, from their taxable income in the first year after they are acquired. Furthermore, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 allowed businesses to deduct 100 percent of the depreciable basis of eligible wind and other facilities from their taxable income after September 8, 2010 and before January 1, 2012. The 50 percent bonus depreciation allowed under the 2008 act narrowed any tax differences between eligible assets, and the 100 percent bonus depreciation introduced in 2010 eliminated those differences altogether under the provision for allowing a full write-off of asset acquisition costs.

[d]An investment tax credit is available for selected types of advanced coal technologies. The Energy Improvement and Extension Act of 2008 authorized $1.25 billion in credits for power generation projects that use integrated gasification combined cycle or other advanced coal-based electricity generation technologies. Qualifying taxpayers may be eligible for a 30 percent credit. The Energy Improvement and Extension Act of 2008 also authorized $250 million in credits for qualified gasification projects (with a credit rate of 30 percent). Prior allocations were awarded by the Internal Revenue Service under the Energy Policy Act of 2005, which provided $800 million for integrated gasification combined cycle projects and $500 million for other advanced coal-based electricity generation technologies. The Energy Policy Act of 2005 also authorized $350 million for qualified gasification projects.

[e]The Investment Tax Credit may include revenue losses associated with fuel cells and microturbines, which are excluded from the scope of this review.

[f]The Production Tax Credit includes revenue losses from the New Technology Credit.

[g]Both corporations and individuals might benefit from the tax credits associated with buying Credit for Holding Clean Renewable Energy Bonds and Credit for Holding Qualified Energy Conservation Bonds, therefore, estimates for revenue losses from both corporations and individuals are combined for both types of bonds.

[h]Zero dollars may represent either that the estimate for that year was rounded to zero, or that there was no estimate for the particular tax expenditure for that year.

Appendix VII: Federal Supports for Utility-Scale Electricity Generation Projects by Agency

Tables 11 through 13 below provide descriptions, by agency, of the federal programs we identified that supported utility-scale electricity generation projects. The tables also provide information on supports that will or have expired, in full or in part, due to an expiration of legislative authority or some other expiration under the law as of the spring of 2015, as well as those supports that currently have no expiration.

Table 11: U.S. Department of Agriculture Supports for Utility-Scale Electricity Generation Projects

Implementing office and program name	Description	Expiration information
Rural Business-Cooperative Service		
Biorefinery, Renewable Chemical, and Biobased Product Manufacturing Assistance Program (formerly the Biorefinery Assistance Program)[a]	Title IX of The Food, Conservation, and Energy Act of 2008 (2008 Farm Bill) authorizes USDA to make loan guarantees for the development of new and emerging technologies for producing advanced biofuels through loan guarantees to fund the development, construction, and retrofitting of commercial-scale biorefineries using an eligible technology. Eligible technologies include anaerobic digesters and others that are being adopted or have been demonstrated to have the potential for application in a commercial-scale biorefinery that produces an advanced biofuel. The maximum available loan guarantee under the program is $250 million.	The Agricultural Act of 2014(the 2014 Farm Bill) provided mandatory funding for the program through fiscal year 2016.
Business and Industry Guaranteed Loan Program	The purpose of this program is to improve, develop, or finance business, industry, and employment, and the economic and environmental climate in rural communities by providing guaranteed loans to borrowers in rural areas. Eligible project proposals include those that will provide employment; improve the economic or environmental climate; promote the conservation, development, and use of water for aquaculture; or reduce reliance on nonrenewable energy resources by encouraging the development and construction of renewable energy systems. Loan amounts are generally limited to $25 million per borrower except under certain circumstances, and the percentage amount of the loan guarantee varies depending upon the value of the loan.	No expiration under current law.
Rural Energy for America Program Grant and Guaranteed Loans	This program, authorized in 2008 Farm Bill, provides funding for grants and guaranteed loans to farmers, ranchers, and small businesses in rural areas to assist with purchasing and installing renewable energy systems, and energy efficiency improvements. Grants under the program are awarded on a competitive basis and can be up to 25% of total eligible project costs or $500,000 for renewable energy systems. Guaranteed loans under the program encourage the commercial financing of renewable energy and energy efficiency projects by guaranteeing between 60 and 85% of the loan (depending upon the amount of the loan).	The 2014 Farm Bill appropriated funding in the amount of $50 million for fiscal years 2014 through 2016 and authorized $50 million for fiscal years 2017 and 2018.

Implementing office and program name	Description	Expiration information
Rural Utilities Service		
Direct and Guaranteed Electric Loans	This program, authorized under the Rural Electrification Act of 1936, provides loans and loan guarantees to establish and improve electric service in rural areas, and to assist electric borrowers to implement demand side management, energy efficiency and conservation programs, and on-grid and off-grid renewable energy systems. These loans and loan guarantees provide financing to eligible nonprofit utility organizations, such as municipally-owned utilities and electric cooperatives, as well as for-profit entities that provide service to eligible rural areas.	No expiration under current law.

Sources: GAO analysis of agency-provided data and legislation. | GAO-15-302

[a]The Agricultural Act of 2014, which passed in February 2014, renamed the Biorefinery Assistance Program the Biorefinery, Renewable Chemical, and Biobased Product Manufacturing Assistance Program.

Table 12: U.S. Department of Energy Supports for Utility-Scale Electricity Generation Projects

Implementing office and program name	Description	Expiration information
Office of Energy Efficiency and Renewable Energy		
Energy Efficiency and Conservation Block Grants	The Energy Efficiency and Conservation Block Grant Program provides assistance to cities, counties, states, territories, and tribes to develop and implement projects and programs that reduce fossil fuel emissions; reduce the total energy use of the eligible entities; improve energy efficiency in various economic sectors; and create and retain jobs. Most of the funding provided under this program supports formula grants, although some funding supports competitively-awarded grants or is used to develop technical assistance tools. Program funds may be used for a variety of energy efficiency and conservation programs and projects, as well as for renewable energy projects.	This program was funded through American Recovery and Reinvestment Act of 2009 (Recovery Act) funding, and no additional funds were appropriated. The Recovery Act funds were required to be obligated by DOE to grantees by Sept.30, 2010 and expended by Sept.30, 2015.

Implementing office and program name	Description	Expiration information
Renewable Energy Production Incentive	The Renewable Energy Production Incentive provides financial incentive payments for electricity generated and sold by new qualifying renewable energy generation facilities. Qualifying facilities are eligible for annual incentive payments of 1.5 cents per kilowatt-hour (1993 dollars and indexed for inflation) for the first 10-year period of their operation, subject to the availability of annual appropriations. The program was originally authorized under Section 1212 of the Energy Policy Act of 1992 and was amended with Section 202 of the Energy Policy Act of 2005. Section 202 reauthorized appropriations through fiscal year 2026 and expanded the list of eligible technologies. According to DOE officials, the program was designed to offset the advantages that private-sector utilities had from the production tax credit by supporting nonprofit entities.	According to DOE officials, in 2008, DOE requested that the program be discontinued, which it formally was in 2010.
State Energy Program	The State Energy Program provides financial and technical assistance through formula and competitive grants for the deployment of energy efficiency and renewable energy technologies. States use their formula grants, plus a 20% match that they provide, to develop state strategies and goals to address their energy priorities. In designing their programs, grantees choose a list of eligible activities to fund with their grant, including a variety of renewable energy-related activities.	No expiration under current law.
Tribal Energy Program	This program promotes energy self-sufficiency, economic development, and employment on tribal lands through the use of renewable energy and energy efficiency technologies. Under this program, DOE provides competitively-awarded funding and technical assistance to tribes to evaluate and develop their renewable energy resources and reduce their energy consumption through efficiency and weatherization.	No expiration under current law.
Loan Programs Office		
Title XVII Section 1703 Loan Guarantee Program	Section 1703 of Title XVII of the Energy Policy Act of 2005 authorizes DOE to provide loan guarantees to support specified kinds of projects that (i) avoid, reduce or sequester air pollutants or anthropogenic emissions of greenhouse gases and (ii) employ technologies that are new or significantly improved as compared to commercial technologies in service in the United States at the time the guarantee is issued. Such projects are typically unable to obtain conventional private financing due to high technology risks. Under Section 1703, borrowers generally pay the credit subsidy costs, although there is a small amount of appropriated credit subsidy available for renewable energy and energy efficiency projects.	No expiration under current law.

Implementing office and program name	Description	Expiration information
Title XVII Section 1705 Loan Guarantee Program	The Recovery Act added Section 1705 to the Energy Policy Act of 2005. Section 1705 authorizes a temporary program to provide loan guarantees for certain renewable energy systems, electric power transmission systems and innovative biofuel projects that began construction no later than Sept. 30, 2011. Under this program, DOE paid the initial credit subsidy costs of loan guarantees using funds appropriated for this purpose. Certain of the Section 1705 loan guarantees, which were issued under the Financial Institutions Partnership Program, guarantee up to 80% of a loan provided for a renewable energy generation project by qualified financial institutions. Other Section 1705 loan guarantees guarantee 100% of a loan provided for an innovative renewable energy generation project by the Federal Financing Bank.	The Recovery Act added Section 1705 to the Energy Policy Act of 2005. The initiative expired on Sept. 30, 2011.

Sources: GAO analysis of agency-provided data and legislation. | GAO-15-302

Table 13: U.S. Department of the Treasury Supports for Utility-Scale Electricity Generation Projects

Implementing office and program name	Description	Expiration information
Internal Revenue Service		
Accelerated Depreciation Recovery Periods for Specific Energy Property: Renewable Energy (accelerated depreciation for renewable energy property)	A taxpayer is allowed to recover, through annual depreciation deductions, the cost of certain property used in a trade or business or for the production of income. The tax code provides a 5-year recovery period for certain renewable energy equipment. The Economic Stimulus Act of 2008 included a 50% first-year bonus depreciation provision for a wide range of eligible properties including renewable energy systems. This provision was extended by The American Recovery and Reinvestment Act of 2009 (Recovery Act), and by the Creating Small Business Jobs Act of 2010. Bonus depreciation was further extended through 2012 by the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, with a 100% deduction allowed for certain property. The Tax Increase Prevention Act of 2014 extended 50% expensing for qualifying property purchased and placed in service before Jan. 1, 2015.	Property had to be placed in service before Jan.1, 2015 to quality for bonus depreciation. The 5-year recovery period for certain solar equipment will expire on Dec. 31, 2016.
Advanced Nuclear Power Production Credit	The advanced nuclear power production credit, under Internal Revenue Code Section 45J, was enacted by Section 1306 of the Energy Policy Act of 2005, and permits a taxpayer to claim a credit for electricity that the taxpayer (1) produces at an advanced nuclear power facility during the 8-year period beginning when the facility is placed in service and (2) sells to an unrelated entity. The credit has not been claimed to date because no new nuclear power facilities have come online since the credit came into place.	No expiration under current law.

Implementing office and program name	Description	Expiration information
Credit for Holding Clean Renewable Energy Bonds and New Credit for Holding Clean Renewable Energy Bonds	Clean Renewable Energy Bonds and New Credit for Holding Clean Renewable Energy Bonds help tax-exempt entities finance capital expenditures for, among other things, new facilities that produce electricity from renewable sources. Bond holders receive tax credits at 70% of the tax credit interest rate in lieu of interest payments. New Credit for Holding Clean Renewable Energy Bonds may be issued by nonprofit entities that have received a loan or loan guarantee under the Rural Electrification Act. The Department of the Treasury publicly solicited applications for an initial volume cap, set by Congress at $800 million, and awarded allocations based on criteria and applications received. An additional $1.6 billion in New Credit for Holding Clean Renewable Energy Bonds authorization was provided under the Recovery Act.	No expiration under current law.
Credit for Holding Qualified Energy Conservation Bonds	Qualified Energy Conservation Bonds provide an opportunity for tax-exempt entities to issue bonds for which bond holders can receive an income tax credit in lieu of interest payments from the issuers of the bonds. Qualified Energy Conservation Bonds can be issued to, among other things, help finance projects that produce or conserve electricity, including capital expenditures incurred for rural development involving the production of electricity from renewable energy resources as well as qualified facilities under Internal Revenue Code Section 45(d). Similar to the New Credit for Holding Clean Renewable Energy Bonds, the tax credit rate for Qualified Energy Conservation Bonds is 70% of the tax credit interest rate. Congress established an initial volume cap of $800 million in Qualified Energy Conservation Bonds that could be issued. The cap was raised to $3.2 billion under the Recovery Act.	No expiration under current law.
Credit for Investment in Clean Coal Facilities	The credit for investment in clean coal facilities was authorized in the Energy Policy Act of 2005 by the addition of Internal Revenue Code Section 48A. Under the Energy Policy Act of 2005, $800 million was allocated for integrated gasification combined cycle projects. The tax credit rate for investments in integrated gasification combined cycle projects was set at 20%. Another $500 million was available for investments in other advanced coal-based electricity generation technologies at a tax credit rate of 15%. Section 111 of the Energy Improvement and Extension Act of 2008 amended Section 48A and authorized $1.25 billion of additional credits to be allocated to qualifying projects; in addition, it increased the tax credit rate for all qualified clean coal investments to 30%. The Department of the Treasury, through the Internal Revenue Service, and the Department of Energy work together to jointly evaluate projects seeking these tax credits, which are then competitively awarded.	No expiration under current law.

Implementing office and program name	Description	Expiration information
Direct Payment in Lieu of a Credit for Holding New Clean Renewable Energy Bonds	Through the Hiring Incentives to Restore Employment Act of 2010, Congress permitted issuers of New Credit for Holding Clean Renewable Energy Bonds the option to receive a direct payment equivalent to and in lieu of the amount of the tax credit that would otherwise go to the bondholder. This option applied to New Credit for Holding Clean Renewable Energy Bonds issued after Mar. 18, 2010. In cases where bond issuers elect to receive a direct payment, this option helps tax-exempt entities finance projects that produce electricity from renewable sources because it provides an incentive for investors to purchase the bonds since the investors' returns would not depend upon having sufficient tax liability to utilize a tax credit.	No expiration under current law.
Direct Payment in Lieu of a Credit for Holding Qualified Energy Conservation Bonds	Through the Hiring Incentives to Restore Employment Act of 2010, Congress permitted issuers of Qualified Energy Conservation Bonds the option to receive a direct interest payment subsidy equivalent to and in lieu of the amount of the tax credit that would otherwise go to the bondholder. This option applied to Qualified Energy Conservation Bonds issued after Mar. 18, 2010. In cases where bond issuers elect to receive a direct payment, this option helps tax-exempt entities finance projects that produce or conserve electricity because it provides an incentive for investors to purchase the bonds since the investors' returns would not depend upon having sufficient tax liability to utilize a tax credit.	No expiration under current law.
Energy Investment Credit (ITC)	The Internal Revenue Code provides an income tax credit based on a percentage of the basis in new equipment that produces electricity and/or heat from renewable energy sources. The credit is for business investments in solar, fuel cells, small wind turbines, geothermal systems, microturbines, and combined heat and power. Solar, fuel cell, and small wind turbine investments qualify for a 30% credit. (The credit for fuel cells is limited to $1,500 per 0.5 kilowatt of capacity.) The tax credit for investments in geothermal systems, microturbines, and combined heat and power is 10%. (The credit for microturbines is limited to $200 per kilowatt of capacity.) Provisions enacted as part of the American Recovery and Reinvestment Act of 2009 (Recovery Act) allow (1) taxpayers to elect to claim this credit for property that otherwise would have qualified for the production tax credit and (2) taxpayers eligible for this credit to receive a Section 1603 payment from the Treasury in lieu of tax credits.	In general, this provision will expire on Dec. 31, 2016; however, the credit for certain solar investments will decrease to 10% and the credit for geothermal investments will remain at 10%.

Implementing office and program name	Description	Expiration information
Energy Production Credit (PTC)	Taxpayers producing energy from a qualified renewable energy source may qualify for a tax credit on a per-kilowatt-hour basis. Qualified energy sources include wind, solar energy, geothermal energy, closed-loop and open-loop biomass, small irrigation power, municipal solid waste, qualified hydropower production, and marine and hydrokinetic renewable energy sources. The credit amount in 2014 is 2.3 cents per kilowatt-hour for wind, solar, closed-loop biomass, and geothermal energy sources and 1.1 cents per kilowatt-hour for other energy sources. The credit amount is based on the 1993 value of 1.5 cents per kilowatt-hour, which is adjusted annually for inflation. This credit is generally available for 10 years, beginning on the date when the facility is placed in service. Taxpayers may claim an investment tax credit in lieu of the production tax credit. In addition, for facilities placed in service during 2009, 2010, and 2011, taxpayers could claim the Section 1603 cash payment in lieu of receiving the production tax credit.	For certain qualified facilities, construction must have begun before Jan. 1, 2015
Office of Domestic Finance		
Payments for Specified Energy Property in Lieu of Tax Credits	Section 1603 of the Recovery Act established a program to provide payments to eligible applicants who place specified energy property in service for use in a trade or business. Applicants could take the payment in lieu of either an energy production or investment credit. These payments provide an incentive for investment in property for electricity and heat production, particularly for applicants without sufficient tax liability to utilize a tax credit. Initially, the program provided payments for renewable energy projects placed in service in 2009 or 2010, or which began construction in 2009 or 2010. However, the program was extended for 1 year as part of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010.	Projects must be placed in service during 2009, 2010, or 2011, or after 2011 if construction began on the property during 2009, 2010, or 2011 and the property is placed in service by a certain date known as the credit termination date (e.g., Jan. 1, 2017 for certain energy property).

Source: GAO analysis of agency-provided data and legislation. | GAO-15-302

Appendix VIII: Financial Modeling Methodology and Additional Analysis

We used the System Advisor Module (SAM) developed by the National Renewable Energy Laboratory (NREL), and, as noted below, a modification of SAM that we developed, to analyze the possible effects of actual and planned reductions in the value of the Energy Investment Credit, also known as the Investment Tax Credit (ITC) or the Energy Production Credit, also known as the Production Tax Credit (PTC) on renewable utility-scale electricity generation projects. These tax credits, among others, represent a key form of federal support for the construction of new renewable utility-scale electricity generation projects, and they can represent a significant portion of the total after-tax returns from investments in renewable energy projects. We used SAM to estimate the magnitude of these effects. This appendix describes our analysis of the role of the ITC and PTC on investments in renewable energy projects, and the effects of changes in the value of these tax credits on those investments by (1) providing an overview of SAM, (2) describing our use of SAM, and (3) providing the key results from SAM.

Overview of SAM

SAM provides energy performance and financing tools that are designed to facilitate investment and analytical decisions in renewable energy projects.[1] These tools can provide information to participants in the renewable energy sector, including policy analysts and developers of renewable energy projects. SAM provides the flexibility to allow the user to input either highly detailed configurations of equipment and financing or generalized assumptions. For example, a solar flat-plate photovoltaic project could be specified in terms of individual solar panel and inverter modules installed with very specific details as to tilt and ability to track the sun, and with component-by-component acquisition and installation costs. Alternatively, the project can be described in a less specific manner, with an aggregate installation cost per watt.

SAM is composed of the following two modules:

- *Performance module*: SAM can be used to analyze many aspects of the expected energy performance of large, utility-scale solar and wind projects. SAM also allows users to compare differences in how specific equipment may perform and can estimate equipment

[1]As of Jan. 30, 2015, SAM was publicly available at https://sam.nrel.gov/.

conversion efficiencies[2] for specific modules of solar panels, wind turbines, and other equipment that can be used to develop estimates of electricity production. SAM also includes data on typical, as well as historical weather patterns for a wide range of locations.

- *Financial module*: In SAM's financial module, the user specifies values for cost and other financial characteristics, including the value of federal tax credits and accelerated depreciation for renewable energy property.[3] The financial module begins with energy inputs automatically transferred from the performance module—specifically, the estimated amount of annual electricity generated. The financial module assumes that the project earns its revenues from sales of this electricity to an electric utility through a contract referred to as a power purchase agreement (PPA). The financial module generates a cash flow analysis over the life of the project given the specification of revenues, costs, and information about the nature of the investment in the project. The financial module is flexible in that different investment structures can be examined. Specifically, the project finance structures that can be analyzed in SAM include two partnership flip structures—a structure in which the vast majority of project cash and tax benefits and liabilities go to one partner until certain financial conditions are met, at which point they flip so that the other partner receives the vast majority of cash and tax responsibilities— and a structure in which the developer owns the project—referred to as the single owner structure.[4] The user must specify other financial parameters, including desired rates of return for the investors—specifically after-tax internal rates of return (IRR)—project borrowing costs, and how project revenues and tax expenditures will be allocated among partners in the two partnership structures.

[2]Equipment conversion efficiency refers to the efficiency with which the wind's kinetic energy or the sun's radiant energy are converted into electricity by the equipment used in renewable wind and solar installations, respectively.

[3]Renewable energy projects can recover investments through the ability to take depreciation deductions from their taxable income on an accelerated period of 5 years instead of a longer period, typically 20 years. SAM allows the user to specify the share of project investment that is subject to accelerated depreciation for renewable energy property.

[4]SAM also allows users to model the sale leaseback project finance structure, whereby the tax investor purchases the project from the developer and leases it back to the developer. However, according to stakeholders we interviewed, this structure is not used as frequently as the partnership flips, particularly for wind projects, therefore, we did not model it as part of our analysis.

SAM's ability to analyze different investment structures is important. As noted elsewhere in this report, some developers have to enter into complex financial partnerships—tax equity partnerships—with third party entities in order for the project to make use of these tax benefits. For this analysis, we examined two such partnerships as follows:

- *All equity partnership flip*: In the all equity partnership flip structure, the developer and tax equity partner create a special-purpose entity, formed exclusively to build and operate the project, which is funded entirely by the equity contributions from both partners. The tax equity partner provides the majority of funding for the project in return for nearly all project revenues and tax expenditures (as well as any tax liabilities) generated by the project for a specified amount of time from the beginning of the project. This period of time, which can vary by project, depends on the tax equity partner's desired rate of return and rules governing the tax expenditures used by the project. Once the tax equity partner realizes its required rate of return, the allocation of project proceeds "flips" so that the developer begins receiving the vast majority of project revenues and tax liabilities.[5]
- *Leveraged partnership flip*: The leveraged partnership flip is similar to the all equity flip, but substitutes some or all of the project developer's equity investment with borrowed funds, referred to as debt. Project revenues and tax expenditures are still shared between the partners in the same manner as in the all equity flip; however, the existence of debt means that the project must make principal and interest payments before any revenues can be shared between the partners. Thus, if the project were to run into financial difficulties, the debt-holder would have a senior claim on project proceeds, so the tax equity investor would receive lower-than-anticipated returns. Several stakeholders told us that tax equity partners prefer arrangements in which their returns are not subordinate to debt, so leveraged structures are not commonly used. They also noted that when leveraged structures are used, tax equity investors require higher rates of return in order to compensate them for the higher risk.

In contrast to the partnership structures, the single owner structure, which we also modeled, is simpler in that there are no arrangements between the partners that must be negotiated and monitored. The owner makes

[5]Many actual partnerships specify terms under which the project developer can buy out the tax investor at some point during the project's life. This aspect of partnerships is not modeled in SAM.

the equity investment, typically accompanied by debt financing, and receives all available cash proceeds and tax benefits (or liabilities), but, as mentioned, this structure is not attractive to those developers without income tax liabilities sufficient to make use of tax credits.

The single owner and leveraged partnership flip structures involve debt-financing. SAM assumes that the project takes on as much debt as possible because debt is typically the least-costly funding source for a project. The maximum level of debt depends on two factors: the amount of cash available for debt service, and the debt service coverage ratio. The amount of cash available for debt service is a pretax measure of earnings defined as total revenue minus total expenses minus the amount set aside for equipment replacement reserves. The debt service coverage ratio is the ratio of cash available for debt service and the amount used for debt service, defined as the sum of principal and interest payments. If the ratio has a value of one, that means all available cash is used for debt service. For a given debt service coverage ratio, the maximum level of debt increases with the amount of cash available for debt service. For a given amount of cash available for debt service, the maximum level of debt decreases with the debt service coverage ratio. The debt service coverage ratio is selected by the user of SAM to represent constraints imposed by the lender. One implication of this aspect of SAM is that, as PPA prices increase, so will the amount of cash available for debt service and thus the share of debt in the project financing. Thus, higher PPA prices are associated with smaller equity investments.

The SAM financial module has two possible solution methods. Both solutions link project investments, returns on those investments, and the PPA price. In one solution mode, the module solves for the lowest PPA price that will provide the investor's return on investment goal. For example, if an investment goal—i.e., an after-tax internal rate of return goal—is 12 percent, the module will determine the lowest PPA price meeting that goal. The second solution mode calculates the cash flows that would result from the selection of a particular PPA price. For example, if a PPA price of $0.07 per kilowatt-hour is desired, the module will determine the financial flows that result from that PPA price, including the rate of return an investor would earn with that price.

Our Use of SAM

In this section, we discuss our use of SAM. Specifically, we discuss: (1) the types of projects we modeled; (2) our investor rates of return targets; (3) installation and finance costs; and (4) aspects of the partnership structures related to equity shares and capital recovery by the project developer. We believe that our use of SAM to examine the possible effects of changes in the value of tax credits is an appropriate use of the model, and that SAM is sufficiently reliable for the purposes of this report. To make that determination, we met with NREL officials to learn about the development and uses of the module, and we identified peer-reviewed and other publications that used SAM to analyze various energy and financial performance issues related to investments in renewable energy.[6] We also interviewed industry experts who had used the modules and shared our preliminary results with officials from NREL and other industry participants and analysts. Where applicable, we incorporated their comments into our analysis.

We modeled a hypothetical solar photovoltaic project and a hypothetical wind project, and we used SAM to examine the role of tax credits on investments in these projects. We located our hypothetical solar photovoltaic project in Phoenix with a generating capacity of 100 MW, and we located our hypothetical wind project in the state of Washington with a generating capacity of approximately 150 MW. The SAM performance module calculated that the solar photovoltaic project would generate172,975,664 kilowatt-hours of first-year energy[7] for a capacity factor[8] of 19.7 percent. Likewise, SAM calculated that the wind project would generate 530,041,600 kilowatt-hours of first-year energy for an implied capacity factor of 40.4 percent. We believe projects of these sizes

[6]See, for instance, X. Wang, L. Kurdgelashvili, J. Byrne, and A. Barnett, “The Value of Module Efficiency in Lowering the Levelized Cost of Energy of Photovoltaic Systems,” *Renewable and Sustainable Energy Reviews*, 15, no. 9 (2011); K. Branker, M. Pathak, and J. Pearce, “A Review of Solar Photovoltaic Levelized Cost of Electricity,” *Renewable and Sustainable Energy Reviews,* 15, no. 9 (2011); J. S. Gifford, R. C. Grace, and W. H. Rickerson, *Renewable Energy Cost Modeling: A Toolkit for Establishing Cost-Based Incentives in the United States*, National Renewable Energy Laboratory (Golden, CO: May, 2011); M. Mendelsohn, C. Kreycik, L. Bird, P. Schwabe, and K. Cory, *The Impact of Financial Structure on the Cost of Solar Energy*, National Renewable Energy Laboratory (Golden, CO: March, 2012).

[7]First-year energy is simply the amount of energy estimated to be generated in the first year of operation. Estimated energy in subsequent years can be assumed to remain the same as in the first year, or it can be assumed to degrade at some annual rate. We assumed constant annual production for the wind project, and a degradation rate of 0.5 percent for the solar project.

[8]Capacity factor is defined as the ratio of the amount of estimated electrical output to the nameplate electrical output, which is the amount of electrical output that would result if the project were to operate at its nameplate capacity for every hour of the year.

and locations represented reasonable examples of utility-scale renewable energy projects.

For each of our projects, we assumed that the costs to install and operate the project would not change across the project finance structures we examined; however, total project costs varied because financing costs vary across the investment structures. For both types of projects, we assumed a project life of 20 years, PPA terms of 20 years, and PPA price escalation at the rate of 2.5 percent annually. After specifying project costs, return on investment targets, and other parameters as inputs to the module, which we describe in more detail below, we analyzed module solutions for each project in two tax credit environments, and compared the results between the two environments. First, we defined a more-generous tax credit environment—which, in the case of the ITC, was at the current level of 30 percent of the value of a qualified investment and, in the case of the PTC, was at the level of the PTC before it is scheduled to expire on December 31, 2014. In 2013, this value was $0.023 per kilowatt hour, which was then set to escalate over a 10-year period.[9] We then defined a less-generous tax credit environment in which the ITC is 10 percent of the value of the investment—a level to which the ITC is scheduled to change in 2017—and there is no PTC—since the PTC is scheduled to expire at the close of 2014. We modeled the solar project using the ITC and the wind project using the PTC because, according to stakeholders, utility-scale solar projects generally use the ITC and utility-scale wind projects generally use the PTC. We modeled both projects with accelerated depreciation for renewable energy property.

In the more generous tax credit environment, we used SAM to calculate the PPA price that yields the investor's rate of return target. We labeled this case as the base case. We analyzed the less generous tax credit environment in two ways. First, we used SAM to calculate the PPA price that provided the investor's target rate of return in the new environment. This solution PPA price will be higher than the solution in the more generous case because the contribution of the tax credit to total after-tax returns is lower (in the solar photovoltaic project), or nonexistent (in the wind project). If the investor is to receive the same return on investment, the returns from energy revenues must increase to replace those lost with the reduction or elimination of the tax credit. Since the amount of

[9]The PTC escalates to adjust for the effects of inflation.

electricity generated by the project does not change, the price at which this electricity is sold is the only mechanism by which higher revenues can be obtained. We labeled this solution as the higher PPA case. In the second solution concept, we maintained the PPA at the level found in the more generous tax credit environment, and we calculated the lower returns that resulted from holding energy revenues at this level while the returns from the tax credit were reduced or eliminated. We labeled this solution as the lower returns case.

For the leveraged partnership and single owner investment structures, the higher PPA case leads to a smaller equity investment by the tax equity investor and the single owner, respectively, because the share of debt financing increases along with increases in the PPA price. In the all equity partnership flip structure, the equity investment share of the tax equity partner does not similarly adjust within the module; rather, it is a parameter chosen by the user of SAM. Because the reduction or elimination of the tax credits would likely reduce the value of these projects to tax investors, and hence their willingness to invest in these projects, we chose to reduce the tax investor’s share in the investment from 60 percent in the base case to 30 percent in the less generous environment.

We specified rate of return targets for the investors based on information we collected in interviews with stakeholders, which included project developers and owners; attorneys and experts who specialize in project finance; industry trade associations; nongovernmental organizations; banks that provide equity and debt financing; and investor-owned utilities, municipally-owned utilities, and electric cooperatives. These stakeholders provided their opinions about investment return targets, including differences that might exist between photovoltaic solar projects and wind projects, and considerations that relate to the different investment structures we analyzed. We synthesized this information in providing specifications for our hypothetical projects, and while we believe that they represent contemporary features and conditions, target rates of return for actual projects vary. Table 14, below, shows the specific rate of return targets we selected for our analysis. Because the choice of target year is influenced by the duration of available tax benefits, we selected different target year values for the partnership flip structures for the wind project; specifically, we selected a 10-year target when the PTC was available to match the 10-year duration of the PTC. We intended for these projects, although hypothetical, to represent utility-scale projects developed by experienced developers with market-tested features. In particular, we did not intend for the rate of return targets we chose to include a premium that investors might look for as compensation for any extra risk that might result from projects that contained particularly risky components—such as untested technology.

Table 14: Rate of Return Targets Used in Analysis Using National Renewable Energy Laboratory's System Advisor Model (SAM)

Investment structure	Energy type	Owner/tax investor rate of return target (%)	Owner/tax investor rate of return target year
Single owner	Solar photovoltaic	10	20
Single owner	Wind	10	20
All equity partnership flip	Solar photovoltaic	8	6
All equity partnership flip	Wind (with Energy Production Credit, also known as the Production Tax Credit [PTC])	8	10
All equity partnership flip	Wind (without PTC)	8	6
Leveraged partnership flip	Solar photovoltaic	13	6
Leveraged partnership flip	Wind (with PTC)	13	10
Leveraged partnership flip	Wind (no PTC)	13	6

Source: GAO interviews with stakeholders. | GAO-15-302.

Installation costs include the costs of acquiring and installing capital equipment, such as panels and inverters in the solar photovoltaic project and wind turbines in the wind project. Installation cost represents the most important determinant of total project costs, and hence affects the scale of the investment on which investor returns are calculated. We relied on studies of recent trends in solar and wind installations conducted by analysts at the Lawrence Berkeley National Laboratory.[10] We discussed the issue of installed costs with several analysts and those familiar with recent trends in renewable energy project costs. We selected an installed cost per watt value of $2.00 for the solar photovoltaic project and an installed cost per watt value of $1.70 for the wind project. We

[10]See G. Barbose, S. Weaver, and N. Darghouth, "Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013," Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory, September 2014; and R. Wiser and M. Bolinger, "2013 Wind Technologies Report," Lawrence Berkeley National Laboratory, August 2014

believe that these values represent reasonable values for installed cost in the environment in which projects are currently being developed.

Total project costs vary across investment structures because of differences in the sources of investment funds. In the single owner and leveraged partnership flip cases, the projects are financed with significant amounts of debt, and there are fees and other costs associated with obtaining loans. Likewise, the partnership flip structures include costs to arrange the partnership and to negotiate the rules under which the partners share the proceeds from the project. Additionally, in the partnership flip structures, we assumed that the project pays the developer a development fee. Table 15 provides information on the values we specified for key cost variables.

Table 15: Values for Cost Items Used in Analysis Using National Renewable Energy Laboratory's System Advisor Model (SAM)

Cost component	Solar photovoltaic project	Wind project
Installed cost	$2.00 per watt, 200,000,000 for the project	$1.70 per watt $254,320,000 for project
Construction financing costs	Construction loan amount = installed costs. Loan term: 12 months, note rate, 5%, loan up-front, 1%	Construction loan amount = installed costs. Loan term: 12 months, note rate, 5%, loan up-front, 1%
Investment structure costs	Equity closing costs: $750,000. Debt closing costs, $450,000. Development fee, 5% of installed costs. Loan up-front fee: 2.75% of loan.	Equity closing costs: $750,000. Debt closing costs, $450,000. Development fee, 5% of installed costs. Loan up-front fee: 2.75% of loan.
Operations and maintenance expenses	$20 per kilowatt, inflated at 2.5%	$ 0.009 per kilowatt hour, inflated at 2.5%
Reserve requirements	6 months of expense reserves, or 50% of year 1 operating expenses. 6 months of principal and interest payments, or 50% of next year's principal and interest payments. Interest rate on reserves: 2%	6 months of expense reserves, or 50% of year 1 operating expenses. 6 months of principal and interest payments, or 50% of next year's principal and interest payments. Interest rate on reserves: 2%
Insurance expenses	0.05% of installed cost, inflated at 2.5% annually	0.05% of installed cost, inflated at 2.5% annually
Equipment replacement	12-year cycle, $250/kilowatt in year 1, inflated at 2.5%, annual reserving to meet replacement schedule	12-year cycle, $250/kilowatt in year 1, inflated at 2.5%, annual reserving to meet replacement schedule

Source: GAO assumptions based on interviews with experts. | GAO-15-302.

As we mentioned above, in addition to tax credits, federal support is available to renewable energy projects through the use of accelerated depreciation for renewable energy property on certain equipment. We allocated 95 percent of the project costs into this depreciation category, and placed the remaining 5 percent into the 20-year straight line category.[11] In the case of the solar projects, we reduced the tax basis by an amount equal to 50 percent of the dollar value of the ITC to reflect the basis disallowance treatment associated with the tax provisions governing the use of the ITC. We assumed that the project's taxable income is subject to a state tax rate of 7 percent and a federal (corporate) tax rate of 35 percent.

In describing partnership flip structures, we mentioned the general rule that the vast majority of cash proceeds and tax benefits early in the project life are allocated to the tax investor, and that once the tax investor meets its rate of return target, the allocation of the proceeds flip, and the vast majority of them flow to the developer. One exception to this rule concerns the possibility of capital recovery by the developer in the all equity partnership flip. The SAM all equity partnership flip permits the developer to recover some or all of its equity investment in the early years of a project by receiving all of the cash proceeds for some period of time or until it recovers its equity investment, at which point the bulk of cash proceeds reverts to the tax investor until the time at which the investor's rate of return target is met. The greater the share of cash that goes to the developer through capital recovery means that less of that cash goes to the tax investor. Thus, a more generous capital recovery selection in SAM increases the developer's after-tax returns and reduces the tax investor's after-tax returns. This in turn means that a higher solution level of the PPA price is required to meet the investor's rate of return target if the developer's capital recovery increases. Looked at another way, there can be different combinations of developer capital recovery and PPA prices that will meet the tax investor's rate of return target, but they will result in different rates of return to the developer.

Because of our analytical focus on the effects of changes in tax credits, we wanted to hold both investor and developer returns constant when looking at the change in the solution value of the PPA price. That is, we wanted the solution PPA price in the higher PPA case to increase by no more than was necessary to meet both partners' investment targets. To

[11]Straight line depreciation refers to an accounting treatment in which the rate of depreciation in an asset's value is assumed to be constant over a period of time. For modeling purposes using SAM, we assumed that some project costs will not be eligible for the ITC. In the case of the solar project we modeled, we assumed that the ITC will not be claimed for the portion of the project costs allocated that we to the 20-year Straight Line depreciation category.

do this in the case of the all equity partnership flip, we modified the SAM financial module so that we could define an explicit after-tax rate of return target for the developer and meet this target by modifying the capital recovery feature in SAM.[12] We specified the developer's target year to be the end of the project life, and we specified a rate of return target of 10 percent.

Analytically, things are somewhat different in the case of the leveraged partnership flip, even though we wanted to hold the developer's returns constant in the higher PPA case. Given the small equity investment by the developer and the presence of a relatively large development fee both occurring at the beginning of the project, we chose to express the developer's returns in terms of the net present value of the total after tax returns, a dollar denominated value rather than in rate of return terms.[13] To do this, we adjusted the size of the development fee paid to the developer so that the developer's returns, defined in net present value terms, did not increase with the higher solution PPA. We used a discount rate of 10 percent to make this calculation; this is the value we selected as the developer's rate of return target in both the all equity partnership flip and single owner structures.

Another aspect of the all equity partnership flip concerns the specification of the ownership shares of the partners. In the current environment, tax investors are generally the majority partners and, based on our interviews with stakeholders, we specified that the tax investor would have a 60 percent ownership share in the more generous tax credit environment. However, information from our interviews and studies by industry analysts also suggests that tax investors would be less willing to make investments at the same scale if the value of the tax benefits is reduced. We specified that the tax investor would have a 30 percent ownership share in the less generous cases we modeled (see table 16).

[12]We accomplished this by first replicating in spreadsheet form the cash flows generated by the SAM financial module for the all equity partnership structure. SAM permits the user to specify that the developer receives full recovery of its equity investment, regardless of how many years that may take, or that the developer receives available cash proceeds for a specified number of years. In either case, SAM contains a built-in constraint to ensure that the developer never receives more than its equity investment. We generalized this constraint so that we could specify that the developer cannot receive more than any given percentage of its equity investment as capital recovery.

[13]For example, in the context of the solar project in the generous case, the developer's equity investment accounted for less than 1 percent of project costs.

Table 16: Characteristics of Partnership Structures

Partnership structure	Key characteristics	
	Solar photovoltaic	**Wind**
All equity partnership flip	Tax investor equity share: 60% when the ITC is 30%, 30% when the ITC is 10%.	Tax investor equity share: 60% when the PTC exists, 30% when the PTC does not exist.
	Tax investor share of cash: preflip 99%, postflip 5%. Tax investor share of tax (includes tax credit): preflip 99%, postflip 5%	Tax investor share of cash: preflip 99%, postflip 5%. Tax investor share of tax (includes tax credit): preflip 99%, postflip 5%.
Leveraged partnership flip	Tax investor equity share, 98%. Tax investor share of cash: preflip 99%, postflip 5%. Tax investor share of tax (includes tax credit): preflip 99%, postflip 5%	Tax investor equity share, 98%. Tax investor share of cash: preflip 99%, postflip 5%. Tax investor share of tax (includes tax credit): preflip 99%, postflip 5%.

Source: GAO assumptions based on interviews with experts. | GAO-15-302

As can be seen from the material presented in this section, SAM requires the user to specify values for many factors that can influence the cost of investments and the returns to those investments. We interviewed many knowledgeable analysts and market participants to develop the values we used for our analysis, and we believe them to be analytically conservative. We recognize that the selection of different values for key factors will lead to different analytical results.

Key Results from SAM

Using SAM, we estimated that reducing or eliminating the value of tax credits increases the required revenues provided through PPAs by approximately 20 to 25 percent in the case of the ITC and approximately 30 to 60 percent in the case of the PTC. The module results suggest that the contribution of the tax credits to total after-tax returns are substantial, and that if developers and investors are to continue to meet their investment targets, projects that appear to have been financially viable in an environment with more generous tax credits would not be viable with less tax credit support without an increased contribution from energy revenue through a higher PPA price or reduced return on investment targets. For example, in the single owner case, the ITC provides approximately half of total after-tax returns when the value of the ITC is 30 percent of a qualified investment and about 23 percent of total after-tax returns when the ITC is reduced to 10 percent. Likewise, for the wind project, the net present value of the PTC is almost half of total after-tax returns when the PTC is in place, and of course makes no contribution to after-tax returns when the PTC is eliminated.

While the increases in calculated solution PPA prices were somewhat smaller in dollars per kilowatt hour for the wind project than for the solar project, when they were expressed in percentage terms, the wind project solution PPA price increases were much larger. The value of the PTC started at $0.023 per kilowatt hour, and increased over time. For the wind projects, the base case solution values were below $0.05 per kilowatt hour in each of the investment structures, so the magnitude of the tax credit was about half or more of the solution PPA price. In terms of the lower returns cases, the projects with debt financing took on the same level of debt as in the base case. This meant that there were large equity investments, but reduction or elimination of the tax credits reduced or eliminated those contributions to total after-tax returns. In the all equity partnership flip structures, the tax equity investor met its rate of return target, but the developer's returns were substantially lower—35 percent in the solar project and over 70 percent in the wind project. In the leveraged partnership flip structure, the project cash flows never flipped, which meant that the tax investor was not able to meet its target rate of return even by the end of the project.

We do not characterize the PPA price or investment return changes shown in these tables as predictions of what will happen to electricity prices or to potential investments in and returns from utility-scale renewable energy projects. Some investment structures may become less favored, and other structures may become more favored in response to a change in the level or form of federal support. Nonetheless, we think that the results indicate that the reduction in federal support of renewable energy projects would put upward pressure on the level of PPA prices and downward pressure on the returns that could be reasonably expected by developers. As such, reducing the ITC or eliminating the PTC could result in a combination of the effects suggested in our modeling. Specifically, to compensate for the decline in federal support, developers might be willing to accept lower rates of return, and states might be willing to require utilities and other retail service providers to pay higher electricity prices. However, there may be limits to which these effects could offset a reduction in federal supports. Placed in a broader context, the willingness of utilities and their regulators to agree to significantly higher prices will likely constrain the ability of developers to maintain their returns on investment by negotiating PPAs with significantly higher prices. Similarly, to the extent that project lenders and investors have alternative investment opportunities, it seems unlikely that they would make financing cost concessions on a scale that would offset the reduction in federal support. Developers themselves are likely to have alternative outlets, either in the energy sector or elsewhere, in which to direct investments if expected returns from renewable energy projects are reduced to unacceptably low levels. Collectively, the constraints faced by project developers may lead to a reduction in the level of investment in renewable energy projects if reductions in the level of federal support in the magnitude examined here are observed.

Tables 17, 18 and 19 present the module's results for the hypothetical solar project under the three ownership structures. In table 17 we express owner returns and in table 18, we express developer returns in terms of after-tax internal rates of return. In table 19, we express developer returns in terms of the present value of after-tax returns flowing to the developer.

Table 17: Solar Photovoltaic Project, Energy Investment Credit (ITC), Single Owner

Case	Value of ITC (%)	Owner's actual internal rate of return (IRR) (%)	Year IRR target met	Debt share (%)	Solution power purchase agreement (PPA) ($/kilowatt hour)	Increase in PPA (%)	Decrease in owner IRR
Base case	30	10	20	48.26	.0891		
Higher PPA	10	10	20	62.32	.1075	20.7	
Lower returns	10	2.4	not met	48.26	.0891		-76.0

Source: GAO analysis using SAM. | GAO-15-302

Table 18: Solar Photovoltaic Project, Energy Investment Credit (ITC), All Equity Partnership Flip

Case	Value of ITC (%)	Investor's actual internal rate of return (IRR) (%)	Year IRR target met	Developer internal rate of return (IRR) (%)	Tax investor equity share	Developer capital recovery selection (%)	Solution power purchase agreement (PPA) ($/kilowatt hour)	Increase in PPA (%)	Decrease in IRR (%)
Base case	30	8	6	10	60	33.1	.1277	————	————
Higher PPA	10	8	6	10	30	61.6	.1617	26.6	————
Lower returns	10	8	6	6.5	30	48.5	.1277	————	-35.0

Source: GAO analysis using GAO's modified version of SAM. GAO-15-302

Table 19: Solar Photovoltaic Project, Energy Investment Credit (ITC), Leveraged Partnership Flip

Case	Value of ITC (%)	Investor's actual internal rate of return (IRR) (%)	Year IRR target met	Developer returns, net present value (million $)	Debt share (%)	Development fee (%)	Solution power purchase agreement (PPA) ($/kilowatt hour)	Increase in PPA (%)	Decrease in developer net present value (%)
Base case	30	13	6	10.6	52.30	5.0	.0977	———	———
Higher PPA	10	13	6	10.6	66.49	4.3	.1168	19.5	———
Lower returns	10	4.2	not met	5.1	52.30	5.0	.0977	———	-51.9

Source: GAO analysis using SAM. | GAO-15-302

Tables 20, 21, and 22 present the module results for the hypothetical wind project under the three ownership structures. In table 20 we express owner returns and in table 21, we express developer returns in terms of after-tax internal rates of return. In table 22, we express developer returns in terms of the present value of after-tax returns flowing to the developer.

Table 20: Wind Project, Energy Production Credit (PTC), Single Owner

Case	Value of PTC, first year ($ per kilowatt hour)	Owner's actual internal rate of return (IRR) (%)	Year IRR target met	Debt share (%)	Solution power purchase agreement (PPA) ($/kilowatt hour)	Increase in PPA (%)	Decrease in owner IRR (%)
Base case	.023	10	20	38.01	.0369	———	———
Higher PPA	.000	10	20	66.26	.0527	42.8	
Lower returns	.000	-0.9	not met	38.01	.0369	———	-109.0

Source: GAO analysis using SAM. | GAO-15-302

Table 21: Wind Project, Energy Production Credit (PTC), All Equity Partnership Flip

Case	Value of PTC, first year ($ per kilowatt hour)	Investor's actual internal rate of return (IRR) (%)	Year IRR target met	Developer IRR (%)	Tax investor equity share	Developer capital recovery selection (%)	Solution power purchase agreement (PPA) ($/kilowatt hour)	Increase in PPA (%)	Decrease in developer IRR (%)
Base case	.023	8	10	10	60	74.9	.0471	———	———
Higher PPA	.000	8	6	10	30	50.8	.0761	61.6	———
Lower returns	.000	8	6	2.8	30	23.3	.0471	———	-72.0

Source: GAO analysis using GAO's modified version of SAM. | GAO-15-302

Table 22: Wind Project, Energy Production Credit (PTC), Leveraged Partnership Flip

Case	Value of PTC, first year, ($ per kilowatt hour)	Investor's actual internal rate of return (IRR) (%)	Year IRR target met	Developer returns, net present value (million $)	Debt share (%)	Development fee (%)	Solution power purchase agreement (PPA) ($/kilowatt hour)	Increase in PPA (%)	Decrease in developer net present value (%)
Base case	.023	13	10	18.9	48.1	5.0	.0438	———	———
Higher PPA	.000	13	6	18.9	72.5	3.6	.0577	31.7	———
Lower returns	.000	1.9	Not met	6.1	48.1	5.0	.0438	———	-67.7

Source: GAO analysis using SAM. | GAO-15-302

Appendix IX: GAO Contact and Staff Acknowledgments

GAO Contact

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Staff Acknowledgments

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Appendix X: Accessible Data

Data Table for Figure 1: Number and Type of New Utility-Scale Electricity Generation Projects, 2004-2013

State	Renewable	Traditional
Alabama	4	5
Alaska	10	6
Arizona	58	8
Arkansas	6	7
California	348	95
Colorado	48	9
Connecticut	3	20
Delaware	11	3
District of Columbia	0	1
Florida	30	24
Georgia	28	4
Hawaii	19	0
Idaho	44	3
Illinois	45	9
Indiana	34	6
Iowa	65	11
Kansas	23	13
Kentucky	5	5
Louisiana	4	14
Maine	18	2
Maryland	30	4
Massachusetts	86	13
Michigan	38	6
Minnesota	102	11
Mississippi	3	4
Missouri	10	4
Montana	16	5
Nebraska	10	6
Nevada	35	12
New Hampshire	8	0
New Jersey	116	13
New Mexico	37	8
New York	53	27
North Carolina	135	11
North Dakota	23	2

State	Renewable	Traditional
Ohio	33	8
Oklahoma	24	5
Oregon	51	4
Pennsylvania	61	10
Rhode Island	9	0
South Carolina	18	6
South Dakota	8	4
Tennessee	16	2
Texas	116	50
Utah	12	9
Vermont	17	0
Virginia	18	5
Washington	37	4
West Virginia	5	1
Wisconsin	29	12
Wyoming	16	4

Data Table for Figure 2: Number and Type of New Utility-Scale Electricity Generation Projects and Added Generating Capacity, 2004-2013

Number of Projects

Solar	Wind	Other Renewables	Coal	Natural Gas
778	686	511	49	446

Generating Capacity (MW)

Solar	Wind	Other Renewables	Coal	Natural Gas
7,179	54,529	7,685	29,848	127,251

Data Table for Figure 3: Renewable Generating Capacity Added From 2004 Through 2013 in States with and without a Renewable Portfolio Standard (RPS) or Renewable Portfolio Goal (RPG)

State	Renewable generating capacity
Alabama	41
Alaska	87
Arizona	1545

State	Renewable generating capacity
Arkansas	22
California	8196
Colorado	2261
Connecticut	45
Delaware	45
District of Columbia	0
Florida	594
Georgia	416
Hawaii	485
Idaho	1023
Illinois	3565
Indiana	1646
Iowa	4648
Kansas	2895
Kentucky	13
Louisiana	164
Maine	499
Maryland	216
Massachusetts	272
Michigan	1402
Minnesota	2525
Mississippi	4
Missouri	481
Montana	716
Nebraska	525
Nevada	935
New Hampshire	254
New Jersey	402
New Mexico	781
New York	1861
North Carolina	691
North Dakota	1744
Ohio	611
Oklahoma	2960
Oregon	3044
Pennsylvania	1653
Rhode Island	67

State	Renewable generating capacity
South Carolina	163
South Dakota	747
Tennessee	183
Texas	11280
Utah	424
Vermont	188
Virginia	611
Washington	4042
West Virginia	520
Wisconsin	768
Wyoming	1134

Data Table for Figure 4: Progress Made by Investor-Owned Utilities toward Completing Their State's Renewable Portfolio Standard (RPS)

Percentage	Requirements and goal completion
25%	Less than halfway
4%	Halfway
54%	More than halfway
8%	They have met all requirements or goals
8%	They have exceeded requirements or goals

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