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WHOLESALE DISTRIBUTED GENERATION (WDG)

A guide to creating a successful solar WDG program

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I. Introduction

The purpose of this paper is to provide guidance that will help policy-makers, market participants and other interested stakeholders develop successful renewable distributed generation programs within wholesale electricity markets in the United States. This paper can serve as a guide that presents a decision tree to help identify and promote best practices for creating effective solar wholesale distributed generation (WDG) programs.

Drawing on California's, and to a lesser extent Arizona's recent experiences, the paper describes issues and potential solutions for designing state and utility programs that will create effective wholesale market opportunities for solar WDG under approximately 20 megawatts ("MW") sold directly to the utility. Regulatory bodies and state legislatures around the United States are considering plans to encourage utilities to ramp up solar WDG purchases because of the potential for WDG to achieve renewable energy goals with greater speed, less risk and lower system costs than large-scale renewable projects. We hope that this paper helps regulators create the most successful programs possible.

II. Solar WDG Procurement in Context

Programs to bring online solar energy come in many forms. Most familiar perhaps are the "retail" side of the meter programs, such as solar energy incentive programs for customer-cited solar. In these programs the utility customers own or lease small-scale solar energy systems, and primarily use the energy to offset their own energy usage. Within many of these programs third party ownership of the generating facilities is allowed. A portion of the power from those small-scale systems may be exported back to the grid for other customers to use through net metering, but in general the energy is used onsite. On the "wholesale" side of the meter, utilities have typically sought to procure large-scale solar energy in renewables-only, or solar-only Requests for Proposals (RFPs). These RFPs are generally driven by Renewable Portfolio Standard ("RPS") requirements or other state mandates. However, the cost, complexity, length and uncertainty of the traditional RFP process has led regulators to consider other procurement options to bring online solar projects that are too small to secure a significant market presence under traditional utility wholesale procurement practices and too large to be well-suited for retail customer programs.

III. Benefits and Goals of Solar WDG Program Goals

A. Benefits

Wholesale Distributed Generation programs provide numerous environmental and economic benefits to utilities and their customers. WDG can generally be located closer to load, reducing congestion, line losses and overall greenhouse gas ("GHG") emissions for a utility. By geographically dispersing renewable resources, the aggregate WDG output is less affected by climate fluctuations at any single location, thereby reducing grid integration costs and enhancing reliability. WDG technologies, particularly solar, have also experienced declining prices, allowing for a more positive financial outlook than was once thought possible.[i] While the goals for a WDG program may vary somewhat based on local market conditions and state policy objectives, three are fundamental to the creation of a sound WDG program: rapid resource deployment, least cost project pricing, and creation of financially viable long-term WDG markets. The remainder of this section discusses each of these goals in turn.

B. Goals

a) Encourage rapid deployment of WDG

One of the primary goals for nearly every WDG program is to encourage rapid deployment of WDG in order to speed achievement of renewable energy and GHG reduction goals. WDG projects sized below 20 MW generally can connect at distribution voltages (69 kV and below) and can potentially use existing transmission and distribution ("T&D") infrastructure, thereby potentially reducing the need for complex transmission studies, queuing processes, and grid upgrades often associated with large-scale projects. Many solar WDG facilities additionally have flexible siting options, and can take advantage of locations such as rooftops, parking lots and already-disturbed land[ii], which helps to minimize environmental impacts and shorten permitting timelines. All of these factors generally speed the planning and deployment process for WDG projects.

b) Least possible cost to utility customers

The second key program goal is to achieve this accelerated resource development at the least possible cost to utility customers through economically efficient pricing. Getting the price right is important for the well being of retail customers and solar WDG facilities. Like other renewable generation programs, WDG provides important benefits for retail customers by diversifying utility generation portfolios;

providing business and economic development benefits; reducing dependence on fossil fuels and hedging against their price volatility; reducing GHG emissions; improving air quality, and improving the health of low-income communities historically impacted by fossil fuel generation. According to the California Energy Commission, in the right circumstances, distributed generation located close to electricity loads can reduce or eliminate the need for transmission and distribution infrastructure.[iii]

Solar WDG projects have often been considered more costly than large-scale renewable projects because of higher transaction costs and lack of economies of scale.[iv] Higher costs form a significant obstacle to solar WDG deployment, particularly in today's troubled economy, which is why cost reduction is a primary goal of WDG programs. Early experience with California's WDG programs demonstrates that this goal can be reached: All contracts signed under Southern California Edison's 2010 Renewable Standard Contract program featured prices below the 2009 proxy market price based on the costs of a new natural gas combined cycle plant.[v] Moreover, the weighted average of the ***highest*** executed contracts resulting from the California investor-owned utilities' ("IOU") initial solicitations under California's RAM program was $89.23/MWh -- lower than the 2011 market proxy price.[vi]

Correct pricing is necessary to the long-term health of solar WDG markets. In order to create financially viable renewable generation development, in the near term, a program must encourage market penetration of currently available renewables technologies. Over the long term, the program should promote technological advancement of renewables that can compete directly against conventional generation without the need for subsidies or quotas. While this could mean paying renewable projects prices that are higher than conventional generation prices in some markets and for some types of projects, the pricing subsidies should be no higher than necessary for projects to attain a reasonable price and secure financing. Inflated prices could result in ratepayer backlash, withdrawal of public support for renewable development, premature termination of renewable development programs, and turmoil in renewable markets. Overly high prices could also promote greater tolerance for less efficient projects and delay the learning curve that drives cost reductions.

c) Create robust and sustainable renewable generation markets

The third fundamental program goal is to create robust and sustainable renewable generation markets. Achieving this goal requires not only renewable technology investment and deployment, but also a complementary dissemination of knowledge throughout the entire energy market. Renewable

developers need ample market opportunities in order to accelerate labor and managerial learning, technology and process improvement, product standardization, and create economies of scale. . Persistent and iterative experience with renewable generation will also encourage utility management, transmission and distribution planners and engineers grid operators, financial institutions, equipment suppliers and state regulators and policy makers to adapt their current approaches to electricity procurement and system planning and operation as required for high penetration of distributed renewable resources. The creation of consistent, predictable, and repeated market opportunities over a sufficient period of time will help drive cost reductions and develop self-sustaining solar WDG markets.

IV. Legal Constraints

State and utility WDG programs must be designed with an eye on the legal constraints imposed by federal law in two critical areas: federal jurisdiction over wholesale power prices and constitutional restrictions on state discrimination against out of state businesses. Neither constraint imposes insurmountable obstacles to the development of successful WDG programs, but federal jurisdiction in particular should be kept in mind during the design of the program to minimize the risk of legal challenges that delay or disrupt it. The purpose of this section of the paper is to help the reader understand the general nature of the legal issues and possible approaches for addressing them. *This is not intended as legal advice, and those who design a WDG program should work with knowledgeable lawyers to obtain specific advice about federal and state law requirements and their implications for the program.*

A. Federal Power Act

Generally speaking, states have a restricted ability to set wholesale power sale prices. Under the Federal Power Act ("FPA"), the Federal Energy Regulatory Commission ("FERC") has exclusive jurisdiction over sales of electric energy at wholesale in interstate commerce not expressly exempted by the FPA itself.[vii] Electric energy is deemed to be sold in interstate commerce if it is transmitted in interstate commerce or is commingled with electric energy that is transmitted in interstate commerce.[viii] All wholesale electrical sales in the continental United States outside of the Electric Reliability Council of Texas are "in interstate commerce"; including sales made entirely intrastate[ix] and sales delivered locally

to a distribution system.[x] FERC's jurisdiction includes exclusive authority over the rates charged for wholesale power sales. [xi]

The most significant exception to FERC's exclusive jurisdiction to set wholesale prices occurs under the Public Utility Regulatory Policies Act ("PURPA"), which allows states to establish rates for qualifying facilities ("QFs") consistent with FERC's avoided cost pricing rules.[xii] These rules prohibit states from forcing a utility to buy electricity at prices that exceed the utility's avoided costs. FERC rules define "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[xiii] In 1995, FERC ruled that California's determination of a standard offer contract price for QFs based on auction segments reserved for bids from QFs was inconsistent with FERC's interpretation of PURPA because those particular auctions did not take into account "all sources" of alternative energy.[xiv] In practice, this decision meant that states could not use their authority under PURPA to set wholesale prices aimed specifically at encouraging renewable generation because the QF avoided cost rate could not exceed the costs of the utility's conventional generation alternative. The avoided cost of conventional generation was almost always too low to attract significant amounts of renewable generation.

Recent FERC decisions, however, outline a new option for states to set avoided cost pricing at levels designed to encourage renewable development. In a series of decisions issued in 2010 and early 2011 addressing California efforts to establish feed-in tariff pricing, FERC clarified that states may base avoided cost rates on the costs of specific types of generation being avoided, such as renewable resources, if the state has required the utility to buy energy from that type of generating resource.[xv] This is a departure from the "all sources" requirement in earlier FERC precedent.[xvi] FERC's clarification opens the door for states with renewable generation procurement mandates to establish feed-in tariffs with avoided cost pricing tailored to the specific type of generation segment mandated by state law.[xvii]

Solar WDG programs that intend to use the avoided cost pricing approach clarified in these recent FERC decisions, however, must comply with other PURPA requirements, a fact which may temper the attractiveness of this approach. First, the administrative process required to set avoided cost prices could be lengthy and contentious. Second, participating generators have to be QFs, which are defined as either cogenerators that meet FERC efficiency standards or small power production facilities that

have a capacity of no greater than 80 MW and produce electricity from biomass, waste, renewable or geothermal resources. The participating generators also have to complete FERC paperwork required to secure QF status, although they can self-certify.[xviii] Third, FERC can terminate a utility's obligation to buy power from QFs if FERC finds that certain market conditions exist.[xix] However, FERC's termination authority should pose minimal risk for WDG programs aimed at projects that are 20 MW or smaller, since FERC rules establish a "rebuttable presumption" that QFs sized 20 MW net capacity or smaller lack nondiscriminatory access to wholesale markets.[xx] Until a utility can overcome this rebuttable presumption and move for relief at FERC, the requirement that an electric utility enter into new contracts or obligations to purchase from a QF remains in effect for that utility.

In addition to PURPA avoided-cost pricing authority, states have legal avenues to shape solar WDG programs in ways that avoid interfering with exclusive federal jurisdiction over wholesale electricity pricing. States have the authority to set resource-specific procurement targets and to regulate renewable generation products and attributes beyond electricity, capacity, and ancillary services. FERC has acknowledged that states have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction.[xxi] States may use this authority to direct utilities to purchase renewable energy from eligible renewable generators to achieve environmental goals or other policy objectives. States may also provide technology-specific incentives to generators and establish charges and exemptions to encourage technologies or applications that are environmentally beneficial or that benefit grid operations.

States also have jurisdiction to regulate and price renewable energy credits ("RECs")[xxii], as well as distribution costs and benefits, environmental attributes such as avoided GHG emissions, and other non-energy benefits or attributes created under state law. States may be able to use this authority to develop supplemental payments to compensate renewable generators for the value they provide beyond their energy, capacity and ancillary service products. While prior FERC decisions indicated that state-imposed adders are inconsistent with federal law unless they reflect "actual costs avoided," FERC's recent orders in *California Public Utilities Commission* clarify that a "state may separately provide additional compensation for environmental externalities," beyond the confines of PURPA, through RECs.[xxiii][xxiv] However, state authority to use RECs and non-energy adders in mandating compensation

for renewable energy purchases is a relatively new regulatory frontier, and the possibility of future legal challenge cannot be eliminated.

Finally, states may direct utilities to procure power from renewable generators through market-based mechanisms consistent with FERC rules.[xxv] California's utility PV programs and Renewable Auction Mechanism ("RAM") program are based on this approach.[xxvi] FERC lets wholesale sellers sell at market-based rates as an alternative to cost-based rates, provided that they seek and obtain FERC's authority, show that they do not have market power, and make regular reports to FERC.[xxvii] States may direct utilities to procure power from renewable generators through market-based mechanisms consistent with FERC rules.[xxviii] Market-based rates may be established in a variety of ways, including through competitive solicitations, organized markets, and bilateral negotiations. As long as the resulting prices fall within a broad "zone of reasonableness," and are "neither less than compensatory to the seller nor excessive to the consumer," FERC will deem the rates to be "just and reasonable."[xxix] States can direct utilities to undertake competitive solicitations producing market-based rates that meet FERC's tests and avoid any conflicts with FERC's jurisdiction.

B. Commerce Clause Considerations

WDG program eligibility restrictions that discriminate in-state projects over out-of-state projects run some risk of challenge under the United States Constitution's Dormant Commerce Clause. Since one attraction of WDG is its potential to use existing distribution system capacity and contribute to the local economy, a natural reaction would be to design program participation rules to guarantee capture of these benefits. This section provides a brief overview of Commerce Clause considerations so that well-meaning attempts to realize the potential benefits of WDG will not result in legal traps for the unwary.

The U.S. Supreme Court has established two lines of analysis in considering Dormant Commerce Clause challenges.[xxx] First, if a state law directly regulates or discriminates against interstate commerce, or if its effect is to favor in-state economic interests over out-of-state interests, the U. S. Supreme Court has held that it is subject to "strict scrutiny," and will be invalidated "unless the discrimination is demonstrably justified by a valid factor unrelated to economic protectionism," or the state "can demonstrate, under rigorous scrutiny, that it has no other means to advance a legitimate local

interest."[1] Second, under the "Pike test," a state statute that "regulates even-handedly to effectuate a legitimate local public interest" and that has only "incidental" effects on interstate commerce will be upheld "unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits."[2] Direct geographic in-state or in-region restrictions on project eligibility, or overt directives that the program be implemented in a discriminatory manner favoring in-state over out-of-state-interests could incite litigation and trigger "strict scrutiny" analysis. However, commentators have generally concurred that neutral, functional requirements present much lower risks of successful Commerce Clause challenge.[3] Functional requirements, such as in-state deliverability or interconnection, are facially neutral because any company, whether in or out-of-state, can meet these requirements.[xxxi] Legal challenges to a facially neutral functional requirement, such as in-state or service area deliverability or interconnection, would likely be reviewed under the "Pike" balancing test, rather than under the "strict scrutiny" test that is much harder to pass. To help bolster the defense of any such functional requirement adopted as part of a WDG program, the local public interest benefits associated with the requirement should be identified and explained when the program is created. For example, the decision adopting an in-state interconnection requirement could show, with support from the administrative record, how benefits such as minimizing T&D upgrades can be realized only through in-state distribution interconnections. For example, in the CPUC's RAM decision, the CPUC linked its decision to limit program eligibility to the utilities' service territories to the program objectives of using existing infrastructure, reducing the costs of T&D upgrades and line losses, avoiding the costs of transactions to firm and shape out-of-state renewable energy imports, and streamlining program administration by allowing bid evaluation to be based on price only.[xxxii] Other legitimate state interests could include enhanced reliability and supply diversity.

V. Over-arching Program Design: Tariff v. Competitive Auction

The key threshold question in designing a solar WDG program is how to set prices for the WDG

[1] *Wyoming v. Oklahoma*, 502 U.S. 437, 454-55 (1992).
[2] *Pike v. Bruce Church, Inc.,* 397 U.S. 137, 142 (1970).
[3] *See* Carolyn Elefant and Edward A. Holt, *The Commerce Clause and Implications for State Renewable Portfolio Standards Programs,* Clean Energy States Alliance State RPS Policy Report (March 2011), pp. 11-12.

products. One approach is to create a tariff with up-front prices that are set based on an administrative process. The other approach is to determine prices through a competitive auction or solicitation. This section discusses the advantages and disadvantages of each basic approach.[xxxiii]

A. Feed-In-Tariff

Vote Solar is in the process of developing a stand-alone document on the best practices in designing Feed-In-Tariffs for U.S. markets. The majority of this paper will focus on competitive auction mechanisms.

B. Auction Pros and Cons

Competitively set prices take advantage of market mechanisms to develop pricing aimed at achieving economically efficient results without the need for an administrative process to develop prices based on predictions of future market conditions and technology evolution. In place of administrative comments and testimony, an auction or solicitation gets market participants' assessment directly through competitive proposals. The competition to win an auction encourages efficient project siting and optimized energy production. Ongoing auctions will let prices adjust automatically to account for market changes and technological evolution, as bidders take these conditions into account in preparing bids and competing to win. The auction approach also avoids the recurring administrative proceedings that would be required to update administratively set prices. Over time, the competitive process should favor those developers with the greatest technological advantage and lowest installation costs through expanded market share, and weed-out less efficient developers. The auction approach should lead to economically efficient outcomes and meet renewable targets at the lowest possible costs to customers.

An auction approach is consistent with the legal constraints discussed below. States have the authority to direct utilities to procure renewable energy through an auction mechanism producing market-based rates that meet FERC's test. In California, to demonstrate compliance with FERC requirements and avoid any basis for arguing FERC jurisdictional conflict, as part of the renewable auction mechanism, the CPUC gave utilities the discretion to reject bids if evidence exists of market manipulation, or if prices are not competitive. A utility intending to exercise this discretion must provide justification through an

advice letter filing. According to the CPUC, the reserved utility right to reject bids strengthens the case for consistency with FERC jurisdiction.[xxxiv]

The high transaction costs of participation in an auction or utility solicitation have been cited as a barrier for developers of small renewable projects and a key justification for adopting a tariff approach in programs aimed at this market segment. As discussed earlier, transaction costs required to site and permit projects, select technology, secure financing and sharpen project economics are common to both the tariff and the auction approaches. However, auction participation may call for higher and more costly levels of developer sophistication and legal and financial support than participation in a tariff program. The difference can nonetheless be greatly reduced by use of standardized auction processes and contracts. But, standardization necessarily limits utility discretion and flexibility in procurement practices and therefore requires very careful upfront design. An auction approach could also encourage developers to submit unrealistically low prices, resulting in projects with high failure rates. Developing standardized programs will require significant investment of time by regulatory bodies, utilities and program participants. The procurement design will need to account for state- and utility- specific needs as well as local market conditions. Structured WDG programs can play an important role in the overall procurement of renewable energy, but will not right be for every project.

VI. Program Criteria

A. Size and Duration

A WDG program should offer market opportunities of sufficient volume and duration to make a meaningful contribution to the goal of creating robust and sustainable renewable generation markets. It should provide opportunities for multiple sellers and multiple transactions over a multi-year period. However, it should also be small enough to minimize the potential impact of unexpected adverse outcomes and higher than expected ratepayer costs. The program should be sized to match the state's overall renewable goals and utility portfolio needs.

The size of a program can be defined and measured in multiple ways. One option is to establish a revenue requirement for the program, and to authorize transactions until their combined costs reach that revenue requirement. A revenue requirement approach could, in theory, fine-tune the program

size consistent with goal of limiting customer subsidies. It could also enable a higher volume of transactions if their costs prove lower than expected. However, a revenue requirement would be complicated to set and track. Another option is to set MW limits. This approach is straightforward and easy to understand. However, it provides no protection against unacceptably high costs. Consequently, programs adopting MW sizing should consider incorporating other provisions that ward against higher-than-expected costs, such as shorter initial time durations, bid price caps or fail-safe program review triggers, as discussed in Section VII.

The program should last for at least two (2) years and preferably longer. Longer time periods would better serve program objectives of educating stakeholders and developing a viable WDG market. A two-year program may, however, suffice for an initial test.

California's statewide renewable auction mechanism program was initially sized at 1000 MW and is expected to last for approximately two years.[xxxv] The size and duration were intended to test the program and provide mitigation against potential adverse outcomes if the program needs adjustment. The decision adopting the program notes that if it succeeds, extensions can be authorized based on utility needs for the WDG products and relative costs of viable alternatives. The California utility-specific PV programs are expected to total up to 1100 MW and run for 5 years.[xxxvi]

B. Project Eligibility

The program must specify the size range, types of renewable technologies, ownership, development timeline, and viability screening criteria required for a project to be eligible to participate in the auction process.

1. Eligible Project Size

Project size eligibility should be set based on program goals and local market and system conditions. To achieve program goals of accelerating WDG development, participating projects should be small enough that they can be developed and brought on-line in a short time period, relative to large projects, (e.g., 18-24 months) with minimal permitting and siting problems. In addition, size limits should be established so that projects should generally be able to interconnect to existing T&D infrastructure without significant upgrades. The program should also encourage projects that can be sited close to

load centers. Increased transparency of the utility grid, localized loads, existing generation, and plans for upgrades and expansion will greatly aid achievement of the goal. Any size limits should be compatible with other state renewable programs.

Twenty MW has been viewed as a logical upper size limit. Under federal regulation, projects sized at or below 20 MW are presumed to have limited ability to access competitive markets.[xxxvii] They are also eligible for streamlined interconnection under the Federal Small Generator Interconnection Process.[xxxviii] Projects larger than 20 MW are more likely to require transmission-level interconnections. The magnitude of investment required for projects larger than 20 MW better justifies the higher initial transaction costs required to customize individualized procurement deals. Projects under 20 MW may have greater difficulty succeeding in solicitations open to large and small projects alike. These considerations led to the selection of 20 MW (based on nameplate capacity) as the upper size limit in California's WDG auction-based programs, although differing local conditions could point to the selection of an alternative limit. The Arizona Public Service Company ("APS") Small Generator Standard Offer Program targets projects up to 25,000 MWh per project, which equates to roughly 15 MW for a single-axis tracker PV system, or up to 18MW or so for a double axis tracker PV system.[xxxix]

A base or minimum size limit should also be set to ensure compatibility with existing state and local programs and to avoid having numerous small projects slow the auction process. California's WDG auction-based program initially selected 1 MW as the minimum size limit, while the APS program adopted 2 MW.[xl] California is now considering changing the minimum size limit for its RAM program from 1 MW to 3 MW in order to avoid overlap with its revised Feed-In Tariff program.[xli]

The imposition of size limits leads invariably to issues about whether projects are being disaggregated to fit under the upper limit, or aggregated to fit over the minimum limit. Programs should address these issues up front by providing basic definitions of what constitutes a "project." The rules should discourage developers from dividing large projects capable of participating in standard solicitations into smaller units just to fit within program eligibility rules. However, the rules should tolerate some level of aggregation, to take advantage of WDG's potential for siting flexibility. For example, California's RAM program allows the aggregation of projects sized 500 KW or greater to reach the 1 MW contract minimum.[xlii]

2. Eligible Renewable Technologies

Given program goals of accelerating WDG development while minimizing retail customer costs, the program should consider targeting commercial technologies, not research and development ("R&D") projects. Another question is whether the program should be technology neutral, or adopt technology-specific set-asides or quotas. While it is appropriate for utilities to signal the product they want to procure based on their portfolio needs, and to look at time-of-delivery profiles in evaluating bids, a program focused on accelerating renewable development at the lowest cost to ratepayers may want to be technology neutral. Technology-specific quotas have the ability to erode the market's ability to achieve economically competitive outcomes that meet renewable targets at lowest possible costs. Nonetheless, quotas may be a useful part of the program design in markets where more mature technologies with lower costs are displacing promising, but less mature technologies with higher costs, or in situations where quotas are necessary to achieve specific societal or environmental goals, such as conversion of agricultural waste to energy.

3. 'Winner-take-all' Restrictions

Programs may wish to consider adopting seller concentration limits to prevent one or a small group of developers from dominating auction outcomes. The desirability of these limits depends in part on local market conditions and program goals. If an objective of the program is to encourage new WDG market entrants or expand the number of participants, seller concentration limits may be appropriate. However, such restrictions could undercut the goal of securing economically efficient outcomes and minimizing retail customer costs. Accordingly, any seller concentrations should be justified and tailored to fit that purpose.

Another type of ownership restriction is a limitation or prohibition on unregulated corporate affiliate participation.[xliii] The need for utility affiliate restrictions depends on the strength of regulations against utility favoritism of affiliates and the dominance of these affiliates in relevant markets. California's WDG programs do not restrict utility affiliate participation; however, the APS small renewable generation program prohibits APS affiliates from bidding.[xliv]

Finally, program designers will need to determine whether to let utility-owned generation participate in the program. California's utility solar PV programs feature utility-owned generation as well as third party-owned generation procured through power purchase agreements, while the renewable auction program does not.

4. Development Timeline Requirements

The program should also set development timeline targets consistent with overall program goals. Timeline targets encourage rapid development of small renewable projects that can be brought on-line faster than larger projects because of their ability to use existing T&D infrastructure and avoid siting and permitting complexities that slow down larger projects. The timeline target should be aggressive, but achievable for projects that have completed initial development phase activities prior to submitting a bid. Suggested target timelines have ranged from 18 to 36 months from final contract regulatory approval to start of operation. California's renewable auction program initially adopted an 18-month development timeline from contract execution to commercial operation, which was quickly revised to alter the start date of the period from the date of contract execution to the date of CPUC approval of the contract.[xlv] The CPUC is now considering revising the development timeline requirement from 18 to 24 months based on the utilities' feedback from the initial solicitation that permitting and interconnection challenges resulting from the CAISO's cluster studies (discussed in more detail in Section X.B) are hindering project ability to meet an 18 month deadline and reducing the pool of eligible program participants.[xlvi] Thus, an important "lesson learned" from the California experience is the need to ensure that the procurement and development timelines are well-coordinated with interconnection timelines.

However, shortening the procurement timeline and imposing development deadlines do not necessarily shorten the overall project development timeline. From a developer's perspective, development timelines shift risk onto developers by requiring them to commit to significant development resources in advance of contracting, and then compound that risk by requiring that projects come online within a specified period, with limited contractual opportunities for extensions. Program designers should carefully weigh the desirability of rapid WDG development against the risks accelerated development timelines place on developers, particularly for their potential to higher bid prices to compensate for the risks, higher rates of project failures, or reduced developer participation.

The development timeline target should be subject to extension for good cause. Establishing a time extension requires making trade-offs between competing considerations. Time extensions for delays beyond developers' reasonable control are fair and reduce project risks (and therefore the costs of financing and investor risk premiums); however, abundant opportunities for extensions could hinder program goals of rapid WDG development. They could also crowd out projects capable of meeting development timeline targets without delay. The time extension provision also should define under what circumstances "good cause" exists for the extension. Reasonable grounds for a time extension could include force majeure or permit or interconnection delays beyond the reasonable control of the developer. The provision should also specify the time period of the delay extension in order to prevent indefinite project extensions that might hinder achievement of program goals. Extension periods equal to a quarter to a third of overall development timeline have been proposed. For example, programs with 18 to 24 month target development timelines might feature extension periods of 6 to 9 months per event, capped at 12 to 18 months on a total cumulative basis.

5. Project Viability Requirements

Strong project viability screening requirements should be considered for programs aimed at achieving accelerated WDG development and robust WDG markets. Non-viable projects can fill program capacity subscription and push out viable projects. If a program has low barriers to entry, such as limited development security requirements and minimal project maturity demonstrations, program participants may have less commitment to or less experience with actual development of their projects and submit proposal with overly optimistic assumptions. In such circumstances, conceptual projects may be submitted using underestimated interconnection and permitting costs and development timelines, and could prevail over projects bid with realistic assumptions. Over time, to avoid program failure, the purchasing utilities could be pressured to bailout developers that bid unrealistic contract prices and development schedules through post-contract renegotiation of prices and milestones. Such a program could ultimately reward inept or inefficient developers with unrealistic bids, penalize developers with realistic bids, impose higher program costs on customers, and lead to economically inefficient program outcomes.

On the other hand, stringent viability requirements could deter new market entrants and reduce developer participation. They could also result in development "bubbles" by requiring significant pre-

development in order to demonstrate viability in advance of contracting. Forcing developers to reach certain milestones in advance of contracting, such as submission of interconnection study requests, could result in unintended consequences, such as flooded interconnection queues. Requiring large fees and securities in order to bid could limit the number of potential bidders to only well capitalized companies. These trade-offs in program design should be resolved through careful consideration of local market conditions and focused attention on making the design achieve the policy makers' objectives.

Features aimed at deterring non-viable project participation, include: (1) pay-for-performance; (2) contractual development and performance security requirements, (3) viability screening as part of the bid evaluation, and (4) contractual project development milestones, with consequences for missed milestones.

Pay for performance means that the developer receives payment under the power purchase agreement only for energy deliveries from the WDG project. The developer receives no compensation if the project is not successfully developed, which is a powerful motivation for project completion and as well as a powerful protection against project failure for retail customers.

However, developers may also be motivated to win auctions through aggressive bidding in order to obtain a relatively low cost fixed-price option to build a project. To deter bids for unrealistic or high-risk projects, the program should consider requiring developers to post development security. The deposited security would either be returned to the developer at the start of project commercial operation or applied to the performance security, if required. The amount and timing of development security is likely to be controversial. Developers often want lower security requirements, as they must provide the security before contract payments begin. Utilities often want higher security requirements to increase the probability of project completion. Program designers must strike a balance between screening out speculative projects and reducing the pool of participants to just those who can afford to front high security deposits. Development security deposits have been initially set in the range of $20 to $30/kW. Initial amounts could be increased if the failure rates of winning bids are high, or lowered if policymakers believe doing so would expand program participation.[xlvii]

California's RPS solicitations, which are oriented towards large, utility-scale renewable projects, feature development security deposits ranging from $30/kW to $50/kW for intermittent resources and $60/kW to $100/kW for baseload resources. The California solar WDG programs have somewhat lower development security requirements. For SCE's Solar Photovoltaic Program, which targets facilities primarily in the 1-2 MW size range, the CPUC adopted a security deposit of $20/kW. In the PG&E Solar PV Program, the CPUC adopted a security deposit of $20/kW for projects less than 10 MW and $35/kW for projects 10 MW or greater. For the RAM program, the CPUC required a $20/kW development security deposit for projects 5 MW and smaller, and a $60/kW deposit for intermittent and $90/kW for baseload projects between 5 and 20 MW.[xlviii] For its 2011 renewable small generation RFP, APS added a development security requirement of $100/kW to increase the probability of selected projects reaching commercial operation.[xlix] These requirements are intended to minimize the submission of bids by developers with no real commitment to developing a project.

Viability screening can also include requirements to provide assurance that the developer can carry out its contract obligations if the project bid is accepted. Well-designed viability screening criteria should favor projects that can become operational within targeted development timeframes and promote informed, rational bids. They should discourage participation from "concept-only" projects that have not been sufficiently vetted for economic viability, permitting risks, interconnection costs, and development schedule. The screening criteria should encourage contract awards to projects that can effectively mitigate the constraints that slow down development of larger projects. Inclusion of project viability elements should be mandatory. Bid selection should not be based on price alone. However, given program goals to streamline program administration and reduce transaction costs, program project screening elements must be objective and easy for bidders with well-developed projects to satisfy as well as for utilities to administer. Elements of viability screening criteria that program designers could consider to meet these objectives include the following:

a) Site control

Site control is often required to demonstrating that project development has advanced beyond the conceptual stage. Site control could be shown based on submission of a short form or memorandum of an executed, binding contract for direct ownership, a lease commensurate with the power sale contract term, or an exclusive option to purchase or lease. Alternatively, program designers might require

affidavits from the project developer and site owner attesting to site control, with submission of long-form underlying site control contracts only for audits or under special circumstances.

b) Interconnection

Interconnection costs for small projects can vary widely. By demonstrating that it has obtained initial interconnection study results prior to bid submission, a developer shows that it has submitted a more credible bid based on well-defined interconnection costs and timing. Such a requirement would also prevent two parties from bidding the same finite and mutually exclusive capacity on the distribution system. But while submission of a completed initial interconnection feasibility or system impact study might be ideal for demonstrating viability, this requirement may overly restrict the supply of potential bidders, given problems with current interconnection processes. It could also place considerable financial risk on developers, who would have to front the money for a project interconnection study without knowing whether the project is selected. Reasonable alternatives could include requiring bidders to demonstrate project fast-track eligibility or submission of a complete interconnection application.

c) Development expertise

Developers who have experience developing successful, similar projects are more likely to submit realistic bids and meet contractual commitments. However, this factor is more subjective and harder to evaluate than those discussed above. Also, the program designers may want to encourage new market entrants and expand the potential bidder pool. Programs with this goal would wish to avoid overly demanding showings of developer expertise. The California renewable auction program requires that at least one member of the development team has either begun or completed construction of at least one project similar to the one being proposed.[l]

d) Technology

The viability screening criteria need to verify that the proposed technology is consistent with the program's project eligibility criteria.

e) Development Timeline

The project viability screening criteria could include a demonstration that the project has a realistic chance of meeting the program's target development timeline. However, such a demonstration can be subjective, and difficult for the utility to assess in a streamlined bid evaluation process. To avoid the need for subjective utility judgments, the program could require the developer to submit a proposed

schedule identifying key development milestone dates, which would then form the basis of contractual milestones as discussed below, which addresses contract terms. Failure to meet the milestones could result in the loss of the development security discussed above, which would provide additional incentive for developers to provide realistic milestone timelines.

For example, California's statewide renewable auction programs adopted the following viability screening criteria: demonstration of site control; demonstration of developer experience; deployment of commercialized technology; interconnection application filed prior to bid submission; ability for project to be operational within 18 months of contract approval; and tracking of project milestones.[li] APS modified its Small Generator Standard Offer Program in 2011 to increase the certainty that selected projects will reach commercial operation on schedule[lii] by imposing deadlines for signing interconnection study agreements and obtaining final study results. APS also requires demonstration of site control. Both programs require development as well as performance security[liii]

VII. Auction Design

In addition to supporting the basic program goals of accelerating WDG deployment, securing economically efficient results that minimize costs to customers, and developing a sustainable WDG market, important considerations in designing an auction include: protection against collusion or other market manipulation; fair and transparent auction outcomes; minimized administrative and transactional costs and timelines; familiarity to industry participants; and compatibility with existing wholesale energy and capacity markets. This section reviews the options for designing an auction with these objectives in mind.

A. Streamlined Process

Streamlining the WDG procurement process is essential to achieving program objectives. The auction should feature ways to simplify and standardize the processes of preparing and submitting bids, evaluating the bids and selecting the winners, and negotiating and obtaining regulatory approval of the resulting contracts in order to meet program goals. Auction elements should therefore be selected with the objective of simplifying and standardizing bid preparation and evaluation. Contracts with standard terms and conditions that can either not be modified, or which can be modified only within preset

parameters can assist in streamlining the program. Such contracts would need to be created and approved as part of process creating the renewable auction mechanism. Pre-approved, standardized contracts can avoid lengthy and expensive negotiations that slow development of large projects. They can also avoid the need for lengthy regulatory review of reasonableness of the terms and conditions of a negotiated agreement. Standardized contracts can also simplify bid evaluation by removing the need to evaluate exceptions to proposed contracts, and promote transparency and fairness by eliminating subjective negotiation judgments. On the other hand, standardized contracts eliminate utility discretion to adapt agreements to fit the needs of individual developers. They also require substantial up-front work in the regulatory process to achieve an appropriate allocation of risks and responsibilities between the utility and the developer. These competing considerations are discussed at more length in Section IX, below.

B. Auction Type

Two basic types of auctions have commonly been used in energy auctions. The first type is a discriminatory-price or "pay as bid" auction. This type of auction yields final prices that differ among buyers and depend on the amount of each buyer's bid. The second type is the uniform-price auction, which results in a single price for all transactions. The uniform price can be based on the highest accepted competitive bid (single-price auction) or the value of the highest rejected bid (second-price auction). The "pay as bid" and uniform-price auction formats are both relatively simple and transparent. The uniform-price auction form is used in most Independent System Operator ("ISO") electricity auctions.[liv] In theory, the bids in a uniform auction will reveal bidders' true values and will produce an efficient outcome. However, uniform-price auctions also may involve some embarrassment if some bidders with very low bids receive prices that are significantly higher than their bids. This may result in criticism that customers are overpaying for the renewable energy procured through the single-price auction. The choice between a "pay as bid" or uniform price auction should depend on the relative level of market participant familiarity and comfort with these auction types.

The number of rounds of bidding must also is determined. The choice is whether to allow one or multiple bid submissions before the final determination of the sale price is achieved. Single-round auctions are sometimes known as sealed-bid auctions, meaning that after the bidder submits a bid there is no further interaction and the bidder simply awaits an announced outcome. In contrast, a multiple

round auction involves interaction because the bidder has a chance to change the bid in response to information that is learned after each round. While the information disclosure featured in multiple round auctions may lead to more economically efficient outcomes, the process is more complex and time-consuming. Single-round bidding is more straightforward and also considered to be more resistant to collusion than multiple round bidding.[lv] As a result, single-round bidding may better match WDG program objectives of minimized transaction costs, transparency, collusion protection, and streamlined auction process.

C. Bid Price Cap

Program designers may consider adopting bid pricing caps in order to protect retail customers from higher-than-expected program costs. However, a price cap feature adds complexity to the program adoption process, since the basis for the cap has to be defined and a resulting price calculated. California's individual utility solar PV WDG programs imposed a price cap on bids for the power purchase agreements created under the programs based on the costs anticipated for the utility-owned PV plants constructed under the program. California's statewide renewable auction program did not adopt any bid price caps, but instead gave utilities discretion to reject bids they determine to be not cost competitive.[lvi]

D. Payment Type

Some wholesale markets feature separate capacity and energy markets, while others feature single unified prices for both products. In general, the program approach should be consistent with the existing wholesale market approach used in the program's market. Separate capacity and energy pricing offers the opportunity to set one component (i.e. capacity) through an auction and the other (i.e. energy) through conventional energy market prices, such as real-time or spot. More complex pricing may better reflect on-going market conditions, but could be harder to evaluate and administer. It could also reduce the pricing stability and predictability required for most renewable projects to be financed and completed.

E. Contract Term

In selecting the contract time period, program designers must balance the need to create the financial stability necessary to encourage investment with the risk of over-subsidizing projects and supporting those that become technologically obsolete or economically inefficient. The designers must also decide whether to adopt a single time period for all projects, which would simplify bid evaluation, or allow developers to pick among a set of options, which could better match project financing needs. Contract terms for procurement of new generation generally range from 10 to 30 years. California's statewide renewable auction program offers 20-year fixed-price contract terms; the APS renewable small generator program sets a 20 to 30 range for the contract term.

F. Auction Timing and Frequency

In setting the timing and frequency of the auctions, program designers should aim to create multiple transaction opportunities to obtain market feedback and accelerate market development, while minimizing transaction costs and streamlining auctions and bid selections. The timing of the auctions should be coordinated with interconnection process timelines, since interconnection costs and timing will be critical for project developers to submit informed, viable bids and meet program development timeline requirements. California's solar WDG programs have required auctions to be held once or twice a year. However, the first program out of the block, Southern California Edison Company's Solar PV Program, lagged in conducting its competitive solicitation process, apparently because of the time required to evaluate the outcome of its first solicitation and obtain regulatory approval for modifications in its subsequent solicitation. Holding auctions or solicitations once a year allows time for "lessons learned" to be incorporated in subsequent auction rounds, and may be useful in the first stage of the program as initial bugs are fixed and participants gain experience.

G. Auction Consistency between Utilities

Statewide uniformity among utility auctions reduces transaction costs for bidders, but may increases transaction costs for participating utilities, at least in the short-term when the program is being developed. Since utilities are generally better positioned to manage such costs, programs may seek to promote consistency among utility auction timing, evaluation criteria, and design, except to the extent differences are based on legitimate differences in utility infrastructure or procurement needs. Requiring utilities to hold their auctions simultaneously and allowing developers to bid the same projects in the

multiple solicitations may create greater competition from the developer's perspective, although it also imposes greater transactional burdens.

H. Auction Products

The program will have to specify the types of products eligible to be offered in the auction. Wholesale electricity products could include baseload, peaking or as-available energy and capacity. The products sought in an auction could be based on utility portfolio needs, but those needs may also be influenced by the relative attractiveness of the product bids. The program may require transfer of a project's REC and GHG attributes to the buyer together with the purchased energy and capacity, to the extent the value of renewable energy and the justification for prices that exceed conventional generation prices stems from those attributes. Separating RECs and GHG credits from energy is also complicated and may therefore conflict with the goal of streamlining auction process and transactions. The program's approach to capacity value should be consistent with the approach used in the wholesale market in which the program will operate. But, program designers should be wary whether existing market rules deal adequately with the capacity value of smaller projects. For example, California wholesale market rules regarding deliverability and resource adequacy initially resulted in zero capacity value being attributed to projects less than 20 MW.

I. Sales Options

While many prospective WDG developers will want to sell their full output to buyers under the program, some may want to sell only amounts that exceed what is used or sold at the project's site. The program should consider allowing both full buy/sell and excess sale options, particularly where no significant problems have been identified in QF programs featuring both options, since greater optionality can provide more flexibility for developers.

J. Auction Monitoring and "Governor" Mechanisms

Programs should consider incorporating on-going monitoring and reporting features, and "governor" mechanisms to make adjustments as required to achieve program objectives. The WDG market will change both on its own and in response to program and other renewable policies that have introduced new market features and incentives. Static programs risk becoming ineffective or counterproductive,

especially if the law of unintended consequences takes hold. A program should also monitor and provide reports regarding utility administration in order to ensure fairness and contract compliance. Even if a program works entirely as intended, one of its objectives is to accelerate market learning and experience, which on-going monitoring and reporting will facilitate. In general, a "governor" mechanism should be forward-looking to avoid upsetting investor expectations and project financibility, and undermining the basic program goal of creating robust and sustainable WDG markets.

California's statewide renewable auction program requires the use of an Independent Evaluator ("IE") unconnected to any market participant to monitor auctions. The IE monitors negotiations and submits a report reviewing the outcomes and assessing their reasonableness, which is used in the regulatory process for approving the resulting contracts. The program also requires the utilities to produce annual reports addressing the competitiveness of their auctions, auction timing and design issues, project status and attainment of project development milestones, interconnection costs and timing. The program anticipates annual program forums to review program design and implementation and obtain stakeholder comment and feedback. The decision adopting the program directs staff and participants to monitor it and recommend modifications as appropriate, and authorizes expedited review for proposed program modifications.

K. Confidentiality of Program Information

Rules regarding the confidentiality of auction bids and outcomes and other commercially sensitive information should strike an appropriate balance between respecting the confidential nature of developers' proprietary data and not creating opportunities for bidder collusion or gaming. At the same time, it should also provide WDG market participants with feedback about auction results in order to accomplish the program goal of accelerating market learning and experience. The rules should also give utility customers and the general public sufficient information about program performance so they may evaluate the program's success in meeting its goals. Because of the strong public interest in educating the market and demonstrating the program's value to those who must pay for it, the rules should consider allowing disclosure of all program information unless a compelling need is identified to keep some portion of it confidential. Both bid and final contract prices may meet this standard, because their disclosure may create opportunities for gaming and competitively harm developers. However, as time passes, these concerns will lessen and detailed price disclosure may become appropriate. For example,

by state law, renewable power purchase agreements with California utilities must become public three years after commercial operation begins.[lvii] Program designers could also consider a more rapid release of aggregated price data. For example, the program could require public disclosure of the average winning bid prices three months after auction winners are selected.

Other program information should generally be made publicly available. For example, the California's state-wide renewable auction program directed the utilities to release the following information regarding all bids received and shortlisted: the names of participating companies and number of bids per company, number of bids received and shortlisted, project size, participating technologies, quantitative summary of how many bids passed each project viability screen, location of bids by county provided in a map format, and achievement of project development milestones for all executed RAM contracts.

VIII. Regulatory Process Options for Creating the Program And Overseeing Results

A. Process to Create Program

Creating a WDG program will likely attract newcomers to the regulatory discussion and raise novel issues. As a result, the process may benefit from an initial period of securing engaged participation of appropriate stakeholders and developing a common understanding of key issues and goals. Regulatory staff can educate stakeholders and guide the process by developing "straw" proposals, holding workshops, and soliciting oral and written comments from the public. The process should seek to identify and resolve any pivotal "threshold" issues (e.g., jurisdiction, legal authority) at the beginning of the process. The use of workshops and other informal processes may help narrow program design issues and expedite any evidentiary hearings or other formal process required to resolve disputed matters. Stakeholder negotiations could be used to develop terms and conditions for standardized power purchase agreements to the extent possible, to avoid bogging down the process with drafting details and to give stakeholders the opportunity to strike a reasonable balance between seller and buyer interests.

B. Process to Review Auction Results

As discussed in Section VII, the program should evaluate a streamlined process to review utility administration of the auction, oversee utility evaluation of bids and approve the resulting contracts. California's state-wide renewable auction mechanism took advantage of existing processes using independent evaluator and procurement review group mechanisms to oversee the auction and bid evaluation. It also authorizes relatively rapid review of contracts using a less formal advice letter process.

Programs that opt for less stringent viability screening criteria and low barriers for new market participants should build additional flexibility into the procurement process, as they may attract inexperienced developers needing additional levels of support and guidance through the process.

IX. Standard Contract Terms and Conditions

A. Why and How to Standardize Contracts

To streamline bid preparation, bid evaluation, and contract formation processes, programs can benefit from developing a core set of standardized, non-negotiable contract terms. Standardized terms should be developed with the participation of all stakeholders as part of the administrative process used to create the program, and should not be imposed by utilities unilaterally. However, with fully standardized, non-negotiable contracts comes loss of the ability to tailor contract provisions to meet the needs of individual projects and developers. A "one size fits all" approach necessarily means ill-fitting contract for some projects. To reconcile these competing considerations, the program could devise different contracts or alternative provisions for projects of particular sizes or that use technologies with unique needs and features. For example, performance requirements appropriate for baseload projects would not be appropriate for peaking or as-available projects. The program could also leave open to negotiation some specific set of terms, such as those pertaining to development and performance commitments, while the remainder is standardized. Policymakers could also give WDG projects that are eligible for the program the option of participating in renewable or all-source procurement solicitations do not require the same degree of contract standardization. In making these choices, program designers need to weigh the benefits of flexibility in expanding the potential project pool and in

enhancing the likelihood of successful project development against the added complexity, time and transaction costs.

B. Common or Individual Utility Contracts

The program could also require all participating utilities to offer the same standard contract terms. Each utility will likely want to develop a contract based on its own standard terms and conditions, and resist efforts to mandate a common standard contract for all utilities. A common contract could simplify the process for bidders and financiers, but could be difficult for the utilities to develop and administer. Utilities may also have legitimate needs for different provisions to account for differences in business processes, technology systems, credit policies, electric infrastructure, system operations or procurement portfolio needs. Since legal and contractual transaction costs are generally easier for utilities to absorb than for developers, policymakers may choose to drive the program towards adoption of a common core of standardized contract terms, with the exception of unique terms required by basic business, technical or portfolio differences among participating utilities.

C. Appropriate Balance of Risks and Obligations

The contracts resulting from the program should allocate risks between the developer (and its financial supporters) and the utility (and its customers) in an appropriate and fair way. A contract should not be so lenient to developer that it basically is little more than an option to develop at a fixed price, which the developer can walk freely from if development is more troublesome than anticipated or a more attractive price opportunity arises. But, the contract also should not be replete with uncapped risks and requirements outside the developer's control. Such risks scare away bidders and project financiers. At the same time, utilities must provide reliable electricity at reasonable prices to their customers, and they need information and assurance that a project will produce electricity as promised, and the ability to cancel and replace the project if it fails. Developing program contract terms through a stakeholder process in which developers and utilities are adequately represented can help to achieve an appropriate balance between their interests.

D. Key Provisions

VOTE SOLAR'S GUIDE FOR CREATING A SUCCESSFUL SOLAR WHOLESALE DISTRIBUTED GENERATION PROGRAM

This section summarizes the key terms and conditions that should be considered for the standardized power purchase agreement developed for the program. It is intended to provide guidance in scoping potential program work and issues; it is not intended to provide legal advice. Knowledgeable legal experts should craft the actual contract terms and conditions.

1. Project Description

The major features of the project, such as location (with adequate legal descriptions of the site), size, technology, and point of interconnection, should be described with sufficient accuracy in the contract to minimize disputes whether the contract covers deliveries from the project, particularly if the project is modified over time.

2. Price

The price term should be clearly defined and aimed at ensuring a set price sufficient to support the successful development of competitively procured renewable generating equipment. The program should consider whether prices will be paid on a levelized, escalating or "as bid" basis. A concern raised with levelized pricing is that sellers may have less incentive to perform in the final years of the contract term.

3. Term

The delivery term (and fixed price period, if it differs from the delivery term) of the contract should be long enough to attract the capital necessary to project finance the program's desired solar WDG. Conditions precedent to the contract and delivery term should be clearly identified.

4. Termination Rights

The right to terminate the contract should be limited to clearly defined events of default or breach. The termination provisions should provide time-limited opportunities to cure defaults. They should also specify the project lender's opportunity to cure or step in rights to assume the seller's contract rights and obligations.

5. Credit and Collateral Requirements

From a utility perspective, post-development performance security deposits provide protection against performance failures, particularly when project operations cease and few assets remain. The California renewable auction program required performance security of $20/kW for projects below 5MW and of 5% of expected total project revenues for projects between 5 and 20 MW.[lviii] For its 2010 small renewable generation solicitation, APS required performance security equal to the average annual

revenue over the life of the contract.[lix] From a developer perspective, a contract with a pay-for-performance pricing structure has little need for performance security.

6. Payment Calculation and Accounting

The contract must establish clear calculations for production and payment. It also should address payment and pricing for energy delivered during the test or start-up period prior to commercial operation.

7. Curtailment

The contract should state whether and under what circumstances the buyer; transmission provider and grid operator have the right to curtail project energy deliveries, and the payment consequences. From a developer's perspective, such curtailment should be clearly bounded to avoid deleterious effects on ability to finance projects.

8. Development Obligations

The contract should include provisions that assure the project is rapidly developed consistent with the program goals and the developer's bid proposal, subject to reasonable extensions of time for events beyond the developer's control (see defaults and remedies, below).

9. Performance Obligations

The contract provisions should accommodate the variability of certain forms of renewable energy production, such as wind and solar PV, while giving the buyer reasonable assurances of minimum and maximum production levels, particularly for larger WDG.

10. Definition of Commodity Being Sold

All components of the product being sold need to be carefully defined (e.g., RECs, GHG offset value, resource adequacy/capacity value) to minimize the potential for disputes, especially as the market will likely change dramatically over the term of the contract. Any assets, such as incentives or rebates, retained by the developer should be clearly identified and excluded or deducted.

11. Change in Law Risk

The contract should include protections for the parties in the event an important governmental requirement or subsidy underlying the commercial terms is repealed or otherwise extinguished, or the costs of compliance change.

12. Defaults and Remedies

The contract should define defaults, remedies, and cure periods, especially in the case of equipment problems, interconnection issues, permitting issues and other events beyond the reasonable control of the defaulting party. Reasonable liquidated damage provisions can bound risks and avoid protracted disputes over actual damages.

13. Indemnities and Limitations of Liability

The contract should contain mutual indemnities protecting against third party claims and address whether a party's liability under the contract is limited in terms of amount or type (e.g., direct but not consequential damages).

14. Insurance

The contract should require the seller to carry commercially reasonable types and amounts of insurance.

15. Dispute Resolution

The contract should include an expedited process for resolving disputes that arise under the agreement. The dispute resolution process should include a time-limited informal process, such as management negotiation or mediation, followed by binding arbitration, which may be somewhat less costly and time-consuming than a judicial determination.

16. Consent to Assignment

The contract should incorporate an assignment provision that allows collateral assignment for financing purposes on terms acceptable to lenders and other financiers, and compatible with the buyer's need for credit-worthy and responsible counterparties. It should also provide limited, reasonable preclusions on change in control at the parent company level because many renewable developers are smaller companies that may merge or consolidate over the life of a project.

17. Grid Interconnection, Metering and Scheduling

Operational coordination, scheduling and cost responsibilities need to be clearly defined and well-coordinated with system operator procedures and wholesale market rules and charges. As discussed in Section XI, costs and responsibilities associated with integration of variable renewable resources should be addressed. These include provision of information necessary for accurate forecasting, and cost responsibilities for potential new requirements and grid charges related to integration. Since other market and operational rules and charges will likely change over the term of the contract, it should include provisions describing how such changes will be addressed and allocated between the parties.

X. Overview of Interconnection Issues and Approaches

A. Interconnection Issues

Successful WDG programs will strain the effectiveness of existing approaches to interconnection processes and may require revisions to the governing procedures in order to achieve low-cost and timely interconnection. Existing interconnection processes can act as a major hurdle to realizing rapid, widespread WDG development. In most cases, WDG projects will be interconnecting under FERC jurisdictional interconnection tariffs, which are generally modeled after the FERC Small Generator Interconnection Procedures ("SGIP").[lx] The SGIP modeled procedures provide "fast track" options for small-sized projects that pass certain screens, these screens tend to limit the use of the expedited procedures to only a subset of projects eligible to participate in a solar WDG auction program. Further, current interconnection procedures were not designed for large quantities of small projects seeking interconnection in the same time period. Existing interconnection processes generally were designed to interconnect a low volume of new generators, study system impacts in a serial fashion, and rarely provide firm estimates of interconnection costs, even after a lengthy study process. These deficiencies can create backlogs in the processing of interconnection applications, and significantly delay completion of interconnection studies. The cumulative result is to reduce the number of projects able to interconnect in the short-term, which may in turn decrease program competition and increase program costs.

However, interconnection processes cannot be changed at a snap of the fingers. WDG interconnections can raise real technical issues that need to be addressed and resolved in order to keep distribution systems safe and reliable, and to avoid degrading power quality for other customers. Utility distribution systems were designed to move power one-way, from the transmission grid to retail customers. The potential for two-way power flows and multiple generators injecting power across the distribution system requires fresh thinking and approaches, and new system designs and investment. Any reform of the interconnection procedures will need to ensure that these considerations are taken into account when evaluating a project's point of interconnection.

However, it is possible to adequately consider these factors without requiring an elaborate and lengthy technical study for each WDG project. The best options for reform of most procedures may come from identifying appropriate screening thresholds that take into account the nature and location of the distributed generator proposed and do not rely on outdated or overly conservative thresholds. Fast Track screens updated in this manner may allow more projects to interconnect rapidly at a low cost, though many will still warrant some additional study. For those projects that do not pass the screens, a robust *supplemental* review process may be appropriate where a full detailed technical study is not required to address particular safety and reliability considerations. Together modifications of this sort may allow a greater number of WDG projects to interconnect quickly and may help direct projects to the most cost efficient locations.[lxi]

In addition to reforms of the interconnection procedures themselves, initiatives are underway to reduce technical hurdles to interconnection by introducing better information into the grid planning process. These include utility "Smart Grid" initiatives to create robust grid-DG communication and improved monitoring and communications software and systems, better control systems and operations, and incorporation of integrated subsystems within the distribution system that create mini-or micro-grids more hospitable to DG interconnection. Such technical initiatives will enable more efficient use of existing system resources and thereby may bolster solar WDG development. These initiatives should be encouraged in parallel with development of a WDG auction program.

Interconnection reforms need to address the concerns of utility and grid operators as well as those of renewable project developers. Utility and grid operators need to make sure their interconnection procedures comply with federal and state grid nondiscriminatory open access requirements. They want to make sure interconnection procedures efficiently use their limited resources, especially T&D engineering and planning expertise. They also want to ensure interconnection rules maintain system safety, reliability and power quality. In general, more coordination between the procurement process and the interconnection process is recommended. This may be one of the most effective ways to minimize the queuing issues highlighted above and could also help with identification of good interconnection locations. Identifying sites with low interconnection costs may be difficult for developers where they do not have sufficient information from utilities. Moreover, increased transparency in the supplemental and full study review processes, along with backstop oversight

authority and an opportunity for independent third party expert technical review of proposed upgrade requirements could improve the interconnection process.

Developers also have a legitimate interest in increasing uniformity among utility interconnection processes and outcomes. Each utility operates their systems differently and has differing interconnection processes and requirements, which creates difficulties for developers working in multiple utility service areas.

Finally, efforts to change interconnection processes must take into account the split in legal jurisdiction over interconnection. FERC has jurisdiction to set interconnection rules for wholesale generation projects interconnecting both to transmission and distribution systems, while states have jurisdiction over QF and retail customer interconnections. Accordingly, the process used for most interconnecting generators participating in a WDG auction program will be FERC-jurisdictional and rule changes will require FERC approval.

B. Interconnection Options

California's interconnection processes have struggled to keep up with the growth in new renewable generation prompted by state policies. The backlog began with large renewable generators seeking to interconnect to state transmission systems, particularly the California Independent System Operator's ("CAISO") system, as a result of California's Renewable Portfolio Standard program. The backlog extended to small generators attempting to interconnect to utility distribution systems in response to state programs encouraging the development of distributed generation. To address the backlogs, the CAISO adopted a cluster study approach in its Generator Interconnection Procedures ("GIP") process. The CAISO recently extended this approach to small generators sized 20 MW or less, and merged its Large and Small GIP processes into one GIP, which FERC approved at the end of 2010.[lxii]

The large California utilities also revised their Wholesale Distribution Tariffs to address backlogs in distribution interconnections, and also incorporated cluster study options.[lxiii] The utilities also made some improvements to the Fast Track screening process to remove the complete prohibition on construction of interconnection facilities and other upgrades solely attributable to the facility. However, despite these changes, limited annual windows for submitting interconnection applications, lengthy

interconnection process times, and restrictive fast track eligibility screens can still create significant WDT project development hurdles.[lxiv]

On a brighter note, the public utilities have recently developed interactive, on-line maps containing information designed to help DG developers identify low-cost interconnection sites. The maps were required as part of the statewide renewable auction program.[lxv] Key features include distribution line and substation locations and identities, maximum normal summer circuit capacity, projected circuit summer, amount of distributed generation existing on the circuit (circuit allocated capacity), and the difference between the maximum normal circuit capacity and the sum of the allocated capacity. The maps are eventually to show the amount of distributed generation in the queue for circuit and substation capacity. The maps have been well received, and with further work promise to become a significant aid for developers trying to optimize DG project locations. Other states developing WDG programs should require participating utilities to develop similar interactive maps.

A subsequent step to the above increased transparency would be to develop a distribution system planning process either discretely or in conjunction with existing integrated resource planning processes that would better plan for the efficient and strategic addition of distributed generation resources to the utility distribution system in a more comprehensive fashion. Once targeted amounts of generation are established by location, wholesale DG acquisition can proceed quickly along the lines outlined above, and projects meeting the distribution resource planning criteria can be provided fast-track status.

Another option to consider for reducing the interconnection challenge is the option of the utility identifying the best sites for renewable energy generation and completing interconnection studies on those sites. Then the winners of the wholesale DG program would be able to lease the land, develop the projects, with the utility retaining ownership rights of the land. Such an approach is being explored in Arizona by Arizona Public Service.

XI. Integration Challenges and Implications

The variability and unpredictability of some forms of renewable generation, particularly wind and solar, create integration challenges for grid operators. Resolving integration challenges can be costly. A

recent study estimated integration costs at $3/Megawatt-hour ("MWh") for low penetration and $8/MWh for high penetration of solar generation.[lxvi] Integration of WDG projects is likely to be a relatively minor part of the overall grid integration challenge, but the resolution of the overall integration issues and costs will likely impact WDG program projects as well. A number of recent studies have shown that geographic dispersion of wind and solar generators reduces their cumulative variability.[lxvii] Advances in forecasting solar and wind generation are reducing uncertainty in their production levels. Reduced variability and uncertainty lowers the need for costly back-up generation, which is generally fossil-fueled. As WDG programs progress, they should consider measures to encourage dispersed siting and improved forecasting. Standard power purchase agreement terms should address operational responsibilities, such as provision of information necessary for accurate forecasting, and cost responsibilities for potential new requirements and grid charges related to integration.

XII. Conclusion

For more information and resources on this topic of successfully creating a WDG solar program please visit www.votesolar.org/WDG.

Endnotes:

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[i] According to the National Renewable Energy Laboratory the per-watt price for solar modules has dropped from $22 in 1980 to under $3 today. *See* California Energy Commission, **2011 Integrated Energy Policy Report, Commission Final Report**, p. 10, posted February 15, 2012. Publication # CEC-100-2011-001-CMF, available at http://www.energy.ca.gov/2011_energypolicy/index.html.

[ii] Previously-disturbed land refers to I land that has already been used for agriculture, mining, drilling, etc, rather than pristine wilderness.

[iii] California Energy Commission, **2011 Integrated Energy Policy Report, Commission Final Report**, p. 11, posted February 15, 2012. Publication # CEC-100-2011-001-CMF, available at http://www.energy.ca.gov/2011_energypolicy/index.html.

[iv] Id. at p. 44.

[v] Id.

[vi] Proposed Decision of ALJ DeAngelis Revising Feed-In Tariff Program, R. 11-02-005, pp. 9, 43 (mailed March 20, 2012), available at http://docs.cpuc.ca.gov/published/proceedings/R1105005.htm .

[vii] *See* 16 U.S.C. § 824(a)-(b) (2010); *Federal Power Comm'n v. Southern California Edison Co.*, 376 U.S. 205, 210, 216 (1964).

[viii] *Fed. Power Comm'n v. Florida Power & Light Co.*, 404 U.S. 453 (1972).

[ix] *Fed. Power Comm'n v. Southern Cal. Edison Co.*, 376 U.S. 205 (1964); *T&E Pastorino Nursery v. Duke Energy Trading and Mktg.,* 2003 U.S. Dist. LEXIS 16352 (S.D. Cal Aug. 25, 2003), *aff'd* 2005 U.S. App. LEXIS 3315 (9th Cir. Feb. 25, 2005).

[x] *Detroit Edison Co. v. Fed. Energy Regulatory Comm'n*, 334 F.3d 48, 51 (D.C. Cir. 2003), *Nat'l Ass'n of Regulatory Utility Comm'rs v. Fed. Energy Regulatory Comm'n*, 475 F.3d 1277, 1280 (D.C. Cir. 2007).

[xi] *See* 16 U.S.C. §§ 824d, 824e (2010); *Fed. Power Comm'n v. Southern Cal. Edison Co.*, 376 U.S. at 208 n. 4; *Miss. Power & Light Co. v. Moore*, 487 U.S. 354, 371 (1988).

[xii] *See* 16 U.S.C. § 824a-3(a), (b), (f) (2010); *Connecticut Light and Power Co.*, 70 FERC ¶ 61,012 at 61,027. Wholesale sales of electricity from the federal government, a state, or a subdivision of the state are also exempt from FERC jurisdiction, 18 U.S.C. § 824(f)(2010).

[xiii] 18 C.F.R. § 292.101(b)(6)(2011).

[xiv] *Southern California Edison Co.,* 70 FERC ¶ 61,215, *reconsideration denied*, 71 FERC ¶ 61,269, 61,677 (1995).

[xv] *California Public Utilities Comm'n*, Order Denying Rehearing, 134 FERC ¶ 61,044 (2011).
[xvi] *See Southern California Edison Co.,* 70 FERC 61,215, *reconsideration denied*, 71 FERC ¶ 61,269 (1995).

[xvii] *See generally* J. Gleason, Adopting State Feed-in Tariff Laws without Federal Preemption, Environmental Law Alliance Worldwide, available at http://www.elaw.org/system/files/fed.preemption.feb_.29.2012.pdf.

[xviii] 18 C.F.R. § 292.207(a)(2011).

[xix] Section 210(m) added by the Energy Policy Act of 2005, 16 U.S.C. §824a-3(m)(2010); 18 C.F.R. § 292.309 (2011).

[xx] FERC Order 688, 71 Fed Reg. 64363, 18 C.F.R. § 292.309(d)(2011).

[xxi] *Midwest Power Systems, Inc.*, 78 FERC ¶ 61,067 (1997) at61,248, citing *Southern California Edison Co.,* 71 FERC ¶ 61,269 (1995) at 62,080).

[xxii] *American Ref-Fuel Co.*, 105 FERC ¶ 61,004 (2003), *reh'g denied,* 107 FERC ¶ 61,016 (2004).

[xxiv] *See California Public Util. Comm'n*, 133 FERC ¶ 61,059 at para.31. Note that FERC's 1995 *Southern California Edison* decisions left open the possibility that this could be consistent: "our decision today does not, for example, preclude the possibility that, in setting an avoided cost rate, a state may account for environmental costs of all fuel sources included in an all source determination of avoided cost." 70 FERC ¶ 61,215 at 61,676, 71 FERC ¶ 61,269 at 62,080. Further, in *California Public Util. Comm'n,* FERC made clear that environmental adders must still reflect the actual costs avoided, unless included as part of the REC.

[xxv] [*Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities* (2007) Order 697, 119 FERC ¶ 61,295; *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities* (2008) Order 697-A, 123 FERC ¶ 61,055].

[xxvi] A description of the RAM, with links to supporting documents, is available at http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm.

A description of the individual utility solar PV programs, with links to supporting documents, is available at http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Utility+PV+Programs.htm.

[xxvii] While many of the participating generators would probably have to obtain exempt wholesale generator status (EWGs) and receive market-based rate authorization, participation would not need to be limited to EWGs; some entities that sell wholesale power, such as state and federal instrumentalities, are exempted from FERC regulation. *See 16 U.S.C. § 824(f).*

[xxviii] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities* (2007) Order 697, 119 FERC ¶ 61,295; *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities* (2008) Order 697-A, 123 FERC ¶ 61,055.

[xxix] *Id*., Order 697-A, p. 265.

[xxx] *See generally* Enrud, *State Renewable Portfolio Standards: Their Continued Validity and Relevance in Light of the Dormant Commerce Clause, The Supremacy Clause, and Possible Federal Legislation*, 45 Harv. J. On Legis. 259 (2008).

[xxxi] *Id*. at p. 12. *See also* Enrud, *State Renewable Portfolio Standards: Their Continued Validity and Relevance in Light of the Dormant Commerce Clause, The Supremacy Clause, and Possible Federal Legislation*, 45 Harv. J. On Legis. 259 (2008); Jacobi, *Renewable Portfolio Standard Generator Applicability Requirements: How States Can Stop Worrying and Learn to Love the Dormant Commerce Clause*, 30 Vt. L. Rev. 1079 (2006); Rader and Hempling, *Renewables Portfolio Standard: A Practical Guide*, prepared for the National Association of Regulatory Utility Commissioners, Appendix A (2001).

[xxxii] California Public Utilities Commission, D. 10-12-048 (Dec. 16, 2010), pp. 46-47 available at http://docs.cpuc.ca.gov/published/Final_decision/128432.htm . ("RAM Decision").

[xxxiii] Hybrid approaches are also possible. For example, California is considering adoption of a FiT with pricing based on the results of its RAM competitive solicitations. *See* Proposed Decision of ALJ DeAngelis Revising Feed-In Tariff Program, R. 11-02-005, pp. 9, 43 (mailed March 20, 2012), available at http://docs.cpuc.ca.gov/published/proceedings/R1105005.htm.

[xxxiv] RAM Decision, pp. 20-21, 36.

[xxxv] RAM Decision, pp. 27-31.

[xxxvi] *See* Investor-Owned Utility Solar Photovoltaic Programs, Background, http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Utility+PV+Programs.htm.

[xxxvii] *See* 18 C.F.R. § 292.309(d)(2011) and discussion at note 17 in Section III.A, above.

[xxxviii] FERC Order No. 2006-B issued July 20, 2006, FERC Stats. & Regs. ¶ 31,221, which was published in the Federal Register July 27, 2006 (71 FR 42587), as amended by the errata issued September 5, 2006, which was published in the Federal Register September 13, 2006 (71 FR 53965),), available at http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

. Note that the California Independent System Operator received FERC approval to merge its large and small generator interconnection processes into one procedure. See discussion in Section X.B.

[xxxix] *Arizona Public Service Company, 2010 Request for Proposal ("RFP" for Renewable Energy Small Generation Resources (April 27, 2010), p. 7. Available at http://www.aps.com/files/_files/rfp/2010SmallGen_RFP.pdf See also Arizona Corporation Commission Decision Nos. 72022, 72147; Decision No. 72255, p. 2 (April 7, 2011). http://images.edocket.azcc.gov/docketpdf/0000124378.pdf. http://www.aps.com/files/rfp/2011SmallGenWEBINAR_FEB_23_FINAL.pdf*

[xl] *Id*. The RAM Decision did not adopt a minimum size for eligible projects, but the CPUC later adopted a 1 MW minimum size limit in the resolution approving the advice letters the utilities submitted to comply with the decision. *See* CPUC Resolution E-4414, p. 8 (August 18, 2011), available at http://www.cpuc.ca.gov/NR/rdonlyres/D68F1B4C-D188-4F02-BF70-CC42BFBB0B71/0/E4414FinalResolution.pdf.

[xli] Proposed Decision of ALJ DeAngelis Revising Feed-In Tariff Program, R. 11-02-005, p 60 (mailed March 20, 2012), available at http://docs.cpuc.ca.gov/published/proceedings/R1105005.htm.

[xlii] CPUC Resolution E-4414, p. 8.

[xliv] APS 2011 Request for Proposal for Renewable Energy Small Generation Resources, p. 5. Available at http://www.aps.com/files/rfp/2011SmallGen_RFP.pdf.

[xlv] CPUC Resolution E-4414 (August 18, 2011), available at http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_RESOLUTION/141513.htm.

[xlvi] CPUC Draft Resolution E-4489, ID#11178, available at http://docs.cpuc.ca.gov/PUBLISHED/COMMENT_RESOLUTION/162052.htm.

[xlvii] The RAM decision took note of a utility assertion that a $20/kW deposit is less than 1% of an estimated minimal $2,100/kW installed cost for the least expensive renewable project. RAM Decision, p. 53.

[xlviii] RAM Decision, pp. 54-55.

[xlix] APS *2011 Renewable Small Generation RFP Process Changes* (February 23, 2011), p. 2. http://www.aps.com/files/rfp/2011_Renewable_Small_Generation_RFP_Process_Changes.pdf.

[l] RAM Decision, p. 66.

[li] RAM Decision, p. 64. The CPUC has also adopted a "Project Viability Calculator" for use in utility RPS solicitations. See http://www.cpuc.ca.gov/PUC/Templates/RPS.aspx?NRMODE=Published&NRNODEGUID=%7b722CB59B-003C-476F-BE7B-D6EABE6DC003%7d&NRORIGINALURL=%2fPUC%2fenergy%2fRenewables%2fprocurement%2ehtm&NRCACHEHINT=Guest#ProjectViability.

[lii] APS 2011 Renewable Small Generation RFP Process Changes, p. 1.

[liii] See http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm, APS 2011 Request for Proposal for Renewable Energy Small Generation Resources, available at http://www.aps.com/files/rfp/2011SmallGen_RFP.pdf.

[liv] Holt, Shobe, Burtraw, Palmer, Goeree*, Auction Design for SellingCO2 Emission Allowances Under the Regional Greenhouse Gas Initiative, Final Report* (October 2007), p. 7 available at http://rggi.org/docs/rggi_auction_final.pdf.

[lv] *Id*.

[lvi] RAM Decision, p. 21. The approach made it unnecessary to resolve a dispute among parties about whether a price cap on bids would be lawful without meeting federal avoid cost pricing rules.

[lvii] CPUC Decision D.06-06-066, which implements Senate Bill (SB) No. 1488 (2004 Cal. Stats., Ch. 690 (Sept. 22, 2004).

[lviii] RAM Decision, pp. 56-57.

[lix] APS 2010 Request For Proposal for Renewable Energy Small Generation Resources (April 27, 2010), p. 10.

[lx]*See* FERC Order No. 2006-B issued July 20, 2006, FERC Stats. & Regs. ¶ 31,221, which was published in the Federal Register July 27, 2006 (71 FR 42587), as amended by the errata issued September 5, 2006, which was published in the Federal Register September 13, 2006 (71 FR 53965). Available at http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

[lxi] For a more detailed discussion of issues associated with interconnection of renewable resources, particularly solar PV, to distribution systems, as well as possible solutions, see U.S. Department of Energy, *SunShot Vision Study* (February 2012), pp. 147-152, available at http://www1.eere.energy.gov/solar/sunshot/vision_study.html; Coddington et al. National Renewable Energy Laboratory, *Updating Interconnection Screens for PV System Integration* (February 2012), available at https://solarhighpen.energy.gov/updating_interconnection_screens_for_pv_system_integration.

[lxii] Information regarding the CAISO generator interconnection process is available at http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx

[lxiii] See Renewable Distributed Energy Collaborative (Re-DEC) March 4, 2011 workshop presentations, Overview on Interconnection Tariff Reform (CAISO, SCE, PG&E), available at http://www.cpuc.ca.gov/PUC/energy/Renewables/Re-DEC.htm

[lxiv] According to a February 2012 California Energy Commission report, the CAISO interconnection queue includes about 47,000 MW of renewable capacity, and there are more than 450 active interconnection requests totaling about 5,200 MW for DG systems in the IOU's wholesale distribution access tariff queue. *See* California Energy Commission, **2011 Integrated Energy Policy Report, Commission Final Report**, p. 35, posted February 15, 2012. Publication # CEC-100-2011-001-CMF, available at http://www.energy.ca.gov/2011_energypolicy/index.html.

[lxv]*Id*. The maps can also be accessed through the CPUC's Renewable Auction Mechanism website page, http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm.

[lxvi] Navigant Consulting, Inc., Sandia National Laboratories, Pacific Northwest National Laboratory, Large-Scale PV Integration Study, Prepared for NV Energy, (July 30, 2011), p. 17. See also GE Energy, National Renewable Energy Laboratory, Western Wind and Solar Integration Study (May 2010), available at http://www.nrel.gov/wind/systemsintegration/wwsis.html.

[lxvii] *See* U.S. Department of Energy, *SunShot Vision Study* (February 2012), p. 129, available at http://www1.eere.energy.gov/solar/sunshot/vision_study.html; Mills, Wiser, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power* (2010), available at http://eetd.lbl.gov/ea/emp/reports/lbnl-3884e.pdf.