Decision **ALTERNATE PROPOSED DECISION OF PRESIDENT PEEVEY**
(Mailed 4/5/2011)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the matter of the Application of PacifiCorp (U901E) for approval to implement a Net Surplus Compensation Rate.	Application 10-03-001 (Filed March 1, 2010)
And Related Matters.	Application 10-03-010 Application 10-03-012 Application 10-03-013 Application 10-03-017

DECISION ADOPTING NET SURPLUS COMPENSATION RATE PURSUANT TO ASSEMBLY BILL 920 AND THE PUBLIC UTILITY REGULATORY POLICY ACT OF 1978

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DECISION ADOPTING NET SURPLUS COMPENSATION RATE PURSUANT TO ASSEMBLY BILL 920 AND THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

1. Summary

This decision fulfills the requirements of Assembly Bill (AB) 920[1] and adopts a net surplus compensation (NSC) rate to compensate net energy metering customers for electricity they produce in excess of their on-site load at the end of a 12-month true-up period. Net energy metering customers who produce excess power over a 12-month period are known as "net surplus generators."

The decision finds that net surplus generation should, as a general principle, count toward the utilities' Renewables Portfolio Standard (RPS) targets, as stipulated by AB 920. However, net surplus generation is not exempt from the conditions normally required of RPS-eligible generation, namely RPS certification by the California Energy Commission (CEC) and CEC-approved metering and tracking requirements. The decision finds that net surplus generation should not apply to the utilities' RPS targets until the CEC finalizes a process for certifying net surplus generation facilities and tracking their output to ensure that net surplus generation is not double counted.

The NSC rate will be calculated using the market price referent (MPR) based upon the showing here that the MPR is the best indicator of the avoided cost of renewable procurement. Specifically, the rate will use the 20-year contract term rate for the earliest date listed in the rate table of the most recently adopted MPR. The MPR includes both variable and fixed cost components. Because net surplus generation is unlikely to provide much capacity value to the purchasing utility, we base the NSC rate only on the variable component of the

[1] Stats. 2009, Ch. 376.

MPR. Using the 2009 MPR as an example, the rate is 7.47 cents per kilowatt-hour. Each utility shall adjust the MPR value using its time-of-delivery factors weighted by the generation profile of a typical fixed-axis solar panel. This adjustment increases the net surplus compensation rate by a range of 12 percent to 32 percent depending on each utility's specific time-of-delivery adjustment factor. Net surplus generators will not receive fixed payments over the lives of their generation facilities. Instead, whenever the MPR rate is updated, a new NSC rate will be calculated for all net surplus generators.

The MPR-based net surplus compensation rate includes a value for the renewable attributes of the generation. On an interim basis, this embedded renewable attribute value shall be set by using the Western Electricity Coordinating Council-wide average renewable energy premium, published annually by the Department of Energy, which is currently listed as 1.83 cents per kilowatt-hour. Net surplus generators who do not transfer their renewable attributes to the utilities purchasing their excess generation will be compensated at the NSC energy-only rate, calculated as the time-of-delivery adjusted MPR minus the renewable energy premium.

To expedite the initial NSC payments while the CEC works to establish a Renewable Energy Credit (REC) ownership verification and tracking process for net surplus generators, all net surplus generators will be paid at the energy-only rate. Once the REC ownership verification process has been approved by the Commission, net surplus generators may be compensated at the full NSC rate. The utilities should add retroactive payments for the renewable energy premiums not paid during the period before the Commission approves the REC ownership verification process to a subsequent NSC payment.

2. Background

Assembly Bill (AB) 920 amends Pub. Util. Code § 2827[2] and requires the Commission to establish a program to compensate net energy metering (NEM) customers for electricity produced in excess of on-site load at the end of a 12-month true-up period. In enacting AB 920, the Legislature stated that an NEM program combined with net surplus compensation (NSC) is one way to encourage substantial private investment in renewable energy resources, stimulate in-state economic growth, and reduce demand for electricity during peak consumption periods. (§ 2827(a).)

Specifically, the statute directs the Commission to adopt an NSC valuation to compensate a net surplus customer-generator for surplus kilowatt-hours produced over a 12-month period. The statute states, in pertinent part, that:

> The net surplus electricity compensation valuation shall be established so as to provide the net surplus customer-generator just and reasonable compensation for the value of net surplus electricity, while leaving other ratepayers unaffected. The ratemaking authority shall determine whether the compensation will include, where appropriate justification exists, either or both of the following components:
>
> (i) The value of the electricity itself.
>
> (ii) The value of the renewable attributes of the electricity.
>
> In establishing the rate pursuant to subparagraph (A), the ratemaking authority shall ensure that the rate does not result in a shifting of costs between solar customer-generators and other bundled service customers. (§ 2827 (h)(4)(A)and (B).)

Customers may opt to receive either a payment for net surplus generation or to roll a credit for that generation into the next 12-month true-up period.

[2] Unless otherwise specified, all further section references are to the California Public Utilities Code.

(§ 2827(h)(3).) According to AB 920, the Commission shall establish an NSC rate by January 1, 2011.

In an Assigned Commissioner Ruling dated January 15, 2010,[3] in Rulemaking 08-03-008 (January 15th ACR), President Peevey directed Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), to file applications no later than March 1 proposing an NSC rate, as well as other program implementation details pursuant to AB 920. Small and multi-jurisdictional investor-owned electric utilities were invited but not required to file applications as well. The January 15th ACR posed a series of questions regarding implementation of AB 920 and asked the utilities to respond to those questions.

On March 1, PacifiCorp, d.b.a. Pacific Power (PacifiCorp) filed the above-captioned application to implement an NSC rate. Subsequently, on March 15, Sierra Pacific Power Company[4] (Sierra Pacific), PG&E, SCE, and SDG&E, each filed their above-captioned applications to establish an NSC rate. The five applications were consolidated by Chief Administrative Law Judge (ALJ) Ruling on April 1 because the applications raise similar issue of law and fact.

Responses to the five utility applications were filed by Californians for Renewable Energy Inc. (CARE), the Commission's Division of Ratepayer Advocates (DRA), the Interstate Renewable Energy Council (IREC), PG&E, and jointly by the California Solar Energy Industries Association and the Environment California Research and Policy Center (together CALSEIA/EC).

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[3] All dates are 2010 unless otherwise noted.

[4] Sierra Pacific is now known as California Pacific Electric Company (CalPECO). We will continue to refer to Sierra Pacific as all filings in this proceeding were made with that name, however any orders from this decision will apply to and refer to CalPECO.

Protests to the applications were filed by the Acton Town Council (Acton), the City of San Diego, CARE,[5] Donald W. Ricketts, and jointly by the Solar Alliance and Vote Solar Initiative (together Joint Solar Parties).

A prehearing conference (PHC) was held on May 18 to discuss the scope and schedule of this application, and a scoping memo was issued on June 1.

On June 21, non-utility parties filed their proposals for NSC rates. Proposals were filed by Acton, CALSEIA/EC, DRA, IREC, the Joint Solar Parties, and the City of San Diego. In addition, PG&E, PacifiCorp, SCE, SDG&E and Sierra Pacific filed supplemental information regarding their applications as directed in the scoping memo.

A workshop to discuss the proposals was held on July 9. Following the workshop, comments and reply comments on the proposals were filed by Acton, CALSEIA/EC, CARE, DRA, IREC, the Joint Solar Parties, PG&E, PacifiCorp, SCE, SDG&E, the City of San Diego, Sierra Pacific, Solutions for Utilities, The Utility Reform Network (TURN), and Wal-Mart Stores, Inc. (Walmart). A PHC scheduled for August 26 was cancelled by the assigned ALJ after she determined that further proceedings were unnecessary and that the case was submitted as of the reply comments on August 6, 2010.

3. Jurisdiction

3.1. Commission Authority to Set a Net Surplus Compensation Rate

3.1.1. Parties' Positions

The utilities raise the issue of whether the Commission has the authority to set an NSC rate given Federal Energy Regulatory Commission (FERC) jurisdiction over "the sale of electric energy at wholesale in interstate

[5] CARE responded to the applications of SDG&E and PacifiCorp and protested the applications of Sierra Pacific, PG&E and SCE.

commerce."[6] According to the utilities, when an NEM customer produces excess power but receives a bill credit, i.e., a credit against its retail purchases, FERC considers this "netting" to be a billing arrangement and not a wholesale sale. PG&E cites a 2004 FERC order that states:

> …under most circumstances [FERC] does not exert jurisdiction over a net energy metering arrangement when the owner of the generator receives a credit against its retail power purchases from the selling utility. [Footnote omitted.] Only if the Generating Facility produces more energy than it needs and makes a net sale of energy to a utility over the applicable billing period would [FERC] assert jurisdiction. [Footnote omitted.][7]

Thus, the utilities claim FERC does not assert pricing jurisdiction over NEM billing arrangements where there is no "net sale" of electricity. However, they contend that if a customer's generating facility produces more energy than it needs and makes a net sale of energy to a utility over the applicable billing period and receives direct compensation for excess electricity, i.e., a check or one time payment rather than a bill credit offsetting future purchases, FERC considers this net sale a FERC jurisdictional wholesale transaction. (PG&E, 3/15/10 at 33; SDG&E, 3/15/10 at 6; PacifiCorp 3/1/10 at 3.)

SDG&E further asserts that the only time a state commission has a role in setting a wholesale rate is under the Public Utility Regulatory Policies Act (PURPA),[8] which establishes a separate framework applicable to qualifying facilities (QFs) and provides that the state adopted rate may not exceed avoided cost. (SDG&E, 3/15/10 at 5-6.) SDG&E notes that FERC recently confirmed this

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[6] 16 U.S.C. § 824(b)(1).

[7] FERC Order 2003-A, 106 FERC ¶ 61,220 (2004) at 747 (footnotes omitted) (FERC Order 2003-A).

[8] PURPA is codified generally at 16 U.S.C. § § 2601, *et seq.* and elsewhere in the U.S.C.

"avoided cost" requirement for state-set wholesale rates. (SDG&E, 7/23/10 at 4, citing 132 FERC ¶ 61, 047 (July 15, 2010).) Similarly, CARE, DRA, PacifiCorp, PG&E and TURN agree that recent FERC orders appear to preclude net surplus compensation unless it represents the utilities' avoided costs.

In contrast to these jurisdictional concerns, CALSEIA/EC, the City of San Diego, and IREC contend the state has the authority to set an NSC rate without restriction. CALSEIA/EC contend the question of Commission authority to set wholesale prices is irrelevant because "no seller is required to sell electricity to the utilities." (4/23 at 17.) Further, CALSEIA/EC assert that AB 920 requires the utilities to offer to compensate for net surplus as an incentive to increase energy efficiency and meet solar rooftop environmental goals. IREC contends that NEM is a "billing arrangement" and not a wholesale sale. Likewise, the City of San Diego considers the utilities' argument that NEM customer-generators must obtain certification as QFs as a creative barrier in order to pay NEM customers a lower rate for their net surplus generation. Both the City of San Diego and IREC note that wind and solar facilities with net power production capacity of 1 megawatt (MW) or less are no longer required to file a QF certification with FERC. (IREC, 4/23/10 at 11, fn. 26 citing FERC Order No. 732, 130 FERC ¶ 61,214 (March 19, 2010).)

3.1.2. Discussion

In identifying the NSC rate to be paid to NEM customers, the Commission must consider both state and federal requirements. State law requires the Commission to establish a value for the NSC rate to be paid to NEM customers. Section 2827 requires that the NEM customer receive "just and reasonable compensation for the value of net surplus electricity, while leaving other ratepayers unaffected."[9] Section 2827 also provides that "where appropriate justification exists" the NSC can include either or both of "[t]he value of the electricity itself" or the "value of the renewable attributes of the electricity."[10] The statute then reiterates that in establishing the NSC the Commission shall ensure that it "does not result in a shifting of costs between solar customer-generators and other bundled service customers."[11]

> When we consider federal law, we find the utilities are correct that FERC has held that a net billing arrangement is not subject to FERC jurisdiction so long as no "net sale" is made to the utility.[12] In addition, FERC has held that transfers of net surplus energy by a net metering customer to a utility are wholesale transactions that may comply with *either* the Federal Power Act (FPA) or PURPA.[13]

A recent FERC order reiterates the Commission has a wide degree of latitude in establishing avoided cost rates under PURPA and clarifies that the concept of a multi-tiered avoided cost rate structure is consistent with the avoided costs requirements of PURPA. (*California Public Utilities Commission,* 133 FERC ¶ 61,059 (October 21, 2010) at 20 and 24.) As this FERC order explains, avoided cost rates under PURPA may "differentiate among [QFs] using various

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[9] Section 2827(h)(4)(A).

[10] Sections 2827(h)(4)(A)(i) and (ii).

[11] Section 2827(h)(4)(B).

[12] *MidAmerican*, 94 FERC ¶ 61,340 at 62,262-63 (2001) (*MidAmerican*) and *Sun Edison LLC*, 129 FERC ¶ 61, 146 (2009) at 18 (*SunEdison*) ("Where there is no net sale over the billing period, the Commission has not viewed its jurisdiction as being implicated; that is, the Commission does not assert jurisdiction when the end-use customer that is also the owner of the generator receives a credit against its retail power purchases from the selling utility. [*citing to MidAmerican*].")

[13] *See*, *e.g.*, both *MidAmerican* and *SunEdison* at 18 ("Only if the end-use customer participating in the net metering program produces more energy than it needs over the applicable billing period, and thus is considered to have made a net sale of energy to a utility over the applicable billing period, has the Commission asserted jurisdiction.")

technologies on the basis of the supply characteristics of the different technologies." (*Id.* at 23.) The order further states that avoided cost rates for purchases from QF must be, among other things, at rates that are not in excess of the "the incremental cost to the electric utility of alternative electric energy" which is further defined as "the cost to the electric utility of the electric energy which, but for the purchase from [the QF], such utility would generate or purchase from another source." (*Id*. at 22.)

Thus, the Commission should implement the NEM Program pursuant to PURPA. Under such a program, the Commission should establish an NSC rate that does not exceed the utility's full avoided costs, but the Commission may differentiate an avoided cost rate for net surplus generators from the avoided costs rates currently paid to other QFs.

NEM customers eligible for NSC under AB 920 must use a solar or wind generation facility of not more than 1 MW. FERC has recently modified its regulations so that generating facilities of 1 MW or less no longer need to file a certification of QF status with FERC to be considered a QF. (FERC Order 732, 130 FERC ¶ 61, 214 (March 19, 2010) and 18 CFR § 292.203(d).) Accordingly, NEM customers can be considered QFs exempt from certification requirements at FERC and may receive net surplus compensation at a rate that does not exceed avoided costs, as determined by the Commission. As discussed further in the next section, for purposes of interconnection, the Commission would require each NEM to notify the utility that they are a QF exempt from certification filing. This notification should occur at the time the NEM customer affirmatively elects either an NSC payment or application of their net surplus to future usage, pursuant to § 2827(h)(3) and can be easily accomplished by the utility creating a notification form that customers would sign when making their NSC payment election.

3.2. Authority over Interconnection

3.2.1. Parties' Positions

In addition to concerns over Commission authority to set the NSC rate, PG&E raises jurisdictional concerns regarding interconnection issues. PG&E is concerned that because FERC will consider payment for net surplus a wholesale sale, FERC will assert jurisdiction over the interconnection between an NEM customer and PG&E. PG&E is concerned that application of FERC interconnection rules to NEM projects could result in customers paying higher interconnection application fees ($500 to $1000), and subject them to costs for interconnection studies and distribution system modifications. (PG&E, 3/15/10 at 32-35 and 6/21/10 at 7.)

PG&E proposes three possible solutions to its jurisdictional concerns. It suggests the Commission: 1) file a petition asking FERC to disclaim jurisdiction over interconnection of NEM customers electing compensation for net surplus generation under AB 920; 2) require all NEM customers to be QFs as a condition for eligibility for NSC (and thereby able to use the Commission's Rule 21 interconnection procedures); or 3) ask FERC to approve changes to the FERC-filed wholesale distribution tariff so that the FERC jurisdictional interconnection rules are the same for NEM customers electing NSC as the rules for those not electing NSC. PG&E prefers the first option, a petition asking FERC to disclaim jurisdiction.

The City of San Diego agrees with PG&E that the Commission should ask FERC to disclaim jurisdiction. Joint Solar Parties, IREC, and CALSEIA/EC disagree with PG&E. They maintain that FERC interconnection rules do not impact NSC implementation and the Commission has clear jurisdiction over interconnection arrangements for NEM customers.

3.2.2. Discussion

We share PG&E's preference for Rule 21 to govern interconnections of customers who receive NSC. Because this program is being implemented pursuant to PURPA, PG&E's second option is self-executing. As described in the section above, NEM customers opting for an NSC payment must self-designate as QFs to receive payment. This QF status entitles NEM customers to interconnect pursuant to the Rule 21 process without any further action by the Commission.

4. Net Surplus Compensation Proposals

Now that we have clarified our authority to identify an NSC rate based on avoided costs under PURPA, we turn to the various proposals offered by the parties.

AB 920 requires the Commission, when implementing the net surplus compensation rate, to consider whether the rate should include both the value of the electricity and the value of the renewable attributes of the electricity. The five utility proposals are similar in that each utility recommends a net surplus compensation rate that reflects a value of electricity based on the costs avoided by the utility for purchases of electricity. Most of the utilities then suggest an adder for the value of the renewable attributes of the power produced by eligible NEM customer-generators, i.e., generators using either a solar or wind turbine electric generating facility, or a hybrid system of both. (§ 2827(b)(4).) The actual basis for the electricity and renewable attribute values varies by utility. All five utilities generally argue that other ratepayers will be unaffected by an NSC rate as long as it is set equivalent to the costs the utility avoids by not generating energy itself.

The other, non-utility parties generally propose higher NSC rates, arguing that net surplus generation should be compared to the price of other renewable power sources. We describe the various proposals in greater detail below.

4.1. PG&E's Proposal

PG&E asserts that the NSC rate should be set equal to the cost the utility avoids by purchasing one less kilowatt hour (kWh) of energy from the California Independent System Operator (CAISO). Therefore, PG&E's proposed NSC rate is based on a simple average of hourly day-ahead locational marginal prices of electricity at the utility's default load aggregation point (DLAP). This simple average would be based on DLAP prices between the hours of 7 a.m. and 5 p.m., or the hours of daylight when NEM customers generally produce power, over the 12-month true-up period. PG&E calculates that for December 2009, this average DLAP price was 5 cents/kWh and that from April to December 2009, the average DLAP price was 3.9 cents/kWh. (PG&E, 3/15/10, Attachment B at 4; PG&E, 6/21/10, Appendix A at 3.) PG&E states that use of an established, fully accessible price as the basis for NSC would reduce utility implementation costs.

To compensate for renewable attributes, PG&E would then add to the DLAP price the average renewable energy credit (REC) price over a 12-month period representing the cost PG&E avoids by purchasing the same amount of renewable kWhs. Because RECs are not yet traded and there is no public REC price available, PG&E proposes that in the interim until REC market prices are publicly available, the net surplus compensation for all payments in a calendar year should be based on PG&E's system average generation rate in effect on January 1 of that year. PG&E states that although this is an embedded, or average cost, as opposed to an avoided cost, it includes both the value of electricity and the value of renewable attributes. Currently for 2010, PG&E's system average generation rate is 8.1 cents/kWh. (PG&E, 3/15/10 at 5.)

4.2. SCE's Proposal

SCE contends that because the Commission must identify a just and reasonable rate that does not shift costs between customer-generators and other customers, the net surplus compensation rate should be based on a market metric. (SCE Testimony, 3/15/10 at 3.) SCE proposes to use a cost figure derived from the Market Redesign and Technology Upgrade (MRTU) Integrated Forward Market (IFM) as a reasonable proxy for a transparent market price for electricity that SCE would otherwise pay to procure electricity. Specifically, SCE would base its rate on the average of hourly MRTU-IFM South of Path 15 Generation Hub prices over a year, weighted using SCE's 2009 load profile for residential customers. (SCE, 6/21/10, Attachment A at A-1.) For the period May 2009 to April 2010, this price is 3.793 cents/kWh. (*Id*. at A-2.) SCE would then add to this a value for renewable attributes based on renewable premiums for the Western Electricity Coordinating Council (WECC), as published periodically by the United States Department of Energy (DOE). SCE states that the average premium reported for the WECC is 1.83 cents/kWh (*Id*.)

SCE proposes that the ultimate NSC a customer would receive would be based on "discounting" any bill credit remaining at the conclusion of the relevant period. Under SCE's proposal, a customer must have a bill credit to receive NSC. SCE would use the bill credit to calculate a "payout percentage" by adding together a class weighted average MRTU price for the applicable period and the average premium for renewable energy in the WECC, and dividing that sum by the average retail price for the individual NEM customer's rate group. A customer's NEM bill credit remaining at the end of the period would be multiplied by the payout percentage to determine net surplus compensation to the customer. SCE would calculate the net surplus compensation payout percentage monthly for each rate group. (*See* Exh. SCE-1, 3/15/10 at 8.)

According to SCE, use of a market-based NSC rate such as the one it proposes ensures that non-participating customers are not impacted because the payment for net surplus reflects what SCE would otherwise pay in the market. In addition, SCE contends that its proposal minimizes the administrative costs of the NSC program, and therefore has a minimal effect on non-participating customers.

4.3. SDG&E's Proposal

SDG&E proposes a net surplus rate based on the 12-month rolling average of short run avoided cost (SRAC) energy rates paid to QFs. The rolling average would correspond to the NEM customer's 12-month true-up period. According to SDG&E, over the last five years, the 12-month rolling average for the non-time-of-use SRAC energy rate has ranged from 4.5 cents/kWh to 9.3 cents/kWh. (SDG&E, Davidson Testimony, 6/18/10 at LCD-6.)

SDG&E's proposal includes a method to account for the time of delivery of the net surplus. For commercial and industrial NEM customers with time-of-use (TOU) metering, surplus kWhs would be aggregated by the TOU period and paid based on the SRAC energy rate for each period. For all other NEM customers, NSC would be calculated using the non-TOU SRAC rate, adjusted for time of delivery using a representative profile of excess generation derived from SDG&E load research data from residential NEM customers. (SDG&E, 7/23/10 at 5.) SDG&E proposes an annual update of this adjustment factor based on changes to both the SRAC TOU factors and the representative load profile. According to SDG&E, since the NEM program is a tariff with no long-term commitment from the customer, payments for excess generation should be at SRAC.

In addition, SDG&E would compensate for renewable attributes by adding the Market Price Referent (MPR) greenhouse gas (GHG) adder, or

0.8 cents/kWh, to the net surplus compensation rate until a REC market in California can be relied upon to provide public information on a competitive REC price. (SDG&E, Davidson Testimony, 6/18/10 at LCD-11.) According to SDG&E, its NSC rate is transparent, has low administrative costs, complies with AB 920's mandate to not shift costs to bundled ratepayers, and meets FERC's avoided cost requirements.

4.4. PacifiCorp's Proposal

PacifiCorp proposes an NSC rate based on the QF avoided cost rates approved in its Oregon service territory, which are currently set at $.0512 per kWh for on-peak power and $.0395 per kWh for off-peak power. (PacifiCorp, 6/21/10 at 3.) A weighted average of these two rates based on the typical annual split of on-peak and off-peak hours results in a rate of $.0462 per kWh. (*Id*.) PacifiCorp also proposes an adder for environmental attributes and transmission and distribution system benefits of $.01 per kWh. According to PacifiCorp, only 34 customers take NEM service in its California territory and none of these customers has ever had net surplus generation at the end of the 12-month cycle.

4.5. Sierra Pacific's Proposal

Sierra Pacific has 20 NEM customers and only two had a net surplus in 2009. Given this low NEM participation, Sierra maintains that its circumstances warrant the use of a simplified approach. Sierra Pacific proposes to use the generation component for baseline quantities from its otherwise applicable retail rates as a proxy for the avoided cost of energy. According to Sierra Pacific, this generation component is currently equal to $.05745 per kWh. (Sierra Pacific, 6/21/10 at 3.) Sierra Pacific does not propose paying for renewable attributes of the electricity because customer generators are not currently eligible for the Renewable Portfolio Standard (RPS) program and most NEM customer generation is not tracked by the Western Renewable Energy Generation

Information System (WREGIS). Sierra Pacific contends that absent revisions to the California Energy Commission's (CEC's) RPS Eligibility Guidebook, generation from NEM customers has no RPS value and it would be inappropriate to include a renewable adder in the NSC rate.

4.6. Responses to Utility Proposals

In response to the utility NSC proposals, most parties agree that the Commission should adopt a consistent methodology to set the NSC rate for all the utilities, but actual rates may vary by utility based on utility-specific cost data. Parties also generally agree that the Commission should minimize the administrative costs of implementing the NSC rate to avoid burdening non-participating customers.

Only two parties support a utility NSC rate proposal. CARE supports SDG&E's proposal to use SRAC energy rates as the basis for NSC, as well as PacifiCorp's proposal to compensate based on Oregon QF avoided costs prices. Wal-Mart supports SDG&E's proposal to use Commission-approved SRAC rates as the basis for NSC.

The remainder of the parties generally opposes the utility NSC proposals. According to the Joint Solar Parties, CALSEIA/EC, City of San Diego, and Acton, the utilities' proposals to use either short-term wholesale market prices, SRAC rates, or average generation rates do not reflect the costs the utilities would incur to procure a similar quantity of renewable generation to meet RPS requirements. CALSEIA/EC maintain that NSC payments based on average energy rates do not reflect that most NEM solar systems provide excess generation during peak periods of electricity demand. Thus, these parties contend that the utilities' proposals substantially under compensate customer generators for the value of on-peak, RPS eligible energy and fail to encourage surplus generation as envisioned in AB 920. Further, the Joint Solar Parties claim the utilities' proposals do not include any compensation for avoided capacity costs.

4.7. Joint Solar Parties

The Joint Solar Parties agree with the utilities in concept that the NSC rate should be based on avoided costs. In their view, however, the proper avoided cost should be the Commission-adopted MPR, which is the all-in cost of a new 500 MW central station combined-cycle plant built in California, and includes costs to mitigate the plant's GHG emissions. They contend that the MPR is the correct avoided cost to use since it represents the "brown power" resource that the utility avoids constructing by instead purchasing and receiving RPS credit for net surplus generation. The Joint Solar Parties assert that because utilities will get RPS credit for net surplus purchases, they will avoid the long term costs of purchasing renewable generation under the RPS program and the value of renewable attributes is captured by the GHG mitigation costs incorporated into the MPR. In the future, however, they suggest a market-based REC price could be substituted for this GHG adder.

The Joint Solar Parties propose adjusting MPR to reflect the time of delivery (TOD) of solar generation, plus an adjustment for avoided line losses and avoided transmission and distribution (T&D) costs. According to the Joint Solar Parties, surplus power from NEM customer-generators typically serves nearby loads and reduces the loadings of both the local distribution feeder and the higher-voltage transmission and distribution grid, thus avoiding line losses. Plus, they assert that collectively, surplus generation from a large number of NEM customers can avoid the need for additional T&D capacity.

Specifically, the Joint Solar Parties propose the following adjustments to the MPR to set an NSC rate:

NSC = MPR x TOD factor + avoided line losses + avoided T&D

The Joint Solar Parties' TOD factor is calculated by applying a representative hourly solar output profile to the TOD factors used in each utility's most recent RPS solicitation. The Joint Solar Parties explain that this TOD factor implicitly assumes that net surplus generation has the same distribution as the typical solar output profile, and is a reasonable simplifying assumption. They recommend a single solar production profile for each utility. Avoided line losses and avoided T&D would be based on the Commission's most recently adopted avoided cost model for energy efficiency (the "E3 avoided cost model").[14]

The Joint Solar Parties recommend that the MPR rate that should apply for an individual NEM customer-generator is the 20-year contract rate beginning in the year that the NEM customer begins operation, and the rate would be fixed for the life of the NEM system. The Joint Solar Parties assert this would provide the customer certainty and would provide ratepayers a hedge against future increases in the price of fossil fuels. Existing NEM generators who went into operation prior to the MPR taking effect in December 2009 would receive a rate based on the 2008 MPR for a 20 year contract starting in 2009. The Joint Solar Parties propose the NSC rate for new projects could be updated by advice letter each time the Commission revises the MPR.

The Joint Solar Parties provide estimates for their proposed NSC, which vary depending on the utility. For a project that begins operation in 2009 or earlier, rates would begin with the 2008 MPR of 11.1 cents/kWh, and then be adjusted by TOD factors, avoided line losses, and avoided T&D costs using values distinct for each utility. Projects that begin in 2010 would be based on the 2009 MPR of 9.67 cents/kWh, also adjusted for TOD factors, and avoided line

[14] The "E3 avoided cost model" is named after Energy and Environmental Economics, the consultants that developed it, and was adopted in D.05-04-024, updated in D.06-06-063, and is described in D.09-08-026.

losses and T&D costs. Given all these adjustments, the Joint Solar Parties proposed rates are as follows:

Table 1: Joint Solar Parties' Proposed NSC Rates in cents/kWh[15]

	PG&E	SCE	SDG&E
NSC Rate for Projects that begin in 2009 or earlier	16.8	17.3	17.6
NSC Rate for Projects that begin in 2010	15.1	15.3	15.9

The Joint Solar Parties contend their proposed NSC is reasonable and will leave ratepayers unaffected because it reflects costs the utility will avoid through purchase of this generation. They maintain that an NSC rate based on MPR is appropriate because it includes payment for the value of capacity similar to the Commission's finding in D.82-01-103 that avoided cost rates should consider the value of energy and capacity from QFs. According to the Joint Solar Parties, the Commission already uses MPR to price surplus output from small renewable generators up to 1.5 MW pursuant to AB 1969,[16] which is a program analogous to NSC. They contend that even if RPS legislation ends the use of the MPR for the RPS program, the Commission can maintain the MPR as an important pricing benchmark.

The utilities and TURN oppose the Joint Solar Parties' proposal to base NSC on the MPR. Acton supports use of the MPR, with suggested modifications. The details of the opposition to MPR are discussed below in Section 6.

4.8. CALSEIA/EC

CALSEIA/EC assert that the NSC rate should be based on the full value of peak-generated renewable electricity because it is essential to give NEM customers an adequate incentive to reduce their electricity consumption and

[15] Joint Solar Parties, 6/21/10, Tables 1 and 2 at 3-4.

[16] Stats 2006, Ch. 731.

avoid sending power to the grid without compensation. They claim that under the current NEM program, homeowners with solar installations have an incentive to waste electricity rather than give it away for free to their utility company. Therefore, they suggest the NSC be set at either of the following: 1) the full retail electric rate, or 2) the feed-in tariff rate for solar power systems that the Commission will determine when it implements Senate Bill (SB) 32[17] in Rulemaking (R.) 08-08-009**.** CALSEIA/EC argue that when the Commission sets a feed-in tariff rate in R.08-08-009, that rate should include social and environmental benefits of solar as well as the electricity value.

CALSEIA/EC recommend that to calculate the NSC rate, the Commission should rely on a study they commissioned as part of the SB 32 feed-in tariff proceeding, which recommends a rate based on the MPR plus environmental and health benefits, time of delivery factors, avoided T&D and line losses, grid reliability, and REC values. They assert that the market value of a REC does not by itself represent the total value of renewable attributes. Therefore, they contend the Commission should consider environmental adders on top of the value of the REC in the NSC rate. Moreover, they suggest the NSC rate should be fixed for a ten-year period beginning with the date of online generation. CALSEIA/EC contend other ratepayers will be unaffected by their NSC rate proposal because few customers will be eligible for NSC. Thus, there will be minimal program cost to non-participants.

The CALSEIA/EC proposal is opposed by PG&E, PacifiCorp, TURN, and Acton, as discussed more fully in Section 6.1.2 below.

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[17] Stats. 2009, Ch. 328.

4.9. DRA

DRA proposes an interim rate to take effect on January 1, 2011, based on the most current MPR, adjusted based on time of delivery of the net surplus. SDG&E opposes DRA's interim MPR proposal, claiming it is not a proper avoided cost measure. Several parties oppose DRA's interim rate proposal, stating the Commission should simply adopt a final and permanent NSC rate at this time.

For a permanent NSC rate, DRA proposes the Commission set the NSC based on the distributed generation (DG) avoided cost methodology recently adopted in D.09-08-026 and used in the NEM cost-effectiveness evaluation performed in accordance with that decision. DRA notes that DG avoided costs have not been subject to public input, so additional public input is needed before they could be used to set NSC rates. Furthermore, DRA suggests that the NSC be adjusted for each customer's net generation profile. DRA contends this would require only simple arithmetic calculations involving TOU data for each customer which DRA asserts should be readily available in the utility billing system. Several parties oppose this proposal, stating it would be too difficult and costly to implement.

4.10. City of San Diego

The City of San Diego is a large customer of SDG&E with an active Distributed Energy Resources Program involving over 18 MW of generating capacity. The City contends that ideally the NSC rate should be set at the utility's marginal cost for renewable generation. However, since this price is not publicly available, a reasonable proxy is the cost of utility-owned renewable energy facilities, such as the all-in average cost of power from the utilities' own photovoltaic (PV) generating facilities. The City of San Diego estimates this rate is 20 to 25 cents per kWh. In the alternative, the City proposes the NSC be set equal to the utility's full retail electric rate.

The City of San Diego asserts this is reasonable because most generation from NEM customers comes from PV, and although this power is intermittent, the Commission has previously paid QFs for capacity. It maintains that a large collection of NEM customers can provide a quantity of energy that is as predictable as power provided by utility-owned solar projects. The City of San Diego asserts its proposed NSC rate leaves other ratepayers unaffected since it displaces purchases of renewable power at the utilities' marginal cost.

The utilities and TURN oppose the City of San Diego's proposal.

4.11. Acton

According to Acton, the NSC should be based on the renewable energy prices defined in executed RPS contracts approved by the Commission. Specifically, the NSC rate should reflect RPS contract rates during the same true-up interval because the surplus generation is new renewable energy that the utilities can count toward their RPS goals, and it avoids purchases of renewable energy. Using RPS contract values will leave other ratepayers unaffected as they will pay the same for all renewable power. Customer generators should be paid for the actual value of their surplus energy and the best measure of this is actual contract prices, not short-term market prices as the utilities propose. Furthermore, Acton proposes that the NSC should be based on the time of delivery, i.e. the time the excess power is placed on the distribution network, relying on existing rate data.

4.12. IREC

IREC does not offer a specific rate proposal, but urges a single methodology where the precise rate can vary across utilities. IREC contends that solar installations by NEM customers are fixed additions to the grid that will provide energy over multiple decades, as recognized in the Commission's long-term procurement proceedings. Therefore, IREC supports the Joint Solar Parties' proposal to value excess energy at a long-run avoided cost using the MPR. Moreover, IREC asserts that to value surplus generation from NEM customer-generators at a short-run avoided cost price while valuing wholesale DG at a long-run MPR price creates an unexplained disconnect in the valuation of these similar resources.

4.13. Solutions for Utilities

Solutions for Utilities supports an NSC rate based on a utility's retail electric rate, which it further maintains should be the Tier 3 summer rate because the utility company will avoid transmission and distribution expenses and it will essentially sell the excess power to adjacent property owners at tiered rates. Solutions for Utilities contends its proposal will incentivize surplus generation.

PG&E and SDG&E oppose this proposal, claiming that payment based on Tier 3 summer rates would be in excess of utility avoided costs.

4.14. CARE

CARE does not provide its own NSC rate proposal, but it supports the proposals by SDG&E and PacifiCorp. In addition, CARE contends that any excess energy produced is FERC jurisdictional, and since TOU meters can take readings in ten second intervals, the applicable NEM true-up period should be a ten second interval. It is unclear from CARE's comments how the Commission would implement a ten second true-up period given the existing NEM program with an annual true-up.[18]

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[18] It was difficult to discern CARE's positions from its comments and in general, its comments provided little assistance in reaching the conclusions in this decision.

5. Renewable Attributes and Renewable Energy Credits under NSC

We now address issues surrounding the renewable attributes of net surplus generation and the treatment of any RECs[19] that may be created by NEM customers' generation facilities. AB 920 provides that the utilities that purchase net surplus generation shall receive the RECs associated with such generation and that the electricity purchased shall count toward their RPS targets. Specifically, § 2827(h)(5) states:

> (5)(A) Upon adoption of the net surplus electricity compensation rate by the [Commission], any renewable energy credit, as defined in Section 399.12, for net surplus electricity purchased by the electric utility shall belong to the electric utility. Any renewable energy credit associated with electricity generated by the eligible customer-generator that is utilized by the eligible customer-generator shall remain the property of the eligible customer-generator.
>
> (B) Upon adoption of the net surplus electricity compensation rate by the [Commission], the net surplus electricity purchased by the electric utility shall count toward the electric utility's renewables portfolio standard annual procurement targets for the purposes of paragraph (1) of subdivision (b) of Section 399.15, ….

[19] Note that RECs per se are only created in cases where net surplus generation is tracked in WREGIS or another voluntary REC tracking system. In this decision, we use the term "RECs" interchangeably to refer both to tracked RECs and more generally to the renewable attributes associated with the output of net surplus generation facilities. Further, we recognize that § 399.16(a)(6) purports to prevent the creation of RECs from electricity generated under a PURPA contract executed after January 1, 2005. However, our decisions have recognized that WREGIS creates RECs, and that the intent of the statute is met by ensuring that the QF RECs at issue are retired for RPS compliance "at the earliest feasible time" by the purchasing utility. *See, e.g.,* D.10-03-021 at 64-65.

Section 399.12 defines a REC as "a certificate of proof, issued through the accounting system established by the [CEC] pursuant to Section 399.13, that one unit of electricity was generated and delivered by an eligible renewable energy resource." Section 399.13 confers upon the CEC the authority to certify eligible renewable energy resources, to design and implement an accounting system to verify compliance with RPS by retail sellers, to ensure electricity generated by renewable energy resources is only counted once, and to establish a system for tracking RECs. Currently, in order to qualify for RPS compliance, renewable energy generators must be certified as eligible by the CEC, and the REC must be tracked and verified in WREGIS, which requires the meter measuring the generation to have accuracy of plus or minus two percent. At this time, almost no customer-side DG is RPS-eligible, except DG systems under AB 1969 tariffs.[20]

Note that the paragraphs cited above do not appear to account for any circumstances where customer generators have already transferred the rights to the RECs associated with their net surplus generation to a third party. This may

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[20] The *RPS Eligibility Guidebook* (3d ed., December 2007) (available at: http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF) explains that:

> The Energy Commission will not certify distributed generation PV and other forms of customer-sited renewable energy into the RPS at this time, with the following exception.
>
> The Energy Commission will certify facilities that would have been considered distributed generation facilities except that they are participating in a standard contract/tariff executed pursuant to Public Utilities Code § 399.20, as implemented through the CPUC Decision 07-07-027 (R.06.05.027), executed pursuant to a comparable standard contract/tariff approved by a local publicly owned electric utility. . ., or if the facility is owned by a utility and meets other requirements, to become certified as RPS-eligible . . . .
>
> The Energy Commission will not certify distributed generation facilities as RPS-eligible unless the CPUC authorizes tradable RECs to be applied toward the RPS. (*RPS Eligibility Guidebook* at 18.)

occur either because the contract between the customer-generator and the developer specifies that the developer retains the right to all renewable attributes or because the customer-generator has retained the right to original ownership of the renewable attributes but sells them to another party in the voluntary REC market.

Broadly, there are three concerns about applying net surplus generation toward the utilities' RPS targets. First, without CEC certification and an approved REC registration process, electricity cannot, with the exception noted above, count toward RPS compliance. We must determine whether the legislature intended a similar exception to apply to net surplus generation. Second, even if the legislature intended net surplus generation to be exempt from the CEC certification and registration requirements, some net surplus generators have sold off the rights to the renewable attributes associated with the electricity produced by their systems. In these cases, the administrative burden of verifying which net surplus generators have retained the rights to their renewable attributes may be large relative to the total value of net surplus generation. Without verification, the net surplus generation produced by any given system that is counted for RPS compliance and also used in a voluntary REC program would be double counted and the integrity of the RPS program and voluntary REC markets would be compromised. Third, RECs for RPS compliance are accounted for in one megawatt-hour (MWh) increments, and it is unclear if the utilities or another entity may aggregate the net surplus generation of multiple small NEM customers to create RECs in the appropriate one MWh increments. Each of these three issues is discussed in more detail below.

5.1. CEC RPS Eligibility and REC Tracking Requirements

Several parties, namely PG&E, SCE, the Joint Solar Parties, CALSEIA/EC, IREC, the City of San Diego and DRA, suggest that AB 920, in effect, exempts net surplus generation from Sections 399.12 and 399.13, which mandate CEC certification of RPS eligibility and REC metering and registration requirements. These parties contend that AB 920 expressly intends for the utilities to receive RPS credit from net surplus generation and count it toward their RPS annual procurement targets. They argue that CEC certification and REC metering requirements are not necessary preconditions for this to occur. According to SCE, AB 920 should be construed in a simple fashion to facilitate utility purchases of renewable attributes from NEM customers. SCE recommends a "carve-out" arrangement, where net surplus generation purchased by the utilities under AB 920 would not have to be tracked in WREGIS or meet CEC RPS eligibility requirements in order to be counted towards utility RPS targets. Similarly, DRA argues:

> To the extent two statutes are irreconcilable, when a subsequently enacted specific statute directly conflicts with an earlier more general provision, it is well settled that the subsequent legislation affects a limited repeal of the former statute…. [fn omitted] Thus, to the extent that the RPS statute (and subsequent regulations) required CEC certification and WREGIS tracking, those requirements do no[t] apply to NEM excess generators under AB 920 because those requirements from the earlier enacted RPS statutes are deemed repealed. (DRA, 6/21/10, at 18, citing *Governing Bd. v. Mann*, 18 Cal. 3d 819, 829 (1977).)

Additionally, PG&E and others claim it would be complex and expensive for customers to obtain RPS certification and register with WREGIS. These parties contend the simple and cost-effective approach is to allow customers with net surplus generation to receive compensation for the renewable attributes of their excess generation, and for the utilities to get RPS credit for the generation, whether or not the facility is certified as RPS eligible by the CEC and whether or not the facility generates a REC that is tracked through WREGIS.

We agree with these parties' suggestion that the language of AB 920, enacted after Sections 399.12 and 399.13, plainly allows net surplus generation to count toward RPS procurement targets. However, the legislature did not provide clear direction that it intended to exempt net surplus generation from the CEC certification and REC tracking requirements that would normally apply. We find that although the statute states that any RECs for net surplus electricity purchased by the utility shall belong to the utility, we find that when AB 920 is read in concert with the RPS program statutory framework, certain prerequisites must be met before the renewable energy associated with net surplus generation can be counted toward RPS compliance goals. We conclude that net surplus generation purchased by the utility cannot be counted for RPS purposes until the CEC revises its *RPS Eligibility Guidebook* to accommodate net surplus generation facilities and approves a mechanism to track the associated renewable attributes.

SDG&E proposes that stakeholders should collaborate to develop a streamlined process for NEM customers to obtain RPS certification from the CEC and meet WREGIS accounting requirements. We agree. If the utilities want the ability to count RECs from net surplus generation toward RPS, they and other parties should work with the CEC through its process for revising its *RPS Eligibility Guidebook* to have RPS certification and accounting requirements dealt with by the CEC.[21]

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[21] As a practical matter, the quantity of NSC generation available to be considered towards the RPS program goals is *de minimus* compared to the utility RPS targets. For example, in 2009, the RPS procurement target for PG&E was 11,623 GWh (*see PUC RPS Quarterly Report to Legislature, 2010 Quarter 2,"* Table 1 at 4), while PG&E reports its

While we defer to the CEC to develop the RPS certification and tracking process for net surplus generators before we will allow net surplus generation to count toward the RPS, we nonetheless require the utilities to purchase net surplus generation at an energy-only rate. The method for establishing the NSC rate is discussed below in Section 6.

Ultimately, the CEC will be responsible for devising the certification and REC tracking rules for net surplus generators. However, complex issues concerning the tracking, aggregation and "splitting" of renewable attributes associated with net surplus generation arose during the course of this proceeding. We discuss these issues in the following sections.

5.2. Renewable Attribute Tracking and Sales of RECs to Third Parties

In order to resolve whether net surplus generation should apply toward the utilities' RPS goals, we must ensure that the NSC program does not undermine the integrity of REC markets by allowing the same net surplus generation to count toward the RPS while producing RECs claimed by another entity. This suggests that NEM customers should certify that they own the RECs associated with their power in order for the utility to compensate the NEM customer for the RECs and count them towards RPS targets. PG&E contends that customers should not be required to prove REC ownership to receive compensation for net surplus generation. The remaining utilities, Acton, IREC, CALSEIA/EC, City of San Diego, and the Joint Solar Parties recommend that customers should only receive payment for renewable attributes if they affirm ownership of the REC. They suggest that if a customer has sold its RECs, the utility should be allowed to pay a lower, or "brown power price," for the net

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excess generation from NEM customers in 2009 was 5,212,073 kWh (5.2 GWh), or approximately 0.04% of the annual RPS target.

surplus generation without RECs. Because the CEC does not currently certify behind-the-meter resources for RPS eligibility, any RECs produced by these facilities cannot be used for RPS compliance. However, RECs from behind-the-meter facilities may be accepted in the voluntary REC market. WREGIS allows facilities as small as 1 kW to register their output, and it also possible that some net surplus generators register their output in voluntary REC tracking systems that do not rely on WREGIS. However, the record of this proceeding does not provide any data to indicate which customer-generators in the IOUs' territories may be generating RECs in WREGIS or other REC tracking systems.

The utilities have expressed concern about the administrative burden of requiring attestations from every net surplus generator. The Joint Solar Parties proposed that only net surplus generators with systems of 100 kW or greater be required to file an affidavit that they have not sold their RECs to another party. (Joint Solar Parties, 6/21/10 at 17.) PG&E agreed with the principle of setting a threshold but suggested setting the threshold at 500 kW. (PG&E, 7/23/10 at 15.) We appreciate the challenges involved with tracking the RECs from numerous small generation facilities, particularly in light of the administrative burden entailed by the need to establish the REC ownership status of each net surplus generator. This issue must be resolved by the CEC and interested parties who choose to participate in the CEC's *RPS Eligibility Guidebook* revision process. Until the CEC establishes its certification and tracking processes and approves a method for determining REC ownership, no net surplus generation shall count toward utility RPS targets. We assume that because § 2827(h)(5) stipulates that the 12-month true-up period commences when the utility receives a customer's notice of election to participate in the NSC program, the CEC will establish a process that allows net surplus generators to retroactively certify their generation facilities to the beginning of their enrollment. In the event the CEC does authorize retroactive certification, any NSC-eligible net surplus generation that occurs before the CEC finalizes its process to certify and track net surplus generation may be carried forward to apply to RPS targets, provided that the RECs, or renewable attributes, are also transferred to the purchasing utility.

5.3. Accounting for Partial RECs

According to § 2827(h)(5)(A), any REC for net surplus electricity purchased by the electric utility shall belong to the electric utility, while any REC associated with electricity generated by the eligible customer-generator and used by the eligible customer-generator remains the property of the eligible customer-generator. It is unclear whether WREGIS or another CEC approved system can track and otherwise account for RECs that would be split between the utility and the customer in such a fashion. RECs for RPS compliance are normally accounted for in one MWh increments. The quantity of net surplus generation for each net surplus generators is determined at the end of a 12-month true-up period. It is likely that few net surplus generators will have a quantity of net surplus generation that adds up to a whole number of MWh with no remaining quantity less than a MWh. Allowing the utilities, or potentially other entities, to aggregate net surplus generation across multiple accounts would help to mitigate this problem. This issue must also be resolved by the CEC.

6. Adopted Value of Electricity and Renewable Attributes

According to the statute, the Commission may determine whether net surplus compensation should include either or both the value of electricity itself and the value of the renewable attributes of the electricity, “where appropriate justification exists.” (§ 2827(h)(4)(A).)

As described in Section 3.1 above, the Commission seeks to implement an NSC rate based on avoided costs. We adopt an avoided cost approach that we determine reflects, as closely as possible, the incremental cost the utility avoids by receiving surplus generation from NEM customers, and complies with the mandate of § 2827(h)(4)(A-B) that the adopted rate be just and reasonable, leave other ratepayers unaffected, and not shift costs between solar customer-generators and other bundled service customers. We accept the suggestion of DRA, TURN and the Joint Solar Parties to base the NSC rate on the Commission-adopted MPR.

We find the MPR to be reasonable for two reasons. First, the use of the MPR is consistent with our previously adopted feed-in tariff for small renewable energy facilities. In D.07-07-027 we established a feed-in tariff for small renewable energy facilities with a capacity of 1.5 MW or less, which is set at the TOD adjusted MPR. Second, the MPR is used as a benchmark to determine the reasonableness of renewable power prices, and as DRA and the Joint Solar Parties have indicated, the average price paid for RPS-eligible energy over the past few years has exceeded the MPR. (DRA, 6/21/10 at 10; Joint Solar Parties, 7/23/10 at 4.) Specifically, DRA notes that the average prices paid for RPS contracts were well above the MPR in 2006, 2007 and 2009. (DRA, 6/21/10 at footnote 14.) No utility refuted this finding.[22] In its prepared testimony, SCE stated that "to hold customers indifferent, utilities should only be required to purchase renewable energy from NEM customers at a proxy for the market price of this resource." (SCE, Ex. SCE-1, 3/15/10 at 4.) This is what we do here in

[22] SCE did assert that "Utilities should be able to, and often do, procure renewable energy at below MPR." (SCE, Ex. SCE-1, 3/15/10 at 7.) However, it appears from DRA's analysis that the utilities just as often are not able to, and do not, procure renewable energy at below MPR.

relying upon the MPR in its capacity as a proxy for the market price of other renewable energy.[23] As the City of San Diego points out, using actual renewable power purchase agreement prices would be preferable, but due to confidentiality concerns data on these prices are not publicly available. (City of San Diego, 5/2/11 at 3.) Since the average prices the utilities have recently paid for renewable energy have been above the MPR, the MPR serves as a reasonable estimate of the costs avoided by the utilities from their procurement of net surplus generation.

The Joint Solar Parties provided data on net surplus generation in PG&E's territory to provide a sense of how the quantity of net surplus generation compares to the renewable contracts that PG&E might otherwise execute. The Joint Solar Parties show that in 2009, PG&E's net surplus generators produced over 5,000 MWh, which is equivalent to 3 MW of solar capacity or two 1.5 MW facilities that could participate in the feed-in tariff program described above. An estimate of the expected future net surplus generation, based on current trends, shows that equivalent capacity of net surplus generation in PG&E's territory could reach 9 MW by 2014. (Joint Solar Parties, 7/23/10 at 10 – 11.)

There was considerable disagreement among parties about whether the NSC rate should include any compensation for capacity value, with the utilities and TURN taking the position that it should not. These parties offer several arguments in support of their position: that net surplus generation is intermittent and unforecastable and only known after the one-year true-up has occurred (PG&E, 7/23/10, at 5; TURN, 7/23/10, at 6); that net surplus generation cannot be counted for resource adequacy (SDG&E, 7/23/10, at 13);

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[23] To be clear, we do not rely upon MPR in this instance as a reflection of the cost to avoid procurement from a 500 MW combined-cycle gas turbine, which is the basis of the MPR formula.

and that there is no long term commitment from net surplus generators and that conceivably they could switch to an alternate program (SDG&E, 7/23/10, at 17; SCE, 7/23/10, at 6). SDG&E references findings from the 2009 CSI Impact Evaluation, which shows that most surplus generation occurs during the non-peak months of April, May and June. Moreover, the most common month for customers to produce surplus generation was April for SCE and SDG&E and the most common for PG&E was May. (SDG&E, 8/6/10 at 5 – 6.)

The Joint Solar Parties responded to these points largely by focusing on net surplus generators as an aggregate resource consisting of thousands of different facilities. The Joint Solar Parties provided evidence that from 2007 through 2009 the share of net surplus generators among all NEM customers remained relatively stable and that the quantity of net surplus generation per customer was stable or consistently growing. (Joint Solar Parties, 6/21/10, Tables 3 – 5.) However, the Joint Solar Parties provide no analysis that indicates when surplus generation is most likely to occur.

We find the arguments of TURN and the utilities to be persuasive that the MPR should not include a capacity value. Therefore, we will use the variable component of the MPR as the basis for the NSC rate, which based on the most recently adopted MPR is 7.47 cents/kWh.[24]

With the passage of Senate Bill 2X on March 29, 2011, the Commission would no longer be required to calculate an MPR for the RPS program. Thus, future updates to the MPR are unknown at present. If the Commission does not continue to update the MPR, the last MPR approved by the Commission will continue to serve as the basis for the NSC rate. In that event, parties may file a

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24 The variable component of the MPR can be found in the 2009 MPR Model at: http://www.cpuc.ca.gov/NR/rdonlyres/1406475F-6F1E-4A3F-85AF-6EA53419BA01/0/2009_MPR_Model.xls.

petition for modification of this decision to request the Commission consider using an alternate method to set NSC rates.

We accept the Joint Solar Parties' recommendation that the NSC rate be adjusted for TOD using the typical hourly profile of solar output, and we adopt the TOD factors that they propose. (Joint Solar Parties, 6/21/10 at 3.) As PG&E noted, hourly export data is not collected so the true export profile is not known. (PG&E, 7/23/10 at 6.) However, in the absence of better data, the typical production profile of fixed-axis solar panels serves as a reasonable proxy. (Joint Solar Parties, 6/21/10 at 6.) SDG&E was the only utility that provided an alternate TOD adjustment factor, which it based on load research data from its residential NEM customers. SDG&E reports that based on this analysis they derive an adjustment factor of 1.056. However, their analysis only covers residential customers, and an adjustment factor is required for all customer classes. At some future time, after the utilities have collected better data on the TOD profile of net surplus generation for all customer classes, they may file a petition for modification of this decision to revise the TOD factors adopted herein.

The Joint Solar Parties propose that net surplus generators receive payments at a fixed rate over twenty years using the twenty-year MPR for the contract start date that applies to the year the solar panels commence operation. (Joint Solar Parties, 6/21/10 at 2.) DRA and TURN support using an NSC rate based on the MPR, but they suggest that the NSC rate vary from year to year using the most recent MPR and that the same rate apply to all customers. Net surplus generators are dissimilar from independent power producers that sell electricity to utilities under long-term contracts. Independent power producers who invest in renewable energy facilities as a business depend on predictable long-term revenue streams, and their motivation for producing electricity for sale to a utility is primarily to generate revenue. In contrast, as NEM customers, net surplus generators install renewable generating facilities on their premises principally to offset part or all of their own electrical requirements, and they do not sign long-term contracts with utilities to sell excess energy at a given price. Taking these factors into consideration, we agree with TURN and DRA that net surplus generators should all receive payments based on the variable component of the most recently approved MPR rate in effect at the time the true-up is calculated, and that same rate shall apply to all customers who receive NSC payments in any given year. In other words, net surplus generators should not receive long-term fixed NSC rates based on the date that the generator's system becomes operational.

The NSC rate will vary as the MPR is updated by the Commission. The MPR approved in any given year is actually an array of values that varies depending on the contract length and the year that a facility commences commercial operations.[25] The NSC rate should be based on the variable component of the twenty-year contract price for the earliest online date listed in the most recently adopted table of MPR values in effect at the time the annual true-up is calculated. Using the 2009 MPR values as an example, the variable component of the 20 year contract rate with a 2010 online date (the earliest online date for the 2009 MPR), before TOD adjustments are applied, is 7.47 cents per kWh.

We do not adopt the adders for avoided T&D costs and avoided line losses that the Joint Solar Parties seek to include in the NSC rate. We agree with the utilities that we should not include avoided T&D in the NSC rate because it has not yet been demonstrated that net surplus generation avoids these costs. PG&E

[25] For example, see the table of 2009 MPR values at: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/111386.htm.

raises several compelling points in its discussion of this issue. (See PG&E, 7/23/10 at 7 – 9.) First, the net exports that are eligible for AB 920 compensation are only known at the end of a customer's true-up period. Thus it is difficult to determine what impact these exports may have had on alleviating demand on T&D systems. Second, the quantity of net exports is so small that for the foreseeable future it would have a *de minimus* impact on the T&D grids. Third, as the Commission has previously determined, the potential for DG to defer upgrades to T&D capacity depends on the time and location that the DG occurs. Finally, as both PG&E and DRA explain, the cost and benefit values for DG have not yet been publicly vetted at the Commission. (PG&E, 7/23/10 at 8; DRA, 6/21/10 at 5.) Therefore, it is not appropriate to include T&D benefits here. For similar reasons, we will not adopt an avoided line-loss adder at this time.

The MPR-based NSC rate is a bundled rate that includes the value of the renewable attributes associated with the net surplus generation. That bundled NSC rate must be disaggregated into an energy-only rate and a green premium for two reasons. First, it will take some time for the utilities to meet with the voluntary REC market organizations and work out a process for satisfactorily resolving REC tracking and ownership, as described in Section 5.2. In order to expedite the initial payments under the NSC program, net surplus generation trued-up before the Commission's approval of the REC ownership verification process should be paid using the energy-only NSC rate because the net surplus generation will not count toward RPS targets until the verification process is approved. Once the REC ownership status and tracking mechanisms have been established, the green premium for the initial true-up period should be paid retroactively to the REC owners whose RECs are transferred to the purchasing utility. Second, separate energy-only and green premium rates will be needed on an ongoing basis in order to pay the energy-only rate to customer-generators who have sold the right to their RECs and to pay the green premium rate to the owners of REC associated with net surplus generation who choose to sell their RECs to the utilities purchasing the net surplus generation. We will adopt SCE's proposal to use the most recent WECC-wide average green premium as reported by the DOE. The value shown in SCE's proposal is 1.83 cents per kWh. (SCE, 6/21/10, Attachment A at A-2.) The resulting rates for SCE, SDG&E and PG&E are shown in the table below.

Table 2:
Net Surplus Compensation Bundled, Green Premium, and Energy Only Rates

	PG&E	SCE	SDG&E
2009 MPR, 20-Year Contract, 2010 Online Date, Variable Component	$0.0747	$0.0747	$0.0747
TOD Adjustment	1.26	1.32	1.12
Full Bundled NSC Rate	$0.0941	$0.0986	$0.0837
Renewable Premium	$0.0183	$0.0183	$0.0183
Energy-Only NSC Rate	$0.0758	$0.0803	$0.0654

With regard to CalPECO (formerly Sierra Pacific) and PacifiCorp, we realize these two utilities have very few customers that may qualify for NSC payments, and we agree that we should make administration of NSC as simple as possible given the unique characteristics of these two utilities with small territories in California. The record does not indicate whether CalPECO has standard TOD factors to adjust MPR and did not provide information on how PacifiCorp's TOD adjustment factors would be applied. In comments, PacifiCorp noted that it has established on-peak and off-peak adjustment factors for use in its AB 1969 feed-in tariff program, although PacifiCorp did not produce the weighted adjustment factor resulting from the application of its on-peak and off-peak factors to the standard solar production profile used by the Joint Solar Parties. We direct PacifiCorp to file a Tier 3 advice letter revising its

NEM tariff to include a provision for NSC and to demonstrate how it derived its TOD adjustment factor in manner consistent with the method utilized by the Joint Solar Parties. For administrative simplicity, we direct CalPECO to file a Tier 2 advice letter in compliance with this order adopting the NSC rate of PacifiCorp, PG&E, SCE, or SDG&E.

The other small and multi-jurisdictional utilities (SMJUs; namely Bear Valley Electric Service (BVES) and Mountain Utilities) were not parties to this proceeding but we must also make provisions for them to offer net surplus compensation to their customers. Consequently, we shall require BVES and Mountain Utilities to each file a Tier 2 advice letter adopting the NSC rate of PG&E, SCE or SDG&E or file an application describing an alternative net surplus compensation rate and a detailed explanation why a deviation from the methodology adopted in this decision is necessary for their operations.

The rates shown above should be updated when a new MPR is adopted by the Commission and/or DOE releases a new value for the average green premium in the WECC. Within 30 days of any change to the MPR or the DOE-published WECC renewable energy premium, each utility shall file updated NEM tariffs with revised net surplus compensation rates by Tier 2 advice letter. BVES and Mountain Utilities may be exempt from this requirement if we approve an NSC rate for them that does not rely on the MPR.

It is important to simplify the calculation of the NSC rate and the administration of the NSC program in order to keep administrative costs reasonable relative to the value of the net surplus generation. According to PG&E, data from 2009 indicates that fewer than 10% of its NEM customers, or 2,450 customers, were net exporters of electricity and they generated a total of 5,212,073 kWhs. (PG&E, 3/15/10 at 10 and 12.) Thus, the total value of PG&E net surplus generation at the full NSC rate shown in the table above equals approximately $500,000. Data supplied by CALSEIA/EC supports the conclusion that total dollars that will be paid out for NSC is likely to be minimal. They report that in 2009, SDG&E had fewer than 1,000 customers eligible for NSC, generating on average less than 2,500 kWhs, indicating a total NSC value of less than $210,000. SCE reported fewer than 1,500 customers eligible for NSC, also generating on average less than 2,500 kWhs, yielding a total NSC value of less than $370,000. (CALSEIA/EC, 6/21/10 at 6.)

We find the Joint Solar Parties' NSC proposal is administratively simple because it relies on a value that has been updated and adopted by the Commission on a regular basis. The simplicity of this approach gives us an avoided cost NSC rate at a low administrative cost. We do not want the cost of implementing NSC to dwarf the compensation the customers receive under the program.

According to § 2827(h)(3), customers were notified in January 2010 that they could opt to receive NSC. Therefore, the NSC rates approved through each utility's advice letter will apply to customers who chose NSC when notified in January 2010, or thereafter.

6.1. Discussion of Proposals Not Adopted

We decline to adopt other parties' proposals as set forth below.

6.1.1. Utility Proposals for Value of Energy

PG&E proposes an NSC rate based on a simple rolling average of the hourly DLAP prices from 7 a.m. to 5 p.m. over the customer's true up period. PG&E argues that this rate represents the price that a utility pays for a quantity of energy sufficient to meet its day-ahead load and the costs the utility avoids when NEM customers export excess energy between 7 a.m. and 5 p.m. We reject PG&E's proposal because it ignores the fact that net surplus generation counts toward the utilities' annual RPS targets; therefore, net surplus generation should more appropriately be compared to the cost of other sources of electricity that apply toward meeting RPS targets. We conclude that basing the NSC rate on a simple rolling average of hourly DLAP prices does not reasonably reflect the costs the utility avoids in procuring electricity from renewable sources.

Similar to PG&E's proposed electricity value, SCE's proposal involves an avoided cost based on short-term CAISO market prices. PG&E's proposal uses DLAP prices because net surplus generation will create exports from NEM customers, which will likely offset other customers' load and result in fewer purchased kWhs of load at the DLAP price. SCE's proposal is less appropriate because the MRTU generation hub price is the price paid for additional kWhs of sales to the CAISO, and NEM customer generators do not sell directly to the CAISO. (PG&E, 3/15/10 at 4, n. 1.)

Moreover, we agree with the Joint Solar Parties and Acton that SCE's method of converting bill credits to NSC using a weighted average ratio is overly complex, results in different prices for different customers, and could result in higher administrative costs. (Joint Solar Parties, 7/23/10 at 17.) As the Joint Solar Parties point out, it is problematic that under SCE's proposed NSC ratio approach, a customer's payment is determined in part by the size of any remaining bill credit. The larger the bill credit, the larger the payout, while a customer with net surplus generation but no bill credit receives no NSC payment. In addition, SCE proposes to weight average hourly MRTU prices based on a customer load profile. SCE provides only one sentence in an attachment explaining this solar profile weighting and we find this explanation insufficient.

SDG&E and PacifiCorp both propose NSC rates based on SRAC prices paid to QFs. We prefer an avoided cost approach to valuing NSC, in line with the authority granted in the recent FERC order that allows us to differentiate avoided costs on the basis of the supply characteristics of the different technologies, i.e., the unique attributes of the excess power received from net surplus generators. (See 133 FERC ¶ 61, 059 (October 21, 2010) at ¶ 23.) Although SRAC QF pricing sounds simple and straightforward, it is not. SRAC QF rates are frequently subject to litigation and adjustment in regulatory proceedings. Plus, there are many different settlements and rates for QFs, depending on whether they are renewable or non-renewable.

We also reject the interim rate proposed by PG&E and the rate proposed by Sierra Pacific. PG&E suggests an interim NSC rate based on its system average generation rate, while Sierra Pacific proposes an NSC equal to the generation component for baseline quantities from its retail rates. PG&E acknowledges that its proposed interim rate is the generation component of retail rates and represents embedded or average, costs and not avoided or marginal costs. (PG&E, 3/15/10 at 5, n. 3.) Sierra Pacific's proposed rate is similar. Both of these rates are set in regulatory proceedings based on utility costs. We consider our approach of identifying an avoided cost to be superior. In our view, it is more appropriate to compensate net surplus generators using an avoided cost rather than an embedded cost.

6.1.2. Other Proposals to Value Net Surplus Generation

We decline to adopt proposals by CALSEIA/EC and Solutions for Utilities to base NSC on retail electric rates because, in our view, this would over-compensate NEM customers by paying them a rate above and beyond the value of electricity. As the utilities point out, costs associated with T&D infrastructure, billing, and other utility services are not avoided when a customer installs a generation system. If we set the NSC at the full retail electric rate which includes T&D, and other utility administrative and overhead costs, this would shift the collection of these costs to other ratepayers in violation of

§ 2827(h)(4)(A) which requires that non-participating customers be indifferent to the NSC rate.

Further, we will not adopt the proposal by CALSEIA/EC to set the NSC rate equal to the feed-in tariff rate that will be adopted in R.08-08-009 pursuant to SB 32. Proceedings to set the SB 32 feed-in tariff rate are at a preliminary stage and it is unclear when the feed-in tariff would be available and whether it would even apply to PacifiCorp and Sierra Pacific.

Moreover, we reject the adders to the feed-in tariff rate proposed by CALSEIA/EC to account for avoided emissions costs and health benefits to society. As PG&E notes, emission control costs are not avoided by the utility when NEM customers provide net surplus power. If the NSC rate included emissions adders on top of avoided energy values, PG&E would be paying twice for the same costs. Moreover, we agree with Acton, TURN and PG&E that non-monetized benefits such as "health benefits for avoided state emissions" have not been recognized by the Commission to date and are too vague.

We will not adopt the proposal by Acton to set NSC based on RPS contract prices. We agree with SDG&E, PG&E and SCE that it is not reasonable to pay RPS contract prices when there is no long-term commitment from NEM customers to generate surplus power. In our view, ratepayers would not be indifferent if they were paying a premium contract price for non-contracted power. As SCE notes, NEM customer generators' systems are intended primarily to offset part or all of each NEM customer's own electrical requirements and are not dedicated generating systems built solely to serve a utility's load.

The proposal by the City of San Diego to equate the NSC with the price paid for utility-owned solar generating plants is also rejected.[26] SCE and TURN contend that the Commission-adopted price of utility-owned solar plants is an "all-in" price for a long-term central station generating facility with a long-term contract, and it is inappropriate to compensate intermittent surplus generation at this rate. TURN adds that it is unreasonable to pay the full, levelized cost of utility-owned solar for excess NEM generation, especially when ratepayers already subsidize NEM customer-generators through California Solar Initiative (CSI) and the Self Generation Incentive Program (SGIP) incentives and by paying NEM bill credits at the full retail electric rate. We agree.

Finally, we reject the proposal by DRA to base the NSC rate on DG avoided cost calculations. While the Commission adopted a methodology to analyze DG costs and benefits in D.09-08-026, and this methodology includes DG avoided cost estimates, certain components of the methodology were not finalized in D.09-08-026, and work continues to address these components. This proceeding is not an appropriate venue to examine these debated components and settle long-standing disputes over DG avoided cost calculations.

6.1.3. Renewable Attribute Value Proposals not Adopted

We have already stated that the MPR-based NSC rate is a bundled rate that includes the value of the renewable attributes associated with the net surplus generation. We have also explained that the bundled NSC rate must be disaggregated into an energy-only rate and a renewable premium. For the interim, we agree with SCE's proposal to base the renewable premium on premiums published for the WECC by the DOE.

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[26] See D.09-06-049 (SCE), D.10-04-052 (PG&E), and D.10-09-016 (SDG&E) where the Commission adopted prices for utility-owned solar plants.

PG&E and SDG&E both suggest that once REC trading is in place in California, renewable attributes could be priced using the average REC price over a 12-month period.[27] In the interim period prior to REC trading, SDG&E suggests adding the MPR GHG adder of 0.8 cents/kWh to the electricity portion of the NSC rate if the renewable energy that is purchased is RPS-eligible. PacifiCorp proposes an adder of one cent/kWh.

CALSEIA/EC, the Joint Solar Parties, Acton, and City of San Diego do not suggest a separate value for renewable attributes because they propose a bundled rate, based on either retail rates, feed-in tariff rates, the MPR, contract prices under RPS, or utility-owned solar prices. The bundled rate proposals include compensation for both electricity and renewable attributes. Similar to the utility proposals, the Joint Solar Parties suggest that once a REC price is established by a market, that price could be substituted for the GHG adder currently embedded in the MPR. Sierra Pacific proposes no compensation for renewable attributes because it maintains NEM customers are not RPS eligible or tracked by WREGIS.

CARE provides no estimated value for renewable attributes, although it maintains that GHG offsets in the form of RECs are an energy ancillary service that the Commission maintains authority over in regard to the price that is paid to QFs. CARE contends the implied REC price is the difference between the cost of the standard contract and the market value of a comparable brown energy product. PG&E claims CARE's comments contain incorrect statements regarding FERC jurisdiction and there is no foundation for CARE's argument that a REC or a GHG offset are similar to ancillary services.

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[27] There is currently no functionality in WREGIS to post a public REC price.

We agree with proposals by PG&E, SDG&E and the Joint Solar Parties that once a REC market develops and there is a means to obtain public REC prices, we should use publicly-available average REC prices in California over a 12-month period as our renewable premium rather than the WECC region renewable premium published by DOE. Therefore, we will reconsider the appropriate value for renewable attributes once there is a publicly-available index of California RPS-eligible REC prices. Parties may file a petition for modification of this decision when such an index emerges.

7. Implementation of NSC Payments

7.1. Does the customer need a bill credit to be eligible for an NSC payment?

SCE, SDG&E, and PacifiCorp maintain that to qualify for an NSC payment, an NEM customer must have a remaining bill credit as well as generation in excess of usage. According to SDG&E, if a customer has used up all its bill credits earned during the 12-month true-up period, the customer has already been compensated for all excess generation at the full retail electric rate. SCE and SDG&E contend that to provide further compensation in excess of the retail rate would amount to double payment, shifting costs to non-participating customers.

In contrast, PG&E, the Joint Solar Parties, Acton, City of San Diego, IREC, and TURN claim that NEM customers should not be required to have a remaining bill credit to receive NSC. These parties generally assert that if a customer has generated surplus power, the customer should be compensated, and that any bill credit at the end of the true-up period should be irrelevant. PG&E maintains that the eligibility for NSC is based on net generation only, and there is no mention of a bill credit requirement in the statute. Moreover, PG&E describes how bill credits can bear no relation to the amount of surplus electricity exported by an NEM customer. PG&E asserts that if bill credits are required for or linked to NSC, senseless and unfair results can ensue, with some customers receiving well below avoided costs and others receiving tens or hundreds of dollars per kWh of net surplus. (PG&E, 3/15/10 at 8.) TURN and DRA both comment that NSC payments should be reduced by any bill debits owed on the true-up date.

Another variation on the issue is raised by CALSEIA/EC. They contend that if an NEM customer has a bill credit but no net surplus generation, the customer should still receive an NSC payment. According to CALSEIA/EC, this can occur when an NEM customer on a TOU rate provides excess generation during hours of peak electricity demand when rates are high, but uses most of its electricity off-peak when rates are lower. As a result, the customer may have a bill credit even though it did not generate excess energy over a 12-month period. The Joint Solar Parties and TURN argue that NEM customers with a bill credit but no net surplus should not be compensated.

Upon review of AB 920, we agree with PG&E that the language in the statute is straightforward and that customers who generate more kWhs than they use in their 12-month true-up period may choose to receive net surplus compensation. We will not add a secondary requirement, which does not appear in the statute, that customers must also have a bill credit to be eligible for net surplus compensation. Moreover, we agree with TURN and DRA that any payment for NSC should be reduced by any amount the customer owes to the utility. We disagree with the proposal by CALSEIA/EC that customers with a bill credit and no net surplus generation should receive further compensation. Again, we return to the plain language of the statute that requires compensation when customers are net generators. If a customer has not generated excess kWhs, the customer is not eligible for NSC.

7.2. Rollover of Excess kWh

Section 2827(h)(3) allows eligible customer-generators to elect whether to receive net surplus compensation for any net surplus electricity generated during the prior 12-month period, or whether to apply, or "rollover," the net surplus electricity as a credit for kWhs subsequently supplied.[28] Several parties raise conflicting views on how to handle NSC if the NEM customer opts to rollover the net surplus as a credit against future usage.

IREC maintains that because AB 920 creates two options for NEM customers, either compensation or a bill credit, there can be two NSC rates — one that applies if a customer chooses immediate compensation, and a separate rate if a customer elects to rollover excess generation. In other words, if a customer chooses to rollover net surplus as a credit against future usage, IREC contends the rate used for future credits is not subject to the requirement in § 2827(h)(4)(A) that other ratepayers be left unaffected. Thus, IREC claims that any rollover of net surplus generation should offset the full retail electric rate of subsequent usage.

PG&E and SDG&E argue that IREC's reading of AB 920 is not credible and defies statutory construction because the statute makes clear that NSC implementation options should leave other ratepayers unaffected, whether a customer chooses an immediate cash payment or a credit against future usage.

We agree with PG&E and SDG&E. The value that customers receive for net surplus generation should be the same whether the customer chooses immediate compensation or opts to rollover net surplus generation against future usage. The value of net surplus generation should be converted to a

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[28] Section 2827(h)(3) states that if an eligible customer-generator does not affirmatively elect service pursuant to net surplus electricity compensation, the electric utility shall retain any excess kWhs generated during the prior 12 month period and the customer shall not be owed any compensation.

monetary credit before being carried forward. If net surplus generation were carried forward as IREC suggests, it could offset later usage at different and potentially higher retail rates. We have already found in Section 6.1.2 that providing NSC payments at the full retail electric rate shifts costs to other customers. We now add to that finding that providing NSC rollover credits at future retail electric rates, which might be higher than the rates in effect at the time the surplus was generated, could shift costs to future customers. Additionally, IREC's proposal could be difficult to implement. Currently, SDG&E, PG&E and SCE convert kWh to dollars on a monthly basis as part of NEM and changing this would cause administrative costs and customer confusion.

We find it more reasonable to adopt the recommendation of PG&E, SCE and the Joint Solar Parties that net surplus generation should be valued at the conclusion of the relevant true-up period at the same price whether a check is mailed to the customer or a credit is applied to the bill against subsequent usage. In other words, if customers choose to rollover excess kWhs, the dollar amount of any net surplus compensation will be applied to the customer's account directly rather than drafting a separate check. Once the excess kWhs have been valued in dollars, the kWh values in all time periods should be reset to zero and the cycle starts anew. We agree with the proposal by several parties that the utilities should allow NEM customers to maintain such NSC bill credits indefinitely. In addition, we will allow customers to switch from compensation to rollover, or vice versa, on an annual basis.

Sierra Pacific, which has very few NEM customers, requests unique treatment. It proposes the same concept that IREC endorsed, that is, to allow banking of surplus electricity in the form of kilowatt hours, which would be treated as a credit and used to offset kilowatt hours subsequently supplied by

Sierra Pacific. Although Sierra Pacific has only a handful of NEM customers, we see no reason for unique treatment. Sierra Pacific should value excess kWhs annually and either mail a payment to the customer or apply that credit to future usage.

7.3. Minimum Payment Amount

PG&E recommends a one dollar minimum payment amount for a customer to receive a check for NSC. The Joint Solar Parties and CALSEIA/EC agree this is reasonable unless the customer is closing the account. Sierra Pacific suggests a higher minimum threshold for its NSC payments based on its unique characteristics. Sierra Pacific proposes that if customer's net surplus is valued at less than $25 after 12 months, the valuation of the net surplus should be applied as credit for kWh subsequently supplied.

We will adopt a requirement that customers need a one dollar minimum NSC payment to receive a check from the utility. We further agree that for Sierra Pacific and PacifiCorp, this minimum payment amount should be $25 to minimize the administrative costs on these smaller utilities with few NEM customers.

7.4. System Sizing Limits

The definition of an eligible customer-generator in § 2827(b)(4) includes the statement that the system "is intended primarily to offset part or all of the customer's own electrical requirements."

The utilities maintain that the NSC scheme established by AB 920 is intended to address random, modest, inadvertent net exports and that NEM customers must adhere to this existing NEM system sizing limit, which has been a long-standing prerequisite for NEM participation, in order to qualify for NSC payments. The utilities contend that since the statute for net surplus compensation retains the system sizing limit language, customers cannot oversize their solar or wind electrical generating facilities to create additional revenue. Moreover, the utilities note that other compensation mechanisms exist for customers who want to generate electricity to sell to the utility, such as feed-in tariffs. CALSEIA/EC agree with the utilities, suggesting that customers who oversize their systems would not qualify for NEM, and therefore would be ineligible for NSC.

In contrast to the utility position, the Joint Solar Parties and Acton read the statute as not limiting the size of a customer's system except to less than 1 MW. DRA suggests the impact of AB 920 on current system sizing limits should be examined in R.10-05-004, where the Commission could consider exceptions to allow systems sized above historic demand.

We agree with the utilities that nothing in AB 920 alters the existing NEM system sizing language and that to be eligible for NSC, a system must meet the definition of an eligible customer-generator within § 2827(b)(4), including that it be intended primarily to offset part or all of the customer's own electrical requirements. Systems that are sized larger than the customer's electrical requirements would not be eligible for NEM and therefore, are not eligible for NSC either.

7.5. Should customers repay CSI or SGIP incentives to receive NSC?

Sierra Pacific and PacifiCorp recommend that the Commission require repayment of CSI or SGIP incentives as a condition for receiving NSC. Most other parties assert that customers should not be required to repay any incentives they received from CSI or SGIP in order to receive NSC. Several parties cite to § 2827(c)(1), which states:

> Eligibility for [NEM] does not limit an eligible customer-generator's eligibility for any other rebate, incentive, or credit provided by the electric utility, or pursuant to any

> governmental program, including rebates and incentives provided pursuant to the [CSI].

We agree with the majority of the parties that it would be inconsistent with § 2827(c)(1) to require repayment of CSI or SGIP incentives. In addition, even without this statutory limitation, it would undoubtedly create administrative and billing complications to attempt to collect repayment of prior CSI or SGIP incentives from customers.

7.6. Are Community Choice Aggregation, Direct Access, and other customers eligible to receive NSC?

Several parties question whether customers of Community Choice Aggregators (CCAs) and direct access customers of energy service providers (ESPs) are eligible to receive NSC payments. PG&E, CALSEIA/EC, IREC, and the Joint Solar Parties generally propose that the Commission require CCAs and ESPs to offer NSC to their customers who participate in NEM and are net surplus generators. PG&E further states that customers who receive service from ESPs and CCAs should not receive NSC payments from PG&E because PG&E is not their generation supplier. The Joint Solar Parties clarify that NEM customers should be compensated by the relevant CCA or ESP for the generation component of the NSC. PG&E proposes that additional customer groups, namely wind energy co-metering customers (i.e., wind generators from 50 kW to 1 MW), multiple tariff treatment customers, and virtual net metering (VNM) customers under the CSI Multifamily Affordable Solar Housing Program also be eligible to receive NSC.

SDG&E opposes requiring CCAs and ESPs to offer NSC, although SDG&E suggests these entities may choose to offer NSC. Sierra Pacific contends that according to § 2827(b)(4), eligible customer-generators must be a "customer of an electric utility" to qualify for NSC.

First, we will not require ESPs to offer NSC because they do not match the definition of electric utility in the statute. Section 2827(b)(3) defines an electric utility as "an electrical corporation,…an electrical cooperative, or any other entity, *except an electric service provider*, that offers electrical service." (Emphasis added.)

Second, we will not require CCAs to offer NSC to their customers at this time because CCAs did not receive adequate notice of this proceeding concerning implementation of the NSC program. CCAs do not appear to have been included on the service list for this rulemaking. CCAs may choose to offer NSC to their customers and the Commission may, at a later date, consider requiring CCAs to provide NSC. CCAs that choose to offer NSC will need to coordinate customer enrollment with the utilities to ensure that no net surplus generator benefits from more than one NSC program for the same generation. We also agree with PG&E that customers who receive service from ESPs or CCAs would not receive NSC payments the distribution utility because the distribution utility is not their generation supplier.

Finally, we will allow PG&E and the other utilities to offer NSC to any NEM customer, including wind energy co-metering customers, VNM customers, and multiple tariff treatment customers. PG&E's compliance filing containing its revised NEM tariffs should address how NSC will apply to these various customer classes.

7.7. Administrative Costs

The utilities propose that their costs to implement and administer NSC should be absorbed by all customers rather than applying an administrative fee on NEM customers alone. PG&E contends that the costs of implementing the NSC program could overwhelm much of the value of the program to eligible net generators. According to PG&E, in 2009, less than 10% of its NEM customers, or

2450 customers, had a credit at the time of their true-up and were net exporters of electricity, and of those net exporters, over 40% had net exports of 100 kWh or less. (PG&E, 3/15/10 at 10-12.) PG&E claims that the cost of tracking these customers, notifying them of their options, cutting checks, and other administrative duties could be larger than their compensation.

The Joint Solar Parties and City of San Diego agree with PG&E that the costs to administer the NSC program should be absorbed by all customers.

We agree that payments to individual net surplus generators are likely to be small. If the utilities assessed a fee on customers to participate in this program, the fee could be larger than any NSC payments. We accept PG&E's recommendation that the administrative costs of NSC, which we expect to be minimal, be absorbed by all customers. This is similar to how costs of implementing NEM tariffs and other alternative billing arrangements are allocated widely to all customer classes as billing-related costs in utility general rate cases. In the event administrative costs are larger than anticipated, we may reconsider this allocation of administrative costs.

7.8. NEM Tariffs

Most parties agree that the details of the NSC program, including the NSC rate and details concerning NSC payments, should be incorporated into the utilities' existing NEM tariffs. We agree and we will require the utilities to include revised NEM tariffs incorporating the NSC rates, terms, and conditions set forth in this decision in the advice letter they each submit with their specific NSC rate calculations in compliance with this decision.

8. Comments on Alternate Proposed Decision

The alternate proposed decision of Commissioner Peevey in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of

Practice and Procedure. Comments were filed on April 25, 2011 by CALSEIA/EC, CARE, Donald W. Ricketts, the Joint Solar Parties, PG&E, SCE and SDG&E, and reply comments were filed on May 2, 2011 by the City of San Diego, the Joint Solar Parties, PG&E, SCE and SDG&E. We have made corrections and clarifications in the proposed decision in response to comments, as well as substantive changes on selected issues, as we describe in today's decision.

9. Assignment of Proceeding

Nancy E. Ryan was the original assigned Commissioner and Dorothy J. Duda is the assigned ALJ in this proceeding. The case was reassigned to Michael R. Peevey as assigned Commissioner in January 2011.

Findings of Fact

1. Section 2827 requires the Commission to establish a program to compensate NEM customers for electricity produced in excess of on-site load at the end of a 12-month true-up period, i.e., "net-surplus generation."

2. Under § 2827, customers may opt to receive either a payment for net-surplus generation or to roll a credit for that generation into the next 12-month period.

3. Section 2827 requires that any compensation for net surplus electricity leave other ratepayers unaffected and not result in a shifting of costs between solar customer-generators and other bundled service customers.

4. According to FERC, a transfer of net surplus energy by a net metering customer to a utility constitutes a wholesale transaction that must comply with either the FPA or PURPA.

5. FERC has found that wind and solar generating facilities of 1 MW can be considered QFs without filing for certification with FERC.

6. NEM customers eligible for NSC must use a solar or wind generating facility of not more than 1 MW.

7. Rule 21 governs QF interconnections.

8. According to § 2827, net surplus compensation may include either or both the value of electricity and the value of the renewable attributes of the electricity.

9. The amount of net surplus generation that is likely to be compensated is quite small compared to California's total electricity load.

10. Within the 12-month true-up period, customers will continue to receive a credit at the full retail electric rate up to the amount that offsets their usage, and the NSC rate will only apply to generation in excess of that amount.

11. Sierra Pacific and PacifiCorp have few customers that may qualify for NSC payments.

12. In recent years, the average price of energy procured by the utilities in their solicitations for renewable energy has exceeded the MPR.

13. Data on the time of day that net surplus generation is delivered to the grid are not currently available for most customers.

14. Data from the *California Solar Initiative 2009 Impact Evaluation* indicate that most surplus generation from NEM customers occurs during the non-peak months of April, May and June.

15. Section 399.12 defines a REC as "a certificate of proof, issued through the accounting system established by the [CEC] pursuant to Section 399.13" and Section 399.13 gives the CEC the authority to certify eligible renewable energy resources.

16. According to § 2827(h)(5)(A), if a utility purchases net surplus electricity, any RECs associated with that net surplus electricity shall belong to the utility.

17. To qualify for RPS compliance, renewable energy generators must be certified as eligible by the CEC, and the REC must be tracked and verified through a CEC-approved accounting system.

18. At this time, the CEC has not certified DG systems as eligible for RPS compliance, except DG systems under AB 1969 tariffs.

19. It is unclear if WREGIS can track and verify RECs that would be split between a utility and a customer.

20. RECs for RPS compliance are accounted for in 1 MWh increments and it is unclear if net surplus generation from multiple small facilities can be aggregated.

21. REC trading was only recently authorized by the Commission, and a publicly available index of California RPS-eligible RECs does not currently exist.

22. Section 2827 does not require NEM customers to have a bill credit to be eligible for net surplus compensation.

23. Section 2827 states that an eligible customer-generator's system is intended to primarily offset part or all of the customer's own electrical requirements.

24. NSC payments to individual net surplus generators are likely to be small and any administrative fee assessed on customers for the NSC program could be larger than the NSC payment.

25. ESPs are not electric utilities under § 2827.

Conclusions of Law

1. The Commission may adopt an NSC rate that does not exceed avoided costs consistent with PURPA.

2. NEM customers may self-certify as QFs.

3. Tariff Rule 21 should continue to govern interconnection between utilities and NEM customers who self-certify to the utility as QFs.

4. An avoided cost approach to valuing net surplus compensation reflects as closely as possible the costs the utility avoids by receiving surplus generation

from NEM customers while leaving other ratepayers unaffected and not shifting costs between customer-generators and other customers.

5. Use of an avoided cost approach to value net surplus compensation allows NEM customers to be compensated for both the value of electricity and the value of renewable attributes.

6. Other ratepayers are unaffected if the utility compensates net surplus generation at avoided cost.

7. The MPR is a reasonable and efficient source for an avoided cost value for renewable electricity as required by § 2827. However, only the variable component of the MPR should be used in recognition of the fact that net surplus generation is likely to provide little, if any, capacity value to the purchasing utility.

8. In the absence of time of delivery data for net surplus generation, the generation profile of a typical fixed-axis solar panel serves as a reasonable proxy.

9. According to § 2827(h)(3), small and multi-jurisdictional investor-owned electric utilities operating in California must offer net surplus compensation to their customers.

10. An NSC rate based on the full retail electric rate would provide compensation above the value of electricity and shift costs to other ratepayers.

11. Net surplus generation purchased by the utility should count toward RPS procurement targets, but only after the CEC revises the *RPS Eligibility Guidebook* to allow certification of net surplus generation facilities and approves a tracking system for the renewable attributes associated with net surplus generation.

12. Until an index of California RPS-eligible REC prices emerges, the use of the Department of Energy's annual survey of average WECC-wide renewable energy premiums should serve as the source of the renewable attribute value embedded in the NSC rate.

13. Payments for NSC should be reduced by any amount the customer owes to the utility.

14. If a customer has not generated excess kWhs, the customer is not eligible for NSC.

15. The value a customer receives for net surplus generation should be the same whether the customer chooses immediate compensation or opts to apply net surplus generation to offset future usage. Therefore, the value of net surplus generation should be converted to a monetary credit before being carried forward.

16. NEM customers may maintain NSC bill credits indefinitely and may switch from NSC payment to rollover, or vice versa, on an annual basis.

17. NEM customers should have a one dollar minimum NSC payment to receive a check from the utility, except NEM customers of Sierra Pacific and PacifiCorp should have a $25 minimum NSC payment to receive a check.

18. Systems sized larger than the NEM customer's electrical requirements would not be eligible for NEM and, therefore, are not eligible for NSC.

19. ESPs should not be required to offer NSC.

20. The Commission should not require CCAs to offer NSC to their customers at this time, although CCAs may choose to offer NSC.

21. Customers of CCAs and ESPs should not receive NSC payments from a distribution utility because the distribution utility is not their generation supplier.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each base their net surplus compensation rate on the variable component of the most recently Commission-adopted Market Price Referent, specifically the twenty-year contract price for the earliest online date listed for the Market Price Referent. This Market Price Referent rate shall be adjusted for time of delivery factors and the most recent Western Electricity Coordinating Council renewable energy premium reported by the United States Department of Energy, as shown in Table 2 of this decision.

2. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 3 advice letter revising their net energy metering tariffs to include net surplus electricity compensation pursuant to Public Utilities Code 2827 and the net surplus compensation rate as set forth in Ordering Paragraph 1. The net surplus compensation rate for each utility shall take effect upon Commission approval of that utility's advice letter and may be used to compensate customers who chose net surplus compensation when notified in January 2010 or thereafter.

3. Within 30 days of the effective date of this decision, PacifiCorp shall file a Tier 3 advice letter revising its net energy metering tariffs to include net surplus electricity compensation pursuant to Public Utilities Code Section 2827. PacifiCorp shall base its net surplus compensation rate on the variable component of the most recently Commission-adopted Market Price Referent,

specifically the twenty-year contract price for the earliest online date listed for the Market Price Referent. This Market Price Referent rate shall be adjusted for PacifiCorp's time of delivery factors, as listed in PacifiCorp's Tariff Schedule ERWW-1, applied to a representative hourly solar output profile in a manner consistent with the Joint Solar Parties' calculations for the other utilities and Table 2 of this decision. In its advice letter, PacifiCorp must demonstrate how it derived the weighted time of delivery adjustment factor. The Market Price Referent shall also be adjusted for the most recent Western Electricity Coordinating Council renewable energy premium reported by the United States Department of Energy, shown in Table 2 of this decision. The net surplus compensation rate for PacifiCorp shall take effect upon Commission approval of its advice letter and may be used to compensate customers who chose net surplus compensation when notified in January 2010 or thereafter.

4. Within 45 days of the effective date of this decision, California Pacific Electric Company shall file a Tier 3 advice letter in compliance with this order to:

a) Revise its net energy metering tariffs to incorporate the net surplus compensation rates, terms, and conditions set forth in this decision; and

b) notify the Commission whether it will use the net surplus compensation rate adopted for Pacific Gas and Electric Company, PacifiCorp, Southern California Edison Company, or San Diego Gas & Electric Company.

5. Within 60 days of the effective date of this decision, small and multi-jurisdictional investor-owned electric utilities operating in California, other than California Pacific Electric Company and PacifiCorp, shall either file a Tier 2 advice letter to adopt the net surplus compensation rate of Pacific Gas and Electric Company, PacifiCorp, Southern California Edison Company, or San Diego Gas & Electric Company, or file an application describing an alternative

net surplus compensation rate and a detailed explanation why a deviation from the methodology adopted in this decision is necessary for their operations.

6. Within 30 days of either the effective date of the Commission adopting an updated Market Price Referent or the publication by the United States Department of Energy of an updated average renewable energy premium for the Western Electricity Coordinating Council region, Bear Valley Electric Service, Mountain Utilities, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, California Pacific Electric Company and PacifiCorp shall each file Tier 2 advice letters revising their net energy metering tariffs to incorporate the updated Market Price Referent and/or renewable energy premium values. Bear Valley Electric Service and Mountain Utilities may be exempt from either or both of these requirements if the Commission approves a net surplus compensation rate for them that does not rely on the Market Price Referent or the United States Department of Energy's published average renewable energy premium for the Western Electricity Coordinating Council region.

7. Until the California Energy Commission approves a process for certifying the Renewable Portfolio Standard eligibility of net surplus generators and tracking the renewable attributes associated with net surplus generation, net surplus generation shall not count toward the utilities' renewable portfolio standard targets, and each investor-owned electric utility shall compensate net surplus generators using the energy-only net surplus compensation rate approved for that utility. Each investor-owned electric utility shall pay net surplus generators at the energy-only net surplus compensation rate as soon as the advice letter described in Ordering Paragraph 2 is approved.

8. Once the California Energy Commission has implemented a Renewable Portfolio Standard eligibility certification and renewable energy credit tracking

process for net surplus generation each investor-owned electric utility may apply the renewable energy credits associated with the net surplus generation it purchases to its Renewable Portfolio Standard compliance obligation, provided that the renewable energy credits are transferred to the investor-owned electric utility.

9. Once the California Energy Commission has implemented a Renewable Portfolio Standard eligibility certification and renewable energy credit tracking process for net surplus generation, each investor-owned electric utility shall use the full, bundled net surplus compensation rate approved by the California Public Utilities Commission for net surplus generators whose renewable energy credits are transferred to the investor-owned electric utility to calculate its net surplus compensation payments.

10. In the event that the California Energy Commission's Renewable Portfolio Standard eligibility certification and renewable energy credit tracking process for net surplus generation allows retroactive certification and renewable energy credit tracking, each investor-owned electric utility may retroactively count renewable energy credits associated with the net surplus generation it purchased prior to the implementation of the California Energy Commission's Renewable Portfolio Standard eligibility certification and renewable energy credit tracking process for net surplus generation toward the investor-owned electric utility's renewable portfolio standard targets, provided that the renewable energy credits are transferred to the investor-owned electric utility. Each investor-owned electric utility shall compensate the owners of the renewable energy credits associated with that net surplus generation that are transferred to the utility using the renewable energy premium as shown in Table 2 of this decision or the most recent renewable energy premium approved by the Commission.

11. Customers opting for net surplus compensation must notify the utility at the time they elect to receive net surplus compensation that they are a qualifying facility exempt from certification filing at the Federal Energy Regulatory Commission.

12. If a customer chooses to rollover excess kilowatt hours of net surplus generation, the dollar amount of any net surplus compensation must be applied to the customer's account directly rather than drafting a separate check. Once the excess kilowatt hours have been valued in dollars, the kilowatt hour values in all time periods should be reset to zero.

13. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Sierra Pacific and PacifiCorp may offer net surplus compensation to any net energy metering customer, including wind energy co-metering customers, virtual net metering customers, and multiple tariff treatment customers.

14. This decision shall be served on Bear Valley Electric Service and Mountain Utilities, Inc.

15. Applications (A.) 10-03-001, A.10-03-010, A.10-03-012, A.10-03-013, and A.10-03-017 are closed.

This order is effective today.

Dated ____________________________, at San Francisco, California.