Federal and State Structures to Support Financing Utility-Scale Solar Projects and the Business Models Designed to Utilize Them

Michael Mendelsohn and Claire Kreycik

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List of Acronyms

ACP	alternative compliance payment
AMT	alternative minimum tax
CSP	concentrating solar power
D.C.	District of Columbia
DG	distributed generation
DOE	Department of Energy
EESA	Emergency Economic Stabilization Act of 2008
FIPP	Financial Institute Partnership Program
IOU	investor-owned utility
IPP	independent power producer
IRS	Internal Revenue Service
ISO	independent system operator
ITC	investment tax credit
LADWP	Los Angeles Department of Water and Power
LSE	load-serving entity
MACRS	Modified Accelerated Cost Recovery System
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas and Electric
PPA	power purchase agreement
PSE&G	Public Service Electric & Gas Company
PTC	production tax credit
PV	photovoltaic
REC	renewable energy certificate
Recovery Act	American Recovery and Reinvestment Act
REFTI	Renewable Energy Finance Tracking Initiative
RPG	renewable portfolio goal
RPS	renewable portfolio standard
SCPPA	Southern California Public Power Authority
SDG&E	San Diego Gas and Electric
SREC	solar renewable energy certificate

Executive Summary

Over the past two decades, state and federal policymakers have enacted numerous policies to support new renewable energy development. The following report evaluates those policies based on industry literature, publicly available data, and questionnaires conducted by the National Renewable Energy Laboratory (NREL). As such, the report is relevant to policymakers who want to enable project financing via effective legislation, to regulators interested in supporting new project development, and to new investors interested in entering the renewable energy project finance space.

Three policy types have been critical to the widespread deployment of utility-scale solar facilities:

1. Federal tax benefits comprising the 30% investment tax credit (ITC) and accelerated depreciation schedules, and the Section 1603 cash grant program available in lieu of the ITC
2. The Department of Energy (DOE) loan guarantee program, which has provided guarantees and access to low-cost financing, enabling larger solar energy projects than ever deployed before
3. State renewable portfolio standards (RPS), enacted by 29 states and the District of Columbia (D.C.), which have created a necessary demand for renewable energy, and in particular, have led to the signing of long-term contracts critical to financing large-scale solar facilities.

As of February 21, 2012, the Section 1603 (also known as the "cash grant") program had awarded $10.76 billion in grants to roughly 23,000 projects (Department of Treasury 2012). The cash grant program expired in 2011 but will award projects that started construction in 2009, 2010, or 2011.

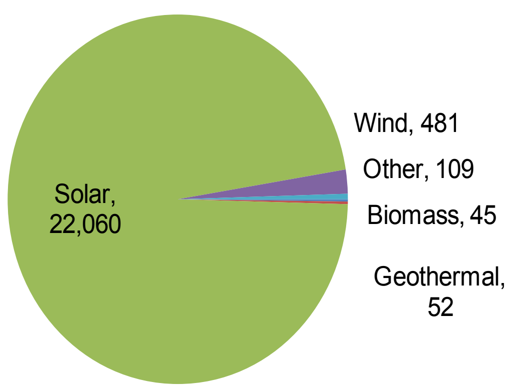

Figure ES-1. Grants awarded by technology

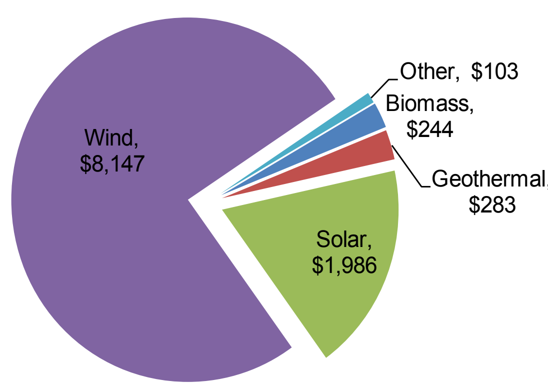

Figure ES-2. Funding awarded by technology ($millions)

Source: Department of Treasury 2012

Utility-scale solar projects in particular benefitted significantly from the loan guarantee program. The loan guarantee program provides access to capital at a lower cost and larger quantity than what private markets would provide without the program. Through January 2012, solar projects have been supported solely under Section 1705 of the loan guarantee program, through which over $12 billion in loans have been made to 3,500 MW of solar projects. To support the solar project loans, an estimated $1.4 billion in credit subsidy costs have been paid under the American Recovery and Reinvestment Act, as shown in Table ES-1.

Table ES-1. Loan Guarantees for Solar Generation Projects

Technology	Loan Amount ($billions)	Estimated Credit Subsidy at 11.7% Rate ($billions)
Solar Photovoltaic (PV)	6.14	0.72
CSP	5.86	0.69
Solar Manufacturing	1.28	0.15
Wind	1.70	0.20
Other Technologies	1.19	0.14
Total	**16.16**	**1.88**
Solar Electric Generation Only	*12.00*	*1.40*

The credit subsidy is essentially a fund set aside by the DOE to cover the costs associated with specific project failures. As the loan guarantee program required an average credit subsidy of 11.7% per project, every dollar the DOE spends in credit subsidy will support $8.55 in loans. Assuming an average financial structure of 60% debt and 40% equity (actual equity investments are not known), each credit subsidy dollar invested can actually be extended to support $14.25 in solar project development.

Of note, the private bond market—without any loan guarantees—has rebounded from the financial crisis. In February 2012, to finance the Topaz purchase, MidAmerican Energy successfully offered $850 million of private placement bonds and is considering a second bond offering to raise an additional $430 million.

State RPSs create critical demand for large-scale generation projects, driving investor-owned and public utilities to sign long-term purchase power agreement (PPA) contracts with solar project developers. These PPAs are fundamental to project financing as debt and equity investors will not risk capital without the surety of revenue from a creditworthy counter-party to the contract.

However, the solar industry is capable of far greater deployment than currently required under the collective RPSs presently enacted. The Lawrence Berkeley National Laboratory recently estimated that nine states and D.C. have specific solar renewable energy certificate requirements and will require incremental solar capacity of 6,729 MW by 2025 (Barbose 2011). That represents roughly 480 MW of solar capacity installed per year, less than half the total domestic installations in 2010. Even in the most aggressive state—New Jersey—current solar project deployment meets the build-out requirements for 2025.

Although the array of federal and state support mechanisms greatly improved the ability of solar energy projects to achieve financing, complex financial structures were still required to utilize the depreciation benefits and access investment capital. The advanced financial structures described in this report include:

- Single owner finance, which includes utility balance sheet financing and developer balance sheet financing
- Lease structures generally referred to as sale-leaseback and inverted leases
- Partnership flips
- Utility prepay (which has been solely utilized by the wind industry only modestly to date).

This report is NREL's second study in a three-part series on utility-scale solar in the United States. In the first study (Mendelsohn et al. 2012b), NREL found that, as of January 2012, approximately 16,000 MW of utility-scale solar projects (defined as 5 MW or larger) are in various stages of advanced development and hold a contract with an investor-owned or public utility. If all these projects come to fruition, the amount of solar in the United States will increase approximately six-fold. The third study (Mendelsohn et al. 2012a) is a quantitative analysis on the cost impact of specific financial structures and terms as they relate to utility-scale solar facilities.

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1 Introduction

Utility-scale solar projects have grown rapidly in number and size over the last few years, driven in part by strong renewable portfolio standards (RPS) and federal incentives designed to stimulate investment in renewable energy technologies. This report provides an overview of such policies, as well as the project financial structures they enable. For the purposes of this report, utility-scale solar plants are defined as generators 5 MW or larger that have a signed power purchase agreement (PPA) with an electric utility (or are being developed by an electric utility).

This report is the second in a three-part series regarding utility-scale solar markets, policies, and financing practices. The first part, *Utility-Scale Solar Concentrating Solar Power and Photovoltaics Projects: A Technology and Market Overview* (Mendelsohn et al. 2012b), describes solar power generation technologies and characterizes the market landscape and projects in the pipeline. The third part, *The Impact of Financial Structure on the Cost of Solar Energy* (Mendelsohn et al. 2012a), provides a quantitative analysis of financial structure and term and insight from renewable energy financial professionals.

The first report, providing technology and market overview, finds that as of January 2012, slightly over 16,000 MW of utility-scale solar projects are in various stages of advanced development and hold contracts with an investor-owned or public utility. Photovoltaic (PV) technologies account for 72% of this capacity, and concentrating solar power (CSP) technologies account for about 26%. The remaining 2% is comprised of projects that utilize unconventional solar technologies. Utility-scale installations represent the fastest growing segment of the solar industry. Third quarter (Q3) 2011 installations of over 200 MW were about as large as total 2010 utility-scale installations (SEIA 2011).

2 Policies Supporting Utility-Scale Solar Development

Federal and state policies provide crucial support to the solar industry in the form of tax incentives, grants, loan guarantees, renewable energy standards, and production incentives.

2.1 Federal Economic Recovery Policies

The Energy Policy Act of 2005 increased the investment tax credit (ITC) for solar energy systems from 10% to 30% of eligible solar property (SEIA 2011). The ITC reduces the overall tax liability for individuals or businesses that make investments in solar energy generation technology.

The Emergency Economic Stabilization Act of 2008 (EESA) extended the 30% ITC for solar and other qualifying renewable technologies through December 31, 2016 (Duval & Stachlenfeld 2008).[1] EESA expanded the ITC use by making it available to public utilities (investor-owned utilities). Prior to EESA, public utilities were not eligible for ITC benefits.

The American Recovery and Reinvestment Act (Recovery Act), passed in February 2009, further expanded the availability and usability of various tax credits, depreciation opportunities, loan guarantees, and other mechanisms designed to encourage private investment in renewable energy and energy efficiency projects (Chadbourne & Parke 2010b). Specifically, the Recovery Act enabled ITC-eligible projects to receive a grant of equivalent value in lieu of the tax credit. The U.S. Department of the Treasury grant program is described in Section 2.1.2.

2.1.1 Investment Tax Credit Provisions

The ITC reduces federal income taxes for qualified owners based on capital investment in renewable energy projects. The ITC is realized in the year in which the solar project begins commercial operations, but Internal Revenue Service (IRS) regulations require the asset be retained for a five-year period during which the asset vests to the owner. As dictated by the "clawback" provision, the IRS will recapture any unvested portion of the credit if the project owner sells the project before the end of the fifth year of commercial operations (Bolinger 2009a).[2]

In addition to extending the 30% ITC for solar and other qualifying renewable technologies through December 31, 2016, EESA allows the ITC to offset both regular and alternative minimum tax (AMT) and permits utilities to claim the ITC when directly investing in solar facilities (although "normalization" rules complicate the benefit to utilities and their ratepayers[3]).

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[1] On January 1, 2017, the ITC will revert back to 10% (Bolinger et al. 2009).
[2] Clawbacks are, in effect, a requirement to return previously distributed money or credited funds.
[3] IRS rules on utility normalization mean that the benefit of the tax credit cannot be passed on to the utility's customers in a time period shorter than the life of the facility (approximated by the length of the PPA). This essentially limits utility customer benefit from the ITC program. For more information, please

"Passive activity loss rules," also known as "passive income" rules, also come into play with the ITC. These rules were enacted as part of the Tax Reform Act of 1986 to prevent the use of losses from activities in which an investor did not actively participate to offset that investor's wage, interest, and dividend income. Passive activities involve the conduct of a trade or business in which the taxpayer does not materially participate, such as rental income (Tracy 2010).[4] This limitation is known to constrain the availability of tax equity.
.

2.1.2 Investment Tax Credit and Treasury Grants

Under Section 1603 of the Recovery Act, qualifying commercial renewable energy projects can accept a cash payment in lieu of either the ITC or production tax credit (PTC). The payment is generally referred to, albeit incorrectly, as a cash grant, and the program as the Treasury grant program.[5] Via the program, the Treasury pays grants equal to 30% of the cost of solar property placed in service (Bolinger et al. 2009). The program was originally scheduled to terminate on December 31, 2010, but Congress extended it through December 31, 2011. Property that is not placed in service prior to December 31, 2011, can qualify for the grant program as long as construction has commenced prior to that date. In order to be considered under construction, a project must begin "physical work of a significant nature" and conduct continuous construction (excluding preliminary work like planning, designing, and preparing land) or meet a "safe harbor" requirement, whereby 5% of total costs are incurred by the end of 2011. In either case, the solar facility must be placed in service before January 1, 2017 (Chadbourne & Parke 2010a; Hastings 2010).

Importantly, the 1603 Treasury grant is not a reduction in taxes and, thus, does not require taxable income to offset. However, only entities that pay taxes (and thus are eligible for the ITC) are eligible to receive the Treasury grant, negating the opportunity for municipal entities and non-profits to directly participate in the program.

According to the latest data issued by the Treasury, as of February 21, 2012, $10.76 billion[6] was awarded through the 1603 Treasury grant program to roughly 22,747 projects[7] (Department of Treasury 2012). As seen in the following figures, 22,060 approved solar projects received $1.99 billion (18%) of the total grant money awarded. Of this amount, $1.85 billion (93%) was awarded to "solar electric" projects and $133 million (7%) to "solar thermal" projects. Wind projects received the majority of Treasury grant awards (in dollar value) with over $8.15 billion, or 76% of the total. The

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see https://financere.nrel.gov/finance/content/normal-accounting-rules-limit-utility-ownership-renewable-energy-projects.

[4] See http://www.irs.gov/businesses/small/article/0%2C%2Cid=146335%2C00.html.

[5] According to grants.gov, a federal grant is "an award of financial assistance from a federal agency to a recipient to carry out a public purpose of support or stimulation authorized by a law of the United States." In contrast, the 1603 Treasury grant is a payment in lieu of receiving the ITC.

[6] From the "List of Awards" spreadsheet made available on the Department of Treasury website. http://www.treasury.gov/initiatives/recovery/Pages/1603.aspx. Accessed February 7, 2012.

[7] Number of awards data cited from the "Status Overview" document, available on the Department of Treasury website, last updated October 31, 2011. The aforementioned "List of Awards" spreadsheet, while more recently updated, groups many smaller projects and thus does not accurately represent the number of projects awarded.

remaining Treasury grants were awarded to an array of other renewable and advanced generating technologies.

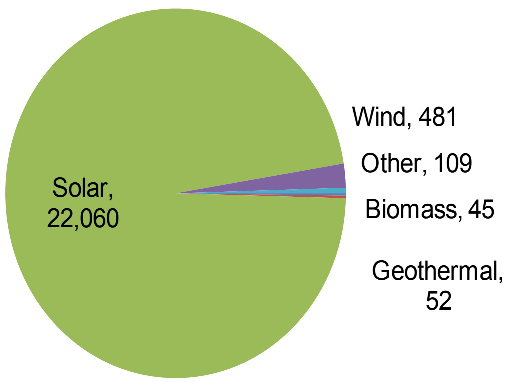


Figure 1. Grants awarded by technology

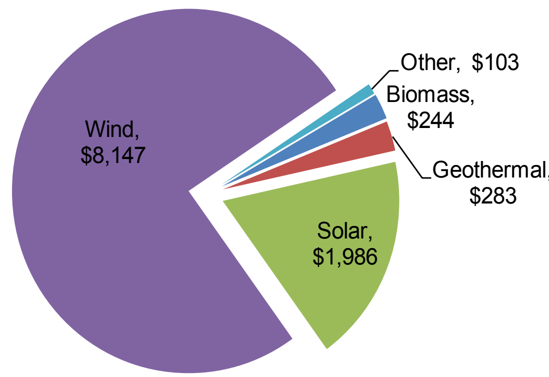


Figure 2. Treasury funding by technology ($ millions)

Source: Department of Treasury 2012

Assuming the 1603 awards equal 30% of all capital invested,[8] the $10.76 billion awarded as of February 21, 2012, has induced $25.11 billion in private investment or led to a total investment of $35.87 billion in renewable energy projects since its inception in 2009.

The top 15 grant-receiving states are depicted in Figure 3 (Department of the Treasury 2012). Texas, with a substantial number of wind projects, leads the nation, receiving almost $1.7 billion in total Treasury grant dollars. Entities in all 50 states, the District of Columbia (D.C.), and Puerto Rico have been awarded Treasury grants.

[8] For several reasons, the 1603 awarded dollars may not match 30% of total expenditures precisely. The 1603 award, like the ITC, is only applied to "eligible" investment, which can exclude certain ancillary costs such as fencing and roads.

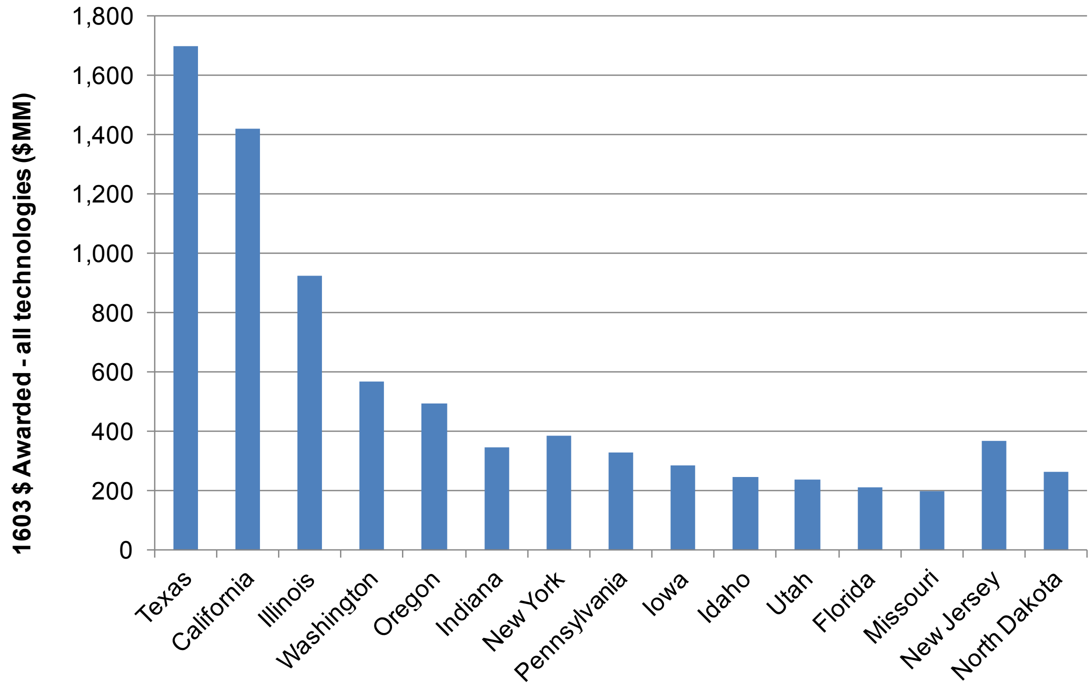


Figure 3. Treasury grants awarded for top 15 States

(as of February 21, 2012)

Since its inception in 2009, the Treasury grant program has been widely credited with improving the speed and accessibility of financing for solar projects (Mendelsohn and Harper, forthcoming). NREL gathers information on project finance terms and gauges attitudes on the value of renewable energy policies through an effort called the Renewable Energy Finance Tracking Initiative (REFTI). A REFTI questionnaire conducted in March 2011 suggests that the renewable energy industry highly values the Treasury grant program. The majority of participants, 42 of 48 (89%), indicated the program is either "extremely" or "very" important to project development success (Figure 4). Participants in the questionnaire place a higher level of importance on Treasury grants than on state incentives or RPSs.

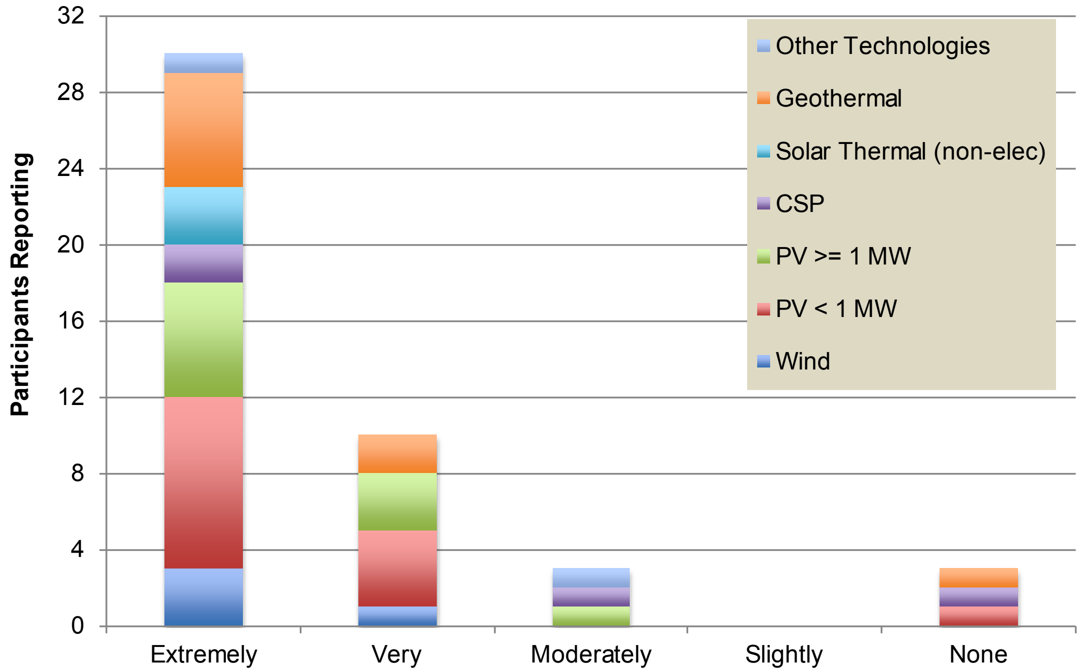


Figure 4. Reported level of importance of the Treasury grant program by renewable energy technology

(Total participants = 48)
Source: REFTI 2011

In a separate REFTI poll conducted by NREL in August 2010, 27 participants indicated that 64% of their projects completed in the prior 12 months were "dependent" on the Treasury grant, meaning they would likely not have been completed without the Treasury grant support.[9]

One reason for Treasury grant popularity is the reduced transaction cost to utilize this support structure versus the ITC. Generally, renewable energy projects and their developers do not have sufficient tax liability to take advantage of the ITC directly and therefore must seek a tax equity investor to monetize the benefit. Sheldon Kimber, Chief Operating Officer of Recurrent Energy, explained in an interview that monetizing the ITC via a tax equity investor can consume 15%–40% of the ITC benefit (Kimber 2010). Kimber explained that the high fees are not only due to the higher yield required by a tax equity investor to monetize a true tax credit but also because certain tax investors seek project ownership after the assumed 20-year life of the facility. Developers, on the other hand, assume cash flows to 25 or 30 years. Passing on project ownership—even after 20 years—alters the developer's return and, in essence, raises the transaction costs associated with monetizing tax credits.

[9] See NREL REFTI results for Q1 2010 at http://financere.nrel.gov/finance/REFTI, slide 27.

Separately, in a third poll conducted by NREL, industry participants indicated that the transaction costs to monetize the ITC represented 23% of the benefit, roughly corroborating the value specified by Kimber (Mendelsohn 2010).[10] That is, on a weighted average basis, 23% of the benefit is lost to monetizing via a third-party tax equity investor. In contrast, poll participants indicated the transaction costs to monetize a Treasury grant equaled 14% of the benefit. Monetization of the Treasury grant can be completed in the form of bridge finance until the award is received.

If accurately represented by these polling participants, monetizing the ITC and the Treasury grant incurs a differential in transaction costs of almost 9%. This transaction cost differential is worth over $900 million of the $10.76 billion awarded via the 1603 program as of February 21, 2012. The estimated $900 million in savings represent a direct investment into renewable energy projects rather than transaction costs to monetize the federal benefit.

2.1.3 Subsidized Financing

The Recovery Act allowed businesses to capture the full value of the ITC or Treasury grant even if projects receive subsidized energy financing (Bolinger et al. 2009). Prior to the Recovery Act, the ITC would not apply to the portion of the investment funded via subsidized financing, including below-market loans, state grants, and private activity bonds. This is frequently referred to as a reduced "basis," representing the percentage of capital expenditures that are eligible for recovery through the ITC. Now, the tax credit benefit of the project is not subject to a reduced basis. Accordingly, utility-scale solar facilities may be able to access tax-exempt funding sources such as municipal or state bonds or other low-interest loan programs without incurring a reduction in the ITC received.

2.1.4 Clean Energy Loan Guarantee Program

The Department of Energy (DOE)[11] offered three financial support structures administered by DOE's Loan Program Office. The loan programs were designed to "mitigate the financing risks associated with clean energy projects, and thereby encourage their development on a broader and much-needed scale" (DOE 2011). These were:

- Section 1703: Section 1703 of Title XVII (from the Energy Policy Act of 2005) authorizes DOE to guarantee loans for projects that employ new or significantly improved energy technologies and avoid, reduce, or sequester air pollutants or greenhouse gases.
- Section 1705: Section 1705 of Title XVII, added by the Recovery Act, authorizes DOE to guarantee loans for certain clean energy projects that

[10] The monetization values represent the weighted averages of bin ranges selected by 17 industry participants participating in a 2010 REFTI webinar. Monetization of the ITC also referenced the accelerated depreciation benefits, which continue to require tax equity investment or direct use by the project developer.

[11] Other agencies, such as the Export-Import Bank, the Overseas Private Investment Corporation, the Department of Defense R&D fund, and U.S. Department of Agriculture also offer loan programs.

commenced construction on or before September 30, 2011. The program was suspended after that date.

- Advanced Technology Vehicles Manufacturing: Section 136 of the Energy Independence and Security Act of 2007 authorizes DOE to provide direct loans to finance advanced vehicle technologies.

Only 1703 and 1705 are relevant to utility-scale solar. Solar projects (both generation and manufacturing) have only been awarded loan guarantees under 1705.

Through the 1703/1705 programs, the government guarantees debt associated with new energy production or manufacturing facilities relevant to renewable and other energy technologies (e.g., clean coal). Government guarantee on debt lowers the risk and required yield on the funds raised for potential lenders (DOE 2011). Initially under the Recovery Act, Congress appropriated $6.0 billion to the 1705 program. However, in August 2009 $2.0 billion was redirected to the Car Allowance Rebate System (also known as Cash for Clunkers program), and in August 2010, an additional $1.5 billion was removed to pay for extended unemployment benefits and other initiatives. These withdrawals have reduced the total 1705 program size to approximately $2.4 billion (Bartlett and Goldstein 2010).

Loan guarantees are awarded in the form of credit subsidies (Jaffe 2009). A credit subsidy is a similar structure to a loan loss reserve, in which banks set aside money to cover defaults in their loan portfolio. Likewise, for each loan guarantee award, the federal government sets aside a sum (the credit subsidy) in the project's name, which acts as insurance in the case of project failure. The credit subsidy is specific to each loan but was initially estimated by industry experts to average roughly 10% (Bracewell & Giuliani 2009). That means every dollar spent in credit subsidy would leverage $10 in loans.

Table 1. 1705 Loan Guarantee Information

Program	Loan Amount ($billions)	Estimated Credit Subsidy at 11.7% Rate ($billions)
PV Electric Generation	6.14	0.72
CSP Electric Generation	5.86	0.69
Solar Manufacturing	1.28	0.15
Wind Generation	1.70	0.20
Other Technologies	1.19	0.14
Total	**16.16**	**1.88**
Solar Electric Generation Only	*12.00*	*1.40*

The total investment supported by the credit subsidy allocation, including investor equity, could actually be much larger than indicated. For example, assume an investment was financed with 60% debt and 40% equity. In such a scenario, assuming an 11.7% credit subsidy, every dollar of credit subsidy invested could support $8.55 in debt and $5.70 of equity, or $14.25 in total investment (see Figure 5). In this case, the 11.7% credit subsidy represents only 7% of the total capital invested. The equity investments of the projects under the 1705 program are unknown, but this concept illustrates the potential capability of the credit subsidy to induce capital investments.

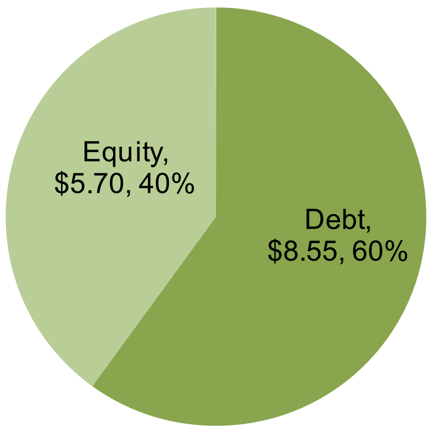


Figure 5. Hypothetical financial structure from $1 of loan guarantee

The solicitation for loan guarantees for "innovative" technologies (Section 1703) was issued on July 29, 2009. "Innovative" technologies are defined as those that either (1) have not been installed and used in three or more projects in the United States or (2) involve meaningful and important improvements in productivity or value in comparison to commercial technologies (Klepper 2009). Loans are available from the Federal Financing Bank—which can provide very low-cost debt—if an applicant seeks a 100% guarantee from DOE (WSGR 2009).

The solicitation for loan guarantees for "commercial" technologies (Section 1705) was issued on October 7, 2009 (DOE 2010). The solicitation defines "commercial" technologies as those that have been used in three or more commercial applications anywhere in the world and that have been in operation for at least two years (Klepper 2009). Under this solicitation, DOE required that developers also partner with a private lender. DOE created the Financial Institution Partnership Program (FIPP), which specifies debt cannot exceed 80% of total capital. The DOE guaranteed up to 80% of the loan, or 64% of the total capital (DOE 2010). FIPP was designed for simple project finance structures without complex tax equity arrangements (Klepper 2009). Accordingly, these projects—which may not have completed financing as of this report publication—will likely not be able to use a complex financial structure such as a partnership flip or sale-leaseback to monetize the tax benefits and take advantage of the loan guarantee program. These financial structures are discussed in more detail in Section 3.2.

To date, renewable energy projects have only been awarded loan guarantees under the 1705 program. In total, the 1705 program awarded $16.16 billion in loan guarantees to 28 projects (DOE 2011). Of those, 19 are power generation projects, including PV, CSP, wind, and geothermal. Solar generation represents 12 projects (7 PV, 5 CSP) expected to produce a peak output of over 3,500 MW, supported by $12.0 billion in loan guarantees.[12]

Table 2. Renewable Energy Loan Guarantee Awarded (by Program)

Program	Loan Amount ($billions)	MW_{AC}	Exp. Annual Generation (GWh)
PV Electric Generation	6.14	2,272	4,730
CSP Electric Generation	5.86	1,243	3,623
Solar Manufacturing	1.28		
Wind	1.69	1,025	2,188
Other Technologies	1.19	180	1,492
Total	16.16		
Solar Generation Only	**12.00**	**3,515**	**8,353**

The specific solar generation projects awarded 1705 loan guarantees are shown in Table 3.

[12] All but one 1705 loan guarantee for solar is considered utility scale. The lone exception is the $1.4 billion loan guarantee to Prologis, the largest owner of warehouses in the country, which plans to develop a large number of rooftop PV sites with the loan guarantee. Individual projects under the Prologis effort are not yet known, although the overall project is predicted to produce 752 MW at peak output in 28 states.

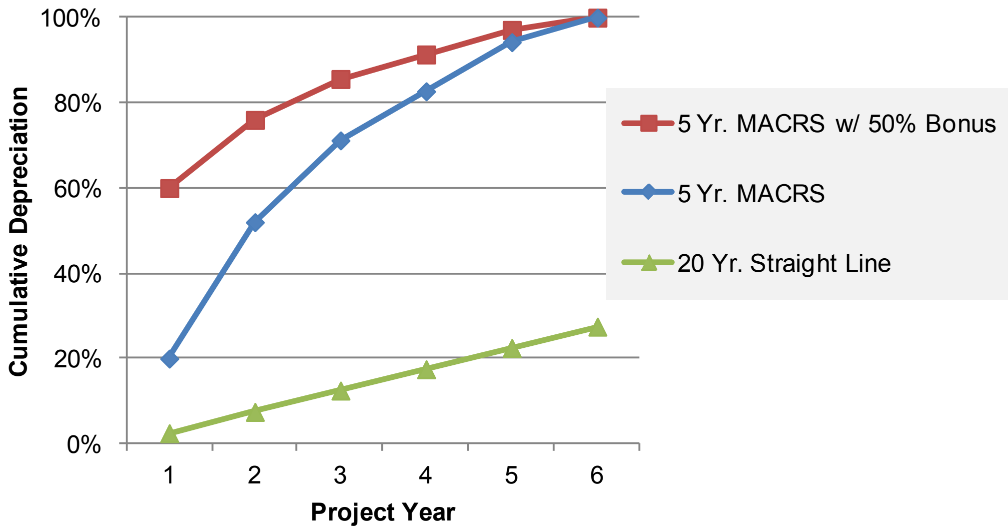
Table 3. Solar Electric Generation DOE Loan Guarantees Awarded (by Project)

Technology/Project	Loan Amount ($B)	MW_{AC}	Exp. Annual Generation (GWh)
PV Electric Generation			
First Solar, Inc. (Antelope)	0.65	230	623
First Solar, Inc. (Desert Sunlight)	1.46	550	1,280
Prologis	1.40	752	1,015
SunPower (CVSR)	1.24	250	740
Mesquite Solar 1, LLC (Sempra Mesquite)	0.34	170	350
Cogentrix	0.09	30	75
Agua Caliente	0.97	290	648
Sub-Total PV Elec. Generation	6.14	2,272	4,730
CSP Electric Generation			
SolarReserve, LLC (Crescent Dunes)	0.74	110	504
Abengoa Solar, Inc. (Mojave Solar)	1.20	250	617
NextEra Energy Resources, LLC (Genesis Solar)	0.85	250	560
BrightSource Energy, Inc. (Ivanpah Solar Gen. System)	1.63	383	998
Abengoa Solar, Inc.	1.45	250	944
Sub-Total CSP Elec. Generation	5.86	1,243	3,623

Continued access to the loan guarantee program is a concern to developers of large projects. According to David Crane, President and CEO of NRG Energy, Inc., projects similar to the 290 MW Agua Caliente project or the 250 MW Colorado Valley Solar Ranch—both supported by the loan guarantee program—would not be viable in the current financial environment without loan guarantees (Englblom 2011).

2.1.5 Modified Accelerated Cost Recovery System Depreciation

Another federal policy encouraging utility-scale solar is Modified Accelerated Cost Recovery System (MACRS). Under Section 168 of the tax code, “equipment which uses solar energy to generate electricity” qualifies for five-year, double declining-balance depreciation (GE Capital 2010). As shown in Figure 6, MACRS allows full depreciation of the asset over five years of project life, or six tax years. Depreciation of the asset can be further accelerated through “bonus depreciation,” which provides significant tax benefits in the first year of an asset life. The bonus depreciation reverts from 100% of the eligible plant in 2011 to 50% in 2012. These depreciation schedules are compared to a 20-year straight-line schedule (over the first six years only) to show the relative speed at which capital can be reduced in book value in order to lower taxes payable on income.



Note: Only the first six project years are shown

Figure 6. MACRS, bonus MACRS, and 20-year straight-line depreciation

The five-year MACRS depreciation schedule provides a tax benefit equal to about 26% of system costs on a present value basis (Bolinger 2009a). In comparison, straight-line depreciation provides a tax benefit value of 14% of system costs. When combined, the accelerated depreciation and the 30% ITC provide a combined tax benefit equal to about 50%–60% of the installed cost of a commercial PV system (Mendelsohn et al. 2012).

2.2 Renewable Portfolio Standard Policies

State-level RPS policies[13] are a significant driver for utility-scale solar development, especially in areas with good solar resources. An RPS requires electric utilities or load serving entities (LSEs) to source a percentage of their electric load from renewable electricity generation. These targets are typically expressed as a percentage of total electricity consumption and range from approximately 2% in Iowa[14] to 33% in California (DSIRE 2012a). As of January 2012, 29 states, D.C., and Puerto Rico have established mandatory RPS policies and eight more have established non-binding renewable portfolio goals (RPGs).

Mandatory state RPS policies have been particularly successful at advancing new renewable energy development in a number of states (Wiser and Barbose 2008). Renewable energy goals are non-binding targets either established by legislation or executive order (Cory and Swezey 2007).

[13] RPS policies are sometimes called renewable energy standards or alternative energy standards. These terms are interchangeable.

[14] Iowa's requirement was actually in terms of capacity, at 105 MW.

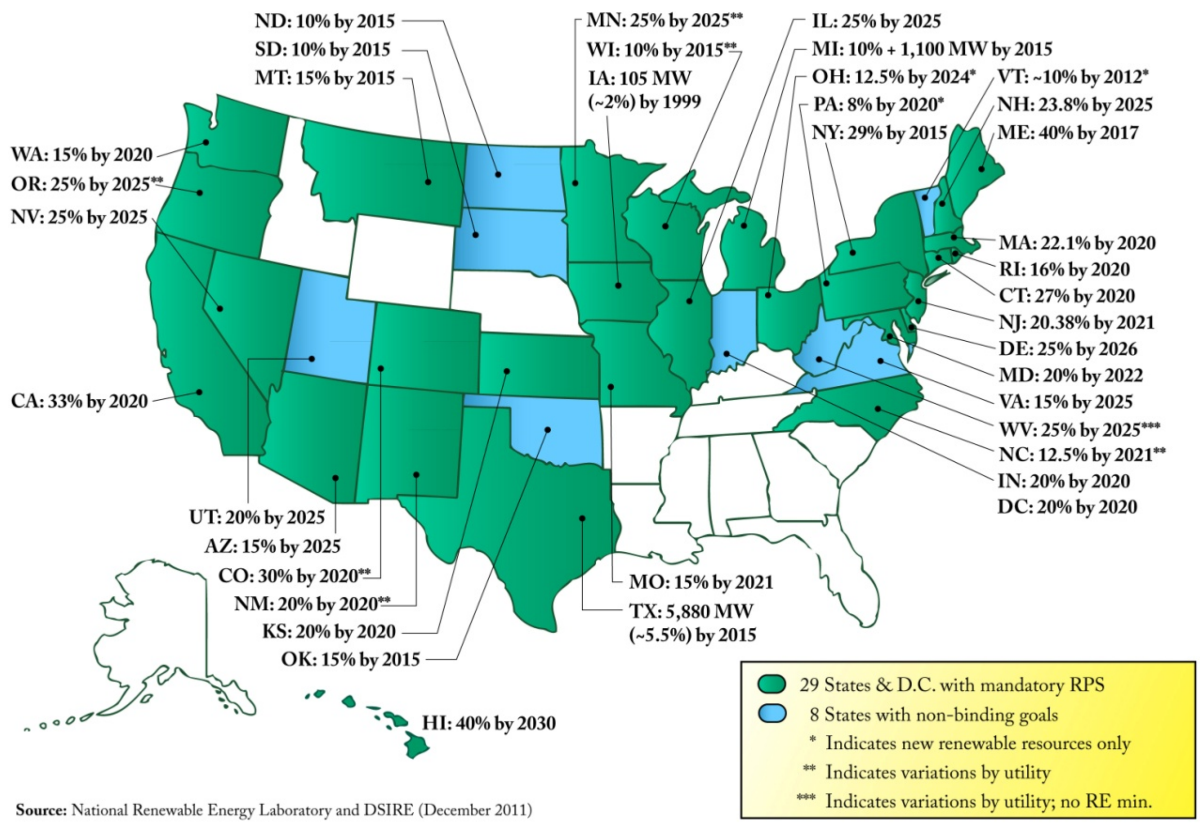


Figure 7. States with RPSs and non-binding goals

2.2.1 Solar Provisions in State RPS Policies

An increasing number of states have adopted distributed generation (DG), solar set-aside, or credit multiplier provisions in their RPS policies to provide differential support to promising technologies that are currently of higher cost (Wiser and Barbose 2008). A solar set-aside stipulates that a portion of the annual renewable energy compliance requirements be fulfilled with solar electricity. Credit multipliers give favored technologies more credit towards meeting RPS requirements than other technologies.

As of January 2012, solar provisions (excluding limited eligibility for DG-specific applications) have been implemented in 16 states and D.C. (DSIRE 2012b). Figure 8 shows the specifics of the solar and DG provisions currently implemented.

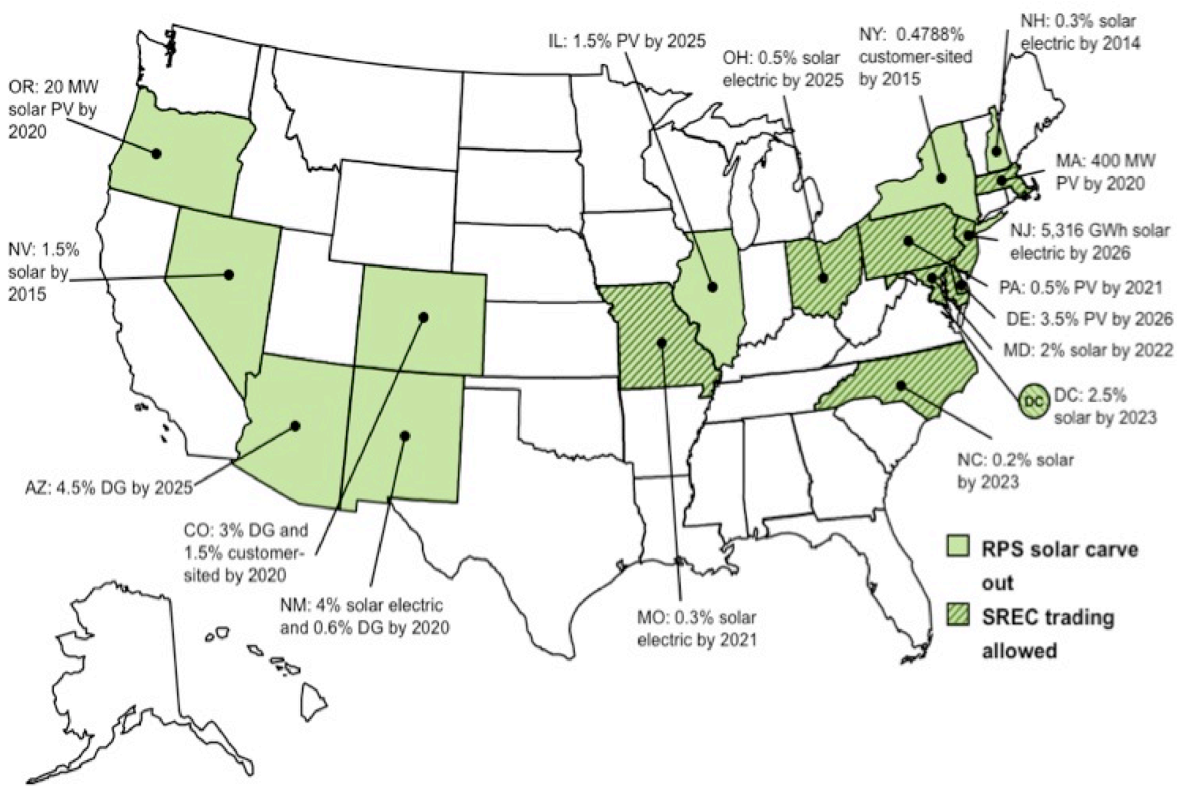


Figure 8. Solar and DG provisions in state RPS policies

Source: Heeter and Bird 2011

Credit multipliers are an alternative approach used by state policymakers to incentivize investment in one or more renewable technologies. Credit multipliers for solar have ranged from 1.1 to 3.0 times the credit that other renewable energy technologies receive (DSIRE 2012b). As shown in Table 4, six states have specific solar energy multipliers. Additionally, Texas has a multiplier for non-wind generation, and West Virginia has multipliers for renewable energy (including various alternative energy sources). Projects developed in the service territories of publicly owned utilities in Colorado receive a 3x credit multiplier for solar generation until July 1, 2015, or a 1.5x credit multiplier for community-owned renewable energy generation (DSIRE 2011b).

Table 4. Multipliers in State RPSs and RPGs (Excluding DG Multipliers)

<table>
<tr><th>Solar PV</th><th>Solar Electric</th><th>Various Multipliers (for which solar is eligible)</th><th>Non-Wind (includes solar)</th></tr>
<tr><td>Oregon (2x)</td><td>Utah (2.4x) (RPG)</td><td rowspan="3">West Virginia (RPG) (3x for renewable energy on a reclaimed mine)</td><td rowspan="4">Texas (2x)</td></tr>
<tr><td>Nevada (2.4–2.45x)</td><td>Michigan (3x)</td></tr>
<tr><td rowspan="2">Delaware (3x)</td><td rowspan="2">Colorado (3x) (for publicly owned utilities only)</td></tr>
<tr><td>Colorado (1.5x) (community-owned renewable energy, < 30 MW, publicly owned utilities only)</td></tr>
</table>

Source: DSIRE 2012b; DSIRE 2011b

2.2.2 State and Regional Renewable Energy Certificate (REC) Markets

RECs, also known as green certificates or green tags, represent a quantifiable mechanism by which to reward renewable energy projects through an additional revenue stream. These certificates represent the environmental, social, and other non-power attributes of renewable electricity generation (Holt and Bird 2005). To comply with RPS policies, utilities or LSEs can directly own renewable energy generation, purchase renewable electricity bundled with RECs through PPAs, and/or purchase unbundled RECs separately (e.g., procured via separate contracts) (Holt and Wiser 2007).

When a utility negotiates a bundled contract with a developer, the parties agree upon the contract duration and PPA price. Under a typical PPA, the buyer agrees to purchase some (or all) of the project's generation at a fixed price or at a price with an escalation term (Cory et al. 2008). The PPA price usually includes an energy payment (dollars per megawatt-hour of generation) and a REC payment (dollars per megawatt-hour). Some PPAs will also include a monthly or annual capacity payment (dollars per installed kilowatt), but this is less frequent for variable generation technologies, such as solar, that lack storage capability.

To show compliance, utilities or LSEs can, in many states, purchase unbundled RECs through long- or short-term contracts or on the spot market (usually to true-up the amount of renewable electricity procured in a given year). Long-term REC contracts provide the most revenue certainty to investors in renewable energy projects.

Because of their value to utilities to demonstrate compliance, RECs can be an important source of revenue for project developers. However, project developers may find that risk-averse investors require long-term contracts with a utility for RECs at predefined prices. Without long-term contracts or other mechanisms of risk mitigation, investors may discount the value of a developer-projected future solar REC (SREC) stream by 50%–90% (Cooney et al. 2008).

Prior to the 2008 financial crisis, some equity investors were willing to finance the construction of renewable energy plants that did not have long-term contractual agreements like PPAs (Schwabe et al. 2009). This is sometimes referred to as the "merchant power" model, whereby generators sell RECs and/or electricity to power marketers on the spot market or on a short-term contract basis, which permits them to take advantage of any upside.

2.2.3 Solar Capacity Required to Meet RPS Requirements

While state RPS and solar set-asides have been instrumental in wide-scale procurement and deployment of solar power, recent evidence indicates the solar industry can already develop solar power projects at rates necessary to meet future RPS requirements. Accordingly, current state RPS regulations are expected to be less of a stimulus to solar power expansion in the future.

The Lawrence Berkeley National Laboratory recently estimated that nine states and D.C. have specific SREC requirements and will require incremental solar capacity of 6,729 MW by 2025 (Barbose 2010).[15] That represents roughly 480 MW of solar capacity installed per year, less than half the total domestic installations in 2010.

Of the nine states and D.C. that have SREC requirements, New Jersey is the most aggressive. The state will require over 3,700 MW of incremental solar capacity by 2025 over its current requirement of 319 MW, equal to 55% of all states with SREC requirements combined (Barbose 2010). While New Jersey's RPS dictates more than a 10-fold build-out over its current solar capacity, the value represents only 264 MW per year, or 66 MW per quarter. To put that in perspective, the state achieved 64 MW of solar installations in Q3 2011, thus currently achieving the pace required through 2025.

Overall, state RPS requirements (for all eligible renewable technologies) will necessitate production of approximately 260,000 GWh in 2020, roughly quadruple the 55,000 GWh of renewable energy required in 2010. On average, the RPS will require an additional 20,000 GWh produced each year through 2020.

[15] See Heeter and Bird 2011. http://www.nrel.gov/docs/fy12osti/52925.pdf.

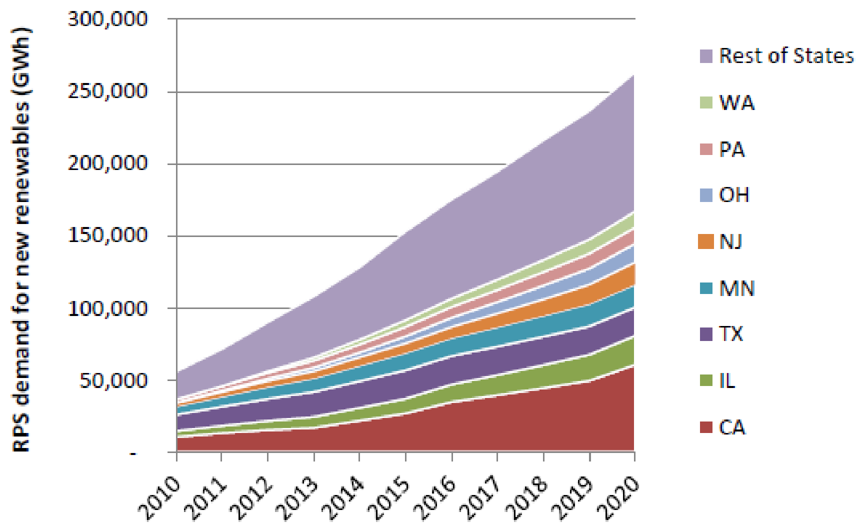


Figure 9. Renewable energy requirements from existing state RPS programs

To comprehend the overall RPS requirement of an additional 20,000 GWh per year, the hypothetical analysis in Table 5 was developed. In this hypothetical, all solar resources (PV and CSP) were assumed to provide 20% of the total RPS energy and generate at an average capacity factor of 20% as a crude approximation. The analysis indicates 2,283 MW of solar resources would be required. That value represents 570 MW per quarter, or about 27% more than the quarterly PV capacity installed in Q3 2011.

Table 5. Potential Renewable Energy Annual Capacity Additions

Technology	% of Assumed Portfolio	Annual Energy Produced	Assumed Capacity Factor	Avg. Annual Capacity Addition (MW)
Wind	70%	14,000	35%	4,566
Solar	20%	4,000	20%	2,283
Biomass	5%	1,000	80%	143
Geothermal	5%	1,000	90%	127
Total	100%	20,000		7,119

2.2.3.1 RECs in Wholesale Power Markets

RECs are more frequently unbundled from electricity in regions where independent system operator (ISO) wholesale power markets have developed (generally in states where electricity market restructuring occurred). REC trading, facilitated by brokers, occurs most frequently in Texas, the Mid-Atlantic (PJM Interconnection), and New England (ISO-NE) but is permitted in numerous state RPS policies (Holt and Bird 2005).

Markets specifically for SRECs are developing in states where policymakers have established solar set-asides within their RPS requirements and have set high solar alternative compliance payments (ACPs). An ACP is a penalty payment for failure to meet an RPS requirement in a given year. In fact, the most active REC spot markets are those where RPS penalty provisions are priced higher than the actual cost to develop eligible projects (Cory et al. 2008a).[16]

Since 2009, SREC prices dropped considerably in most markets (Heeter and Bird 2011; see Figure 10). The New Jersey SREC market, the largest in the country, has experienced spot market SREC price drops of roughly two-thirds in the six months ending September 2011, representing a trend that supply is outpacing demand (Heeter and Bird 2011).

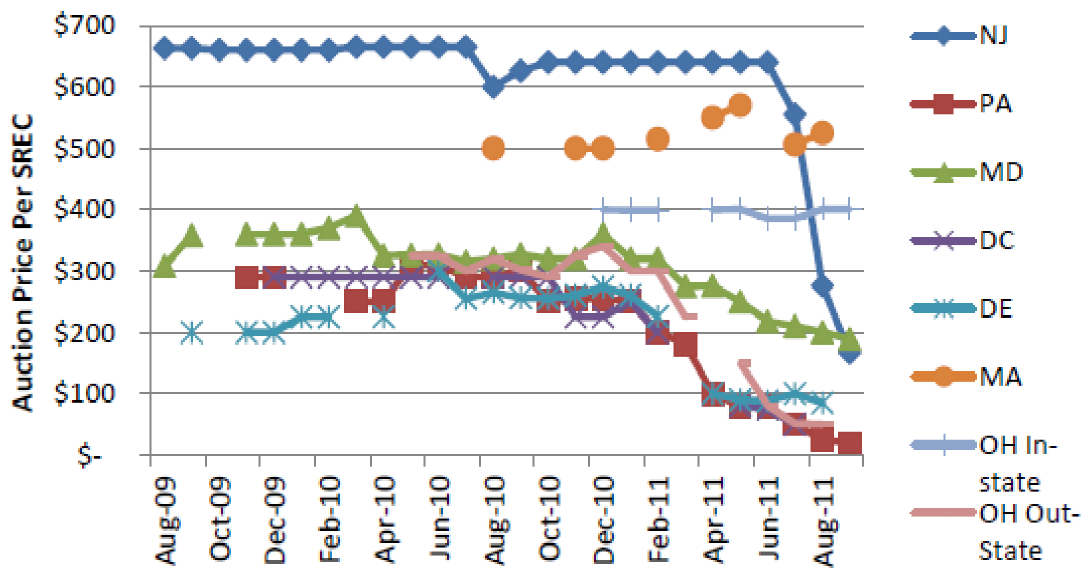


Figure 10. SREC spot prices (per MWh), August 2009–September 2011

2.2.4 Focus on the U.S. Southwest Solar Market

The U.S. southwest—the territory encompassed by Arizona, California, Colorado, Nevada, New Mexico, and Utah—has the strongest solar resource of any region in the country (both for CSP and PV). With aggressive renewable energy targets, and perhaps the provision of solar set-asides, the states in this region could potentially drive the growth of the U.S. solar market.

Five of the six southwestern states have enacted an RPS, and the remaining state, Utah, has an RPG, a non-binding requirement that utilities must fulfill to the extent it is cost effective (DSIRE 2012a).The targets for investor-owned utilities (IOUs) and relevant solar provisions are bulleted in Figure 11.

[16] SREC trading is active, or anticipated to become active, in D.C., Delaware, Maryland, Massachusetts, New Jersey, New Hampshire, North Carolina, Ohio, and Pennsylvania where solar ACPs are high. For example, New Jersey's solar ACP was set at $711/MWh for compliance year 2008/2009 and declines 2.5% per year for at least the next eight years (DSIRE 2011c). Ohio's solar ACP was set at $450/MWh in 2009 and will decline by $50/MWh every other year until stabilizing at $50/MWh in 2024, whereas D.C.'s is set at $500/MWh for 2009 through 2018 (DSIRE 2011d; DSIRE 2011e). Massachusetts's recently passed solar set-aside established a $600/MWh solar ACP for 2010 (DSIRE 2011a).

Arizona - 15% by 2025

California - 33% by 2020 (33% goal)

Colorado - 30% by 2020

- 3.0 multiplier for publicly owned utilities

Nevada - 25% by 2025

- Solar set-aside - 5% of RPS through 2015, 6% starting 2016
- 2.4 multiplier for solar PV

New Mexico - 20% goal for 2020

- Solar set-aside - 20% of RPS from solar

Utah - 20% goal for 2025

- 2.4 multiplier for solar PV

Figure 11. RPS provisions in southwestern states (IOUs only)

Source: DSIRE 2012a

New Mexico and Nevada are currently the only states in the Southwest with solar provisions in their RPS. If these provisions are met, then these two states could be supplied with almost 1,500 GWh of solar generation annually by 2025 (Barbose 2010).[17]

Even in the absence of a specific solar set-aside, market demand for solar electricity is expected to increase in other southwestern states due to the quality of the solar resource and the lack of other renewable resources. For example, the “Arizona Renewable Energy Assessment” conducted by Black & Veatch estimates that in 2025, 65% of the Arizona renewable demand (or over 8,000 GWh) will be met by solar (Black & Veatch 2007). Assuming a 20% capacity factor, roughly 4,500 MW of solar resources could be installed in Arizona to meet in-state RPS requirements.

A recent analysis of the 11 states that comprise the western interconnection system, however, indicates only 1,877 MW of renewable capacity are needed in the broader region by 2020 beyond the slate of currently planned facilities (Haase et al. 2012)[18] (see Table 6). Importantly, the analysis assumes significant transmission capacity will be built to interconnect new renewable energy facilities in Wyoming, Oregon, Idaho, and Washington with California, Arizona, and Colorado, which are projected to have unmet demand for renewable energy.

[17] Lawrence Berkeley National Laboratory estimates may represent over 600 MW of solar PV and CSP in the two states, assuming a capacity factor of 24% for a central station PV plant with tracking and a capacity factor of 30% for a CSP plant (Barbose 2010).
[18] Based on the expected mix of supplying projects and capacity factors.

Table 6. Projected Oversupply or Unmet Demand for Renewable Energy Capacity in 2020

				Arizona	California	Colorado	Idaho	Montana	Nevada	New Mexico	Oregon	Utah	Washington	Wyoming	Total WECC
SUPPLY	As of December 2011 – Not Including Hydropower[4]		Existing Renewable Energy Plant Capacity (MW)[1] (SNL 2011c)	194	7,880	1,372	441	404	589	738	2,558	287	2,547	1,419	**18,429**
			Planned Renewable Energy Projects Capacity (MW) (SNL 2011a)	1,045	10,367	91	564	300	1,374	130	864	0	1,245	2,841	**18,820**
			Sum of Existing and Planned Renewable Energy Capacity (MW)	1,239	18,247	1,462	1,005	704	1,963	868	3,422	287	3,792	4,260	**37,249**
DEMAND	Capacity Required in 2020 to Meet Current RPS Requirements (MW)[2]	A	High Capacity Factor, Low Capacity (MW)	1,380	18,653	2,741	0	325	958	896	1,733	0	1,807	0	**28,493**
		B	LBNL Capacity Factors (Barbose 2011) (MW)	1,415	27,944	2,741	0	382	896	985	1,811	0	2,952	0	**39,126**
		C	Low Capacity Factor, High Capacity (MW)	2,144	31,354	2,741	0	662	1,421	896	3,079	0	3,238	0	**45,535**
GAP	Oversupply or (Unmet Demand) in 2020[3]	A	High Capacity Factor, Low Capacity (MW)	(141)	(406)	(1,279)	1,005	379	1,005	(28)	1,689	287	1,985	4,260	**8,756**
		B	LBNL Capacity Factors (Barbose 2011) (MW)	(176)	(9,697)	(1,279)	1,005	322	1,067	(117)	1,611	287	840	4,260	**(1,877)**
		C	Low Capacity Factor, High Capacity (MW)	(905)	(13,107)	(1,279)	1,005	42	542	(28)	343	287	554	4,260	**(8,286)**

Source: Haase et al. 2012

2.3 State-Level Tax Incentives

Utility-scale solar systems may be eligible for multiple types of state tax incentives. Developers often use state tax incentives in concert with other incentives to support renewable energy deployment (Lantz and Doris 2009). The primary state tax policies that apply to large-scale solar energy development are corporate, property, and sales tax incentives. Corporate income tax incentives may take the form of tax deductions or tax credits and may be awarded on the basis of investment, or they can be based on the quantity of renewable electricity produced.

State property tax incentives reduce or limit the amount of taxes levied against property improvements as a result of building renewable energy projects. Sales tax incentives reduce—or provide exemptions from—sales and use taxes levied against goods purchased for renewable energy projects (Lantz and Doris 2009).

As of December 2011, in various forms, 16 states offer corporate tax incentives, 31 states offer property tax incentives, and 21 states offer sales tax incentives for solar projects (DSIRE 2012c; DSIRE 2012d; DSIRE 2010e).

2.4 State-Level Clean Energy Funds

Clean energy funds are typically developed to ensure continued support for renewable energy, energy efficiency, or low-income energy programs. Two common uses are to support rebate programs for renewable energy systems and to fund renewable project loan programs. Clean energy funds are complementary to other renewable energy support policies on the state and federal levels. Any financial support received through a state fund may increase the effectiveness of other policies (e.g., tax incentives or RPS) by bringing down capital costs.

As of January 2012, 18 states, D.C., and Puerto Rico have implemented renewable energy technology funds, generally referred to as public benefit funds or system benefit funds programs (DSIRE 2012f). The funds are most often supported by a small surcharge on electricity consumption but can also be based on voluntary funding (as in Maine) or recharged through loan repayments and other returns on investment (as in Pennsylvania) (Doris et al. 2009).

According to Clean Energy Group, between 1998 and 2007, state clean energy funds invested approximately $1.5 billion in renewable energy projects and leveraged an additional $2.6 billion in private capital (CESA 2009). State funds have supported a broad range of renewable technologies including significant investment in grid-connected solar PV. States traditionally rely on RPS policies to promote large-scale development and use the clean energy funds to encourage DG projects. It is estimated that between 1998 and 2007, 82% of the financial support from state clean energy funds was allocated to distributed energy projects, whereas 18% was allocated to grid-scale projects (CESA 2009). Although likely limited in their application to utility-scale solar systems, clean energy funds should be investigated as a potential source of project capital.

In addition to providing direct financial support to renewable energy, clean energy funds may be designed to fund initiatives with longer-term benefits, such as research, development, and demonstration, or initiatives that address regulatory or market barriers. Furthermore, clean energy fund investments can stimulate the development of companion industries and infrastructure and promote consumers' awareness of clean energy (Doris et al. 2009).

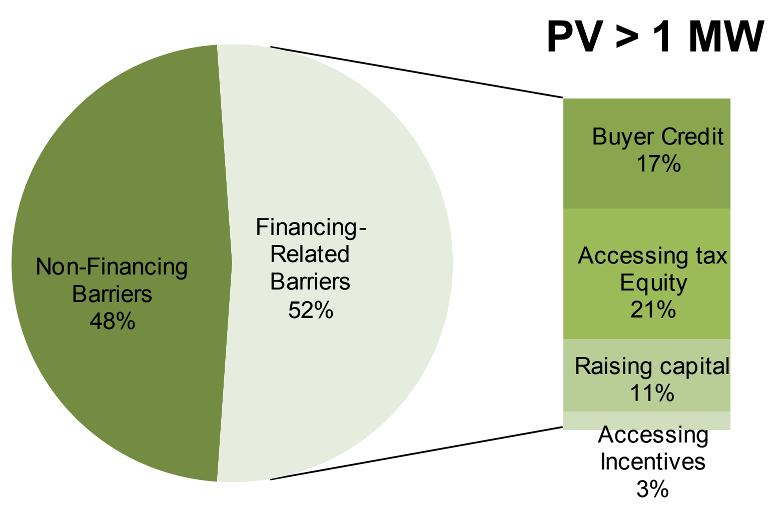
3 Financing Mechanisms to Develop Utility-Scale Solar

3.1 Background

Many of the policies supporting renewable energy comprise tax incentives (in the form of credits or accelerated depreciation benefits), as discussed in Section 2. However, renewable energy projects and their developers generally do not have enough tax liability, also known as "tax appetite," to utilize the credits to their full potential. The tax credits can be "carried forward" to shelter future income, but this greatly reduces the present value of the benefit.[19]

Accordingly, a number of financial structures have been developed to take advantage of the tax credits at their highest value. These structures generally require an equity investment from a firm with sufficient tax appetite to utilize the tax credits; this is referred to as a tax equity investment. The firm is therefore the tax equity investor. Such investments, and the financial structures that build upon them, are designed to maximize the value of federal, state, local, and utility-based incentives; allocate risk and reward among different funding sources; and allow project participants to focus on core competencies.

According to a database of questionnaire responses via NREL's REFTI project,[20] financing-related aspects of project development were referenced as the largest barrier to project development for 52% of respondents in large-scale PV projects (>1 MW) and 41% of respondents involved in CSP projects.[21] Figure 12 provides the questionnaire responses for the nearly two years of data collected from Q4 2009–1H 2011.



[19] Developers generally have very high discount rates due to the risk associated with project development.
[20] The REFTI process included developers, financiers, and others associated with PV projects 1 MW or larger and CSP projects.
[21] Financing-related barriers include PPA/creditworthiness of power purchaser, finding tax equity investor, raising capital, and accessing government incentive programs. Non-financing-related barriers include project economics, technological hurdles, environmental permitting, transmission, other, and none.

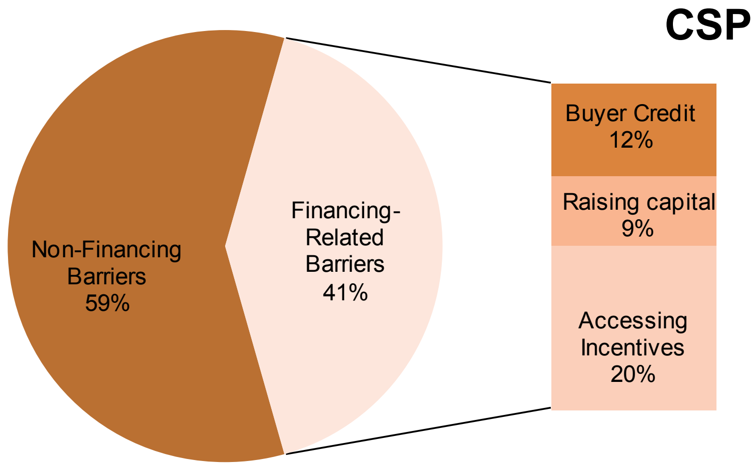


Figure 12. Primary barriers to renewable energy project development

PV (n = 115) and CSP (n = 34)

Notably, REFTI participants involved in PV and CSP deployment offered distinct viewpoints on the primary barriers to successful project development. About 21% of those involved in PV projects indicated that finding tax equity was a critical barrier; by contrast, 0% of CSP respondents considered tax equity a barrier. About 20% of this group indicated instead that access to government incentives was their primary concern.

Of the non-financing barriers referenced by REFTI participants, project economics and transmission had the highest reporting. PV respondents, in particular, indicated access to transmission as their primary barrier. Participants involved in CSP projects also listed technological factors as critical to project success.

3.2 Specific Financing Structures

A variety of project finance structures may be applied to utility-scale solar. This report discusses four structures that may be employed in the market: (1) single owner (also referred to as balance sheet finance); (2) leases, including sale-leaseback and inverted lease; (3) partnership flip; and (4) utility prepay.[22] An array of adjustments can be made under each structure based on the needs of a given project. Moreover, projects may employ unique, one-off financing structures based on the risk appetites of the entities involved (including the developer, investor, and utility) as well as the investment climate at the time (e.g., the cost of debt and equity and perception of technology risk).

These structures are born out of the current ITC and accelerated depreciation structures. If the ITC expires at the end of 2016, as currently legislated, these structures may lose some appeal. The DOE and NREL are currently evaluating how projects might be financed without the ITC and gaining valuable examples in the securities and real estate industries.

[22] The accompanying report, *The Impact of Financial Structure on the Cost of Solar Energy* (Mendelsohn et al. 2012a), provides a description of and quantitative assessment on four specific structures: single owner, sale-leaseback, and two forms of partnership flip [all-equity and levered (i.e., with debt)].

3.2.1 Single Owner (Balance Sheet) Finance

Single owner finance represents the direct investment by a developer into a project asset using the balance sheet (as opposed to project finance) of the developing entity. Utility-scale solar projects can be balance-sheet financed in one of two ways: (1) utility-owned generation and (2) developer balance sheet.

3.2.1.1 Utility-Owned Generation

Owning generation projects allows utilities to diversify their portfolios and maintain a higher level of control over project siting and grid reliability impacts (especially for distributed projects). Utilities may experience shortfalls in renewable energy procurement to meet RPS targets if independent power producers (IPPs) cannot fulfill contractual obligations. Furthermore, as discussed in Section 2.1.1, with the passage of the EESA in 2008, investment in solar generation projects has become more attractive to utilities due to their ability to access the 30% ITC.

In utility-owned generation, utilities either purchase turnkey projects from independent developers pursuant to a competitive solicitation or they develop and build the project themselves (see Figure 13).

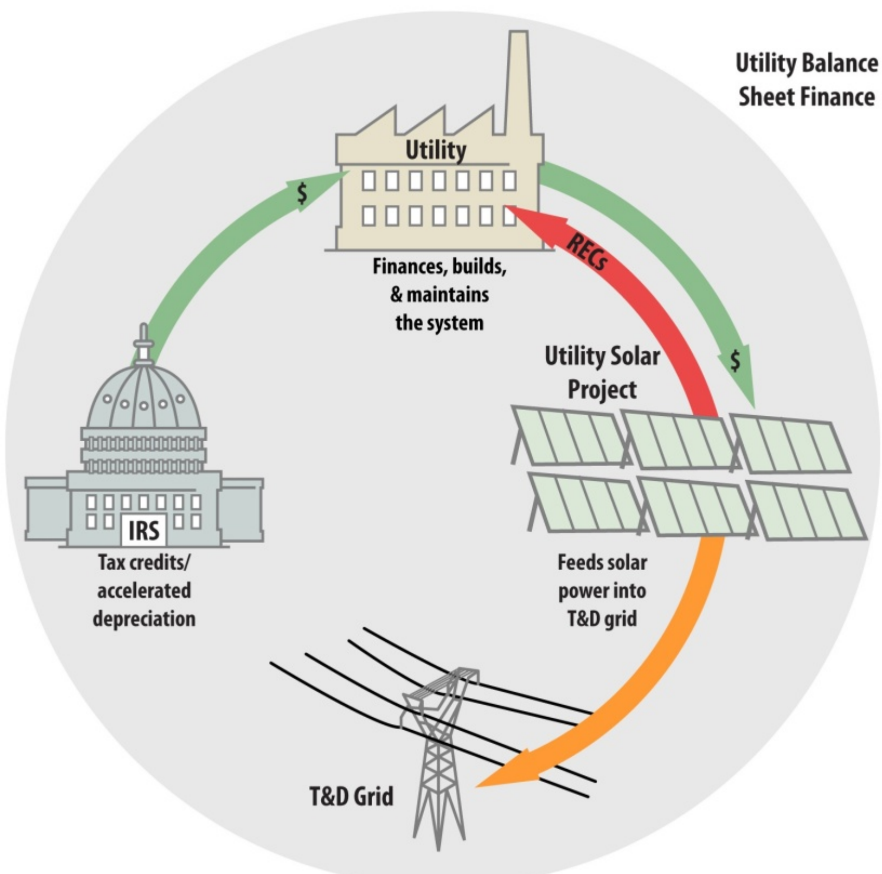


Figure 13. Utility balance sheet finance

Though utilities have not traditionally invested in solar facilities, several factors make them well-positioned to invest in large electricity generation projects. IOUs are considered stable, creditworthy entities and can attract capital at a favorable interest rate (even in tight credit markets). IOUs also have franchised authority to provide electric services and are experienced in raising capital in both the public equity and debt markets. Accordingly, utility balance sheets could prove a valuable anchor to support solar project development.

Utilities can invest in solar assets in one of four ways. First, utilities can directly finance, own, and operate solar energy projects for a variety of operational and economic reasons. For example, Pacific Gas and Electric (PG&E) and Southern California Edison invest directly in solar energy projects via the Solar Power Initiative approved by the California Public Utilities Commission. Through the program, each utility will own 250 MW of solar to be developed over a five-year period. The investments will be recovered through each utility's base rates and be allowed to earn the company's weighted average cost of capital (CPUC 2009).

The largest IOU serving New Jersey, Public Service Electric & Gas Company (PSE&G), has also started to develop and operate its own solar systems. In July 2009, PSE&G received approval for its $515 million "Solar 4 All" program where it will install, own, and operate 80 MW of solar by 2013 (PSE&G 2009a; PSE&G 2009b). PSE&G's program will double the amount of solar in New Jersey—a state that already ranks second in the country for installed solar power—highlighting the ability of utility-owned generation to drive solar market growth.

Second, utilities can invest through developer subsidiaries or affiliates. Several major utilities—including Duke Energy, San Diego Gas and Electric (SDG&E), and NextEra (formerly Florida Power & Light)—have development arms that are very active in the market and have installed solar and other renewable technologies across the country. MidAmerican Energy Holdings, owned by Warren Buffett's Berkshire Hathaway, is the corporate owner to MidAmerican Energy Company, a large utility serving Iowa and surrounding states, and MidAmerican Renewables, LLC, the unregulated owner of wind, solar, geothermal, and hydro power plants (MarketWatch 2012). MidAmerican made significant headlines in December 2011 when it purchased the 550-MW, $2.4 billion Topaz Solar Farm project from First Solar and a 49% share of the 290 MW, $1.8 billion Agua Caliente project from NRG (MoneyNews 2012). To finance the Topaz purchase, MidAmerican successfully offered $850 million of private placement bonds in February 2012. The 27.5-year, 5.75% bonds were rated BBB-, the lowest investment grade available, by Fitch Ratings. As of March 2012, a second bond offering is being planned to raise an additional $430 million.

Third, utilities can use ratepayer tax appetite to support investment by a third party. For example, in 2011, SDG&E invested tax equity into the Rim Rock Wind facility located in northern Montana (Schwabe 2011). The deal—approved by the Federal Energy Regulatory Commission in January 2012—invests $285 million of tax equity, most of which is ratepayer funded. SDG&E will purchase the energy and RECs, although the energy will not be delivered to the utility (Recharge 2012). The structure is a first for California utilities. Certain stakeholders to the regulatory submission originally objected to investment of only ratepayer funds, and ultimately negotiated with SDG&E to lower ratepayer investment in the project and add shareholder funds (Schwabe 2011).

Fourth, utilities can invest shareholder tax appetite into a third-party project. Such investment would not be recovered by ratepayers but could modify taxes paid by, and dividends paid to, shareholders. For example, subsidiaries of PG&E have invested tax equity in SolarCity and SunRun, enabling these entities to develop residential and commercial solar systems (PG&E 2010a; PG&E 2010b). The funds were provided purely as shareholder funds and will not be incorporated in rates.

However, the tax code treats utilities and third-party developers differently. "Normalization" accounting rules require utilities to levelize the ITC benefits when setting retail electricity rates. That is, the utility must spread the payment of the ITC benefit to ratepayers over the useful life of the asset.[23] Although the utility benefits from the ITC in the first year of the project, that benefit cannot be directly transferred to the ratepayers in the same year (Miller 2009). Because their use of the ITC cannot directly result in lower rates, electric utilities may incur a cost disadvantage relative to non-utility developers when all other things are equal.

3.2.1.2 Developer Balance Sheet

Developers often finance utility-scale solar projects by utilizing their own balance sheets. Some examples include:

- Duke Energy Generation Services (the unregulated developer subsidiary of Duke Energy) financed the Blue Wing Solar facility in Texas via balance sheet capital (Bloomberg New Energy Finance 2010a). The Blue Wing Solar project will consist of panels supplied by First Solar and is expected to generate about 14.4 MW (ac) at peak output. The power will be sold to CPS Energy under a 30-year PPA. Duke bought the project from juwi Solar in January 2010.

- NRG Energy used its balance sheet to finance the 13.5 MW second phase of the Blythe PV project. The project was originally developed by First Solar and later sold to New Jersey-based power generator NRG Energy in November 2009 (Bloomberg New Energy Finance 2010b).

- In October 2010, Iberdrola announced its intent to finance—via its balance sheet—construction of 50 MW of solar electric projects in Arizona and Colorado (Murray 2010). Construction costs were reported to be $60 million. In November 2011, Iberdrola dedicated its 20 MW Copper Crossing Solar Ranch project located in Florence, Arizona (Iberdrola 2011). The project holds a 25-year power purchase contract with the local utility, Salt River Project.

A developer who maintains a strong financial position can recapitalize its balance sheet by selling an equity or debt position in their project or portfolio of projects (Kimber 2010). Once recapitalization takes place, the development cycle can start again. For

[23] There is no equivalent requirement for independent developers.

example, Hudson Clean Energy financed Recurrent Energy's broader development capabilities by investing $75 million in 2008 (Recurrent Energy 2008). In return, Recurrent Energy completed the 5 MW Sunset Reservoir project in San Francisco and was able to sell project debt to recapitalize its balance sheet, thus enabling the development of other projects in its 1 GW portfolio pipeline.

3.2.2 Partnership Flip

Under a partnership flip structure, the project developer partners with a tax equity investor to fully use a project's tax benefits (Coughlin and Cory 2009). Partnership flip structures are specifically designed to take advantage of federal incentives, including the ITC and MACRS, which frequently cannot be fully utilized by the developer alone (Cory et al. 2009). Wind projects widely used this financial structure in the past.

The structure comes in two basic forms: the all-equity partnership flip, where all capital is provided as equity, and the leveraged partnership flip, where project-level debt is also provided by a lender. The debt in a leveraged partnership flip can be provided by the tax equity investor (as a separate tranche) or by a third entity depending on how the project is structured.

The flip structure is generally designed to provide the tax equity investor a pre-negotiated return in a set number of years (e.g., a 9% yield by year eight of the project). After that design goal is met, the annual stream of benefits (including tax benefits and cash) is reallocated, or "flips," to the sponsor to reward the risk taken and work invested. The partnership arrangement defines the terms between the developer and tax equity investor, including:

- Initial equity investments
- "Pre-flip" distribution of the project's cash revenues and tax benefits
- "Post-flip" distribution of the project's cash revenues and tax benefits.

The "flip-point" occurs once the tax equity investor achieves an agreed-upon internal rate of return associated with the equity contribution. Some important tax law considerations relevant to a partnership-flip structure include the following:

- The developer must have at least a 1% interest in all material items associated with the partnership
- Each tax equity investor must have at least a 5% interest in all material items associated with the partnership
- The tax equity investor must bear the risk of solar resource availability (another project participant may not guarantee the availability of the renewable resource) (Baker Botts 2007).

Figure 14 presents a potential tax equity partnership. In this example, the developer provides 40% of the initial equity with a tax investor providing the remainder. The benefits are divided into three streams: the cash (or net revenue from the project), the depreciation benefits from applying MACRS, and the ITC. In this example structure, the cash benefits are reallocated with two flip points, the depreciation benefits are reallocated with one flip, and the ITC benefits are not redistributed during the project life.

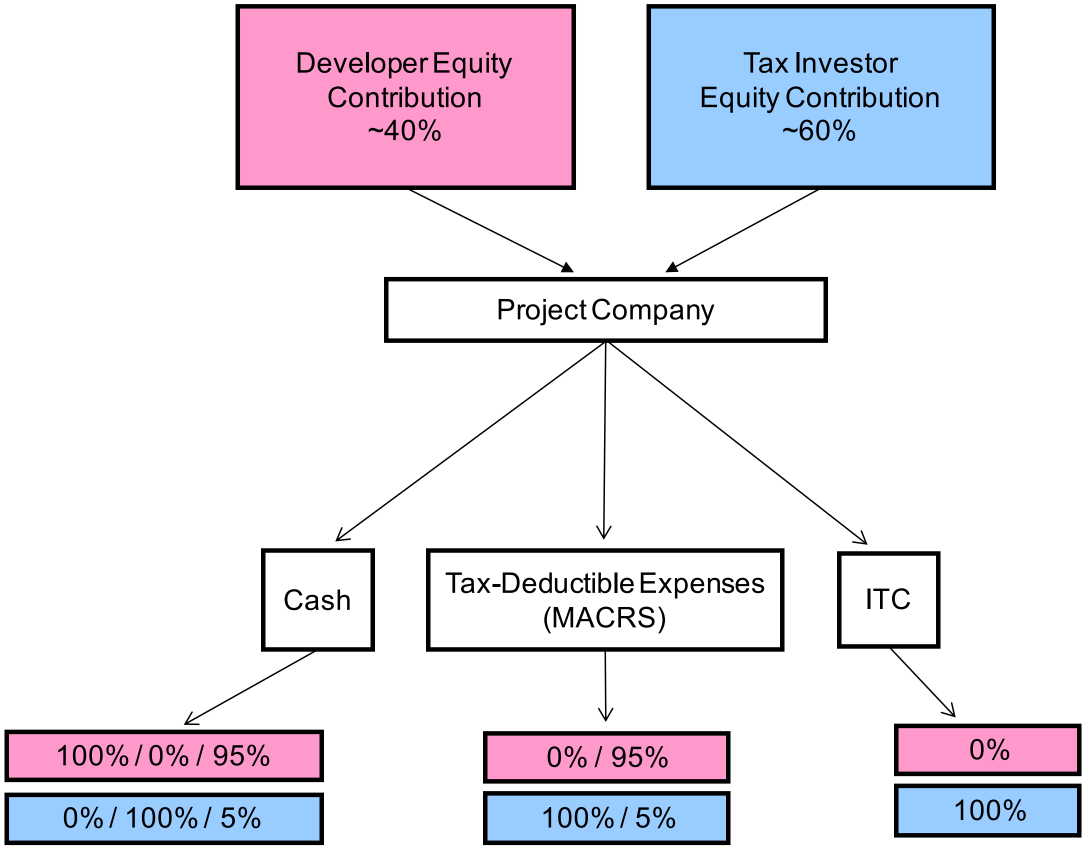


Figure 14. Tax equity financial structure

Source: Adapted from Harper et al. 2007

3.2.3 Lease Structures

Two basic lease structures are utilized by the U.S. solar industry. These structures include sale-leaseback and inverted lease.

3.2.3.1 Sale-Leaseback

In sale-leaseback financing, a project developer sells the project assets for cash and simultaneously signs a long-term lease with the investor. The financial transaction is accomplished by conveying the title of the asset, at an agreed upon value, to an investor in exchange for a lump-sum payment to the developer. The developer then makes lease payments to the investor in exchange for the cash injection (Jacobs 2009). A sale-leaseback is distinct from an inverted lease structure, also referred to as an operating lease, whereby the lessee has the option to purchase in year six or beyond (Kendall 2009).

The developer, in turn, arranges a PPA with the power purchaser, which becomes the primary revenue stream used to pay the lease payments. The developer (the lessee in this structure) is obligated to pay a fixed rent to the investor (the lessor) for the term of the lease regardless of how the system performs or if force majeure events occur (Feo and Tracy 2009). Figure 15 is a graphical representation of the sale-leaseback structure.

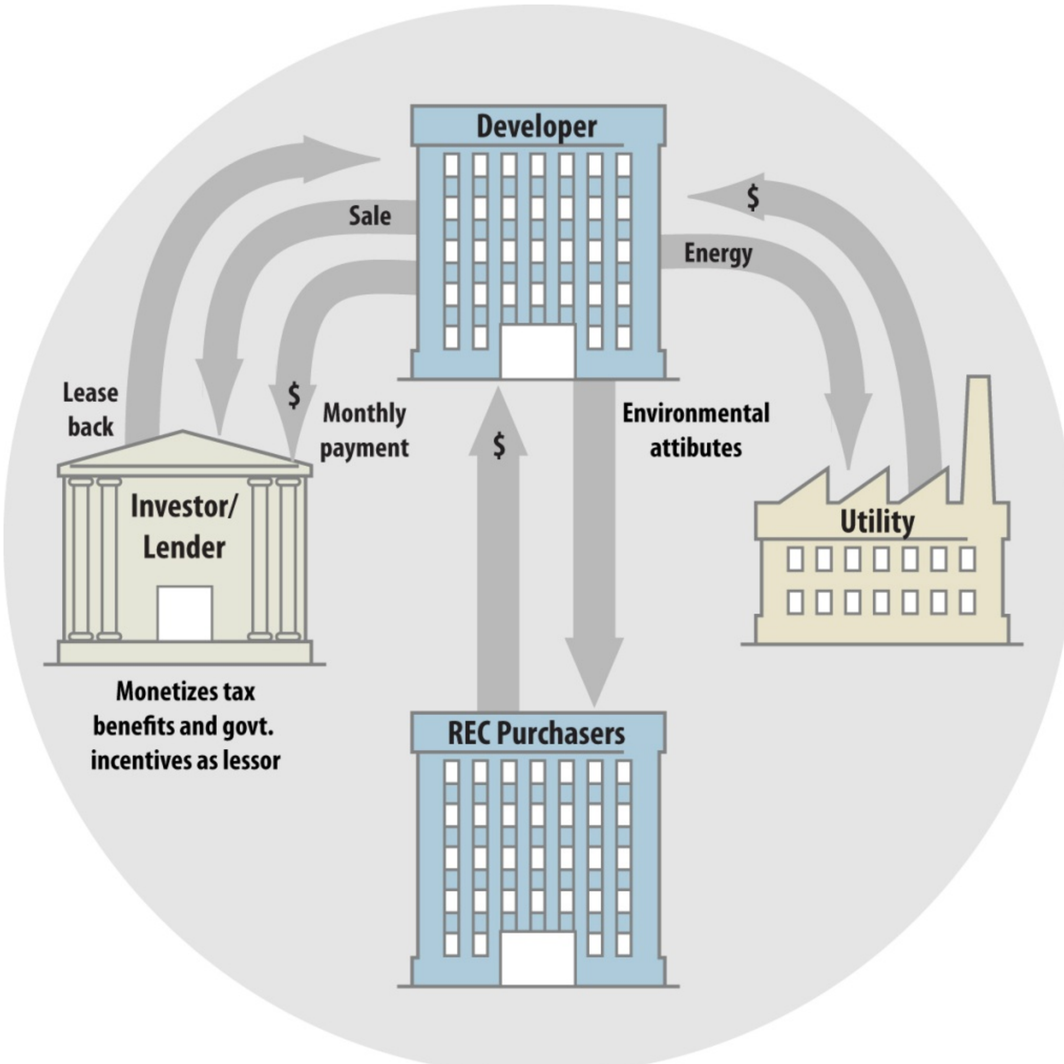


Figure 15. Sale-leaseback financial structure

In June 2009, Wells Fargo and SunPower Corp. announced the development of a $100 million sale-leaseback financing program (SunPower 2009). The financing vehicle was later utilized to finance a 1 MW solar power system installed at the University of California, Merced (UC-Merced). Under the financing program used for the UC-Merced system, the developer (in this case, SunPower) entered into PPAs with qualified customers and designed, built, operates, and maintains the solar energy systems. Wells Fargo financed the project and receives the tax benefits. Customers hosting the systems buy the electricity from the developer with no initial capital investment (SunPower 2009).

A primary benefit of the sale-leaseback structure is that it provides 100% upfront financing. The sale-leaseback arrangement allows the business owner to raise capital while retaining the use of the assets that are needed in the business. Sale-leasebacks enable companies to realize the market value of their facilities and redeploy that capital into other projects (W.P. Carey 2010). A sale-leaseback can provide a significant source of funds for various purposes, including paying off a specific lender, buying back capital stock, buying out a partner, funding a working capital account, and/or upgrading assets (W.P. Carey 2010).

Sale-leaseback arrangements also allow a developer to strengthen its balance sheet by eliminating debt, increasing its borrowing capacity, and improving its return on assets or return on investment (Ray and Rawley 2007). Lease payments are considered operating expenses and thus are 100% tax-deductible. Sale-leaseback structures improve credit availability because capital equipment is no longer being financed at a regular bank, nor is it cutting into the lines of credit businesses retain with banks (Ray and Rawley 2007).

3.2.3.2 Inverted Lease

In an inverted lease (also referred to as a pass-through lease or master tenant lease), the developer leases the project to a tax equity investor and passes through the ITC to the tax equity investor. In turn, the tax equity investor, the lessee, sells the electricity to the developer via a PPA arrangement (Tracy et al. 2011). The developer may operate the system on behalf of the investor pursuant to an operation and maintenance agreement.

Unlike the sale-leaseback structure, the tax credit and depreciation benefits in the inverted lease are split between the lessor and the lessee (the developer retains them to reduce its taxes). The lease term in such transactions runs anywhere from 6 to 15 years (Competitive Energy Insight 2011). At the end of the lease, the developer takes back the project without having to pay any additional costs. According to some consultants, the market has utilized this structure “to an aggressive form that presents significant tax risk” (Competitive Energy Insight 2011).

The advantages of the inverted lease structure include an easy exit for the investor after the lease is completed, the ITC is based upon fair market value of the system rather than the developer’s cost, and separation of the ITC from the depreciation benefits as some investors do not want both tax streams (Cuddy 2011).

A primary disadvantage of the inverted lease structure is that the investor/lessee is obligated to pay fixed rent to the developer/lessor for the term of the lease, irrespective of the actual performance of the system or existence of force majeure events, for example. The project must also be structured under specific guidelines for U.S. federal tax purposes. Finally, although not relevant to solar projects, the PTC cannot be combined with inverted lease structures because of tax-related ownership requirements.

3.2.4 Utility Prepay

Utility prepay (sometimes referred to as hybrid financing) uses a utility’s low-cost capital to directly finance a renewable energy project. Under the structure, a utility will prepay for the energy to be delivered under a contract. In turn, the prepayment provides a massive down payment enabling the termination of the construction financing debt. The utility indirectly applies its access to low-cost capital to finance the facility and receives beneficially priced power in return (Delony 2008) (see Figure 16).

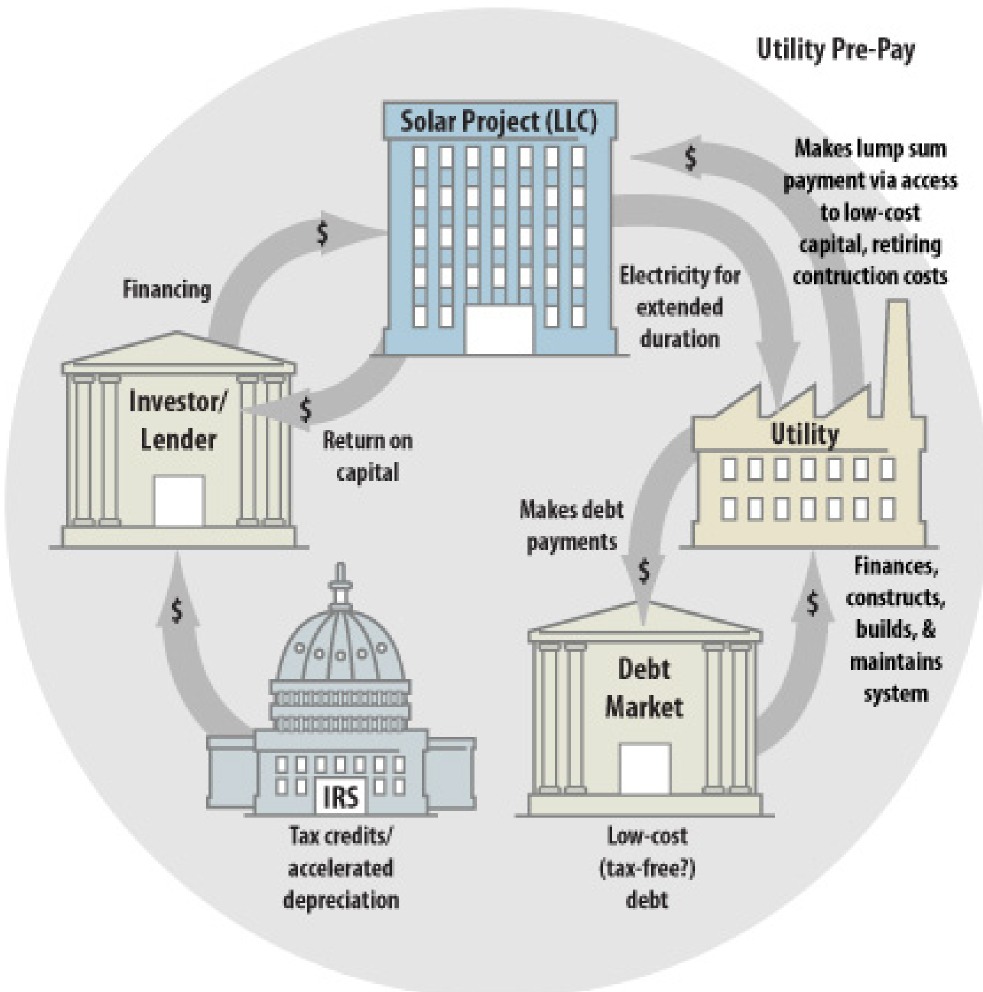


Figure 16. Utility prepay financial arrangement

To date, only municipal utilities have taken advantage of this financial structure. This structure has also been limited to wind projects but remains a potential option for utility-scale solar.

In 2007, the Los Angeles Department of Water and Power (LADWP), along with the City of Burbank and City of Pasadena, signed a 20-year contract with UPC Wind for a 200 MW wind project being developed in Millard County, Utah (LADWP 2007). Acting on behalf of the LADWP and the municipalities, the Southern California Public Power Authority (SCPPA) prepaid for the energy to be delivered during the 20-year term with proceeds from an upcoming bond sale. By prepaying up to $270 million for a guaranteed amount of energy, the utilities saved at least $42 million compared to the cost of constructing and financing the plant themselves (Carnahan 2007).

The deal also had an early buyout option to enable LADWP, along with Burbank and Pasadena, to acquire ownership of the facility after 10 years. SCPPA contracted with UPC Wind for the 20-year term, provided the project financing once the project was completed, and signed power sales agreements with LADWP and the other participants for the output of the project at a price sufficient to retire the debt and pay for the ongoing operating expenses.

In a similar arrangement, the 205 MW White Creek Wind Project in Klickitat County, Washington, was developed to take advantage of public power's access to tax-free debt. The project was initiated by four Washington utilities and became a reality with the help of a power prepay arrangement that accessed tax credits from the project and tax-free financing that reduced the cost of delivered power (Delony 2008). To finance the project, the utilities floated bonds on their balance sheets and prepaid for the power to be delivered under the project (Delony 2008).

While the aforementioned projects were related to wind, the utility prepay financial structure could benefit solar projects, and the structure takes advantage of low-cost municipal debt and federal tax credits associated with private project ownership.

4 Summary

Federal and state policies have provided crucial support for renewable energy project development. In response to these policies, developers of and investors in utility-scale solar projects have created innovative financial structures to maximize the benefits available and allocate risk and reward according to specific preferences. Each financing innovation has its own advantages and challenges and depends on various factors, including technology, counter-party, and the risk appetite of various investors.

Critical to successful utility-scale solar development, the federal ITC and accelerated depreciation programs provide a powerful set of incentives, representing approximately 50%–60% of a project's initial capital cost. In response to the 2008 financial crisis and difficulty in arranging specialized tax equity to monetize the ITC, the 1603 Treasury grant program provided additional stimulus. Through February 21, 2012, the 1603 program has awarded $10.76 billion to roughly 23,000 projects, stimulating an additional $25.11 billion in private market investment.

The DOE loan guarantee program also provided significant stimulus to the utility-scale solar sector. Section 1705 under the loan guarantee program supported $12 billion in loans, which will enable development of over 3,500 MW of solar generation capability. Section 1705 terminated on September 30, 2011, as required under its original statute.

At the state level, RPS requirements have spurred IOUs to sign long-term contracts with private developers or invest directly in renewable energy projects. At present, 29 states and D.C. have implemented RPS requirements.

To take full advantage of depreciation benefits and other tax incentives, the industry relies on complex financial arrangements, which include various forms of partnerships and lease structures. These financial arrangements are designed to allocate risk and reward among the developer and a specialized tax equity investor that can specifically take advantage of the various tax incentives made available at the federal and state level.

The perceived risk of utility-scale solar projects is still quite high and market acceptance remains elusive in this era of tight credit markets. For the immediate future, utility-scale solar development will remain dependent on the array of government incentives designed to support project financing. This will likely be true until solar technologies can provide energy at grid-parity (i.e., on par financially with competing technologies).

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