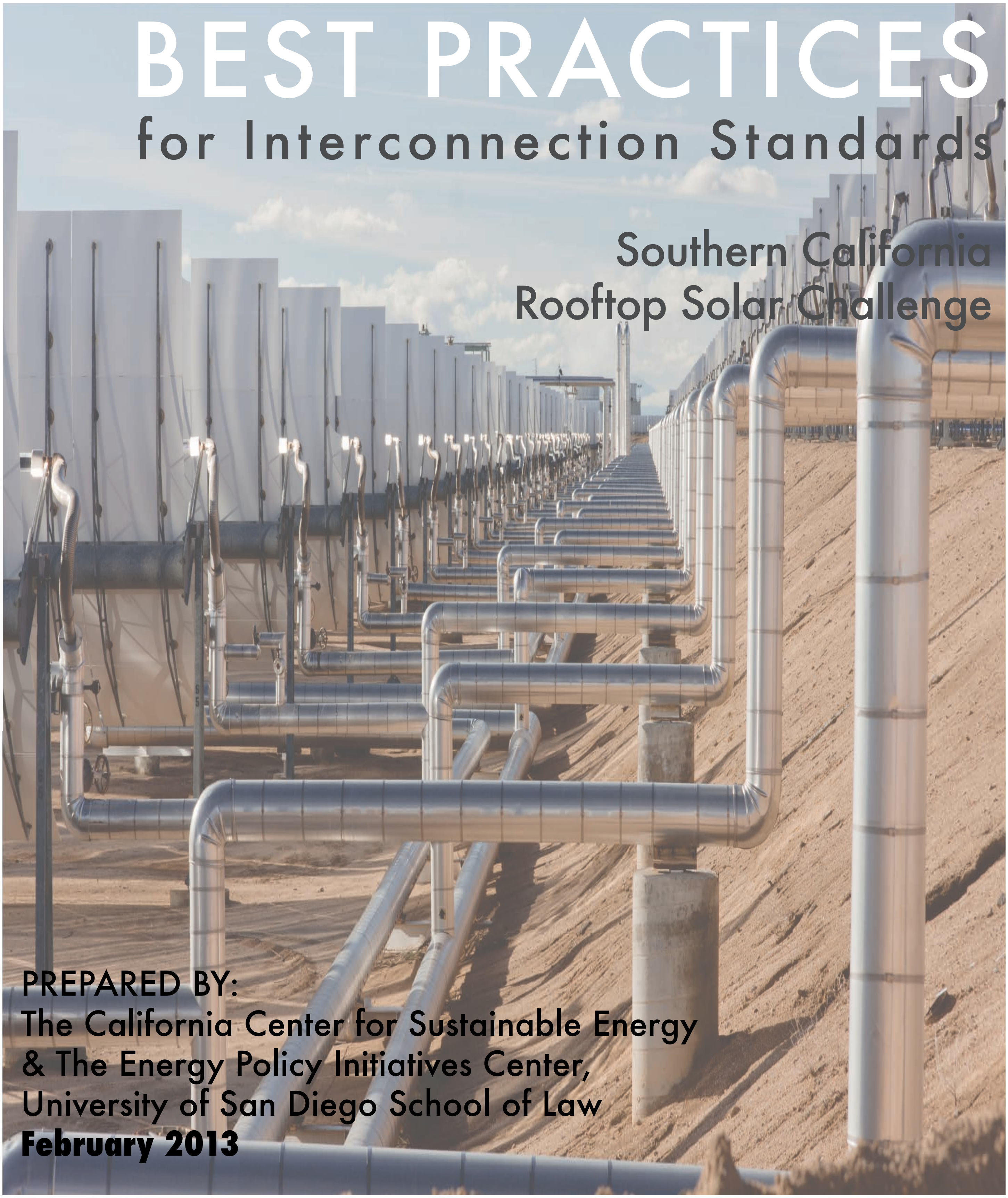

BEST PRACTICES
for Interconnection Standards

Southern California
Rooftop Solar Challenge

PREPARED BY:
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Center for Sustainable Energy California

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1. INTRODUCTION

The Southern California Rooftop Solar Challenge (SCRC) supports the goals of the Department of Energy (DOE) Solar Energy Technologies Program and the SunShot Initiative, which seek to make solar electricity cost competitive without subsidies by 2020 by reducing balance of system costs for photovoltaics (PV). To encourage market transformation, the California Center for Sustainable Energy (CCSE) is leading a regional Southern California team that will focus on expanding financing options for residential and commercial customers, streamlining permitting processes, and standardizing net metering and interconnection standards across investor- and municipally-owned utilities in the region. The goals will be achieved by fostering cross-jurisdictional collaboration and information sharing.

The SCRC evaluated regional Net Energy Metering and Interconnection Standards under the framework established by the Network for New Energy Choices' (NNEC) *Freeing the Grid 2011 Edition*.[1] This evaluation assigns points to practices that encourage or support renewable energy development and demerits to practices that hinder renewable energy development. Each utility receives positive or negative points based on this methodology. This type of evaluation seeks to both create flexible NEM standards that can facilitate the integration of large numbers of renewable energy systems and establish consistent Interconnection Standards across the Southern California region. Standardization would benefit the region by allowing customers to operate efficiently across utility service territories and eliminating inconsistencies, thus decreasing the soft costs faced by utilities and contractors and helping to mature the rooftop PV market in Southern California.

ABOUT THIS REPORT:

This report provides a summary of the best practices in the NEM Standards and Interconnection Standards categories among the local utilities in the SCRC team. This report diverges from the SCRC policy overview document[2] by grouping together sections that are interrelated under California law and regulation. This grouping both helps to make this document California-specific and highlights the areas where a utility maintains discretion to implement their own policies and standards. Sections are also combined where overlap exists to avoid repetition. Additionally, the report uses the only utility exempted from California's statutory and regulatory NEM scheme[3] – Los Angeles Department of Water and Power (LADWP) – to compare and contrast the state regulatory scheme and its implementation where applicable.

This report identifies best practices across both investor-owned utilities (IOUs) and publicly-owned utilities (POUs). This report treats both IOU and POUs the same unless a distinction is useful in explaining a best practice. Additionally, model performers are identified as well as individual utility processes that represent a regional best practice.

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2. Net Energy Metering (NEM)

Net Energy Metering is the billing arrangement that allows a customer-generator to receive financial credit for feeding the excess energy generated by a PV system into a utility distribution system. The NNEC methodology "awards points for elements that promote participation, expand renewable energy generation, or otherwise advance the goals sought by net metering" and "issues demerits for program components that discourage participation or limit renewable energy generation."[4] The goal of identifying and implementing the best practices in this category is to expand market participation, renewable energy generation, and advance NEM goals across the region. ***Please Note:*** *this document will acknowledge any instances where the SunShot criteria differ from the criteria used by NNEC.*

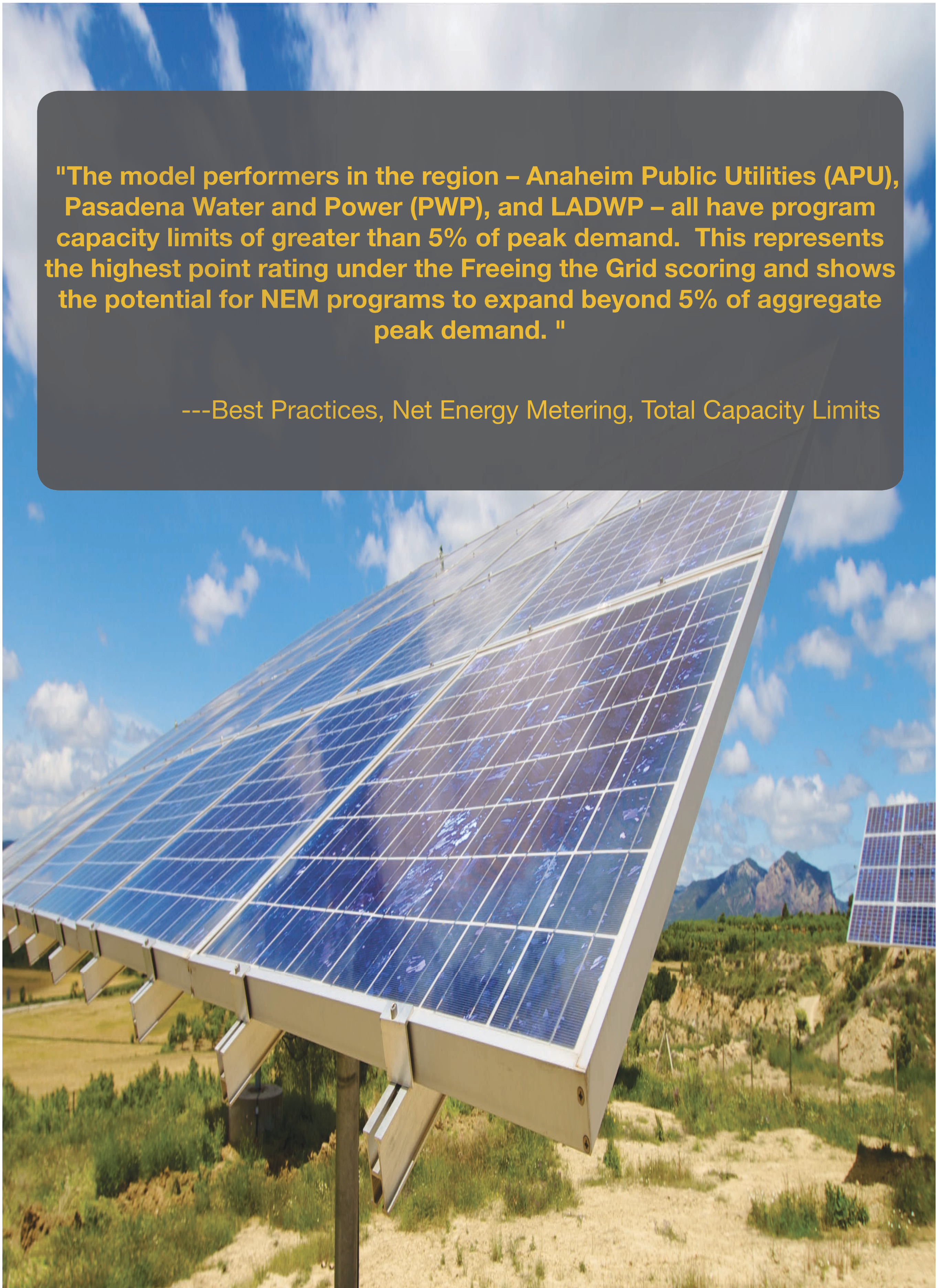
2.1 Policy Coverage

The breadth of policy coverage determines the market penetration and market size of NEM. California law defines an "[e]lectric utility" as "an electric corporation, a local publicly owned electric utility, or an electrical cooperative, or any other entity, except an electric service provider, that offers electrical services. This section shall not apply to a local publicly owned electric utility that serves more than 750,000 customers and that also conveys water to its customer."[5] NEM policy extends to all eligible technologies under the Renewable Portfolio Standard and to all investor- and publicly-owned utilities in the Southern California Region except for LADWP. LADWP operates its own NEM program ensuring that the market penetration of NEM extends across all jurisdictions. Additionally, because LADWP is not governed by Public Utilities § 2827 et seq., an installer must comply with two sets of requirements depending on whether or not the work is performed in or outside of LADWP's service territory. This offers an opportunity to implement best practices to standardize NEM practices across all applicable utilities in the region.

2.1.1 Total Program Capacity Limits as a Percentage of Peak Demand

Freeing the Grid recognizes that many states have placed limits on program capacity as a percentage of peak demand. However, the NNEC recommends eliminating any limit on total program capacity to encourage the production of clean energy that can meet a consumer's need and/or contribute to the grid. NNEC bases this on the idea that program capacity caps may limit on-site renewable generation investments, the size of the distributed generation market, and conflict with California's aggressive renewable portfolio standards.[6]

California law places a cap on the capacity of systems that can participate in NEM. California Public Utilities Code § 2827 (c)(1) requires an electric utility to provide NEM on a first-come-first-serve basis until the 5 percent aggregate peak demand mark is met. However, California



"The model performers in the region – Anaheim Public Utilities (APU), Pasadena Water and Power (PWP), and LADWP – all have program capacity limits of greater than 5% of peak demand. This represents the highest point rating under the Freeing the Grid scoring and shows the potential for NEM programs to expand beyond 5% of aggregate peak demand. "

---Best Practices, Net Energy Metering, Total Capacity Limits

Public Utilities Code § 2827 (c)(4) states that an electric utility "is not obligated to provide net energy metering" to eligible customer-generator "when the combined total peak demand of all electricity used by eligible customer-generators…exceeds 5 percent of the aggregate peak demand…" It is important to emphasize that the legislation uses the words "not obligated" as opposed to "shall not." The plain meaning of this language allows utilities to expand their NEM programs beyond 5% of aggregate peak demand. The model performers in the region – Anaheim Public Utilities (APU), Pasadena Water and Power (PWP), and LADWP – all have program capacity limits of greater than 5% of peak demand. This represents the highest point rating under the *Freeing the Grid* scoring and shows the potential for NEM programs to expand beyond 5% of aggregate peak demand.

Notably, in a recent decision, the California Public Utilities Commission increased the overall NEM cap for IOUs by defining peak demand as the aggregation of individual customers' peak demand rather than system peak demand, i.e. the sum of all individual customers' non-coincident peak demand.[7] The CPUC's decision essentially doubles the number of megawatts allowed under the NEM cap and continues an expansion of the NEM cap from the .1% of peak utility demand forecast in 1996 to the current CPUC methodology. However, the cap may still be viewed by NNEC as a limit on distributed generation under the *Freeing the Grid* criteria.

Recognizing this dilemma, the California CPUC is conducting a study to determine the costs and benefits of NEM as required under Assembly Bill 2514 (Bradford, 2012) and CPUC Decision 12-05-036.[8] Similarly, a Solar Stakeholder Group in the San Diego Gas & Electric (SDG&E) service territory is conducting a study to determine the impacts of distributed solar PV on the system.[9] Both studies are due out in spring 2013.

2.1.2 Individual System Capacity

According to the NNEC, correctly sizing a system to meet a customer's demand is the most appropriate parameter for determining individual system capacity. A statutory, regulatory, and/or utility-based limit on the size of photovoltaic systems may arbitrarily limit system capacity without evaluating the appropriate system size for a customer.[10] NNEC focuses solely on commercial system capacity limits because these are the largest types of system under NEM. Additionally, restrictions on residential and commercial system capacity by utilities and California Law are addressed under Section 2.1.3 of this document.

California Public Utilities Code § 2827(b)(4) sets forth that an "[e]ligible customer generator" for NEM shall have a "total capacity of not more than one megawatt." Additionally, Public Utilities Code § 2830(a)(4)(A) allows a renewable generating facility of no more than five megawatts if it "[i]s owned by, operated by, or on property under the control of, the local government or campus" as required under Public Utilities Code § 2830(a)(4)(D).

Anaheim Public Utilities (APU) represents the best regional performer because it provides the largest individual system capacity. APU allows system sizes of greater than 1 megawatt but less than 2 megawatts for individual system capacity. APU utilizes Public Utilities Code § 2830(a)(4)(A) for systems up to 2 megawatts expanding its individual system capacity beyond the limitations found under Public Utilities Code § 2827(b)(4). A list of APU's rooftop solar projects that it owns, operates, or that are found on property under its control can be found on its website.

All other utilities in the Southern California region permit systems sizes of between 500 kilowatt and 1 megawatt. Most residential systems range between two and four kilowatts according to the Go California Solar Website with a general potential range for residential and commercial of one kilowatt to one megawatt.[11]

2.1.3 Eligible Customers

Allowing all customer classes to participate in NEM encourages investment in distributed generation. California Public Utilities Code § 2827(b)(4) defines "[e]ligible customer-generator" as:

"a residential customer, small commercial customer as defined in subdivision (h) of Section 331, or commercial, industrial, or agricultural customer of an electric utility, who uses a renewable electrical generation facility, or a combination of those facilities, with a total capacity of not more than one megawatt, that is located on the customer's owned, leased, or rented premises, and is interconnected and operates in parallel with the electric grid, and is intended primarily to offset part or all of the customer's own electrical requirements."

All utilities in the SCRC region provide NEM to all customer classes making this a regional best practice.

2.1.4 Eligible Technologies

Freeing the Grid operates under the premise that restricting NEM to only certain technologies limits the potential for renewable energy technologies generally. Technologies such as biomass, landfill gas, and small hydroelectric benefit from inclusion in NEM and provide access to clean energy. The inclusion of solar, wind, other renewable technologies and low-emission technologies in a NEM scheme represents the regional best practice. Anaheim Public Utilities, Pasadena Water and Power, SDG&E, and Southern California Edison (SCE) all allow NEM for additional technologies other than solar and wind representing the regional best practice.

Public Utilities Code § 2827(b)(5) defines eligible NEM technologies as the same technologies that are Renewables Portfolio Standard (RPS) eligible under Public Resources Code § 25741(a)(1) with certain limitations. (RPS) eligible under Public Resources Code § 25741(a)(1) with certain limitations. Current California eligible renewable technologies include: solar thermal electric, photovoltaic, landfill gas, wind, biomass, hydroelectric of 30 megawatts or less, geothermal electric, fuel cells using renewable fuels,[12] municipal solid waste conversion, digester gas, ocean wave, ocean thermal, and tidal current.[13]

2.1.5 Restriction on “Rollovers”

Unlike in the original NNEC *Freeing the Grid* criteria for “rollovers,” the DOE criteria does not differentiate between standards that allow excess kilowatt-hours to “roll over” to the next month and those standards that instead provide for payment at the end of twelve months for excess generation at a retail or wholesale rate. Therefore, any credit in the month after the excess generation occurred is considered “monthly” rollover and any credit for excess generation at the end of a year is considered “indefinite rollover.”

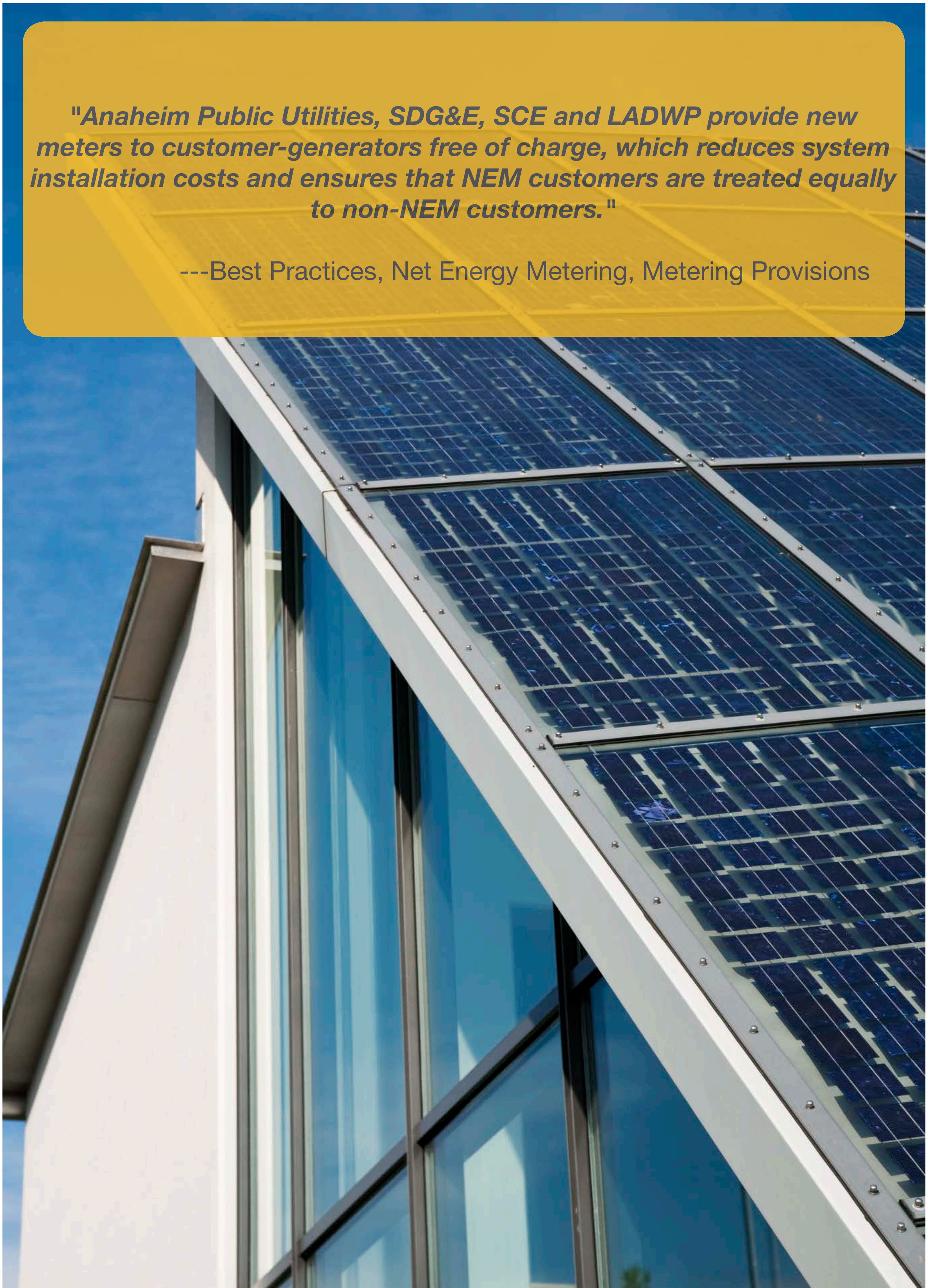
The term “rollover” refers to excess generation that is credited to the next billing cycle. For example, if generation exceeds electricity consumption over the billing month and a credit is allowed for the next month, this is a “rollover.” *Freeing the Grid* considers any restriction on “rollover” as a net negative because the administrative cost associated with tracking and paying generators for small, single month excess generation may exceed any perceived revenue losses from rollover credits. Instead, rollover credits allow generators to achieve zero net electricity consumption on an annual basis by crediting their accounts during high generation periods such as the summer and subtracting from their accounts during low generation or high consumption periods such as winter. According to the NNEC, indefinite rollovers provide the best process to account for variations among system technologies and locations allowing generators to realize the most financial benefit.[14] While this is not counted in the DOE scoring, all utilities in the SCRC region provide rollovers making it a best practice.

In California, a customer generator receives net surplus compensation for excess generation at the end of the year at an avoided cost rate derived from an hourly day-ahead electricity market price known as the "default load aggregation point" (DLAP) price. A utility's DLAP price reflects the costs the utility avoids in procuring power during the time period net surplus generators are likely to produce their excess power, generally 7 a.m. to 5 pm. Details of net surplus compensation are included in CPUC decision D. 11-06-016. Additionally, Pasadena Water and Power offers net surplus compensation equal to the applicable energy services charge over the customer's billing period plus 2.5¢ per kWh, an amount higher than the DLAP.

2.2 Metering Provisions

Freeing the Grid discourages both the requirement that customer-generators pay for additional meters and the use of special and/or duplicative meters for NEM that add cost and hardware without augmenting a utility’s ability to manage its resources. As such, the Department of Energy favors the use of meters for real time data with larger commercial systems because they provide the greatest benefit to utilities.

Anaheim Public Utilities, SDG&E, SCE and LADWP provide new meters to customer-generators free of charge. This represents the regional best process. This reduces system installation costs and ensures that NEM customers are treated equally (i.e. that they are not forced to pay additional costs or fees to become NEM customers) to non-NEM customers.



"Anaheim Public Utilities, SDG&E, SCE and LADWP provide new meters to customer-generators free of charge, which reduces system installation costs and ensures that NEM customers are treated equally to non-NEM customers."

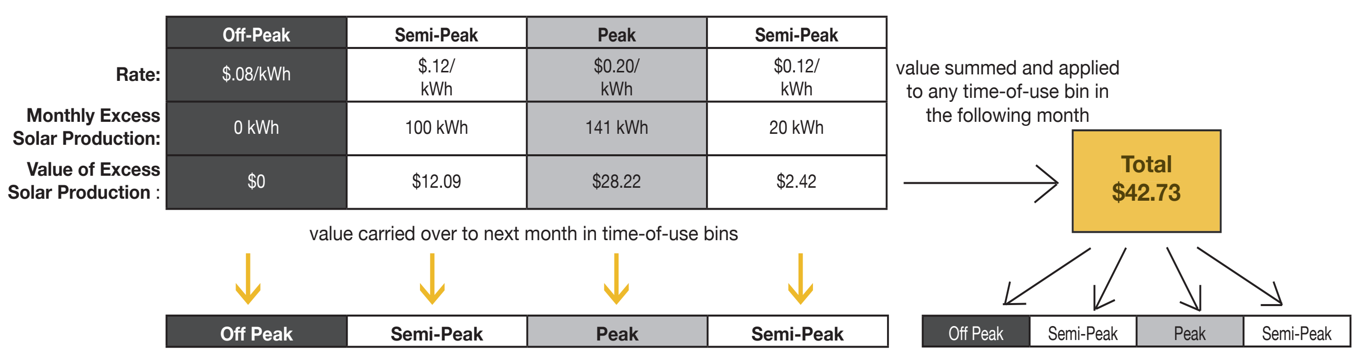
---Best Practices, Net Energy Metering, Metering Provisions

The regional practices range from the use of single smart meters that can track generation production and consumption to Anaheim Public Utilities' use of two meters. APU uses a billing meter to track customer electricity use and a power production meter to track system power sold back to APU. These amounts are determined from two registers on the single billing meter and provide the net consumption of the customer, which may be positive or negative.[15] APU's power production meter provides exact production information for the applicable system. APU currently does not provide this information to the customer but intends to roll out smart power production meters that accurately provide real-time production information both to APU for demand response and forecasting and to the customer as an actual measurement of system performance. This goes beyond the "net" offset calculated by other meters and suggests a regional opportunity to augment available distributed generation performance information.

2.3 Metering Provisions under Time-of-Use

Time-of-Use (TOU) meters track electric usage during regular intervals allowing utilities to charge differential prices for electricity consumed during specific periods of time (e.g., peak, off peak, super off-peak, etc). Combining TOU meters and NEM raises questions about how to carryover excess solar production from one month to the next. There are at least two approaches (Figure 1). One allows customer-generators to apply a credit from excess generation in a time-of-use period to the same time-of-use period in the next month. For example, a credit in the peak period in one month would only be applied to the peak period in future months. This approach can create a situation in which a customer-generator accumulates credits in a specific rate period that cannot be used, thus yielding a pool of unusable credits. Another approach would monetize the credits for each time-of-use period, sum them all to create a single credit that can be applied to any time-of-use period in subsequent months. This approach allows customers to apply credits from higher rate periods (e.g., peak) to those with lower rates Ie.g., off-peak). *Freeing the Grid* recognizes the latter approach as a best practice.[16]

Figure 1: Two Approaches to Carry Over NEM credits with TOU Meters



SDG&E, SCE, Pasadena Water and Power, and LADWP all allow time of use customers to allow excess credits to apply to any time of use period in subsequent months.

Additionally, California Public Utilities Code §2851 (a)(4) authorizes the CPUC to develop a time variant tariff that creates the maximum incentive for ratepayers to install solar energy systems so that the system's peak electricity production coincides with California's peak electricity demands. This code section also ensures that ratepayers receive appropriate value for their contribution to the purchase of solar energy systems and customers with solar energy systems continue to have an incentive to use electricity efficiently. In developing the time-variant tariff, the CPUC can exclude customers participating in the tariff from the rate cap for residential customers for existing baseline quantities or usage by those customers of up to 130 percent of existing baseline quantities, as required by Section 80110 of the Water Code. This code section does not authorize the CPUC to require time-variant pricing for ratepayers without a solar energy system. To date, the CPUC has not yet developed this tariff.

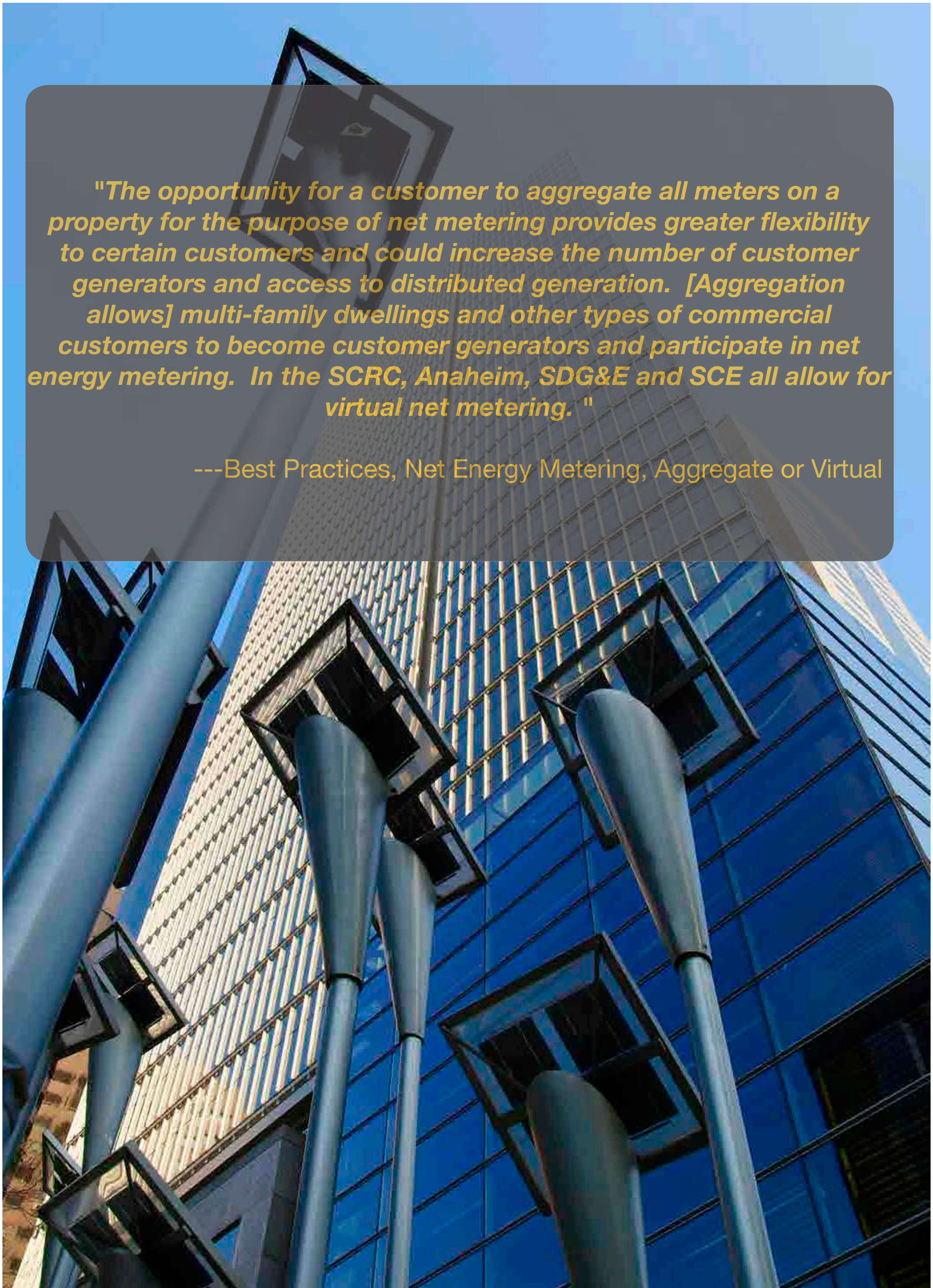
2.4 Renewable Energy Credit Ownership

Renewable energy credits (RECs) serve as a potential additional revenue stream for customer-generators. RECs are defined as the generation and delivery of one unit of energy by an eligible renewable energy source including all renewable and environmental attributes associated with the generation.[17] RECs can be freely sold between parties. For example, a large event like the Super Bowl may purchase enough RECs to offset all the energy used during the event. Also, utilities can purchase RECs to meet their renewable portfolio standard targets. The regional best practices are listed in Table 4.

Figure 2: REC Ownership Model Performers

	SDG&E	SCE	Pasadena	LADWP
Is the REC Owned by the Customer?	X	X	X	X
Is the REC owned by the utlity?				X

The model performers allow customer-generators to own the RECs that they produce as required by Public Utilities Code § 2827 (h)(5)(A) and CPUC decisions D.05-05-011 and D.07-01-018. This provides each utility with a potential market in which to buy RECs and provides customer-generators with a potential additional revenue stream, assuming the customer-generator qualifies to trade RECs in the Western Renewable Energy Generation Information Systems (WREGIS) and that the RECs are RPS eligible. RECs are eligible to be used to meet the RPS under Public Utilities Code § 399.16 (b)(1) or (b)(2) if they are not "unbundled" (where the electricity and REC are sold separately) and remain part of the energy that has – in the case of distributed generation – a first point of interconnection with a distribution facility. Public Utilities Code § 2827 (h)(5)(B) allows IOUs and MOUs to use net surplus electricity purchased from customer-generators to meet RPS annual procurement targets. The California Energy Commission determined, as stated in its Renewable Portfolio Standard Eligibility Sixth Edition, that all grid-connected renewable electric generation facilities may be certified as RPS eligible if the facility meets all eligibility requirements.[18] This



"The opportunity for a customer to aggregate all meters on a property for the purpose of net metering provides greater flexibility to certain customers and could increase the number of customer generators and access to distributed generation. [Aggregation allows] multi-family dwellings and other types of commercial customers to become customer generators and participate in net energy metering. In the SCRC, Anaheim, SDG&E and SCE all allow for virtual net metering. "

---Best Practices, Net Energy Metering, Aggregate or Virtual removes the prior restriction of RPS-eligibility to customer-side DG installations that limited participation to installations participating in IOU tariffs under D.07-07-027.

RECs generated from electricity produced and used on-site remain with the customer-generator unless a customer receives financial compensation for the generated excess electricity after a 12-month period.[19] The utility will then be granted the RECs associated with the surplus electricity purchased as required by Public Utilities Code §2827 (h)(5)(A).[20] The utility may then put the REC towards either its RPS requirement if the REC meets all requirements for RPS eligibility and WREGIS tracking or as a carbon offset,[21] but not both.[22] Eligible unbundled RECs, such as those from distributed generation, count towards the RPS standard under Public Resources Code § 399.16(b)(3) and as authorized under the California Energy Commission's (CEC) Renewable Portfolio Standard Eligibility Sixth Edition referencing eligibility determined in the Portfolio Standard Eligibility Fifth Edition.[23]

LADWP

Uses an Expected Performance Based Buydown incentive formula to calculate incentive payments for REC customers. This makes LADWP's price of $.40 per watt payment significantly higher than the minimum set by the State of California

LADWP – the only utility not regulated under Public Utilities Code § 2827 – allows a customer the option of assigning the REC to LADWP in exchange for an additional cash rebate at the time of purchase of $0.40 per watt as part of its Solar Incentive Program.[24] LADWP uses an Expected Performance Based Buydown (EPBB) incentive formula to calculate its upfront lump sum incentive payment. This formula accounts for the type of PV module, number of modules, mounting method, DC rating, inverter, inverter efficiency, shading, array tilt, and array azimuth (orientation). This makes LADWP's price per watt payment significantly higher than the minimum set by the State of California and ensures that LADWP can use the REC for its RPS requirements.

Additionally, Pasadena Water and Power allows eligible customer generators to sell their REC to the utility. Pasadena pays 2.5 cents per kilowatt hour for RECs bundled with net surplus electricity. Customers opt into this program when they enroll in net surplus electricity compensation program. Eligible customers join the program by completing Pasadena's Net Metering and Surplus Compensation Enrollment Form.

2.5 Aggregate or Virtual Net Metering

In general, net energy metering is associated with a specific meter and customer account, such as a single-family residence or a business that is a single building on a parcel. All solar production is associated with the single meter. There are certain circumstances in which there are multiple loads and meters on one contiguous property but only one meter is served by solar, given system sizing limitations. For example a large commercial office building on a campus may have enough roof space to install more solar capacity than is needed to serve the individual building. Under an aggregate net energy metering scenario, such a building would be able to overproduce on one meter and apply that excess energy to other meters on the same contiguous parcel. The opportunity for a customer to aggregate all meters on a property for the purpose of net metering provides greater flexibility to certain customers and could increase the number of customer generators and access to distributed generation. For instance, aggregation would allow multi-family dwellings and other types of commercial customers to become customer generators and participate in net energy metering. Anaheim, SDG&E, and SCE all allow for the aggregation of meters through virtual net metering. These utilities represent the regional best practice by providing the opportunity for all property owners to participate in NEM regardless of the zoning or number of units on a property.

SCE explains its virtual net metering program as such: "Under Virtual Net Metering, the owner or operator of a multi-tenant property designates the percentage of the total metered output of the generator or generators, to be allocated to each tenant service account known as 'Benefitting Accounts'. The kilowatt-hours (kWhs) allocated to each Benefitting Account is subtracted from the tenant's consumption resulting in a credit in the same manner as under Schedule NEM. If kilowatt-hours (kWh) credits exceed kilowatt-hours (kWh) use, those credits are carried forward to the next billing cycle, until the conclusion of the tenant's 12-month 'Relevant Period'." [25]

California law also allows local government, under certain circumstances, to distribute bill credits from a renewable energy system across more than one meter. [26] The local government must own all accounts and all electrical accounts involved must receive electricity under a time-of-use tariff. Additionally, California law seeks to provide virtual net metering to residents of all income levels. Specifically, the Multi-Family Affordable Housing (MASH) program provides incentives to qualifying low-income multi-family residential customers for the installation of rooftop solar and other distributed generation. The MASH program helps to ensure that net metering is accessible across all multi-tenant properties and all eligible renewable technologies, not just solar. The bill credits are then distributed across all of the tenants' electrical bills. SCE's MASH program provides interested parties with straightforward and easily accessible information on how to participate in the program.

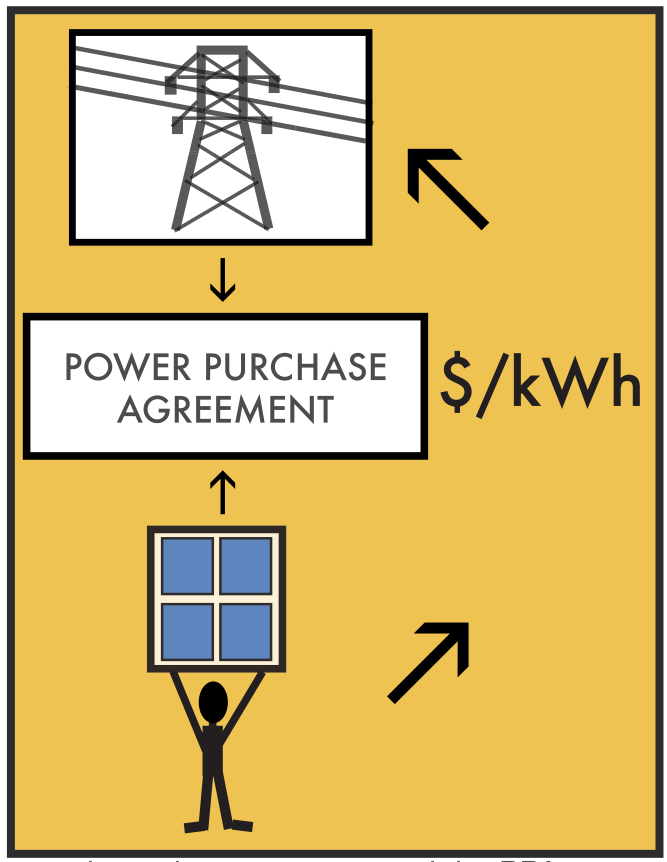
California also passed additional legislation on aggregating meters. SB 594, signed into law by the Governor Brown in 2012, allows an eligible customer-generator with multiple meters to aggregate the electrical load of meters located on the property where the generation facility is located and on all adjacent or contiguous property if those properties are solely owned, leased, or rented by the eligible customer-generator.   The bill authorizes the CPUC to determine that aggregation will not result in an increase in expected revenue obligations of electric corporations (IOUs) and publicly-owned electric utilities or cooperatives non-eligible customers. Finally, the bill prohibits an eligible customer-generator who aggregates from receiving net surplus electricity compensation and requires the utility to retain surplus kilowatt-hours.

2.6 Safe Harbor Provisions, Standby Charges, or Other Fees

Safe harbor provisions prevent a utility from treating a NEM customer prejudicially by charging fees or requiring additional equipment, insurance or any other requirement unless such requirements also apply to other customers that are not customer-sited generators. For example, standby fees are charged in the event that a system fails requiring a utility to obtain that energy from another source. This has the potential to increase customer generator costs.[27] California law, such as Public Utilities Code § 2827 (g), does not allow new or additional charges of any type that would increase a NEM customer's billing rate beyond what a similarly situated customer would pay. Public Utilities Code § 2827 (g) applies to the following utilities: Anaheim Public Utilities, SDG&E, SCE, and Pasadena Water and Power. Each of these utilities provides safe harbor language that prevents disparate treatment of NEM customers. This represents a regional best practice. Additionally, under CPUC regulation, systems of 1 megawatt or less are exempt from interconnection application fees and initial and supplemental interconnection review fees.[28]

2.7 Third-Party Financing Model

Figure 3: Power Purchase Agreement

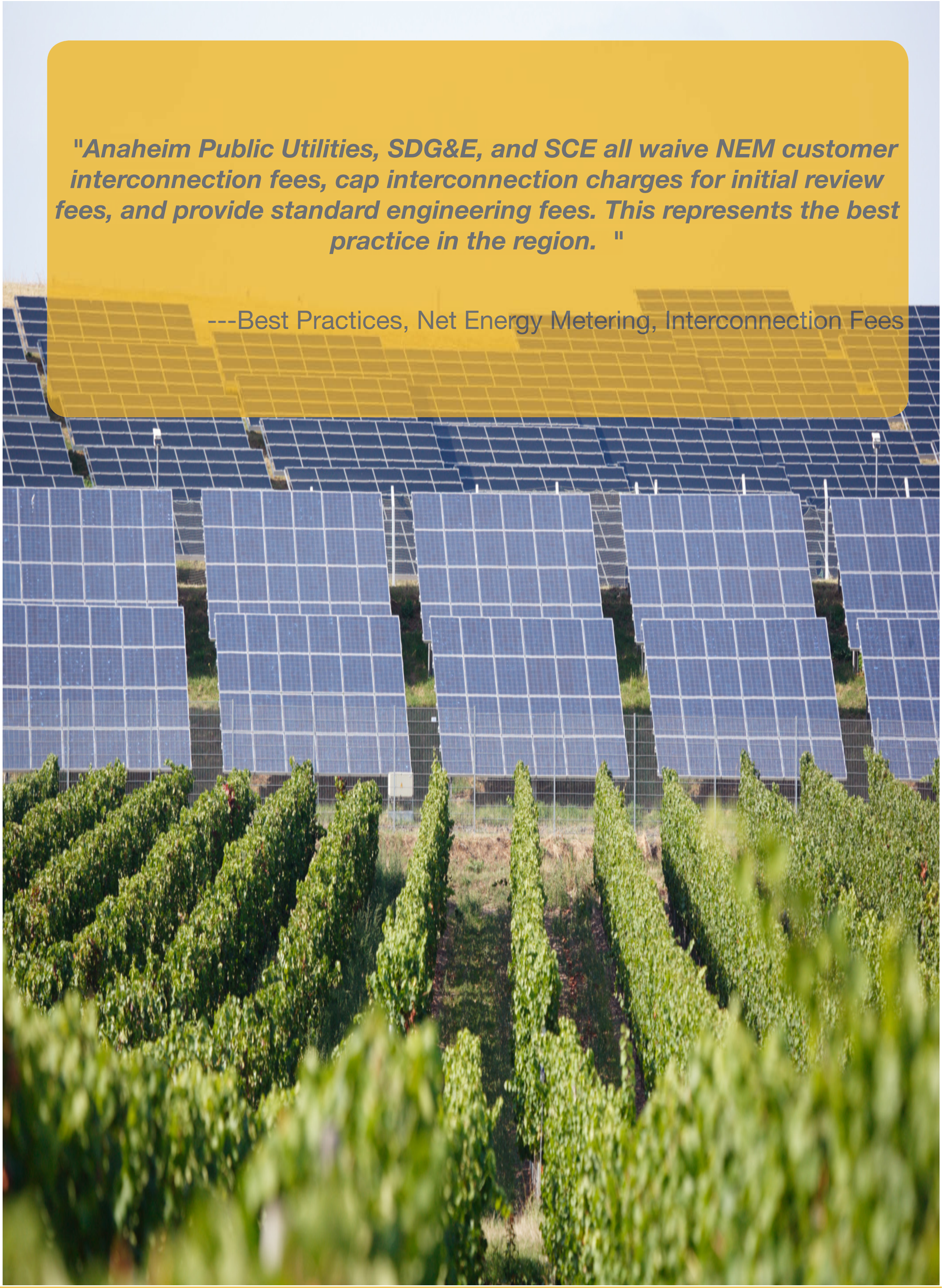


Contracting with a third party to build a distributed generation system provides access to renewable energy for customers who would not otherwise have the capital to purchase and build a system. This model is useful to finance rooftop solar projects through long-term contracts that provide access to renewable energy while offsetting load. The contracting property owner also benefits by having zero operation and maintenance costs.

All utilities in the SCRC region allow NEM under the third-party model. Under the third-party financing model the property owner purchases power under a power purchase agreement (PPA) or leases the solar array. This model has had the greatest penetration in the residential property and large commercial property markets in California. Specifically, under the PPA structure, a property owner pays for the energy generated at a set kilowatt hour basis. At end of the PPA the property owner may purchase the system, extend the PPA agreement, or have the third party remove the system from the property. Under a lease agreement, the property owner makes lease payments to the third-party at a fixed rate over the term of the lease. The rate is not connected to the kilowatt hour production of the system and at the end of the lease the property owner may remove the system, purchase it, or negotiate an extension of the lease.

"Anaheim Public Utilities, SDG&E, and SCE all waive NEM customer interconnection fees, cap interconnection charges for initial review fees, and provide standard engineering fees. This represents the best practice in the region. "

---Best Practices, Net Energy Metering, Interconnection Fees



3. INTERCONNECTION STANDARDS

How interconnection standards apply to distributed generation affects the "soft costs" born by customer-generators. The time and cost of an interconnection review process can add cost above the cost of equipment, particularly for small residential systems.[29] As such, for purposes of this report, the interconnection standards evaluations are based on the scoring method of NNEC's **Freeing the Grid** *and the analysis of SolarABCs' and IREC's* ***Comparison of the Four Leading Small Generator Interconnection Procedures****. The evaluated criteria of this section use the Federal Energy Regulatory Commission's (FERC) Small Generator Interconnection Procedures (SGIP) as a baseline (a utility scores a zero for each criteria if it adheres to the SGIP standard). While some of the sections are the same as the NEM portion of this report, it is important to keep in mind that interconnection standards apply to all ranges of systems in California and that the interconnection standard criteria are focused on different issues or requirements than the NEM criteria.*

California has standardized interconnection for all generator interconnections under Rule 21 for its three IOUs. The CPUC and interested stakeholders are reforming Rule 21 in a two-phase process. The CPUC approved redesigns under Phase 1 to its Rule 21 process in Decision 12-09-018 to more adequately address interconnection of distributed generation in a timely, non-discriminatory, cost-effective, and transparent process. A scoping memo for Phase 2 was issued on September 22, 2012 to address additional actionable issues in the near and midterm regarding the interconnection of distributed generation. The region's MOUs have developed their own interconnection standards. APU's Rule 23 and Pasadena Water and Power's Regulation 23 are the standards under which an eligible customer-generator interconnects with the respective grids of both utilities.

3.1 Eligible Technologies

According to the NNEC, compliance with all applicable technical and engineering standards allow a customer-generator to interconnect regardless of the type of technology used. System and engineering impacts of a system should be evaluated under a single technical standard that does not differentiate between non-renewable and renewable systems. Compliance eliminates operation and safety concerns that would otherwise make interconnection problematic.[30]

In the SCRC, limited to the purposes of this report, all customer-sited generators qualify that are eligible under the Renewable Portfolio Standard and the Public Utilities Code as listed in Section 2.1.4.[31] Under these standards, the customer-generator must use an eligible resource or fuel and/or technology subject to specific time or fuel restrictions as determined by the CEC. If eligible and compliant, the customer-generator may interconnect.

3.2 Individual System Capacity Limit

The individual system size and type of interconnection (wholesale transmission v. retail distribution) determines which interconnection standards apply. Utility interconnection standards should account for a wide range of systems including systems larger than 20 MW to ensure that a gap between state and federal interconnection is not created. The size of the on-site load and type of structure should determine the size of the system.[32] Across the SCRC region, interconnection standards differ by system size and residential or commercial application.

Rule 21 does not have a system size limitation; that is, SDG&E and SCE are not subject to a system size limit. Pasadena Power and Water, and LADWP all accommodate generators up to 20 megawatts following the SGIP 20 MW limit. In the SCRC region, those utilities that allow interconnection of systems up to or beyond 20 MW represent the best practice.

3.3 "Breakpoints" for Interconnection Process

The most efficient means of considering renewable generation is to break a single interconnection process into "tracks" based on generator capacity. *Freeing the Grid* advocates four levels of track: 10 kW – 2 MW, 2 MW – 10MW, 10 MW (non-exporting) – 20 MW, and 20 MW and larger.[33] This division allows ample study and consideration of larger systems while reducing the administrative cost and time of thorough evaluation of simpler systems.

Anaheim Public Utilities and LADWP break their interconnection process into three levels representing the regional best practice. APU uses breakpoints for customer-owned parallel generation of less than or equal to 100 kW, greater than 100kW and less than 1,000kW, and greater than 1,000 kW with customer-owned protection. Each of these breakpoints required distinct protection, metering and operating requirements. Additional information on these breakpoints, protections, metering and operating requirements can be found on pages 9-18 of Anaheim's Guidelines for Interconnection of Customer Generators.

3.4 Timeline for Completing Interconnection

FERC established standard timelines regarding the completion of steps required for interconnection. These federally-determined timelines decrease the time it takes to submit paperwork, receive a response, and efficiently move through the interconnection process. For example, the FERC's SGIP 10 kW Inverter Process and Fast Track Process, a utility has three business days to notify an interconnection customer that a request was received and ten days to notify the customer if it is complete or incomplete.[34] A utility must perform an initial review using the SGIP screens and notify the customer of the result within 15 days of giving notice of a complete application.[35] Within five days of passing the screens the utility must provide an executable interconnection agreement to the customer.[36] All utilities in the SCRC region adhere to the FERC's timeline, making it a regional best practice.

Additionally, the requirement of an adverse impact check for mid-sized facilities is considered a penalty because the purpose of a fast-track process with screens is to avoid an additional requirement such as an adverse impact check. LADWP consequently is assigned a -1 for requiring an adverse system impact check for systems under 2 MW as it adds an additional step.

3.5 Interconnection Charges and Engineering Fees

Transparent, reasonable, and upfront fees allow project developers to better estimate and assess the projected cost. Providing standard engineering fees is the best means to inform interconnecting customers of all reasonable costs incurred by a utility to review, study, and test for interconnection. This information should be readily available to a contracting party or customer in advance. Anaheim Public Utilities, Pasadena Water and Power, SDG&E, and SCE all waive NEM customer interconnection fees, cap interconnection charges for initial review fees, and provide standard engineering fees. This represents the best practice in the region.

SCE does not assess fees for NEM interconnection applications and generally does not assess fees for review as noted in its Interconnection Handbook. SCE follows Public Utilities Code §2827 et seq and CPUC rules that make systems eligible for net metering technologies (up to 1 MW) exempt from interconnection application fees, as well as from initial and supplemental interconnection engineering review fees under Rule 21 (E)(2)(b) & (C)(1)(d).[37] The CPUC also waives interconnection fees up to $5,000 for non-NEM solar distributed generation up to 1 MW.[38] Rule 21 further states that a system larger than 1 MW must included an interconnection fee with the application. An additional fee will also be accessed if a supplement review is required.

3.6 External Disconnect Switch Requirement

A manual disconnect switch allows a utility to physically separate the interconnecting system from its own equipment in case of an emergency, nonperformance of the interconnection agreement, or other safety reason such as islanding during a power outage. *Freeing the Grid* regards external disconnect switches as unnecessary and an additional cost for systems less than 10 kW.[39] This is because all inverters that meet IEEE standards automatically detect a power loss and shut down avoiding the safety concern that a line worker will come into contact with a line energized by an interconnected PV system or other power producing distributed generation system.

The model performers in the region, SDG&E and SCE, do not address or require external disconnect switches in their applications and therefore do not require a disconnect switch. Rule 21 (D)(1)(d) exempts systems of 1 kW or less from an external disconnect switch. Rule 21 also does not require an external disconnect switch for larger systems leaving the decision to the applicable IOU. The MOUs in the region require an external disconnect switch. Consequently, not requiring a disconnect switch represents the regional best practice.

3.7 Certification of Interconnecting Distributed Resources with Electrical Power Systems and Inverters, Converters, and Controllers used in Independent Power Systems

Electrical safety and operation of the grid require that an interconnection procedure adhere to IEEE 1547 and UL 1741 engineering standards and not be based on policy determination that step outside of established engineering standards.[40] Conflicting technical standards should be avoided as well as the introduction of other uncertainties in technical requirements.

All utilities in the region utilize UL1741/IEEE 1547 standards making this a best practice. Additionally, Anaheim, SDG&E, SCE, and Pasadena all also provide other options to customer-generators such as self-certification of equipment. This allows the same type of unlisted generator to be installed in multiple locations without repetitious studies under California Rule 21, Anaheim's Rule 22, and Pasadena's Regulation 23. These practices streamline the process and eliminate uncertainty regarding what equipment is certified. Additionally, LADWP has a Department of Building and Safety Materials Test Lab to certify equipment not certified under the Underwriters Laboratory (UL) standard 1703 ensuring safety, reliability, and compliance.

3.8 Technical Screens

FERC standards provide a standardized set of technical screens that determine how complex the interconnection process will be based on the size of the generator relative to the size of the grid where it interconnects and the rating of protective equipment, among other things.[41]

However, all investor-owned utilities in the region use Rule 21. Rule 21 is significantly different from the FERC standards because it does not include separate levels of interconnection. The FERC's SGIP process has three levels of interconnection: (1) 10 kW Inverter Process; (2) Fast Track Process for systems no greater than 2 MW; and (3) a Study Process for a system greater than 2 MW but less than 20 MW or that fails the Fast Track Process or 10 KW Inverter Process. However, all interconnection applicants are subject to eight screens of qualifying technical

Figure 4: SCE Net Energy Metering Interconnection Agreement

SOUTHERN CALIFORNIA EDISON COMPANY
NET ENERGY METERING SOLAR AND WIND GENERATING FACILITY 10 KILOWATT OR LESS
INTERCONNECTION AGREEMENT

This Net Energy Metering (NEM) Solar and Wind Generating Facility 10 Kilowatt or Less Interconnection Agreement ("Agreement") is entered into by and between ____________________________ ("Customer") and Southern California Edison Company ("SCE"), sometimes also referred to herein jointly as "Parties" or individually as "Party."

1. **APPLICABILITY**

This Agreement is applicable only to customers who satisfy all requirements of the definition of a Renewable Electrical Generating Facility ("Generating Facility") as set forth in paragraph 1 of subdivision (a) of Section 25741 of the California Public Resources Code.

2. **SUMMARY OF GENERATING FACILITY AND CUSTOMER ACCOUNT**

2.1 Generating Facility Identification Number: NM ____________________

2.2 Customer Meter Number: ____________________

2.3 Customer Service Account Number: 3 - ______ - ______ - ______

2.4 Applicable Rate Schedule: ____________________

2.5 Generating Facility Location: ____________________

____________ CA ____________

2.5.1 This agreement is applicable only to the Generating Facility described below and installed at the above location. The Generating Facility may not be relocated or connected to SCE's system at any other location without SCE's express written permission.

2.5.2 This agreement is applicable only to solar and/or wind Generating Facilities, or a hybrid system of both with an aggregate capacity of 10 kilowatts (kW) or less that is located on Customer's premises as defined in SCE's Rule 1 Definitions and operates in parallel with SCE's Distribution System.

2.6 Generating Facility Nameplate Rating (kW): ____________

2.7 Estimated monthly energy production of Generating Facility (kWh): ____________

3. **GENERATING FACILITY INTERCONNECTION AND DESIGN REQUIREMENTS:**

3.1 Customer shall be responsible for the design, installation, operation, and maintenance of the Generating Facility and shall obtain and maintain any required governmental authorizations and/or permits.

requirements under Rule 21 to determine whether they qualify for a simplified interconnection. If they fail a screen, then the interconnection request proceeds through a supplemental review.

The CPUC is in the process of updating Rule 21 in several phases to ensure that an applicant is directed into the most appropriate study path for their project. The most recent update makes NEM systems eligible for Fast Track review avoiding the detailed study process and exempts these projects from most fees and deposits normally required for this process.[42] Therefore a best practice cannot be determined for IOUs as Rule 21 is currently being redesigned. However, based on the *Freeing the Grid* criteria, LADWP represents the best practice for MOUs because it follows the FERC SGIP interconnection standards.

Please note: Because California created Rule 21 before the creation of FERC's SGIP, SDG&E and SCE are penalized. Pasadena Power and Water is also penalized for not adopting FERC's SGIP standards.

3.9 Standard Agreement Form

Agreements with standard clauses simplify the interconnection process across the region saving time and fairly balancing the rights and duties of both the generator-customer and utility. Clauses are considered "friendly" if they make interconnection easier than the FERC Small Generator Interconnection Agreement (SGIA). In the SCRC region, all utilities provide standard agreement with standard clauses for interconnection. This represents the best practice in the region. For example, SCE provides a five page NEM Interconnection Agreement for Solar and Wind Generating Facilities 10 kilowatts or less. This agreement sets forth standard clauses for duties, requirements, performance, system information, indemnity, and other relevant considerations.[43]

3.10 Insurance Requirements

Utilities generally require customer generators to hold some type of general liability insurance because of the potential personal injury and property liability risk associated with interconnection. However, the NNEC has noted that excessive insurance requirements and their consequent premiums can discourage investment in distributed generation by adding cost that can undermine the cost effectiveness of such technologies.[44]

SDG&E, SCE, and Pasadena Water and Power represent the best practices in the region. These three utilities avoid adding unnecessary costs to customer generation by not requiring additional insurance for non-inverter-based systems under 50 kW or inverter-based systems under 1 MW. Additionally, all utilities appear to indemnify themselves against damage caused by an interconnected customer and expressly waive liability for any damage to a customer's system. This shifts monetary liability, damage and risk to the interconnecting customer-generator.

3.11 Dispute Resolution

Requests for interconnection or the need to maintain or upgrade transmission equipment can result in a dispute between the interconnecting party, the utility, and other relevant parties. A mechanism to efficiently and cheaply resolve such disputes eliminates the potential cost of time and money to adjudicate such disputes. In the SCRC region, LADWP's use of a basic and broadly applied no-cost dispute resolution process represents the best practice in the region.

LADWP's Rule 10 of its *Rules Governing Water and Electric Service October 2008* provides that "…in cases where the correctness of other charges or practices of the Department is disputed by the Customer, the Department shall, upon request, conduct an investigation. This investigation shall determine if an adjustment is warranted." A request for a dispute determination must be filed in writing with the Customer Relations Office within a 19-day period to avoid delinquency on the disputed charge and termination of service. LADWP will resolve the dispute determination within 30 days for multifamily master-metered residential services and within 60 days for all other services by referral to the Department manager empowered to resolve the dispute. Dispute determination requirements that are not timely filed, not in writing, or not accompanied by the undisputed amount of a bill will be investigated without a guarantee from LADWP of stopping delinquent processing, including termination of service. Failure to make a payment prescribed by this Rule waives a Customer's right to dispute resolution and will result in service termination and bill collection actions.

Additionally, Rule 10 holds that "[i]f after determination by the appropriate authority that all or a portion of the disputed amounts are due and Customer disputes the findings, then the Customer may, within 10 days, and upon further written request, accompanied with payment of the entire outstanding bill, be granted a hearing before the Department Management pursuant to the provisions of the Department's then current Disputed Bill Procedure." Rule 10 also requires that the Customer be informed of the investigation, disputed bill procedure, and other LADWP practices under Rule 10 by a statement on the customer's bill or other appropriate methods.

4. CONCLUSIONS & NEXT STEPS

This document has provided a summary of the best practices in the major Net Energy Metering and Interconnection Standards categories among the local utilities in the Southern California Rooftop Solar Challenge team. Although we cannot expect each utility to completely standardize its NEM and Interconnection Standards to conform to the best practices identified here, it is important to identify the best-in-class practices as ways to improve the predictability of the solar installation process.

This is the third report in a series in which the Rooftop Solar Challenge team will be identifying best practices in permitting, interconnection, and net metering in the region. Subsequent activities include developing resource guides to provide more practical information on how a local jurisdiction and utility can implement the best practices in each category.

For updates and more information on the Southern California Rooftop Solar Challenge, please visit our website: www.energycenter.org/sunshot

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ENERGY POLICY INITIATIVES CENTER
UNIVERSITY OF SAN DIEGO SCHOOL OF LAW

Center for Sustainable Energy® CALIFORNIA

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U.S. Department of Energy

1. NNEC: Freeing the Grid 2011 Edition: Best Practices in State Net Energy Metering Policies and Interconnection Procedures, http://www.newenergychoices.org/uploads/FreeingTheGrid2011.pdf .
2. Southern California Rooftop Solar Challenge, Streamlining Solar Standards and Processes, as found here: www.energycenter.org/sunshot
3. California Public Utilities Code §2827.
4. NNEC, Freeing the Grid 2011 Edition, p. 11-12.
5. California Public Utilities Code § 2827(b)(3).
6. NNEC, Freeing the Grid 2011 Edition, p. 12.
7. CPUC Decision 12-05-036 May 24, 2012 http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/167591.pdf.
8. CPUC Decision 12-05-036 May 24, 2012 http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/167591.pdf.
9. See http://www.sandiego.edu/epic/research_reports/other.php#NEMStudy.
10. NNEC, Freeing the Grid 2012, p. 10.
11. Go Solar California: Net Energy Metering in California, as found: http://gosolarcalifornia.org/solar_basics/net_metering.php.
12. The California Legislature took action during last session concerning fuel cell eligibility under NEM. AB 2165 (Hill), signed into law by Governor Brown, changed the definition of eligible fuel-cell customer-generator to require that the customer be physically located within the service territory of the relevant electrical corporation and receive bundled service, distribution service, or transmission service from the electrical corporation. It also makes the NEM tariff available in an electrical corporations service area until the total cumulative rated generating capacity of the eligible fuel cell electrical generating facilities reaches a level equal to its proportionate share of a statewide limitation of 500 megawatts cumulative rated generation capacity and provides that the CPUC may raise the limitation incrementally to continue market growth. The law, among other things, also requires that the CPUC authorize electrical corporations to charge a fee based on the cost associated with providing interconnection inspection service for that customer.
13. California Public Resources Code § 25741(a)(1).
14. NNEC, Freeing the Grid 2011 Edition, p. 13.
15. APU, Net-Metering-Frequently Asked Questions, p. 1-2, as found: http://www.anaheim.net/Utilities/adv_svc_prog/pv/FAQ_Net%20Metering_2011.pdf.
16. NNEC, Freeing the Grid 2011 Edition, p. 14.
17. EPIC: Renewable Energy Credits in California, p. 2, as found: http://www.sandiego.edu/epic/research_reports/documents/070625_RECs_SB107_FINAL_000.pdf.
18. CEC: Renewable Portfolio Standard Eligibility Sixth Edition, p. 52, http://www.energy.ca.gov/2012publications/CEC-300-2012-006/CEC-300-2012-006-CMF.pdf.
19. The CPUC's Decision D.11-06-016 established a rate for payment of excess generation from distributed wind and solar generation as required by AB 920. The Decision also requires electric utilities to compensate NEM customers for electricity they produce in excess of their onsite load at the end of a 12-month period (net surplus generation).
20. DSIRE, California:Incentives/Policies for Renwables & Efficiency, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA02R
21. CPUC, Decision 11-12-052 , p. 35, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/156060.PDF.; Reporting requirements include reporting generation based on a meter with an independently verified rating of 2 percent or higher accuracy.
22. The current net surplus compensation policy (D.08-08-028) provides value for the long run avoided cost (LRAC) and leaves open the possibility of an environmental adder. Avoided GHG attributes associated with a REC are sold to the buyer of the REC. However, the purchaser cannot double count the attribute. Thus, if the REC is used for RPS compliance it cannot also be used as a carbon offset under current regulation (see p.24-25 of D.08-08-028).
23. CEC: Renewable Portfolio Standard Eligibility Sixth Edition, p. 52-54, http://www.energy.ca.gov/2012publications/CEC-300-2012-006/CEC-300-2012-006-CMF.pdf.
24. LADWP, News and Updates, https://www.ladwp.com/ladwp/faces/ladwp/residential/r-gogreen/r-gg-installsolar/r-gg-is-new-updates?_adf.ctrl-state=15jk4318b8_143&_afrLoop=2202372390706000.
25. SCE, Net Energy Metering Facts, http://www.sce.com/customergeneration/net-energy-faqs/net-energy-metering-faqs.htm.
26. DSIRE, California:Incentives/Policies for Renwables & Efficiency, http://www.dsireusa.org/incentives/

incentive.cfm?Incentive_Code=CA02R
27. NNEC, Freeing the Grid 2011 Edition, p. 16.
28. DSIRE, California:Incentives/Policies for Renwables & Efficiency, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA02R
29. SolarABCs/IREC, Comparison of the Four Leading Small Generator Interconnection Procedures, p. 1, http://www.solarabcs.org/about/publications/reports/interconnection/pdfs/ABCS-07_studyreport.pdf .
30. NNEC, Freeing the Grid 2011 Edition, p. 17.
31. Must be eligible under the Renewable Portfolio Standard described on pages 12-31 of the CEC's Renewables Portfolio Standard Eligibility and codified under Public Utilities Code § 25741 (a).
32. NNEC, Freeing the Grid 2011 Edition, p. 17.
33. NNEC, Freeing the Grid 2011 Edition, p. 17-18.
34. SolarABCs/IREC, Comparison of the Four Leading Small Generator Interconnection Procedures, p. 14, http://www.solarabcs.org/about/publications/reports/interconnection/pdfs/ABCS-07_studyreport.pdf .
35. Ibid.
36. Ibid.
37. Id. p. 17; DSIRE, California: Incentives/Policies for Renwables & Efficiency, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA02R
38. CPUC Decision No. 01-07-027, 2001, p. 70.
39. NNEC, Freeing the Grid 2011 Edition, p. 19.
40. NNEC, Freeing the Grid 2011 Edition, p. 19.
41. NNEC, Freeing the Grid 2011 Edition, p. 19.
42. DSIRE, Interconnection standards, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA21R.
43. Sothern California Edison also provides a Generating Facility Interconnection Application and an application for NEM of Renewable Electrical Generating Facility of not more than 10 kW. Forms may be found at http://asset.sce.com/Documents/Shared/SCE_NEM_Document_List.pdf .
44. NNEC, Freeing the Grid 2011 Edition, p. 21.