ALJ/DOT/sid **Mailed 8/25/2006**

Decision 06-08-028 August 24, 2006

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 06-03-004 (Filed March 2, 2006)

OPINION ADOPTING PERFORMANCE-BASED INCENTIVES, AN ADMINISTRATIVE STRUCTURE, AND OTHER PHASE ONE PROGRAM ELEMENTS FOR THE CALIFORNIA SOLAR INITIATIVE

TABLE OF CONTENTS

OPINION ADOPTING PERFORMANCE-BASED INCENTIVES, AN ADMINISTRATIVE STRUCTURE, AND OTHER PHASE ONE PROGRAM ELEMENTS FOR THE CALIFORNIA SOLAR INITIATIVE

I. Summary

This decision adopts performance-based incentives (PBI) for payments to qualifying solar photo-voltaic (PV) technologies through the Commission's California Solar Initiative (CSI.) In addition, the decision adopts an administrative structure and other program design features for successful implementation of the CSI.

As the Commission prepared to vote on this decision, the Governor signed Senate Bill (SB) 1 into law on August 21, 2006, to take effect January 2007. SB 1 requires the Commission to implement CSI with a number of specific provisions, some of which differ from those in this decision, particularly with regard to total budget dollars and funding from gas ratepayers. SB1 is, however, consistent with many key aspects of CSI as outlined in this decision, particularly the adoption of performance-based incentives. While certain program and budgetary issues may need future modification in light of SB 1, we will move ahead now with this order as drafted to ensure CSI program administration, performance-based incentives, and other crucial program requirements are operational in January 2007. To bring this CSI decision into conformance with SB 1, we direct the Administrative Law Judge (ALJ) to issue a ruling requesting comments from parties on aspects of SB 1 that will impact the longer-term implementation of the CSI. Our goal is to issue a further order modifying this decision as necessary before SB 1 takes effect on January 1, 2007.

Beginning on January 1, 2007, the Commission will pay PBI for solar projects 100 kilowatts (kW) and larger, with payments based on kilowatt hours (kWh) of solar power produced over a five-year period. Solar projects receiving

PBI incentives will be paid a flat per kWh payment, determined monthly and incorporating an 8% discount rate. The Commission will pay incentives to solar projects below 100 kW through an up-front incentive, known as an "Expected Performance Based Buydown" (EPBB), based on an estimate of the system's future performance. EPBB incentives combine the performance benefits of PBI with the administrative simplicity of a one-time incentive paid at the time of project installation. This order adopts the following initial incentive rates for PBI and EPBB payments based on three customer designations--residential, commercial, and government/non-profit:

Table 1: Summary of Initial Adopted Incentive Rates for 2007

Sector	Maximum EPBB Incentive (per watt) for projects below 100 kW	PBI Payment (per kwh) for projects 100 kW and larger
Residential	$2.50	$0.39[1]
Commercial	2.50	0.39
Government/Non-Profit	3.25	0.50

The Commission modifies the single CSI incentive rate of $2.80 per watt adopted in Decision (D.) 06-01-024 in favor of rates tailored to consider the tax effects seen by these three customer groupings. Residential and commercial customers are paid the same incentive rate, despite different tax effects, because they have different payback periods for their solar investments. Tax-exempt government and non-profit entities who do not receive federal tax credits shall receive a higher incentive rate, unless they choose to engage in third-party

1 Any size project may opt for PBI payments.

ownership and financing for their solar projects. In that case, they would receive the lower commercial rate.

These incentive levels will be automatically reduced over the duration of the CSI program in 10 steps based on the volume of megawatts (MWs) of solar installations. We find it is reasonable to link incentive reductions to achieved levels of solar demand. Therefore, as demand for solar rebates reaches the MW levels specified in this order, CSI incentive payments will automatically drop. This approach avoids the risk of incentives dropping prematurely, before the economics of the solar industry reflect growing demand, as would be the case with calendar year reductions. Additionally, the order finds: (1) solar incentive levels may vary by utility service area, depending on the pace of solar demand in each utility's territory; and (2) incentive levels may differ based on demand in the residential and non-residential customer sectors. Thus, the MW targets that trigger automatic incentive reductions are allocated across the utilities and customer segments, as follows:

Table 2

CSI MW Targets by Utility and Customer Class

		PG&E (MW)		SCE (MW)		SDG&E (MW)		So Cal Gas (MW)	
Step	**MW in Step**	**Res**	**Non-Res**	**Res**	**Non-Res**	**Res**	**Non-Res**	**Res**	**Non-Res**
1	50[2]	--	--	--	--	--	--	--	--
2	70	10	21	8	16	3	6	2	4
3	100	15	29	11	23	4	9	3	6
4	130	19	38	15	30	6	11	4	8
5	170	25	50	19	39	7	15	5	10
6	230	33	68	26	52	10	20	7	14
7	300	44	88	34	68	13	26	9	18
8	400	58	118	45	91	17	35	12	24
9	500	73	147	56	114	21	44	15	30
10	650	94	192	73	148	28	57	19	39
Totals		1122		867		332		230	
Percent		44%		34%		13%		9%	

2 The first 50 MW are allocated under the 2006 Self-Generation Incentive Program (SGIP) and are not pro-rated by customer class or service territory. In 2006, most residential systems participated in the California Energy Commission's Emerging Renewables Program.

Table 3

Incentive Levels by MW Step ($/watt)[3]

Step	MW in Step	Gov't/ Non-Profit	Res	Commercial
1	50[4]	$2.80	$2.80	$2.80
2	70	$3.25	$2.50	$2.50
3	100	$2.95	$2.20	$2.20
4	130	$2.65	$1.90	$1.90
5	170	$2.30	$1.55	$1.55
6	230	$1.85	$1.10	$1.10
7	300	$1.40	$0.65	$0.65
8	400	$1.10	$0.35	$0.35
9	500	$0.90	$0.25	$0.25
10	650	$0.70	$0.20	$0.20

In our initial CSI decision, we endeavored to preserve program simplicity by having a single statewide incentive that adjusted either on a calendar year basis or with demand level, whichever was sooner. We reiterate our commitment to simplicity, but comments from the solar industry, the utilities, and many other parties now persuade us to revise our program design to better accomplish the Commission's long-term solar goals. Therefore, we modify our initial CSI program design to allow incentives to respond to the level of demand for solar rebates, reserve program funds for residential customers, and allow the program in each utility territory to unfold at its own pace.

This order finds that to ensure program continuity, the administrators of the Commission's existing Self-Generation Incentive Program (SGIP), namely

---

3 The basis for these step changes is discussed in Section VII.B.2.

4 The first 50 MW are disbursed under the 2006 SGIP at a uniform rate of $2.80 per watt.

Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas) and the San Diego Regional Energy Office (SDREO), should administer all aspects of the CSI program in 2007. Nevertheless, the order finds there are still valid reasons to consider non-utility, or independent, administration for the residential retrofit portion of CSI in the future. In Phase II of this proceeding, the Commission will consider statewide marketing and outreach for CSI and whether the Commission should direct one entity to handle statewide administration of residential retrofit solar programs.

Other notable features of this order include development of a statewide on-line application process and database, drafting of the initial CSI Program Handbook, and creation of a "CSI Program Forum" to provide a further process for stakeholder involvement in the on-going implementation of CSI.

With regard to metering of solar projects, this decision requires accurate solar production meters for all solar projects that receive CSI incentives because accurate measurement of solar output is of paramount importance to ensure optimum value for both solar owners and ratepayers. Systems under 10 kW require a meter accurate to within 5%, while systems 10 kW and larger require a more precise meter accurate to within 2%. The decision sets minimum metering requirements, including a performance reporting capability. Further discussion of technical standards, communication protocols and other specific metering requirements will occur as part of the initial CSI Program Handbook or the on-going CSI Program Forum. Interested parties are encouraged to establish a metering and data committee of appropriate technical personnel from the solar, utility, and metering industries to participate in these discussions.

Incentives for non-PV solar projects and energy efficiency requirements will be addressed in a separate order, as soon as possible.

Finally, the order establishes a future review process where significant features of CSI may be reexamined by the Commission through a future rulemaking.

Staff of the California Energy Commission (CEC) has worked collaboratively with Energy Division staff on all aspects of this proceeding and consulted with the ALJ and the Assigned Commissioner on the issues resolved in this order.

II. Background

In D.06-01-024 (the "January CSI Decision"), the Commission collaborated with the CEC to jointly create the CSI, an 11-year $3.2 billion incentive program with the goal of ensuring that customers of California's investor-owned utilities install 3,000 MW of new solar facilities at their homes and businesses in California. The Commission will implement the CSI in partnership with the CEC, and the initiative runs from 2006 through 2016. The Commission portion of the CSI targets the installation of 2,600 MW of solar technologies, based on a budget of $2.8 billion derived from the distribution rates of PG&E, SCE, SoCalGas, and SDG&E. The CEC portion of the program targets 400 MW of solar installations in new home construction, using a budget of $350 million derived from renewable energy Public Goods Charge funds.

As the Commission stated in D.06-01-024, the objectives of the CSI are to add clean energy to peak demand resources, to reduce risk by diversifying the state's energy portfolio, and to reduce the need for transmission and distribution system additions. Through the CSI, the Commission and CEC endeavor to transform the existing energy market to make solar products cost-effective, with the goal of eliminating the need for incentive payments after 2016. (D.06-01-024, mimeo. at 4.)

In 2006, the first year of the CSI, incentives to solar projects are funded through the Commission's Self-Generation Incentive Program (SGIP) and the CEC's Emerging Renewables Program (ERP). The SGIP provides monetary incentives for customers to install distributed generation, including solar PV technologies with a capacity of 30 kW or more. Solar facilities of this size are generally installed by commercial and industrial customers. The ERP provides incentives for solar PV projects of less than 30 kW, most of which are installed by or for residential customers.

Beginning in 2007, the Commission will consolidate its implementation of all solar incentives into the CSI, while the ongoing SGIP will fund distributed generation projects that are non-solar. In addition, a portion of the CEC's current solar incentive program will transfer to Commission oversight, specifically solar projects that are less than 30 kW in capacity for existing homes and non-residential facilities. The CEC portion of the CSI will focus on solar incentives solely to the residential new construction market.

Following adoption of D.06-01-024, the Commission opened Rulemaking (R.) 06-03-004 (the "CSI/DG OIR") to develop program rules and policies for the CSI. In Phase I of this rulemaking, the Commission has explored whether to adopt performance-based incentives for PV facilities, whether to adjust incentives to account for federal tax credits, the proper incentive levels for solar technologies other than PV, and other issues regarding the structure and adjustment of these incentive payments. Phase I has also included an examination of the appropriate administrative structure for implementation of the CSI, and energy efficiency and metering requirements for CSI projects.

The key issue in Phase I is whether to amend the incentive levels the Commission adopted in D.06-01-024 in order to bring a performance dimension to incentive payments. The Energy Division staff held a workshop on March 16, 2006 on the topic of performance-based incentives. Following the workshop, Energy Division staff prepared a proposal for CSI Incentive Design and Administration that was circulated to all parties through an ALJ's Ruling on April 25, 2006.[5] A further workshop was held on May 4, 2006 to allow parties to ask questions about the Staff Proposal. On May 9, 2006, the ALJ issued a ruling with one modification to the Staff Proposal related to administration of CSI. Interested parties filed opening and reply comments on the Staff Proposal on May 16 and May 25, 2006, respectively.

Comments were filed by Americans for Solar Power (ASPv), R. Thomas Beach, the California Farm Bureau Federation (Farm Bureau), Californians for Renewable Energy (CARE), jointly by the California Solar Energy Industries Association (Cal SEIA), PV Now and the Vote Solar Initiative (hereinafter "Joint Solar Parties"), City and County of San Francisco (CCSF), Clean Power Markets, Consumer Federation of California (CFC), the Commission's Division of Ratepayer Advocates (DRA), Energy Innovations Inc., Fat Spaniel Technologies Inc. (FST), Golden Sierra Power, Michael Kyes, PG&E, Pacific Power Management, NorCal Solar Energy Association, SCE, jointly by SDG&E and SoCalGas, San Diego Regional Energy Office (SDREO), Solargenix Energy Inc.,

[5] See "ALJ's Ruling Requesting Comment on Staff Proposal for Performance Based Incentives and Other Elements of the California Solar Initiative," April 25, 2006, (hereinafter "Staff Proposal").

Sun Light and Power Company (Sun Light), and The Utility Reform Network (TURN).[6]

Reply Comments were filed by ASPv, R. Thomas Beach, jointly by CalSEIA, Crossborder Energy, PV Now, Sunlight & Power and Vote Solar Initiative (Joint Solar Parties), CFC, DRA, Energy Producers and Users Coalition (EPUC), FST, Michael Kyes, PG&E, SCE, SDREO, SDG&E/SocalGas, Solargenix Sun Light, and TURN.

III. Performance Based Incentives and Treatment of Federal Tax Incentives

The two existing solar incentive programs managed by the Commission and the CEC, namely the SGIP and ERP respectively, currently provide payments on the basis of solar project size. In other words, a project owner is paid the full incentive on the basis of the project's rated electrical capacity at the time of installation.

In D.06-01-024, the Commission stated its intent to further explore PBI to fund solar projects, concluding that a good incentive program is one that promotes efficient operation of solar facilities. The Commission reasoned that existing capacity-based incentives do not recognize power production or motivate good project management and maintenance once the project is installed. In contrast, performance-based incentives pay the project owner on the basis of energy production and, in theory, promote efficient operation of solar projects.

---

6 The comments of Solargenix and Pacific Power Management were not filed formally, but were placed in this proceeding's correspondence file.

The decision also noted that the Federal Energy Policy Act of 2005 provides tax incentives for solar projects, and these federal tax credits could obviate the need for some or all state-sponsored solar incentives. The decision found the record unclear as to how federal tax credits may affect solar investment decisions and stated the Commission's intent to gather more information on this subject.

On March 16, 2006, the Commission sponsored a workshop on the subject of performance-based incentives and federal tax credits. Presentations were given at the workshop by Tom Hoff of Clean Power Research, a consultant to the National Renewable Energy Laboratory (NREL) and the CEC, and Ryan Wiser from the Lawrence Berkeley National Laboratory. In addition, panels of interested parties discussed various PBI alternatives and presented views on the tax consequences of various incentive structures.

In the sections below, we address the overall incentive level for CSI programs beginning in 2007, and two methods for bringing a performance dimension to the incentive structure, namely a structure incorporating PBI for solar projects 100 kW and larger, as well as up front performance-based payments, known as an EPBB, initially for projects less than 100 kW.

A. Incentive Levels and Interaction with Federal Tax Incentives

In D.06-01-024, the Commission adopted a solar incentive level for 2006 of $2.80 per watt, along with a mechanism to reduce the CSI incentive level in each calendar year through 2016, or when specific MW levels of program participation had been reached. In D.06-05-025, the Commission implemented the first "trigger" reduction to $2.50 per watt to take effect as soon as 50 MW of solar applications had reached "conditional reservation" status.[7]

Following the March 2006 workshop on PBI, the Energy Division staff issued a proposal to differentiate incentive levels based on the tax credits available to different system owners. In effect, the Staff proposes to realign CSI incentives in 2007, the first year of the program, and every year thereafter through 2016. The Staff Proposal recommends reducing the 2007 CSI incentive level to $1.50 per watt for commercial customers and to $2.25 per watt for residential and tax-exempt customers, such as federal, state and local governments, schools, and non-profit organizations who cannot take advantage of federal tax incentives.

Staff reasoned that commercial customers can take advantage of the federal tax credit of 30% of solar installation costs, while residential customers' tax credit is capped at $2000.[8] In an attempt to minimize these differences in the effective cost of solar facilities after tax credits, Staff proposed a lower incentive of $1.50 per watt for commercial customers, while allowing residential and tax exempt entities to receive $2.25 per watt.[9] The Staff's incentive proposals were

---

[7] "Conditional reservation" is defined as the initial application screening and payment of the application fee. As of July 18, 2006, the SGIP program administrators website indicates conditional reservations have reached a level of 46 MW, so it is expected the incentive level will automatically drop to $2.50 per watt before the end of 2006.

[8] The federal tax credit reverts to 10% on January 1, 2008, unless currently pending legislation extends it.

[9] The Staff proposed that in order to qualify for a higher incentive, tax exempt entities must certify they will not enter into any third party financing arrangements that qualify participants for federal solar tax credits. (Staff Proposal, p. 13.) Otherwise, tax-exempt entities will receive the commercial rate.

selected based on calculations that considered installed system costs, expected solar production, retail energy prices, tax credits, and a 10-year simple payback for a solar facility with a 25-year life. (Staff Proposal, pp. 11-12.) Staff analyzed the effective net cost per kWh for solar installations based on these assumptions, both for taxable and non-taxable entities. (Staff Proposal, pp. 17-18.) Staff further supported its proposed 75¢ per watt differential in the incentive rate by reasoning that residential system owners, unlike commercial system owners, are unable to take advantage of the tax benefits of depreciation. Residential systems, which are smaller in size, are typically more costly per installed watt than commercial systems.

In response to the Staff Proposal, the solar industry generally opposes the $1.50 per watt level proposed by Staff, arguing that this level is too significant a reduction from the current rebate level of $2.80 per watt. Specifically, the Joint Solar parties and ASPv contend the reduction in incentive levels in the Staff proposal is premature, risks disrupting the solar market, and does not account for the actual state of the solar market. The Joint Solar parties cite data from the SGIP program administrators, which suggests the rate of customer applications for rebates at $2.80 per watt has slowed considerably. They also claim that reducing the incentive level to $1.50 per watt would result in an even larger rebate reduction when combined with other elements of the Staff Proposal, particularly Staff's proposals to change how system capacity is measured, use a "design factor" in calculating EPBB payments, and ignore the time value of money in PBI payments. Therefore, the Joint Solar parties maintain the rebate should remain at $2.80 per watt until there is further market response.

Sun Light comments that the incentive levels proposed by Staff are inadequate and will prevent the Commission from meeting its goal of 2,600 MW of solar installations. Sun Light contends the CSI MW goal will only be met with a growing pool of solar suppliers and incentive levels that motivate buyers. To support its view, Sun Light provides data from the CEC's current solar rebate program indicating a trend away from residential toward commercial installations, with residential growth rates flat since 2003. (Sun Light, 5/16/06, pp. 5 and 9.) According to Sun Light, this trend indicates that growth in the solar industry is slower than what is needed for the CSI to reach its MW targets. It contends high solar material costs are driving systems costs up, not down, and the incentive levels proposed by staff will not motivate residential or commercial customers to invest in solar.

Sun Light also provides a survey performed by Cal SEIA indicating the payback periods required by various customer segments. Sun Light maintains that residential customers are satisfied with longer paybacks ranging from 10 to 15 years, while commercial customers often find a six to eight-year payback more reasonable. Sun Light contends that government and non-profit customers are not always price conscious, their decisions are often politically motivated, and therefore, they may be less concerned with payback term. Sun Light uses this insight on payback terms and other critical assumptions regarding costs for PV systems, labor, and electricity costs to perform a detailed analysis of rebate levels and the internal rates of return they generate. Based on this analysis, Sun Light concludes the $1.50 per watt level proposed by Staff will result in an unacceptably long payback term for commercial customers that would lead to massive reductions in commercial PV sales. Sun Light suggests 2006 residential rebate levels be retained at $2.80 per watt to provide a reasonable payback for residential solar investors and steady growth in the residential market sector.

For 2007, Sun Light recommends that both residential and commercial rebates be $2.70 per watt, declining in later years by $0.25 per watt each year.

Regarding the federal tax credit, ASPv claims it is premature to differentiate rebates between the private and public sectors on the basis of the federal tax credit. ASPv provides specific recommendations for an incentive level of $.492/kwh (corresponding to $4.31/watt), which it later revised to $.39/kwh (or $3.42/watt),[10] based on its own analysis of the PV market and the returns it assumes investors require. Golden Sierra expresses concern that Staff's proposed incentive levels are based on incorrect assumptions regarding capacity factors and payback periods for solar facilities. Golden Sierra contends the higher incentive rate for non-taxable entities fails to account for their willingness to accept a longer payback period and other financial benefits these entities might receive, such as CEC low-interest loans. Golden Sierra recommends a starting incentive rate of $.36 to $.40/kwh (equating to $3.15 to $3.50 per watt).

Comments on the Staff Proposal from other interested parties present additional concerns. SDG&E/SoCalGas supports Staff's proposed incentive rates, but they express concern that it will be administratively difficult to prevent government and non-profit applicants from gaming the system to receive the higher non-taxable incentive rate. PG&E and SCE oppose incentives proposed by solar industry commentors, which are higher than those adopted in D.06-01-024. SCE argues these incentive levels are inflated and will result in fewer total installations within the CSI budget. CARE proposes that residential and non-profit organizations should receive an incentive closer to $4.00/watt to

---

[10] These per watt figures assume a 20% capacity factor and no discount rate.

bring solar costs for residential and non-profit customers in line with costs for taxable entities.

The starting incentive level for the 2007 CSI program is a critical threshold decision. The debate on this topic has been informed by analyses performed both by Staff and the parties, all with competing assumptions about discount rates, payback periods, and the effect of tax incentives on financial decision-making. In reviewing the various proposals, we find that certain assumptions are more reasonable than others and inform our decision-making.

We will modify the single incentive rate adopted in D.06-01-024 in favor of two separate incentive rates, one for the commercial and residential sectors, and a separate rate for tax-exempt entities. These new incentive rates will take effect on January 1, 2007 as follows:

Table 4: 2007 Initial Solar Incentive Rates

Residential Customers	$2.50/watt
Commercial Customers	$2.50/watt
Government/Non-Profit Customers[11]	$3.25/watt

1. One Incentive Rate for Residential and Commercial Segments

First, we adopt a single incentive rate of $2.50 per watt for both the commercial and residential customer classes despite the Staff proposal to pay commercial $1.50 per watt and residential $2.25 per watt. We are persuaded by

[11] Government/Non-Profit customers must certify they will not enter into any third party financing arrangements that qualify participants for federal solar tax credits. Otherwise, they will be paid at the lower commercial rate.

the comments of solar industry participants that a reduction to $1.50 per watt at this time for the commercial segment would prove disruptive to the solar market, particularly coupled with the introduction of performance-based incentives through PBI and EPBB. We prefer to keep the incentive level at a steady rate for now and avoid introducing numerous changes at once into the CSI program. Pursuant to D.06-01-024, the $2.80/watt rate for 2006 will drop to $2.50/watt when 50 MW of conditional reservations are reached. We now find that the rate should remain at $2.50 per watt, until program administrators receive applications and reserve incentives for an additional 70 MW of solar installations. In Section VI below, we discuss future adjustments to the incentive rate throughout the duration of CSI.

Moreover, the commentors persuade us that Staff may have relied on inaccurate assumptions in its analysis supporting the $1.50/watt incentive level. For example, Staff assumed a 10-year payback level for all customer classes and a 20% capacity factor. In contrast, solar participants claim that commercial customers require a shorter payback, in the realm of six to eight years, and capacity factors of 16% to 18% are more reasonable. Sun Light claims an incentive level of $2.50/watt provides a reasonable payback for commercial customers and a reduction to $1.50/watt ignores high solar module costs. We find these comments on payback periods, capacity factors, and module costs provide sufficient justification to leave incentives at $2.50/watt at this time.

We will adopt a residential incentive rate of $2.50/watt, the same as the commercial rebate. Although staff had proposed that residential customers should receive a higher rebate level than commercial customers because their federal tax credits are capped at $2,000, we are persuaded by the comments of solar participants that residential customers are generally willing to accept a longer payback period for their solar investment. Thus, even though residential customers receive less federal tax benefit, the Staff assumption of a 10-year payback for residential customers may have been too short. We see no reason to pay residential customers a higher rebate when comments suggest they may accept a payback period of up to 15 years.

We will not lower the residential incentive rate to $2.25/watt, as Staff had proposed, because Sun Light convincingly points to data indicating slower growth in the residential solar sector in the last few years. Again, we do not think it advisable to lower the current incentive level when data indicates slower adoption of solar technology in this market segment. We prefer to keep incentives at their current level while we await further experience with the introduction of a performance dimension to incentive payments through an EPBB mechanism for residential customers, as discussed further in Section III.C below.

Solar parties alleged they need higher incentive levels than those proposed by Staff, arguing solar panels are a large portion of installed system costs and costs have risen in the last year due to a world shortage of silicon. Parties estimate the worldwide silicon shortage will lessen by 2009. Despite these comments, we will not increase incentives over their current levels for those customers taking advantage of federal tax credits. As Staff noted in its proposal, the CSI budget cannot support higher incentives in 2007 and still maintain reasonable levels throughout the duration of the CSI program.

2. Higher Rebate Level for Tax Exempt Entities

We will adopt a higher incentive rate of $3.25/watt for tax-exempt entities such as government and non-profit institutions. As Staff pointed out, these entities are not eligible for the substantial federal tax credits available to commercial enterprises to offset the costs of system installation unless they can somehow take advantage of sophisticated third-party financing techniques.[12] Under a third-party ownership arrangement, a for-profit entity owns the solar facility installed on a tax-exempt entity's property and sells or leases the energy from that system, through a power purchase agreement, to the tax-exempt entity at a discounted rate that reflects some part of the various tax benefits available to the taxable owner. This strategy may not be feasible for all tax-exempt entities. Complex power purchase agreements may not be readily embraced by local government and public agency elected boards, or non-profit boards. We run the risk of discouraging non-profit entities from making solar investments if we pay them the same incentive as commercial entities, thereby forcing them to use third-party ownership arrangements to get a tax benefit and bring installation costs in line with those entities that receive a federal tax credit.

Parties did not dispute Staff's analysis that the net effective cost per kWh of solar is higher for those entities that cannot reap federal tax advantages. Nevertheless, the comments on the Staff Proposal generally do not support a higher incentive for tax-exempt entities, citing difficulty administering two incentive levels and the risk of gaming. Solar industry participants suggest this segment is less price-sensitive, willing to accept a lengthy payback period, and has access to other incentives such as low cost loans. In comments on the draft decision, CARE, CCSF and PG&E also support the higher rate for government/non-profits.

---

[12] In addition, tax-exempt entities are not able to take advantage of other tax benefits such as depreciation and interest deductions.

We are hesitant to ignore Staff's proposal despite its lack of support from parties. The Staff analysis shows a significantly higher net cost per kWh for a tax-exempt entity making a solar investment.[13] We note there was no participation from the government or non-profit sector in comments on this topic. Lack of support from parties does not mean the idea is not worthy. Further, Staff research on SGIP program participation indicates that government and non-profit institutions have been a vital component of SGIP program participation and we do not want to risk losing penetration in that sector as we transition to CSI.[14] Solar installations by government agencies offer the opportunity to raise public awareness of solar power and further its market acceptance through projects on high visibility public buildings.

For these reasons, we conclude the $0.75 per watt differential proposed by Staff is reasonable because it will mitigate the higher net solar costs for tax-exempt entities and will allow government and non-profit entities to consider solar investments without third-party financing and ownership arrangements. Of course, tax-exempt entities may still find it to their advantage to use third-party financing, and if they do so, they will be paid at the lower incentive level of $2.50/watt. The program administrators should ensure marketing and outreach to applicants from the government and non-profit sector makes them aware that third-party financing arrangements are available and

---

[13] Staff estimates customer net cost per kWh of 13¢/kWh for tax-exempt entities versus 9.4¢/kWh for a commercial customer. (Staff Proposal, p. 18.)

[14] An Energy Division data request on June 16, 2006 to SGIP Program Administrators indicates SGIP applications from government and non-profit customers have amounted to 45% of the total PV capacity installed through SGIP since the program began in July 2001.

may be more beneficial in the long-run than the higher incentive rate. Tax-exempt entities who apply for the higher incentive level must include with their incentive application a certification under penalty of perjury from their Chief Financial Officer or equivalent that they are a government or non-profit entity and they are not receiving, and will not in the future receive, federal tax benefits through financing arrangements. Non-profit entities must renew this certification annually if they receive PBI payments. We conclude it is reasonable to adopt this rate, at least for the first few years of the CSI. We will reassess the necessity for the higher tax-exempt rate after a few years of data and experience.

3. Conclusion

In summary, we modify the single CSI incentive of $2.80/watt adopted in D.06-01-024 in favor of rates tailored to consider the tax effects seen by residential, commercial and tax-exempt customers. Residential and commercial customers will be paid the same incentive rate, even though they experience different tax effects, because they have different payback periods for their solar investments. Tax-exempt entities will receive a higher rate, unless they choose to engage in third-party financing arrangements. We shall revisit the necessity for this higher incentive rate for tax-exempt entities after a few years of experience with CSI. In addition, we will reconsider incentive levels for all customer classes if the federal tax credit is not extended past December 31, 2007.

B. Performance-Based Incentives for Large Solar Projects

We now turn to the issue of whether a PBI structure is a prudent and effective way to encourage installation of well-performing solar systems, given the Commission's earlier statements in D.06-01-024 that a good incentive program is one that promotes efficient operation of solar projects.

The basic rationale for a PBI structure is to ensure that ratepayer subsidies for solar are paid based on effective system design, installation, and ultimately on performance, and not simply the rated capacity of the physical components. In the past, incentives were paid up front to help reduce the net investment cost of a solar system. These incentives may have been paid either as a percentage of the capital cost up to a cap or as a fixed contribution based on the rated wattage capacity of the solar system. Neither approach necessarily motivates the system designer to deliver a well-designed and installed system, nor ensures the system owner will attend to ongoing maintenance and performance of the system.

Thus, the Commission has been motivated to move in the direction of paying incentives based on solar system performance. The Staff Proposal recommended a PBI incentive structure for large solar installations with the following basic parameters:

- Base the PBI incentive on the dollar-per-watt incentive level for 2007, then convert it to a cents-per- kWh payment.

- Apply a system capacity factor of 20% to estimate kWh production per watt.

- Apply PBI to systems greater than 100 kW in size, but allow smaller systems to opt-in to the PBI structure.

- Offer fixed and flat PBI payments over five years, with no discount rate incorporated into the payment.

- Cap PBI payments at 10% over estimated output to preserve the CSI budget in the event there are very high performance technologies.

- Pay building-integrated PV systems using the PBI structure, regardless of size.

- Do not apply PBI to new construction applications.

- Consider phasing in the PBI structure over a period of three years, with:

  - 50% of the incentive paid up front, and 50% via PBI in 2007,
  - 25% of the incentive up front, and 75% via PBI in 2008, and
  - 100% PBI in 2009.

Parties' comments on the Staff Proposal were generally supportive of moving towards a PBI structure. There were few comments opposing PBI, though one party did recommend offering consumers a choice of a PBI or an up-front, capacity-based payment, pointing out there is not yet an example of a successful PBI program in place in the country. CCSF contends a performance warranty approach would be superior to PBI because it would place the performance risk of a solar installation on the system installer.

We remain convinced that the reasons for moving forward with PBI are compelling. A PBI incentive structure accounts for five distinct factors that affect system performance:

- Actual system rating may differ from the reported rating due to incorrect equipment ratings and/or poor workmanship during installation;

- System design may not be optimal due to orientation (compass direction and tilt) and shading issues;

- Geographical location may reduce output because some areas of California have a better solar resource than others;

- System performance may be less than ideal due to poor system maintenance, e.g., dirty modules or equipment failures that are not repaired in a timely manner; and

- Weather variability may be different than the estimated typical year, thus resulting in a lower or higher amount of energy production than was expected.

Overall, under a PBI structure, consumers will be motivated to focus on the proper installation, maintenance, and performance of their systems. We reject the warranty option suggested by CCSF because it does not contain adequate protections for ratepayers who fund CSI incentives. While a system owner can count on a warranty to recoup the cost of a poor performing system, the warranty approach provides no mechanism for repayment of ratepayer funds. For all of the reasons stated above, we elect to move to a PBI structure now. Thus, for the remainder of this section, we will focus on the details of how to design the appropriate PBI structure.

1. Size Threshold for PBI

The first issue we encounter in PBI design is whether to apply PBI to all systems or only those systems over a certain size threshold. As noted above, the Staff Proposal would apply PBI only to those systems over 100 kW in size.

All parties representing the solar industry agree with the Staff Proposal to apply PBI initially only to projects over 100 kW in size. In addition, ASPv would make PBI mandatory for newer, innovative solar technologies such as building integrated PV and bifacial modules, since system ratings are not yet capable of estimating output from these technologies. As noted earlier, Sun

Light, while supporting PBI in general, suggests offering each customer installing a system over 100 kW a choice between PBI and a capacity-based incentive payment.

Several parties, including PG&E and TURN, suggest starting PBI with systems over 100 kW but then transitioning PBI's application to smaller systems over time as the industry gains more experience with PBI payments. SCE would apply PBI to all systems over 30 kW immediately and transition down to systems as small as 10 kW over time. A number of other parties, including DRA, SDG&E/SoCalGas, SDREO, and CFC, would apply PBI immediately to all non-residential systems, regardless of size. Only CFC recommends applying PBI to residential systems immediately, though SDG&E and SoCalGas also recommend that the Commission consider this in 2007. CFC reasons that the only exception to the PBI requirement should be low-income households and businesses that are credit-worthy but unable to obtain "reasonable" financing. Several parties provided statistics showing that the number of projects in the size category over 100 kW is very small, while the solar system capacity associated with those projects is comparatively large.

Overall, we find parties provided little justification for the size threshold recommendations in their comments. Based on the lack of compelling evidence or reasoning offered by the parties in their comments, we prefer to adopt the Staff recommendation to require initially a PBI structure for systems 100 kW and larger. The main reason offered by Staff for this initial recommendation was the ability of customers investing in larger systems to finance additional system costs up front.

Lowering the size threshold at this time would potentially limit investments in solar systems by smaller commercial customers, i.e., those who are likely to invest in solar systems in the 30 kW to 100 kW size range. We are concerned that suddenly expecting these customers to pay for or finance an extra 30% to 40% of a solar facility cost, absent an up-front incentive, could jeopardize their investments in solar. Moreover, the EPBB approach to incentives for systems under 100 kW (discussed below in Section III.C) takes different but equally important steps to align incentives with realistic and site-specific expectations of performance for smaller systems. We prefer to start PBI in 2007 with the larger systems and then transition to smaller systems over time, in order to allow sales and financing arrangements to evolve in the direction of PBI. We conclude that after an initial transition period and more experience with the PBI structure, we will be able to apply this structure to smaller systems. We envision a two or three year transition period before applying PBI to smaller systems in the 30 to 100 kW range. Therefore, we anticipate applying PBI to all systems over 30 kW beginning in 2010.

In the meantime, we will allow any system, regardless of size, to "opt-in" to a PBI payment structure beginning in 2007. There are some high-performing systems and system designs that may benefit from a PBI structure because of their performance characteristics, if the customer is willing to forego an up front payment in favor of a presumably-larger PBI payment over time. Certain other newer solar technologies, such as concentrating solar PV and tracking systems, also may opt in to the PBI to the extent their system size characteristic does not already require it. In addition, we will require that all building-integrated PV (BIPV) systems, even those that otherwise qualify as new construction, be paid on a PBI basis because no accurate system rating yet exists to evaluate the likely performance characteristics of these systems. We can reconsider this restriction if reliable BIPV ratings become available at a later date.

Finally, we will exempt all new construction applications, other than BIPV, from a PBI requirement, regardless of size, in order to allow the net up front cost of a solar system to be integrated into the financing of the new building as a whole. Solar installations on new construction projects will be paid under the EPBB approach outlined in Section III.C.

2. Time-Differentiated Payments

Although the Staff Proposal did not address time-differentiated payments, several parties commented on whether PBI payments should vary based on the time of day that the solar system produces energy. In particular, Thomas Beach recommended time-differentiated PBI payments. The rationale for this recommendation is that while south-facing systems will provide a larger total kWh output annually, west-facing systems offer greater value in kWh produced during the peak period (but lower annual kWh).

SCE, in its reply comments, rejects the concept of time-differentiated PBI payments as too complex. SCE maintains that the on-peak benefits of solar do not necessarily translate into transmission and distribution system benefits. The utility also points out that net energy metering already rewards on-peak performance of systems through time differentiated net energy credits for customers on time-of-use (TOU) rates.

At this time, we will not require time-differentiated PBI payments because of the added complexity in calculating and communicating the value of solar incentives. Moreover, many customers are already on TOU rate schedules that vary energy prices throughout the day, so that solar production reduces utility bills at values mirroring the TOU rates. In addition, most customers with solar facilities already participate in the net energy metering program which is inherently time-differentiated for those on TOU rates. If we tried to value solar output based on utility system peak times, this would require more precision in a PBI payment scheme than is the case for the utilities' current TOU tariffs (which typically define peak as 12 noon to 6:00 p.m. or 1:00 p.m. to 7:00 p.m.), or creation of a more complicated incentive scheme layering the EPBB site installation factors onto a PBI payment scheme. We are not convinced such complexity could be easily communicated or administered.

Though we will not make PBI payments time-differentiated at this time, we remain interested in structuring the payment of solar incentives to further reward on-peak delivery of kWh to the system. One of the key goals of the CSI is to produce valuable energy during peak times. In general, we are attracted to the German feed-in tariff system, which combines our two-part approach (i.e., PBI and net energy metering) into one payment for system performance that can be time-differentiated. We believe it is preferable to embed time-differentiated signals into a tariff structure rather than an incentive structure such as PBI. Therefore, we will not require a time-differentiated PBI structure at this time, but will ask our staff to continue investigating and evaluating alternative incentive structures for later phases of the program.

3. Payment Period

We now address over what period of time to make PBI payments. The Staff Proposal recommended payments over a five-year period.

Most parties generally agreed with the Staff Proposal to offer PBI payments over a five-year period. SDG&E/SoCalGas would prefer to make PBI payments over the life of a system (20 to 30 years), but stated that they can accept the Staff Proposal. CCSF commented that public entities might prefer a 10-year payment stream to match the payment stream of project financing, but CCSF would not object to a five-year structure.

We see a tradeoff between the preferred payment period for ratepayers and solar investors. A shorter payment period is more attractive to solar buyers and has lower administrative costs. A longer period guarantees pay-for-performance for ratepayers, but incurs higher administrative costs and risks stalling the solar market since most homeowners and businesses are less likely to invest in solar if they have to wait 20 to 30 years to recoup their investment. We see no reason to depart from the Staff recommendation of a five-year performance payment period for PBI because it will have lower administrative costs and less market risk than a longer payment period. This is a reasonable balance between the current up-front payment structure and longer-term payments over the life of the system.

4. Capacity Factor

In order to provide continuity to the market from the current capacity-based incentive structure, Staff proposed to convert the per-watt up front incentive payment to a PBI payment (in cents per kWh) using a capacity factor to calculate expected system output. Staff initially proposed using a 20% capacity factor, based on CEC-alternating current (AC) ratings.[15]

Many parties provided data in support of their recommendations in this area. PG&E states that Itron data from the SGIP program shows an average capacity factor of 16% for systems installed through 2004. They recommend using this capacity factor initially, and then adjusting the capacity factor in subsequent years based on further data. CFC cites U.S. Department of Energy (DOE) and CEC data on capacity factors, showing that in 2004, the average

---

[15] CEC-AC ratings are one means of estimating system output. They are defined and discussed in detail in Section III.C.1 regarding EPBB incentive payments.

commercial system capacity factor was 14%, and in 2005, the average residential system capacity factor was 16%. According to CFC, these sources project that average capacity factors will reach the 18%-20% range by 2010.

The Joint Solar Parties suggest 18% using CEC-AC wattage, or a higher 20% factor if a different rating method known as "system AC" is used. SDG&E/SoCalGas, and SCE all suggest using 20%. Sun Light provides analysis assuming a PV installation will provide initial annual energy savings of 1,625 kWh, which is approximately equivalent to an 18.5% capacity factor. (Sun Light, 5/16/06, p. 15.) It also comments that it is reasonable to expect that PBI and EPBB will bring about at least a 10% improvement in system efficiency in the PV market. (*Id*., p. 21.) TURN suggests incorporating an assumption of a 1% per year degradation factor. Golden Sierra Power suggests a lower capacity factor, because of lower solar production when panels are not matched to the inverter, but it does not propose a specific capacity factor.

We are persuaded that the 20% capacity factor proposed by Staff may have been too optimistic. The data cited by PG&E and CFC indicates as much. The comments of many parties suggest the same, preferring a lower capacity factor based on historic system performance. We accept the recommendation of the Joint Solar Parties, who propose an 18% capacity factor as a reasonable mid-point for the beginning of the program in 2007, based on CEC-AC wattage ratings.[16]

At the same time, we are convinced by some commentors that a higher capacity factor can act as a performance target. CFC presents DOE data

---

16 We will maintain the CEC-AC rating system, as we discuss in more depth in Section III.C.1.

that capacity factors should reach the 18%-20% range in a few years. We prefer to send a strong signal to encourage increases in system performance over time. Therefore, we will start with an 18% capacity factor for 2007, but we will increase the assumption automatically to 20% beginning with Step 4 of the Incentive Adjustment Mechanism, as discussed in Section VI of this decision. We anticipate that the Step 4 incentive level will not be reached for a few years, which should correspond to the higher capacity factors DOE projects. This will reward those technologies and installations with the best performance. We choose the Step 4 incentive level for this adjustment now in order to calculate and publish the specific incentive levels per kWh that will be paid in upcoming years.

We may consider subsequent changes to the capacity factor assumptions in later program years based on future evaluation findings regarding market trends in system output.[17]

5. Performance Cap

The issue here is whether to put an upper limit on incentive payments to high performing systems as a way to manage the CSI budget. The Staff Proposal suggested capping payments for system performance at 10% above the output produced by the assumed capacity factor.

The utilities generally favor the imposition of some sort of performance cap in order to track and manage budgets, although PG&E suggests a cap should not discourage innovation. SCE, on the other hand, reasons that

---

[17] The Commission can review data on capacity factors in the periodic CSI review discussed in Section VII.3.

innovation needs to come from within the solar industry, rather than through the program offering rewards with unlimited upward incentives.

In contrast, the solar industry is unanimous in its opposition to the performance cap provision of the Staff Proposal. The Joint Solar Parties feel that such a performance cap undermines the entire purpose of having PBI. ASPv agrees that a performance cap discourages maximum system output. The solar industry parties suggest the budget can be managed by estimating each system's expected output at the reservation stage and then reserving the appropriate funding for the project at that time.

We agree with the solar industry that the imposition of a performance cap is inconsistent with our overall goal of rewarding systems for higher performance. We wish to send a clear and strong signal that high-performing designs and installations are desirable in this program. We also agree that the CSI budget can be managed if program administrators make a reasonable forecast of incentive payments at the time of system installation based on the design characteristics of each project. If future solar technologies offer significantly higher energy performance per watt than is evident or foreseeable today, the Commission can reexamine this in its periodic review of the CSI program. In addition, TURN points out that most systems experience a modest degradation of performance over time, which will tend to work in favor of preserving budget funding. Therefore, we do not adopt the performance cap suggested by staff. A solar facility receiving PBI payments will be paid for actual output over the five-year payment period. Nevertheless, the program administrators must operate within their total budgeted CSI funds, as set forth in D.06-01-024. Although we will not put a limit on the incentives paid to any one project through PBI, beyond the 5 MW limit adopted by the Commission in

January, the program administrators may not exceed their individual budgets and the total CSI program budget will not be exceeded.

6. Funding Security

The Staff Proposal recommended that the program administrators set aside reserved PBI incentive funds for completed systems in an interest-bearing escrow account. No party commented on this provision in the Staff Proposal.

We agree with Staff that it is important to send a clear signal to the solar industry and the financial community that the money for PBI payments will be available for the full five-year PBI period. Therefore, we will require each utility to deposit the expected PBI payments for all completed solar projects into a single interest-bearing balancing account for each utility so it is available for the five-year incentive payment period. This should occur quarterly for all projects completed in that quarter. Furthermore, we will require each utility to include a description of this PBI balancing account and the PBI program description and payment criteria in the preliminary statement of its tariffs. Thus, each utility's tariffs should provide further clarity that PBI payments are ensured once an incentive application is approved by the CSI program administrator.

7. Discount Rate

In the Staff Proposal, Staff did not include a discount rate when calculating the five year PBI incentive payments. Instead, Staff recommended offering a flat incentive payment for the sake of simplicity.

Parties representing the solar industry, as well as PG&E, disagreed with the Staff Proposal to ignore the discount rate. Neither ASPv nor the Joint Solar Parties propose a specific discount rate, though the Joint Solar Parties embed a 10% rate in some of their calculations. PG&E does not recommend a specific rate either, although it contends PBI should be made equally attractive with an up-front EPBB payment in order to entice smaller systems to opt in to the PBI structure. Sun Light recommends using an 8% discount rate.

We elect to apply a discount rate of 8%. Applying a discount rate is appropriate for several reasons. First, we find it reasonable to offer a comparable net present value for PBI as compared to the current up-front payment structure and not penalize those systems that must wait five years to receive their full PBI payments. Second, as PG&E points out, offering this additional incentive may cause some smaller systems to opt-in to the PBI structure, which furthers the overall program goal of increasing system performance. Finally, the budgetary cash flow consequences of a discount rate will be partially offset by the requirement that program administrators place incentive funds for PBI projects in an interest-bearing escrow account over the five years of the PBI period. In addition to interest growth, the escrow account may grow to the extent systems under-perform based on the average capacity factor used to set incentive levels and budgets.

We choose an 8% discount rate because we find it a reasonable assumption for the range of interest rates different solar buyers might receive on deferred payment streams. ASPv and the Joint Solar Parties suggest a 10% rate, but we prefer the more conservative 8% rate used by Sun Light for its analyses.

Although we will apply a discount rate of 8%, we still wish to keep the incentive payment structure simple. Therefore, in our incentive calculations offered at the end of this section in Table 5, we express the PBI incentive structure in levelized cents per kWh over five years. The incentive level will not change for each individual solar system over the five-year performance period.

Instead, the level of the incentive payments has been adjusted to account for the 8% discount rate on a net present value basis.

8. Frequency of PBI Payments

We now address how frequently a solar system owner should receive PBI payments over the five-year period, and whether these payments should be incorporated with utility bills. The Staff Proposal recommended monthly payments, on utility bills, if possible, with quarterly payments if monthly payments prove too administratively costly or burdensome.

The Joint Solar Parties agree with monthly PBI payments to best match cash flow for installment payments on solar systems, and suggested this be paid in an off-bill mechanism to make the incentive most visible to the system owner. SDG&E/SocalGas indicated they plan to support monthly on-bill payment of PBI incentives within a short transition period following this decision, and to add on-bill system performance data on a later schedule. PG&E indicated that while it already reports net energy metering credits monthly on-bill, it could not immediately make incentive payments in the same way. PG&E suggests it could arrange a monthly payment through its off-bill Alternate Billing System. SCE prefers to pay incentives quarterly by a separate check and performance statement. SCE contends an on-bill payment by January 2007 would be "very challenging" based on the time and cost of billing system modifications.

We are pleased to see that most utilities can accommodate some form of monthly PBI payments, whether on or off-bill, and that this comports with the preference of one set of solar parties. We will require PBI payments at this time on a monthly basis, consistent with our desire for frequent customer feedback on system performance. We allow utilities discretion whether to make the payment as a credit on the utility bill or separately. Those utilities that can offer monthly payments on or parallel to utility bills are applauded for their abilities to do so at their earliest opportunity. If SDG&E chooses to pursue this option, SDREO should make arrangements with SDG&E for monthly PBI payments as utility bill credits, which may be separate from a solar system performance reporting mechanism.

9. Phase In of PBI Structure

The Staff Proposal suggested the option of phasing in the PBI incentive structure over a three-year period, to allow the solar industry time to prepare the market for higher up-front investments under PBI. Specifically, Staff suggested that half of the total incentive could be given up front in 2007, with the remaining half paid based on performance. In 2008, 25% of the total incentive could be given up front, with 75% paid out in PBI. By 2009, all incentives would be through the PBI structure for applicable system sizes.

The Joint Solar Parties favor an even more gradual phase in of PBI than recommended in the Staff Proposal. Under their phase-in proposal, PBI payments would reach a maximum of 50% of the incentive as of 2010, with smaller percentages paid through a PBI mechanism in earlier years, starting at 20% in 2007. The rationale is that such a system would avoid forcing system owners to rely on third-party ownership structures due to their own lack of capital for solar investment. In addition, the Joint Solar Parties argue that larger systems already have an inherent incentive to police the performance of their systems because of the large capital investments associated with their system installations. They also contend PBI will make solar installations more expensive for customers due to the increased costs of financing.

SDREO agrees with the Staff Proposal for a three-year phase in, in order to avoid market disruption. TURN favors a four-year phase in period. Pacific Power Management would phase in PBI in six-month increments over two years, because financing for the larger up front costs is a significant hurdle for commercial customers.

The utilities, CCSF, and ASPv, on the other hand, prefer an immediate switch to a PBI incentive structure. They argue that phasing in a PBI structure will be a confusing, administrative hassle. In addition, they feel that instituting PBI immediately will send a strong signal to the market that the Commission values performance. Further, they argue that PBI is easier to administer, easier to verify, and generally clearer than a phased in approach.

We choose to institute PBI immediately as of January 1, 2007. We note that the solar industry parties differ in their opinions on this topic. Both SCE and SDG&E/SoCalGas indicate that systems over 100 kW to which PBI will be applied only account for about 1% of the total project applications each year. These systems account for about one-third of the installed capacity, however. They are also typically installed by sophisticated building owners, who generally have access to a greater array of financing options than smaller system owners. We are not persuaded that an immediate transition to PBI will cause market disruption. We understand that most systems over 100 kW are already financed at the 60%-70% level. Thus, the transition to 100% financing should not be as significant a hurdle for these types of installations.

Finally, we are persuaded that phasing in the PBI structure will be more confusing to administer and to explain, thereby diluting the clear signal we wish to send to the solar market that we are interested in rewarding high-performance systems and installations. Therefore, we will move to the PBI structure as described herein, for systems 100 kW and larger, starting January 1, 2007. We anticipate moving to PBI for systems larger than 30 kW in 2010.

10. Conclusion

As noted above, the Commission will apply a PBI structure to all systems 100 kW and larger beginning on January 1, 2007. Any other size system may also opt in to the PBI structure. The Commission will require building integrated systems, even those on new construction, to receive incentives through a PBI structure, but will not require other new construction solar installations to be paid through PBI. Beginning in January 2010 and after Commission review of PBI experience, we anticipate requiring systems over 30 kW to be on a PBI incentive structure.

The PBI payments will be made over a five-year period following system installation. Payments should be made on a monthly basis, and utilities may choose whether payments appear as credits on the utility bill or a separate payment. Payments will not be time-differentiated.

Payment levels identified in this decision take into account an 8% discount rate to provide comparability of PBI payments with EPBB payments addressed in the next section of this decision. Each utility shall estimate the total five year PBI payments for completed projects and deposit this amount in an interest bearing balancing account to ensure fund security over the period of the expected PBI payments.

PBI incentive levels also incorporate an assumed capacity factor of 18%, calculated on CEC-AC wattage ratings, beginning January 1, 2007. Once Step 4 of the Incentive Adjustment Mechanism is reached, the PBI payment is based on a capacity factor of 20% of CEC-AC wattage. Finally, PBI payments will not be subject to a performance cap for budget purposes.

The adopted PBI incentive rates over the duration of CSI are shown in the table below.[18] Appendix A provides the calculations supporting the levelized payments in this table.

[18] This table is based on the EPBB per watt rates shown in Table 6, Section III.C.

Table 5
Levelized PBI Monthly Payment Amounts at 8% Discount Rate

MW Step	MW in step	PBI payments (per kWh)		
		Residential [19]	Commercial	Government Non-Profit
1[20]	50	n/a	n/a	n/a
2[21]	70	$0.39	$0.39	$0.50
3	100	$0.34	$0.34	$0.46
4[22]	130	$0.26	$0.26	$0.37
5	170	$0.22	$0.22	$0.32
6	230	$0.15	$0.15	$0.26
7	300	$0.09	$0.09	$0.19
8	400	$0.05	$0.05	$0.15
9	500	$0.03	$0.03	$0.12
10	650	$0.03	$0.03	$0.10

[19] Residential PBI payments are shown in this table for those cases where a residential solar owner opts in to PBI, presumably because they believe they have a high-performing system.

[20] Incentives for the first 50 MW are disbursed under the 2006 SGIP program and PBI payments do not apply.

[21] Although Step 2 may commence before the end of 2006, the PBI payment structure in this table for systems 100 kW and larger applies to applications received after January 1, 2007.

[22] The PBI payments in Steps 2 and 3 are based on a capacity factor of 18%. Steps 4 through 10 are based on a 20% capacity factor.

C. Expected Performance Based Buydown (EPBB) Incentives for Smaller Solar Projects

Given our preference to move toward performance-based incentives, we must address the issue of how to develop an incentive structure for systems less than 100 KW that combines many of the performance benefits of PBI with the administrative simplicity of a one-time incentive paid up front at the time of system installation.

The Staff Proposal recommended an incentive methodology, the EPBB, which pays an up-front incentive based on a system's estimated future performance. The methodology considers factors such as solar system capacity ratings and system design (i.e., location, orientation, and shading). Staff proposed EPBB incentives would be paid based on the following formula:

EPBB Incentive = Incentive Rate x System Rating x Design Factor

This EPBB incentive formula would apply initially to systems under 100 kW, and to all new construction other than building integrated systems, regardless of size. In the case of new construction, staff believes an up-front payment best motivates the builder or developer to include solar in a new building design because these entities may not be the long-term owners or occupants of the property.

Most parties' comments were supportive of EPBB as an incentive structure. Many parties proposed refinements to a number of technical issues, which we address below.

1. System Rating

A system rating attempts to quantify, in wattage, how well the components of a solar generator will perform when combined into a single system. The two primary components are the solar modules and the inverter.[23] Manufacturers and independent testing facilities assign ratings to panels and to inverters to estimate their expected individual performance. A total system rating can be estimated by factoring in additional system losses due to installation variables and operational losses. In estimating total system performance, the primary differences among the calculations are the system loss input factors. The CEC developed a methodology known as "CEC-AC," which rates system components based on PVUSA test conditions.

Staff proposes that EPBB calculations use a "System AC" rating, which uses a flat 10% loss factor as a proxy for overall system losses beyond those accounted for in the CEC-AC rating.

Most parties, including Joint Solar Parties, ASPv, Michael Kyes, and PG&E, generally support the idea of moving from the current CEC-AC towards a "true system AC" rating system, which corresponds more closely to actual system performance. ASPv cautions, however, against adopting a methodology which assumes a specific loss rate, as loss rates may vary. ASPv argues that it makes more sense to wait until actual system output can be routinely verified before moving to "true system AC" as the basis for incentive payments. ASPv, along with SDG&E/SoCalGas, recommend retaining the CEC-AC rating for now.

---

[23] An inverter converts the direct-current (DC) electricity from solar panels into alternating current (AC) electricity.

Joint Solar Parties and PG&E support a system rating similar to the Staff Proposal. SCE recommends a workshop to determine whether a better method exists to determine a solar facility's true peak AC capacity rating, perhaps one which begins with the Standard Test Conditions (STC) power maximum peak rating. The STC rating is a peer-reviewed international standard to which equipment is tested, and is stamped on all solar panels. However, additional work would still be needed to develop a true system rating. Otherwise, SCE supports a verified rating, which can only be determined through system output metering. All parties agree it is essential to maintain consistency, whichever method is adopted.

For now, we will retain the current CEC-AC rating system as the basis for calculating EPBB incentive payments because we are persuaded by the arguments of ASPv that System AC ratings are not verifiable at this time. While System AC ratings may be more accurate, they cannot be verified until systems are installed. This could introduce delay in applying the EPBB incentive method, as well as uncertainty in the incentive amount to be paid. We believe CEC-AC ratings serve as a reasonable proxy until a true system rating or verification method is developed. Additionally CEC-AC ratings for EPBB are consistent with the capacity factor we use to calculate PBI incentives for larger systems. While we agree with parties that the CSI should move towards developing a true system rating, we doubt that it can be developed in time for CSI implementation in 2007.

2. Design Factor

The other major factor in the EPBB incentive formula is the "design factor," which is a ratio comparing a given solar facility's expected to optimal output. The Staff Proposal calls for the EPBB design factor to include measurements for compass orientation, tilt, and shading, calculated at the time the project's incentive application is submitted. The design factor is measured relative to a reference, or "optimally designed," solar system. The factor equals the ratio of simulated solar output for a customer's specific system divided by the simulated output for an optimal reference system.

$$\text{Design Factor} = \frac{\text{Simulated solar output of customer's proposed system}}{\text{Simulated solar output for optimal reference system}}$$

In the Staff Proposal, an optimal reference system is assumed to be oriented south, tilted 30º, and without any shading. Staff requested comments on how the EPBB should account for systems with solar tracking mechanisms, which produce more output than a simple fixed panel installation. Additionally, the staff supports utilizing an estimation tool, to be available online and in other forms, to calculate the EPBB design factor, noting that a number of these tools already exist.

The Staff proposed that the design calculation should not consider geographic location. While the Staff Proposal acknowledges that geographical location affects expected system performance due to variations in annual insolation, or sun exposure, around the state, Staff believes that since all ratepayers contribute to the CSI funding, the EPBB structure should neither punish nor reward solar customers based on their location in the state.

There were no parties who agreed with the Staff Proposal to disregard geographic location. Most parties, namely CFC, Golden Sierra, PG&E, SCE, SDG&E/SoCalGas, and TURN, agreed that including geographic location would result in the highest level of overall system production at the lowest cost, even if it means incentives will vary throughout the state depending on climate zones.

Several parties including Thomas Beach, CFC, Michael Kyes, SCE, and TURN argue that a system oriented to the west reaches peak production during a time more closely aligned to the utilities' system peak demand, and yields energy of higher value, compared to a south-facing system that may reach maximum output at noon or in the early afternoon. Therefore, they argue, the EPBB design factor should be adjusted to properly reward west-facing systems. ASPv believes this approach would result in less overall energy production for systems facing away from due south, as total solar output is maximized when solar panels or collectors face south. SCE suggests that PV systems be given maximum incentives when positioned in either a south or southwestern direction. TURN and PG&E propose that west-facing systems oriented between 180° and 270° receive equivalent design factor ratings. Some argue that an ideal tilt could be determined for each compass direction, representing the tilt at which a solar system would achieve its greatest output for each compass direction. Sun Light illustrates this in a table showing expected annual production levels by tilt for each of several illustrative compass directions. (Sun Light Comments on Draft Decision, 8/14/06, p. 7.) Thomas Beach argues further that the optimal reference tilt should be based on summer production conditions, not annual production, to encourage installations that maximize summer output. (Beach, 5/16/06, p. 6.) In addition, parties recommend determining a system's optimal tilt at location-specific latitudes rather than a standard 30°, citing the wide variance in latitudes from north to south in California. Finally, Thomas Beach and Michael Kyes suggest that local geographic factors for ambient temperature and typical solar hours also affect solar production and should be taken into consideration in determining the expected solar performance.

Only three parties commented on whether to consider tracking capability as a specific design factor. SCE argued against the inclusion, pointing out that a higher performing system will be compensated by higher bill savings. SDG&E/SoCalGas contend that since minimal historical data exists on tracker performance, the Commission should revisit this issue when sufficient data is available.

Parties supported the use of various performance estimation tools, citing the Clean Power Estimator and PV Watts, estimation tools that are available in down-loadable software versions. Michael Kyes suggests that a portable table-based reference system is likely to be more reliable than a software-based system, particularly in the early stages of implementation. Others note that the Solar Pathfinder model is typically used to assess shade conditions.

Based on the comments, we must consider which elements to include in the EPBB system design factor. First, we must take into account whether our goal is to promote peak solar production, or maximum total solar output. We believe it is important to incorporate both approaches to fully achieve the benefits that diversity and flexibility can provide within the total portfolio of CSI projects. We will allow equivalent "optimal" reference design factors for south, southwest, and west orientations (i.e., for systems oriented with a compass direction anywhere in the range of 180° to 270°). In other words, the optimal reference system in the denominator of the design factor ratio does not have to face south, but can face south, southwest, or west. This will necessitate determining an optimal reference tilt for each of the compass directions, as Sun Light illustrated. We agree with Beach this should be calculated based on optimizing summer production because one of our goals is to contribute to peak energy needs.

Second, there were no parties who proposed a design factor for trackers, and we will not adopt one at this time. As discussed in the PBI section of this decision, systems of any size which utilize trackers will be allowed to opt in to PBI whenever the solar owner believes the PBI payment better rewards the enhanced performance of trackers. We may revisit this issue in the future in the periodic CSI review process as historical tracker data becomes available.

Third, parties provided compelling reasons why EPBB should take geographical location into account in the incentive payment calculation. Variability in California's geographic and climate factors affects the levels of solar energy production possible around the state. If we include a geography component in the design factor, this ensures the ratepayer investment results in the highest possible solar energy production per dollar of ratepayer support. With geography included in the design factor, EPBB does a more precise job of estimating likely system performance. This achieves our overall objective of pay-for-performance solar incentives, while still using an up-front incentive payment for smaller solar installations, and parallels the similar outcome obtained from the metered performance structure of PBI for larger systems.

Now that we have determined the elements to incorporate in the design factor, we must address how to turn these design elements into a user-friendly estimation tool that can be incorporated into the CSI Program Handbook and used by program participants. Solar companies, program administrators and EPBB incentive applicants would use this estimation tool, either as software or a set of reference tables, to calculate their incentive payments. In short, we direct the program administrators to ensure a set of technical protocols and a corresponding user-friendly estimation tool (either software or a set of reference tables) are developed to calculate the design factor for each solar incentive application. The technical protocols and estimation tool should include the following characteristics:

- All systems oriented between 180º and 270º, facing south, southwest, and west, will be treated equally.

- An "optimal reference orientation tilt" that corresponds to the different acceptable compass directions from 180º to 270º, optimized for summer production.

- Location-specific criteria which account for weather variation and varying degrees of solar insolation, based on local climate and geography.

- An "optimal reference latitude tilt" that relates to local latitude.

To accomplish this, we direct the program administrators collectively to issue a single solicitation for a technical expert or experts(s) to provide a single design factor protocol and an initial estimation tool. This must be available by January 2007 and utilize generally available data (or default values) for design factor components. We note the CEC is developing an EPBB solar output estimation tool for use in its New Solar Homes Partnership program, which pays solar incentives to residential new construction. This tool is expected to be available by fall 2006. Once the CEC's tool is completed and operational, the program administrators should consider whether it or some other calculation approach is most appropriate to calculate EPBB payments. We prefer, if possible, that the CSI's initial estimation tool be consistent with the CEC's tool, for statewide harmony in estimation of solar system performance.

We state "initial estimation tool" because we do not wish to preclude the development of a variety of estimation tools based on identical design factor criteria, but we want to ensure that at least one is available to calculate EPBB incentives as of January 2007. The program administrators should ensure this protocol and initial estimation tool are incorporated in the initial CSI Program Handbook. We intend to circulate a draft of the initial handbook for comment, according to the schedule in Section IV.B.4.

3. EPBB Verification

The Staff Proposal calls for projects sized between 30 kW and 100 kW to receive a post-construction inspection to verify the accuracy of system data submitted in the original CSI incentive application. The proposal also recommends a verification protocol whereby actual system output would be measured for one month following installation. The program administrator would compare actual output with the expected output. For systems under 30 kW, the proposal recommends random verification. As added protection for performance, the Staff Proposal invited comments on whether there should be warranty requirements beyond those now used in SGIP.

Most parties agree with the need to verify the accuracy of system characteristics described in incentive applications. There was little support, however, to require the administrators to collect actual system performance data. SDG&E/SoCalGas believe on-site inspection that verifies easily observable system characteristics (i.e., number of modules, orientation, and tilt) should be required for all systems. PG&E points out that it already visits each site to inspect system interconnections. The CCSF and SCE recommended requiring warranties on equipment to protect both consumers and ratepayers.

We see two primary issues associated with system verification. The first is administrative feasibility. Verification will add time and cost to program overhead, whether it is performed by third-party verification services or by utility interconnection personnel. If we require the utilities to perform system output verification for all system sizes as part of an interconnection inspection, this will require additional personnel training and time, and has the potential to delay the interconnection process for solar or other distributed generation facilities. We must weigh the potential for higher administrative costs and delays in interconnection practices against the benefits of verifying the accuracy of solar incentive applications. We find it reasonable to require program administrators to verify system characteristics for all systems between 30 kW and 100 kW, as these larger systems will receive significant ratepayer investment through the EPBB incentive. We will adopt the Staff recommendation to require administrators to perform a statistically reasonable random sample of systems under 30 kW to verify their design characteristics. We will not require the administrators to collect one month of system data at this time, but we may revisit this issue in the future, if warranted.

As suggested in the Staff Proposal, project installers who fail three random inspections must be excluded from program participation. Program administrators shall develop appropriate procedures and incorporate these into the CSI Handbook. Procedures should address the severity of transgressions, correction opportunities, notification, and an appeal mechanism. In addition, we direct the staff and program administrators to ensure that measurement and evaluation (M&E) plans include an assessment of system output for a sample of solar installations.[24] This may occur through analysis of system output metered data or through alternative, site-specific data collection methods.

The second issue is the availability of trained personnel to perform the verification procedures. All system verification visits must be performed by trained personnel, whether the verification is performed by utility interconnection inspectors, other utility personnel, or contractors. We will require program administrators to develop a training plan for EPBB site inspectors that is consistent among the participating utilities.

As a final protection, we will continue to require equipment providers to provide the five-year equipment warranty already required under the SGIP program rules. We may adjust this through the Handbook process to reflect technical requirements set by CEC regulation. We direct program administrators to ensure that all installers continue to report expected annual output performance on program application forms.

4. Conclusion

We adopt maximum EPBB incentive payments for solar projects under 100 kW and all new construction regardless of size, to begin no sooner than January 1, 2007, as set forth in the Table below.

Table 6
Maximum EPPB Payment Amounts

MW Step	MW per step	EPBB payments (per watt)		
		Residential	Commercial	Government/ Non-Profit

[24] This issue will be addressed more specifically in Phase 2 of this proceeding.

1[25]	50	n/a	n/a	n/a
2	70	$2.50	$2.50	$3.25
3	100	$2.20	$2.20	$2.95
4	130	$1.90	$1.90	$2.65
5	170	$1.55	$1.55	$2.30
6	230	$1.10	$1.10	$1.85
7	300	$0.65	$0.65	$1.40
8	400	$0.35	$0.35	$1.10
9	500	$0.25	$0.25	$0.90
10	650	$0.20	$0.20	$0.70

We anticipate that in 2010, EPBB will apply only to projects less than 30 kW.

IV. Program Administration

The fundamental debate concerning CSI administration is whether to expand the role of the existing SGIP administrators into solar program areas they do not currently handle, or direct the utilities to contract with an independent, non-profit administrator for some portion of the CSI program, and if so, for which portions of the program. An explanation of the current circumstances may clarify this.

Currently, administration of solar incentives depends on project size. Solar incentives for facilities above 30 kW are handled through the Commission's SGIP, which is currently administered by four entities -- PG&E, SCE, SoCalGas and SDREO. SDREO is a private non-profit corporation that has experience administering a variety of energy programs in the San Diego area. Solar incentives for facilities less than 30 kW are currently handled by the CEC.

[25] The first 50 MW incentives are disbursed at a statewide rate of $2.80 per watt through the 2006 SGIP program.

Beginning in 2007, this size distinction will no longer be relevant because the CEC's focus will shift to solar incentives solely for residential new construction and it will no longer handle incentives for any solar retrofit projects less than 30 kW. Incentives for projects of this size, which are predominantly residential projects, will need to shift to a new administrative structure.

Aware of the impending administrative question, the Commission found in D.06-01-024 that third-party administration of the residential retrofit portion of the CSI by one or more non-profit organizations, was most likely to accomplish the Commission's solar objectives. Specifically, the Commission stated:

> The residential retrofit portion of the CSI program is one that is well-suited to third-party administration. It is an area where, in the past, the administration has been done by the CEC and not the utilities. Thus, a new administrative structure will need to be developed in any case. We expect to explore, over the next year, a pilot approach using third-party administration initially only for the residential retrofit portion of the program.
>
> For the commercial and industrial sector, we find it prudent to continue the status quo with existing program administrators, including SDREO. (D.06-01-024, p. 35.)

In its April 2006 Staff Proposal, the Staff expanded upon the Commission's suggestion to explore non-profit administration for residential retrofit projects by recommending non-profit administration for all projects less than 100 kW. Essentially, the Staff proposed separate administration for large and small systems to correspond to the Staff Proposal for two incentive structures. For systems 100 kW and larger that receive incentives based on measured performance, the current SGIP administrators would continue their work. For systems below 100 kW that receive an up front EPBB payment, Staff proposed that PG&E should conduct a competitive bidding process to select and contract with a non-profit administrator. Significantly, the utilities would, by necessity, remain in fiscal control of the contract. An advisory panel would consult with PG&E on administrator selection, and PG&E would make the final selection in consultation with the advisory panel.[26]

Staff supported its proposal by reasoning that if the utilities could contract with a non-profit administrator with a demonstrated commitment to promoting solar development and innovation, that non-profit would be committed to the long-term success and sustainability of the CSI program. Further, a non-profit could ensure marketing and outreach to all ratepayers without perceived or inherent conflicts that might discourage solar installations. Staff reasoned that expanding non-profit administration to all projects less than 100 kW would achieve economies of scale in administrative costs by consolidating large numbers of homogenous transactions within a single entity. The Staff Proposal claimed that existing program administrators, with the exception of SDREO, have neither the experience nor the infrastructure to handle large numbers of applications for small solar system incentives. Despite its proposal for non-profit administration, Staff stated it remained an unresolved issue whether the Internal Revenue Service (IRS) would determine that a program administered by a non-profit under contract to one or more utilities would be able to offer non-taxable residential incentives. Based on this alleged uncertainty, Staff requested comment on whether administration by a non-utility entity could jeopardize or restrict a residential participant's ability to take advantage of solar tax credits under IRS rules.

[26] This element of the Staff Proposal was clarified in an ALJ ruling of May 9, 2006.

A. Parties' Comments

Numerous commenting parties, including the Joint Solar Parties, the utilities, DRA, Michael Kyes, Solargenix, TURN, and Sun Light, voiced support for the current SGIP administrators continuing in their role for the CSI. These parties expressed concern there is insufficient time available for a new administrative structure to be in place for the January 2007 CSI starting date without market disruption. Additionally, these commentors argued in favor of continuing with the current SGIP administrators based on their past performance as administrators and a belief that the utilities are best positioned to meet their customers' overall energy needs. PG&E defended its experience and proven infrastructure to handle a high volume of transactions based on its expertise delivering energy efficiency and low-income programs over many years. PG&E also contended it has demonstrated its commitment to solar power through its many voluntary reallocations of budgets from non-renewable programs to fund solar projects from 2001 through 2005. According to PG&E, utility administration of CSI programs can provide numerous "one stop shopping" advantages due to the utilities' continuing role in interconnection, billing, new service connections, energy efficiency audits, and other programs.

Several commentors, notably the utilities and DRA, noted the Commission recently rejected the concept of independent administration for energy efficiency programs in D.05-01-055, in part over concerns with the Commission's ability to exercise control over an independent administrative entity. The Commission also determined there were benefits from the utilities' role in administration given their role in integrated resource planning. These parties generally allege there is no reason for the Commission to revisit the concept of non-utility administration for CSI when the concept was rejected for energy efficiency programs.

In contrast, a number of parties, namely; ASPv, Clean Power Markets Inc., CFC, Golden Sierra, NorCal Solar Energy Association, and SDREO, argued the CSI would be better served by an independent administrator for small systems based on an alleged lack of utility commitment to promoting solar development and potential conflicts of interest with other utility goals. SDREO described the benefits of an independent administrator more closely aligned to customer needs and the state's sustainable energy goals, rather than a profit motive. It further noted the positive relationships and local alliances a non-profit entity can foster with community stakeholders and other non-profits to maximize education, outreach and program service delivery. Parties also expressed the view that independent administration would have lower overhead costs than the current administrative structure for SGIP.

Many parties expressed the view that before moving to a non-profit administrative structure, the Commission should first obtain an IRS ruling on whether non-utility administration would jeopardize the ability of a residential applicant to take advantage of federal tax credits.

B. Discussion

The key debate is whether to expand the role of the existing administrators into program areas they do not currently handle, or direct the utilities to contract with a non-profit administrator for some portion of the CSI program, and if so, which portion.

1. Existing SGIP Administrators Will Administer CSI

The utilities and SDREO already administer solar incentives through the SGIP for all projects above 30 kW and many argue they are well situated to take on CSI administration and provide one-stop shopping for energy efficiency, solar and interconnection purposes. Staff had proposed keeping the existing SGIP administrators only for commercial projects over 100 kW, while expanding non-profit administration to all projects under 100 kW, both residential and commercial. If we adopted the Staff Proposal, we would actually reduce the administration role of the utilities and SDREO by handing administration for all projects between 30 kW and 100 kW to a non-profit administrator.

We find it more reasonable to define CSI administration in terms of customer sector, i.e., residential or non-residential, than by project size distinctions. A size distinction worked in the past when size was the dividing line between CEC and Commission programs. Now that the Commission will oversee residential solar retrofits of any size, it is more meaningful to discuss administration options based on residential and non-residential distinctions.

With that as a framework, we find it reasonable to allow the existing SGIP administrators to continue in their roles and administer the CSI in 2007 and beyond for the non-residential sector. This will allow all non-residential projects, regardless of size, to be handled essentially in the manner they are handled today. Although the Staff had proposed reducing the role of the existing administrators by limiting them to projects above 100 kW, we disagree with this suggestion. The comments persuade us that if we limited the existing administrators to solar projects above 100 kW, they would be left with very few projects to administer, as the majority of applications are for projects below 100 kW. The Staff Proposal would transfer responsibility for programs that the utilities and SDREO have experience administering to a new entity. We see no reason to reduce the role of the existing administrators at this time. This would place even more pressure on a new administrator to take over the majority of the CSI program in a very short time. There is no obvious reason to reduce the role of the existing administrators to such a great extent at this time and jeopardize the smooth transition from SGIP to CSI.

We must now determine whether to pursue non-profit administration for the residential retrofit portion of the CSI. For now, we will shift the residential retrofit solar programs from the CEC's single statewide administration to the existing SGIP administrators as well, i.e., PG&E, SCE, SoCalGas, and SDREO. Although we strongly endorsed the concept of non-profit administration for residential retrofit CSI programs in D.06-01-024, and we still support the concept, we find there simply is not enough time between now and January 2007 to ensure this move is done well and without disrupting the residential solar market. We are more concerned with ensuring a smooth and timely transition from CEC administration to experienced administrators and preventing any gaps in the provision of solar incentives to the residential retrofit market. Essentially, we agree with the concerns expressed by many parties that there may not be one or more candidates for non-profit administration that could be competitively selected and fully operational on a statewide basis by January 2007.

We reiterate that we still endorse the concept of non-profit administration for the residential retrofit portion of CSI. Although we make the choice to shift these programs from the CEC to the existing SGIP administrators for now, we make this choice for expediency and to ensure program continuity in 2007. In the longer term, there are still very good reasons to consider non-profit administration for this portion of CSI. The residential retrofit programs have been handled by one entity, the CEC, on a statewide basis until now. A future hand-off to one statewide entity may still prove the best long-term option. The rationale articulated by the parties resonate with us, particularly that a non-profit administrator might achieve economies of scale by consolidating residential retrofit programs statewide, exhibit lower overhead costs, and be driven by a mission to promote solar development. We agree with SDREO that a single non-profit entity with strong community alliances might be best positioned to maximize education, outreach and program delivery.

We will explore in Phase II of this rulemaking whether to direct the administrators to contract with a single statewide entity for marketing and outreach of CSI programs. If we find that a reasonable option, and we direct the administrators to contract with one entity for statewide marketing and outreach, we might also consider directing the administrators to expand that statewide contract at some future date to include the actual administration of residential retrofit programs altogether. We also may look in the future at alternate administrative approaches for a single region or utility service area if it appears that one region lags others in solar penetration, ease of interconnection, or administrative performance and cost. In the near term, we discuss at the end of this section the development of one statewide on-line application system. This concept of a single portal for solar incentive applications from residential customers could allow a smooth transition, at a later date, to a single statewide administrator for residential programs.

2. IRS Tax Concerns

Turning to the issue of whether program administration affects the tax status of incentive payments, we find that IRS taxation issues do not impact our decision between existing administration or transfer of administrative duties to a non-profit entity. Almost all parties commenting on CSI administration questioned whether residential solar incentives, or subsidies, would be taxable if administered by a non-utility administrator and whether it is desirable to obtain a ruling on this issue from the IRS. Under Section 136 of the Internal Revenue Code, a taxpayer does not receive taxable income when he receives a "subsidy provided (directly or indirectly) by a public utility for the purchase or installation of any energy conservation measure." No question has been raised as to whether the subsidies here would be "for the purchase or installation of an . . . energy conservation measure." Rather, some have questioned whether the subsidies would be "provided (directly or indirectly) by a public utility" if the Commission requires the utility to enter into a contract with a third-party administrator to administer the subsidy program. However, the clear language of Section 136 includes a subsidy provided by a public utility, even if the utility contracts with a third-party administrator to administer the subsidy program, where the money comes from utility rates and is issued in the form of a check payable from one of the utility's checking accounts.[27] Indeed, the legislative history of this language shows that the purpose of Section 136 is to "provide tax-free treatment for the receipt of subsidies relating to energy conservation

---

[27] There are other facts present here that further support our conclusion that these would be subsidies provided by a public utility. These include the following: the source of the funds are utility rates (not including Public Goods Charge (PGC) funds); the funds never pass through the hands of a governmental entity; the third-party administrator is hired pursuant to a contract with the utility; while the Commission may advise about the selection of the administrator, the administrator is selected by the utility.

measures in order to encourage customers of public utilities to participate in energy conservation programs *sponsored by the utilities* (emphasis added)." (H.R. Rep. No. 102-474(VI) 2nd, Sess., p. 2247 (1992).) The subsidies to be provided here will be "sponsored by the utilities" whether or not the utilities use a third-party administrator to handle the administration of the subsidies.[28]

Parties have expressed concern whether an IRS Private Letter Ruling (8530004 (April 30, 1985)) calls this conclusion into question. We believe that that Private Letter Ruling does not. In the first place that private letter ruling deals with a different section of the Internal Revenue Code and different language. The language being interpreted there was "financing *provided under* a Federal, State, or local program . . ." as opposed to the language at issue here which is "subsidy *provided by* a public utility" (emphasis added). Furthermore, the portion of the private letter ruling that has caused these concerns is dicta, is not supported by citation to any authority, and seems directly contradictory to a prior Revenue Ruling (Revenue Ruling 83-145). Moreover, a Private Letter Ruling cannot be cited as precedent, whereas a Revenue Ruling can be cited as precedent. Accordingly, we see no reason for the Commission to seek a ruling from the IRS on this issue.

[28] Thus, even if it should prove necessary to have the check that is issued to the consumer bear the name of the third-party administrator, it would seem that the subsidies are still "sponsored by" the utility and thus are still eligible for Section 136 treatment. Of course, it will be important to have sufficient accounting controls to ensure that the monies paid to the consumer are those provided by the utility.

3. Statewide Online Application Process

In its January CSI decision, the Commission stated the intent to "encourage web-based administrative options to facilitate quick and transparent transactions for applications and other activities" noting that "a single interactive database would allow applicants, evaluators and administrators to readily access statewide project information." (D.06-01-024, p. 35.)

Several parties expressed support for this idea, and recommended creation of an Internet accessible, online application tool and uniform statewide database to streamline the CSI application process as well as administration and data collection activities. As SDREO noted in its comments, CSI applicants could use this online tool to download and submit program documents (such as the program handbook and incentive application forms), while administrators could use the database for project management, monthly reporting, data collection, and possibly program tracking of system performance. Similarly, ASPv emphasized the immediate need for such an online application tool and data accumulation system.

We remain convinced that a statewide online application system will enhance the ability of customers to take advantage of our solar programs. In addition, a single database of project information would provide a valuable tool for ongoing program assessment. Therefore, we direct the administrators to coordinate hiring an entity to create a statewide application process and program database within 30 days of this order. The program administrators should designate one administrator to handle the competitive bidding process and contract with the entity selected to create the online application and database. We understand that even if this effort is begun immediately, the end-result of a uniform statewide on-line application system may not be ready for implementation on January 1, 2007. Nevertheless, we hope the program administrators can make every effort to get this statewide application system operational as soon as possible after the first of the year. The program administrators should report back with their progress on this statewide application project through a letter to the Director of the Energy Division, copied to the service list for this proceeding, no later than December 31, 2006.

Once the program database is established as described above, the data it contains should initially be accessible only to the program administrators and CEC and Commission staff. We will direct the CSI Program Forum, which we discuss below, to address broad access to non-confidential information in the database and consumer-oriented summary statistics, so the general public can monitor program details.[29]

4. Program Handbook

The program administrators, solar industry, and participating customers need a handbook to facilitate program implementation. In D.06-01-024, the Commission stated its intent to use the existing SGIP manual as the foundation for the CSI Program Handbook. (D.06-01-024, p. 35.) It may also prove useful to build on the existing handbook from the CEC's ERP program.

This decision confirms the process laid out in the Scoping Memo for this proceeding that the work related to the CSI Program Handbook should begin immediately following adoption of today's order. We direct Energy Division to convene a workshop within 15 days of the effective date of this order

---

[29] Rulemaking 05-06-040 is examining confidentiality generally. Parties may wish to refer to the first decision in that proceeding, D.06-06-066, for guidance on how to treat information relevant to CSI.

to discuss handbook revisions and create subgroups to work on various sections of the handbook. The workshop efforts should produce one draft CSI Handbook that Energy Division will forward to the ALJ no later than 60 days following the workshop. The ALJ will issue a ruling, attaching the proposed CSI Handbook, and requesting comments from all interested parties. Depending on the proposed Handbook and the comments, the Commission shall either issue a decision or the assigned ALJ shall consult with the Assigned Commissioner to review and approve the final CSI Handbook through a ruling. The table below indicates the anticipated timeline for handbook development. The Assigned Commissioner or ALJ may modify these dates or events by ruling.

Table 7: Program Handbook Schedule

Workshop and initiation of subsequent working group activities to propose Handbook revisions	15 days after Phase I decision adopted by Commission
Energy Division forwards draft CSI Handbook to ALJ and ALJ issues ruling with proposed revisions for comment	45-60 days after workshop
Written Comments on Proposed Revisions	15 days after ruling
Reply Comments	10 days after comments
Ruling or Draft Decision Adopting Handbook	No later than 60 days after reply comments (possibly sooner if approved by ruling)

5. CSI Program Forum

In establishing the CSI in January 2006, the Commission stated that Staff should convene "regular and public meetings of the utilities, program administrator(s) and any parties interested in articulating and solving administrative or implementation problems and identifying program opportunities." (D.06-01-024, p. 35.) In comments on the Staff Proposal, the Joint Solar Parties and ASPv reiterated support for creation of an industry group, with broader participation than the current SGIP Working Group, to tackle ongoing CSI program implementation issues.

Consistent with our statements in D.06-01-042, we will create a CSI Program Forum, which will provide a public venue for interested parties to identify and discuss ongoing issues related to CSI administration and implementation. The purpose of forum meetings is to provide the opportunity for CSI stakeholders to fashion consensus-based revisions to the CSI Program Handbook. If the group achieves consensus, it may designate one of its members to file a proposed Handbook revision by Advice Letter with the Energy Division, which should be served on the service list of this or any successor rulemaking. If the group achieves consensus for more substantive program modifications that go beyond the level of the Program Handbook, it may designate a member to file a petition to modify a Commission order relating to CSI.

We expect participants in the Forum to include utilities, solar manufacturers, solar installers and other interested parties. The program administrators should convene the first public meeting of the CSI Program Forum in the first quarter of 2007, after the CSI Program Handbook has been developed through the process described in the section above and the incentives and other program features discussed in this order have taken effect. Energy Division staff should facilitate this initial meeting. The program administrators will then arrange and facilitate future public meetings of the CSI Program Forum, after working with Energy Division staff to set the agenda for each meeting. The program administrators should provide notice of all meetings to the service list for this proceeding, and work with Energy Division staff to provide meeting notices on the Commission's Daily Calendar. The program administrators shall also maintain meeting minutes and post them on the CSI portion of the Commission's website, with the assistance of Energy Division. We expect Energy Division staff to participate in or monitor all meetings of the CSI Program Forum.

V. Metering Requirements

There are two critical CSI implementation issues concerning meters: (1) whether to require separate metering of solar output, and (2) to what extent, to whom, and through what communications medium to relay solar system performance data from these meters. Subsidiary questions relate to the associated costs and benefits of the meters and ongoing communication functions, how the metering and communications mechanisms might be integrated into the proposed advanced metering infrastructure (AMI) plans of the utilities, and TOU tariff requirements.

An explanation of the current circumstances may help put this in context. First, with regard to total solar system output, both the Commission's SGIP program and the CEC's ERP program currently require a second customer-owned meter, separate from the main utility meter, to measure the *gross* solar output performance of the solar system. This meter is referred to as the net generation output meter. However, there is no requirement to connect any kind of communications device to this solar meter in order to deliver real-time or periodic reports about system performance to the owner, the manufacturer, or the utility. Some owners pay at their own expense for a reporting function. Smaller systems may have this meter installed as an integral part of inverter equipment, with accuracies in the range of plus or minus 5%.

Second, solar customers that elect to go on a net energy metering (NEM) credit system face specific metering requirements. An NEM customer is only required to have a standard "cumulative" NEM meter that spins forward and backward, registering just the *net* purchase of electricity from the grid. Customers who take service on a TOU tariff typically install a two-channel time-interval meter that separately records the *net* inflow and outflow of electricity for each applicable time interval. Neither of these utility-owned meters collects information on the *gross* generation of the solar system, nor do the meters have a communication path to the customer-owned NGOM meter that measures gross solar system output.

The Commission has previously expressed the need for good metering to manage and monitor solar installations and the program generally. (D.06-01-024, p. 31.) Accurate solar metering helps ensure that ratepayer incentives result in expected levels of solar generation. In D.06-01-024, the Commission identified the need for greater specificity of metering solar performance, and urged exploration of approaches rewarding on-peak solar production, including the kinds and costs of meters used in relation to quantifying solar production, utility bill savings, and NEM credits.

In its April 2006 Staff Proposal, the Staff recommended measures to address both meter accuracy and system performance feedback. First, Staff proposed that all CSI incentive recipients must have a dedicated revenue-grade meter to measure solar system output. Staff reasoned that a dedicated revenue grade meter ensures accuracy in monitoring system output for PBI payments and can support communication of accurate system performance data to all solar owners. Staff also envisions administrative cost savings when a PBI system's performance data can be sent remotely to the program administrator for payment processing.

Second, Staff proposed that all systems larger than 30 kW, even those not receiving PBI, have not only a dedicated solar meter measuring gross output, but also the ability to communicate this information remotely over the Internet (for a web-based reporting system) or by a utility reading and reporting system. According to Staff's proposal, solar performance data can better inform system owners about their system performance than the customer's net-metered utility bill. A specific solar report also serves as a reminder to the customer to check on system maintenance. Further, if tens of thousands of small solar systems were to have remote meter communications, Staff envisions the solar market would develop affordable metering and communication devices incorporated into system designs.

Staff made no specific proposal concerning the entity that would process this performance information and report it to customers and program administrators, and suggested a working group examine the possibility of a third-party operating the performance data retrieval and reporting system. Along with this proposal, Staff invited comments on the feasibility of including solar performance data on utility bills by January 2007.

A. Metering Quality and Accuracy

There is little disagreement that revenue grade meters are required to ensure accuracy of PBI payments. Parties were split on whether the Commission should require revenue grade meters for all other CSI participants. FST, SCE, and Clean Power Markets support revenue grade meters (+-2% accuracy) for all CSI participants. FST contends California may need revenue grade meters for all sizes of systems to meet the measurement and accuracy rules required by Renewable Portfolio Standard participation, if Phase II of this proceeding requires solar output measurements for DG solar renewable energy credits. CARE advocates that all systems should have a TOU net generation output meter, which we presume would be revenue grade. Similarly, CFC supports "real time meters" (presumably revenue grade) if the utility will be paying for the meters, but otherwise believes the meter choice must be "cost-effective" relative to performing production measurement. Parties that support revenue grade meters for all CSI participants based their support on increased data accuracy on performance to help drive technological advancement, increased owner knowledge of system performance to foster adequate maintenance, and a meter industry ready to provide these meters at a cost-effective level.

On the other hand, the Joint Solar Parties, ASPv, SDG&E/SoCalGas, PG&E, and CCSF believe revenue grade meters should be applicable to PBI participants only, while a lesser meter with plus or minus 5% accuracy should suffice for systems receiving EPBB incentives. While the cost for external revenue grade meters may be only slightly higher than standard accuracy meters, parties supporting an exemption from revenue grade meters for small systems argue revenue grade quality is simply unnecessary for smaller systems receiving the up-front EPBB incentive, since these do not require the same measurement function as larger systems receiving PBI incentives paid on measured performance. PG&E is not opposed to a revenue grade requirement for smaller systems, but would exempt residential systems unless generation data is used to calculate the EPBB incentive. SDG&E commented that it already uses revenue grade meters for all solar systems larger than 30 kW.

SDG&E offered detail on a range of revenue grade meters and their costs as indicated in the table below.[30]

---

[30] See SDG&E/SoCalGas Comments, 5/16/05, p. 22.

Table 8: SDG&E Data on Meter Costs[31]

PV System Size	System Installed Cost	Meter Cost as a Percentage of System Installed Cost[32]
2.5 kW	$15,000	$25 meter = 0.2% $175 meter = 1.2% $750 meter = 5%
10 kW	$60,000	$25 meter < 0.1% $175 meter = 0.3% $750 meter = 1.3%
30 kW	$180,000	$25 meter < 0.1% $175 meter < 0.1% $750 meter = 0.4%
100 kW	$600,000	$25 meter < 0.1% $175 meter < 0.1% $750 meter = 0.1%

A few parties made the distinction between the cost of external meters and less expensive meters integrated with the solar system inverter. Others state that internal meters are not accurate enough to rely upon for program needs. PG&E states that internal meters may be sufficient for small residential customers, but large systems participating in PBI should have a separate revenue grade meter. Joint Solar parties state that internal meters should be satisfactory if they are revenue grade. SCE and SDG&E/SoCalGas state that they are not aware of an internal meter that is revenue grade.

31 SDG&E explains that a simple meter costs $25, an interval data recording (IDR) meter costs $175, and a meter with remote communications for collecting historical time series data costs approximately $750. (SDG&E/SoCalGas Comments, 5/16/05, p. 22.) These are costs of the meter alone, without installation or on-going communication costs.

32 SDG&E's percentages of solar system installed cost are based on an assumed PV system cost of $6000/kW. Other parties' comments indicate systems today cost considerably more than that.

We find SDG&E/SoCalGas' comments particularly helpful as they explain different types and costs of revenue grade meters. Staff proposed an unspecified "revenue grade" meter to confirm solar production levels for all sizes of solar installations. SDG&E/SoCalGas reveal that revenue grade metering of solar system production is achievable at a variety of prices. Essentially, the meter price depends on the degree of time interval detail and the communication capability built into the meter.

In its January CSI decision, the Commission expressed the desire for system performance metering that permits the customer to identify potential system problems requiring adjustments or repairs. We will require accurate solar production meters for all systems paid incentives through CSI, either through the PBI or EPBB mechanism. We will not dictate that meters are "revenue grade" because parties comment that definitions of revenue grade can vary by utility. Instead, we will require accuracy of plus or minus 5% for systems less than 10 kW, and accuracy of plus or minus 2% for all larger systems. We continue to believe that it is in the ratepayers' interest to have accountability for solar generation output under the EPBB incentive structure even though the incentive mechanism itself does not require metered output. Accurate measurement of performance for all system sizes is of paramount importance to ensure optimum value for both solar owners and ratepayers, and has the potential to better inform the solar industry and utilities about technology performance. Moreover, such accuracy preserves options when we later turn our attention to the treatment of renewable energy credits in Phase II of this proceeding.

Using the cost data for revenue grade meters provided by SDG&E/SoCalGas, we find that requiring a simple meter with accuracy of at least plus or minus 5% for systems less than 10 kW strikes an appropriate balance between accuracy and cost. We find that for larger systems 10 kW and above, a meter with plus or minus 2% accuracy would not add a significant cost burden to CSI participants. Thus, we find it reasonable for all PV owners participating in the CSI program to install these meters at their own cost, regardless of the type of incentive payment received. While mutual benefits exist, we believe it is fundamentally in the interest of solar owners to include meters and communication technologies in their solar system designs. Thus, the metering and communication hardware and software shall be installed at customer expense as a condition for receiving the CSI incentives.

In summary, we set minimum requirements for solar production meters as follows:

Table 9: Metering Requirements

Size of System	Minimum Solar Production Meter Required
< 10 kW	Basic meter (+/- 5% accuracy
10-29 kW	IDR meter (+/- 2% accuracy)
30+ kW	IDR meter (+/- 2% accuracy)

To the extent that internal meters are certified as accurate to within 5% based on national metering standards, these are equally acceptable to stand-alone external meters for systems smaller than 10 kW.

There are myriad technical and procedural details yet to be resolved related to the guidance provided by this decision on meters. These include specifications, issues of standards and certification, communication protocols and platforms, eligible recipients of information, and appropriate parties to execute these arrangements. We make general policy conclusions here, but need utility and industry metering experts to work out the technical details and to advise us further before we make decisions on further technical and procedural issues. In Section V.C below, we discuss the process for this further work, and we encourage the appropriate parties and technical personnel in the solar, utility, and metering industries to create a metering and data committee as part of the CSI Handbook process and on-going CSI Program Forum to address these issues.

B. Communicating Solar Performance

Having required accurate solar production meters, next we address what happens with the data collected. Specifically, we must resolve: (1) whether to move ahead now with reporting system performance information or wait and coordinate this effort with AMI rollout, (2) who will performing the monitoring and reporting function, i.e., what entity will receive the information and consolidate it into a report, and (3) which entities will receive the report once it is produced.

Although the Staff Proposal recommended revenue-grade meters and communication functionality, it made no specific proposals on these three issues. Parties provided comments on the issues, and we take each issue up separately below.

1. Ensuring Solar Performance is Monitored in 2007

First, we address whether to require performance reporting and communication functionality now, ahead of AMI roll-outs by the utilities.

A number of parties, namely ASPv, CCSF, SDG&E/SoCalGas, PG&E, and FST, generally support the goal of using remote communication to carry out solar system performance feedback. Most of the utilities recommend the Commission not make a decision on requiring solar system performance monitoring until such time as AMI is decided. PG&E and SCE argue there is a potential for stranded costs if CSI meters are not compatible with AMI meters. PG&E comments that it expects a five-year roll out once it receives Commission approval for its proposed AMI plan.[33] It comments that remote communication capabilities "would be helpful in providing general information on system operations for smaller installations," and that the specific meter and monitoring arrangement would need to be cost-effective. SCE believes all metering and communication technology should be AMI-compatible, and the utility should determine the "best fit" choice of meters and their placement. SCE states this requirement was not urgent and should be optional until AMI plans are resolved. SCE notes it would start its AMI rollout in 2009. SDG&E observes there needs to be flexibility of approach to fit with individual utility circumstances. SDG&E recommended the Commission go no farther than requiring an IDR meter at this time, reserving action on requiring a remote communication meter package until AMI is decided.

A few parties indicate that remote communication requirements should be applied to larger systems. ASPv and PG&E suggest remote communication for PBI only, while SDG&E, CCSF, and FST recommend this for all systems above 30 kW.

Offering a different view, FST supports immediate use of remote communication, indicating such methods are cost-effective now for systems 30 kW and above and amount to under 1% of system costs. FST believes this could be extended to systems greater than 10 kW in 2008, and to all size systems in 2009. To guide the pace of expanding remote communication and

---

[33] PG&E's AMI proposal (A.05-06-028) was approved by the Commission on July 20, 2006.

performance reporting, FST suggested the Commission require immediate remote communication capability where the combined cost of a package of hardware, software and the first five years of monitoring service does not exceed 1% of the total system installed cost up to 100 kW, 0.75% for 100 – 500 kW, and 0.25% for systems over 500 kW. For example, this would be up to $200 for a $20,000 solar system, and $1,250 for a $250,000 system. FST suggests individual customers can always upgrade to higher functionality. FST also believes a general requirement of communicating meters can reduce M&E and administrative costs.

The earlier sections of this decision have discussed in great detail the redesign of CSI incentives to incorporate a performance dimension and reward solar system output. We consider a performance feedback loop critical to achieving our goal of high performance solar technology. Therefore, we will not delay action pending the completion of the utilities' AMI proceedings. We will require that all solar systems receiving a CSI incentive, either PBI or EPBB, have some form of communication reporting capability. Options include remote communications via telephone, cable, modem or wireless transmission, or utilizing a utility's existing meter reading system. As discussed more fully in Section V.C below, the parties participating in the CSI Handbook Process can refine and recommend the exact details of this minimum communication function, within cost limits.

While the Commission would like data for all solar systems to be accessible remotely to both support solar technology improvement and to support monitoring and evaluation data requirements, we are concerned that requiring this capability without limits could become a cost barrier. While parties generally did not comment on who should pay for the reporting hardware and software, existing rules for SGIP and NEM make it clear that the customer typically pays for any expenses beyond providing the minimum utility revenue meter. A dedicated solar system meter goes beyond this minimum.

To ensure reasonable balance between customer cost and value received, the metering subgroup developing the draft CSI Program Handbook should develop minimum standards and functional requirements within an overall cost constraint for inclusion in the Handbook. We will rely on the comments of FST to specify that the total cost of the minimum metering, communication, and reporting system over the first five years for each solar installation size grouping shall be less than 1% of total installed solar project cost for systems up to 30 kW. For larger systems, we choose a middle ground cost cap of less than 0.5% to be somewhat conservative in the expense that owners of larger systems will have to incur. If the communications functions should cause anticipated five-year expenditures to fall outside the cost cap, we urge the metering subgroup to find some effective solution for performance feedback to solar owners while still remaining within the cost cap applicable to the different system sizes.

With respect to issues of coordination between CSI metering requirements and AMI, it is vital that performance monitoring be available commencing in 2007 for all systems that receive incentives. While we appreciate the potential value of integrating such a performance reporting system with AMI in the future, we do not want the prospect of future AMI decisions and not yet developed technical parameters to hold back solar performance monitoring for all systems sizes. Systems of 100 kW and larger must have reporting capabilities as part of the incentive payment mechanism, and this must be in place by January 1, 2007. In addition, a performance monitoring and feedback requirement within the cost cap outlined above is a legitimate requirement, even for systems below 100 kW. Although comments on the draft decision urge us to drop performance feedback requirements for small customers and avoid stranded metering investments by customers in advance of utility AMI rollout, we take a different view. Performance feedback to owners of systems below 100 kW, including residential customers, is consistent with the CSI program objective of achieving high performance solar technologies. Performance data will provide valuable feedback to customers so they can maximize the value of their solar investments. Further, if a feedback loop leads to a higher performing system, ratepayers ultimately benefit as well by ensuring a payoff from their incentive investment. The information can be used for measurement and evaluation purposes to assess the success of our EPBB incentives. Finally, the investment in good performance feedback is not expensive, as we have capped the cost of five-years of performance monitoring at 1% of total system cost for smaller systems.

The metering committee working to develop the initial draft CSI Program Handbook should address the tasks necessary to establish minimum performance monitoring capabilities for both PBI and EPBB customers within the cost caps outlined above in advance of AMI. Proposed protocols should be included in the initial draft CSI Program Handbook, which will be developed according to the schedule in Section IV.B.4. Wherever possible, standard data communication protocols and other specifications should be selected to preserve greater likelihood of AMI integration in years ahead and avoid duplication of costs.

2. Independent Performance Monitoring

Turning to the issue of what entity carries out the performance data collection and reporting function, Staff noted that in addition to the solar owner or installer, a utility or other third party could perform the role of system monitor.

In response to Staff's proposal, FST explains these services can be provided by independent third parties who may be preferred to avoid potential bias from solar owner or solar manufacturer/installer performance reporting systems. FST contends that if the Commission later decides that renewable energy credits will be available for solar system owners, the renewable energy credit rules require independent third-party verification of renewable production using revenue-quality meters.

SDG&E maintains the utility must have access to the solar system meter, although it adds that its Rule 25[34] is a good starting point for defining a possible role of third-party meter providers and services. FST agrees with this in their reply comments. PG&E states that even prior to AMI resolution, it could produce performance reports through its Alternate Billing System.

We find the entity responsible for administering the performance reporting system(s), should be an independent party – either the existing program administrators or one or more third-parties not affiliated with solar system manufacturers or installers. We will require parties to include a proposal for independent performance monitoring as part of the initial draft CSI Program Handbook, as discussed in Section IV.B.4. We agree with SDG&E and FST that

---

[34] Rule 25 pertains to Direct Access third-party meter and data rules. This is Rule 22 for PG&E and SCE.

Rule 25 regarding metering for direct access may serve as useful guidance for this effort.

3. Access to Solar Performance Information

Staff made no specific proposal on who should get access to the metered information beyond customers and program administrators.

Two parties address this issue. ASPv advocates a "data accumulation service" should be available for customer use in January 2007, and that data should be made available to solar market participants as soon as possible. FST argues that in the case of residential solar systems, performance data is far more useful when provided to solar industry stakeholders, i.e., installers and panel manufacturers, who have a business interest to ensure their systems are performing.

We will require that performance information be communicated to customers and program administrators as soon as feasible, and we direct Energy Division to ensure this issue is addressed in the initial draft CSI Program Handbook. In addition, we agree with FST that the information could prove useful to the solar industry in their design of components and integrated systems. We also see value to providing the information to the general public for general consumer research on prospective solar investments. The CSI Program Forum should consider the concept of broader release of program information, and accompanying privacy or data confidentiality concerns, and make a proposal through the process described in Section V.C below.

C. Further Work in CSI Handbook Process and CSI Program Forum

There was uniform support among the utility parties and FST for initiating a CSI meter and communication technology work group. These parties recommended the group could be comprised of solar and metering industry representatives, utilities, and Commission staff. The group would be tasked with establishing metering and data communications standards and coordinating details with unfolding AMI efforts.

In the sections above, we have directed various metering issues to be addressed either through the CSI Program Handbook development process described in Section IV.B.4, or through the CSI Program Forum that will convene in 2007. If the parties find it beneficial, they are free to organize a metering and data communication committee of either group so that the appropriate technical representatives of utilities, program administrators, solar installers and manufacturers, metering and remote data communication providers, and customers can address these issues. In summary, we direct the parties to address the following metering issues in the CSI Program Handbook process:

1. Propose agreed upon meter standards and data transfer protocols, within 1% of total installed cost for systems up to 30 kW, and less than 0.5% of total installed costs for larger systems, for the requisite hardware, software, and performance reporting services, with the goal of standardization and widespread utilization in California.

2. Propose the kind of solar performance data to be included on the owner's solar system report or energy bill and the options for providing this information.

We direct the following issues to be considered by the CSI Program Forum:

1. Whether and how solar system manufacturers and integrators/installers should have access to performance data about their components and systems. There should be consideration of how to use data as potential for general consumer research for those considering buying a solar system, and how solar industry might use the data

to improve performance of component products and/or integrated solar system designs.

2. AMI coordination issues once each utility's AMI plans, schedules, and any associated fee-for-service offerings become clear.

D. TOU Tariffs

A related dimension to solar system performance meters is whether we should require all CSI participants to be served on TOU tariffs to the extent participants' default meters and tariffs do not already have time differentiation.

Both CFC and CARE commented that the Commission should consider having all solar customers use either real-time or TOU meters, respectively. PG&E commented that "currently about half of PG&E's net metered customers take service on a TOU rate." (Reply comments, page 14.) No other parties commented on this topic.

The Commission has a long history of supporting TOU tariffs for customers, where they are cost-effective. Moreover, we understand that a large portion of solar capacity is already served by time-differentiated meters and tariffs, either because large customers required to be on TOU tariffs, or smaller customers, have opted for a TOU tariff to capture the financial advantages in bill savings and NEM credits from solar's day-time availability. Thus, many solar customers not already required to be on a TOU tariff voluntarily choose a TOU tariff to capture these benefits.

In the case of smaller solar systems for smaller customers not choosing a TOU tariff, the EPBB incentive structure, which pays based on a system's design relative to optimal south-to-west orientation for on-peak production, fulfills the goal of providing incentives for on-peak solar production. This is achieved without imposing the additional customer costs of IDR utility revenue meters and their associated monthly meter reading costs.[35]

To properly consider the possibility of requiring small solar customers to use a time-differentiated tariff, we need to look at the overall economics of such an action for the solar owner and ratepayers, including how this interacts with the value of bill savings, net energy metering, and avoided energy supply costs. We intend to address this tariff question together with the cost-effectiveness issue scheduled for Phase II of this proceeding, as outlined in the Scoping Memo. We may also need to coordinate such a decision with other proceedings involving AMI and demand response tariffs. Commission staff and interested parties should raise and consider in appropriate proceedings, such as general rate cases, the relationship between these tariffs and our goals for renewable distributed generation.

VI. Incentive Adjustment Mechanism

In the January CSI decision, the Commission established a mechanism for solar incentives to automatically decline each year by 10% over the 10 years of the CSI. (D.06-01-024, Appendix A, p. 15.) The Commission's objective in establishing a declining rebate schedule was to reduce incentives over time as technologies become more efficient and less costly, with the hope that incentive reductions would drive the market price of solar energy down to the level where ratepayer subsidies are no longer required. The adjustment mechanism adopted in D.06-01-024 reduces the statewide incentive level at the start of each calendar

[35] We require an IDR solar production meter for systems above 10 kW. The cost for these meters can be substantially lower than the utility charges for rate-based utility TOU meters and utility meter reading.

year or when specified MW levels, or "triggers," of solar installations are achieved, whichever occurs first. In the same order, the Commission noted that automatic annual reductions might not adequately recognize market conditions. The Commission delegated authority to the assigned ALJ to reduce incentives further, following justification for incentive changes from CEC and Commission staff and an opportunity for parties to comment. (D.06-01-024, pp. 24-25.)

In this order, the Commission makes adjustments to the 2007 starting point incentive level adopted in D.06-01-024 to incorporate a performance-based dimension and account for federal tax incentives. Thus, it is reasonable at the same time to reconsider how these new 2007 incentive levels should adjust over time. Moreover, in the first few months of 2006, the program administrators received a higher than anticipated level of solar incentive applications and the first MW "trigger" level appeared to be quickly reached. When the ALJ issued a ruling notifying parties of the trigger reduction in incentive levels, parties raised concerns with myriad implementation details surrounding the trigger reduction, particularly regarding how the Commission should determine whether the MW trigger had actually been reached.

Based on this implementation difficulty with the trigger mechanism, the Staff proposed a simple 10% annual reduction in incentive levels rather than a combination of reductions based on either calendar years or MW levels as adopted in D.06-01-024. Staff proposed a flexible approach whereby the Commission could adjust incentives to reflect breakthroughs in solar technology or could retain them at the same level for a second year if market factors do not produce a lower cost per kWh.

In response to the Staff Proposal, few parties supported the idea of a 10% annual incentive reduction. Instead, several parties, namely ASPv, Golden

Sierra, the Joint Solar Parties, SDREO, and TURN, supported incentive adjustments based solely on the volume of solar installations, measured in MWs, rather than a calendar-based schedule. The Joint Solar Parties claim that a volume-based trigger is transparent, administratively simple, and allows for consistent development of the market by avoiding program stops and starts. TURN contends a volume-based approach allows external market factors such as retail energy costs, installed costs per watt, and changes in the global solar marketplace to influence incentives through market demand without the burdensome task of monitoring market conditions. In contrast, SCE and SDG&E/SoCalGas support a reduction mechanism combining calendar years and MW levels, as the Commission had adopted earlier. SCE contends a trigger based on both time and MW levels preserves the CSI budget and gives the solar industry an incentive to lower costs on a yearly basis.

A key reason the Commission adopted an adjustment mechanism for CSI incentive levels was to manage CSI funds over the 10-year program period while achieving the goal of 2,600 MW for the Commission's portion of the CSI. Although the trigger mechanism we adopted in D.06-01-024 has been in operation less than one full year, the parties have provided meaningful insight into the impacts of the trigger on the solar market going forward. Given these comments and our own experience with implementing the first incentive reduction using the trigger mechanism, we find it necessary to fine tune the incentive adjustment mechanism at this time.

There are three issues surrounding the incentive adjustment mechanism which we need to resolve: (1) whether to base reductions solely on the volume of solar MWs installed or on a combination of calendar years and MW targets; (2) whether the incentive levels should adjust uniformly statewide or vary by utility territory; and (3) whether we should provide for further review and stakeholder involvement in the incentive adjustment process. We address these issues below.

A. Incentive Adjustment Mechanism Based Solely on Volume of MWs

First, we agree with the numerous parties who urged that any adjustment mechanism should be simple, transparent, and predictable to avoid uncertainty and confusion over incentive levels in the solar market. Ideally, adjustments to the incentive levels should correspond to the economics of the solar marketplace, without requiring a complicated economic formula or a resource intensive review process.

We will modify the incentive adjustment mechanism adopted in D.06-01-024 to base adjustments purely on the volume of MWs of solar installations rather than the combination of calendar year and target MW levels. This change should take effect as soon as the program administrators commence Step 2 of the incentive adjustment mechanism. As demand for solar rebates reaches the MW levels specified in D.06-01-024, measured in conditional reservations for incentive funds,[36] the CSI incentive level will automatically drop to the next lower level. Essentially we create a "waterfall" style trigger, where as each MW level of solar applications is attained, the incentive automatically defaults to the next lower incentive level, in a natural rhythm.

We make this change to a volume-based MW trigger mechanism because we agree with comments from the solar industry, SDREO, and TURN

---

[36] A "conditional reservation" means the application has passed initial screening for program eligibility and the application fee has been paid.

that we should avoid premature incentive reductions through arbitrary calendar-based adjustments. As TURN points out, an approach based solely on actual reserved MW levels is administratively simple and transparent and captures market factors without burdensome market monitoring. We agree with Sun Light that the Commission should let market forces determine the cost of solar and not incentive levels. We also agree with SDREO that eliminating the time dimension removes the "rush" to submit applications during the final days before a scheduled reduction. A volume-based adjustment mechanism allows the level of demand for solar facilities to drive reductions in Commission incentives.

Another reason for our modification is that we want to avoid the risk of reducing incentives before the economics of the solar industry have caught up to our incentive levels. It is unreasonable to assume that incentive levels in California can by themselves impact the market price for solar. We agree with several parties who have pointed out that solar labor and material costs are independent of Commission incentive levels and set to a significant degree by a worldwide market. If we reduce incentives each calendar year before target MW levels are achieved, we run the risk of the solar market stalling in California while solar panels and installers move to other more lucrative markets. It is more reasonable to link our incentive reductions to actual levels of demand.

We prefer this approach even though the funds budgeted for CSI, as set forth in D.06-01-024, might be spent faster or slower than we originally envisioned. A trigger based solely on volumes of participation means the program will not stop each calendar year if an annual budget is exhausted, only to wait for the next year's budget allocation before starting up again. Instead, the incentive drops whenever MW levels of participation are reached, allowing the program to continue unabated by calendar years. Essentially, the market demand for solar power controls the pace at which incentives drop and the pace at which funds are spent. It is an unnecessary and artificial market manipulation to allow only a certain amount of dollars to be spent each year. If demand exceeds that estimated level, a waiting list develops and the market stalls, increasing the risk that solar materials and suppliers will turn to markets outside California. We find it preferable to let the solar market control the pace at which total budgeted dollars are spent, rather than attempt to exert artificial control over the pace of solar market development. The overall program budget is protected by a cap on the CSI budget for each utility. (D.06-01-024, p. 6, Table 1.)

Thus, while we maintain a cap on the total CSI budget for each utility,[37] there is no mandate on the timing of the expenditures on a yearly basis. One utility could move through its MW triggers quickly if demand in its service territory is high. In that case, the incentive might drop several times in one year and the utility could move through funds rapidly. It would essentially borrow from future years' budget dollars, and could spend its budget in less than 10 years, ending its program early. If this occurred, the utility would have successfully installed the MWs it was targeted to achieve. If we achieve 2,600 MW of solar installations before 2016, we can happily close the program early as a success. If market demand does not materialize fully, then the associated funding would be unspent.

In comments on the draft decision, CARE requests the Commission make the incentive application fee non-refundable to ensure the trigger

---

[37] The annual utility revenue requirements for CSI and total CSI Program budget for each utility are set forth in D.06-01-024, Tables 1 and 2, pps. 6-7.

accurately reflects the volume of solar installations. We are concerned that if application fees are refundable for too long a period, particularly past the conditional reservation stage, this could impact the incentive trigger mechanism. We encourage parties to address this issue in the CSI Handbook development process, discussed in Section IV.B.4, and propose a reasonable but short time frame for application fee refunds.

B. Incentive Levels May Vary by Utility Territory

On the issue of statewide uniformity in CSI incentive levels, a few parties suggested the Commission's previous decision to keep incentive levels uniform statewide should be reconsidered. TURN claims triggers by service territory will allow each distinct market to respond to incentive levels appropriately and independently. PG&E and the Joint Solar Parties agree the Commission should allow incentives to vary on a utility by utility basis. SCE and SDREO oppose the concept of different incentive levels in each utility territory. SCE reasons that since CSI is a statewide program, incentives should be available to all customers under the same set of rules.

With great reluctance, we are persuaded to modify our concept of one incentive level statewide in favor of allowing each utility territory to reduce its incentive level when conditional reservations for solar incentives in that territory reach pro rata shares of the MW targets. While it would certainly be administratively simpler to have only one statewide incentive level that adjusts everywhere at the same time, this ignores the unique characteristics of the solar market in the different geographic regions of the state. If installations in Southern California are booming and cause the first MW target to be reached, but installations in Northern California are moving more slowly, an incentive level reduction statewide to respond to demand conditions in the south could negatively impact the economics of the solar market in the north. Essentially, we must now trade the goal of program simplicity for a more complex program design that has a better chance of accomplishing the Commission's long-term solar goals.

Those most burdened by this approach will be solar companies operating in multiple regions, yet these same companies advocate this non-uniform approach as do PG&E and TURN. In the Commission's experience with SGIP incentives, PG&E often has a higher demand for incentives in its territory and uses up its budget allocation more quickly, forcing it to close its program until the next calendar year when additional funding sources are available. If PG&E were able to reduce its incentive ahead of other territories, it could manage its funds more efficiently and avoid starts and stops in its program activities.

Therefore, we will allocate our total MW goals across each utility, using the percentage contribution that each utility makes to the total CSI budget.[38] Incentives for each utility's service area will adjust as these MW triggers are met. Again, this refinement to the incentive reduction process should take effect as soon as program administrators commence Step 2. The table below indicates the

[38] These percentages are set forth in Table 2 of D.06-01-024 and are 44% for PG&E, 34% for SCE, 13% for SDG&E and 9% for SoCalGas.

total MW allocations for each utility, for Steps 2 through 10 of our trigger mechanism.[39]

---

[39] Incentive applications may not fall neatly into these MW cut-offs. Program administrators should use discretion in applying these MW allocations using conventional rounding principles.

Table 10

MW Allocations by Utility

Incentive Step	MWs in Step	PG&E	SCE	SDG&E	SoCalGas
1	50[40]	n/a	n/a	n/a	n/a
2	70	31	24	9	6
3	100	44	34	13	9
4	130	57	44	17	12
5	170	75	58	22	15
6	230	101	78	30	21
7	300	132	102	39	27
8	400	176	136	52	36
9	500	220	170	65	45
10	650	286	221	85	59
Total	2600	1122	867	332	230
	Percent	44%	34%	13%	9%

C. Additional Incentive Adjustments

Comments from solar industry participants generally request greater participation in the incentive adjustment process. ASPv suggests the Commission establish a "PV Market Assessment Group" that would meet each November to evaluate all relevant market factors related to the trigger incentive adjustment. This market assessment group would include representation from

[40] The first 50 MW are allocated on a first-come, first-served basis through the 2006 SGIP program.

all major parties, including the solar industry, Commission staff, utilities, program administrators, environmental, and ratepayer groups. The group would review market factors including tax credits, utility rates, market acceptance of solar technology, and other relevant factors. The current program administrators oppose creation of any new market assessment group and see no reason for an additional incentive review process. Instead, they generally support the existing delegation of authority to the assigned ALJ to consider incentive adjustments through a ruling and comment process.

Given the implementation difficulty after the first trigger reduction in solar incentives in 2006, it is clear that communication of pending incentive changes is critical for the success of CSI. The solar industry needs a clear understanding of pending changes in incentive levels to provide accurate information to potential customers. In our view, the detail we adopt in this order for future incentive reductions based on predetermined MW volumes should provide sufficient advance notice to the solar industry of the schedule for incentive changes. To reiterate, we herein direct the program administrators to automatically lower incentive levels when the conditional reservations for CSI incentives reach the MW levels adopted in today's order. Each administrator shall send a letter notifying the ALJ and the service list of this proceeding or its successor when the MW level has been reached in its territory.

In addition, when the Commission implemented the first solar incentive reduction, the ALJ directed the program administrators to establish a website communicating solar application information so applicants could assess whether an incentive reduction is approaching. This website is now operational and is an important tool for industry participants to gauge when an incentive level reduction is approaching.[41] When incentive levels automatically drop, these changes should be highlighted appropriately on the program administrators' websites.

We will not create a special group or meeting to discuss incentive changes. To the extent the need arises, we prefer that unscheduled incentive changes be implemented through the delegation process we established in D.06-01-024. In other words, as we stated in that order, the assigned ALJ in this or a successor proceeding may issue a ruling reducing incentives where the ALJ has received written justification from CEC and Commission staff and where that written justification has been served on all parties to this or its successor proceeding for their comment. Any ruling will clarify the effective date of the incentive change.

Moreover, we have discussed in Section IV.B.5 the CSI Program Forum where interested stakeholders can discuss on-going CSI issues. The Forum is not intended specifically to discuss incentive levels, but if the group achieves consensus on changes, it may file a petition for modification of discrete Commission orders. Absent consensus in the Forum, an interested party always has the opportunity to follow Commission rules and file a petition to modify a Commission decision regarding incentive levels if there are new or changed facts for the Commission to consider.

---

[41] The web address for this site is http://www.sgip-ca.com.

VII. Funding Levels

The Commission established CSI funding levels for 2007 through 2016 in D.06-01-024. (D.06-01-024, p. 6.) Table 1 in that order sets the annual revenue requirements by investor-owned utility, and Table 2 indicates the portion of the total CSI budget allocated to each utility. The order provides for funding flexibility between program years because the Commission recognized that actual demand for solar incentives may vary from year to year. Further, the Commission specified that 10% of the total CSI budget should be reserved for administrative costs, including program evaluation, marketing, and outreach, 10% for assistance to low income residential customers and affordable housing projects, and up to 5% for research, development and demonstration.

The Staff Proposal recommends refinements to the funding approach adopted in D.06-01-024 in conjunction with the overall proposal to bring a performance dimension to the incentive payments and adjust incentives to account for federal tax credits. Specifically, Staff proposes the following:

- Adhere to the budget schedule established in D.06-01-024, with each utility's budget based on its prorated share of CSI collections.

- Consider dividing budgets based on customer classes or system sizes.

- Allow fund shifting in the first half of each calendar year to residential and small system applications only.

- Allow fund shifting in any direction in the second half of each calendar year.

In describing its proposal, Staff highlights the importance of preserving equity across service areas by limiting CSI funds to each utility's pro rata share of funds. The Staff Proposal specifically requested parties comment on whether and how to divide the CSI budget based on customer class or system size.

A. Parties' Positions

Several parties, including ASPv, CFC, DRA, EPUC, the Joint Solar parties, PG&E, SDREO, and TURN, support the concept of reserving portions of the total CSI budget for discrete customer classes. ASPv recommends the Commission reserve 50% of funds for residential solar incentives, and 50% for commercial incentives, while the Joint Solar parties suggest funds be reserved based on the collections from residential and non-residential customers. DRA suggests a set-aside of 30% of the annual CSI budget for residential solar rebates, corresponding to the approximate percentage of residential sales to total system sales among the electric utilities. CFC, TURN, and EPUC contend funds should be reserved based on how funds are collected from each class of customers. They are concerned with equity and want to avoid cross-subsidization, where the majority of funds are collected from residential customers but the majority of incentives are paid to non-residential customers. TURN recommends the Commission establish volume triggers for several customer segments to account for the various external factors on each customer group. EPUC suggests that customer classes should contribute to CSI based on their benefits received.

Unlike the other proposals, PG&E proposes a reservation of CSI funds based on system size rather than customer class, with 50% of funds reserved for projects under 100 kW, and 50% for projects over 100 kW. DRA opposes reserving funds based on system sizes because it fears gaming might occur. For example, applicants might size their systems solely to fall in one category under the assumption funding will be easier to obtain, and disregarding other key sizing considerations.

In contrast to the other parties, SCE and SDG&E/SoCalGas see no need to set aside funds based on customer class, although SCE would not oppose funding allocations based on system size. SCE argues the benefits of solar power accrue to all ratepayers regardless which customer installs a system, and these benefits will be the same whether the program results in fewer large installations, or many small ones. SCE also cites the administrative burden of managing separate incentive budgets.

B. Discussion

First of all, this order does not modify the adopted yearly revenue requirements by utility that were set forth in D.06-01-024, nor does the order modify the reservation of 10% of the total CSI budget for administration, 10% for low income and affordable housing solar programs, and 5% for RD&D, as set forth in that order. We will address plans both for marketing and outreach, and for measurement and evaluation in Phase 2 of this proceeding. Until that time we direct administrators to spend no more than half of the funding reserved for administration (thus, up to 5% of total spending from the 10% reserved for all administrative components). We understand that administrative activities will be detailed in the CSI Handbook, expected to be resolved by the end of 2006. Thus, we direct each of the administrators to submit estimated CSI administrative costs for 2007 and 2008 to Energy Division staff by March 31, 2007. During Phase 2, we will also address program rules for affordable housing and low income customer incentives for CSI. For now, our incentive budget assumptions include a minimum of 10% of total incentive dollars for affordable housing and low income customers, as adopted in the January CSI decision. (D.06-01-024, p. 27.)

The key funding issue that needs resolution is whether we should reserve CSI funds for specific customer classes or project sizes, i.e. residential versus commercial, or projects under 100 kW versus those over 100 kW. The Staff proposed the concept of reserving funds, but did not provide specifics other than suggesting a limit on fund shifting within each calendar year, to allow small customers better access to program funds. In this order, we have determined that we will not use a calendar year basis for incentive changes, but will reduce incentives as volume triggers of program participation are reached. Thus, the Staff approach focused on calendar years of funding no longer applies. In response to parties' comments, however, we must decide whether CSI funds should be reserved based on customer class or system size.

1. Reserve CSI Funds for Residential Customers

After considering the parties' comments, we are persuaded to reserve a portion of CSI funds for residential and non-residential customers based on equity concerns and the desire to ensure all customer classes have access to CSI incentive funds. This is responsive to parties' concerns that we avoid residential ratepayers cross-subsidizing large commercial solar projects. We conclude it is better to reserve funds based on customer class distinctions rather than system sizes because this will be administratively simpler and less prone to gaming. By reserving a portion of CSI incentive funds for residential customers, customers who install small solar facilities will not have to compete for funds with large commercial customers, who have the added bonus of larger tax incentives and typically build larger solar projects. Without differentiation between residential and non-residential sectors, the CSI program could be heavily dominated by commercial rather than residential systems. As with the changes to the trigger mechanism outlined in Section VI, this program refinement should take effect as soon as the program administrators commence Step 2.

An additional reason to reserve funds for residential applicants is linked to the change in administration from the CEC to the Commission. Formerly, the CEC administered residential rebates from a single budget source, while the SGIP administrators handled medium and large solar projects through the SGIP budget. Now, residential retrofit and small commercial incentives will be administered together with non-residential incentives under Commission oversight. We do not know the future level of demand for residential retrofit solar rebates, and for this reason, we find it prudent to reserve a portion of CSI funds specifically for the residential market.

We must now decide what portion of CSI funds to reserve for residential customers. Parties suggested numerous methods, but we find the simplest and most reasonable method is to reserve one-third of total CSI funds for residential customers, and two-thirds of funds for non-residential customers, i.e. commercial and tax-exempt segments combined. We accomplish this by reserving one third of the total MWs for residential solar applicants. DRA had suggested a 30% reservation for residential customers because they represent approximately 30% of total system sales based on data from recent general rate cases. (DRA, 5/16/06, p. 5 and n. 1.) The data cited by DRA actually suggests that residential customers approximate one-third of system sales, so we will use one-third rather than 30%. This method is consistent with our pro rata allocation of CSI funding and MW among the four utilities based on their percentage of total sales. After more experience with the CSI program, we can determine whether a reservation of one-third of MWs for residential customers is reasonable. If we find that one class is achieving its MW targets and facing precipitous incentive reductions, we will reassess whether to reconsider the allocation of MW goals between the residential and non-residential sectors. If necessary, we can consider adjusting the total amount of MWs available for residential vs. non-residential customers when we review the CSI program in two years. We describe the future review of CSI more fully in Section VII.B.3 below.

2. Residential and Non-Residential MW Triggers

Now that we have decided to allocate CSI funds between residential and non-residential customer groups, we must make another key refinement to our "trigger" process for incentive adjustments. If we reserve one-third of CSI funds for residential customers, we should also allow residential incentives to adjust based on demand in the residential solar market. This means we need to establish MW triggers not only for each investor-owned utility, but also for the residential and non-residential customer segments[42] within each utility. We recognize this adds more complexity to the CSI program, but we find this complexity is necessary to ensure residential customers have access to solar incentives.

In D.06-01-024, the Commission had established a ten-year schedule for incentive reductions based on either calendar year or MW levels. We will use the same MW levels of participation for each step-down in our volume-based trigger mechanism. The tables below indicate the MW triggers for each utility, separated into residential and non-residential portions and the total allocation of MWs between residential and non-residential sectors. In the second table, we

---

[42] The non-residential sector includes commercial and tax-exempt customers.

show Steps 2 through 10 only because the first 50 MW were allocated in Step 1 of the 2006 SGIP Program.

Table 11

CSI MW Targets by Utility and Customer Class[43]

Step	MW in Step	PG&E (MW) Res	PG&E (MW) Non-Res	SCE (MW) Res	SCE (MW) Non-Res	SDG&E (MW) Res	SDG&E (MW) Non-Res	So Cal Gas (MW) Res	So Cal Gas (MW) Non-Res
1	50[44]	--	--	--	--	--	--	--	--
2	70	10	21	8	16	3	6	2	4
3	100	15	29	11	23	4	9	3	6
4	130	19	38	15	30	6	11	4	8
5	170	25	50	19	39	7	15	5	10
6	230	33	68	26	52	10	20	7	14
7	300	44	88	34	68	13	26	9	18
8	400	58	118	45	91	17	35	12	24
9	500	73	147	56	114	21	44	15	30
10	650	94	192	73	148	28	57	19	39

[43] During Phase 2, we will adopt a decision regarding the program rules for affordable housing participation in CSI. The above table now treats residential targets alike, and may be amended in Phase 2 to separate out affordable housing solar goals.

[44] The first 50 MW are allocated under the 2006 SGIP program and are not pro-rated by customer class or service territory.

Totals	1122	867	332	230
Percent	44%	34%	13%	9%

Table 12

CSI MW Allocations by Customer Sector

Customer Sector	**MW**	**Percent** [45]
Residential MW	842	33%
Non-Residential MW	1708	67%
2006 SGIP Program	50	
Total MW	2600	100%

Essentially, we have taken the CSI budget allocations for each utility initially established in D.06-01-024 and used those percentages to assign each utility a pro rata portion of the total goal of 2,600 MW. Then, we have further subdivided each utility's MW goal into a residential and non-residential segment on a one-third, two-thirds basis. As an example, when PG&E conditionally reserves 10 MW of solar incentives for residential customers, its incentive level will automatically lower from Step 2 to Step 3. When that occurs, if PG&E has not yet received 21 MW of conditional reservations from the non-residential sector, then the incentive level for non-residential customers, both commercial and tax-exempt, will stay at Step 2 even if residential incentives have dropped to Step 3.

Additionally, since we changed the starting incentive level from the one originally adopted in D.06-01-024, and set a higher rate for tax-exempt customers, we must create a new schedule for how these incentives decline over

[45] The percentages are based on one-third of 2,550 MWs because we do not include the approximately 50 MWs of solar applications received in 2006.

the course of the CSI. The table below indicates how the incentive levels will alter as they decrease from Steps 2 through 10.

In order to develop the table below, several important assumptions were necessary. First, for the governmental/non-profit sector, we have kept the same $0.75 per watt differential relative to the other non-residential rebates that staff proposed. This difference strikes a reasonable balance between the additional benefit available to the non-residential taxable entities through the federal investment tax credit and the longer payback period that comments suggest government/non-profit customers can accept (see Section III.A of this decision for more discussion). Second, we have assumed that the composition of the non-residential installation market will be 30% governmental or non-profit, with the remainder taxable entities. Thus, overall, government/non-profit is assumed to make up 20% of the market, residential 33%, and other non-residential 47%. These assumptions may need to be revisited as we gain more experience with the market during the CSI review process described in the next section.

We also relied upon the MW amounts adopted in D.06-01-024 to determine the MW size of each step. Working from these assumptions, while staying within the overall incentive budget constraint, Staff optimized to determine the maximum incentive levels that could be paid at each step and still reach the goal of 2,600 MW. We placed several constraints on this optimization process. First, we wanted incentive drops no bigger than $0.45 and no smaller than $0.05; any larger drops would be disruptive to the market, and any smaller would not be meaningful. Second, we wanted incentive drops of no more than $0.30 in the first two steps, in order to minimize the potential disruptive impact on the market during the early phases of the program. Third, we determined

$0.20 per watt to be the minimum meaningful incentive to offer during the last step to close out the program (if the incentive were any lower, the incentive payment would not make a significant contribution to customers' system costs under any scenario). Finally, since the government/non-profit sector starts with a higher incentive, we allowed a larger drop in the incentive rate for this sector in Steps 9 and 10.

Utilizing all of these assumptions, the final resulting per-watt equivalent incentive levels are shown in the table below. If assumptions prove to be invalid, review of the incentive levels may occur sooner than described below.

Table 13
CSI Incentive Levels by Incentive Step and Customer Class

Step	MW in Step	Gov't/ Non-Profit	Res	Commercial	Total $ Disbursed in Step ($ in millions)
1	50[46]	n/a	n/a	n/a	n/a
2	70	$3.25	$2.50	$2.50	$186
3	100	$2.95	$2.20	$2.20	$235
4	130	$2.65	$1.90	$1.90	$267
5	170	$2.30	$1.55	$1.55	$289
6	230	$1.85	$1.10	$1.10	$287
7	300	$1.40	$0.65	$0.65	$240
8	400	$1.10	$0.35	$0.35	$200
9	500	$0.90	$0.25	$0.25	$190
10	650	$0.70	$0.20	$0.20	$195
				Total	$2,088[47]

[46] The first 50 MW are disbursed under the 2006 SGIP program at a uniform rate of $2.80 per watt.

[47] As stated earlier, this total incentive budget assumption includes a minimum of 10% of incentive dollars for affordable housing and low income customer incentives, to be addressed in Phase 2.

The table indicates total CSI expenditures of approximately $2.1 billion, equivalent to the CSI Budget less administrative, marketing and outreach, evaluation and RD&D costs.

In comments on the draft decision, SDREO requests continued authority to transfer unspent SGIP funds into the following year's incentive budget, based on D.01-03-073 regarding SGIP. By this order, we clarify that as of December 31, 2006, program administrators should transfer unused SGIP solar incentive (i.e., "Level-1") funds, and unspent SGIP administration and measurement and evaluation funds, to their 2007 CSI budgets. However, we will not automatically sanction transfer of unspent CSI funds in future years at this time. We prefer to review whether this is necessary in our periodic CSI review process, which is discussed below.

3. Periodic CSI Review Process

Throughout the order, we have described issues we will review after we have two years of experience with CSI. The Commission should institute periodic reviews, every two years, through the duration of the program. Thus, in 2009 or earlier, we anticipate opening a new rulemaking to review, among other issues, the following:

- Whether to continue to offer government and non-profit customers a higher incentive rate.
- Assess the need for incentive changes depending on federal tax credit status or other factors.
- Review the capacity factor used in the PBI payment calculation, based on M&E findings.
- Consider the impact of applying a PBI mechanism to all systems over 30 kW.

- Review whether it is reasonable to reserve one-third of CSI funds for residential customers.
- Evaluate and investigate a "feed-in tariff" approach.
- Whether any determinations regarding renewable energy credit (REC) ownership or the future value of RECs affects incentive levels.
- Consider adding trackers to the EPBB design factor.
- Evaluate the allocations of total budget funds for administration, marketing, evaluation, RD&D and low income programs, and the use of any unspent funds.

The commissioner assigned to this future review proceeding may determine whether additional CSI program elements should be included in the scope of the review, or whether the above issues should be modified.

VIII. Energy Efficiency Requirements and Incentives for Solar Technologies other than PV

We originally intended to address energy efficiency requirements and incentives for solar technologies other than PV in this order. The Staff Proposal contained recommendations on this issue, and parties supplied comments on the subject as well. We consider these important CSI issues which are critical to the success of CSI. We intend to address these two issues as soon as possible, in a separate order that we expect to issue shortly.

IX. Comments on Draft Decision

The draft decision of ALJ Dorothy Duda was mailed in accordance with 311(g)(1) of the Public Utilities Code and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed by ASPv, R. Thomas Beach, CARE, jointly by Cal SEIA, PV Now and the Vote Solar Initiative (Joint Solar Parties), CCSF, CFC, DRA, FST, Michael Kyes, NorCal Solar Energy Association, PG&E, SCE, jointly by SDG&E and SoCalGas, SDREO, jointly by the SGIP Program Administrators, and Sun Light and Power Company. Reply comments were filed by ASPv, CARE, CCSF, FST, the Joint Solar Parties, Michael Kyes, PG&E, SCE, SDG&E/SoCalGas, SDREO, and TURN.

In response to the comments, we make minor modifications and clarifications to the draft decision, but do not make substantive changes to the program design. Minor modifications are noted below, along with the section where the change is discussed.

- Require non-profit organizations to certify their status every year they receive PBI payments. (Section III.A.2 and Ordering Paragraph 3.)

- Clarify all building integrated PV, even on new construction, shall be paid incentives on a PBI basis. (Section III.B.1.)

- Allow PBI payments to be deposited in balancing accounts, not escrow accounts, and require utilities to file tariffs explaining the balancing accounts. (Section III.B.6.)

- Revise the Design Factor for EPBB to clarify the reference system should optimize summer output, consistent with the goal of maximizing peak energy needs. (Section III.C.2.)

- Require program administrators to develop appropriate procedures to address project installers that fail three random inspections for EPBB applications. (Section III.C.3.)

- Revise metering requirements to specify accuracy within 5% for small solar projects (less than 10 kW), and accuracy within 2% for all larger systems above 10 kW based on parties' comments that revenue grade requirements were unclear and onerous for smallest systems (Section V.A.)

- Clarify budget for incentives includes a minimum of 10% for incentives to low income customers and affordable housing projects. (Section VII.B.)

- Allow program administrators to shift unspent SGIP funds. (Section VII.B.2.)

In addition, we make specific note of comments raised by CFC, the utilities, and SDREO.

CFC contends that before the Commission embarks on CSI, it should undertake further strategic planning, including a thorough cost-benefit analysis of CSI. Similarly, SCE suggests the Commission add specific language that the CSI periodic review will include an analysis of CSI cost-effectiveness. The scoping memo for this proceeding provides that a methodology for cost-benefit analysis of distributed generation projects, including solar, will be addressed in Phase 2 of this proceeding. Given that the ALJ will turn to Phase 2 shortly, the concerns of CFC and SCE can be considered there.

SDG&E/SoCalGas provide two areas of comment that warrant discussion. First, they ask for an opportunity to identify additional costs that SDG&E may incur for set-up and maintenance of on-bill PBI payment systems and "any additional costs resulting from the Commission's issuance of its decision on Phase One issues." We will allow SDG&E and the other utilities to track costs for set-up and maintenance of on-bill PBI payments in a CSI memorandum account. The Commission can determine in the utilities' general rate cases whether recovery of these costs is appropriate, or whether the costs can be absorbed within the CSI administrative budget. We will not allow SDG&E to track "additional costs" resulting from this Phase I order. The Commission has previously denied SDG&E's request to recover costs for administering its contract with SDREO.[48] SDG&E provides no basis to differ from that conclusion and no detail on potential costs it might incur.

Second, SDG&E maintains that since it will not administer CSI programs in its service territory, it should be allowed to "fully participate on an equal basis with other business entities in this program." SDG&E suggests it could own and operate PV systems and receive incentives in the same manner as other program participants. We decline to address SDG&E's request in this order for several reasons. First, several Commission orders have expressly excluded the utilities from qualifying for solar incentives. Most recently, in D.06-01-024, the Commission stated conclusively the utilities will not qualify for CSI funds, but the Commission would reconsider this in the first program review in 2009. (D.06-01-024, p. 15.) In D.01-03-073 and again in D.04-12-045, the Commission expressly prohibited a utility from receiving SGIP incentives. (D.01-03-073, Attachment 1, p. 25; D.04-12-045, p. 23.) Aside from these direct prohibitions on utility participation, the issue was not within the scope of Phase 1 and a proper record on the ramifications of such a proposal was not developed. SDG&E does not provide sufficient detail regarding how it would participate in CSI and how this business enterprise might overlap with its utility business. Even though SDREO will administer CSI in SDG&E's territory, conflicts could arise from SDG&E's role in managing the SDREO contract. As SDG&E itself notes, concerns could arise over SDG&E ratepayers paying twice – once for incentives and again for capital equipment in rate base. As the Commission has previously stated, "If the utilities wish to construct cost-effective large solar projects

---

48 See D.04-12-045, p. 19.

themselves, such investments are recoverable in utility rate base following general rate case review." (D.06-01-024, p. 15.) If SDG&E desires to pursue its proposal, it should file a separate application with a detailed description so that the legal, policy, and ratemaking concerns surrounding the proposal can be properly addressed.

PG&E and SDREO ask the Commission to direct the participants in the Program Handbook process to address treatment of projects that may be on a waiting list for incentive funds through the existing SGIP program. We agree this issue should be discussed in the Program Handbook process. We also agree that any existing applications should not lose their place in the queue if they must augment or replace their application to meet new program criteria, as long as this is done in a reasonable timeframe.

X. Assignment of Proceeding

President Michael R. Peevey is the Assigned Commissioner and Dorothy J. Duda is the assigned ALJ in this matter.

Findings of Fact

Incentive Levels

1. According to D.06-05-025, the current solar incentive rate of $2.80 per watt will drop to $2.50 per watt when 50 MW of applications are conditionally reserved.

2. Data from the CEC's solar rebate program for systems under 30 kW shows residential solar growth rates flat since 2003, and a trend toward commercial solar installations.

3. The cost of solar panels has risen in the last year due to a world shortage of silicon.

4. A Cal SEIA survey indicates residential customers may accept a payback of 10 to 15 years for solar investments, while commercial customers generally require a shorter payback in the range of six to eight years.

5. Solar installations are experiencing capacity factors in the range of 16% to 18%.

6. Tax-exempt entities, such as government and non-profit institutions, are not eligible for federal tax credits to offset solar installations costs, unless they use third-party financing and ownership techniques.

7. Tax-exempt entities face a higher net effective cost per kilowatt hour for solar investments because they are not eligible for federal tax credits.

8. Government and non-profit institutions are a significant percentage of current SGIP participants.

PBI for Systems 100 kW and Larger

9. Incentives paid up front do not ensure a well-designed and installed system or that the system owner will attend to ongoing system maintenance and performance.

10. Actual system rating may differ from reported ratings due to incorrect equipment rating and/or poor system design and installation.

11. System performance is affected by compass orientation, tilt and shading.

12. Poor system maintenance and weather variability can impact solar output.

13. System ratings are not yet capable of estimating output for newer solar technologies, such as building integrated PV and bifacial modules.

14. Solar projects over 100 kW are about 1% of total project applications each year, but account for about one-third of installed solar capacity.

15. South-facing solar installations generally provide more total kWh output annually than west-facing installations, which reach peak production during a

time more closely aligned to the utilities' system peak demand and yield energy of higher value.

16. Net energy metering rewards on-peak performance through time-differentiated net energy credits for customers on TOU rates.

17. Most customers with solar facilities participate in net energy metering.

18. A shorter PBI payment period has advantages for solar buyers and lower administrative costs.

19. To calculate a PBI payment, the dollar per watt incentive must be converted to cents per kilowatt hour using a capacity factor.

20. SGIP data shows an average capacity factor of 16% for systems installed through 2004, while U.S. Department of Energy and CEC data projects average capacity factors will reach 18%-20% by 2010.

EPBB

21. System AC ratings cannot be verified until systems are installed.

22. The Design Factor in the EPBB calculation is the ratio of a customer's simulated solar output to the simulated output for an optimal reference system.

23. Variability in California's geography and climate affects the level of solar production around the state.

Program Administration

24. In D.06-01-024, the Commission determined existing program administrators should administer CSI for the commercial and industrial sector.

25. Residential solar retrofit projects, formerly administered by the CEC, must shift to a new administrative structure in January 2007.

26. If we limited the existing administrators to projects above 100 kW, they would have few applications to administer.

27. Under Section 136 of the Internal Revenue Code, subsidies are treated as non-taxable income if provided directly or indirectly by a public utility for the purchase or installation of an energy conservation measure.

Metering Requirements

28. Meters to measure solar output are available at a variety of prices, depending on the degree of time interval detail and communication system.

29. Under SGIP and net energy metering rules, the customer pays for any expenses beyond the minimum utility revenue meter.

30. Performance monitoring can be provided by third parties independent of solar manufacturers, installers, or owners.

31. A large portion of solar capacity is already served by time-differentiated meters and tariffs.

Incentive Adjustment Mechanism

32. In D.06-01-042, the Commission established a mechanism for solar incentives to automatically decline 10% a year for 10 years.

33. Demand for solar incentives varies by utility territory, with some utilities using their budget allocations more quickly.

34. In D.06-01-024, the Commission established a process for the ALJ to implement reductions to incentive levels.

Funding Levels

35. Residential customers approximate one third of total system sales.

Conclusions of Law

Incentive Levels

1. Reducing solar incentives to $1.50 per watt, as suggested by Staff, could disrupt the solar market, particularly in conjunction with the introduction of performance-based incentives.

2. It is reasonable to adjust the single solar incentive rate adopted in D.06-01-024 in favor of rates tailored to the tax effects seen by residential, commercial, and tax-exempt customers.

3. A single incentive rate for commercial and residential customers is reasonable given information on the record concerning customer payback periods, current capacity factors, tax effects, and solar equipment costs.

4. A residential incentive rate of $2.50 per watt is reasonable given data indicating slower adoption of solar technology in this market segment.

5. It is reasonable to adopt an incentive rate of $3.25 per watt for tax-exempt entities that do not use third-party financing, to bring net solar installation costs in line with those entities that receive federal tax credits.

PBI

6. A performance-based incentive structure will motivate consumers to focus on the proper installation, maintenance, and performance of their systems.

7. We should apply a PBI structure to solar projects 100 kW and larger based on the ability of customers investing in larger systems to finance system costs.

8. We should transition smaller systems, larger than 30 kW, to a PBI structure in 2010, after we have experience with PBI and to allow sales and financing arrangements to evolve.

9. It is reasonable to allow any size system to opt for PBI payments.

10. All sizes of building integrated PV systems, even those on new construction, should receive PBI payments because it is difficult to estimate performance for these systems.

11. New construction projects other than BIPV, regardless of size, are exempt from PBI and should be paid up-front incentives to allow financing of net building costs by builders and developers.

12. We should not adopt time differentiated PBI payments because many customers with solar facilities and most solar MW capacity already participate in TOU tariffs.

13. A lengthy PBI payment period has the potential to dampen interest in solar installations because solar investors must wait to recover their investment.

14. A five-year PBI payment period has lower administrative costs and less market risk than a longer payment period.

15. PBI payments should be based on an 18% capacity factor initially, based on data from SGIP, the U.S. Department of Energy, and the CEC.

16. To encourage increases in system performance, the capacity factor to calculate PBI payments should be increased to 20% after 220 MW are installed through the CSI program (i.e., at Step 4 of the program).

17. A performance cap is inconsistent with the goal of rewarding systems for higher performance.

18. A solar facility receiving PBI payments will be paid for actual output over the five-year payment period, with no cap other than the total funding cap of the CSI program.

19. At the time of system installation, each utility should deposit expected five year PBI payments for each solar project into a single interest-earning balancing account maintained by each utility.

20. We should incorporate a discount rate into levelized PBI payments so the payments do not penalize systems that must wait five years to receive their full PBI payments.

21. A discount rate of 8% is a reasonable assumption for the range of interest rates different solar buyers might receive on deferred payment streams.

22. PBI payments should be made on a monthly basis, either as a utility bill credit or a separate payment, to provide frequent customer feedback on system performance.

23. An immediate transition to PBI for systems 100 kW and larger should not cause market disruption to these systems which are already financed at the 60%-70% level.

EPBB

24. It is reasonable to use CEC-AC ratings because System AC ratings are not verifiable at this time.

25. The Design Factor for EPBB should include geographic location to more precisely estimate likely system performance and yield the highest level of overall system production per dollar of ratepayer support.

26. We should allow equivalent optimal design factors for south, southwest, and west orientations to promote either peak solar production or maximum total solar output.

27. The Design Factor for EPBB should: (a) treat all systems oriented between 180^{o} and 270^{o} equally, (b) assign an optimal orientation tilt for each compass direction in the range of 180 ^{o} to 270 ^{o}, optimized for summer production, (c) include location-specific criteria to account for weather variation; and (d) determine an optimal reference latitude tilt that relates to local latitude.

28. It is reasonable to verify system characteristics for all systems between 30 kW and 100 kW, and for a sample of systems under 30 kW.

29. Trained personnel should verify system characteristics.

30. Project installers who fail three random verifications shall be excluded from program participation, according to CSI Program Handbook procedures

addressing the severity of the transgression, opportunities for correction, proper notification, and an appeal mechanism.

Program Administration

31. We should shift administration of the residential retrofit portion of CSI to the existing administrators to prevent any time gaps in the provision of residential incentives.

32. We should consider one statewide entity for residential CSI administration in the future if we find economies of scale, overhead savings, or other benefits.

33. Alternate administration may be reasonable for a single region or utility service area if one region lags others in solar penetration, ease of interconnection, or administrative performance and cost.

34. IRS taxation issues do not impact our decision between utility or independent administration.

35. Subsidies provided by a public utility are non-taxable under Section 136 of the Internal Revenue Code as long as the money comes from utility rates and the monies paid to the consumer are those provided by the utility, as in the case of CSI.

36. A statewide online application system will enhance the ability of customers to use CSI programs.

37. A single database of project information will benefit ongoing program evaluation, but some data should initially be accessible only to program administrators and CEC/Commission staff.

38. We should create a CSI Program Forum to provide a public venue for interested parties to identify, discuss, and fashion consensus-based solutions to ongoing issues related to CSI administration and implementation.

Metering Requirements

39. Accurate metering of solar output should increase owner knowledge of system performance, foster adequate system maintenance, and thereby ensure ratepayer incentives result in expected levels of solar generation.

40. Solar production meters with accuracy within 2%, are required to ensure accuracy of PBI payments and may be needed to meet renewables portfolio standard rules.

41. Meters with 2% accuracy for systems 10 kW and larger and accuracy of 5% for systems under 10 kW will not add a significant cost burden to CSI participants.

42. All systems paid incentives through CSI should install a solar production meter with either 2% or 5% accuracy depending on system size, at the customer's expense that includes some form of communication reporting capability.

43. The entity administering solar performance reporting should be an independent party, either existing administrators or a third party not affiliated with solar manufacturers, installers or owners.

44. We should consider the overall economics of time-differentiated tariffs when we examine cost-effectiveness in Phase II.

Incentive Adjustment Mechanism

45. If we decrease incentives on a calendar basis, we might reduce incentives before the economics of the solar industry and market demand match incentive levels.

46. An incentive adjustment mechanism based purely on the volume of program participation allows the market demand for solar power to control the pace of incentive reductions.

47. A volume-based incentive reduction mechanism is transparent, administratively simple, and allows external market factors to influence incentives through market demand.

48. It is reasonable to maintain a cap on the total CSI budget, as adopted in D.06-01-024, but not mandate the timing of the expenditures on a yearly basis.

49. A uniform statewide incentive level ignores the unique characteristics of solar markets throughout the state.

Funding Levels

50. For equity reasons, we should reserve one-third of CSI funds for residential customers.

51. We should establish MW triggers for each utility, and for the residential and non-residential sectors within each utility, based on the MW levels of program participation adopted in the trigger mechanism in D.06-01-024.

52. The Commission should open a rulemaking in 2009, or sooner if needed, to review major aspects of the CSI program as described in this order.

53. The Commission should periodically review the CSI program at two-year intervals.

O R D E R

IT IS ORDERED that:

1. The California Solar Initiative (CSI) incentive levels, program structure, and budget described herein are approved through December 31, 2016. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas), (collectively "the utilities"), shall implement this program consistent with today's decision. Within 45 days of this order, SDG&E shall

contract with the San Diego Regional Energy Office (SDREO) to administer the CSI in the SDG&E service territory.

2. The incentive rates adopted in Decision (D.) 06-01-024 are modified to reflect the performance-based incentives (PBI) and Expected Performance Based Buydown (EPBB) incentives set forth in Sections II.B and C and Tables 5, 6 and 13 of this order. Beginning January 1, 2007, PG&E, SCE, SoCalGas and SDREO (collectively, the "program administrators") shall pay performance-based incentives (PBI) and EPBB incentives, as set forth in Sections III.B and C and Tables 5, 6 and 13 of this order, to gas and electric customers of the utilities for eligible residential retrofit and non-residential solar projects.

3. In order to receive the higher government/non-profit incentive rate rather than the commercial rate, tax-exempt entities must include with their incentive application a certification under penalty of perjury from their Chief Financial Officer or equivalent that they are a government or non-profit organization, and they are not receiving and will not receive federal tax benefits through third-party financing or ownership arrangements. The certification shall include a copy of the entity's bylaws and articles of incorporation if it is a non-profit entity. Non-profit entities must renew their certification annually if they receive PBI payments.

4. Beginning January 1, 2007, the Commission will apply a PBI structure to all systems 100 kilowatts (kW) and larger. Any system, regardless of size, may opt for the PBI payment structure in Table 5. The Commission will require all building-integrated photo-voltaic (PV) systems, including those on new construction, to receive incentives through a PBI structure, but will not require other new construction solar installations to be paid through PBI.

5. Program administrators shall pay any solar facility receiving the PBI incentive rate for its actual output over the five-year payment period, although program administrators shall not exceed their individual CSI budgets as set forth in D.06-01-024. The rate to be paid for the five-year period is determined based on the rate in the year the project is conditionally reserved. Program administrators may make the payment as a credit on the utility bill or separately at this time. SDREO should arrange with SDG&E for monthly on-bill payments, if necessary.

6. PG&E, SCE, SDG&E, and SoCalGas may each file a separate advice letter to establish a CSI memorandum account to track the cost of providing on-bill PBI payments. The Commission will determine in each utility's general rate case whether to allow cost recovery or include the cost in the CSI administrative budget.

7. PG&E, SCE, SDG&E, and SoCalGas shall each file an advice letter to establish an interest-earning PB1 balancing account and amend the preliminary statement of their tariffs to describe the PB1 balancing account and PBI program description and payment criteria. On a quarterly basis, each utility shall forecast the total five years expected PBI payment amount for all solar projects completed in that quarter, and deposit that amount into its balancing account to ensure fund security over the five-year payment period.

8. Beginning January 1, 2007, program administrators shall pay an EPBB incentive to qualifying solar projects under 100 kW, where the EPBB incentive shall equal the incentive rate multiplied by a system rating and a design factor, as set forth in Section III.C of this order.

9. Within 30 days of this order, the program administrators shall issue a single solicitation for a technical expert to provide a single design factor protocol

and initial estimation tool that matches the criteria set forth in this Section III.C of this order. Program administrators shall ensure the design factor protocol and estimation tool are delivered by November 1, 2006 for inclusion in the initial CSI Program Handbook.

10. Program administrators shall use trained personnel to verify system characteristics for all systems between 30 kW and 100 kW that receive EPBB incentives, and for a random sample of systems under 30 kW.

11. Program administrators shall develop a coordinated training plan for EPBB site inspectors and submit the plan by Advice Letter no later than January 5, 2007.

12. Program administrators shall ensure solar installers report expected annual system output on program application forms.

13. Within 30 days of this order, program administrators shall designate one administrator to contract with an entity to create a statewide online application process and program database as set forth in Section IV.B of this order, and report on their progress through letter to the Director of the Energy Division no later than December 31, 2006.

14. Energy Division Staff shall convene a workshop within 15 days of the effective date of this order to discuss CSI Program Handbook development and create subgroups to work on sections of the handbook. Energy Division shall forward a draft CSI Handbook to the Administrative Law Judge (ALJ) no later than 60 days from the workshop, for review and comment according to the schedule in Section IV.B., unless modified by the Assigned Commissioner or Administrative Law Judge by further ruling.

15. The program administrators shall convene the first meeting of the CSI Program Forum in the first quarter of 2007, to provide the opportunity for CSI

stakeholders to discuss proposed revisions to the CSI Handbook. Energy Division Staff shall facilitate this meeting. The program administrators shall: (a) arrange and facilitate future meetings no less than quarterly after consulting with Energy Division to set each meeting's agenda, (b) provide notice of all meetings on the Commission's Daily Calendar and to the service list of this or any successor proceeding, and (c) maintain meeting minutes and post them on the CSI portion of the Commission's website. The CSI Program Forum may fashion consensus handbook revisions, as needed, and file them by Advice Letter.

16. All solar projects that receive an incentive through the CSI program shall install a separate solar production meter accurate to within 5% for systems under 10 kW and accurate to within 2% for systems 10 kW and larger, as set forth in Table 9 of this order. Internal meters certified as accurate to within 5% are acceptable for projects under 10 kW. All solar production meters shall be equipped with communication reporting capability, as set forth in Section V. Systems 100 kW and larger must have reporting capabilities before receiving PBI payments, and systems below 100 kW shall have reporting capabilities as soon as protocols are established through the CSI Handbook process. The total cost of a customer's metering, communication, and reporting system for the first five years of solar production shall be less than 1% of total installed costs for systems up to 30 kW, and less than 0.5% for larger systems.

17. Program administrators shall ensure the entity responsible for performance monitoring and reporting is not affiliated with the incentive recipient, or any solar manufacturer or installer.

18. Energy Division shall ensure that parties participating in the CSI Handbook development process, or any metering subgroup within that process,

address the following issues for inclusion in the CSI Handbook: (a) meter standards and data transfer protocols, and other details of a minimum solar output communication function, within cost limits specified in this order, (b) solar performance monitoring in advance of Advanced Metering Infrastructure, (c) a method for independent performance monitoring of solar output, and (d) communication of solar performance to customers and program administrators initially, and to the general public at a later date.

19. Upon commencement of Step 2, the incentive adjustment mechanism adopted in D.06-01-024 (Appendix A, Table 5) is modified to base incentive adjustments purely on the volume of megawatts (MWs) of solar installations, as set forth in Table 11 of this order. Incentives may vary by utility service territory and customer sector, according to the MWs of achieved solar demand specified in Table 11. Each program administrator shall automatically reduce its incentive level when conditional reservations for solar incentives in its utility service territory reach the MW targets in Table 11, and provide written notification of this incentive reduction by letter to the ALJ and the service list of this proceeding, or any successor proceeding.

20. CSI MW goals are allocated across each utility using the percentage contribution that each utility makes to the total CSI budget, as shown in Table 10. Upon commencement of Step 2, program administrators shall ensure a portion of program funds, equivalent to one-third of program MWs, are reserved for residential applicants.

21. The ALJ may issue a ruling, according to the process established in D.06-01-024, to implement any additional or unscheduled incentive reductions.

22. Program administrators shall submit estimated CSI administrative costs for 2007 and 2008 to Energy Division Staff no later than March 31, 2007, and shall

spend no more than 5% of their total budget for administration until the Commission addresses marketing, outreach, and measurement and evaluation in Phase II of this proceeding.

23. In 2009, or sooner if necessary, the Commission will open a rulemaking to review CSI rules and policies as described in this order. The Commissioner assigned to this future rulemaking may determine the CSI program elements included in the review.

24. The Commission shall review the CSI program at approximately two-year intervals throughout its duration.

25. The Administrative Law Judge shall promptly issue a ruling requesting comments from parties on how aspects of Senate Bill 1, signed into law on August 21, 2006, will impact the longer-term implementation of CSI and require modifications to today's decision.

26. Rulemaking 06-03-004 shall remain open for consideration of other CSI and distributed generation issues in Phase II.

This order is effective today.

Dated August 24, 2006, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

APPENDIX A
PBI Levelized Payment Explanation

Levelized PBI Monthly Payment Amounts at 8% discount rate.

Step	statewide MW in step	EPBB payments (per watt)			PBI payments (per kWh)		
		Res	Non-Res	Non-Tax	Res	Non-Res	Non-Tax
1	50	$2.80	$2.80	$2.80	**	**	**
2	70	$2.50	$2.50	$3.25	$0.39	$0.39	$0.50
3*	100	$2.20	$2.20	$2.95	$0.34	$0.34	$0.46
4	130	$1.90	$1.90	$2.65	$0.26	$0.26	$0.37
5	170	$1.55	$1.55	$2.30	$0.22	$0.22	$0.32
6	230	$1.10	$1.10	$1.85	$0.15	$0.15	$0.26
7	300	$0.65	$0.65	$1.40	$0.09	$0.09	$0.19
8	400	$0.35	$0.35	$1.10	$0.05	$0.05	$0.15
9	500	$0.25	$0.25	$0.90	$0.03	$0.03	$0.12
10	650	$0.20	$0.20	$0.70	$0.03	$0.03	$0.10

* For PBI Calculations, the first three steps assume a capacity factor (CF) of 0.18; Steps 4-10 assume a CF of 0.20.
** The first 50 MW incentives are disbursed under the 2006 SGIP program; PBI payments do not apply.

Overview:
We convert from a capacity based output (in watts) to a performance based output (in kWh). We calculate a levelized monthly payment so that we can provide a uniform per kWh incentive that adjusts for discount rate and is equivalent to an up-front EPBB payment.

In order to convert from EPBB payments to a levelized monthly PBI payment, we calculate and assume the following:

- We assume an 8% discount rate (which we divide by 12 disbursement periods)
- 60 monthly periods during the time of the five-year payment period under PBI
- The Present Value of the payment to be levelized is the value of the EPBB
- We make each payment occur at the end of the payment period
- We levelize each payment into a uniform series
- We multiply the levelized payment by the Capacity Factor (either 0.18 or 0.20 depending on which Step)
- We divide the levelized payment by the kWh/month per Watt (0.1314 or 0.146 depending on the CF)
- This gives us the levelized monthly PBI Payments in $ per kWh

(END OF APPENDIX A)