Decision **PROPOSED DECISION OF ALJ DUDA (Mailed 11/3/2010)**

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

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DECISION ADOPTING NET SURPLUS COMPENSATION RATE PURSUANT TO ASSEMBLY BILL 920

1. Summary

This decision fulfills the requirements of Assembly Bill 920[1] and adopts a net surplus compensation 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."

Specifically, the net surplus compensation rate will be calculated using a market-based mechanism derived from an hourly day-ahead electricity market price known as the "default load aggregation point" (DLAP) price. A utility's DLAP price reflects the costs the utility avoids in procuring power during the time period net surplus generators are likely to produce their excess power.

The net surplus compensation rate will be a simple rolling average of each utility's DLAP price from 7 a.m. to 5 p.m. to match the hours that most net surplus generators produce electricity with their solar or wind generating facilities. The simple rolling average will match the 12-month period over which a customer's net surplus generation is calculated. In 2009, this average DLAP price for Pacific Gas and Electric Company was five cents per kilowatt hour.

Next, the decision finds that net surplus generators should be compensated for the renewable attributes of their electricity if and when they produce renewable energy credits. The decision finds that net surplus generators must meet certain preconditions, namely Renewables Portfolio

[1] Stats. 2009, Ch. 376.

Standard certification by the California Energy Commission and Western Renewable Energy Generation Information System metering and tracking requirements, in order to create renewable energy credits and for the utilities to count any net surplus generation they purchase toward Renewables Portfolio Standard annual procurement targets. The decision does not adopt a value for renewable attributes at this time, finding that valuation is premature until renewable energy credits are created by net surplus generators. Finally, net surplus generators seeking net surplus compensation payments for the renewable attributes of their electricity must certify they own any renewable energy credits associated with their generating facilities.

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. (Section 2827(a).)

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

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

> 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. (Section 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. (Section 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 and 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.

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[3] All dates are 2010 unless otherwise noted.

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 (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). Protests to the applications were filed by the Acton Town Council (Acton), the City of San Diego, CARE,[4] 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.

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

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 commerce."[5] 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

[5] 16 U.S.C. § 824(b)(1).

> over the applicable billing period would [FERC] assert jurisdiction. [Footnote omitted.][6]

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),[7] 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 "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

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

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

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. According to CALSEIA/EC, PURPA does not preempt state environmental laws, as the Commission noted in Decision (D.) 09-12-042. (CALSEIA/EC, 4/23/10 at 18.) 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. First, 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."[8] Section 2827 also provides that "where appropriate justification exists" the NSC can include either or both of "[t]he value of the

[8] § 2827(h)(4)(A).

electricity itself" or the "value of the renewable attributes of the electricity."[9] 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."[10]

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.[11] However, we disagree with the utility argument that the Commission is limited to identifying a net compensation rate pursuant to PURPA. FERC has held that a transfer of net surplus energy by a net metering customer to a utility constitutes a wholesale transaction that must comply with *either* the Federal Power Act (FPA) or PURPA. FERC summarized its holdings in the 2009 case of *Sun Edison*, stating:

> The Commission has explained that net metering is a method of measuring sales of electric energy. [Footnote: *MidAmerican, 94 FERC P 61,340 at 62,262-63 (2001)*]. 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. [Footnote: *Id.*] 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. [Footnote: The Commission, in *MidAmerican*, found that a one-month billing period was reasonable, but indicated that other billing periods could also be reasonable. *Id. at 62,262-64*] **If the entity making a net sale**

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

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

[11] *See, e.g*. FERC Order 2003-A.

> **is a QF that has been exempted from section 205 of the FPA by section 292.601 of our regulations, [Footnote: *18 C.F.R. § 292.601 (2009)*.] no filing under the FPA is necessary to permit the net sale;** however, if the entity is either not a QF or is a QF that is not exempted from *section 205 of the FPA* by *section 292.601* of our regulations, a filing under the FPA is necessary to permit the sale.[12]

As noted in the citation above, the Commission may pursue one of two paths in determining the value of the NSC under federal law. The Commission may implement the NEM Program pursuant to PURPA. Under such a program, the Commission would require each NEM to be a QF, and establish an avoided cost NSC rate to be paid by the utility to each NEM customer.

Alternatively, under the FPA,[13] the Commission may identify a mechanism that will produce a market-based rate to be paid by the utility to NEM customers for their net surplus. To engage in such market-based rate sales, NEM customers would either need to obtain market-based rate (MBR) authorization from FERC, or identify themselves to their utility as a QF exempt from FERC's MBR filing requirements. The latter path is possible, with no FERC filing by NEM customers, because: (1) FERC has previously found that QFs may engage in market-based sales; (2) FERC regulations provide that sales of energy or capacity made by certain QFs under 20 MW "shall be exempt from scrutiny under sections 205 and 206" of the FPA (18 CFR § 292.601(c)(1)); and (3) FERC has recently ordered that wind and solar generating facilities of 1 MW or less no longer need to file a certification of QF status with FERC to be considered a QF.

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[12] *Sun Edison LLC*, 129 FERC P61,146 (2009) at ¶ 18 (bolded emphasis added; italics in original).

[13] The Federal Power Act is codified at 16 U.S.C. §§ 791a *et seq.*

(IREC 4/23/10 at 11 citing FERC Order 732, 130 FERC ¶ 61, 214 (March 19, 2010).)

NEM customers eligible for NSC under AB 920 must use a solar or wind generation facility of not more than 1 MW. Accordingly, NEM customers can be considered QFs exempt from certification requirements at FERC and are able to sell power at market-based rates subject to the FPA filing exemption for QFs under 20 MW.

In sum, we conclude that we are not restricted to setting an avoided cost rate under PURPA. We choose instead to identify a market-based mechanism for identifying a net surplus compensation value that will include payment for both the value of electricity and the value of its renewable attributes. In order to receive the NSC payment, while also complying with the FPA MBR filing requirements, customers opting for NSC must notify the utility that they are a QF exempt from certification filing.[14] 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 Section 2827(h)(3).

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

[14] There is a remote possibility that an NEM customer may have filed and obtained MBR authorization from FERC. In that event, the customer should notify the utility of this instead.

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 cannot speak for FERC as to whether it will assert jurisdiction over interconnections involving net energy metering arrangements where there is a net sale of energy to a utility. (See, e.g. FERC Order 2003-A, 1006 FERC ¶ 61,220 (2004) at ¶ 747.) At the same time, the Commission's Rule 21 interconnection tariff governs interconnections between distribution systems of electric utilities and distributed generation (DG) facilities.[15] As IREC notes, the Commission previously concluded in D.03-02-068 that "California's interconnection rules and guidelines should apply to distributed generation that falls within the definition of a QF." (IREC, 4/23/10 at 11-12 citing D.03-02-068 at 37-41.) In that decision we stated: "… technical interconnection rules and procedures for distributed generation are state jurisdictional, regardless of whether incidental sales of energy occur." (D.03-02-068 at 41.)

We share PG&E's preference for Rule 21 to govern interconnections of customers who receive NSC. As we understand it, all or a large majority of the interconnections required for participation in the net metering program are at the distribution level. Notwithstanding the possibility that FERC may assert jurisdiction over an interconnection in the event of a net energy sale to a utility, Section 201(b)(1) of the FPA provides that FERC has no jurisdiction, with some limited exceptions inapplicable here, over facilities used in local distribution. There is no reason to assume that simply because a *de minimus* FERC jurisdictional sale – or any wholesale sale for that matter - occurs over distribution facilities, that the mandate of the FPA does not apply and that FERC may somehow "convert" the facilities to its jurisdiction. Because the Commission retains jurisdiction over distribution facilities, Rule 21 will continue to govern interconnection of those facilities, even if the facilities are intended to

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[15] *See, e.g.* D.05-08-013 at 3 ("PG&E's Rule 21 provides that its purpose is to govern 'the Interconnection, operating and Metering requirements for Generating Facilities to be connected to PG&E's Distribution System over which the California Public Utilities Commission (Commission) has jurisdiction. Subject to the requirements of this Rule, PG&E will allow the Interconnection of Generating Facilities with its Distribution System.' Rule 21 for SDG&E and SCE state similar objectives.").

be used to facilitate a wholesale transaction to the utility in the form of a net metering surplus. We do not believe that the options presented by PG&E need to be pursued.

4. Net Surplus Compensation Proposals

Now that we have clarified our authority to set an NSC rate based on market prices or avoided costs, we turn to the various proposals offered by the parties.

AB 920 requires the Commission, when setting 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. (Section 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 $.05/kWh. (PG&E, 3/15/10, Attachment B, at 4.) 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 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 shifts 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 Electric Coordination Council (WECC), as published periodically by the United States Department of Energy (DOE). SCE states that the average premium reported for the WECC is 1.8 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 oppose 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 a 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 the utility's most recent RPS solicitation. 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").[16]

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 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

[16] 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.

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

Joint Solar Parties' Proposed NSC Rates in cents/kWh[17]

	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. According to the Joint Solar Parties, it is appropriate to use an adjusted MPR because the Commission already uses MPR to price surplus output from small renewable generations up to 1.5 MW pursuant to AB 1969,[18] 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 5.

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

18 Stats 2006, Ch. 731.

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 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[19] 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

[19] Stats. 2009, Ch. 328.

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 5.1 below.

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 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 NSC 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.[20]

5. Adopted Value of Electricity

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." (Section 2827(h)(4)(A).) We discuss the value of electricity itself first.

As described in Section 3.1 above, the Commission can adopt an NSC rate based on either market-based rates for electricity, or avoided cost. We will adopt a market-based approach that we determine reflects, as closely as possible, the spot market value of the net surplus generation and complies with the mandate of Section 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. A market-based mechanism is consistent with the Commission's oft-stated goal of "markets first"[21] and it allows us to compensate NEM customers, when feasible, for both the value of electricity and the value of renewable attributes in order to fulfill a stated goal of AB 920 to encourage private investment in renewable energy resources.

We find PG&E's proposal to use DLAP prices is the most reasonable and efficient source for a market-based electricity value to include in our adopted NSC rate for several reasons. First, DLAP prices are hourly day-ahead electricity

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[20] 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.

[21] *See, e.g.* D.07-12-052.

market prices that are transparent and publicly available on the CAISO website.[22] DLAP prices represent the price that a utility pays for a quantity of energy sufficient to meet its day-ahead load and are the costs the utility avoids when NEM customers export excess energy between 7 a.m. and 5 p.m. We conclude other ratepayers will be unaffected if the utility compensates net surplus generation at this rolling average of the day ahead market price for power.

Second, PG&E proposes to base its rate on a simple rolling average of these hourly DLAP prices from 7 a.m. to 5 p.m. over the customer's true up period. We agree with PG&E that these hours reasonably correspond to the hours that most NEM customer-generators produce power. We find it appropriate to compensate net surplus generators at an average of the market-based rate the utility potentially avoids by receiving the customer's net surplus generation. We conclude that basing the NSC rate on a simple rolling average of hourly DLAP prices for the 12-month period that corresponds to the NEM customer's true-up period reasonably reflects the costs the utility avoids in procuring power during the time period NEM customers are likely to produce their excess power.

Moreover, this simple rolling average over a 12-month period is a reasonable market-based approach when we consider that the amount of net surplus energy that is likely to be compensated is quite small compared to

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[22] PG&E's DLAP prices can be found at http://www.caiso.com by clicking on the link to "OASIS," then clicking on "Prices" and choosing the "Locational Marginal Prices" report from the Report dropdown menu.

California's total electricity load. The cost of calculating market prices with more specificity would likely outweigh the value of the program. According to PG&E, data from 2009 indicates that less 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.) Over 40% of the net exporters on PG&E's systems had net exports of 100 kWh or less. (*Id.* at 10.) 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 less than 1,000 customers eligible for NSC, generating on average less than 2,500 kWhs, while SCE reported less than 1500 customers eligible for NSC, also generating on average less than 2,500 kWhs.[23] (CALSEIA/EC, 6/21/10 at 6.) This data indicates that SDG&E and SCE net surplus generators would receive individual annual payments of less than $125, if the NSC rate is five cents/kWh.

We find PG&E's NSC proposal is administratively simple because it takes public electricity prices and uses a simple methodology to convert those prices into an NSC rate that corresponds to the 12-month true-up period for the NEM customer. The three utilities can each use their own published DLAP prices using the same averaging technique proposed in PG&E's application to calculate the NSC rate for their customers. (*See* PG&E, 3/15/10, Attachment B.) The simplicity of this approach gives us a market-based 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.

[23] Assuming an NSC rate of five cents/kWh (based on the 2009 average) and annual net surplus generation for PG&E, SCE, and SDG&E of 12 million kWh, total annual net surplus compensation would equal $600,000.

Finally, our adopted DLAP pricing approach works well with the annual netting period required by Section 2827(h)(3). DRA and Acton object to the annual average pricing approach and propose an NSC that attempts to compensate based on the time that surplus is placed on the distribution system. (Acton, 6/21/10 at 5; DRA, 6/21/10 at 6.) We conclude that tracking individual customer usage and exports more frequently than on an annual basis would drive up administrative costs and deviates too greatly from the existing NEM program and statute. The statute repeatedly refers to net surplus as calculated over a 12-month period. Within the 12-month period, customers offset their usage with their generation at the full retail electric rate. AB 920 does not change this, but merely adds a compensation requirement over and above the full retail credits. If we base NSC on a rolling average DLAP price, it allows the monthly NEM netting process at full retail rates to continue in accordance with the current NEM program.

In summary, we will direct PG&E, SCE and SDG&E to use the simple rolling average of their DLAP prices from 7 a.m. to 5 p.m., corresponding to the customer's 12-month true-up period, as the value of electricity incorporated into each utilities' NSC rate. Each utility should file a Tier 3 advice letter containing the initial calculations for this DLAP-based NSC rate. The NSC rate for each utility shall take effect upon Commission approval of that utility's advice letter. According to Section 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 and who have true-up periods ending January 1, 2011 or later.

With regard to Sierra Pacific and PacifiCorp, we realize that 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. It is unclear if separate DLAP prices exist for Sierra Pacific and PacifiCorp. If Sierra Pacific and PacifiCorp have DLAP prices, those prices should be used to calculate each utility's NSC rate using the methodology described in this decision. We expect that Sierra Pacific and PacifiCorp can mirror the PG&E DLAP pricing approach without undue burden. In the event DLAP prices do not exist within the California territories of Sierra Pacific and PacifiCorp, we direct Sierra Pacific and PacifiCorp to base their NSC rate on PG&E's DLAP price. Sierra Pacific and PacifiCorp shall each file an advice letter in compliance with this order either to provide their calculations for a DLAP-based NSC rate or to notify the Commission they will use PG&E's NSC rate.

5.1. Discussion of Proposals Not Adopted

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

5.1.1. Utility Proposals

Similar to PG&E's proposed electricity value, SCE's proposal involves a market-based pricing source. We prefer PG&E's proposal to use 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 a market-based approach to valuing NSC. Although QF pricing sounds simple and straightforward, it is not. 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 prefer a publicly available market-price as the source for our NSC rate. In addition, SDG&E is not simply using the QF SRAC price, but proposes to adjust that rate based on an annually determined time-of-delivery factor. For non-TOU customers, this adjustment would be based on a representative profile of excess generation derived from SDG&E load research data. (SDG&E, 7/23/10 at 4-5.) We find this adjustment to QF rates complicated and likely to make annual NSC rate updates overly contentious and resource-intensive.

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 a market-based rate, such as publicly available DLAP prices, to be superior. In our view, a utility's DLAP price more reasonably reflects the costs a utility avoids when NEM customers deliver excess generation to the grid and it is more appropriate to compensate net surplus generators using a market-based rate rather than an embedded cost.

5.1.2. MPR

We reject the Joint Solar Parties' suggestion to base the NSC rate on the Commission-adopted MPR, plus additional adjustments, for several reasons. First, the utilities and TURN are correct that the Commission-adopted MPR does not reflect the actual market price of electricity because it is based, in part, on a long-term forecast of natural gas costs. As SCE and TURN both note, the MPR is a legislatively mandated metric intended as a cost benchmark for RPS projects with a known energy output, while NSC involves payment to NEM customers for an inherently unknown amount of net surplus generation. We agree with TURN that net surplus generation bears greater similarity to short term energy purchases by the utilities than the output of a long-term renewable generator under a power purchase agreement. As TURN notes, surplus generation cannot be forecast and only reduces real time market purchases. It does not serve as a hedge against gas price volatility so it should not be compensated as such. Since an individual NEM customer has no obligation to provide any energy to the utility, the only generation cost that the utility avoids when an NEM customer provides surplus is the reduced procurement of electricity from the CAISO wholesale market. While Joint Solar Parties contend the MPR should determine the NSC rate because it is used to pay generators under AB 1969 tariffs, we find the AB 1969 program is distinguishable from NSC because AB 1969 involves contracted power, while NSC involves payment for incidental, non-contracted power production.

Second, we reject the proposal to use the MPR to set the NSC rate because we agree with the utilities and TURN that it is not appropriate to pay net exports which can be occasional, intermittent, and unpredictable, using a cost methodology that assumes a long-term projection of costs and includes a value for capacity. As SDG&E notes, NEM customers are not under long-term contract to provide surplus generation. Thus, the NSC program cannot be counted on for resource adequacy and the utilities do not avoid capacity costs when a customer installs net metered solar or wind generation. As PG&E notes, AB 920 describes payment for the "value of electricity itself," implying an energy only payment. We agree with SCE that NEM customers already receive compensation for capacity by having their total generation netted with their total consumption at the bundled retail electric rate. An additional payment for capacity from net exports would over-compensate them and violate the customer indifference requirement in AB 920.

Third, we reject the proposal by the Joint Solar Parties to include avoided T&D costs in an MPR-based 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. As PG&E, Sierra Pacific and SDG&E explain, NEM customers make use of the T&D system to export their generation and it is impossible to forecast when and if exports will occur. As a result, net surplus generation may not defer capital investments. Moreover, NEM customers with exports during peak months already receive compensation for exports that offset their usage at the bundled retail electric rate. In our DG cost-benefit methodology decision (D.09-08-026), the Commission stated it would be reasonable to attempt to measure T&D benefits based on DG penetration, location, and diversity levels but found that no such benefits could be quantified at this time.[24] While we found it reasonable to include avoided T&D in our cost-benefit methodology for DG, the cost-benefit studies have not yet established a value for avoided T&D. Therefore, it is not appropriate to include T&D benefits here.

Fourth, we reject the concept of fixing the NSC rate for each customer for the life of that customer's system based on the MPR adopted in the year the system becomes operational. We agree with DRA, PacifiCorp and TURN that it is unreasonable to fix an NSC rate for the system life based on a 20-year forecasted rate such as the MPR. Further, we agree with SDG&E that basing the NSC rate on a fixed MPR value would create a mismatch between NEM credits, which are based on current retail electric rates that vary annually, and a fixed MPR-based payment for net exports. As we determine here, the NSC rate should reflect a short-term market price for electricity that represents the costs avoided

[24] D.09-08-026 at 35.

by the utility over the same 12-month period in which the exports were produced.

Finally, we disagree with the Joint Solar Parties' use of an estimated solar generation profile to adjust the MPR. While we understand the Joint Solar Parties' argument that use of a generation profile is a simplifying assumption because a profile of net exports (i.e., generation minus usage) is customer specific, we find this is too great a simplifying assumption. We agree with PacifiCorp, PG&E and TURN that a profile of net exports would likely yield a different shape than a profile of generation alone.

5.1.3. Other Proposals

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 Section 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. AB 920 requires the Commission to set the NSC rate by January 1, 2011. 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. CALSEIA/EC fail to suggest what rate should apply in the interim, while there is no feed-in tariff rate in effect.

Moreover, it is unclear that a rate under SB 32 to compensate for power provided pursuant to a tariff should apply for incidental and occasional net surplus power provided by NEM customers.

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. We agree with SCE that the only generation cost avoided by the utility when an NEM customer delivers surplus generation is reduced procurement of electricity in the short-term wholesale market.

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.[25] 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 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. To undertake this effort would inappropriately delay a final NSC rate beyond the statutory deadline in Section 2827 and require an interim rate.

6. Renewable Attributes and Renewable Energy Credits under NSC

Next, we must address issues surrounding the treatment of RECs arising from net surplus generation. AB 920 provides that the utilities that purchase net

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[25] 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-owner solar plants.

surplus generation shall receive the RECs associated with such generation and that the electricity purchased shall count toward their RPS targets, consistent with the RPS statutes. Specifically, Section 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, ….

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 2 percent. At this time, almost no customer-side DG is RPS-eligible, except DG systems under AB 1969 tariffs,[26] and it is unclear whether systems on net metering tariffs have meters that comply with WREGIS accuracy requirements. The CEC will determine the eligibility of customer-side DG for the RPS. Thus, although there are technologies that can be used for customer-side renewable DG, most current installations are not in fact RPS-eligible because they have not been certified by the CEC and cannot be certified until the CEC revises its *RPS Eligibility Guidebook*.

6.1. RPS eligibility and WREGIS requirements

Several parties, namely PG&E, SCE, the Joint Solar Parties, CALSEIA/EC, IREC, the City of San Diego and DRA, suggest that in order to implement AB 920, the Commission can ignore the RPS statutes, essentially Sections 399.12 and 399.13, which mandate CEC RPS eligibility and WREGIS metering and

[26] 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 . . . .

Footnote continued on next page

registration requirements. These parties contend that AB 920 expressly intends for the utilities to receive RECs from net surplus generation and count them toward their RPS annual procurement targets, and that CEC certification and WREGIS 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.

PG&E and others claim it would be complex and expensive for customers to obtain RPS certification and register with WREGIS. Further, if customers have sold their RECs to a third party through a Power Purchase Agreement (PPA), it will be impractical and costly for PG&E to obtain ownership declarations from each customer. 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, whether or not the facility generates a REC that is tracked through WREGIS, and whether or not the NEM customer actually owns the REC.

We disagree with these parties' suggestion that the language of AB 920 replaces RPS certification and tracking requirements and allows us to ignore

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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.)

existing statutes that confer authority upon the CEC to set RPS eligibility and verification requirements. AB 920 does not repeal RPS statutes, and the language of Section 2827(h)(5)(A) specifically references RECs as defined in Section 399.12. Section 399.12 further references 399.13. Thus, we conclude that Section 2827(h)(5)(A) and (B) must be harmonized with existing RPS statutes. SDG&E and Sierra Pacific presented this logic and we agree. 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. Without meeting the precondition of CEC certification and WREGIS metering and tracking requirements, net surplus generation purchased by the utility cannot be counted for RPS purposes.

Moreover, we agree there are unresolved issues related to accounting for split ownership of RECs. According to Section 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 systems can track and otherwise account for RECs that would be split between the utility and the customer in such a fashion. In addition, RECs for RPS compliance are accounted for in 1 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 1 MWh increments.

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, including split ownership of RECs and aggregation, dealt with by the CEC and WREGIS.[27]

In summary, we find that the utilities cannot count net surplus generation obtained from NEM customers toward RPS procurement targets until NEM customer facilities are CEC certified and their RECs are tracked in WREGIS. Once NEM net surplus generators are deemed RPS eligible and their net surplus generation is appropriately accounted for by WREGIS, including REC splitting and aggregation, the utilities may then count RECs for RPS purposes. Similarly, the NEM customer should not be compensated for the renewable attributes of electricity in the form of RECs until such time as they actually create RECs and make them available to the utility.

6.2. What if customers have sold their RECs to a third party?

Another concern is whether NEM customers need to 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

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[27] 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 (s*ee PUC RPS Quarterly Report to Legislature, 2010 Quarter 2,"* Table 1 at 4), while PG&E reports its excess generation from NEM customers in 2009 was 5,212,073 kWh (5.2 GWh), or approximately 0.04% of the annual RPS target.

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 surplus generation without RECs. The Joint Solar Parties suggest that only larger customers with systems 100 kW and above should be required to provide an affidavit they have not sold or transferred the RECs to another entity as a condition of receiving full NSC. PG&E concedes it may be appropriate for larger customers 500 kW or greater to certify they own their RECs. CALSEIA/EC proposes that the utilities should be required to identify those customers under third-party ownership arrangements who may have assigned RECs to third party owners.

We have found above that in order for the utilities to receive RECs from net surplus generation and count them toward RPS requirements, NEM customers must meet CEC RPS certification and WREGIS metering and tracking requirements. Similarly, we find that any NEM customer seeking NSC payments for the renewable attributes of its generation must certify it owns the RECs associated with its generating facility. We will require the utilities to obtain certification of REC ownership from all NEM customers prior to compensating them for any renewable attributes or counting any RECs created by net surplus generators toward RPS procurement targets.

6.3. Value of renewable attributes

We now turn to the question of whether to include payment for the value of the renewable attributes of electricity in the NSC rate. Again, the statute does not mandate compensation for the value of renewable attributes, but allows the Commission to determine if appropriate justification exists for such compensation.

A quick recap of the proposals for pricing renewable attributes is in order. The utilities generally suggest establishing a value for renewable attributes separate from the value of electricity. Specifically, SCE proposes a value based on renewable premiums for the WECC as published by the DOE. 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.[28] 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.

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

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.

RECs are the appropriate measure of a generator's renewable attributes and we believe that it is appropriate to compensate NEM customers for RECs conveyed to the utility with excess generation, separate from the compensation for their electricity. However, in keeping with our findings above that NEM surplus generators must meet CEC RPS eligibility and WREGIS metering and tracking requirements, and that RECs are not created until those conditions occur, we will not address payment for the value of renewable attributes until RECs are created by NEM customers.

We reject proposals to use proxies for the market-value of RECs because it is premature to value RECs that are not yet created by NEM customers. We prefer a market-based valuation for the renewable attributes of net surplus generation, once RECs are created by NEM customers, similar to our choice to use electricity market-prices to value the net surplus generation exported to the grid by NEM customers. Conceptually, we preliminarily agree with proposals by PG&E, SDG&E and the Joint Solar Parties to value renewable attributes based on the average REC price over a 12-month period once RECs are traded, although this will require a means to obtain public REC prices. Therefore, we will reconsider the appropriate value for renewable attributes once net surplus generators actually create RECs that can be traded. Parties may file a petition for modification of this decision once RECs are created by NEM customers and REC trading occurs. If such a petition is filed, it should supply new information for the Commission to consider in the valuation of the renewable attributes of net surplus generation. Any petition should also address the process by which all customers will certify to their REC ownership prior to receiving compensation.

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.[29] 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 Section 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

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[29] 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

Footnote continued on next page

immediate compensation or opts to rollover net surplus generation against future usage. The value of net surplus generation should be converted to a 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 5.1.3 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

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retain any excess kWhs generated during the prior 12 month period and the customer shall not be owed any compensation.

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 Section 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 Section 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 Section 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 Section 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. 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 Section 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.

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 file advice letters in compliance with this decision to revise their NEM tariffs to accommodate the NSC rates, terms, and conditions set forth in this decision.

8. Comments on Proposed Decision

The proposed decision of ALJ Duda in this matter was mailed to the parties in accordance with Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by________ and reply comments were filed by _________.

9. Assignment of Proceeding

Nancy E. Ryan is the assigned Commissioner and Dorothy J. Duda is the assigned ALJ in this proceeding.

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 Section 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. 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.

4. 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.

5. FERC has found that QFs may engage in market-based sales, QFs under 20 MW are exempt from sections 205 and 206 of the FPA, and 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 interconnections between distribution systems of electric utilities and DG facilities such as those of NEM customers.

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

9. DLAP prices are hourly day-ahead electricity market prices that a utility pays for a quantity of energy to meet its day-ahead load.

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

11. 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.

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

13. It is unclear if separate DLAP prices exist for Sierra Pacific and PacifiCorp.

14. MPR is the all-in cost of a new 500 MW central station combined cycle natural gas plant and is based, in part, on a long-term forecast of natural gas costs.

15. An individual NEM customer has no obligation to provide energy to the utility.

16. The only generation the utility avoids when an NEM customer provides surplus generation is reduced electricity procurement from the short-term wholesale market.

17. 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.

18. 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.

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

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

21. 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.

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 Section 2827.

Conclusions of Law

1. The Commission may identify a market-based mechanism to value net surplus compensation consistent with the FPA.

2. NEM customers can be considered QFs exempt from FERC certification and able to sell at market-based rates subject to the FPA filing exemption for QFs under 20 MW.

3. Tariff Rule 21 should continue to govern interconnection between utilities and NEM customers, even if the NEM customers' facilities will generate net surplus electricity.

4. Net surplus generation will create exports from NEM customers which will likely result in fewer purchased kWhs of load at the DLAP price.

5. A market-based approach to valuing net surplus compensation reflects as closely as possible the day-ahead market value of generation while leaving other ratepayers unaffected and not shifting costs between customer-generators and other customers.

6. A market-based approach to net surplus compensation allows NEM customers to be compensated for both the value of electricity and the value of renewable attributes.

7. Other ratepayers are unaffected if the utility compensates net surplus generation at the rolling average of the DLAP price between 7 a.m. and 5 p.m. because it represents costs the utility potentially avoids in procuring power during the time period NEM customers are likely to produce excess power.

8. DLAP prices are a reasonable and efficient source for a market-based electricity value for net surplus compensation that corresponds to the 12-month true-up period for NEM customers as required by Section 2827.

9. Sierra Pacific and PacifiCorp should have the ability to mirror the PG&E DLAP pricing methodology without undue burden.

10. If Sierra Pacific and PacifiCorp do not have DLAP prices within their California territories, they should base their NSC rate on PG&E's DLAP price as set forth in this decision.

11. It is not appropriate to base an NSC rate on the MPR, which includes payment for generation capacity, when NEM customers do not provide surplus generation under long-term contract.

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

13. The NSC program must be harmonized with existing RPS statutes. Net surplus generators must be certified as RPS eligible by the CEC and must meet WREGIS metering and verification requirements for their generation to be counted for RPS purposes.

14. The utilities cannot count net surplus generation obtained from NEM customers toward RPS procurement targets until NEM customer facilities are CEC certified as RPS compliant and the facilities' RECs are tracked and verified in WREGIS.

15. RECs are the appropriate measure of a generator's renewable attributes.

16. NEM customers should not be compensated for the renewable attributes of their generation in the form of RECs until they actually create RECs and provide them to the utility.

17. Any NEM customer seeking NSC payment for the renewable attributes of its generation must certify it owns the RECs associated with its generating facility.

18. The Commission can address the appropriate value for the renewable attributes of net surplus generation once net surplus generators actually create RECs that can be traded.

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

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

21. 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.

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

23. 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.

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

25. ESPs should not be required to offer NSC.

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

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company shall each use the simple rolling average of their default load aggregation point price from 7 a.m. to 5 p.m., corresponding to the customer's 12-month true-up period, as the value of electricity portion of their individual net surplus compensation rates.

2. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company shall each file a Tier 3 advice letter containing the initial calculations for a net surplus compensation rate based on their individual default load aggregation point prices. 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, as long as the customer's 12-month true-up period ends January 1, 2011 or later.

3. If Sierra Pacific Power Company (Sierra Pacific) and PacifiCorp d.b.a. Pacific Power (PacifiCorp) have default load aggregation point prices in their California territories, Sierra Pacific and PacifiCorp shall each use their individual default load aggregation point price to calculate a net surplus compensation rate in the same manner as described in Ordering Paragraph 1 above.

4. In the event default load aggregation point prices do not exist within the California territories of Sierra Pacific Power Company (Sierra Pacific) and PacifiCorp d.b.a. Pacific Power (PacifiCorp), Sierra Pacific and PacifiCorp shall base their net surplus compensation rate on the net surplus compensation rate adopted for Pacific Gas and Electric Company.

5. Within 30 days of the effective date of this decision, Sierra Pacific Power Company and PacifiCorp d.b.a. Pacific Power shall each file an advice letter in compliance with this order to provide their calculations for net surplus compensation rate based on their default load aggregation point prices or to notify the Commission they will use the net surplus compensation rate to be adopted for Pacific Gas and Electric Company.

6. Customers opting for net surplus compensation must notify the utility at the time they elect to receive a net surplus compensation payment or to apply their payment toward future usage that they are a qualifying facility exempt from certification filing at the Federal Energy Regulatory Commission.

7. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and Electric Company, Sierra Pacific Power Company, and PacifiCorp d.b.a. Pacific Power shall obtain certification of renewable energy credit ownership from a net energy metering customer prior to compensating that customer for any renewable attributes or counting any renewable energy credits from net surplus generation toward Renewables Portfolio Standard annual procurement targets.

8. 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.

9. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas and 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.

10. Applications 10-03-001, 10-03-010, 10-03-012, 10-03-013, and 10-03-017 are closed.

This order is effective today.

Dated _____________________________, at San Francisco, California.