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Cooperative Utility PV Field Manual

Volume I

Business Models and Financing Options for Utility-Scale Solar PV Installations

Prepared by:

National Rural Electric Cooperative Association

In partnership with SunShot, U.S. Department of Energy

VOLUME I: BUSINESS MODELS AND FINANCING OPTIONS

VOLUME II: PLANNING, DESIGN, INSTALLATION/INTERCONNECTION, AND COMMISSIONING

VOLUME III: OPERATIONS, MAINTENANCE, AND MONITORING

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About this Series

Many co-ops are interested in solar PV, but only a few have deployed utility-scale (1 MW or more) systems because of industry gaps in standardized designs; cost-benefit analysis tools; assistance with finance, procurement, and permitting; and training and best practices for operations and maintenance.

NRECA's Cooperative Utility PV Field Manual is a three-volume series designed to support electric cooperatives as they explore and pursue utility-scale, utility-owned solar PV deployments. It is a product of the Solar Utility Network Deployment Acceleration (SUNDA) project, a four-year, multi-state 23-MW solar installation research project and collaboration among U.S. electric cooperatives, the National Rural Utilities Cooperative Finance Corporation (NRUCFC/CFC), Federated Rural Electric Insurance Exchange, PowerSecure Solar, and the National Rural Electric Cooperative Association (NRECA). The SUNDA project is funded in part by the U.S. Department of Energy's SunShot program; its overarching goal is to address the barriers to utility-scale, utility-owned solar PV systems faced by co-ops. Participating cooperatives include the following:

Anza Electric Cooperative	Anza, CA
Brunswick Electric Membership Corporation	Shallotte, NC
CoServ Electric	Corinth, TX
Eau Claire Energy Cooperative	Fall Creek, WI
Great River Energy	Maple Grove, MN
Green Power Electric Membership Corporation/Oglethorpe	Tucker, GA
North Arkansas Electric Cooperative	Salem, AR
Oneida-Madison Electric Cooperative	Bouckville, NY
Owen Electric Cooperative	Owenton, KY
Pedernales Electric Cooperative	Johnson City, TX
Sandhills Utility Services	Fort Bragg, NC
Sussex Rural Electric Cooperative	Sussex, NJ
Tri-State G&T Association	Westminster, CO (options in UT, WY, NM, & NE)
Vermont Electric Cooperative	Johnson, VT

The standardized products for evaluation, implementation, and operation of utility-scale solar PV at co-ops are discussed in detail in this Cooperative Utility PV Field Manual:

- Volume I: Business Models and Financing Options for Utility-Scale Solar PV Installations
- Volume II: Planning, Design, Installation/Interconnection, and Commissioning
- Volume III: Operations, Maintenance, and Monitoring

This document, the second release of Volume I, is a living document and should be treated as such. The document will continue to be modified throughout the project, based on lessons learned, and then re-released. Feedback will continue to be collected and incorporated to improve the usefulness of the end product.

Your Feedback Welcome

Because this is a draft, anyone who reads or uses this document is invited and encouraged to provide feedback:

What parts of the manual are most valuable/helpful?

What is not clear? Where are changes needed? What is missing?

What challenges or technical projects should NRECA be thinking about for the future?

NRECA is under no obligation to incorporate information based upon feedback received. Any modification made to this document shall be solely owned by NRECA. All comments, questions, and suggestions may be sent to SUNDA@nreca.coop.

Updated versions of all three PV Field Manual volumes are available at www.NRECA.coop/SUNDA. A final version will be posted no later than October 1, 2017.

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Acknowledgments

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Executive Summary

The National Rural Electric Cooperative Association (NRECA), National Rural Utilities Cooperative Finance Corporation (NRUCFC/CFC), and Federated Rural Electric Insurance Exchange (Federated) have created this document to present a suite of business solutions that address various options for ownership of "utility-scale" PV systems, defined in this project as greater than 250 kW. This document contains information on potential business and financing models for the deployment of utility-scale PV systems by electric cooperatives, provides guidance on choosing and implementing the best approach, and identifies key resources available. It is a companion piece to the Engineering and Operation Field guides also developed in this project (Volumes II and III).

Below are the key lessons learned from the first two years of the three-year project:

i. Cooperatives should consider broad strategic questions—such as why renewables, why solar, how much renewables and solar, the implications of and imperatives for solar, etc.—through broad-based consultations with and among stakeholders—before exploring business models.
ii. Following the determination of how much solar to deploy and how to phase it in, cooperatives should explore and consider the various business model options that may be available for them to pursue.
iii. In many instances, the circumstances of the cooperative and a consensus on strategic questions may determine the business models most appropriate for the cooperative.
iv. Close coordination and working within their integrated system [generation and transmission (G&T) cooperatives and distribution cooperatives, working together in a coordinated manner] are highly desirable to ensure cooperatives' effective and efficient implementation of utility-scale solar installations. Lack of coordination would lead to suboptimal implementation—both from the point of view of the extent (how much) of solar deployment and the economies that can be achieved.
v. Direct financing, although the most expensive of the common financing options for deploying utility-scale solar, is the easiest business model to access.
vi. New Clean Renewable Energy Bonds (NCREBs) are a lower-cost option than direct conventional loans for solar PV projects because of the lower borrowing costs and relatively low transaction costs involved. This financing vehicle is likely to be only marginally more expensive than tax-equity flip financing for larger stand-alone solar PV projects. A combination of NCREBs with grants available for state and federal agencies is an attractive option for qualifying cooperatives to pursue.
vii. Beginning March 5, 2015, NCREBs have been available on a first-come, first-served basis, by application. On February 3, 2015, the IRS announced that it would reallocate nearly $281 million in NCREBs for eligible renewable energy projects owned by electric co-ops. The amount stems from $800 million in NCREBs previously earmarked for cooperatives by Congress but not used. As of December 1, 2015 more than $195 million in NCREBs still were available for electric cooperatives.

viii. Tax-equity flip and lease structures have the potential to deliver the best economics for the deployment of utility-scale solar PV installations, provided that transaction costs can be spread over a large number of projects and implemented in a standardized manner. Larger projects—2 to 5 MW and larger—when offered to tax-equity investors on a pipeline basis, present little or no difficulty in sourcing and implementing tax-equity structures. However, the small size of the currently contemplated cooperative projects and the "scarcity" of tax-equity investors/tax investors make it challenging for cooperatives to implement the tax-equity flip/lease structures on a stand-alone or one-off basis at this time. The recent extension of the solar Investment Tax Credit (ITC) is expected to ease this situation.

ix. Viable solutions for cooperatives to implement tax-equity flip and lease structures include working with network organizations, locating and working with local tax-equity investors, rolling up multiple projects through master structures, using standardized documents/structures, and working with developer-aggregators. These options have been tried, tested, and implemented successfully. Ongoing developments in the industry confirm that these options are viable for cooperatives.

x. Cooperatives can also leverage their connectivity and relationships with their members and work with taxable and tax-paying local businesses/large customers (mostly commercial and industrial accounts) to implement utility-scale solar PV projects in their service territories. It is strongly recommended that cooperatives should not pursue this route without specialized help.

xi. Cooperatives can also implement tax-equity flip and lease structures through their tax-paying, taxable subsidiaries.

xii. Cooperatives are ideally suited to implement community ownership in utility-scale solar projects. Community ownership can be overlaid on any of the business models outlined in this manual. Community solar projects should, however, be designed carefully to avoid being characterized as "offering securities" or "offering investments" on the one hand, and avoiding "erosion" of contribution to margins from lost sales and the consequent "cross-subsidization" across participating and non-participating customers.

xiii. Business model implementation often requires cooperatives to hire specialized help. Such help could be accessed from network organizations as well as outside experts. Expertise is needed to set up the various required entities (such as blocker LLCs and Special Purpose Entities to implement projects) and the needed resources, such as standardized documents, contracts, etc.

xiv. Land requirements, as well as accounting, regulatory, finance, tax, and legal issues, require careful planning and hiring of the required help.

xv. Insurance products to cover small cooperative projects are plentiful. Insurance requirements are not likely to present hurdles for cooperatives in implementing utility-scale solar PV projects.

xvi. Property insurance rates have remained stable to slightly downward trending in the past few years. Premiums for recently constructed projects have ranged from $0.27 to $0.40 per $100 of replacement cost, with the average in the U.S. being $0.37.

xvii. Every pathway described in this document, regardless of ownership, financing, or community/member participation, is designed to enable the cooperative(s) to achieve full ownership of the PV system.

Extension of ITC

Solar projects under construction by December 2019 will qualify for a 30 percent ITC pursuant to the tax credit extensions included in the Consolidated Appropriations Act, 2016 (the omnibus spending bill). The credit will fall to 26 percent for projects starting construction in 2020 and 22 percent for those starting construction in 2021. Projects under construction before these deadlines must be placed in service by December 2023 to qualify. The credit will revert to its permanent 10 percent level after that time. Thus, any project not yet under construction would still qualify for a 10 percent ITC.

The bill would also extend the residential solar credit for homeowners who choose to buy solar rooftop systems or solar hot water heaters rather than enter into solar leases or power contracts with solar companies. They could claim a 30 percent tax credit on such equipment put in service through 2019. The credit will drop to 26 percent in 2020 and 22 percent in 2021. It disappears after that year.

Other tax benefits

The tax extenders bill would extend a 50 percent “depreciation bonus” that expired at the end of 2014 and make it retroactive to the start of 2015. Companies that put new equipment in service in 2015, 2016, 2017, or 2018 could deduct 50 percent of the tax basis in the equipment immediately and the other 50 percent using the normal depreciation table. New equipment put in service in 2019 would qualify for a 40 percent bonus. Equipment put in service in 2020 would qualify for a 30 percent bonus.

Assets such as transmission lines and gas-fired power plants that have longer depreciable lives could qualify for the 50 percent, 40 percent, or 30 percent bonus for an extra year. Thus, for example, a 50 percent bonus could be claimed on the cost of transmission assets completed in 2019. However, this 50 percent bonus would apply only to the basis built up in the asset through the end of 2018. Presumably, a 40 percent bonus could be claimed on the remaining basis.

Projects on Indian reservations can be depreciated more rapidly than projects in other parts of the United States. For example, a wind farm or solar project on an Indian reservation can be depreciated over three years rather than five years. This provision will remain true of any such projects completed by December 2016. The provision had expired at the end of 2014, but the tax extenders bill would extend it retroactively.

Source: News publications.

1 Introduction and Scope

This manual covers the business models or pathways through which electric cooperatives can deploy utility-scale solar PV installations to meet their renewable energy goals. The cooperative's choice of business model will have important implications for the economics and extent of solar PV that can materialize in its service territory.

Exploration of business models in this manual is confined to utility-scale solar installations. "Utility scale" is generally understood in the industry to be solar PV installations sized at 5 MW or more. The definition typically excludes residential rooftop installations as well as most other rooftop and demonstration or experimental installations that utilities may install. In this report, we define utility-scale solar PV installations for the electric cooperative sector as being 1 MW or larger—to account for the interest we have witnessed in the sector as well as the smaller scale of operations of cooperative utilities. However, the analysis and discussion presented in this manual, as well as the models used herein, apply to installations as small as 0.25 MW.

This manual embraces the potential for community partnership—through community solar or solar gardens—as an integral and important variant of the business models. As member-owned utility systems, electric cooperatives are uniquely positioned to encourage community participation in solar PV installations. As we elaborate later in this manual, community participation can be achieved within cooperative-sponsored utility-scale solar PV installations without the cooperative getting caught up in "selling investments" or being seen as offering "securities." It is advised that any cooperative exploring such community participation work with legal counsel.

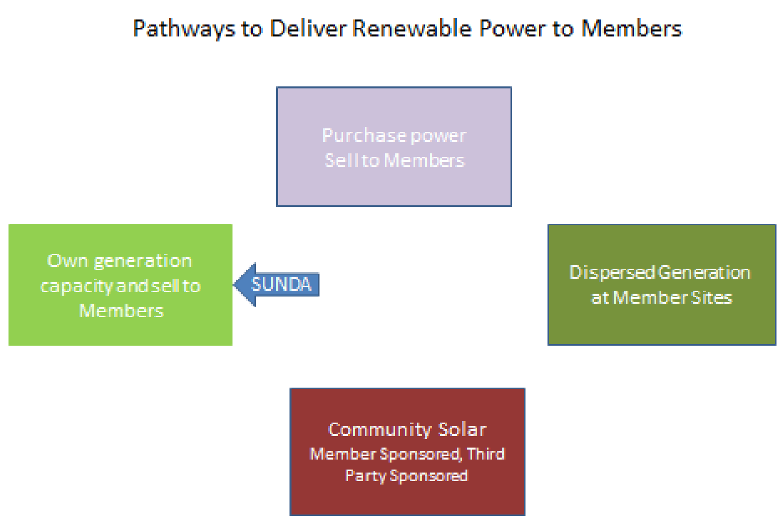


Figure 1: Pathways to Deliver Renewable Power to Members

In exploring the business models, we have deliberately excluded the purchase power pathway and dispersed generation at member sites, shown in Figure 1, since the control of the installations in those models would rest largely with third parties. Further, the pathways not considered in this manual could potentially be more expensive in the long run in meeting the profit and return objectives of sellers or the counter-parties involved, and through the loss of scale economies in dispersed locations, compared to the deployment of the utility-owned solar capacity by not-for-profit, cost-based electric cooperative power suppliers at centralized locations. It should be noted that owning generation capacity and selling to members does not preclude a community solar project; how the cooperative recovers the cost of the system, either via a community solar program or by way of traditional power sales, is up to the co-op.

This manual is composed of seven sections.

- **Section 1: Introduction and Scope**
- **Section 2: Business Models for Implementing Utility-Scale Solar PV Projects**—begins with an exploration of the strategic thinking process that cooperatives may need to go through before exploring the business models for implementing their utility-scale solar PV installations. It then details the various business models that cooperatives potentially could use. The business models are organized as a series of organizational, financial, and structural choices that cooperatives may make as they develop the business model that best fits their needs in implementing their utility-scale solar projects.

The next three sections outline information that cooperatives will find useful in choosing a business model for their projects.

- **Section 3: Comparison of Business Models**—outlines the various advantages and disadvantages of the business models and financing options.
- **Section 4: Economics of the Financing Options**—details the economics/cash flows for each of the business models/financing options. It develops and illustrates a number of financial metrics, such as the levelized cost of energy, the cost per solar panel, etc., to compare the economics of the business models/financing options available to cooperatives. This section includes a useful examination of key differences between the value of power and the levelized cost of energy.
- **Section 5: Insurance Requirements**—outlines typical insurance requirements for typical utility-scale solar PV installations and indicative current costs.
- **Section 6: Summary Guide to Utility-Scale Solar PV and Business Models and Financing Options**—concludes the report with a summary of the basic steps involved in implementing the business models and provides descriptions and contact information for key organizations related to financing, insurance, and tax credits.

A compilation of supporting material for the various business models is included in the appendices at the end of this manual, as follows:

- Documents Required to Implement Tax-Equity Flip Financing
- Illustrative Term Sheet for Tax-Equity Flip
- NCREBs-Related Links and Materials

- Illustrative Term Sheet for NCREBs
- Applicable Security Laws
- Sample Request for Proposal
- Cost Screening Tool Financial Glossary
- Financing and Insurance Resources and Contact information

2 Business Models for Implementing Utility-Scale Solar PV Projects

Cooperatives' implementation of utility-scale solar PV must start with the exploration of a number of strategic questions, as follows:

- Why renewables?
- Why solar?
- How much solar/renewables?
- What are the possible implications of pursuing and not pursuing renewables?
- What is the desirable timing (deciding if it should be graduated) and sizing (deciding what proportion of the total power supply portfolio should renewables/solar make up)?
- Where is it best done—at the generation and transmission (G&T) cooperative level or by the distribution cooperative?
- What is the consensus or prevailing view at the G&T and among the G&T members?

This exploration process could be iterative; answers to one set of questions and issues may lead to questions relating to issues that have already been explored and supposedly resolved. Cooperatives could converge on an action plan through a series of explorations. The processes must involve all relevant stakeholders, such as the G&T, a cross-section of key staff from appropriate business units, end-use consumers, board members, boards, regulators, and other "significant" relevant voices.

The exploration ideally should be conducted in forums of manageable size, each forum with a narrow scope, to deal with specific issues that forum participants can uniquely address. The flow chart shown in Figure 2 depicts a typical process a cooperative may consider in pursuing deployment of solar PV in general, and utility-scale solar in particular. It should be pointed out that the relative scope and effort in the process should be modulated and tailored to the individual circumstances of the cooperative to avoid overkill or "analysis paralysis." Involvement of experienced staff and learning from the shared experiences of other related organizations—such as other cooperatives and network organizations—would be of immeasurable value in pursuing the process.

Ideally, the choice of business models and questions on implementation would follow ONLY after the cooperative concludes a strategic thinking process that it deems appropriate for its specific circumstances.

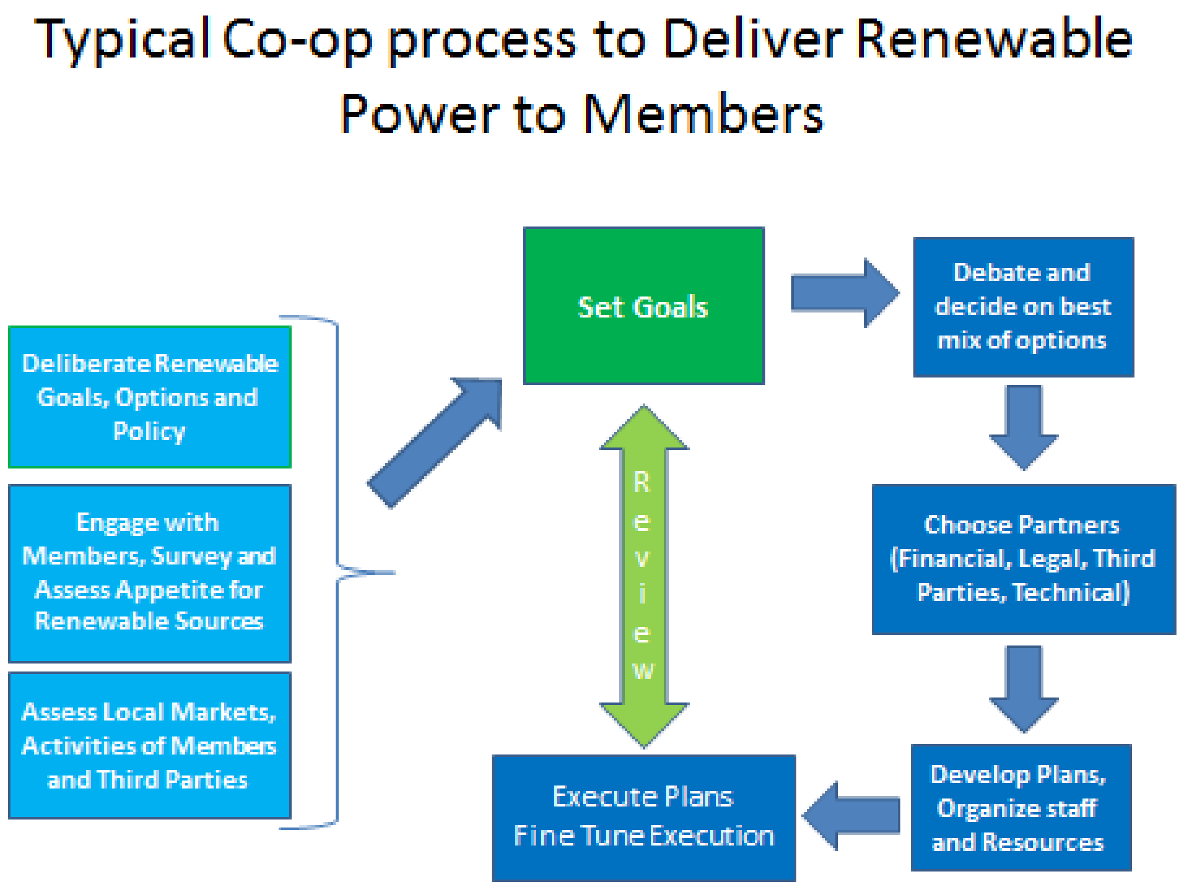


Figure 2: Typical Co-op Process to Deliver Renewable Power to Members

The business models or pathways for implementing utility-scale solar PV could be classified broadly based on the four choices that an electric cooperative can make:

1. **Choice of Organization:** Where should the project be implemented? Electric cooperatives, unlike investor-owned and municipal utilities, are seldom vertically integrated. Cooperatives are organized along such specialized functions as distribution, transmission, and G&T entities, as detailed in Section 2.1.

2. **Choice of Ownership:** Will the distribution co-op or G&T purchase the PV system or use some form of partial ownership to take advantage of tax benefits, followed by full ownership (as detailed in Section 2.2)?

3. **Choice of Financing:** How are the projects financed? Linked directly with the choice of ownership, will the electric cooperative seek traditional debt financing, subsidized financing, or implement a lease or tax-equity flip arrangement, as detailed in Section 2.4?

4. **Choice of Participation:** Will community participation be built into the business plan? Often described as community solar farms or gardens, the cooperative could accept payments from individuals in exchange for assignment of output to offset expenses and/or cultivate member-owner involvement, as detailed in Section 2.5.

Each of these distinguishing choice factors are depicted in Figure 3 and will be explored further. Each pathway described in this report may lead to the cooperative's full ownership of the PV asset.

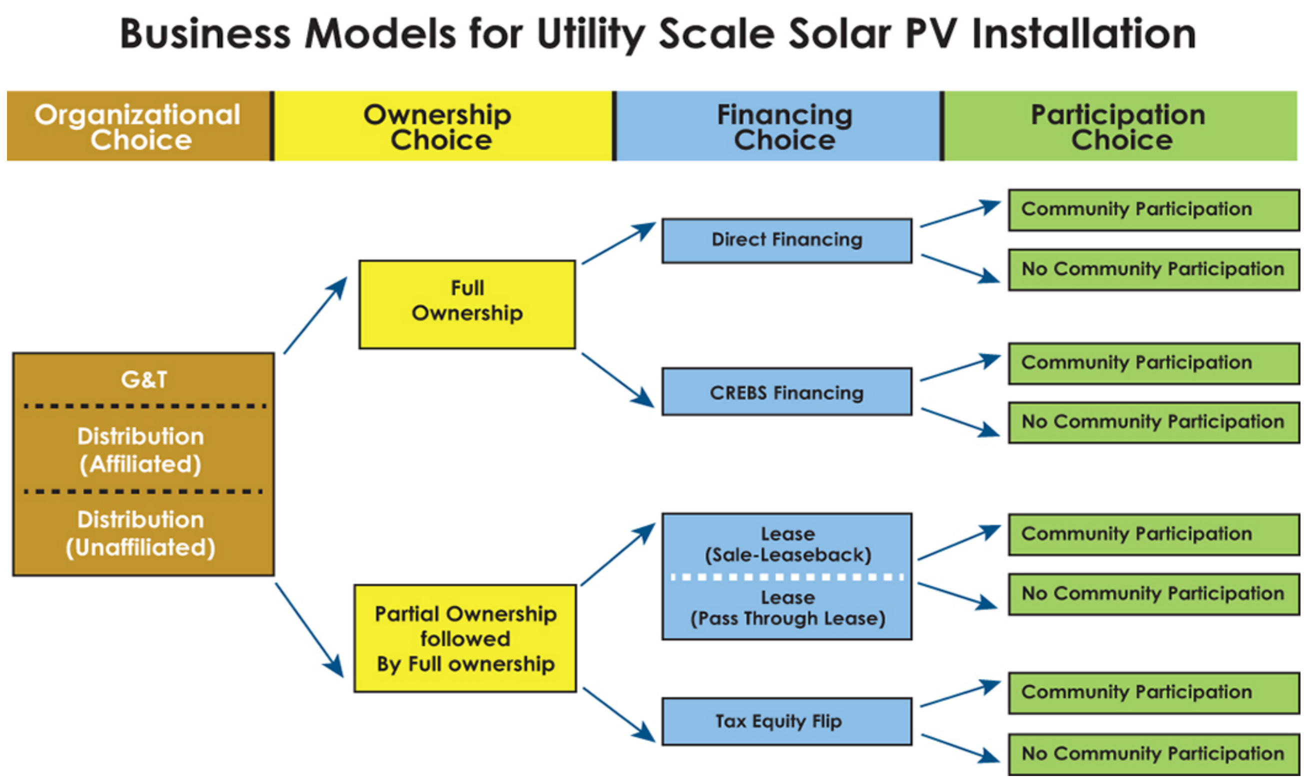


Figure 3: Business Models for Utility-Scale Solar PV Installation

If you would like to discuss the business models or their pros and cons to formulate your own business plans, please contact **Krishna Murthy** at krishna.murthy@nrucfc.coop.

2.1 Organizational Choice

Utility-scale solar PV projects can be implemented by distribution cooperatives or G&Ts. The choice of where it is implemented can influence how much capacity can be implemented, how the power output flows contractually, how it is paid for, who controls it, and whether community participation can be implemented. Organizational choice, although it is dictated mainly by what a cooperative *can do,* also has implications for the economics of solar projects. Project economics are driven by the following:

- Interest coverage ratios required by lenders, which typically are lower at the G&Ts and higher at distribution cooperatives
- Borrowing costs that depend on the credit strength of the implementing entity
- Scale economies that are more easily achieved at G&Ts than distribution cooperatives

2.1.1 Ownership at Distribution Cooperatives

Distribution cooperatives can be divided broadly into two categories: unaffiliated cooperatives (those *not* bound by all-requirement wholesale power contracts) and affiliated cooperatives (those with long-dated all-requirement contracts).

Unaffiliated distribution cooperatives generally have no limit on how much utility-scale solar PV capacity they can add to their portfolio of power supplies. Limits in these cooperatives are either self-imposed or set by the economic parameters or other factors, such as the amount of generation capacity desired, amount of debt they want to take on their books, power purchase agreements (PPAs) that may indirectly limit their ability to implement solar, and other objectives that the cooperatives seek to achieve.

Affiliated cooperatives, on the other hand, are bound by wholesale power contracts with the G&Ts of which they are members. These wholesale power contracts are often long dated and restrictive as to the amount of power the distribution cooperatives can obtain from other sources—if they are even allowed that flexibility. Since the wholesale power contract serves as the basic foundation for G&T financing, and since a multiplicity of stakeholders (such as lenders, regulators, or trustees, for example) have approval rights on any modifications to the contracts, it is nearly impossible to side-step the provisions of all-requirements wholesale power contracts in accessing and using power from sources other than the G&T. In its most common form, the all-requirements wholesale power contract requires distribution cooperatives to obtain all of their power requirements from their G&T. These affiliated cooperatives are generally prohibited from owning *and* using *any* utility-scale solar PV installation.

In some isolated instances, affiliated distribution cooperatives are allowed to obtain (and use in the mix of their power supplies) an "up-to-a-specified limit" of power from other sources. Often the amount of capacity that can be installed under this type of provision is quite modest. In many cases, it is indicated either as a specified percentage of their requirements (such as 5 or 10 percent of the members' capacity or energy requirements—in some cases, the "lower of the two") or as a fixed number of kW per member cooperative (e.g., 150–250 kW per cooperative), subject to a G&T system-wide limit on the aggregate capacity (e.g., 10 MW).

If the cooperative utility has an all-requirements wholesale power contract with an affiliated G&T cooperative (without any flexibility, carve outs, or choice for the distribution cooperatives to source power for part or all of their power requirements on their own), as shown in Figure 4, the G&T cooperative must enter into the PPA with the renewable energy project rather than directly with the cooperative utility. In that case, the renewable power is passed through as a part of a wholesale contract.

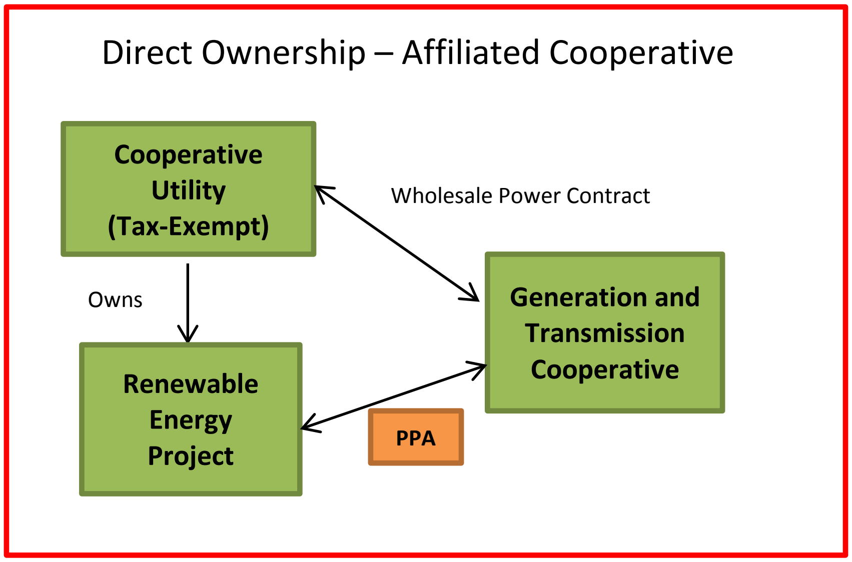


Figure 4: Ownership Choices – Full Ownership

In rare instances, to the extent that wholesale power contracts have been modified to include such a provision, affiliated distribution cooperatives are allowed to source all of their incremental power needs, over and above requirements stipulated in the all-requirements contract, as long as the distribution cooperative takes responsibility for all of the G&T's legacy costs. Under this arrangement, distribution cooperatives are essentially "partial requirements" members; they can deploy utility-scale solar PV installations in the same way as unaffiliated cooperatives.

One potential way for affiliated cooperatives constrained by their wholesale power contracts to install utility-scale solar PV involves selling *all* of the output from their (owned) utility-scale system to/through their G&T and buy the equivalent power back. Presumably such an arrangement could add to the cost of power from solar installations by the amount, if any, of margins the G&T might add to the basic cost of power from the solar project.

Examples of All-Requirements Contracts

The seller (G&T) shall sell and deliver to the consumer (distribution member), and the consumer shall purchase and receive from the seller all electric power and energy which the consumer shall require for the operation of the consumer's PV system.

If this obligation exists, the distribution system may be prevented from owning and operating any generation facilities to service any portion of its load.

There are sometimes slightly more relaxed all-requirements obligations that allow distribution systems to supply a portion of their power and energy requirements.

(1) Allowing a member to procure its own future wholesale power supply as long as it remains fully obligated for its pro rata share of all outstanding (legacy) obligations. As purchase power obligations expire, the member's obligations to the G&T are reduced accordingly.

(2) Including provisions for distribution members to supply up to an agreed-upon percentage of their G&T requirements from non-G&T sources.

(3) In some cases, providing the option, upon giving proper notice of at least three years, for a member to terminate all-requirements service, after which the member shall begin receiving a form of partial requirements service.

These provisions help provide financial assurance for G&T loans associated with G&T facilities. If a distribution system is limited from owning generation by its wholesale power contract, there may be other options, including ownership of the solar generation by the G&T, with associated wholesale rates or credits based upon the output of the project provided to the distribution member.

2.1.2 Ownership at G&Ts

Electric cooperative G&Ts are owned by their affiliated distribution cooperatives, and all capital investment decisions made by the G&T are decided upon by its board of directors. G&T boards typically comprise managers/directors of member distribution cooperatives, with decisions made on the "one-member, one-vote" principle. The amount of utility-scale solar PV capacity that can be implemented at the G&T level is limited only by what the G&T's owners (members) decide to deploy. Considerations that go into capital investment decisions include the need for generation capacity, financial impacts of various options available to the cooperative (purchase vs. ownership, for example), and any regulatory/legislative mandates.

Distribution cooperatives can often work with their G&Ts to implement solar. In this scenario, the PV array would be owned by the G&T but sited, maintained, and operated by the distribution cooperative.

2.2 Ownership Choice

The choice of ownership could be either full ownership (wherein the cooperative is the exclusive sole owner of the installation from inception through the life of the project), or partial ownership followed by full ownership, wherein the cooperative begins with a partial ownership or the right to use, followed by a right to full ownership after a certain specified period or upon the occurrence of a specific event, such as the exercise of a buyout option. The nature of ownership has implications for a cooperative regarding the control it can exercise over project operation as well as the economic benefits.

2.2.1 Full Ownership

Full ownership essentially involves a cooperative owning the utility-scale solar PV installation within the corporate entity or in a wholly owned subsidiary (Figure 4). A wholly owned subsidiary may be used as a means of accessing non-recourse debt as well as facilitating financing of the asset without encumbering the legacy assets of the cooperative. Depending on lenders' debt-service covenants, such an arrangement with a wholly owned subsidiary could reduce the revenue requirements to service the debt.

Cooperatives, as well as their wholly owned special-purpose entities (whether pre-existing or newly created), can access grants and incentives, if available (such as Rural Energy America Program [REAP] grants), to enhance the economics of the full ownership model. In this model, the traditional sources of financing or NCREBs are supplemented with grant funds—see the text box **Enhancing the Economics of NCREB Financing by Harnessing Other Incentives (Grants).**

Full ownership can also be pursued through a taxable subsidiary if the subsidiary has, and expects to continue to have, tax liabilities that can be shielded by capturing tax incentives available for utility-scale solar PV projects.

In this business model, a cooperative could decide to forgo tax benefits available for the installation of utility-scale solar PV installation in preference to a simplified and expeditious implementation of the solar project within the corporate ownership of the cooperative. As seen later in Section 2.4, "Financing Choices," cooperatives could pursue the direct ownership business model and access the benefits of specialized lower-cost financing vehicles (such as CREBs) available exclusively to tax-exempt entities, such as cooperatives and municipals, in lieu of the tax benefits that can be harnessed by taxable entities.

2.2.2 Partial Ownership Followed by Full Ownership

In practical terms, partial ownership followed by full ownership could be deployed either as a lease with a buyout option (by the cooperative itself or a wholly owned co-op subsidiary) or indirect ownership through a wholly owned entity (i.e., the tax-equity flip structure). In either case, the co-op (or its wholly owned subsidiary) would have step-in rights to full ownership upon the exercise of a "fair market value buyout" of the other owners' interest(s). The two business models are represented in graphic terms in Figure 5 below.

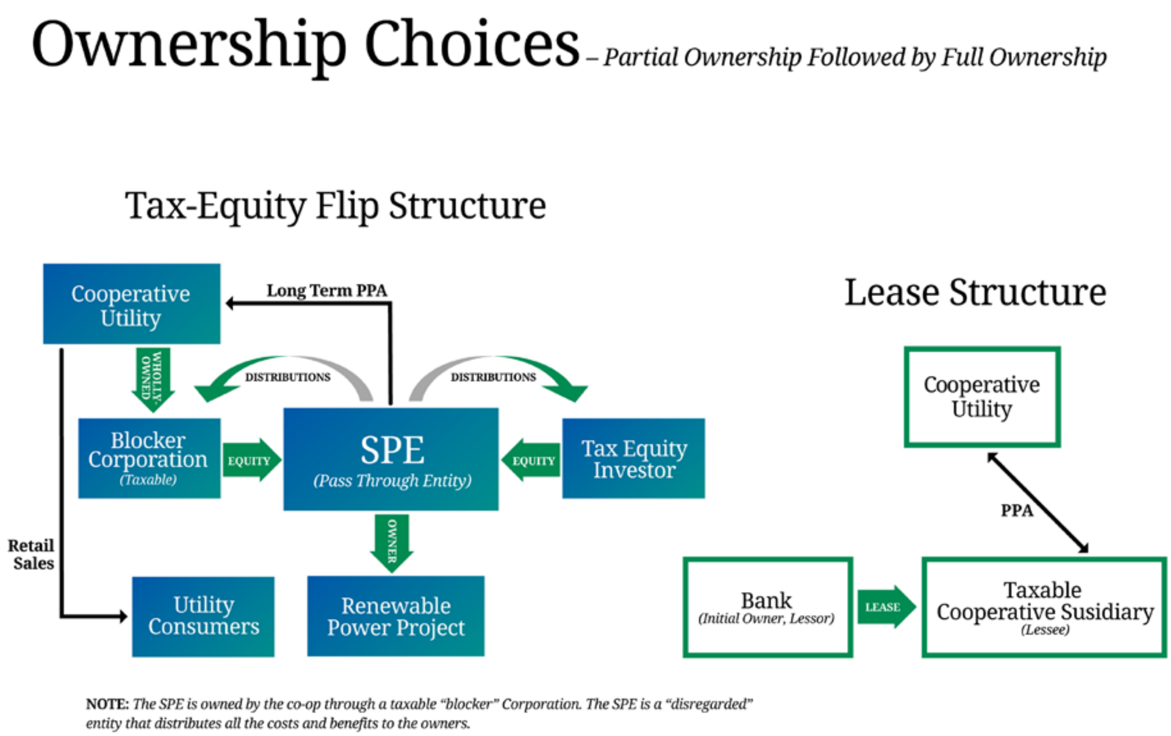


Figure 5: Ownership Choices – Partial Ownership Followed by Full Ownership

Partial-ownership models essentially permit cooperatives to access the benefit of incentives—such as the ITC, production tax credits (PTCs), and tax benefits arising from the deductibility of accelerated depreciation and regular depreciation against taxable income—otherwise not available for tax-exempt, not-for-profit entities such as electric cooperatives. Once the tax benefits are exhausted, the cooperative could exercise a buyout option—built into the agreements upfront—to step into a full ownership role by paying a formula-based fair market value to the other owner(s). This business model was used extensively by cooperatives during the mid-1980s to develop conventional power plants and related equipment eligible for bonus depreciation, and more recently for renewable energy projects eligible for the ITC and accelerated depreciation.

In a partnership, project control and operation often rests with the owners, subject to the stipulations of the partnership agreement. Partial ownership permits the economic attributes (whether they are tax attributes or cash flows) arising from the operation to be apportioned to the owners to maximize value.

For example, in a lease structure, the lessor (the owner) captures the economic benefits of the ownership (such as tax incentives, ability to capture depreciation of the assets, etc.), as the ownership remains with the lessor; the lessee enjoys operational benefits from the assets as long as the lessee complies with the requirements (such as the payment of rentals, maintenance and operation of the facilities, etc.) of the lease. When a buyout option is exercised, the lessee becomes the exclusive and sole owner; all of the operating and economic benefits accrue to the lessee.

Similarly, in a tax-equity flip arrangement (described more fully later in this manual), economic benefits are distributed to the partners pursuant to the partnership agreement; distributions to them (both timing and the amount) are designed to maximize the harnessing of eligible tax benefits.

2.3 Investment Tax Credits and Depreciation

Two significant tax incentives created to encourage renewable generation development and potential state tax incentives can be captured by cooperatives through shared ownership with entities having significant tax liabilities. Under §48 of the Internal Revenue Code of 1986, commercially sited (non-residential) solar PV arrays qualify as renewable energy property eligible for the ITC. The ITC is available as a direct offset to federal tax liability for an amount equal to 30 percent of the qualifying basis of solar PV property placed in service through December 31, 2016. This incentive was recently extended to December 2019 at the 30 percent level and authorized to be phased out by December 31, 2021 (see the text box on **Extension of ITC**).

To fully monetize the value of the tax credit, the taxpayer claiming the credit must have federal tax liability in an amount larger than the ITC. In general, a high percentage of solar construction costs qualify; only those project costs related to land and land improvements would be excluded.

In addition to the ITC, a properly structured solar project is eligible for depreciation based on the Modified Accelerated Cost Recovery System (MACRS), as described below.

These MACRS depreciation rates allow for the deduction of the eligible amount of the investment for tax reporting purposes over the first six years of project life. (Note, however, that approximately 50 percent of the ITC claimed will be netted out of the total investment to arrive at the amount eligible for the accelerated depreciation.) The accelerated depreciation creates tax losses for the entity that owns the project. By applying the effective tax rate of the taxpayer that owns the project entity, a tax deduction is created to monetize the tax losses as a deduction to taxable income from other sources in the amount of the effective tax rate times the tax loss from the project entity.

The combination of these two federal tax incentives, which may be enhanced further by available state tax incentives, require a solar project owner to have other sources of taxable income that generate actual tax payments to fully monetize the value of the incentives. It should be noted that certain incentives, such as grants, will reduce the depreciable “basis value” of the project that can be used to claim other incentives, thus effectively prohibiting “double dipping.” Although individuals may claim the ITC for solar property installed on their residences, a community solar project may not qualify an individual owner for the ITC. Also, individuals are not able to claim accelerated tax depreciation for solar property installed at their residences even if they qualify to claim the ITC.

Electric cooperatives are almost exclusively tax exempt and thus not able to monetize these tax incentives. For this reason, they require an option that utilizes a taxable subsidiary or a plan that brings in a third party having tax liability that it seeks to reduce through participation in transactions eligible for tax benefits to efficiently monetize the available tax incentive and lower the cost of energy produced from the project.

State Solar Tax Incentives

State tax credits vary widely by eligibility criteria, incentive level, annual budget, installer and equipment requirements, and other criteria. The Database of State Incentives for Renewables and Efficiency is the most up-to-date resource to track state and federal tax incentives for PV.

Summary tables of state tax credits can be found at: http://programs.dsireusa.org/system/program/tables/.

2.4 Financing Choices

Financing choices available to cooperatives are shaped by the ownership choice made. Among the choices available to the cooperatives are the following:

- Direct financing, available from program lenders such as CFC or CoBank
- Federal financing, through the Rural Utilities Service (RUS)
- NCREBs financing
- Leasing arranged by CFC or through CoBank Farm Credit Leasing
- Tax-equity flip financing (organized by third-party vendors or cooperative network organizations)

2.4.1 Direct Financing

Direct financing, as the name implies, simply consists of a cooperative accessing loans or financing and

Financing Choices Contact List

Electric cooperatives interested in Financing Choices can contact:

For RUS Financing:
Victor Vu, RUS, Deputy Assistant Administrator, Portfolio Management and Risk Assessment
(202) 720-6436
Victor.Vu@wdc.usda.gov

For CFC Financing:
Krishna Murthy, CFC, Vice President Energy and Industry Analysis
(703) 467-2743
Krishna.murthy@nrucfc.coop

For NCREBs Financing:
Linda Graham, CFC, Director, Financial Products
(703) 467-1752
Linda.Graham@nrucfc.coop

For CoBank Financing and NCREBs:
Tamra Reynolds, Regional Vice President, Southern Region, Electric Distribution, Water & Community Facilities Division
Phone: (303) 740-4034

executing the project within its corporate ownership. Although this may be a more expensive route to implementing utility-scale solar projects because no incentives or tax benefits are harnessed, it is by far the simplest and most expeditious route to implementing them. The loans (usually secured under the cooperative's mortgage or indenture) can be obtained for terms running up to the life of the project (generally up to 25 years for solar PV), at fixed or variable interest rates, and under a variety of amortization schedules (level principal, level debt service, or customized amortization). Such loans can be accessed from program lenders such as CFC, CoBank, and RUS. RUS loans may have limitations regarding amortization schedules and the rate options available. However, the loans may have longer terms of up to 30–35 years. These loans typically are made to the cooperative directly, although in some instances they may be available even when the project is housed in a wholly owned cooperative subsidiary. Interest rates offered for the loans change daily and generally can be fixed at the time when funding is advanced.

Electric cooperatives may prefer to finance a solar generation project with conventional financing and forego the benefits of tax incentives available under other options. The most significant reasons for this choice are as follows:

- Funding requirements are small and transaction costs, together with timing considerations, outweigh the tax benefits available.

- Funding through RUS or a traditional cooperative lender offers longer-term financing to cover the estimated life of the project for up to 30–35 years. Annual cash flow requirements for a project will be lower under this scenario. As a result, the cooperative could achieve a positive cash flow earlier than from other financing alternatives.

- Amortization options for RUS loans or RUS-guaranteed Federal Financing Bank loans include either level debt service payment or level principal payment. Private lenders offer tailored principal amortization options, including full principal repayment at maturity.

RUS Financing for Renewables

RUS has taken the position that projects seeking its financing for renewables move to the front of the queue—that is, such projects will be funded before other RUS loan applications, regardless of when the application is received. Renewable projects can be financed with RUS at the U.S. Department of Treasury (Treasury) rate plus an eighth of a percent. In today's historically low interest rate environment, borrowing from RUS for the construction of a renewable facility is an attractive option. RUS will loan to entities that are not currently RUS borrowers; however, those entities must agree to be bound by all RUS rules and regulations.

- For more information on RUS borrower responsibilities: https://www.cooperative.com/InterestAreas/Generation/DistributedGeneration/Pages/RUS-Borrower-Responsibility.aspx.

- For more information on RUS loan programs: http://www.rurdev.usda.gov/RD_Loans.html.

- Information about the electric loan programs and advice on completing and assembling an application are available from the national office. Please contact the following: Office of Loan Origination and Approval (OLOA) at (202) 720-1264.

2.4.2 Clean Renewable Energy Bonds (CREBs) and New CREBs (NCREBs) Financing

Note on NCREBS for 2015

In February 2015, the Internal Revenue Service (IRS) issued a Notice soliciting applications for nearly $281 million in previously unused NCREBs for eligible renewable energy projects owned by electric cooperatives, available on a first-come, first-served basis. NCREBs are a tool to lower the cost of financing facilities generating electricity from solar, wind, landfill gas, biomass, and other renewable sources. The IRS Notice may be found under the link "TEB Published Guidance" on the IRS website at http://www.irs.gov/Tax-Exempt-Bonds. Additional resources and materials can also be found on the SUNDA webpage: http://www.nreca.coop/what-we-do/bts/renewable-distributed-energy/sunda-project/. Treasury stated that the amount of available volume cap (out of the initial $281 million availability) was $195,697,775 as of December 1, 2015.

For more information, please contact Linda Graham, CFC director of financial products, at (703) 467-1752 or linda.graham@nrucfc.coop, or your preferred lender.

Enhancing the Economics of NCREB Financing by Harnessing Other Incentives (Grants)

Cooperative utilities (such as electric cooperatives and Tribal Utility Authorities) have access to grants and incentives available from state, federal, and local government agencies. Accessing those grants generally will not work well in conjunction with tax-equity flip structures, since the basis value of the project—for the purposes of ITCs and accelerated depreciation—is reduced to the extent that grants are accessed to finance all or a portion of the sponsors' project costs. However, the low-cost NCREBs can be accessed even while taking advantage of the grants.

REAP grants available for small businesses, rural electric cooperatives, and Tribal Utility Authorities provide for up to 25 percent of the project cost (up to a maximum of $500,000) as a grant to qualifying projects. A combination of 25 percent of project cost through a grant, together with the remaining 75 percent of the project costs financed through NCREBs (at an estimated current effective interest cost of 1 to 1.25 percent for the life of the project), can potentially deliver lower overall cost than the tax-equity flip structure or NCREBs alone (providing 100 percent of the financing).

Further details about the REAP grants, eligibility, and the procedures for application and allocations can be found at: http://www.rd.usda.gov/programs-services/rural-energy-america-program-renewable-energy-systems-energy-efficiency.

NCREBs are a lower-cost option than direct conventional loans for solar PV projects because of the lower borrowing costs and relatively low transaction costs involved in the transaction. This financing vehicle is likely to be only marginally more expensive than tax-equity flip financing for moderately sized, stand-alone solar PV projects.

Through CREBs (now called NCREBs), electric cooperatives can capture finance-related benefits, once available only to taxable private sector entities, for the construction of utility-scale solar PV installations. Similar to the incentive of production or investment tax credits for renewable energy projects offered by the federal government to for-profit ventures, CREBs improve renewable energy project economics and encourage investment in renewable energy production by public sector entities, including electric cooperatives and municipals.

As approved by the Energy Policy Act of 2005, CREBs were issued to investors who could obtain a tax credit from Treasury in lieu of an interest payment on the bonds. However, the tax credit was small, and investors required the bond issuer/borrower to pay supplemental interest payments. Thus, the advantage of CREBs depended upon finding investors looking for the associated federal tax credits over the life of the bonds.

A combination of attributes made these bonds less attractive than anticipated, including the inability to carry tax credits forward or backward into any other tax year if the credit exceeded the investor's limitation and the risk of forecasting an entity's actual tax credit needs over the life of the bonds.

These attributes became of more concern to investors following the financial market crisis at the end of 2008. As a consequence, in 2010, Congress enacted a revised and expanded program for CREBs—

NCREBs—that changed the former from tax credit bonds to direct subsidy bonds. The issuer makes an irrevocable election to receive a direct payment (a refundable tax credit) from Treasury, equivalent to and in lieu of the amount of the non-refundable tax credit that otherwise would be provided to the bondholder. In this case, an issuer (an electric cooperative) pays a lender an interest rate on an NCREB-related loan and receives a direct payment from Treasury to offset a portion of the interest expense.

NCREBs can be accessed in a single-step transaction when a cooperative is ready to fund a project, since the issuance of bonds to tax investors is no longer required. Under the old CREBs program, the high transaction costs associated with issuing bonds to investors required several cooperatives to bundle smaller projects into a single bond issue to size the issue to be at least $25 million, thus spreading the transaction costs over several projects.

NCREBs also include the ability to finance 100 percent of a project's cost, excluding interest during the construction period, and the ability to finance dedicated facilities, such as a distribution line, that may be required to deliver the output of the renewable energy project to end-use consumers.

2.4.2.1 Interest Rate and Federal Direct Payment Subsidy

NCREBs have financed renewable generation projects at a cost of less than 1.5 to 2 percent. Historically, the financing term has been as long as 27 years and is generally in the range of 20 years. Treasury has reduced the annual tax credit rate allowed for NCREBs to 70 percent of the rate as determined by the IRS.

Table 1 below shows the recent direct payment rates published by Treasury, with and without the 70 percent credit reduction. As an example, on September 8, 2015, the maximum term for NCREBs financing was 25 years, and the direct payment would be 3.297 percent of the outstanding NCREBs loan balance. The direct payment would offset the fixed interest rate on the lender's financing. Thus, if the lender's loan rate on September 8, 2015 was 4.75 percent, the effective cost to the cooperative would be 4.75 percent minus 3.297 percent, or 1.453 percent.

NCREB Tax Credit Rates, Maturities & Permitted Sinking Fund Yields				
DATE	**RATE**	**70% of Rate**	**Maturity**	**PSFY***
4/30/2015	4.26%	2.982%	26 years	2.70%
5/12/2015	4.59%	3.213%	28 years	2.52%
6/29/2015	4.94%	3.458%	26 years	2.73%
7/2/2015	4.76%	3.332%	24 years	2.99%
8/28/2015	4.69%	3.283%	23 years	3.08%
9/8/2015	4.71%	3.297%	25 years	2.88%
10/27/2015	4.61%	3.227%	25 years	2.82%
11/10/2015	4.88%	3.416%	25 years	2.81%
12/7/2015	4.78%	3.346%	25 years	2.85%

* Permitted Sinking Fund Yield (PSFY) is the return allowed on a debt service reserve fund for the project repayment.

Table 1: NCREB Tax Credit Rates, Maturities, and Permitted Sinking Fund Yields

The economics of the low cost of NCREBs can be further enhanced by accessing state and federal grants. For example, electric cooperatives qualify for these grants (REAP grants, for example, are available for most rural electric cooperatives to implement renewable projects to cover up to 25 percent of the project costs, with a grant limit of $500,000). Thus, a $2,000,000 solar project could potentially be implemented using $500,000 of the REAP grant money, with the remainder—$1,500,000—financed with NCREBs. This hybrid financing is especially well suited to smaller community solar projects. Another significant feature of NCREBs financing is that it does not have a sunset date; that is, funds are available until they are fully allocated and used up (i.e., no other time limit on availability).

As a result of Congress not reaching agreement on the federal budget, the requirements of the Balanced Budget and Emergency Deficit Control Act, otherwise known as sequestration, went into effect on March 1, 2013 and resulted in 7.2, 7.3, and 6.8 percent reductions in the refundable credit payment during fiscal years 2014, 2015, and 2016, respectively. The sequestration reduction will be applied until the end of the fiscal year (September 30, 2016) and thereafter until 2021, or until intervening congressional action to end sequestration.

2.4.2.2 Highlights of NCREBs

The IRS released a Notice in February 2015 that identified an NCREB volume cap of $280,778,469 available to fund projects for cooperatives. Cooperatives have been able to submit applications beginning on March 5, 2015. There is no deadline for submitting an application; however, requests for NCREB allocations will be considered on a first-come, first-served basis. The requirements under the new IRS Notice are similar to the previous Notice, with some significant changes, as follows.

- The IRS will consider requests for NCREBs on a first-come, first-served basis by order of application date, beginning as early as March 5, 2015. Previously there was a deadline for submitting applications; all requests then were considered by order of smallest to largest amount requested for a project.
- The maximum allocation available to any cooperative is the greater of (i) 20 percent of the NCREB volume cap, which starts at the $280,778,469 remaining for cooperatives; or (ii) $40 million. The IRS will update the NCREB volume cap approximately every 60 days and post the amount on its website.
- NCREB financing must be issued within 180 days from the date of the IRS allocation letter. Previously, a cooperative had up to three years to close the NCREB financing. Allocations not utilized within the 180-day period will be treated as forfeited and revert to the IRS for reallocation.

The IRS Notice may be found under the link "TEB Published Guidance" on the IRS website, at http://www.irs.gov/Tax-Exempt-Bonds.

Accessing NCREBs for utility-scale solar PV projects requires the interested cooperatives to apply to Treasury, be selected to receive an allocation, and meet certain spending requirements stipulated for tax-advantaged bonds. These processes and requirements are fairly detailed; they are outlined in Appendix III. Additional highlights of NCREBs include the following:

- Generally, 100 percent of the project costs (excluding interest during construction) are eligible to be financed by NCREBs.
- NCREBs are relatively complex but provide one of the lowest costs of financing for electric cooperatives.
- The term for the financing is not as lengthy as for conventional financing, since it is limited by Treasury as a function of the overall benefit received; that is, higher interest rate environments result in higher federal direct payments. As a consequence, the NCREB financing terms are set to be shorter when interest rates are higher.
- Financing may be used during the construction period.
- NCREBs may not be used to reimburse project expenditures paid before the receipt of the NCREB allocation.
- A typical term sheet for NCREB financing is included in Appendix IV.

2.4.3 Leasing

Lease structures can also be used by electric cooperatives to access the benefits of tax incentives associated with the ITC and accelerated depreciation. Typically, lease structures deliver economics substantially similar to tax-equity flip financing—subject, of course, to the return expectations prevailing in the market and the supply-demand dynamics in the tax-equity/tax investor market.

Two varieties of lease structure can be considered: a sale leaseback and a pass-through lease. Under both options, ITC benefits cannot be accessed if the property is directly owned by or leased to tax-exempt entities. Property leased to a partnership (to the extent of the partnership interest owned by a tax-exempt entity) would lose a proportionate amount of the ITC.

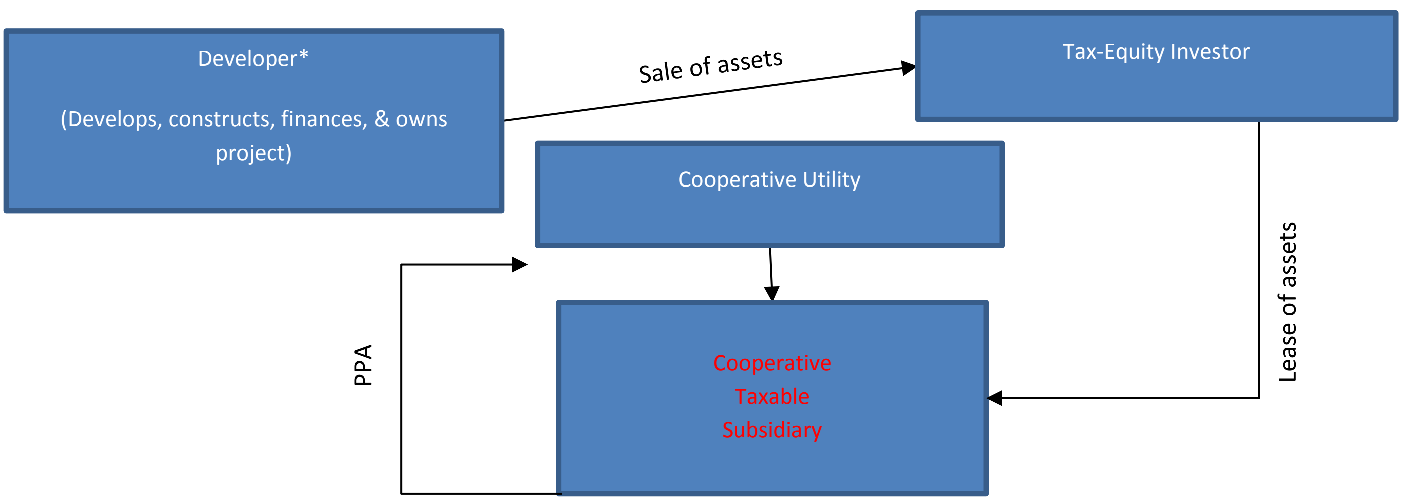
2.4.3.1 Sale Leaseback

In this structure, the project developer/cooperative sponsor (developer) builds the solar facility (using construction financing) and, upon completion of construction but before placing the project into service, sells the entire project to a tax investor (TI)/lessor. Simultaneously, the developer/lessee enters into a long-term lease agreement to use the assets. If the lease is treated as an “operating lease” or “true lease” for tax purposes, the TI will be treated as the owner of the property and should be entitled to the tax benefits. However, if the lease is treated as a capital lease for tax purposes, the developer should be treated as the owner of the property and consequently entitled to the tax benefits; in other words, the lease would be viewed as a financing transaction. In the case of a true lease, the expectation is that the developer benefits through lower lease payments than otherwise would be required if the ITC and MACRS were not available to the TI.

According to IRS guidance, for the lease to be treated as a true lease for tax purposes, among other criteria, the lease term should not extend past 80 percent of the project’s expected useful life. After the lease term, the parties may pursue three options: (1) negotiate a new lease at fair market value, (2) negotiate a purchase of the project by the lessees at fair market value, or (3) terminate the lease, with assets reverting to the TI. The TI bears the risk of profit or loss from the residual project value at the end of the lease. The terms of the lease agreements must be drafted to allow the lease to be treated as a true lease for tax purposes.

Under a sale-leaseback structure, proceeds from a sale of the property are generally used to repay any obligations associated with construction of the solar facility. This means that the developer assumes the potential upside and risk of any difference between the construction costs and the project sale price. Under the terms of the lease, generally the TI will be responsible for the operation and maintenance of the facility. The developer would negotiate a PPA with the cooperative for the sale of the energy generated by the project. The developer then uses the proceeds of the PPA to cover its operating costs and make lease payments to the TI.

Under the federal tax code, if the lessee is a tax-exempt entity, it will not be eligible for the ITC, since it will be treated as "tax-exempt use property." Thus, if the developer is a tax-exempt entity, it should utilize a "blocker" corporation for the transaction. In addition, for these same reasons, the terms of the relevant agreements need be drafted to avoid the PPA being treated as a lease under IRS rules if the PPA off-taker is an exempt entity. Figure 6 depicts the relationships involved in the sale leaseback.



***Developer role could be filled by cooperative or cooperative blocker.**

Figure 6: Sale-Leaseback Structure

CoBank Solar Array Leasing Program

Through Farm Credit Leasing, CoBank's wholly owned subsidiary, co-ops can lease solar arrays to capitalize on the ITC benefits. This benefit is realized through utilizing CoBank's tax appetite and passing tax savings on to the customer as a reduced lease payment.

CoBank takes ownership of the solar array, and thus the tax depreciation and ITC. In most cases, CoBank takes assignment of the solar array construction contracts before work begins. It provides construction funding during the installation process and owns the arrays during the term of the lease. Leases generally are written for terms of 10–12 years, with a purchase or renew option at the end of the lease term.

How your co-op is structured, or whether you have a taxable subsidiary, will impact who should lease the solar array and the structure of the lease to qualify for the ITC.

1. **If the cooperative is a taxable entity:** Because the cooperative is taxable, the lease can be written directly to the cooperative.
2. **If the cooperative is a nontaxable entity but has a taxable subsidiary:** The lessee would be the taxable subsidiary, which also must meet additional requirements. A guarantee of the lease is not required from the parent cooperative, but a PPA between the parent and its taxable subsidiary is expected.
3. **If the cooperative is a nontaxable entity and does not have a taxable subsidiary:** The cooperative would be required to find a taxable partner. The lease would be written to the taxable partner (or a taxable joint venture between the partner and the cooperative), supported by a PPA between the lessee and the cooperative. CoBank Farm Credit Leasing is available to discuss potential options for partners.

The solar ITC program and leasing option have very specific rules for a tax lease to apply and qualify for the ITC. The primary principle is that CoBank Farm Credit Leasing can provide only true lease pricing (and the ability to qualify for the ITC) to a taxable entity (see the text box on **Potential Tax Risks Associated with Tax-Equity Flip and Lease Arrangements**).

Some examples of projects financed with Farm Credit Leasing are as follows:

- Great River Energy (32 projects)
- Hoosier Energy(2projects)
- Prairie Power
- Mid-South Synergy (2 projects)
- Western Farmers Electric Coop (various projects)

More information on CoBank Leasing Services can be found at: http://www.cobank.com/Products-Services/Leasing.aspx. Additionally, interested parties should contact the following:

Tamra Reynolds – Regional Vice President, Southern Region, Electric Distribution & Water Division
Phone: (512) 330-9060; jslagle@cobank.com

Noiel Fontaine – Regional Vice President, Farm Credit Leasing
Phone: (860) 814-4049
e-mail: nfontaine@cobank.com

2.4.3.2 Pass-Through Lease

In a pass-through lease structure, the roles of the lessor and lessee are reversed. In this case, the developer or taxable cooperative subsidiary (blocker) retains ownership of the assets (as lessor) and leases them to the TI (lessee). The ITC benefits are passed through to the TI that claims them against taxable income. Note that the MACRS does not pass through to the TI, but instead remains with the developer.

In this structure, the TI enters into a PPA with the cooperative utility off-taker for the sale of the electricity generated. The developer does not receive a large upfront payment from the TI, as it does in the sale-leaseback structure, but rather receives lease payments over time. The developer thus must carry the financing costs for development and construction of the project for a longer term. The developer (i.e., the cooperative blocker corporation) is at risk for profit or loss on the project, depending on the lease payments received for it as compared to the construction and other costs. Unlike the previous structure, the lessor generally is responsible for the operation and maintenance of the facility. Also, the TI (lessee) negotiates a PPA with the cooperative for the sale of energy generated by the project. The lessee then uses the proceeds of the PPA to make lease payments to the developer (cooperative blocker), which uses the revenue to cover its operating costs and any long-term debt obligations.

Because the depreciation stays with the equity owner of the project, value added by MACRS may be left unrealized if the developer or blocker does not have sufficient tax obligations to take advantage of the MACRS deductions. Also, this structure still requires the cooperative to form a taxable subsidiary to develop and own the project assets. As with the sale-leaseback structure, the terms of the relevant agreements would need to be drafted to avoid the PPA being treated as a lease to the cooperative utility and for the lease to be treated as a true lease for tax purposes. Figure 7 depicts the relationships involved in the pass-through lease.

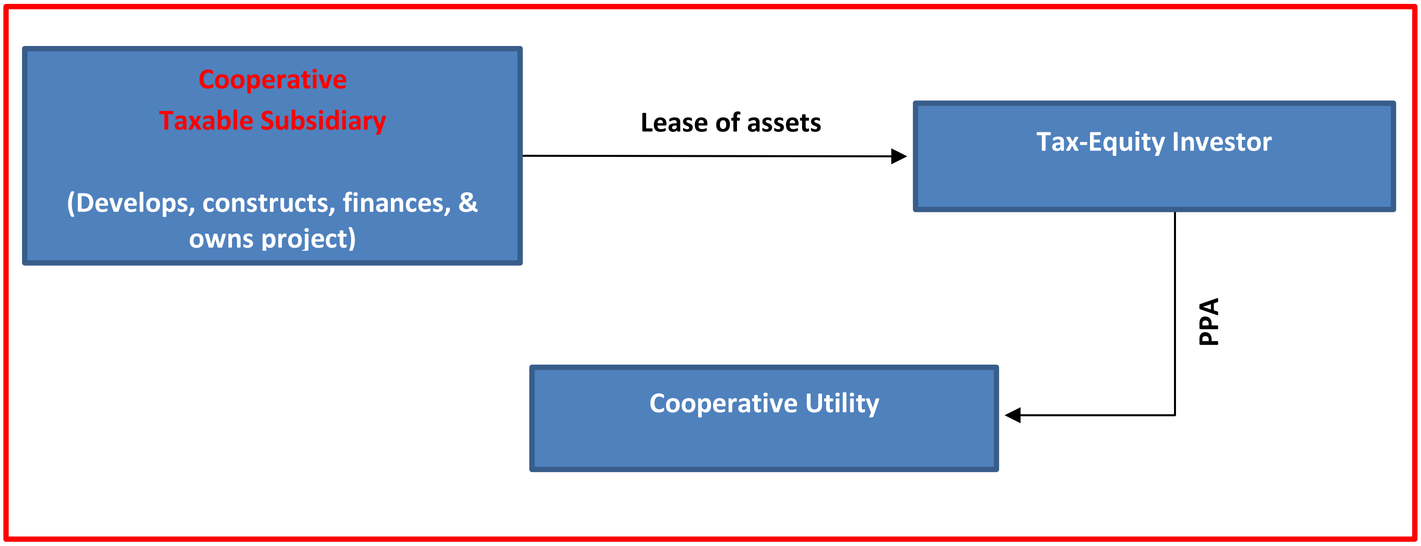


Figure 7: Pass-Through Lease Structure

2.4.4 Tax-Equity Flip Financing

A tax-equity flip allows tax-exempt entities to monetize federal and state tax incentives, thus reducing overall costs. Tax-equity flip financing is a low-cost option for large solar PV projects, as well as smaller projects when they are aggregated/rolled together through standardized master programs—that is, when several cooperatives or smaller projects are implemented with a common tax-equity investor using standardized document sets, structures, and developers. For very small systems (less than 1 MW), NCREBs financing, state and federal grants, aggregated tax equity programs such as the Solar Cooperative Community Projects (sCoop) model, and leases may be more suitable pathways than tax-equity flip models on a stand-alone basis.

Potential Tax Risks Associated with Tax-Equity Flip and Lease Arrangements

Although the tax equity structure is a financial vehicle well understood by developers and participants, this structure should be implemented with care to ensure that the IRS will agree with the characterization of the transaction for income tax purposes. Generally, participants in tax-equity flips follow a structure previously deemed appropriate by the IRS in a private letter ruling. However, if the chosen structure is based only on the private letter rulings, entities that wish to use the same structure take on some degree of risk that the IRS could view their transaction as a pure tax avoidance play rather than the establishment of a legitimate business—since the facts and circumstances of the transaction, although similar, may be different and thus could cause the IRS to view the transaction differently. Many view this risk as small, but it does exist.

In leasing arrangements that capitalize on the ITC and other tax benefits, CoBank Farm Credit Leasing is of the opinion that to provide true lease pricing to a taxable entity (the electric cooperative, a subsidiary, or a partner), the entity must be a legitimate business (versus a shell company) with income and employees, and meet a few additional requirements before entering into a lease.

Additionally, all transactions are subject to future changes in the tax law (although retrospective applications of the change in law to transactions entered into before that change are extremely remote). Changes in tax laws that affect an investor's assumptions, if these are in fact applicable to specific transactions regarding the availability and magnitude of tax benefits, may trigger clauses in the transaction documents requiring "make whole" payments to be made. Such payments typically may involve not only the value of any lost tax benefits, but also the returns expected by the equity investor over the life of the project. Cooperatives should consider the terms of the transaction, negotiate adequate protections, and consider all residual risks they are assuming, if any. It is possible that some of these risks may be avoided at a cost. Cooperatives should carefully consider the representations and warranties embedded in all contract documents, particularly those referencing tax risks. We recommend researching these requirements with competent tax and legal counsel to establish a thorough understanding of what these requirements entail.

Source: Utility Solar Tax Manual – Version 3. A Comprehensive Guide to Federal Incentive Programs, Solar Electric Power Association, March 2012.

Additional information is provided in Section 2.4.4.7, "Pros and Cons of Leasing Compared to Tax-Equity Flip Structure."

The Utility Solar Tax Manual can be found at:
http://www.nreca.coop/wp-content/uploads/2015/02/Attachment-A-SEPA-Utility-Solar-Tax-Manual-updated-2012.pdf

2.4.4.1 Tax-Equity Partnership Structure

An ownership structure that creates a partnership for tax purposes between the project sponsor (with limited or no outside sources of taxable income) and a tax-equity investor capable of monetizing the tax incentives often is referred to as a "tax-equity flip." This structure has been used for years by renewable project developers having little or no tax appetite; it can be used in the context of developing utility-scale solar installations by electric cooperatives.

Tax-equity flip models differ by financial institutions and developers of renewable projects as follows:

- Whether or not leverage (debt financing) is used
- Whether and when a buyout option is offered to sponsor organizations
- Whether or not an independent developer is involved in the project
- What cash flows and tax attributes are allocated, to whom, when, and in what proportion

The structure and allocation depicted below is specifically tailored to the needs of tax-exempt electric cooperatives and based on proven models that actually have been deployed. A graphical depiction of the relationships involved in the tax-equity structure is summarized in Figure 8.

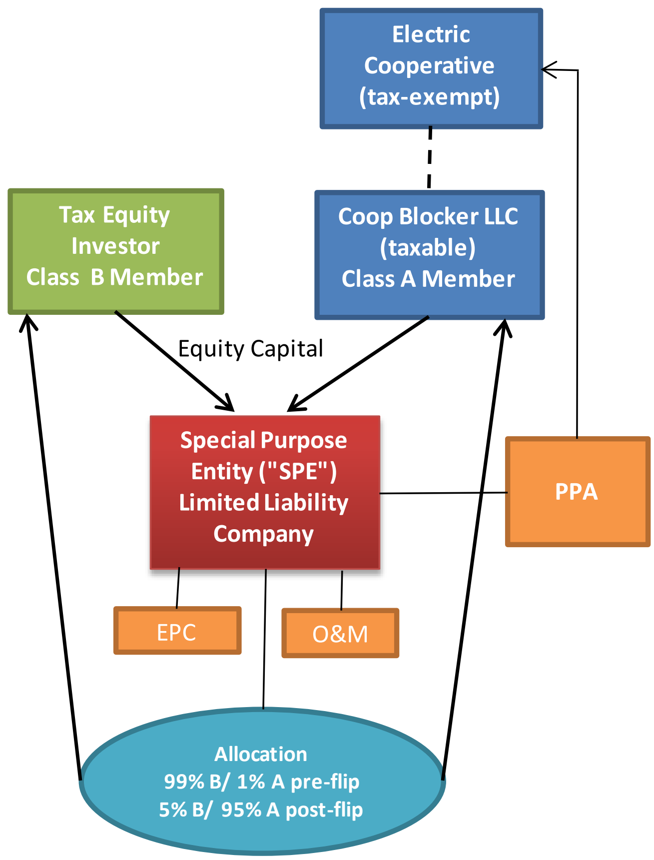


Figure 8: Tax-Equity Partnership Structure and Allocation

A special purpose entity (SPE) is formed for the partnership arrangement. The SPE is organized with two classes of member-owners (Class A and Class B members/owners/investors) as a pass-through limited liability company (LLC), so there are no taxes at the partnership level. Taxes are paid by the respective Class A (cooperative blocker corporation) and Class B (tax-equity investor or TEI) owners/investors via their own corporate tax returns. This structure entails an all-equity partnership in which the TEI contributes approximately 50 percent of the required project funding and the cooperative contributes the remaining funding requirements through the blocker corporation. The TEI enters into this partnership to gain a pre-determined percentage return on their investment, whereas the cooperative benefits by halving the initial development costs and then purchasing the rest at a fair market value post-flip.

Cash generated and tax profit or loss are distributed to the owners/investors—as agreed to and memorialized in the SPE Partnership Agreement—in different proportions (compared to the ownership percentages) according to their participation. Furthermore, the allocation of cash and tax-benefits flips (again, as agreed in the SPE Partnership Agreement) takes place between the owners/investors after the occurrence of certain events and the passage of time. At the beginning of the partnership, the TEI generally receives 99 percent of the cash distribution and tax profit or loss, which includes accelerated depreciation and ITC benefits. Once the TEI's targeted return is achieved, typically at approximately six years, the allocations will change (or flip); from then on, the cooperative blocker corporation will receive 95 percent of the cash distribution and tax profit or loss allocation. The flip in allocation of cash flow and tax benefits cannot happen before the end of year five or the IRS will recapture a portion of the ITC claimed.

2.4.4.2 Cooperative Blocker Corporation

There are special restrictions and considerations regarding a tax-exempt cooperative being a direct co-owner of renewable energy projects that utilize benefits arising from the ITC and accelerated depreciation. To insulate the cooperative from these limitations, the project sponsor creates a taxable blocker corporation that owns an interest in the project.

2.4.4.3 Special Purpose Entity (SPE)

The SPE that constructs, owns, and operates the project typically is organized as a Delaware LLC. Membership interests in the SPE typically are designated as Class A and Class B, with particular rights, income allocations, and distinct governance rights. SPE governance and allocation of income are controlled by the LLC operating agreement. The project sponsor's blocker corporation is typically the Class A member, whereas the TEI typically holds all of the Class B membership interest.

The SPE contracts for construction of the project, enters into PPAs with the cooperative for the sale of energy, and contracts for the operation and maintenance of the project. The SPE is a disregarded entity for federal tax purposes, meaning that any income or loss at the SPE level is passed on to its owners (referred to as members in an LLC) and reported on Form 1099.

2.4.4.4 Special Purpose Entity Capitalization

The TEI makes an equity investment in the SPE through buying Class B membership interests. To qualify for federal tax incentives, the TEI must be an equity owner. Preferred stock, subordinated debt, or other instruments with the characteristics of a debt obligation, including but not limited to a guaranteed return, greatly diminish and complicate the capture of tax incentives associated with equity ownership. The amount of the TEI's purchase of its Class B membership interest is calibrated to provide a target internal rate of return (IRR) on the TEI's equity over approximately six years to fully monetize the tax incentives.

The IRR represents the returns realized from receiving the Class B membership allocation of the ITC, operating losses that produce tax deductions, and distributions of cash from the SPE's positive cash flow.

The balance of the SPE's capitalization that the cooperative sponsor contributes through the blocker corporation serves as an equity investment via purchase of Class A interests. The source of that capital can be either general funds or loan proceeds designated for equity investment in the SPE. Although it is possible for the SPE to borrow the balance of the capital at the SPE level, this action increases the complexity of the transaction and often provides discomfort to the TEI because a default on the debt obligation could result in a transfer of ownership, triggering recapture of the previously claimed ITC.

Table 2 summarizes the sources and uses of funds for a 1-MW project funded by Class A and Class B membership equity purchases. These numbers are given for illustration purposes only.

Sources and Use of Funds						
($000's)						
Sources		**Amount**	**Uses**		**Amount**	
Debt	$	-	EPC Cost	$	2,297	
Tax Equity Investor (TEI)	$	1,080				
Cooperative Blocker	$	1,217				
TOTAL	$	2,297		$	2,297	

Table 2: Sources and Use of Funds Funded by Class A and Class B Membership Equity Purchases

2.4.4.5 Tax-Equity Investor Returns

During the initial period following the commercial operation of the project, the TEI Class B membership interest is allocated 99 percent of the income, 99 percent of the ITC, and 99 percent of any cash flow distributions from the SPE. The Class A member is allocated 1 percent. Once the TEI's after-tax IRR has been reached, ideally at or about the expiration of accelerated depreciation deductions following year six, the allocation flips to 5 percent for the Class B member and 95 percent for the Class A member. The TEI is able to claim the Class B member allocation of the ITC immediately following the project going into service, thereby receiving an almost immediate recovery of a sizeable portion of its investment in the subsequent quarterly tax payment (which would be reduced by the amount of the ITC claimed). The 50 percent equity split structure and the income/ITC/cash distribution allocations referenced above may vary by transaction, although this split is illustrative of proven models that have been deployed for electric cooperatives.

Tax losses created by accelerated depreciation over the first six years provide additional returns equal to the TEI's effective marginal tax rates times the amount of the loss. Project cash distributions typically represent a minor component of the distributions received by the TEI to reach its IRR.

According to Bloomberg New Energy Finance, returns required by TEIs have ranged from 8 percent to 12 percent in recent years. This is the after-tax return to the TEI, net of its tax benefits. It should be noted that TEIs account for returns on their specific circumstances and effective marginal tax rates, which may vary. Higher return (15 or even 18 percent) requirements may be explained by the current scarcity of tax investors as well as the TEI's circumstances. A typical term sheet for tax-equity flip investor/financing is included in Appendix II.

2.4.4.6 Post-Flip Buyout

In this structure, the cooperative blocker corporation typically is given a buyout option in the partnership/operating agreements. Like any option, this grants the blocker the right, but not the obligation, to buy out the TEI after it has achieved its target IRR, usually after the flip of cash flow distributions. (See the text box **Challenges in Finding Tax-Equity Partners**.)

If the cooperative blocker corporation chooses to exercise the option, it purchases the TEI's ownership interest in the LLC (which entitles it to 5 percent of the distributions following the flip) at fair market value, calculated as a present value of future cash flows to which the TEI is entitled, based on the PPA rate and the expected power generation over the remaining life of the project. The income approach for determining fair market value by using the discounted value of future cash flows also will include selecting the appropriate discount rate and terminal value of the facility, the latter of which is determined if and when the buyout option is exercised.

If the cooperative blocker corporation exercises the option and becomes the 100 percent owner of the SPE, the cooperative then can choose whether to retain the SPE or collapse the vehicles and transfer ownership of the assets, making it the owner of a taxable subsidiary. This will require the cooperative to file a tax return for the subsidiary, and the entity will have tax obligations at some point during the project's life. After the buyout, the decision of the cooperative to wind up or keep the SPE and blocker company will have tax consequences. NRECA has prepared an outline of the accounting and tax issues for cooperatives to consider in implementing the tax-equity flip structure. In addition, co-ops should seek an additional tax opinion for their side of the transaction from tax counsel or a CPA firm. (For more information, see the text box on **Potential Tax Risks Associated with Tax-Equity Flip and Lease Arrangements**.) Cooperatives should contact qualified tax counsel on this issue**.**

Challenges in Finding Tax-Equity Partners

As advantageous as the tax-equity flip financing is in implementing utility-scale solar PV installations, the key implementation challenge is to locate and confirm engagement with a tax-equity investor.

The scarcity of tax-equity investors and their propensity to prefer large single projects (involving investments in the range of $50 to $200 million each) stand in sharp contrast to the typically small scale of the current utility solar PV projects (ranging in investment from $2 to 10 million each) by electric cooperatives.

An approach involving a “master program,” in which a number of cooperatives participate, has the potential to significantly drive down the transaction costs of implementing tax-equity flip financing. A select number of tax-equity investors, both national and regional players, have shown willingness to work with cooperative network participants and have demonstrated the ability to participate in cooperatives’ utility-scale solar projects on a programmatic basis.

For more information, refer to Section 3.1, “Challenges and Benefits to Cooperatives Implementing Tax-Equity Flip Financing.”

The National Renewables Cooperative Organization's (NRCO) sCOOP Program

NRCO, in collaboration with CFC and Federated, created the Solar Cooperative Community Projects (sCOOP) program in response to growing interest among electric cooperatives in deploying small-scale solar generation resources, thus allowing members to purchase part of the output of the solar arrays on a voluntary subscription basis. Through the initiative, NRCO oversees program management and supporting marketing and legal documents. Program partner CFC provides debt capital as needed for solar projects, and Federated has committed up to $6 million as a tax-equity investment for initial solar projects. The program is designed for projects of 100–1,000 kW, though larger projects can be accommodated.

NRCO, along with its financing partners, will provide the following services:

- Customer marketing templates and customer agreement documents
- Tax-equity investment to cover a significant portion of project costs
- Debt financing
- Pre-commercial financial modeling
- Engineering, procurement, construction, operations, and maintenance contracting
- Pro forma organizational documents and contracts
- Ongoing project company management on behalf of the investors

More information can be found at the NRCO website: http://www.nrco.coop/.

Although most of the equity funding for the sCOOP program is earmarked for specific projects, reportedly there is room available for additional projects in 2016 and beyond; expansion of the program through new sources of equity funding and the revolving nature of the currently committed equity sources (especially given the extension of the ITC beyond 2016) make it possible for additional projects to be implemented using a tax-equity flip structure. Electric cooperatives interested in pursuing solar power options can contact CFC or NRCO for more information.

- **Krishna Murthy**
  CFC, Vice President, Energy and Industry Analysis
  (703) 467-2743
  Krishna.Murthy@nrucfc.coop

- **Todd Bartling**
  NRCO VP, Renewables Development
  Info@NRCO.coop
  (317) 344-7900

List of Cooperatives that Have Participated in the NRCO and Federated CFC sCOOP Program*	
Cooperative	**State**
Lake Region Electric Cooperative, Inc.	MN
Hendricks County Rural Electric Membership Cooperative	IN
Hawkeye Rural Electric Cooperative	IA
Tri-County Electric Cooperative	MN
St. Croix Electric Cooperative	WI
Tipmont Rural Electric Membership Corporation	IN
North West Rural Electric Cooperative	IA
Connexus Energy	MN
Jo-Carroll Energy, Inc.	IL
North Carolina Electric Membership Corporation	NC
Heartland Power Cooperative	IA
Northeast Rural Electric Membership Cooperative	IN
Eau Claire Energy Cooperative	WI
Prairie Power, Inc.	IL
***As of December 2015, eight other cooperative projects in MN, IA, and TN are in various development stages.**	

2.4.4.7 Pros and Cons of Leasing Compared to Tax-Equity Flip Structure

2.4.4.7.1 Pros

Leasing and tax-equity flip structures typically are offered by banks and financial institutions, and reportedly provide comparable economics. However, individual institutions may prefer one structure over the other as a matter of practice. Leasing transactions are simpler to implement than tax-equity flip structures because of the preset documentation and procedures preferred by the lessor financial institutions; however, investors offering leasing structures to capture tax benefits also are scarce—much like tax-equity investors.

The IRS allows a 90-day period in which the property must be sold and leased back by the lessee or leased to the lessee. Although the lease can be executed within three months after the date the property originally is placed in service, a partnership transaction must be closed **before** the facility is placed in service. The lessee must be the entity that originally placed the property in service.

A lease can provide 100 percent of financing needs for a project, whereas a tax-equity flip typically provides 50–60 percent—and at times less than 50 percent. A lease offers additional flexibility at the end of the term, when the parties can elect to extend the lease or sell the project back to the lessee at fair market value. In the pass-through lease structure, the developer (taxable cooperative or blocker subsidiary) owns 100 percent of the facility for its entire life.

2.4.4.7.2 Cons

Any cooperative considering a lease or tax-equity flip structure should have the specifics reviewed by tax counsel. (Electric cooperatives with questions regarding the procurement of a tax specialist can contact

Russell Wasson, Senior, NRECA, Associate Director of Tax Finance and Accounting Policy; (703) 907-5802.)

A lessee is obligated to pay a fixed rent, regardless of project performance or its ability to collect under the PPA. Lease payments can be structured to facilitate any performance concerns regarding the project. Conversely, if a project underperforms as to expectations in the tax-equity flip structure, the worst case for the cooperative is a delay in the flip/buyout.

A lessor or the TEI in the tax-equity flip structure may seek to be indemnified against successful qualification and collection of tax credits.

If the cooperative sponsor wants to own the assets in the long term in a sale-leaseback transaction, it has to purchase the facility back from the TEI at the fair market value at the end of the lease. (This amount may be more than the buyout in a tax-equity flip structure.)

Under the pass-through lease structure, since depreciation stays with the cooperative blocker corporation as project owner, the value added by MACRS may be left unrealized if the taxable cooperative subsidiary does not have sufficient tax obligations to take advantage of the deductions.

Lease structures are viewed by the IRS as a potential vehicle by which taxpayers may transfer tax benefits through disguised sales. Court decisions have provided a framework that may be used to distinguish between a lease and a sale, and should be explored for further guidance:

- Frank Lyon Co. v. U.S., 435 U.S. 561 (1978)
- Grodt & McKay Realty, Inc. v. Commissioner, 77 T.C. 1221 (1981)
- Torres v. Commissioner, 88 T.C. 702 (1987)

IRS Revenue Procedure 2001-28[1] provides guidance applicable to "true lease" analysis for leveraged leases. Lessors likely would review the advanced ruling guidelines for determining whether a leveraged lease is a sale or a lease for tax purposes. A leverage lease is created when the lessor obtains the property using primarily non-recourse debt (i.e., very little cash investment).

Additional considerations on whether a purported lease should be respected as a lease for tax purposes or re-characterized as a financing arrangement include the following:

- Property generally must be returned to the lessor at the end of the lease term with a significant remaining useful life and/or residual value (generally 20 percent is considered "significant").
- Options by the lessee to purchase the property must be at fair market value. Option prices materially below fair market value are likely to be characterized as a sale.
- Rental renewals priced at fair market value at the end of the lease term support the characterization of the transaction as a lease.

[1] https://www.novoco.com/energy/resource_files/irs_guidance/rulings/proc_01-28.pdf.

- The lessor's reasonable potential to recoup its investment in the property from renting the property and its residual value (as opposed to operation and daily use of the property) supports the characterization of the transaction as a lease.

2.5 Participation Choice

Cooperatives, as member-owned organizations, may invite and offer participation by their member-owners in the utility-scale solar projects they develop. Construction and fractional sale of the output and corresponding bill credit often is referred to as "community solar" or a "solar garden." The projects also could be developed to be owned exclusively by the cooperatives, with the project output counted as part of the cooperative's power supply portfolio.

In implementing business models that provide for community participation, however, cooperatives may want to structure the participation in ways that avoid their being labeled as offering investment options or products (see Appendix V, Applicable Security Laws, for state and federal laws that could be triggered). Cooperatives could avoid the appearance of offering investment options to subscribing consumers by offering entitlement to power output from a specified fractional share of the project in return for an upfront payment in support of the project and setting off their "share" against power use/purchases from the cooperative during the life of the project. Subscriptions by member-owners could be offered for a specified number of panels or kW, not to exceed the power demand of the consumer, and paid for upfront on a per-kWh basis or a combination hybrid basis.

The advantages of the community solar approach are as follows:

- Fractional ownership of the output lowers costs to the member, thus encouraging participation.
- Participation can be opened to members that rent, do not desire to install solar PV arrays, or whose property is too shaded or otherwise does not support solar array installation.
- Aggregation of demand for member participation can achieve economies of scale in the size of the project on a cost per-installed-kW basis and on annual costs for operations and maintenance.
- Aggregation provides for participation when responsibility for operations, maintenance, and insurance is subcontracted and not a concern for the participating member.

Community solar projects can be implemented either on a prepaid, pay-as-you-go, or lease basis. A cooperative wishing to implement utility-scale solar PV projects with community participation would execute a contract with interested consumers obligating them to purchase a defined portion of generation capacity.

Under a prepaid PPA, a consumer makes a single upfront payment to acquire the panel (i.e., the entitlement to the power output) for the defined life of the project—typically 20 or 25 years. Under the pay-as-you-go or lease structure, a consumer contracts to purchase the output of an identified fractional share of the project at a price per kWh for a specified period (up to the entire project life).

The sponsoring electric cooperative agrees to provide a kWh credit on the consumer's electric bill for the renewable energy produced by his/her share of the project's output. The cooperative also agrees to provide for maintenance and operation of the project. Ongoing and other costs, such as insurance and property rent, should be accounted for in the prepayment amount or periodic payment collected from participating consumers to avoid transferring these costs to the broader membership.

The prepaid option can be used to fund the cooperative blocker corporation's purchase of its Class A membership interest, thereby using member prepayments in addition to the TEI's equity purchase to fund project construction.

The Solar Electric Power Association (SEPA) recently published *Expanding Solar Access Through Utility-Led Community Solar,* a report in which it quantifies community solar design trends and performance metrics based on actual data provided by utility program managers. It also highlights keys to success and potential roadblocks, as described by utility staff.[2]

[2] A free executive summary can be accessed at: http://www.solarelectricpower.org/media/214973/Community-Solar-Report-Executive-Summary-ver3.pdf. The full report is available free of charge to SEPA members.

Community Solar Compliance with Investment Security Laws

According to SEPA's *Utility Community Solar Design Handbook*, published in 2013:

Complying with investment securities, tax, and other legal issues need[s] careful consideration when designing a community solar program. These issues can be very complicated, nuanced and depending on the design, need to be considered from both the utility's and the participant's vantage points. Careful consideration, either utilizing internal counsel or outside assistance, can minimize the program's costs through efficient use of tax credits and avoiding unforeseen legal or compliance costs. Community solar is a unique financial and technology product and unless the utility has the skill set to manage both, it should consider seeking outside assistance.

If either state or federal regulators view the utility's community solar program as issuing securities, the utility must comply with securities laws. In addition to working with the utility's legal counsel, it is recommended to check with the appropriate state securities administrator before proceeding with a community solar program offering. Securities laws can be enforced through criminal, civil and administrative proceedings, including those brought through private law suits.

With securities laws, there are four primary issues for community solar:

1. *Is it an investment of money?*
2. *Is there an expectation of profit?*
3. *Are customers investing in a common enterprise?*
4. *Is the return solely based on the effort of others?*

The law does not provide a clear "yes or no" on any of these questions. The determination of whether a community solar project becomes a regulated investment is a body of work. Although there may be some ambiguity in determining exactly when an economic transaction is considered a security, this is all the more reason why the utility needs to consult with legal counsel.

The complete *Utility Community Solar Design Handbook* can be found at: http://www.solarelectricpower.org/media/8189/sepa-utility-community-solar-handbook_final-1-.pdf.

For more information, see Appendix V, Applicable Security Laws, which details state and federal laws that could be triggered.

3 Comparison of Business Models

The pros and cons of the various business models are highlighted in Table 3. Additional information outlining broader cooperative solutions to the challenges and costs associated with the tax-equity flip structure follows the table.

Pros and Cons of Business Models				
Category	**Business Model Choice**	**Applicability**	**Pros**	**Cons**
Organization	At the G&T	G&Ts and distribution co-ops that have limitations under wholesale power contracts	No issues with wholesale power contracts	Community participation difficult to implement; needs consensus of/participation by all members or rate mechanisms to allocate costs to participants
	At the Distribution Cooperative(s)		Visibility and ability to offer participation to ultimate consumers	Limited as to the amount of capacity that can be installed
Ownership	Full Ownership	All cooperatives	Simplicity, minimal transaction costs, no reliance on third parties; ideal with grant funding	Tax benefits are not harnessed; more costly than most business models
	Partial Ownership – Leasing	Applicable to taxable cooperatives, tax-exempt co-ops having taxable subsidiaries, or those needing to establish taxable subsidiaries	Simple structure; some investors prefer this route due to the low cost; ability to benefit from incentives otherwise not available to co-ops	Lease stipulations can be onerous; owner (lessor) requirements must be met

	Partial Ownership – Tax-Equity Flip Structure	Requires tax-exempt cooperatives to set up taxable blocker LLC to implement	Ability to benefit from incentives otherwise not available to co-ops	Challenges with locating tax-equity investors for small projects; no current mechanisms to roll up multiple projects to attract investor participation; transaction costs for one-off implementation very high for small projects
Category	**Business Model Choice**	**Applicability**	**Pros**	**Cons**
Financial	Direct Financing	All cooperatives	Simplicity of implementation; based on bilateral relationships with lenders	Tax benefits not harnessed; more costly than most business models
	CREBs Financing	All cooperatives	Lower cost than direct financing	Requires compliance with applicable governmental requirements; application, documentation, and other requirements
	Leasing	All co-ops; very simple if the co-op has an existing taxable subsidiary or would need to establish one	Possibly the lowest-cost option	Lease stipulations can be onerous; owner (lessor) requirements must be met
	Tax-Equity Flip Structure	All co-ops; if the co-op is nontaxable, it will need to set up a taxable blocker	Possibly the lowest-cost option	Challenges in locating tax-equity investors for small projects; needs mechanisms to roll up multiple projects for tax-equity investor participation; transaction costs for one-off implementation very high for small projects
Participation	Community Participation	Applicable for all projects implemented	Ideal for cooperatives; gives them visibility in the community	Need to design program to avoid application of state and federal security

		by distributions systems		laws (see Appendix V, Applicable Security Laws); address issues of cross-subsidy and revenue erosion
	No Community Participation	All cooperatives	No need to worry about security laws and member issues upon death, move, or complaint; no cross-subsidization issues	Member-consumer need is not met (if they are interested); opens up a path for third parties to make their way between co-op and customer

Table 3: Pros and Cons of Business Models

3.1 Challenges and Benefits to Cooperatives Implementing Tax-Equity Flip Financing

As advantageous as tax-equity flip financing is for implementing utility-scale solar PV installations, the key implementation challenge is to locate and confirm engagement with a tax-equity investor. Investors in this category are scarce and choosy for the following reasons:

- They need to have current and ongoing tax liability
- They have to be conversant and comfortable with the structures, documentation, and intricacies involved in tax-equity investing
- They have to be comfortable in understanding and embracing the risks and returns involved in investments in which a large proportion of the return relates to savings in or reduction of taxes that may otherwise be paid

Consequently, the qualified investor base has the following characteristics:

- Currently comprises some 15–20 large profitable corporations, commercial banks, and wealth managers/insurance companies
- Centralizes its tax planning; for example, local and regional banks and branches depend on the headquarters tax departments to make most of the TEI decisions
- Typically works directly with projects or through “middle men” and is comfortable with proven partners and technology
- Prefers and seeks to implement large individual projects—$20 million to $30 million in TEI investment is generally considered to be a floor
- Is generally understood to be in short supply—amounting to a half or a third of the demand in the marketplace (driving up the return requirements)

Further TEIs require tax planning—typically a year or so ahead of actual commitments. For example, at the time of this report (early 2016), tax-equity investors are in the midst of their planning and making commitments to investments for 2017. The implementation of tax-equity flip structures by cooperatives to deploy utility-scale solar projects is particularly challenging because the ITC and incentives are eligible for projects that enter commercial operation on or before the end of 2016.

Sourcing Tax-Equity Investors

Sourcing tax-equity investors, especially for smaller projects under approximately $50 million, is challenging at this time. Most traditional tax-equity investors prefer larger projects so as to optimize transaction costs and deploy their resources efficiently (human as well as financial resources). Also, traditional tax-equity investors prefer to work either with established project sponsors who have a pipeline of projects or those with which they already have a relationship.

Electric cooperatives, as locally owned entities and reliable suppliers of power, could leverage their relationships to source tax-equity investors locally—from among suppliers, commercial and industrial customers, or large locally owned businesses—for their utility-scale solar PV projects. The search for such local tax-equity investors could be built around the following parameters:

- Stability of the cooperative business model
- Solid current and projected credit fundamentals of the cooperative
- Balanced mix of power supplies and well-conceived renewal portfolio plan
- Well-structured solar PV project that yields benefits to investors, the cooperative, and end-use customers
- Investor(s) with a stable and predictable tax situation
- Investors having capital to deploy and those comfortable with tax-efficient structures to optimize their returns
- Investors whose return requirements and environmental goals align with those of the cooperative
- Investors having a close working relationship with the cooperative and familiarity and comfort with the cooperative's management, operations, and leadership role in the community

3.1.1 Burdensome Costs

The cost of developing the documents involved in the tax-equity structure (see Appendix I for a list of documents) can be high—ranging from $250,000 to $500,000—depending on the size and complexity of the project. Traditionally, only large projects (in the range of $50–$200 million each) could absorb these costs and still retain the economic attractiveness of the tax-equity flip structures. Although the formation of SPEs is relatively straightforward, negotiating and amending an LLC operating agreement to meet investor requirements can be time-consuming and require much legal expense. This additional expense may be difficult to justify for small projects.

However, working with seasoned tax-equity investors committed to working with a pipeline of projects using standard document sets (tweaked to fit the smaller projects on hand) can reduce the transaction costs substantially, to roughly 2 to 2.5 percent of the project cost. It is possible to implement projects in the 15–25 MW range on a stand-alone basis using the tax-equity structure, yet keep the transaction costs to a manageable level and implement the projects on a cost-effective basis. Even smaller projects (for example, in the 2–5 MW size range) can be implemented using a tax-equity financing model on a cost-effective basis, provided they are bundled together in a pipeline.

3.1.2 Tax-Equity Flip Project Cost Implications

The tax-equity flip structure allows tax-exempt entities to effectively monetize federal and state tax incentives to reduce overall project costs; the cooperative blocker corporation is typically responsible for less than half of the upfront construction and development costs of the project. To be sure, the cooperative also will incur SPE management fees and legal costs associated with the development of the PPA for the purchase of energy from the project. In most cases, however, total project costs to the cooperative, including its share of upfront capital, development, and PPA expenses, are less than would be accrued in bearing the total upfront costs of development and construction. Moreover, a cooperative benefits from the time value and lower financing costs associated with paying the PPA over time rather than shouldering the costs upfront.

3.1.3 Cooperative Solutions

The scarcity of tax-equity investors and their propensity to prefer large single projects (involving investments in the range of $50–$200 million each) stands in sharp contrast to the typically small scale of current utility solar PV projects (ranging in investment from $2 to 10 million each) by electric cooperatives. Cooperatives can overcome this handicap either by working with third parties and network organizations to aggregate or roll up a number of projects (either at a single cooperative or by doing multiple projects at multiple cooperatives), developing and using standardized structures and document sets, and working with one or more tax-equity investors willing to collaborate on a pipeline and portfolio of projects. An approach involving a “master program,” in which a number of cooperatives participate, has the potential to significantly drive down the transaction costs of the implementation of tax-equity flip financing. It also offers the tax-equity investors the advantage of streamlined, easy-to-implement PPAs as well as structures in which the dynamic tension typically present between the off-taker and the project owners is substantially absent.

This approach—of a master program, roll up, or aggregation—has been implemented (and is being developed further) by third-party vendors, such as the Clean Energy Collective, as well as by a cooperative network organization (the National Renewables Cooperative Organization, or NRCO).

Electric cooperatives can also leverage member relations and work with taxable and tax-paying local businesses/large customers (mostly commercial and industrial accounts) to implement utility-scale solar PV projects in their service territories. Cooperatives can also implement tax-equity flip structures through tax-paying, taxable subsidiaries. The SUNDA team is actively developing tools to make these options easier. A preliminary cost and finance screening tool allowing cooperatives to perform an initial cost analysis for their specific needs can be found at www.omf.coop/quickNew/solarSunda or through the SUNDA website at www.nreca.coop/SUNDA. A more in-depth model can be accessed on the SUNDA website or through a hyperlink on the results page of the preliminary modeling tool.

4 Economics of the Financing Options

The economics of utility-scale solar PV installations are project specific and depend on the financing options chosen. Project-specific variables, such as the project capital costs per kW, solar generation from the project, and the interest rate environment (which drives the borrowing/lending rate and return requirements of the lessors and the tax-equity investors), determine project economics. One way to evaluate the various financing options available to a cooperative involves life-cycle cash flows (inclusive of financing and operating costs). The method is used is to generate a set of metrics for the utility-scale solar PV project under a uniform set of assumptions and then compare them.

The following are cost comparison metrics provided in SUNDA financial models:

- **Cost to Customers per Panel** – specifies how much it would cost a customer, one time, up front, for the entitlement of power output from one panel over the life of the system
- **Cost to Customers per 10 W** – specifies how much it would cost the customer, one time, up front, for the entitlement of power output from 10 W of capacity over the life of the system
- **Levelized Cost of Energy** – the non-varying cost of power to the customer over the full life of the project, from the project to the consumer

Levelized Cost of Energy

"Levelized cost of energy," as used in this report, is the "cost of power output" from the panels in the solar project. It is not the value of power received from the solar project. The value of power from the panels could be different, depending on whether the point of view is that of the customer or the cooperative.

Value of Power from the Point of View of the Customer:

The value of power received from the panels from the point of view of the customer is determined by the structure of the community solar program. The following variables can be used to determine the value of PV power to the customer for a variety of programs:

kWh produced by the panels that the customer uses = kWh(u)

kWh produced by the panels that the utility purchases (or credits) = kWh(p)

Total kWh output from the panels = kWh(u) + kWh(p)

Standard customer electricity payments per kWh = RR

Compensation per kWh by the co-op to customers for power not used by them = AC

Value of power from the panels = kWh(u) * SR + kWh(p) * AC

Different forms of community participation and rate structures can provide different results. If using a net billing or green power approach, kWh(u) would be zero, and kWh(p) would be the total output of the panel. The resulting value to the customers would be the product of Total kWh output and the compensation per kWh.

Value of Power from the Point of View of the Cooperative:

The value of power received from the panels from the cooperative's point of view would be simply the total kWh output from the panels times the avoided cost for the power PLUS any value the co-op may want to assign to the capacity of the solar panels.

The metrics above reflect the different potential options a cooperative utility could offer to its member/consumers to recover the full costs of the utility-scale solar PV system.

Cost to the customer (whether it is per panel, per 100 W, or per MWh) is computed as the total life-cycle cash flow (i.e., revenue requirement) for the project (discounted or undiscounted), divided by the relevant parameter (i.e., the number of panels in the project, project capacity expressed as multiples of 100 W, or the MWh generated in the project).

The levelized cost of energy ($/MWh) is the single non-varying rate for energy (in $/MWh) to be charged to consumers for output during the full life cycle of the project, such that it would produce the same net present value of revenues as the net present value of the project's life-cycle costs. Due to the use of the net present value metric, inflation inherently is accounted for in the levelized cost. Thus, the levelized cost charged to the consumers should not vary throughout the full life cycle of the project.

5 Insurance Requirements

Insuring solar facilities for property losses is a straightforward proposition these days. Many well-regulated insurers are willing to insure utility solar facilities for reasonable premiums. Although arranging coverage is not quite as simple as for homeowners insurance, the process is not complicated; buying property insurance should not be a roadblock for cooperatives in implementing utility-scale solar PV projects.

5.1 Insurance Carriers

There are two basic types of insurers writing property insurance for utility solar installations: admitted and non-admitted companies. The differences are important, but either usually is acceptable.

Admitted carriers are insurance companies that are "admitted" into the state in which they are conducting business. They are regulated by the state, their financial condition is monitored, and the coverage they write generally is protected by a state guaranty fund. (In the event of an insurance company failure, the fund steps in to settle claims, usually for cents on the dollar.) The rates charged by admitted carriers usually are approved by the state regulators as fair and actuarially sound. (Some states allow large insurance buyers to purchase coverages not approved by the state. The theory is that large buyers are sophisticated enough to look after themselves and can negotiate their own rates and coverages fairly.)

Non-admitted insurers are licensed by the states but not heavily regulated. Their financial conditions are not monitored, and there is no guaranty fund to back up the carrier. Non-admitted carriers do not pay premium taxes to the states; thus, the taxes and fees must be paid by the insurance buyer. The rates they charge and the coverages they provide are not examined or approved by the state. The insurance buyers must rely on themselves to judge the soundness and claims-paying ability of non-admitted carriers. Several independent rating agencies, such as A.M. Best Company, Fitch, Standard & Poor's, and others, issue opinions about the financial well-being of insurance companies, which can aid in this determination process.

Non-admitted carriers, such as the companies and syndicates operating through Lloyd's of London, can quickly respond to changing market conditions and are invaluable in placing harder-to-insure coverages. Premiums are not necessarily higher, and coverage usually is not more difficult to secure. A knowledgeable commercial insurance broker is vital to the process of using non-admitted carriers. Usually they are the only intermediaries the companies allow to place business.

5.2 Major Insurance Risks of Solar Property

Property insurance is meant to cover fortuitous losses—those that are unexpected and accidental from the property owner's standpoint. This means that normal wear and tear and maintenance is not insurable. Gradual deterioration in the units' efficiency is not typically insurable, nor is periodic cleaning or maintenance. Speaking generally, of course, there are some companies that will insure anything, given enough time and money.

The perils most commonly insured against are fire, lightning, wind, hail, vandalism, malicious mischief, theft, falling objects, automobile or aircraft damage, riot, civil commotion, explosions, and, optionally, terrorism. Perils generally not covered are war—declared or not, nuclear radiation, intentional acts on the part of the insured, government action, rust, mold, wear and tear, hidden or latent defects, vermin, insects, loss of income, earth movement, flood, volcanic eruption, physical damage to property caused by malicious software, and mechanical breakdown.

Some perils, such as flood, earthquake, malicious software damage, and mechanical breakdown, can be covered, sometimes by a separate policy or an endorsement to the regular policy. These coverages usually cost more, and coverage can be restricted due to geographical or manufacturer characteristics. Those systems that use mechanical heliostat-tracking systems would greatly benefit from some type of mechanical breakdown coverage (variously called “mechanical breakdown,” “equipment breakdown,” or “boiler and machinery” coverage).

Coverage usually is available for the loss of income that results from a covered loss. This is an optional coverage not commonly purchased but available. This coverage makes up for lost income that would have been made had the solar facility not been off line due to a covered loss. Instead of deductibles, there is usually a waiting period of 24, 48, or 72 hours before coverage begins. The amount of coverage is calculated using a worksheet to determine expenses and income over a fixed period of time. Premium costs can vary widely, but an estimate of $2.10 per $1,000 of coverage has been reported.

Another important peril that should be considered is liability. Although this is not a “property” insurance coverage, it is important to note that certain liabilities can attach to the ownership of solar installations. Lawsuits have been filed against utilities for environmental concerns, unwanted reflective nuisances and nuisances attractive to children, and harm that can come to first responders and law enforcement officials. Newer technologies can mean newer liability exposures. Proper training of local firefighters and other first responders to the hazards of solar panels, which can remain energized during a fire or other loss, is imperative. Coverage for such liabilities can be purchased along with the property insurance.

5.3 Securing Coverage

Property insurance should be arranged early in the planning stages of the project. When the specifics of the project become known, such as size, cost, location, and ownership, an estimate of the insurance costs can be obtained. In conjunction with a trusted insurance adviser, the coverage is selected and priced. Trade-offs often are made between the desired coverages and their associated costs. Lender requirements often factor into the insurance-buying decision. Some lenders using federal funds are required by law to have flood insurance if it is commercially available.

It is normal for the insurance company to have its underwriters, engineers, or loss control consultants review the plans, or at least discuss the project with the supervisor or manager. An in-person visit is not unusual. The insurance company will ask many detailed questions about the facility, ranging from engineering to accounting questions. The better they understand the facility, the better their pricing usually will be, so it is beneficial to answer all of their questions as accurately as possible.

Pricing of the property insurance is a function of several variables. The insurer bases the premium on the replacement cost of the facility; its exposure to loss; its protection from loss; and the insurance company’s profit, overhead, and expense costs. Rates will vary based on location, amount and type of coverage, deductibles, and the insurance buyer’s loss history.

Property insurance rates have remained stable to trending slightly downward in the past few years. Premiums for recently constructed projects have ranged from $0.27 to $0.40 per $100 of replacement cost, with the average being $0.37 in the U.S.

Note: the replacement cost may not be the construction cost. The figure used to purchase the insurance should include only those costs that will be incurred repeatedly. Some costs, such as land acquisition, grading and leveling, some architectural and engineering services, and others may not be needed again, depending on the degree of damage or local building codes.

With a knowledgeable insurance adviser, buying property insurance for a utility solar project should be a straightforward process that provides economical protection for the project, its owners, and financiers.

Illustrative Economic Costs of Property Insurance for Utility-Scale Solar PV Installation (2014)

Replacement Cost of Installation		Annual Estimated Insurance Costs
0.5 MW	$ 1,000,000	$ 4,000
1 MW	$ 2,000,000	$ 8,000
5 MW	$ 10,000,000	$ 40,000

Pricing contemplates the following coverages:
Business Interruption: Business Income/Extra Expenses – $2,000,000

Mechanical Breakdown Included

Debris Removal – $1,000,000

Pollutant Clean-Up – $250,000

Property in Transit (U.S., Canada, possessions) – $500,000

Property Off-Premises – $500,000

Deductibles Assumed – $25,000

30-Day Limit for Business Income/72-Hour Waiting Period

Factors Influencing Cost:

Location

Deductibles/Coverages
Based on Replacement Cost of $2/W

Table 5: Illustrative Economic Costs of Property Insurance for Utility-Scale PV Installation—2014

More Information About Insurance

Federated Rural Electric Insurance Exchange (Federated) is the leading provider of property and casualty insurance for rural electric cooperatives in 42 states. Federated's primary goal is to offer its members affordable coverage over the long term so they can focus on serving their communities and making them better, safer, and more vibrant places to live. More information is available at: www.federatedrural.coop.
Contact: Bill West (800) 356-8360

6 Summary Guide to Utility-Scale Solar PV Business Models and Financing Options

A number of business models may be used to achieve a cooperative's goals. Some business models may require investment partners, such as tax-equity investors with sufficient liabilities to utilize federal tax benefits, or others that can be implemented directly at the cooperative, such as NCREBs financing.

The decision on a business model depends upon a variety of available financing pathways. Federal or state grants and incentives may also influence the decision, along with the ease of business model execution, the timeline needed to obtain funding, and the size of the PV solar asset.

Business models that take advantage of the ITC and accelerated depreciation realize substantial economic benefits, but also impose complexity and transaction costs. If a cooperative is considering a modestly sized solar PV project, it could well conclude that conventional financing at the cooperative with sole ownership is preferred, since the transactions costs of tax-equity flip or leasing structures outweigh possible savings. These more innovative business models may be practical and suited only for larger projects. In some instances, timing may be a major factor in the deployment decision, which may preclude waiting for tax-equity investors or NCREBs availability; the cooperative may decide to finance the project directly.

Each business model will have financing options that produce different cash flows, based upon the term of the funding; the effective cost (interest rate for debt financing); the rate of return to the investor; and, ultimately, any costs related to a buyout option in a lease or a tax-equity flip transaction. For example, NCREBs are very economical, with a lower effective interest cost than traditional financing. However, the financing term is shorter, averaging about 18 years, whereas conventional financing would have a term that matches an asset life of 20 to 25 years.

The pursuit of business models more often than not will require a cooperative to engage experienced third parties/consultants/network organizations to navigate the requirements of the business and take advantage of pre-packaged offerings to execute specific business models.

This manual is designed to provide an overview of the options and enable cooperatives to formulate questions to assess the business model options and develop an initial action plan. Primary considerations include, but are not limited to, the following:

- Availability of land: Typical solar PV projects require six to eight acres of land per MW installed, so the land for the project must be identified and permitted for construction well in advance. Acquisition, zoning, and permitting may be subject to lengthy processes.
- Project schedule: Despite concerns that the ITC tax incentive would sunset at the end of 2016, it has been extended for another 5 years. This lessens pressure to complete solar projects by the end of 2016 and will provide a measure of financial stability to planners of solar projects at all levels. That smoothing of demand should ease pressure on suppliers of solar components. Prior

to the ITC extension, suppliers had projected a shortage of modules, structures, and inverters in 2016. See the Solar ITC Advisory Appendix for more details.

- Approvals: Financing approvals, regulatory compliance (certificates of convenience and necessity, when needed), and lender consents (lien accommodation from traditional lenders, approval to invest in power sources) will impact project schedules.
- Accounting, taxes, legal issues, and project management: Solar PV projects, especially those that involve complicated business models and structures, will require specialized advisers and third-party outside help. This is particularly important when cooperatives (in particular, distribution cooperatives, which traditionally are not involved in power plant construction) embark on unfamiliar activities.
- Applicable costs and analysis: Site-specific cost estimates (capital costs—including interconnection costs, operating costs—including operations and maintenance [O&M], insurance, and project management costs) should be developed to evaluate the project economics correctly.
- If the cooperative is contemplating a community solar option, it should develop the estimates for the costs associated with billing, consumer outreach, contract administration, adders for "foregone margins," line loss allowance, decommissioning costs, etc., and consider them explicitly in developing the economic projections.

Once a cooperative determines the size of the solar installation it plans to install and identifies the land upon which the project will be installed (with site-specific cost estimates), it will need to engage with personnel—in-house as well as hired help—regarding resources that will assist in developing an appropriate business model for project implementation. The following are some key steps involved in the various business models discussed in this manual.

Direct Financing

1. Identify financing needed (construction financing, permanent financing).
2. Locate and identify potential lenders (RUS, cooperative lenders).
3. Obtain indicative rates for substantially similar terms (tenors, fixed or variable rates desired, amortization schedules, legal and other transaction expenses, prepayment terms, commitment fee, benchmark rates, etc.).
4. Compare all-in costs.
5. Compare qualitative terms (environmental requirements, documentation, timing, etc.).

NCREBs

1. Review the application form in preparation for applying for NCREBs allocation in advance of a notice from Treasury/IRS soliciting such applications.
2. Any funds spent on a solar PV project before receipt of an allocation are not reimbursable from NCREBs proceeds.
3. Any construction contract financed by the proceeds of NCREBs must meet Davis-Bacon Act prevailing wage requirements for laborers and mechanics employed on contracts in excess of $2,000.
4. Locate an independent engineer who will provide the certification required as part of the application to the IRS.
5. Funding must be closed within 180 days of the NCREB allocation.

6. NCREB proceeds must be utilized within the following three years. Before NCREB funds are used to reimburse project expenses that the cooperative pays, the proceeds must be maintained in a restricted bank or trust account.

Leasing

1. Cooperative approaches potential lessors to request term sheets and lease terms.
2. Cooperative reviews and negotiates lease terms and documentation.
3. Cooperative or its subsidiary funds construction of solar PV project, to be owned by the cooperative's taxable subsidiary. Construction is funded by a construction loan.
4. Cooperative or its taxable subsidiary installs the solar PV system and the tax investor (TI, generally a financial institution) buys the facility before it is placed in service. Cooperative uses the proceeds to pay off the construction loan.
5. Lease transaction is closed, and taxable subsidiary of the electric cooperative leases the system back from the TI.
6. Taxable subsidiary of electric cooperative enters into a PPA with the cooperative and generally assigns the contract or revenue stream to the TI (lessor).
7. As the owner of the systems, the TI is eligible to receive 100 percent of the ITC and depreciation benefits.
8. The lease term is generally around 10 to 12 years, with a buyout option at generally predetermined residual values after the sixth or seventh year.
9. Cooperative subsidiary purchases the solar project back from the TI at residual value. The transaction is funded with internal or loan funds.

Tax-Equity Flip

1. Cooperative engages an integrator/project manager, such as NRCO or a third-party integrator, to assist with project planning. The project manager/adviser runs the tax-equity flip model to develop the cash flow estimates that can be expected for the transaction. The estimates must make allowances for the following:
    - Developer's fee and charges, both upfront and ongoing
    - Legal and accounting expenses at the cooperative level (for review)
    - Expected power generation from the project
    - Estimated O&M expenses, including insurance and taxes
    - Tax consequences, if any, for the buyout and post-buyout consolidation
2. Working with the adviser, the cooperative locates and identifies a tax-equity partner that could provide approximately 50 percent of the capital required to fund the project.
3. Cooperative engages with and selects a lender to fund construction as well as the cooperative's investment in the blocker LLC.
4. Cooperative conducts an outreach/marketing campaign to identify consumers willing to purchase rights to the output (if the project is a community solar project).
5. Cooperative engages counsel to review and advise on the documentation.
6. Cooperative's subsidiary and tax-equity partner execute documents to establish the project company LLC.
7. Either the project company LLC or the cooperative subsidiary (i.e., the blocker corporation) hires the engineering, procurement, and construction company to perform the installation.
8. The cooperative subsidiary (blocker) and TEI fund the SPE prior to the commercial operation date.

9. Shortly after the sixth year, upon reaching the target return of the TEI, the cooperative blocker purchases ownership interest of the tax equity in the SPE. The purchase is funded with internal funds or by accessing loan funds/equity inflow from the cooperative.
10. The blocker corporation pays the income taxes due that arise from the purchase of the SPE; the losses carried forward are used in computing the taxes due.
11. The blocker corporation is merged into the cooperative.

Taking Advantage of NRECA's National Discounts Program (NDP)

NRECA has secured contracts with vendors for purchase discounts available to NRECA and NRECA member cooperatives for modules, inverters, racking systems, administrative systems, and EPC firms through its established NDP. To take advantage of these discounts, use the links below to access the NDP through Cooperative.com and use the supplier contact listed. NDP discounts with other solar vendors are also currently being negotiated to provide further discount pricing choices for cooperatives.

Photovoltaic Modules for Utility-Scale Solar

- **REC Americas**: Discounted pricing for various REC Americas PV module types, including 72-cell and 120-half-cut cell modules used in utility-scale solar-powered energy generation applications
- **Suniva**: Discounted pricing available from Suniva for certain Suniva PV modules, including monocrystalline modules used in utility-scale solar-powered energy generation applications

Solar Power DC to AC Inverters

- A 25 to 30 percent discount off list price previously was available from Advanced Energy for DC to AC inverters used in solar-powered energy generation. However, Advanced Energy is not now manufacturing DC to AC inverters used in solar-powered energy generation. Please contact NRECA'S Business and Technology Strategies (BTS) unit directly for a list of DC to AC inverter manufacturers until additional manufacturers of DC to AC inverters are added to the NDP.

Racking for Utility-Scale Solar

- **GameChange**: Discounted pricing available from GameChange Racking for racking used with PV modules in utility-scale solar-powered energy generation applications

Administrative Systems

- **Clean Energy Collective (CEC)**: CEC's Software as a Service (SaaS) tools are operating in more than 100 community solar programs and integrated with more than 20 utility billing systems. CEC offers significant discounts, from turnkey installations to selectable SaaS tools.

Engineering Procurement and Construction (EPC) Firms

- **American Capital Energy (ACE)**: ACE is a U.S. solar-electric power systems integrator and developer specializing in large and medium-scale PV projects for commercial and utility clients.
- **PowerSecure Solar**: PowerSecure Solar is a North Carolina-based sustainable energy company offering solar energy products and services for large industrial, commercial, and utility-scale installations across the country.

If you have trouble accessing Cooperative.com, please contact the NRECA Member Contact Center, 7 a.m.–7 p.m. CST | 877-766-3226 | support@cooperative.com

Request for Proposal (RFP)/Request for Proposal Quote (RFPQ) Sample Additional Language

If you are procuring your own solar equipment, insert the following language into your RFP or RFPQ to take advantage of vendor discounts through NRECA of which you may not be aware:

"Because [Member Co-op Name] is a National Rural Electric Cooperative Association (NRECA) member cooperative, [Respondent] may already have discounts or other incentives available to [Member Co-op Name] through the NRECA National Discounts Program, and such may be used in [Respondent's] response to this RFP/Q as beneficial to [Member Co-op Name]. If [Respondent] is not familiar with or not sure if [Respondent] is a participant in the NRECA National Discounts Program, [Respondent] may contact Dale Bartholomew, NRECA Contracts Representative, at (703) 907-6699 or dale.bartholomew@nreca.coop."

Appendices

- Documents Required to Implement Tax-Equity Flip Financing
- Illustrative Term Sheet for Tax-Equity Flip
- NCREBs-Related Links and Materials
- Illustrative Term Sheet for NCREBs
- Applicable Security Laws
- Cost Screening Tool Financial Glossary
- Financing and Insurance Resources and Contact information
- Solar ITC Extension

Appendix I – Documents Required to Implement Tax-Equity Flip Financing

The following is a comprehensive list and description of the documents required to implement a tax-equity flip structure:

Document	Description
Blocker Certificate of Formation, Organizational Documents, and IRS Form 8832	Registration with Delaware, formation documents, and taxable election.
SPE Certificate of Formation, Organizational Documents	Registration with Delaware, formation documents, and taxable election.
State Authority to Do Business	The SPE formed in Delaware may need permission to do business locally.
Amended LLC Operating Agreement	Brings tax-equity investor into SPE through the Class B membership. Defines target IRR, investment amounts, managing member, allocations, distributions, buyout provisions, and limitations of liability.
Financial Pro Forma	Optimizes capital contributions based on expected production and return targets. Establishes PPA price necessary to achieve target returns within desired time horizon. Projects lifetime project costs, including O&M, rent, insurance, management, etc. Will also determine the amount to be collected from members participating in a community solar variation.
Land Lease	Gives SPE legal rights and access to property.
Purchase Power Agreement	Project company's source of revenue from the sale of the generation output to the cooperative.
Interconnection Agreement	Between the SPE and interconnecting utility.
Engineering, Procurement, & Construction Contract	Between the SPE and a third-party installer for engineering, procurement, and construction of the facility.
Operations & Maintenance Agreement	Between the SPE and a third-party installer for operations and maintenance of the facility.
SPE Management Agreement	Third-party management services for the SPE, including accounting, tax filings, warranty claims, PPA billing, etc.
Stamped Design Drawings	Independently reviewed and verified structural and electrical designs.
Member Subscription Agreement	Only needed if pursuing a community solar variation, as described in Section 2.5, "Participation Choice." Allows for participation and funding by a subset of cooperative members.

Appendix II – Illustrative Term Sheet for Tax-Equity Flip

Indicative Term Sheet for Equity Investment in an SPE Jointly Owned by a Wholly Owned Subsidiary of an Electric Cooperative and a Tax-Equity Investor (*)

Project:	A 5-MW solar photovoltaic project (the "Project," implemented possibly as two 2.5-MW projects) owned by a special purpose entity (SPE) and located in the service area of ABC Electric Cooperative (ABC).
Siting:	The Project is expected to be sited on a piece of land owned or leased by ABC Electric Cooperative/SPE.
Project Cost:	Estimated to be $10 million (at $2,000 per kW) plus interconnection costs.
Ownership	The SPE will be jointly owned by XYZ LLC ("XYZ," a taxable subsidiary wholly owned by ABC Electric Cooperative) and a tax-equity investor (TEI). It is anticipated that the ownership share of XYZ LLC and the TEI in the SPE will be in the ratio of 46 to 54. All terms and conditions of the ownership shall be pursuant to an ownership agreement between and among the TEI, SPE, and XYZ LLC.
Project Construction:	It is anticipated that the project will be constructed by the SPE using a construction loan advanced by ABC Electric Cooperative to XYZ LLC. The construction period is estimated to be six months.
Owner's Funding:	Owners (the TEI and XYZ LLC) will fund their ownership contribution upon the completion of the construction of the Project. XYZ LLC will pay off the construction loan, together with any interest owed on the loan, using proceeds of the owners' contributions. Project assets upon the payment of the construction loan are expected to be free and clear of any and all security claims. The SPE will gain clear title to all of the assets and contracts pertaining to the project, and will be funded 100 percent by the owners' funding into the Project.
Ongoing Capital Expenditure:	None expected.
Project Operation:	The project will be operated and maintained, pursuant to an operating and maintenance agreement between the SPE and

	ABC Electric Cooperative and/or a third party, by ABC Electric Cooperative and/or a third party.
Insurance and O&M:	The SPE is expected to carry sufficient insurance coverage for all insurable events in/at the project and conduct operations and maintenance for the project pursuant to standard utility practices.
Power Purchase Contract:	All of the output from the project will be sold, pursuant to a purchase power agreement (PPA) for the life of the project, estimated to be 25 years, to ABC Electric Cooperative. Power from the project is expected to be delivered to ABC Electric Cooperative at the busbar; it shall be the responsibility of ABC Electric Cooperative to handle the power from the project thereafter.
PPA Price:	<XX> cents per kWh
Distributions from SPE:	As a pass-through disregarded entity, the SPE will deliver the power to ABC Electric Cooperative, collect all of the revenues, pay for all of the operations and maintenance expenses, and distribute, on a quarterly basis, net cash flows and all tax attributes (consisting of accelerated depreciation, investment tax credits, etc.) to its owners, i.e., the TEI and XYZ LLC.
TEI's Internal Rate of Return:	Each year, at the end of the year, the TEI's internal rate of return (the TEI's IRR) on its investment in the project is calculated, made up of the TEI's investment in the SPE, the TEI's tax attributes allocated to it, and the TEI's share of the value of distributions received.
TEI's Targeted Rate of Return:	TBD <inputs from the TEI>
Ratio of Distributions from SPE Initial Years:	During the initial years, estimated to be not less than five years, and up until the targeted rate of return is achieved, the distributions from the SPE will be in the ratio of 99 percent to 1 percent: 99 percent to the TEI and 1 percent to XYZ LLC.
Flip Date:	The date when the targeted rate of return is achieved is designated as the "flip date."
Ratio of Distributions from SPE Following the Flip Date:	Once the targeted IRR is achieved, the ratio of distributions from the SPE will be flipped to 5 percent and 95 percent: 5 percent to the TEI and 95 percent to XYZ LLC.

Buyout Option:	Following the flip date, XYZ LLC will have an option to buy out the TEI's ownership interest in the SPE at any time by paying fair market value.
Fair Market Value:	Fair market value is defined as the net present value of the remaining cash flows attributable to the TEI, discounted to the buyout date using a discount rate of <xx% per annum>.
Other Terms:	Terms and conditions outlined in this term sheet are intended for initial discussions and to explore statements of interest by potential tax-equity investors, lenders, and the cooperative. The terms are neither comprehensive nor final. They are expected to be developed further and supplemented with inputs from the TEI, the cooperative, its consultants, and the lenders (lenders to the construction loan as well as those of the cooperative that provides the source of funds for its equity funding into XYZ LLC). No commitments or warranties are stated or implied by any party to any other party involved in the discussions.

*This illustrative term sheet, developed by NRUCFC may be used/adopted, with required changes by cooperatives, in consultation with their financial advisors, to seek potential tax-equity investors.

Appendix III – NCREBs-Related Links and Materials

Note on NCREBS for 2016

In early 2015, the Internal Revenue Service (IRS) issued a Notice soliciting applications for nearly $281 million in previously unused NCREBs for eligible renewable energy projects owned by electric cooperatives, available on a first-come, first-served basis. NCREBs are a tool to lower the cost of financing facilities generating electricity from solar, wind, landfill gas, biomass, and other renewable sources. The IRS Notice may be found under the link "TEB Published Guidance" on the IRS website at http://www.irs.gov/Tax-Exempt-Bonds. Treasury stated that the amount of available volume cap (out of the initial $281 million availability) was $195,697,775 as of December 1, 2015. Additional resources and materials can also be found on the SUNDA webpage, http://www.nreca.coop/what-we-do/bts/renewable-distributed-energy/sunda-project/

For more information, please contact Linda Graham, CFC director of financial products, at (703) 467-1752 or linda.graham@nrucfc.coop, or your preferred lender.

NCREBs-Related Materials

Application Procedure

The application must identify the following:
(1) The qualified borrower and organization under Section 501(c) (12) or 1381(a) (2) (C);

(2) The location of the project (more than one possible location may be identified);

(3) A detailed description of the project that also includes a breakdown of the project cost, the dollar amount of NCREB volume authority requested for the project, the expected date the construction of the project will commence, and the expected placed-in-service date;

(4) The status and plan to obtain all necessary federal, state, and local regulatory approvals;

(5) Demonstration that the project will constitute a qualified project, supported by a certification by an independent, licensed engineer that the project will be both a qualified project and technically viable;

(6) A copy of an Inducement Resolution passed by the cooperative's board indicating intent to use NCREB proceeds to finance the project (or an indication of when the Inducement Resolution is expected to be adopted); and

(7) A detailed description of all sources of financing for the project.

Applications must be submitted in hard copy and electronic format. Electric cooperatives interested in NCREB financing may contact **Linda Graham** at CFC (see contact information above) to obtain more information, including an Inducement Resolution template and an application form.

Eligible Project Cost

100 percent of the project capital expenditures may be financed with NCREBs, excluding Interest During Construction (IDC). Under federal guidelines, interest expenses incurred on the project during construction are not considered a capitalized expense.

Costs that are not capital expenditures cannot be funded from NCREB proceeds. The purpose of this requirement is to keep NCREB proceeds from being used for working capital, to cover the operating cost of a project, and/or to fund debt service reserve for the repayment of NCREBs.

The timing of the project commencement is important, since eligible project costs are only those paid on or after the date the IRS allocates NCREBs for the project.

Issuers of tax-exempt bonds or, in the case of NCREBs, issuers of tax credit bonds, are required to adopt an Inducement Resolution showing intent to use tax-advantaged financing to reimburse project expenditures. An issuer must describe the project in the resolution and state the maximum size of the allocation wanted to fund the project. The borrower may reimburse itself from proceeds of NCREBs for costs paid not more than 60 days prior to adoption of the resolution.

NCREBs may also be used to finance related and subordinate facilities. These include only those expenditures for facilities required for the output of a renewable energy facility to be made available to consumers through the electric system. Examples of related and subordinate facilities are transmission or distribution facilities required for the sole purpose of carrying the output of the generation to the electric system grid.

Additionally, up to 2 percent of the proceeds may be used for issuance costs, primarily related to bond counsel expense. For NCREBs to qualify for tax-advantaged benefits, many detailed rules set forth in IRS Code and Treasury regulations must be satisfied and outside bond counsel engaged to review and confirm compliance with these rules as of the issue date.

Important reminder

The proceeds of NCREBs may be used for project funding during the construction phase. Reimbursable costs can be claimed only for expenses paid after the NCREB allocation is approved by the Treasury.

Maximum Maturity and Amortization Options

Because longer bond terms mean longer-lasting tax benefits and increased costs to the Treasury, the NCREBs program has a more limited maximum term than conventional financing would provide. The maximum term for an issue of NCREBs is set by the Treasury each month. A bond is sold on the first day on which there is a binding contract in writing for the sale or exchange of the bond. Consequently, at closing, the maximum maturity may be set to a term no greater than the term set that month by the Treasury.

The maximum term is currently on the order of 22 to 25 years. As interest rates (including applicable federal rates) fall, the maximum maturity of an NCREB rises. Waiting to close and lock into a fixed rate on the NCREB financing with a longer maturity might make sense if interest rates are expected to fall.

Before the program changes for NCREBs, the borrowers/issuers were required to repay a level principal amount each year. Under NCREBs, borrowers may repay the principal amount at maturity, provided there is underlying credit repayment capability. Typically, borrowers opt to make a more traditional level debt service payment, wherein interest and principal plus the projected federal direct payment result in an approximate level debt service payment over the life of the financing.

Allocation Process

The NCREB program is administered by the Treasury. The IRS issues guidance for soliciting applications from qualified borrowers, which include electric cooperatives, public power providers, and governmental bodies. Specifically, a qualified electric cooperative borrower includes any mutual or cooperative electric company described in Section 501(c)(12) or 1381(a)(2)(C). An NCREB-financed project must be owned by a qualified borrower.

Participation in the program is limited by the volume of bonds available for allocation. Initial availability was $280 million and, as of December 1, 2015, the NCREBs available for allocation amounted to more than $195 million. Further, any allocation not used within 180 days reverts back to the IRS and is available for future allocations.

Additionally, for purposes of the NCREB allocation, all qualified projects located at the same site and owned by the same qualified borrower are treated as a single project. For instance, if a cooperative seeks funding for a solar project and a wind project that will be located on the same site, the two applications will be considered as a single project in the aggregate amount for the purpose of reviewing and awarding an allocation.

Spending Requirements

Several spending requirements and other rules are associated with NCREBs, similar to provisions around tax-exempt bonds. In particular, a qualified issuer of NCREBs must reasonably expect the following:

(1) To enter into a binding commitment within six months of the date of issue with a third party to spend at least 10 percent of the proceeds of the issue;

(2) 100 percent of the available project proceeds must be spent within the three-year period beginning on the date the NCREBs are issued; and

(3) The project will be completed with due diligence, and the proceeds of the issue will be spent with due diligence. Upon submission of a request before the expiration of the three-year period described in (2) above, the Secretary of the Treasury may extend the period if the borrower/issuer establishes that the failure to satisfy is due to reasonable cause and the related projects will continue to proceed with due diligence. If less than 100 percent of the proceeds of the issue are

spent by the end of the three-year anniversary date (or by the end of the extension), the borrower must redeem the NCREBs, in an amount equal to those funds unused plus any associated prepayment fee, within 90 days.

Note that available project proceeds include any interest earned on the NCREB proceeds while they are maintained in a segregated account before reimbursement for project expenditures. NCREBs, like any bond proceeds, are fully advanced following closing and are held in a restricted account until such time as the funds have been fully advanced for reimbursement of eligible project costs. NCREBs, like tax-exempt bonds, are subject to the investment yield restrictions and arbitrage rebate requirements under IRS Section 148. However, those rules were liberalized for NCREBs during the construction spending period.

There are limitations on the reimbursement period to ensure that money paid for the expenditure is not available on a long-term basis; otherwise, issuers might be motivated to invest low-cost bond proceeds on a long-term basis to achieve higher yields.

Additional Requirements for NCREBs

Davis-Bacon Act labor standards apply to all projects financed by NCREBs. Davis-Bacon prevailing wage laws do not apply to the issuer employees but do apply to contracted labor. Davis-Bacon prevailing wage requirements apply to laborers and mechanics employed on contracts in excess of $2,000 for construction and repair work. The Davis-Bacon contract clauses stated in 29 CFR 5.5(a) must be incorporated into covered contracts for construction, alteration, or repair work. Contractors that perform work for municipal electric utilities should be familiar with these standards, since electric municipals using tax-exempt financing are subject to Davis-Bacon prevailing wage laws. Additional information regarding the application of Davis-Bacon labor standards may be found at the U.S. Department of Labor Wage and Hour Division website at: www.dol.gov/whd/recovery/index.htm.

NCREB proceeds may be advanced only for work completed and already paid for by the cooperative. In certain cases, a line of credit used to finance the project may be refinanced with the proceeds of NCREBs.

Documentation

In addition to a loan agreement, the borrower executes a tax compliance and certificate agreement. That agreement outlines the additional rules that continue to apply throughout the entire term of the bond issue, such as the following:

- The issuer/borrower agrees to keep and retain sufficient records to demonstrate compliance, such as the inducement resolution and documentation evidencing the expenditure of amounts and the use of property financed with the NCREB proceeds. These records are to be retained until three years after the NCREB maturity date.

- Neither the project, nor any portion thereof, is expected to be sold or otherwise disposed of before NCREB maturity; otherwise, that likely would constitute an action requiring the repayment in full of the NCREBs.

- A copy of the IRS allocation letter and application is included in the documentation, along with a description of any changes to the project and cost estimates that may have occurred after the application was submitted.

Appendix IV – Illustrative Term Sheet for NCREBs

CFC Clean Renewable Energy Financing
Generic Term Sheet for Funding New Clean Renewable Energy Bonds (NCREBs)*

Borrower	A qualified borrower that has received an NCREB allocation for a qualified project(s).
Purpose	To provide financing for a qualified project(s), within the meaning of Section 54C of the Internal Revenue Code, that has been awarded an allocation for NCREBs from the Department of the Treasury.
Loan Amount	Not to exceed the amount of the NCREB Allocation awarded by Treasury for the Issuer's Project(s).
Loan Term and Amortization	Generally for a term of 20 to 25 years, as determined each month by Treasury for NCREBs as in effect on the date the loan is cleared. A loan is "cleared" on the first day on which there is a binding written contract for the loan ("Commitment Date"). An NCREB Loan may be designated either with a set principal repayments schedule or a non-amortizing loan with the full principal amount due at the maturity.
Loan Security	Generally a first lien on and security interest in all assets and revenues of the borrower, including any property acquired after the date of the NCREB. The lien or security interest is to be equal to or superior to liens or security interests of other creditors.
Borrower's Election for the Federal Direct Subsidy Payment for NCREB Loan	The Borrower of the NCREB Loan will elect to have the special rule apply, whereby the Borrower receives a direct subsidy payment from the federal government similar to the Build America Bond subsidy payment in lieu of providing tax credits to owners of NCREBs. The amount of the subsidy payment with respect to any interest payment associated with an NCREB Loan shall be equal to the lesser of the interest payable on the NCREB Loan, or 70 percent of the tax credit rate published by Treasury on the Commitment Date of the NCREB Loan.
NCREB Interest Rate and Payment Dates	NCREB Loans will be subject to an NCREB interest rate that is quoted daily and in effect on the Commitment Date. The interest rate is fixed through the maturity of the NCREB Loan and will be established two (2) business days before the advance of Loan funds. Interest will be payable generally on a semi-annual basis, due the first business day of June and December.
Federal Subsidy Payment Procedures	The Borrower submits IRS revised Form 8038-CP to request the subsidy payment no earlier than 90 days before each interest payment date and no later than 45 days after an interest payment date. The foregoing may be subject to further guidance to be issued by the IRS.

NCREB Loan Proceeds

100 percent of the Available Project Proceeds are to be used for capital expenditures incurred by the qualified facility owner within three years of the date of issuance of the bonds. “Available Project Proceeds” means the excess of (i) the proceeds from the Loan over (ii) the documentation fee financed by the loan (to the extent that such costs do not exceed 2 percent of such proceeds). To the extent that the 100 percent test is not met within a three-year period following the Commitment Date, then all nonqualified loan proceeds must be prepaid within 90 days of the end of the period.

Fee

The Borrower shall pay a nonrefundable fee for the preparation of loan documentation and bond counsel services.

Mandatory Prepayment Requirements

Extraordinary mandatory prepayments will be required consistent with special expenditure rules and eligibility requirements for NCREBs. A make-whole fee will be charged on the mandatory prepayment, based upon the spread in the NCREB interest rate and Treasury securities with a comparable maturity. Voluntary prepayments of the NCREB loan are permitted, subject to a make-whole fee charged on the same basis as for a mandatory prepayment.

Loan Advance

All funds are to be advanced two (2) business days after the Commitment Date, and any loan proceeds not yet eligible for reimbursement of qualifying project expenditures are to be invested. The Borrower will need to maintain, or cause to be maintained, records relating to the investment of the NCREB proceeds. The Borrower may also choose to use a Trustee to act as the Paying Agent and instruct the investment of the proceeds. There are no rebate or yield restrictions on the earnings from invested funds for the first three years. In the event the Borrower is reimbursed with all of the bond proceeds within three years of the Commitment Date, any earnings on the invested funds must be used by the Borrower upon requisition for qualifying project expenditures.

Sample Conditions Precedent to Closing

Conditions customary in long-term commitments of this type include, but are not limited to, the following:

Receipt of application materials, satisfactory completion of lender’s review, and final approval.

Completion of mutually agreeable documentation that includes terms, covenants, representations, warranties, defaults and remedies, and other supporting documentation.

The execution and delivery of security agreements and other supporting documentation, including opinions of its Corporate counsel, in a form and substance satisfactory to the lender.

Compliance with any applicable federal or state laws, regulations, and delivery of tax documents satisfactory to bond counsel.

Federal Subsidy Tax Compliance Covenants & Representations	Representations and covenants for federal subsidy tax compliance include, but are not limited to, the following: Terms and covenants consistent with the requirements of the U. S. Department of the Treasury. Neither the entire Project nor any portion thereof may be sold or disposed of before the maturity date of the NCREB loan. Issuer must keep records to demonstrate compliance with covenants and documentation on expenditures and use of property financed. The records are to be kept until three years after the maturity date of the NCREB loan. Representation regarding the Issuer's reasonable expectation that the work on the Project will proceed and be completed with due diligence.
Sample Representations and Warranties	Representations and warranties customary for certain provisions of NCREB guidelines include, but are not limited to, the following: Representation regarding the Borrower's reasonable expectation that either before the date of the loan or within six months thereof, the Borrower shall incur a substantial binding obligation (not subject to contingencies the Borrower controls) to a third party to expend at least 10 percent of the Loan Proceeds. Representation regarding the Borrower's reasonable expectation that 100 percent of the Available Project Proceeds are to be used for capital expenditures paid by the qualified renewable energy facility owner within three years of the Commitment Date of the loan.
Conditions Precedent to Loan Advance	The Borrower shall be required to certify the following, among other conditions prior to Loan advance: Certification of use of loan proceeds consistent with the requirements of Treasury and qualification of the Borrower and the Project under the regulations applicable to NCREBs; All representations and warranties made by the Issuer are true and correct in all material respects; and No material adverse change, default, or event of default shall have occurred and be continuing for the Borrower.
Loan Agreement Event of Default and Remedies	Usual and customary in transactions of this type, to include without limitation the following: Nonpayment of principal, interest, or other amounts; violation of covenants (with cure periods as applicable); inaccuracy of representations and warranties; bankruptcy and other insolvency events; material judgments; or cross-default.

*Illustrative terms for lending by NRUCFC in connection with the use of NCREBS by electric cooperatives. Actual terms are subject to negotiation and an offer of lending by NRUCFC. Additional terms may be added to reflect cooperative-specific credit review and determination by NRUCFC.

Appendix V – Applicable Security Laws

Applicable Securities Laws

Courtesy of David Swanson, Dorsey & Whitney LLP

Member participation in cooperative projects, either through prepayment for the sale of power or sale of ownership shares to members, raises potential securities regulation issues that should be evaluated. To be overly simplistic, federal and state securities laws require registration with the SEC or a state securities regulator if a "security" is offered to the public. Registration with the SEC is costly and time-consuming and would create many problems for a sponsoring cooperative; initial and ongoing costs are significant, and the business transparency required could cause competitive problems. Offering a prepayment contract or direct LLC investment option to members potentially could trigger a registration requirement. However, there are two potential ways to approach this problem.

One is to focus on the definition of "security" and structure the member prepayment contract so that a comfort level can be achieved that the prepayment contract is not a security at all. This approach may work for the prepayment program but may not work as well for a direct member investment in the LLC (which, if a passive equity participation, is almost certain to be classified as a security).

The legal standards for determining whether a consumer contract such as a prepayment program would be classified as a security are subjective. Clearly, however, a consumer contract can be found to be a security, depending on its characteristics. It does not have to be called "stock" to be classified as a security. The standards focus on facts such as (a) whether the program is promoted as an investment, and (b) whether the member can be considered to have an expectation of profits. Good arguments can be made that a properly constructed and promoted prepayment is not a security—it is more likely the members would participate because they like the idea of promoting green generation sources than because they really expect an investment return. There is no clear legal precedent on this issue, however, and different individuals will reach different conclusions on whether it is reasonable and worth the possible risks to conclude a prepayment program that is not going to be treated as a security.

The second approach is to find an exemption from state and federal securities registration requirements. In many states, there is an exemption for offering securities by cooperatives to their members. The state laws vary widely, so consulting legal advice on your particular state blue sky laws is advisable. As examples:

- The Colorado Cooperative Law, applicable to most or all the Colorado electric cooperatives, provides that "any security . . . issued or sold by a cooperative association as an investment in its stock or capital to the members . . . is exempt from securities laws" of Colorado
- The Wisconsin blue sky law exempts "[a]ny securities of a cooperative corporation organized under chapter 185," which is the host statute for most or all Wisconsin electric cooperatives.

Even in states where a cooperative exemption is not available, or if there is a desire to permit members to invest directly in the LLC, it may be practical to register the offering with the state securities regulators. Unlike SEC registration, state registration does not typically require the costly ongoing reporting and compliance programs associated with SEC registration. This approach has been used effectively by many ethanol plant LLCs in the upper Midwest.

A federal exemption would still need to be available, and the so-called "intrastate" exemption (Section 3(a)(11) of the Securities Act of 1933) should work for many cooperatives. The intrastate exemption precludes SEC jurisdiction if all the offerees (members) are resident in a single state and the issuer (the cooperative) is doing business and incorporated in the state. The SEC has issued its Rule 147; under an integration rule included in Rule 147, sequential intrastate offering periods may need to be separated in time by six months or more.

Many natural foods cooperatives have used the combination of intrastate and cooperative exemptions to sell stock and notes to their members.

SEC Rule 147

Requires that (i) the cooperative must have derived 80 percent of its gross revenue from within the state in the past six months, (ii) 80 percent of the cooperative's assets must be located in the state, (iii) 80 percent of the proceeds of the offering must be used within the state, and (iv) the principal office of the cooperative must be located in the state.

Appendix VI – Cost Screening Tool Financial Glossary

Input Term	Description
System Size (MWac)	Total inverter size for the system, in AC.
Hardware Costs	Includes modules, racking, and inverter. Costs are based on real-world quotes obtained by cooperatives or through the NDP.
Project Management	Cost of cooperative for implementing the project. Can include wages for project manager.
EPC Markup (%)	Contractor markup on hardware. Calculated as a percentage of hardware costs.
Distribution Adder	Accounts for the cost of distributing the electricity from the PV array to the end customers. Allows for a comparison to existing retail rate.
Expected System Life	Currently estimated as a range of 25–35 years. Drives system returns more than any other input.
Discount Rate	Cost of capital to the cooperative. Typically close to the 20-year Treasury bill rate for the project period.
Loan Interest Rate	Can increase drastically if a tax-equity flip is implemented.
NCREB Tax Credit Rate	Rate used by Treasury to calculate the 70 percent interest reimbursement.
Lease Buyback Rate	The effective rate of the lease buyback.
Targeted Tax-Equity Return	Return sought by tax-equity partners.
PPA Inputs	Allow for comparison to any offered PPAs. These do not have to be entered for the model to run.
Inverter Type	Both central and string options are provided. String inverters typically are not used for projects larger than 1 MW.
DC to AC Ratio (Array Size)	Industry standards dictate that for maximum performance, this ratio should be 1.3908.
Watts per Panel (Number of Panels)	Watts per panel input is used only to calculate number of panels and is not used otherwise.
System Configuration	The information entered here is used in NREL's PV Watts program to calculate outputs.
Azimuth	The cardinal direction the array will face. It typically is south, but may vary if a cooperative wishes to harness more afternoon sun.
Tilt	Automatically calculated to a recommended value based on the latitude of the zip code input.
Annual Degradation of Array	Will be given by the manufacturer as a part of the panel warranty.
Capacity Factor	Calculated from array output and rating. Cannot be changed.
Capital Cost Inputs	Costs of engineering, hardware, construction equipment, installation, site preparation, and land. Can vary depending on the specific site chosen.
Development Costs	Consulting, legal, and banking fees to set up any new system requirements. Will be higher if tax-equity flip is implemented.

Interconnection Costs	Costs of connecting from the included medium-voltage transformer to the substation.
Total System Costs	Includes all equipment, engineering, installation, and connecting costs.
Operative Cost Inputs	Outputs calculated by NREL's PV Watts program based on system inputs.
Management Fee (Annual Escalation of Management Fee)	Only needed for a tax-equity flip. Cost of management, paperwork, and taxes for SPE and blocker.
Term of Borrowing (Direct Financing)	Length of loan taken by the cooperative.
Lender TIER	TIER = Times Interest Earned Ratio. The dividend earned if lender is CFC and part of patronage capital. Ignore if lender is non-CFC.
Term of Borrowing (NCREB Loan)	Length of NCREB loan taken by the cooperative.
NCREB Financing Rate	The rate at which the cooperative is able to borrow money to finance the project.
Lease Buyback Cost Inputs	Inputs needed if the lease buyback structure is to be considered.
Tax-Equity Investor Share	Percentage of initial costs for which the tax-equity partner is responsible. Usually around 50 percent.
Rate at which Co-op Finances their Share	Financing rate for cooperatives if they require a loan to finance their share of the initial costs.
Targeted Blocker Return	Percentage return to the cooperative blocker for the IRS to acknowledge it as a real entity.
Switch Gear/Disconnects	Cost for AC/DC disconnects.
Balance of System	Cost for wire, conduit, copper PV wire, and aluminum combiners.
Combiner Box Unit	Cost per unit for a combiner box. The number of combiner boxes is calculated automatically.
Monitoring Material/Weather Station	Cost for a unit to monitor the weather for the system.
Site Preparation Inputs	Cost for engineering, blueprints, permits, labor, and other site-specific expenses.

Appendix VII – Financing and Insurance Resources and Contact information

About CFC
The National Rural Utilities Cooperative Finance Corporation (CFC) is a nonprofit finance cooperative created and owned by America's electric cooperative network. With more than $22 billion in assets, CFC is committed to providing unparalleled industry expertise, flexibility, and responsiveness to serve the needs of its member-owners. CFC is an equal opportunity provider and employer. More information is available at www.nrucfc.coop.

Contact: **Krishna Murthy** – CFC, Vice President, Energy and Industry Analysis, at (703) 467-2743

About CoBank
CoBank is a national cooperative bank serving vital industries across rural America. CoBank supports rural communities and agriculture with reliable, consistent credit and financial services in all 50 states today and in the future.

CoBank is a member of the Farm Credit System, a nationwide network of banks and retail lending associations chartered to support the borrowing needs of U.S. agriculture and the nation's rural economy. In addition to serving its direct retail borrowers, the bank also provides wholesale loans and other financial services to affiliated Farm Credit associations serving approximately 70,000 farmers, ranchers, and other rural borrowers around the country. More information is available at http://www.farmcreditnetwork.com/.

Contacts:
Tamra Reynolds – Regional Vice President, Southern Region, Electric Distribution, Water & Community Facilities Division, at: (303) 740-4034
Noiel Fontaine – Regional Vice President, CoBank Farm Credit Leasing, at (806) 814-4049
Todd Telesz – Senior Vice President, Power Supply and Utilities Division, at (303) 740-4327

About Federated
Federated Rural Electric Insurance Exchange (Federated) is the leading provider of property and casualty insurance for rural electric cooperatives in 42 states. Federated's primary goal is to offer its members affordable coverage over the long term so they can focus on serving their communities and making them better, safer, and more vibrant places to live. More information is available at: www.federatedrural.coop.

Contact: **Bill West**, at (800) 356-8360

About the National Renewables Cooperative Organization (NRCO)
Cooperatives across the country formed NRCO to promote and facilitate the development of renewable energy resources for its members. NRCO's main purposes are to facilitate the cost-effective, joint development of renewable resources nationwide for its cooperative owners, helping them meet the requirements of voluntary and mandatory renewable energy standards. For more information, please visit www.nrco.coop.

Contact: **Todd Bartling**, VP – Renewables Development, at (317) 344-7900

About the RUS Electric Program:
Under the authority of the Rural Electrification Act of 1936, the RUS Electric Program makes direct loans and loan guarantees to electric utilities (wholesale and retail providers of electricity) that serve customers in rural areas. The Electric Program helps nearly 700 borrowers in 46 states finance safe, modern, and efficient infrastructure. The resulting loan portfolio of approximately $46 billion is managed by the Electric Program. RUS-financed electrical systems provide service to more than 90 percent of the nation's counties identified as suffering from persistent poverty, out-migration, or other economic hardships. The Electric Program also provides financial assistance through High Energy Cost Grants to rural communities with extremely high energy costs to help them acquire, construct, extend, upgrade, and otherwise improve energy generation, transmission, or distribution facilities.

Contact: **Victor Vu**, RUS, Deputy Assistant Administrator, Portfolio Management and Risk Assessment, at (202) 720-6436

About Clean Renewable Energy Bonds (NCREBs)
NCREBs may be used by certain entities—primarily in the public sector—to finance renewable energy projects. The list of qualifying technologies is generally the same as that used for the federal renewable energy production tax credit (PTC). NCREBs may be issued by electric cooperatives, government entities (states, cities, counties, territories, Indian tribal governments, or any political subdivision thereof), and certain lenders. The bondholder receives federal tax credits in lieu of a portion of the traditional bond interest, resulting in a lower effective interest rate for the borrower. The issuer remains responsible for repaying the principal on the bond.

Contact: **Zoran Stojanovic** or **Timothy Jones** of the IRS Office of Associate Chief Counsel, at (202) 622-3980
Contact: **Linda Graham**, Director, Financial Products at CFC, at (703) 467-1752

About the Database of State Incentives for Renewable Energy
Database of State Incentives for Renewable Energy (DSIRE) is the most comprehensive source of information on incentives and policies that support renewables and energy efficiency in the United States. Established in 1995, DSIRE currently is operated by the N.C. Clean Energy Technology Center at North Carolina State University, with support from the Interstate Renewable Energy Council, Inc. DSIRE is funded by the U.S. Department of Energy. For more information, go to www.DSIREUSA.org/.

Contacts at NRECA
Russell Wasson, Sr. Associate Director of Tax Finance and Accounting Policy, at (703) 907-5802
Doug Danley, Technical Contractor, at Doug.Danley-contractor@nreca.coop
Andrew Cotter, Renewables Program Manager, at (703) 907-6069

About the Solar Electric Power Association (SEPA)
SEPA is a nonprofit educational membership organization with more than 20 years of experience in helping utilities integrate solar energy into their portfolios. Members learn about the latest research on solar trends and other key issues through publications and interactive tools. SEPA also offers fee-based advisory services to utilities on topics such as design of customer solar programs, developing overall solar strategies, and procuring solar assets. For more information, go to http://www.solarelectricpower.org/.

Contact: **Ruth Hupart**, Member Relations Manager, at (202) 559-2032

Appendix VIII – Solar ITC Extension

What has changed and why is it important?

The fiscal year 2016 Omnibus Spending Bill, enacted into law in December 2015, includes a provision that extends for five years (and later phases out) the solar Investment Tax Credit (ITC) for commercial applications (Section 48), the solar ITC for residential applications (Section 25(d)), and the wind Production Tax Credit (Section 45(d)).
The extensions will lessen pressure to complete solar projects by the end of 2016 and provide a measure of financial stability to planners of solar projects at all levels. While the change will likely result in the completion of fewer solar projects in 2016, the probability of a "significant drop" in installations in 2017 will be lower as well. That smoothing of demand should ease pressure on suppliers of solar components. Prior to the ITC extension, suppliers had projected a shortage of modules, structures, and inverters in 2016.

What do cooperatives need to know about it?

The new ITC law is slightly different for commercial and residential solar applications:

Section 48 – Commercial Solar
The ITC for commercial applications has been extended for three years, followed by a four-year phase out. The requirements have also been changed to reflect a "construction started" clause for five years.

(Note: The Treasury Department has clarified the "commence construction" clause of the ITC law. Under the new definition, "physical work of a significant nature is treated as beginning when more than 5 percent of the total costs of the qualifying property has been paid or incurred" with the further stipulation that "physical work of a significant nature does not include preliminary activities such as planning or designing, securing financing, exploring, researching, clearing a site, test drilling of a geothermal deposit, test drilling to determine soil condition, or excavation to change the contour of the land (as distinguished from excavation for footings and foundations)."1)

The full 30 percent extension covers projects, for which construction begins before January 1, 2020. The previous language was "placed in service before 1 January 2017." The full three year extension plus the "construction started" provision effectively extends the tax credit for more than three years.

For projects that start construction in 2020, the ITC is 26 percent; for projects that begin in 2021, the ITC is 22 percent.

A final clause says projects that commence construction before January 1, 2022, but are not "placed in service" until January 1, 2024 or later, will receive a 10 percent ITC.

Section 25(d) – Residential

The ITC for residential applications follows a similar pattern, with a three-year extension followed by a two-year phase-out. The difference is that a residential application must be "placed in service" before the specified dates, as compared with the "commence construction" clause in the commercial section.

- 30 percent: Property placed in service after Dec. 31, 2016 and before January 1, 2020
- 26 percent: Property placed in service after Dec. 31, 2019 and before January 1, 2021
- 22 percent: Property placed in service after Dec. 31, 2020 and before January 1, 2022

What should cooperatives do about it?

Electric cooperatives' interest in solar energy has risen in recent years. Although not-for-profit co-ops are not typically eligible for tax benefits, they often seek a "taxable partner" for solar and wind projects, either through a power-purchase-agreement or through a shared ownership model, such as a tax-equity flip or a tax-lease-buyback project.
The ITC extension reduces pressure for planners to implement solar projects in 2016 and allows for more careful planning. This is especially important for co-ops that are planning community solar projects, because it allows them to pursue a multi-year plan and avoid trying to cram everything into 2016.

Solar costs are expected to continue falling as the technology and the industry continue to mature. The steep rate of cost savings seen in recent years will likely slow, however. Solar Power Purchase Agreements utilizing various tax incentives have already fallen under $60 per MWh in many parts of the US—and below $40 per MWh in some areas. With the continued cost reduction, more parts of the country will start to see prices for large scale projects in the $50 to $60 per MWh range. When combined with falling costs and industry maturity of large scale energy storage, this may open opportunities for investment in carbon-free generation technologies as replacement for more traditional sources of energy, especially peaking plants.

The new law will also provide a measure of stability for the development of wind projects over the next four years. Both wind and solar will play an important role in developing state implementation plans to meet the 2015 EPA Clean Power Plan.

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NAEC
North Arkansas Electric Cooperative, Inc.
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