Developing Solar Friendly Communities

Permitting, Interconnection, and Net Metering: An Overview of Model Standards and Policy Design Criteria

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Executive Summary

Over the past several years, procedures and policies surrounding permitting, inspection, interconnection, and net metering of distributed photovoltaic (PV) systems have been the subject of extensive analysis and scrutiny, given their substantial contribution to solar costs. This ongoing period of critical analysis has produced a wide variety of process innovations and model standards capable of streamlining processes for local governments and reducing solar PV costs. As a member of the Colorado-based "Solar Friendly Communities" team under the Rooftop Solar Challenge, Rocky Mountain Institute (RMI) has evaluated a number of these standards, innovations, and policy design criteria and developed some specific recommendations. This document surveys a subset of existing permitting, interconnection, and net metering processes and is meant to serve as an initial point of inquiry for interested local governments and communities.

While several communities (including many in Colorado) already have leading permitting, inspection, interconnection, and net metering standards in place, a number of model standards and policy design criteria have been created that can help guide jurisdictions looking to create new processes or change existing ones. This document outlines several such standards and policy design criteria including:

- **Permitting & Inspection:** *The Solar ABCs Expedited Permit Process and Emerging Approaches to Efficient Rooftop Solar Permitting*
    - The Solar ABCs' Expedited Permit is capable of providing a consistent, easy to understand starting point for jurisdictions with little to no existing experience with solar installations. Furthermore, for more experienced jurisdictions, it can be adopted in a piecemeal fashion to complement existing building permits.
    - While not a single model standard, the Interstate Renewable Energy Council (IREC) survey of emerging approaches to efficient rooftop solar permitting is an excellent overview of leading permitting and inspection practices from across the country.
- **Interconnection:** *The IREC Model Interconnection Standards*
    - The IREC model interconnection standard and associated agreements synthesize the best components of existing interconnection standards to expedite interconnection of small- to medium- sized distributed generators and remove unnecessary fees.
- **Net Metering:** *The Network for New Energy Choices (NNEC)—Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures*
    - Although not a single, comprehensive standard, the design criteria used by NNEC to review existing net metering regimes is a good starting point for development of new standards or adaption of existing policy frameworks.

In addition, the current state of the Rooftop Solar Challenge action areas in Colorado is outlined and discussed to better situate readers in the context of the Colorado solar market.

Introduction

The U.S. is comprised of over 18,000 local government authorities and 5,000 electric power producers. Colorado alone is home to over 200 cities and towns, 64 counties, and some 65 utilities. While these authorities and jurisdictions are beholden to several state and federal regulations, they are independently responsible for setting the bulk of local standards that govern the development of rooftop PV systems. It falls to them to oversee the process of installing and connecting a rooftop PV system to the grid—from the minutiae of having building official contact information available on city websites to providing guidelines for electricians to inspect a system before it is activated.

This vast network of jurisdictions, utilities, and thousands of different local policies has created a complicated landscape for rooftop PV in the U.S. and entails high non-hardware balance of system costs. As illustrated below, estimates and analyses of non-hardware balance of system costs vary substantially due to accounting differences and survey approaches. However, it has been reported that such costs can account for up to 40% of installed system costs.[1]

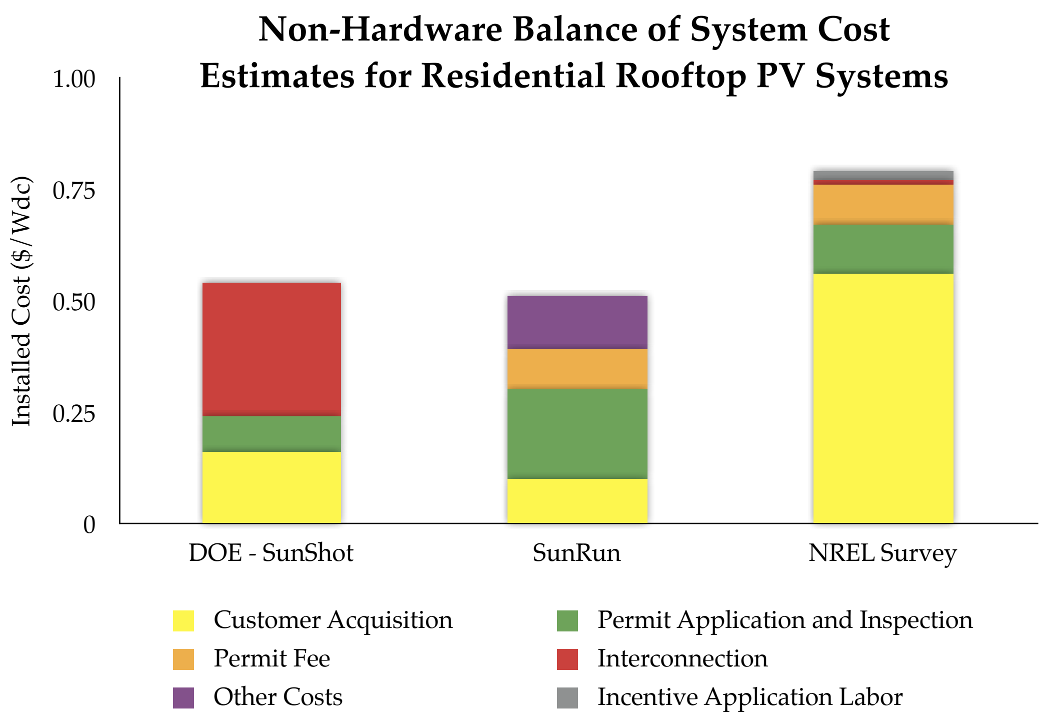

Figure 1 Various non-hardware balance of system cost estimates[2]

[1] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. *Rooftop Solar Challenge*. U.S. Department of Energy. Available from: http://www.eere.energy.gov/solarchallenge/.
[2] DOE – SunShot: U.S. Department of Energy. *SunShot Vision Study*. U.S. Department of Energy. January 2011. Available at: http://www1.eere.energy.gov/solar/sunshot/vision_study.html. SunRun: SunRun. *The Impact of Local Permitting on the Cost of Solar Power*. SunRun. January 2011. Available at: http://www.sunrunhome.com/solar-lease/cost-of-solar/local-permitting. NREL Survey: Ardani K. et al.

With these challenges in mind, the Department of Energy's Rooftop Solar Challenge program was launched in 2012 to streamline this immensely complicated landscape. The program and its 22 participating teams are focused on making the installation of rooftop solar PV easier, faster, and cheaper for both homeowners and small businesses. [3] The challenge specifically targets four action areas: permitting and inspection, interconnection and net metering, planning and zoning, and financing.

The Colorado-based Solar Friendly Communities team of the challenge is collaborating directly with local governments to improve rooftop solar market conditions and recognize leading communities for their initiative in developing "Solar Friendly Communities."

A key part of improving local market conditions and streamlining the current landscape is to recognize existing best practices and processes that can help reduce costs and improve efficiency.

In this document we outline key standards and criteria within the permitting, inspection, interconnection, and net metering action areas of the Rooftop Solar Challenge. Given our team's Colorado-specific focus, we then highlight where Colorado stands now in the context of these standards and best practices. It is our hope that this document will serve as an introduction to the aforementioned action areas for interested local governments and utilities looking to develop new standards and regulations that will foster healthier, more efficient, and sustainable rooftop solar markets in their communities.

Permitting & Inspection

Rooftop solar permitting and inspection processes can add $2,000—3,000 in costs per U.S. residential installation.[4] While larger commercial installations are better able to absorb such variable costs because of project size, high permitting and inspection costs can seriously alter project economics for residential and small commercial projects. Using standardized permitting and inspection processes can help overcome these challenges.

Unfortunately, standardizing across thousands of local governments is difficult because permitting and inspection procedures currently vary greatly from jurisdiction to jurisdiction.

Existing processes are largely dependent on the size of the jurisdiction. Rural communities, for example, may have a completely non-existent permitting process and place all emphasis on a single field inspection. In contrast, major urban centers may employ a group of officials that focus on pen and paper-based

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Quantifying Non-hardware Balance of System Costs for Photovoltaic Installations in the United States Using a Combined Annual Expenditure-Labor Hour Productivity Approach. National Renewable Energy Laboratory. 2012. Customer acquisition costs include sales, marketing, and a portion of reported overhead.

[3] See http://www.eere.energy.gov/solarchallenge/ for more information.

[4] SunRun. *The Impact of Local Permitting on the Cost of Solar Power*. SunRun. January 2011. Available from: www.sunrunhome.com/download_file/view/414/189/

plan reviews and are not involved in the inspection process whatsoever. Broadly speaking, the process of issuing permits and inspecting installations is completely isolated from interconnection procedures. Permitting and inspection procedures generally follow the process outlined in Fig-2.

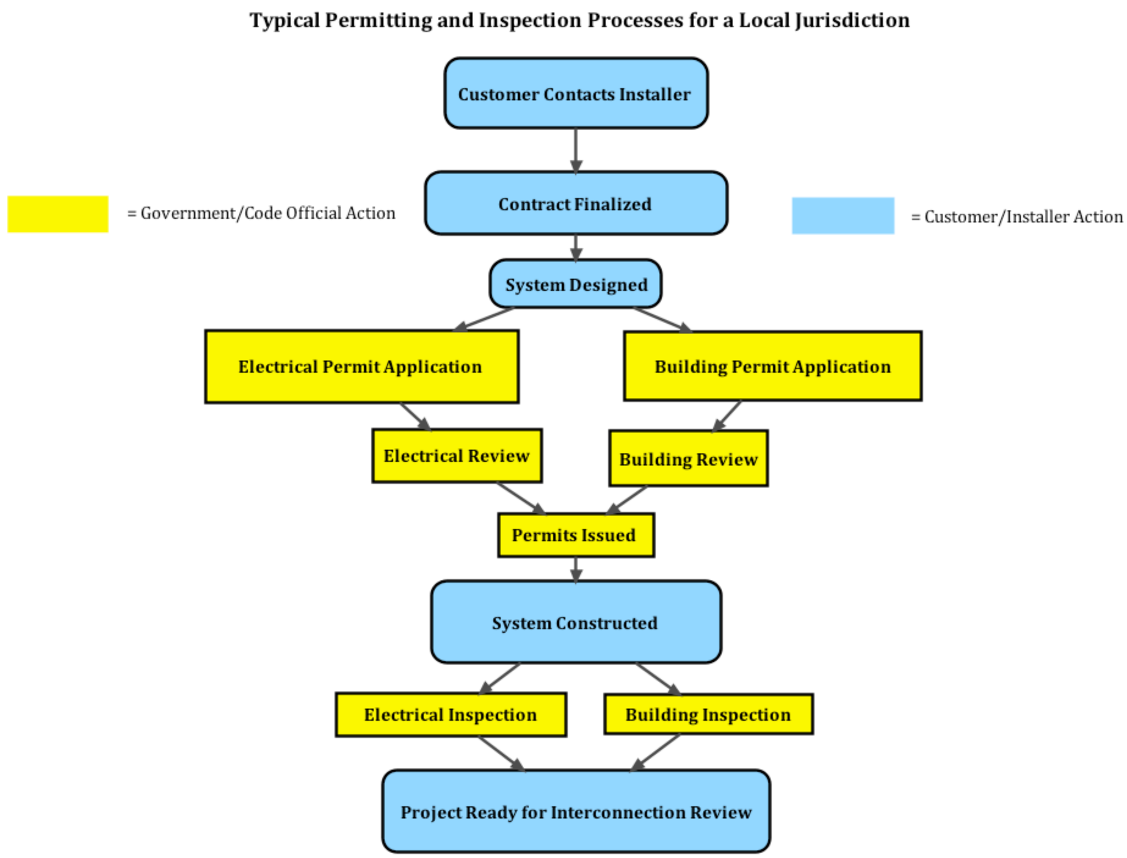

Figure 2 - Diagram of Local Permitting and Inspection Processes

As illustrated in Fig-2, permitting is commonly split into two discrete segments: permitting and field inspection. Depending on the jurisdiction, installers may have to go through several departments and offices to obtain the necessary permits. The flow chart above assumes that an installer would have to obtain an electrical permit and a separate building permit (probably from two different offices) and eventually have two final inspections performed. In reality, many jurisdictions require installers to go through many more departments and undergo multiple inspections. Every department inquiry and inspection adds cost and time to the process of installing a system. Furthermore, it is expensive and time-consuming for installers to learn the ins and outs of local procedures when, two blocks down the road, another home may be subject to a completely different—yet equally complicated—process.

Cost isn't the only reason local jurisdictions should establish streamlined and effective permitting and inspection procedures, however. In some cases, inexperienced field inspectors can add cost and time to the installation process—due to either a lack of familiarity with PV systems or a misinterpretation of local codes. Similarly, confusing permits and diagram requirements may result in inaccurate information being reported by installers.

Model Permitting Standards

Solar ABCs

As solar PV prices become more competitive and adoption rates increase across the country, many industry groups, local governments, and even solar manufacturers have developed several key "living" standards meant to streamline permitting and inspection for rooftop PV systems. Most attempts to standardize focus on three major themes:

1. Simplifying permit documentation requirements for PV systems.
2. Establishing a streamlined process for certain PV systems.
3. Standardizing processes and procedures across jurisdictions to shorten learning curves for installers, inspectors, and local regulators.

Since the late 1990's, organizations such as the Interstate Renewable Energy Council (IREC), Pace University, the Sierra Club, SolarTech, and several state chapters of the Solar Energy Industries Association have been developing model processes aimed at reducing complexity and increasing standardization across jurisdictional boundaries. In 2009, the these organizations, in conjunction with the U.S. Department of Energy (DOE) and the National Renewable Energy Laboratory, reviewed and approved the "Expedited Permit Process for PV Systems." The process was prepared by the Solar America Board for Codes and Standards (Solar ABCs) as part of a DOE-funded collaborative effort among industry experts.

The Solar ABCs expedited permit process is an excellent framework for jurisdictions to consider—especially for those with nascent solar markets that are looking to prepare for future market growth. In addition to its short length, relative simplicity, and design for review by a single department within a jurisdiction, it includes a standard electrical diagram. This standardized diagram makes it possible for both the review and approval of permit package submissions to be quickly conducted "over the counter" or easily modified for online use.

RMI and the Solar Friendly Communities team recognize that many regions and jurisdictions across the United States have existing policies and requirements that limit their ability to adopt "Solar ABCs' Expedited Permit Process" in its entirety. However, at the very least, the process is capable of providing:

1. A consistent, easy to understand starting point for jurisdictions with little to no existing regulations or experience surrounding PV installations.
2. Template diagrams that can be used by installers as a standard for permit submissions.

Furthermore, given the ever-changing landscape of electricity standards, building codes, and other regulations, SolarABCs is continually updating the Expedited Permit Process and making it consistently and easily available online. In effect, as codes are updated (including complicated codes with recurring updates like the National Electrical Code), the Expedited Permit Process stays up-to-date and can be adapted to suit most local and national code changes.[5] [6]

Best Practices in Permitting

Incorporating the Solar ABCs expedited permit process isn't the only way to streamline solar permitting. As outlined by IREC's recently released *Sharing Success: Emerging Approaches to Efficient Rooftop Solar Permitting*, many jurisdictions have developed innovative systems—usually based on their existing building permit—that streamline permitting and make life easier for both the solar industry and local government.[7] Innovative examples can be found across the country:

- In Philadelphia, standard systems that meet certain criteria under 10 kW in size are exempt from the building review process that normally applies to all systems.
- Several cities including Denver, San Jose, and Portland have solar-specific websites that walk potential customers and new installers through local jurisdictions' solar permitting process and required documentation. Smaller, resource-constrained jurisdictions like Boulder County, Colorado take a different route by regularly communicating code changes or updates to the local solar industry via email.
- Miami-Dade County in Florida has a unique solar-specific roof permit.
- In addition to offering over the counter same-day permit review, the cities of San Francisco and Sacramento are currently rolling-out online permitting systems that have the potential to greatly reduce permit-related labor costs.

More information can be found on these examples and more at the IREC website or on solar30.org, a DOE-funded website with a number of resources for interested local governments.[8]

Model Inspection Guidelines

Although efforts to expedite and improve permitting processes have been widespread, somewhat less focus has been placed on field inspection standards, training, and guidelines. Efforts to aggregate guidelines and field inspection best practices are ongoing (one such effort has produced a comprehensive step-by-step guidebook for PV field inspection by IREC and Brooks Engineering[9]). Such resources can help jurisdictions both codify their inspection procedures and provide guidance for inspectors in the field. Most model inspection guidelines address the following issues that are common in jurisdictions across the U.S.:

— Site plan review requirements

[5] For more information on the SolarABCs Expedited Permitting Process, see: http://www.solarabcs.org/about/publications/reports/expedited-permit/

[6] See Appendix for examples of the Expedited Permit Process.

[7] Stanfield, Sky, Schroeder, Erica and Thad Culley. *Sharing Success. Emerging Approaches to Efficient Rooftop Solar Permitting*. Interstate Renewable Energy Council, Inc. 2012. Available from: www.irecusa.org/wp-content/uploads/Sharing-Success-final-version.pdf

[8] See http://www.irec.org and http://www.solar30.org/toolbox/permitting for more information.

[9] Brooks Engineering. *Field Inspection Guidelines for PV Systems*. Interstate Renewable Energy Council. Vacaville, CA: June 2010. Available from: http://www.irecusa.org/2010/07/irec-releases-2010-edition-of-its-field-inspection-guidelines-for-pv-systems/

- Some jurisdictions require detailed site plan drawings (as depicted in Appendix A) while others allow for simpler, lower-cost approaches to site planning.[10]

— Rough-in inspection requirements
  - Many local inspection guidelines are vague about how complete a system can be prior to or during rough inspection (e.g., half of a project's racking system must be exposed and clear of modules for inspection). Clarifying and simplifying these rules can help installers meet inspection requirements more often.

— Inspection window of time
  - Leading jurisdictions notify installers with a half hour call-ahead for inspection times. Less experienced jurisdictions often specify a four to eight hour window when an inspection will take place, adding significant labor costs to the installation.

— Congruent inspector expectations and training
  - Field inspections can differ drastically from inspector to inspector. Code official training to establish congruent PV inspection practices can greatly improve the efficiency and safety of jurisdiction-specific inspection procedures.

— Ongoing inspector education
  - Considering the pace of innovation throughout the PV industry, ongoing efforts to update inspectors on new technologies and their electrical and/or mechanical treatment are needed (e.g. self-grounding systems and microinverter-based AC modules).

— Number of inspections
  - Jurisdictions with combined building, zoning, and electrical inspection procedures that require a single, all inclusive field inspection of a PV system are usually highly efficient and cost effective.

Many of these training and inspector education-oriented approaches are currently being delivered through DOE-funded programs, including Solar 3.0, a resource hub that will provide in-person code official trainings, webinars, safety presentations, and educational materials for use by jurisdictions throughout the country.[11]

Interconnection

Interconnection standards are comprised of the legal, technical, and procedural requirements that customers, installers, and utilities must follow when connecting a distributed generator (DG) to the grid. Most interconnection procedures are developed and implemented at the state level by either a public utility commission or state government (in Colorado, for example, interconnection requirements are largely set by the Colorado Public Utility Commission). Except in some select leading municipalities, interconnection is handled separately from the permitting process.

[10] Such approaches include simple Google maps or Google earth-based imaging of the project site.
[11] See http://www.solar30.org for more information.

Interconnection procedures can hamper PV growth in three main ways. First, labor hours are spent preparing for and meeting interconnection requirements. Second, many interconnection regimes require fees to recapture the costs of connecting distributed generators to the grid. Third, inefficient interconnection procedures add days and even weeks to the installation process, significantly slowing installation cycles and in many cases adding costs to the process.

Prior to 2000, few states had adopted all-encompassing rules for the interconnection of distributed generators of any size. Until that point, most utilities defaulted to rules contained by the Public Utility Regulatory Policies Act (PURPA) of 1978. Under PURPA, generating facilities under 80 megawatts in size were designated "qualifying facilities" and made eligible to receive special rate and regulatory treatment. In other words, a 5 kW rooftop PV system would be subjected to the same regulation and review as a 10 MW geothermal plant, because PURPA did little to officially expedite the interconnection process for small-distributed generators. This was the case until the early 2000s when two major developments took place.

First, the Institute of Electrical and Electronic Engineers (IEEE) finalized IEEE 1547, the Standard for Interconnecting Distributed resources with electric power systems. Second, the Federal Energy Regulatory Commission (FERC) issued order 2006 that created the Small Generator Interconnection Procedure (SGIP). This procedure and its standardized documents are commonly used to interconnect systems over 2 MW in size to the grid and have served as a template for utility commissions to develop their own slightly modified interconnection processes for distributed generators of all sizes.

Since then, different states and public utility commissions throughout the U.S have adopted varying model interconnection procedures, many of them based on SGIP. It is worth noting that because the Colorado-based Solar Friendly Communities project is focused on local government initiative, the program's ability to impact interconnection procedures may be somewhat limited, especially when crafting recommendations for communities served by Colorado's major Investor Owned Utility (IOU), Xcel energy.

Model Interconnection Standards

The three major interconnection standards applicable to distributed PV systems under 2 MW in size are outlined below:

— California Rule 21 — This rule currently governs the interconnection of most rooftop PV systems in the U.S. thanks to California's majority share of the PV market. Rule 21 outlines standard interconnection, operating, and metering requirements for distributed generators that interconnect to the distribution system of a California Public Utilities Commission-governed utility. Accordingly, three different variants of Rule 21 are in effect throughout California that reflect the different requirements of the three major public utilities. Several municipal utilities within California have also adopted interconnection procedures modeled after Rule 21. Importantly, net-meter capable systems under 1 MW in size are exempt from interconnection fees and can qualify for simplified interconnection procedures to speed up the process. To better understand the decision making processes and engineering requirements behind Rule 21, see figure 2 below.

Rule 21 Interconnection Process and Logic Tree

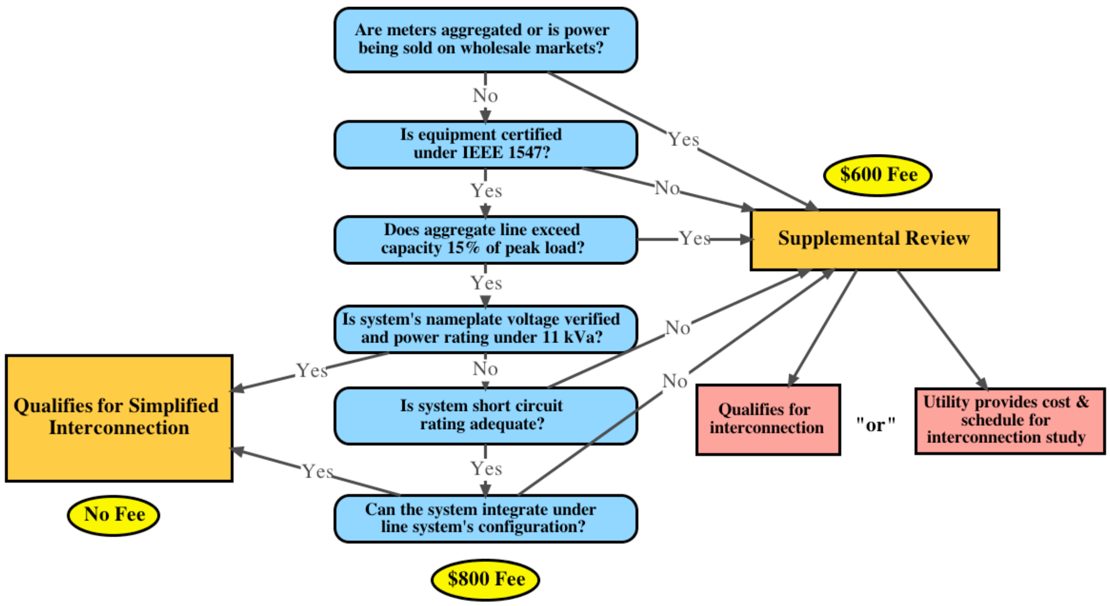

Figure 3 California's Rule 21 Interconnection Screening Process[12]

—Mid Atlantic Demand Resource Interconnection Procedures (MADRI) —
The MADRI procedures were created by a collaborative of several east coast utility commissions, the PJM interconnection, and FERC as an alternative to the SGIP. Development of MADRI largely excluded non-utility industry members, resulting in some sub-par procedures including very long contract length, high interconnection fees, and uneven treatment of non-inverter based systems. However, the MADRI procedures were developed only as a model for state utility commissions to modify for adoption as they saw fit. They have been successfully adopted and implemented in Illinois and Oregon and, according to some, are among the best interconnection procedures in the U.S. This is largely because the MADRI procedures provide a large suite of options for state regulators to consider, making them very amiable for different requirements between state governments and utility commissions.

—Interstate Renewable Energy Council Model Interconnection Procedures—
Throughout the development of Rule 21, SGIP, and MADRI, IREC has been involved in the creation of dozens of interconnection procedures in several different states. The IREC procedures are a model interconnection standard that combine the best components of the existing interconnection standards discussed above to create a standard that's friendly towards interconnection of distributed systems. Of particular note is IREC's treatment of inverter-based systems smaller

[12] Endecon Engineering. *California Rule 21 Overview.* Presentation by Endecon Engineering. October, 2003. Available from: www1.eere.energy.gov/solar/pdfs/19_brooks.pdf

than 10 kW, allowing them to undergo an expedited review process and prohibiting utilities from requiring a second external disconnect switch for smaller systems. Compared to the other major interconnection standards, the IREC model interconnection procedure is easier to understand thanks to its direct language and short length.

For these reasons, we recommend interested governments and local utilities look to the IREC Model Interconnection Procedures for guidance when developing new or changing interconnection standards.[13] For a more exhaustive exploration of the key interconnection standards discussed above, we recommend exploring SolarABCs excellent summary work on the topic.[14]

Net Metering

While interconnection standards establish the technical requirements and legal procedures whereby a distributed generator connects with the grid, net metering standards represent the billing arrangement between DG customers and utilities that allows customers to capture value from excess electricity generation.[15] Net metering regimes primarily differ across states and utility territories in the following ways:

- Individual system size limits in net metering programs
- Total program capacity limits
- Restrictions on billing rollover (i.e., monthly or annual)
- Ownership of renewable energy certificates
- Payment multipliers for special projects including community solar gardens or virtually net metered projects
- Eligible customers (residential and/or commercial) and technology
- Net metering charges including standby and network use charges
- Treatment of third-party-owned systems
- Safe harbor provisions to protect DG against additional net metering charges

Net metering rules and design can drastically affect the return on investment in DG systems. High network use or standby charges placed on solar systems by utilities can negatively impact otherwise profitable investments. Conservative net metering program capacities of 5% or less of peak load severely limit the amount of DG that can be added to a utility's system. Furthermore, exemption of third party owned systems from participation in net metering programs restricts the ability of well-capitalized installers and developers to expand into new markets.

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[13] See Appendix B for an overview of the IREC Model Interconnection Procedures.
[14] Interstate Renewable Energy Council and Solar ABCs. *Comparison of the Four Leading Small Generator Interconnection Procedures.* October 2008. Available from: http://www.solarabcs.org/about/publications/reports/interconnection/.
[15] Laurel Varnado and Michael Sheehan. *Connecting to the Grid*. Interstate Renewable Energy Council. 2009. Available at: http://www.irecusa.org/2009/10/irec-releases-the-6th-edition-of-its-connecting-to-the-grid-guide/

On the flipside, net metering can create problems for utilities too. Crediting customer accounts on a monthly basis—especially for virtually net-metered projects where customers receive credit on their utility bills for off-site projects—increases administrative costs. Distribution-level feeder circuits saturated with high levels of intermittent generation are still being studied and may represent a technical risk when generation from such systems reaches more than roughly one-third of feeder level load—especially in the absence of advanced controls.[16] Most importantly, net metering programs that reimburse customers at full retail rates may not account for all of the costs and benefits of distributed generation.

When designing or changing net metering regimes, a full analysis on both the values and costs of distributed generation must be conducted. Any analysis of such costs and benefits should consider—on a case-by-case basis—existing rate structure design, utility cost recovery mechanisms, transmission and distribution line congestion issues, and DG's ability to shave peak loads.

Model Net Metering Design Criteria

Although net metering standards are constantly evolving (especially in California, where both Rule 21 and net metering standards are entering into a transition period as rooftop solar supplies an increasing share of the state's electricity), several best practices and key design criteria have emerged that are applicable across state boundaries.

IREC and the Network for New Energy Choices (NNEC) use a rating system to assess both net metering and interconnection standards across the U.S.[17] Their rating system and report provides a broad overview of net metering standards from around the country and grades them accordingly. We recommend considering NNEC's rating system and design criteria when developing net metering standards and policy. For another resource, SolarABCs has also developed a generalized approach for states and utilities to analyze potential rate impacts of net metering.[18]

These recommendations come with one caveat: while the NNEC criteria for net-metering standards and the SolarABCs approach are good starting points, their approaches tend to marginalize the challenges faced by the traditional utility in a world with an increasing amount of DG.

RMI's recent collaboration with a major California utility may shed some light on this dynamic. Along with Pacific Gas and Electric, we analyzed the issues that arise from a combination of aggressive net metering policies, explosive growth in

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[16] For more information on technical limits at the feeder level, see Coddington et al. *Updating Interconnection Screens for PV System Integration*. National Renewable Energy Laboratory. January 2012. Available from: www.nrel.gov/docs/fy12osti/54063.pdf

[17] Network for New Energy Choices. *Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures*. October 2011. Available from: www.newenergychoices.org/uploads/FreeingTheGrid2011.pdf

[18] Interstate Renewable Energy Council and Solar ABCs. *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*. January 2012. Available from: http://solarabcs.org/about/publications/reports/rateimpact/index.html

rooftop PV solar, and existing utility solar business models.[19] As we discovered in this collaboration, rating systems like the NNEC criteria largely ignore the services provided by a traditional utility, including backup storage and transmission and distribution services. However, it is worth noting that an increasing number of studies show a net benefit from the existence of net metering-supported distributed generation on utility networks, especially when distributed generation accounts for less than one-third of regional electricity generation.[20]

Existing Policies and Standards in Colorado

With over 45 MW of new installations reported in the fourth quarter of 2011 alone, Colorado is quickly becoming one of the U.S.' leading solar markets. Colorado has developed and implemented a number of state-wide, solar-friendly policies to help drive market growth, resulting in 24 watts of solar power per person in 2010—making Colorado the state with the fifth highest per capita installed capacity in the U.S.[21] In addition, several communities throughout the state have taken steps to reduce PV costs even further through incentive-based programs and customer education campaigns. Relevant statewide standards, programs, and policies are outlined below.

Permitting

Permitting and inspection varies substantially across local government jurisdictions in Colorado, but HB 1199 passed in 2011 placed strict controls on permitting fees for residential and commercial rooftop PV installations across the state. HB 1199, the Fair Permit Act, established accounting procedures that limit permit fees to $500 for residential systems and $1,000 for commercial systems under 2 MW in size. The law applies to both solar thermal and PV systems. It also provides protection for systems above 2 MW in size by establishing clear and consistent accounting standards for local jurisdictions to abide by when reviewing larger PV projects.

Interconnection and Net Metering

Colorado is widely recognized as a leader in solar-friendly interconnection and net metering standards. According to the NNEC scoring criteria for these two areas, Colorado is a top performer that competes for the highest possible rating with leading solar states like California and New Jersey. Colorado's current interconnection rule was adopted in 2005 and is largely based on FERC's SGIP standards. Further rulings in later years extended most interconnection requirements to large municipal utilities and electric cooperatives within

[19] See http://rmi.org/rmi_pge_adapting_utility_business_models for more information on this topic.
[20] Examples of such evidence include a recent debate in New Mexico and Lawrence Berkeley National Labs' recent analysis of high penetration renewables. Information on both can be found from the following resources: John Farrell. "Net Metering a Cost to Utilities, or a Benefit?" *CleanTechnica*. May 2012. Available from: http://cleantechnica.com/2012/05/21/net-metering-a-cost-to-utilities-or-a-benefit/; Andrew Mills and Ryan Wiser. *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California.* Lawrence Berkeley National Laboratory. June 2012. Available from: http://eetd.lbl.gov/EA/EMP
[21] Network for New Energy Choices, *Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures*.

Colorado. The state specifies three levels of interconnection for review with break points at 10 kW, 2 MW, and 10 MW.

In 2009, the Colorado legislature revisited existing net metering regulations and voted to remove their net metering cap of 2 MW. In place of the cap, now all systems sized up to 120% of annual on-site consumption are eligible for net metering. In many states, such net metering standards only apply to systems in the service area of IOUs. In contrast, Colorado's net metering standards go beyond the major IOU, Xcel, by requiring municipal utilities with more than 5,000 customers and all electricity cooperatives to offer net metering to their customers.[22] For IOU customers, net excess generation is credited to bills at the full retail rate from month to month indefinitely. Municipal utilities and cooperatives provide annual reimbursement to customers at rates set locally.

Other Policies and Standards in Colorado

Statewide Renewable Portfolio Standard (RPS)

Colorado has committed to meeting a renewable portfolio electricity generation standard based on the creation and trade of renewable energy certificates (RECs). IOUs must produce 30% of their electricity from renewable sources by 2020. The requirement for electricity cooperatives and municipal utilities serving over 40,000 customers is 10% by 2020.[23] In addition, 3% of retail sales in the area of an IOU in Colorado must be from distributed resources. Colorado's renewable portfolio standard also includes several multipliers for RECs that amplify their value in certain situations:

- Centralized in-state generators: 125%
- Community-based projects: 150%
- Solar PV in cooperative or municipal utility territory: 300%
- > 30 MW projects connected to cooperative or municipal utility grid: 200%

Xcel energy, Colorado's only IOU, has met most of their requirements under the distributed portion of the renewable portfolio standard through their well-subscribed Solar Rewards rebate program. Due to the program's widespread popularity, the program is being reviewed by Xcel and will be kept open subject to its future requirements.

HB 1342 – Community Solar Gardens

A law that sets Colorado apart from most other states is HB 1342, which allows for the construction of Community Solar Gardens. Customers that buy into gardens up to 2 MW in size with at least 10 subscribers are eligible to receive virtually net metered kWh credits on their utility bills in proportion to the size of their subscription.[24] The legislation also allows meters to be aggregated (something usually done on properties in rural areas like ranches and farms with

[22] For municipal utilities and cooperatives, the 120% rule does not apply. Instead, residential and commercial systems are capped at 10 and 25 KW respectively.
[23] Fort Collins, a member of the Colorado-based Rooftop Solar Challenge team, adopted a more aggressive standard. The municipal utility must procure 15% of its supply from renewable resources by 2017.
[24] Network for New Energy Choices, *Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures*

multiple buildings) and entered into a garden. Community Solar Garden subscribers must generally live in the county where the garden is located.[25]

Special Tax Treatment
In Colorado, all renewable energy systems are exempt from Colorado property, sales, and use taxes. Current rules do not remove local taxes, but do allow jurisdictions to do so on their own.

Solar Ready Homes
In 2009 a bill was signed into law to encourage construction of "solar ready homes" in Colorado.[26] The law requires homebuilders to offer homeowners either:

1. A solar PV or thermal system with their home
2. Pre-wiring or pre-plumbing for a solar PV or thermal system to be roughed-in prior to installation.

Builders are also required to provide customers with a list of solar thermal and electric installers in the area.

Fair Permit Act
Colorado's Fair Permit Act limits permitting fees for residential and commercial systems across the state. For systems up to 2 MW in size, local city and/or county governments cannot charge customers more than their actual costs or in excess of $500 for a residential application or $1,000 for a commercial application. For systems over 2 MW size, local governments can charge no more than what it actually costs the government to issue the permit.

Conclusion

Overcoming the procedural and administrative challenges that arise from having thousands of local governments and utilities individually responsible for setting local solar policies won't happen overnight. However, as outlined in this document, several model standards and process innovations currently at work in states across the U.S. can help local actors and, in some cases, state governments, create thriving and sustainable solar markets. Adoption—or at the very least consideration of these various model procedures, innovations, and policy design criteria—can help lower costs and reduce rooftop solar's added administrative burden on local governments.

As discussed above, many model standards and forward-thinking policy approaches are already in effect at the state level in Colorado. Thanks to a state congress that supports renewable energy, a well-designed interconnection regime, and DG-friendly net metering rules, the state is a leader when it comes to rooftop solar.

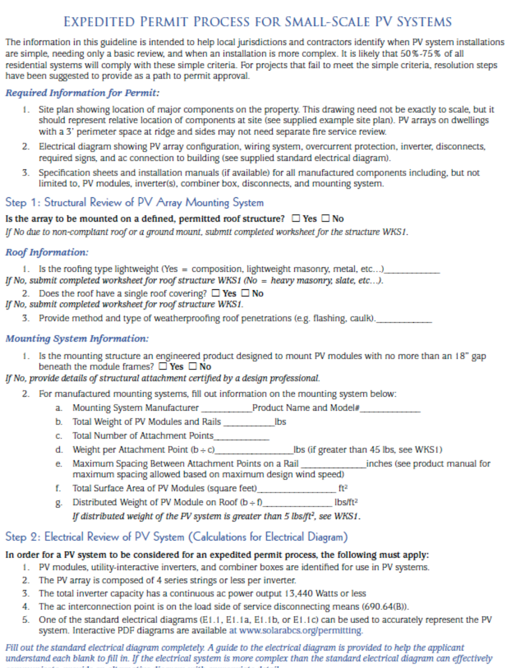
[25] In cases where a subscriber lives in a county with a population of less than 20,000, the garden may be situated within another county.
[26] U.S. Department of Energy SunShot Initiative. "Colorado Passes 'Solar Ready Homes' Legislation." May 2009. Available from: http://www1.eere.energy.gov/solar/sunshot/news_detail.html?news_id=12499

Leading state policies alone won't be enough to fully realize the potential of the Colorado solar market, however. Improved policies and practices must be adopted at the local level as well. It is worth noting that streamlined and efficient solar policies aren't just good for the solar market—they're good for communities too: as more and more customers become interested in rooftop solar, an increasing amount of pressure will be placed on local governments everywhere to be educated and proactive on the topic. It is our hope that five years from now we will be able to look across Colorado and write case study after case study on local government initiatives that helped to both knock down solar costs and enable market growth rates ten times faster than today's.

Appendix

Solar ABCs Expedited Permit Process for Small-Scale PV Systems

Solar ABCs expedited permitting process differentiates systems by size and other criteria in order to allow for quick and efficient approval of small-scale PV systems. For jurisdictions that adopt the Solar ABCs expedited process, forms can be filled out electronically and submitted either in person or via email. For a normal residential or small commercial PV system, the permit is only four pages long. For rooftops that do not meet the permit's baseline criteria, the process requires additional worksheets to be completed that supply more granular detail on the project's roofing material and structure. The screenshots below are taken from the four-page permit.



Expedited Permit Process for Small-Scale PV Systems

The information in this guideline is intended to help local jurisdictions and contractors identify when PV system installations are simple, needing only a basic review, and when an installation is more complex. It is likely that 50%-75% of all residential systems will comply with these simple criteria. For projects that fail to meet the simple criteria, resolution steps have been suggested to provide as a path to permit approval.

Required Information for Permit:

1. Site plan showing location of major components on the property. This drawing need not be exactly to scale, but it should represent relative location of components at site (see supplied example site plan). PV arrays on dwellings with a 3' perimeter space at ridge and sides may not need separate fire service review.
2. Electrical diagram showing PV array configuration, wiring system, overcurrent protection, inverter, disconnects, required signs, and ac connection to building (see supplied standard electrical diagram).
3. Specification sheets and installation manuals (if available) for all manufactured components including, but not limited to, PV modules, inverter(s), combiner box, disconnects, and mounting system.

Step 1: Structural Review of PV Array Mounting System

Is the array to be mounted on a defined, permitted roof structure? ☐ Yes ☐ No

If No due to non-compliant roof or a ground mount, submit completed worksheet for the structure WKS1.

Roof Information:

1. Is the roofing type lightweight (Yes = composition, lightweight masonry, metal, etc...)____________

If No, submit completed worksheet for roof structure WKS1 (No = heavy masonry, slate, etc...).

2. Does the roof have a single roof covering? ☐ **Yes** ☐ **No**

If No, submit completed worksheet for roof structure WKS1.

3. Provide method and type of weatherproofing roof penetrations (e.g. flashing, caulk).____________

Mounting System Information:

1. Is the mounting structure an engineered product designed to mount PV modules with no more than an 18" gap beneath the module frames? ☐ **Yes** ☐ **No**

If No, provide details of structural attachment certified by a design professional.

2. For manufactured mounting systems, fill out information on the mounting system below:
   a. Mounting System Manufacturer ___________Product Name and Model#_____________
   b. Total Weight of PV Modules and Rails ___________lbs
   c. Total Number of Attachment Points____________
   d. Weight per Attachment Point (b ÷ c)_________________lbs (if greater than 45 lbs, see WKS1)
   e. Maximum Spacing Between Attachment Points on a Rail ______________inches (see product manual for maximum spacing allowed based on maximum design wind speed)
   f. Total Surface Area of PV Modules (square feet)_________________ ft^2
   g. Distributed Weight of PV Module on Roof (b ÷ f)_______________ lbs/ft^2

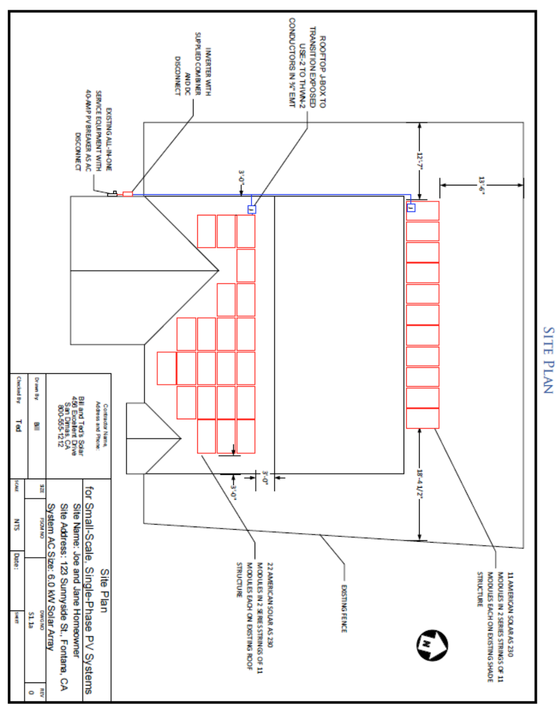
   If distributed weight of the PV system is greater than 5 lbs/ft^2, see WKS1.

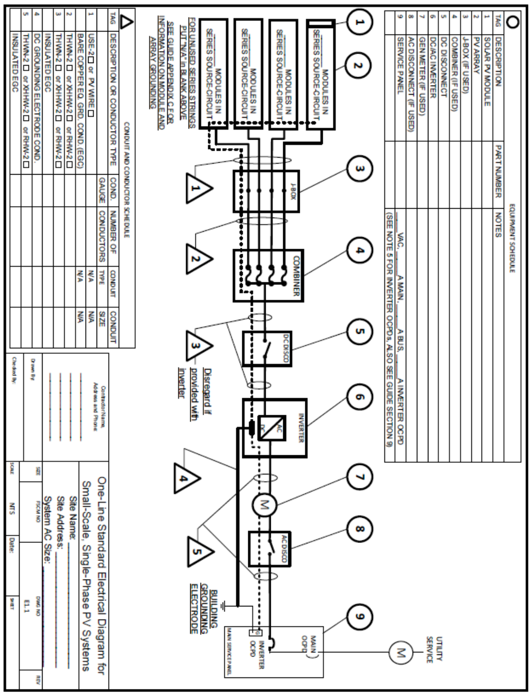
Step 2: Electrical Review of PV System (Calculations for Electrical Diagram)

In order for a PV system to be considered for an expedited permit process, the following must apply:

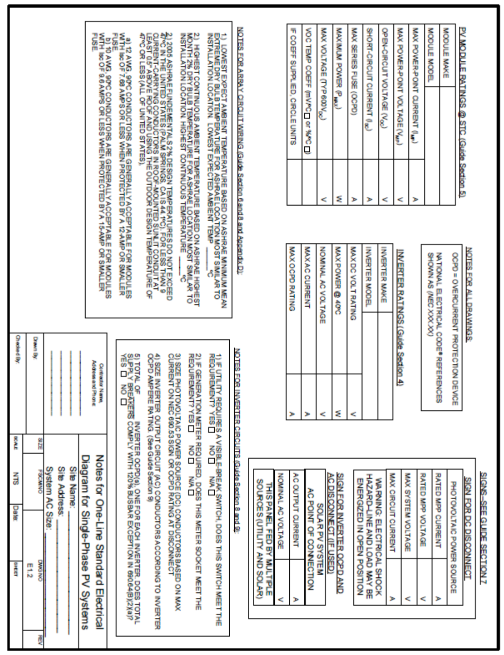
1. PV modules, utility-interactive inverters, and combiner boxes are identified for use in PV systems.
2. The PV array is composed of 4 series strings or less per inverter.
3. The total inverter capacity has a continuous ac power output 13,440 Watts or less
4. The ac interconnection point is on the load side of service disconnecting means (690.64(B)).
5. One of the standard electrical diagrams (E1.1, E1.1a, E1.1b, or E1.1c) can be used to accurately represent the PV system. Interactive PDF diagrams are available at www.solarabcs.org/permitting.

Fill out the standard electrical diagram completely. A guide to the electrical diagram is provided to help the applicant understand each blank to fill in. If the electrical system is more complex than the standard electrical diagram can effectively communicate, provide an alternative diagram with appropriate detail.





STANDARD ELECTRICAL DIAGRAM



NOTES FOR ELECTRICAL DIAGRAM

IREC Model Interconnection Procedures

The IREC Model Interconnection Procedures have three different breakpoints at 25 kW, 2 MW, 10MW. While the interconnection process for systems larger than 25 kW is extensive, the actual information required for interconnection of a 25 kW system or smaller is only two pages long. Below are screenshots of the two page “level one” interconnection agreement drafted by IREC. It should be noted that these two pages are followed by additional attachments that include key terms and conditions.

IREC 2009 Model Interconnection Procedures

Attachment 1: Level 1 Application and Interconnection Agreement for Inverter-Based Generating Facilities Not Greater than 25 kW

This Application is complete when it provides all applicable and correct information required below and includes a one-line diagram if required by the Utility and a Processing Fee of $20 if required by the Utility.

Applicant:
Name: ______
Address: ______
City, State, Zip: ______
Telephone (Day): ______ (Evening): ______
Fax: ______ E-Mail Address: ______
Utility Customer Number: ______
Electricity Provider (if different from Utility): ______

Contact: (if different from Applicant)
Name: ______
Address: ______
City, State, Zip: ______
Telephone (Day): ______ (Evening): ______
Fax: ______ E-Mail Address: ______

Generating Facility:
Location (if different from above): ______
Facility Owner (include percent ownership by any electric utility): ______

Inverter Manufacturer: Model: ______
Nameplate Rating: (kW) (kVA) (AC Volts) ______
Single Phase ______ Three Phase ______ (check one)
System Design Capacity: ______ (kW) ______ (kVA)
Prime Mover: Photovoltaic / Turbine/ Fuel Cell / Other (describe) ______
Energy Source: Solar / Wind / Hydro / Other (describe) ______

IREC 2009 Model Interconnection Procedures

Is the equipment UL1741 Listed? Yes ______ No ______
If Yes, attach evidence of UL1741 listing.

Estimated Installation Date: ______ Estimated In-Service Date: ______

List components of the Interconnection Equipment Package that are certified:

	Equipment Type	Certifying Entity
1.	______	______
2.	______	______
3.	______	______

If required by the Utility, attach a one-line diagram of the Generating Facility.

Applicant Signature
I hereby certify that, to the best of my knowledge, the information provided in this application is true. I agree to abide by the terms and conditions for a Level 1 Interconnection Agreement, provided on the following pages.

Signed: ______
Title: ______ Date: ______

Operation is contingent on Utility approval to interconnect the Generating Facility.

Utility Signature
Interconnection of the Generating Facility is approved contingent upon the terms and conditions for a Level 1 Interconnection Agreement, provided on the following pages (“Agreement”).

Utility Signature: ______
Title: ______ Date: ______
Application ID number: ______

Utility waives inspection/witness test? Yes ______ No ______