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OPENING BRIEF OF THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION ON IMPLEMENTATION OF SB 32

Sue Kateley, Executive Director
California Solar Energy Industries Association
P.O. Box 782
Rio Vista, CA 94571
916-747-6987
info@calseia.org

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OPENING BRIEF OF THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION ON IMPLEMENTATION OF SB 32

The California Solar Energy Industry Association (CALSEIA) hereby submits its brief on implementation of SB 32.

SUMMARY OF RECOMMENDATIONS

CALSEIA recommends the following:

1. Phase in implementation, beginning with projects below 1MW and establishing participation criteria as described in this brief
2. Expedite implementation
3. SB 32 pricing set at a value that includes but it not limited to energy, environmental, time of delivery, location, and congestion benefits
4. Voluntary participation by small investor owned utilities
5. Method to allocate SB 32 MWs

I. INTRODUCTION AND BACKGROUND

CALSEIA is a non-profit industry association founded in 1977. Its membership includes approximately 200 solar companies doing business in California. CALSEIA was the sponsoring organization for SB 32.

Beginning in December 2007, the CALSEIA Board of Directors formally recognized that existing state policies to encourage distributed generation[1] were unduly constraining the market potential for solar in California and that a new policy was needed to address this constraint. At the time, California policies for distributed generation were limited to:

[1] Distributed generation resources are grid-connected electrical generation connected to the distribution level of the distribution grid and located at or very near the location where the energy is used.

- Annual Renewable Portfolio Standard (RPS) Solicitations
- California Solar Initiative Incentives in combination with net metering
- AB 1969 wastewater feed in tariff for projects 1.5 megawatt (MW) and less, priced at the Market Price Referent.

In CALSEIA's view, the RPS solicitations discouraged participations by small renewable generators because of the cost and complexity of negotiating the contracts. The California Solar initiative limits the size of systems to offset on site demand, thereby excluding any site where there is no or little on site demand for electricity. And the AB 1969 feed in tariff price was set at the value of a natural gas generator, below the market value of distributed renewable generation. Each of these programs unintentionally inhibited the market for distributed generation in California, even though state policy was calling for more emphasis on customer and utility owned distributed generation.[2]

To remedy this policy gap, CALSEIA sponsored SB 1714 in 2008. While SB 1714 was not enacted, the following year, 2009, SB 32 was introduced, and CALSEIA worked to address concerns raised throughout the legislative process with organizations such as Southern California Edison, Pacific Gas and Electric, San Diego Gas and Electric, The Utility Reform Network, Environment California, the Center for Energy Efficiency and Renewable Technologies, and the California Public Utilities Commission so that SB 32 could be successfully implemented in California.

In 2009, the California Energy Commission Integrated Energy Policy Report included this recommendation:

> "To facilitate lower-cost development of renewable resources, the Energy Commission recommends the following actions to expand the use of feed-in tariffs in California: To help meet the goal of the RPS and expand the amount of renewable energy located near load, the CPUC should require the investor-owned utilities to offer simplified and

[2] Energy Action Plan 2005, Appendix Page 6, http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

> standardized contracts set at reasonable prices for renewable energy projects 20 megawatts or less in size. The contracts should be designed to help small businesses participate in the RPS, reduce the transaction costs of the RPS contracting processes, and provide gradually declining, publicly available, technology-specific (or product-specific) price signals to stimulate competition among manufacturers to lower the cost of renewable energy.[3]"

To its credit, the Commission has authorized a variety of programs to increase the market for distributed generation. But these programs have not resulted in much market activity, with the exception of Southern California Edison's (SCE) photovoltaic procurement program. The Commission authorized SCE's program in March 2008 and it appears that approximately 20 MWs have been completed (approximately 0.5MW/month). An additional 40MWs are expected to become operational through the 2010 SCE PV solicitation,[4] at an average rate of about 3MW/month if projects are completed without extensions (based on the completion dates indicated in the Advice Letter 2513-E[5]. Based on publicly available information, the AB 1969 tariffs have also not experienced much market response.

CALSEIA is eager to work with the Commission and all parties to implement SB 32 in a manner that will stimulate market activity in a manner that is reasonable for ratepayers and utility system reliability and good for stimulating economic activity in communities throughout California. This is an ambitious goal but one which CALSEIA believes can be accomplished.

II. CALSEIA IMPLEMENTATION PROPOSAL

CALSEIA recommends the Commission phase in implementation of SB 32. We strongly recommend this for several reasons:

1. Ensure the program meets the Legislative intent[6] to encourage the location of clean generation close to load centers and encourage the generation of eligible renewable

[3] http://energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF, page 235
[4] http://www.cpuc.ca.gov/NR/rdonlyres/BEC3CEE2-F98C-4434-A73C-78679C344EF3/0/2513E.pdf
[5] ibid
[6] http://leginfo.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_32_bill_20091011_chaptered.pdf, Section 1

energy resources strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers.

2. Ensure that, as much as possible, this program does not overlap with other renewable procurement programs in a manner that perversely encourages developers to submit projects to multiple programs (for example, RPS solicitations, RAM, or CSI).
3. Ensure that the program encourages competition within the industry and minimizes seller concentration.
4. Facilitate rapid implementation of SB 32 so that renewable energy projects can be built and provide local economic benefits to communities.
5. CALSEIA believes that the Commission should set a monthly goal of megawatts completed in order to encourage achieving renewable energy generation goals and to help ensure near term economic stimulus in California in the form of local jobs building these projects. CALSEIA believes a goal of completing 20 megawatts (MW) per month would be a good initial goal which the Commission could adjust based on how the program progresses.

Phased in approaches to statutorily authorized programs has been used in Commission programs, including both the General Market California Solar Initiative (Steps 1 and 2 were limited to commercial projects) and the CSI Thermal program which initially limited projects to residential customers only. The implementation of SB 32 would benefit from a phased implementation which focuses first on smaller projects that can be completed within a short time frame, provide an opportunity for a review and assessment, then follow with full implementation.

CALSEIA recommends that a first phase implementation have the following program elements:

Proposed Program Element	Rationale
Limit maximum eligible project to no larger than 1MW	Minimize program overlap. The utility PV procurement programs are limited to projects 1MW

	and the CPUC's reverse auction program does not facilitate participation by small businesses or self-owned projects. By limiting projects to 1MW and below it will target a renewable energy project segment that is more likely to be located close to load centers.
Time to complete: 12 months, no extension	This program element would discourage speculative projects from being submitted to the program and put more burden on developers to perform their due diligence prior to submitting a project.
Existing projects not eligible	For purposes of creating new market activity, CALSEIA recommends the first phase of implementation be limited to new projects only.
Seller concentration cap: no more than 10MW per developer per year, statewide	CALSEIA strongly recommends this rule in order to ensure a competitive market. Bidders who lost out on the RAM or utility procurement programs have an advantage in that their projects have already started development. This would be unfair and anticompetitive against smaller developers or private property owners who can participate in a FIT but not be able to participate in the RAM or utility PV procurement programs.
No assignment of contracts until after project completion	CALSEIA proposes this provision in order to minimize speculative applications.
Prohibit 'daisy chaining'	Daisy chaining is a technique used by developers to split larger projects into smaller projects so that they can participate in the programs designed for smaller projects. Existing programs are available for larger project developers. CALSEIA strongly recommends that the FIT program prohibit daisy chaining.
Distribution level projects only	CALSEIA recommends that eligibility be limited to those projects that can interconnect to the distribution system. This would exclude projects that would interconnect to the transmission system. This would further encourage smaller projects that are located close to load.
Interconnection procedures	CALSEIA recommends that the utilities use, to the maximum extent possible, the Rule 21 procedures that are currently used for self-generation facilities. This could be accomplished by a modification of the FERC

	Wholesale Distribution Access Tariffs (WDAT). Utilities should be instructed to quantify the ratepayer/utility benefits of any necessary upgrades to ensure that costs are appropriately shared between the developer and the utility/and or ratepayer, when applicable. CALSEIA also recommends that utilities provide a breakdown of their estimated interconnection cost to provide transparency on engineering, equipment, and labor costs so that project developers and the Commission can monitor these costs.
Price adjustments and MW tranches	As suggested in CALSEIA's discussion in this brief on pricing
FIT procurement targets should not be counted toward other program goals	FIT program should not count toward utility DG procurement goals in RAM or other programs in order to encourage additional new distributed renewable generation

To the extent that this is possible, CALSEIA would encourage the utilities to voluntarily implement CALSEIA's proposals and the Commission to approve such a voluntary effort. We note that PG&E has suggested FITs in other proceedings before the Commission and we are encouraged by their willingness to consider the prospect.[7] CALSEIA is ardent in its desire to see this program create near term, competitive, economic activity throughout California.

CALSEIA proposes the Commission set a value for the SB 32 Feed in Tariff that reflects all of the value of distributed renewable generation. However, CALSEIA also recognizes that based on economies of scale and location with respect to load, the price should be scaled according to the size of the project. CALSEIA suggests:

Table 1: Proposed SB 32 Pricing by Project Size

	Projects less than 250kW	Projects between 250kW and 1MW	Greater than 1MW

[7] PG&E CSI Filing, http://docs.cpuc.ca.gov/efile/CM/128725.pdf, page 4 and PG&E SGIP Filing, page 1: http://docs.cpuc.ca.gov/efile/CM/127924.pdf

PG&E (Ex. San Joaquin Valley, SJV)	$0.22 /kWh	$0.17/kWh	$0.12/kWh
PG&E (San Joaquin Valley)	$0.22 /kWh	$0.17/kWh	$0.12/kWh
SCE	$0.22 /kWh	$0.17/kWh	$0.12/kWh
SDG&E	0.22 /kWh	$0.17/kWh	$0.12/kWh

*The rates shown in this table are not inclusive of utility time of delivery adjustments

CALSEIA also recognizes that the Commission would want to and should monitor market response to the Feed in Tariff and therefore we recommend that the Commission review the market response and, if necessary, make adjustments to ensure that the program is resulting in the construction and connection of new distributed renewable generation. We recommend prices that are neither in the highest or lowest values to provide flexibility to the Commission to adjust the rates based on market response. In addition, CALSEIA recognizes that there may be substantial market response to this new market opportunity, therefore CALSEIA also proposes that the MWs available through this Feed in Tariff be made available in quarterly tranches which will facilitate the Commission's ability to make adjustments to the price by either increasing or decreasing the rate based on market response. CALSEIA suggests that if any single calendar quarter is oversubscribed, the Commission should automatically reduce the rate by 10% for the following calendar quarter. Conversely, the Commission should leave the rate unchanged if it finds that there is little or no market activity. But CALSEIA also cautions the Commission must also enforce a 12 month completion date in order to minimize the submission of speculative projects. We sincerely want to avoid having speculators submit projects that will not ultimately be constructed. Further, CALSEIA believes it is important to ensure that the project ownership allows participation by site owners as well as third-party investor organizations. Therefore, CALSEIA recommends the following quarterly tranches (the MW allocation for each utility service area is discussed later in this brief):

Table 2: Proposed SB 32 Quarterly Allocation

	Total MW	Quarterly MW tranche for projects <250kW	Quarterly MW tranche for projects >250 and <1MW	Quarterly MW tranche for projects >1MW*	Total MW Tranche per quarter
PG&E	250	20	20	10	50
SCE	260	20	20	10	50
SDG&E	60	5	5	2	12

*Note: CALSEIA recommends a pilot for projects less than 1 MW, therefore projects of this size would not initially be eligible for the feed in tariff if CALSEIA's recommendation is adopted. However, if CALSEIA's pilot proposal is not adopted, these are the allocation of MWs that CALSEIA suggests.

CALSEIA notes that the modest number of MWs combined with the weighted average price based on size of the project, paid out over the term of the contracts, will result in de minimus ratepayer impacts as well as meet the requirements for ratepayer indifference.

If the Commission adopts CALSEIA's proposal, CALSEIA recommends the Commission conduct a review of the lessons learned from Phase 1, perhaps within six (6) months after the tariff is available, and make modifications to the program if deemed needed. At that time, CALSEIA recommends expanding the program to allow participation for projects up to 3 MW.

III. ISSUES RAISED IN COMMISSION RULING

CALSEIA offers the following comments with regard to the issues raised in the Opening Ruling:

A. Customers and Eligibility

SB 32 reduced barriers to program participation, specifically: eliminated the separate tariff for water/wastewater facilities and removing the retail customer requirement will allow other local governments and private property owners to participate in this program. The eligible facility requirement was to maintain consistency with the goal to develop clean renewable generation close to where the energy will be used.

B. Increase In Size Of Eligible Facility To Three Mw Commission's Discretion To Reduce Three Mw Capacity Limit To Maintain System Reliability

CALSEIA's original legislative proposal called for a feed in tariff for projects up to 20MW. In discussions with the Investor Owned Utilities (IOUs),[8] the IOUs expressed concern regarding large intermittent generation on distribution feeder lines potentially creating reliability

[8] Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas and Electric (SDG&E)

problems due to unexpected cloud cover or an unplanned facility outage. They explained that a smaller project cap would address their concern and CALSEIA supported a reduced project cap of 3MWs. CALSEIA also recognizes that large photovoltaic (PV) facilities require substantial acreage, which would necessitate their being located further from load centers. More smaller projects supports CALSEIA's view that distributed generation is ideally made up of numerous small projects rather than fewer large projects. In CALSEIA's view, ten (10) 100 kilowatt (kW) facilities are the same as one (1) one megawatt (MW) facility. In many ways, smaller projects have advantages over large projects in terms of siting within load centers and ability of a project developer to complete a project in a short time window. Smaller projects also provide reliability benefits from smaller generators in multiple locations.

In various reports and studies, it has been shown that distributed generation can improve reliability and reduce distribution costs in a manner that saves money for ratepayers.[9] A recent report by the California Energy Commission,[10] found that:

> "Distributed energy resource projects in the right locations and with the right characteristics and operating profiles can improve the performance of an electric power system by reducing power losses, improving reliability and power quality, and increasing load-serving capability."

CALSEIA also strongly believes that where there are concerns about reliability state and utility representatives should be able to exercise discretion as to where projects should not be located if it could cause a clearly identified reliability problem. On the other hand, it is important to note that there are circuits and distribution lines where renewable distributed generation will improve reliability. CALSEIA believes the Commission and utilities should publicize the criteria that would be used to identify such location so that project developers can work to avoid those potential locations for project development. We believe there are currently a substantial number

[9] The Potential Benefits Of Distributed Generation And Rate-Related Issues That May Impede Their Expansion A Study Pursuant To Section 1817 Of The Energy Policy Act Of 2005, US Department of Energy, 2007
[10] Verification of Energy Net Modeling, Public Interest Energy Research, California Energy Commission, December 2010

of locations where reliability would be enhanced due to a distributed generation facility so this guidance to direct efforts toward preferred regions would be extremely useful.

If an IOU has information regarding the placement of a particular renewable facility where a reduction in size in necessary due to a concern regarding reliability, the Commission should authorize the IOUs to convey that information to the project developer and provide the developer guidance on what size project would work for that particular site. The developer can then determine if the project can still be built as modified or if the project should be abandoned. The Commission should also require the IOUs to provide data on preferred sites and site to avoid to the Commission to help monitor trends and responses to these situations in the event that a better means of addressing these situations can be implemented.

C. Utility Reporting Requirements

Public Utilities Code 399.20 (m) specifies that:

> "Within 10 days of receipt of a request for a tariff pursuant to this section from an owner or operator of an electric generation facility, the electrical corporation that receives the request shall post a copy of the request on its Internet Web site. The information posted on the Internet Web site shall include the name of the city in which the facility is located, but information that is proprietary and confidential, including, but not limited to, address information beyond the name of the city in which the facility is located, shall be redacted."

The reporting requirement specified in statute is similar to what is already provided by SCE's CREST and PG&E's AB 1969 program. SCE provides information on operational facilities[11] and PG&E provides a spreadsheet of both operational and pending projects.[12] CALSEIA believes PG&E's current practice is consistent with the utility reporting requirements in SB 32.

D. Adjustment Of Program Cap And Allocation To 750 Mw

SB 32 provides direction on allocating the 750MW allocation, "The proportionate share shall be calculated based on the ratio of the utility's peak demand compared to the total statewide peak demand." Further, SB 32 excludes utilities with less than 75,000 customers. According to

[11] http://www.sce.com/EnergyProcurement/renewables/crest.htm
[12] http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/standardcontractsforpurchase/

publicly available data, CALSEIA compiled data on customers and peak demand for publicly owned utilities[13] and investor owned utilities.[14]

According to the California Energy Commission, in 2009, coincident peak demand was 60,356 MW and non-coincident peak demand was 61,841 MW.[15] With rounding, CALSEIA suggests the following allocation for the investor owned utilities (we provide the allocations for the publicly owned utilities for reference purposes only):

Table 3: Proposed SB 32 Allocation of MWs by Utility

	Number of Customers	Peak Demand MW (2009)	Percent of Non-Coincident %	Percent of Coincident %	Proportion of 750 MW	MW Allocation Rounded
LADWP	1,400,000	5,812	9	10	72	75
SMUD	592,490	3,039	5	5	38	40
Anaheim	175,004	559	1	1	7	10
Imperial ID	145,916	969	2	2	12	15
Modesto ID	110,000	646	1	1	8	10
Riverside	106,000	588	1	1	7	10
Burbank	100,000	304	0	1	4	5
Turlock ID	99,453	553	1	1	7	10
Glendale	84,500	335	1	1	4	5
PG&E		19773	32	33	246	250
SCE		20899	34	35	260	260
SDG&E		4487	7	7	56	60
Statewide non coincident peak		61,841	94	96	720	750

E. Yearly Inspection and Maintenance Report

Public Utilities Code 399.20 (p) specifies the following:

> "In order to ensure the safety and reliability of electric generation facilities, the owner of an electric generation facility receiving a tariff pursuant to this section shall provide an inspection and maintenance report to the electrical corporation at least once every other year. The inspection and maintenance report shall be prepared at the owner's or

[13] Customer Counts Source: http://www.anaheim.net/utilities/adv_svc_prog/SB1037.pdf (March 2010); Peak Demand Source: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF, Page 44

[14] http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF, Page 44

[15] California Energy Commission, page 44, http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF.)

operator's expense by a California licensed contractor who is not the owner or operator of the electric generation facility. A California licensed electrician shall perform the inspection of the electrical portion of the generation facility."

This statute specifies that inspection and maintenance reports shall be provided to the utility ***biennially (every other year)***. In addition, the reports must be performed by a California licensed contractor. The State Contractors licenses that are allowed to perform solar electrical work are: A (engineer), B (general), C-46 (solar), C-10 (electrical) and C-39 (roofing).[16] Any of these licensed contractors are allowed to provide these inspection and maintenance reports. These licensed contractors must use an electrician to perform the inspection of the electrical portion of the facilities. If the licensed contractor is an electrician or has an employee who is an electrician, they can perform the inspection and maintenance report themselves. If they are not an electrician or do not have an employee who is an electrician, they must retain the services of an electrician. The State Department of Industrial Relations publishes a list of certified electricians.[17] There is no similar statutory restriction on the employee classification for the non-electrical portions of the facility, therefore the licensed contractor or any employee of the licensed contractor may perform the inspection and maintenance report for the non-electrical portion of the facility.

F. New contract provisions

CALSEIA would like to work with the IOUs to propose revisions to the standard contracts currently used by the IOUs for their AB 1969 tariff contracts. In particular, CALSEIA urges the Commission and the IOUs to consider that smaller project developers will face more difficulties with up-front deposits and costs due to the lower potential revenue stream from a smaller project. We would like to see the contracts take into consideration the deposits and other fees that are made for interconnection studies and distribution system upgrades so that the upfront net cost per MW is reasonable and manageable for small project developers.

[16] http://www.cslb.ca.gov/generalinformation/newsroom/industrybulletins/industrybulletins2010/industrybulletin20100630.asp

[17] http://www.dir.ca.gov/DAS/CA_Electricians_Certified.pdf

G. Utility discretion to deny tariff, subject to appeal to the Commission

CALSEIA believes that the discretion to deny the tariff is limited to causes related to maintaining reliability. CALSEIA would like to work with the Commission and utilities to specify general criteria that would cause a denial so that project developers can, to the maximum extent possible, avoid those locations. If a utility determines it is necessary to deny the tariff, the utility should provide the Commission and the developer an explanation of how the utility determined a denial was deemed necessary. If a developer disagrees with the determination of the utilities, the Commission should provide an avenue for the developer to appeal the utilities determination.

H. Contract termination provisions

CALSEIA has no comment at this time.

I. Performance standards to be established by the Commission

Public Utilities Code 399.20 states that:

> "(j) (1) The commission shall establish performance standards for any electric generation facility that has a capacity greater than one megawatt to ensure that those facilities are constructed, operated, and maintained to generate the expected annual net production of electricity and do not impact system reliability."

CALSEIA believes that the Feed in Tariff has an inherent performance standard in that the developer cannot receive payment until and unless the project generates energy. With regard to more specific performance standards, CALSEIA recommends a review of the existing reliability and performance provisions already incorporated in interconnection agreements and standard contracts to determine if the there are any additional requirements that are needed. With regard to projects less than 1MW, their performance should be adequately address through the standard contract and interconnection agreements with the utilities.

J. Commission discretion to make adjustments for small utilities

CALSEIA recommends that small utilities should be allowed to voluntarily participate in the feed in tariff program or opt out due to their small size.

K. Setting the tariff price

SB 32 provides authority to the Commission in Section 399.20 (d) to establish a price for renewable generation that is based on the attributes of renewable energy generation and specifies the following:

> "(d) (1) The tariff shall provide for payment for every kilowatt-hour of electricity purchased from an electric generation facility for a period of 10, 15, or 20 years, as authorized by the commission. The payment shall be the market price determined by the commission pursuant to Section 399.15 and shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located.
> (2) The commission may adjust the payment rate to reflect the value of every kilowatt-hour of electricity generated on a time-of-delivery basis."

CALSEIA commissioned a study in 2010 by Dr. Lori Schell at Empowered Energy to assess the value of renewable generation as established by SB 32.[18] The study quantified the incremental value of solar PV over and above the TOD-adjusted 2009 MPR (these are summarized in Table 4), which shows the range of the regional PV Adder for each of four regions examined.

Table 4: Solar PV Adder: Value Provided Over and Above the 2009 MPR, without time of delivery adjustment, without Time of Delivery Adjustment

Utility	Minimum PV Adder (cents/kWh)	Maximum PV Adder (cents/kWh)	Total MPR + PV Adder (cents/kWh)
PG&E (Ex. San Joaquin Valley, SJV)	4.761	11.738	17.154-24.132
PG&E (San Joaquin Valley)	5.529	11.908	17.619-23.997
SCE	5.279	11.460	17.738-23.919
SDG&E	7.890	12.744	18.608-23.462

[18] Small-Scale Solar Photovoltaics In California: Incremental Value Not Captured In The 2009 Market Price Referent – Description Of Methodology, 2010

In order to quantify these values, Empowered Energy took the following steps:

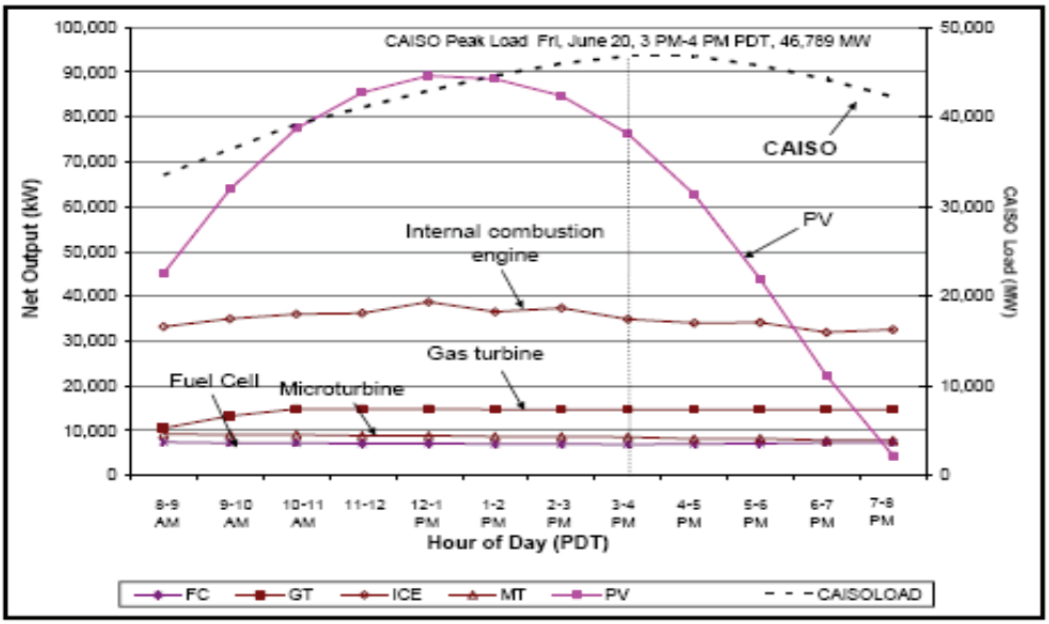
- Step 1: Take as given 2009 MPR
  - Value for 10-year contract, 2010 start date
- Step 2: Understand 2009 MPR component values
  - 500 MW natural gas combined cycle ("NGCC") generator
  - Baseload generation
- Step 3: Calculate total PV value, adjusted for TOD without including any values already included in the MPR
  - Representative 100 kWac PV system
  - Directed south at a 10-degree tilt
  - Range of weighted average TOD factors: 1.108-1.288
- Step 4: Quantify incremental *above-MPR* value of PV to include as PV Adder in SB32 FIT

Empowered Energy's research identified components that are not included in the Market Price Referent that are authorized by SB 32 to be included in setting the price for the feed in tariff. Excerpts from this research are described below:

An important attribute of solar PV is that it generates electricity during periods of high demand. The effective load carrying capacity ("ELCC") of any electricity generator is a measure of that generator's capacity to contribute effectively to serving a utility's peak load.[19] The ELCC determines what percentage of a generator's capacity is available to serve a utility's peak demand. The electricity generated by solar PV peaks when the sun is at its zenith, whereas California's peak electricity demand usually occurs later in the afternoon, sometime between 2:00-4:00 p.m. Figure 1 shows the peak capacity contribution of various distributed generation technologies, including PV, during the 2008 peak hour for the California Independent System Operator ("CAISO"), which occurred between 3:00-4:00 p.m. on June 20, 2008.[20]

[19] Herig, September 2001, p. 2,
[20] Itron, Inc., July 2009, p. 1-6, Figure 1-4.

Figure 1: Self-Generation Incentive Program, Technology-Specific Capacity



Based on the data from which the generation profiles in Figure 1 are derived, the ELCC of the representative PV system assumed in this analysis (oriented to the south at a 10 degree tilt) is estimated to be approximately 60 percent.[21] This is consistent with an independent estimate of the ELCC for PV in California of 59 percent for a horizontal PV system, 61 percent for a PV system directed to the south at a 30 degree tilt, and 69 percent for a PV system directed to the southwest at a 30 degree tilt.[22] The ELCC plays an important role in converting avoided costs that are expressed in $/kW-year into cents/kWh, the latter of which is the metric used in this analysis.

[21] Itron, Inc., September 2008, p. 1-6, Table 1-7, indicates a 60.1% coincident-peak capacity factor in 2007 for PV systems receiving incentives under the Self-Generation Incentive Program ("SGIP"); Itron, Inc., July 2009, p. 1-6, Table 1-7, indicates a 58.5% peak capacity factor in 2008 for PV systems receiving SGIP incentives.

[22] Perez, *et al.*, July 2006, p. 5, for up to a 2 percent statewide PV penetration.

As seen in Figure 1, electricity demand varies over the course of the day; peak demand is usually met by natural gas peaking units that have significantly higher heat rates than the 2009 MPR proxy plant.[23] The higher heat rate of peaking units means that the electricity generated during peak demand periods is more costly than electricity generated during off-peak demand periods. To reflect the difference in the value of electricity delivered during different time periods, each IOU has utility-specific TOD factors. Attachment A defines the time periods and the TOD factors that apply during each time period for the three IOUs included in this analysis.

The weighted average TOD factor for each region reflects the approximate hourly generation profile of a representative PV system located in the city noted and oriented to the south with a 10 degree tilt. The weighted average TOD factor for each region is calculated by allocating the kWh generated by the representative PV system into each of the applicable TOD time periods for the IOU serving that region. The weighted average TOD factors used in this analysis are as follows:

Region	Location	Weighted Average TOD Factor
PG&E (Ex. SJV)	Oakland	1.281
PG&E (SJV)	Fresno	1.250
SCE	Rosemead	1.288
SDG&E	San Diego	1.108

Except for Renewable Energy Credits ("RECs") and the Value of Avoided Transmission & Distribution ("T&D"), each of the value components described below has been TOD-adjusted by multiplying the raw component value times the Weighted Average TOD Factor for each region shown above. The purpose of the TOD adjustment is to reflect the higher value of electricity generated and delivered by PV systems during higher demand periods when, for instance, the level of avoided emissions increases because higher heat rate generators are required to meet the increased load. To simplify the discussion that follows, however, only the raw component values (prior to the TOD adjustment) will be presented in the discussion of each component's derivation. For comparison, Table 5 presents the range of the regional PV Adder

[23] The 2009 MPR proxy plant has a new-and-clean heat rate of 6,879 British thermal units ("Btu") per kWh and a maximum heat rate of 6,932 Btu/kWh. This 2009 MPR proxy plant heat rate range of 6,879-6,932 Btu/kWh is used throughout this analysis.

for each of the four regions examined before and after application of the utility-specific TOD factors:

Table 5: Regional Above-MPR PV Adder for Representative PV System, with and without TOD Factor Adjustment

Above-MPR PV Adder (¢/kWh)	Without TOD Factor Adjustment		Wt. Avg. TOD Factor	With TOD Factor Adjustment *	
	Minimum	Maximum		Minimum	Maximum
PG&E – Ex. SJV	4.233	10.801	1.281	4.761	11.738
PG&E – SJV	5.013	10.957	1.250	5.529	11.908
SCE	4.758	10.494	1.288	5.279	11.460
SDG&E	7.650	12.324	1.108	7.890	12.744

* Not applied to Avoided T&D or Value of RECs

It is important to note that the hourly generation profile of a PV system will differ significantly based on both the geographic location and the orientation of the system. The fact that each utility has different TOD factors means that the optimal orientation for a PV system may vary by region, depending on whether the goal is to maximize (i) the total amount of kWh produced or (ii) the weighted average TOD factor. The tables below demonstrate the magnitude of this impact for each of the four regions included in this analysis, for each of four different PV system orientations.[24]

[24] The PV generation profile for each PV system orientation and region was calculated by members of the California Solar Energy Industries Association using PVSYST software and TMY3 weather data.

Table 6: PG&E (Ex. SJV), Solar PV Adder, by PV Orientation

PV Orientation, 100 kW_{ac} System	Total kWh Per Year	Wt. Average TOD Factor *	Above-MPR PV Adder (¢/kWh)	
			Minimum	Maximum
Flat	157,847	1.294	4.786	11.782
South, 10º Tilt	***168,600***	***1.281***	***4.761***	***11.738***
Southwest, 20º Tilt	170,552	1.307	4.809	11.824
West, 30º Tilt	149,442	1.355	4.899	11.984

* Not applied to Avoided T&D or Value of RECs

Table7: PG&E (SJV), Solar PV Adder, by PV Orientation

PV Orientation, 100 kW_{ac} System	Total kWh Per Year	Wt. Average TOD Factor *	Above-MPR PV Adder (¢/kWh)	
			Minimum	Maximum
Flat	168,676	1.260	5.550	11.947
South, 10º Tilt	***179,416***	***1.250***	***5.529***	***11.908***
Southwest, 20º Tilt	178,410	1.281	5.595	12.028
West, 30º Tilt	154,392	1.337	5.711	12.242

* Not applied to Avoided T&D or Value of RECs

Table 8: SCE, Solar PV Adder, by PV Orientation

PV Orientation, 100 kW_{ac} System	Total kWh Per Year	Wt. Average TOD Factor *	Above-MPR PV Adder (¢/kWh)	
			Minimum	Maximum
Flat	172,536	1.370	5.429	11.738
South, 10º Tilt	***184,563***	***1.288***	***5.279***	***11.460***
Southwest, 20º Tilt	184,610	1.331	5.358	11.607
West, 30º Tilt	159,494	1.411	5.503	11.875

* Not applied to Avoided T&D or Value of RECs

Table 9. SDG&E, Solar PV Adder, by PV Orientation

PV Orientation, 100 kW_{ac} System	Total kWh Per Year	Wt. Average TOD Factor *	Above-MPR PV Adder (¢/kWh)	
			Minimum	Maximum
Flat	176,143	1.112	7.899	12.761
South, 10º Tilt	***188,496***	***1.108***	***7.890***	***12.744***
Southwest, 20º Tilt	191,772	1.122	7.920	12.798
West, 30º Tilt	168,481	1.143	7.967	12.880

* Not applied to Avoided T&D or Value of RECs

Because the weighted average TOD factor differs for each region even for the representative PV system, the above-MPR value components presented reflect the raw values for each above-MPR value component, prior to application of the weighted average TOD factor for each region applicable to a PV system directed south at a 10 degree tilt.

ELEMENTS USED IN DETERMINING THE ABOVE-MPR ADDER

Renewable Energy Credits. Electricity generated by solar PV is 100% renewable and will therefore have incremental, above-MPR value in the form of RECs. There is no explicit value for RECs included in the 2009 MPR since the proxy plant for which MPR costs are calculated is a natural gas-fired combined cycle generator that relies on fossil fuel rather than on a renewable source of energy.

The range of values for RECs is based on both regulatory and market input. The California Public Utilities Commission ("CPUC") issued Decision 10-03-021[25] on March 16, 2010, in Docket No. 06-02-012 under its Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard. In the Decision (p. 59), the CPUC adopted a temporary price cap of $50/MWh for RECs, which is the penalty amount for noncompliance with the California Renewables Portfolio Standard ("RPS"). This $50/MWh temporary price cap for RECs is used as the upper end of the range of above-MPR value for the RECs associated with PV electricity generation. The lower end of the range of value for RECs is based on the $20/MWh market price index for RECs for the Western Electricity Coordinating Council (of which the California Independent System Operator is a member), as quoted by the CantorCO2 Environmental Brokerage.

Converting the $/MWh price range for RECs to the cents/kWh metric used i results in a range of incremental, above-MPR value for RECs associated with PV-generated electricity of 2-5 cents/kWh. Because RECs are priced on a per unit basis that is not adjusted for the time of delivery, the range of value for RECs is not adjusted by the utility-specific weighted average TOD factors in this analysis.

Although RECs are defined by the CPUC as including "all renewable and environmental attributes associated with the production of electricity from the renewable energy resource," *there is also an explicit recognition that "although avoided emissions are included in the definition of the REC, this definition does not create any right to use those*

[25] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/115056.htm

avoided emissions to comply with any [greenhouse gas] regulatory program."[26] *Whereas a REC can be used for compliance with California's RPS program, separate emissions reduction credits must be purchased for compliance with individual air quality district regulations and separate greenhouse gas allowances will have to be purchased to comply with the mandates of California's Global Warming Solutions Act of 2006 ("AB 32").* Consequently, separate above-MPR value components have been included in this analysis for both the value of RECs and the value of avoided proxy plant emissions of criteria pollutants and greenhouse gases.

Avoided Fuel use as a Natural Gas Price Hedge. The 2009 MPR includes a 10-year levelized forecast of delivered natural gas prices equal to $7.39 per million British thermal units ("MMBtu"). This is the natural gas price assumed for natural gas use by the 2009 MPR proxy plant. Since this fuel cost is already included in the 2009 MPR value, there is no above-MPR value attributed to solar PV for any avoided natural gas costs.

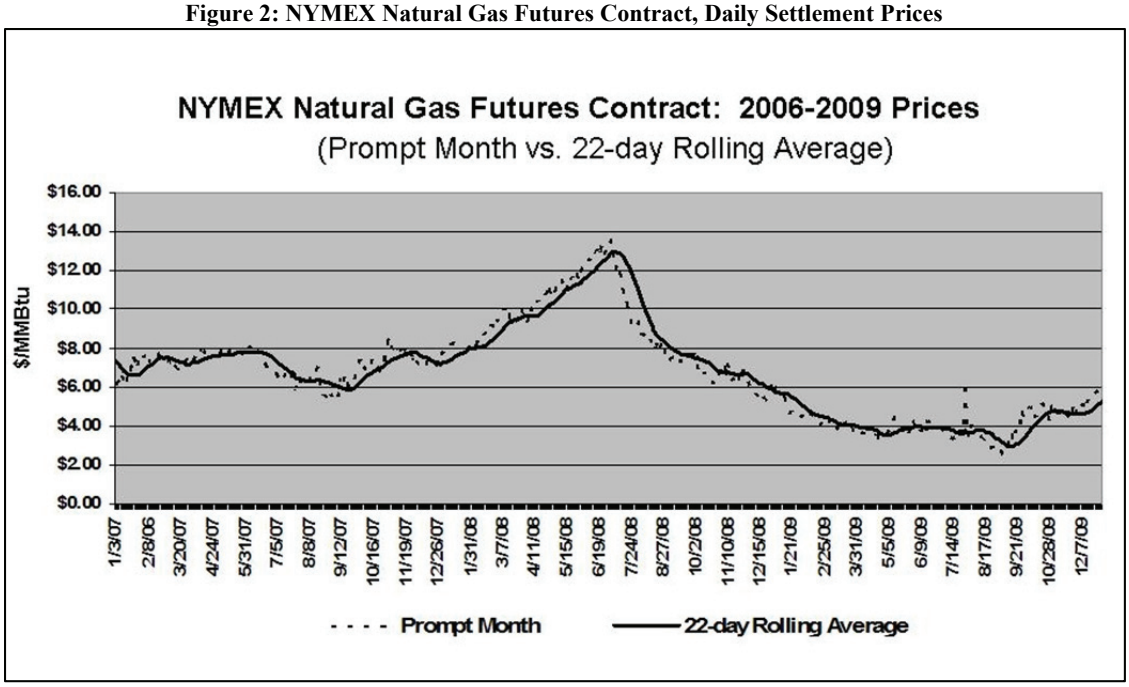
Natural gas futures prices are notoriously volatile, as illustrated in Figure 2, which compares the monthly rolling average of daily settlement prices for prompt-month natural gas futures contracts on the New York Mercantile Exchange ("NYMEX") with the same trading day's prompt-month settle price.[27] As can be seen in Figure 2, the daily NYMEX prompt-month price range since January 2006 has been $2.51-$13.58/MMBtu and the monthly rolling average range has been $2.96-12.97/MMBtu, for natural gas located at the Henry Hub, onshore Louisiana. Natural gas prices delivered to the California border

[26] California Public Utilities Commission, D.08-08-028, August 22, 2008, p. 45. Note that there is some debate about how much of the value of the "environmental attributes associated with the production of electricity from the renewable energy resource" is captured in the price of RECs. This analysis has added the above-MPR Value of Avoided Emissions to the price of RECs based on the fact that a utility must procure both RECs and emissions reduction allowances for separate compliance purposes. To the extent that it could be demonstrated otherwise, it may be appropriate to reduce the value of RECs included in the PV Adder.

[27] The term "prompt month" refers to the earliest month for which futures contracts are trading. Trading of futures contracts for any given delivery month ends prior to the end of immediately previous month. Therefore, "the prompt month" in mid-April would be May, but by the end of April, after trading for the May futures contract closes, the prompt month becomes June. The monthly rolling average of daily settlement prices is based on a 22-day trading month and is appropriate for those generators buying natural gas on a monthly basis; the daily settlement prices are appropriate for natural gas purchases made on an as-needed basis.

have been lower than Henry Hub prices over the past few years, and the 2009 MPR reflects this difference in its forecast of delivered natural gas prices.[28]

Figure 2: NYMEX Natural Gas Futures Contract, Daily Settlement Prices



The 2009 MPR levelized forecast of delivered natural gas prices includes a Hedging Transaction Cost of $0.082/MMBtu of natural gas. The Hedging Transaction Cost reflects the cost of entering into a long-term natural gas supply contract for the purpose of fixing (hedging) the natural gas price. Hedging removes the buyer's exposure to natural gas price volatility (up or down), but it comes at a cost. The fact that the 2009 MPR incorporates hedged natural gas prices based on a forward market price curve removes the volatility in natural gas prices faced by the proxy plant. There is therefore no above-MPR value attributable to PV systems for the ability of these systems to act as a natural hedge against natural gas price volatility.

Value of Grid Support. The estimated incremental, above-MPR Value of Grid Support reflects the avoided ancillary services costs associated with the electricity load displaced by

[28] A negative cost adjustment of $0.21/MMBtu is made to the 10-year average projected value of transportation from the Henry Hub to California for the 2009 MPR proxy plant. (*See* California Public Utilities Commission, December 18, 2009, p. 19 and Energy and Environmental Economics, Inc., 2009, "CA_Gas_Forecast" tab.) This transportation value (known as the "basis") is highly volatile, varies seasonally, and has historically had both positive and negative values from the Henry Hub to California.

solar PV generation. This value, which is not captured in the 2009 MPR, is based on 2.84% of the range of natural gas costs discussed above, since fuel cost is assumed to be a major driver of wholesale electricity prices in California. Note that 2.84% is the same value used in several significant cost studies in California, including the 2004 avoided cost analysis developed by Energy and Environmental Economics, Inc. ("E3 Avoided Cost Study")[29] and E3's more recent Net Energy Metering Cost-Effectiveness Evaluation.[30] Both studies apply the 2.84% value of ancillary services to the avoided market price of electricity to estimate the value of avoided ancillary services. In this analysis, the 2.84% value is applied to the range of natural gas prices as a surrogate for the avoided market price of electricity. The result is converted to cents/kWh by multiplying by the heat rate range of 6,879-6,932 Btu/kWh of the 2009 MPR proxy plant.[31] The resultant above-MPR Value of Grid Support for PV ranges from 0.051-0.249 cents/kWh, prior to application of the utility-specific TOD adjustment.

Avoided Transmission & Distribution Costs. Because the 2009 MPR calculates the threshold costs for a proxy plant that is represented by a central station natural gas combined cycle generator, it does not include any value related to potential avoided T&D costs. For purposes of quantifying the above-MPR value of solar PV, this means that there is no value included in the 2009 MPR to reflect the fact that PV systems located at specific points within the electric grid may avoid the need for T&D investments by reducing peak load.

The potential value of avoided T&D costs depends on the specific location of the PV system on the electric grid, as noted in the graph in Figure 1. Small-scale PV systems typically interconnect to the electric grid at distribution-level voltages, and therefore have a Value of Avoided Transmission Capacity component, as well as an upstream Value of Avoided Distribution Capacity component related to the fact that PV-generated electricity displaces

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[29] Energy and Environmental Economics, October 25, 2004, pp. 146-147.

[30] Energy and Environmental Economics, January, 2010, Appendix A, p. 14.

[31] The average California avoided natural gas-fired plant had a five-year weighted-average heat rate for 2003-2007 that was approximately 10.6% less efficient than that of the 2009 MPR proxy plant, based on state-specific electricity generation and fuel consumption values as reported by the U.S. Department of Energy at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html for electricity generation and at http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SCA_a.htm for natural gas consumption.

the T&D use associated with delivering electricity from remote central station electricity generators.

To adequately capture the potential value of avoided T&D costs attributable to PV systems placed at various locations on the electric grid, the upper end of the range of avoided transmission costs is calculated separate and distinct from the upper end of the range of avoided distribution costs; both are taken from the E3 Avoided Cost Study, and have been adjusted to reflect (i) the assumed California average ELCC of 60% for small-scale PV and (ii) the average availability of 99% for small-scale PV systems. Because the E3 Avoided Cost Study adjusts the avoided T&D costs by attributing all costs to the peak demand hours for each utility and climate zone, the avoided T&D costs in the E3 Avoided Cost Study already capture the higher value of avoiding T&D utilization during the peak periods. Therefore, to avoid double counting, the avoided T&D costs from the E3 Avoided Cost Study are not TOD-adjusted.

Value of Avoided Transmission Cost. Depending on utility service territory, the Value of Avoided Transmission Cost for a PV system ranges from a low of 0.045 cents/kWh for transmission into PG&E's service territory to a high of 0.746 cents/kWh for transmission capacity into SCE's service territory; the Value of Avoided Transmission Cost for a PV system in SDG&E's service territory is 0.407 cents/kWh. SCE's Value of Avoided Transmission Cost of 0.746 cents/kWh is calculated by multiplying its 2010 E3 avoided transmission cost of $22.01/kW-yr[32] times the 60% ELCC and 99% availability and dividing it by 1,752 hours per year (= 8,760 hours/year x the 20% average annual PV capacity factor). SDG&E's 2010 E3 avoided transmission cost is $12.01/kW-yr and PG&E's E3 2010 avoided transmission cost is $1.33/kW-yr.

It should be noted that even SCE's 2010 E3 avoided transmission cost of $22.01/kW-yr is relatively low, based on a recent survey of analyses of the cost of new transmission required

[32] Energy and Environmental Economics, Inc., October 25, 2004, p. 136.

to bring remotely located renewable energy supplies to market.[33] For California-specific analyses, the estimated cost of new transmission ranged from $90-$1230/kW of incremental generation capacity. Applying a 15% annual capacity charge to these estimates, the annualized cost of new transmission capacity would be $13.50-$184.50/kW-yr, or $13.50-$81.00/kW-yr if the high-end cost-outlier of $1230/kW is replaced by the second-highest estimate of $540/kW. Thus, the Value of Avoided Transmission Capacity could be nearly four times greater than even SCE's avoided transmission cost, which is based on the E3 Avoided Cost Study and included as an above-MPR PV value component in Figure 1.

Value of Avoided Distribution Cost. Similar to the Value of Avoided Transmission Cost, the Value of Avoided Distribution Cost also depends on the utility service territory, but the Value of Avoided Distribution Cost also depends on the climate zone in which the PV system is located within any given utility service territory. Thus, the Value of Avoided Distribution Cost for a PV system ranges from 0.200-1.389 cents/kWh within SCE's service territory, 0.308-2.421 cents/kWh for PG&E's service territory outside of the San Joaquin Valley, 0.902-2.102 cents/kWh for PG&E's service territory in the San Joaquin Valley, and is 3.025 cents/kWh within SDG&E's service territory. Using SDG&E as an example, the Value of Avoided Distribution Cost is calculated by multiplying SDG&E's 2010 E3 avoided distribution cost of $89.23/kW-yr[34] times the 60% ELCC and 99% availability and dividing it by 1,752 hours per year (= 8,760 hours/year x the 20% average annual PV capacity factor).

Avoided Emissions And Related Health Benefits. Solar PV does not have any generation-related emissions. Therefore, the emissions-related incremental, above-MPR value of small-scale PV depends on how the region-specific value of avoided emissions attributed to PV compares to the cost of emissions allowances that is included in the 2009 MPR.

To calculate the region-specific value of avoided emissions related to PV installations, it is first necessary to identify *for each pollutant* (i) the emissions rate in pounds per MMBtu ("lb/MMBtu") of natural gas applicable to the avoided generating technology and (ii) the

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33 *See* Mills, *et al.*, February 2009, p. 23.

34 Energy and Environmental Economics, Inc., October 25, 2004, p. 136.

resultant emissions rate in pounds per MWh ("lb/MWh") over an assumed range of heat rates. Natural gas is typically the marginal fuel source that sets the market price of electricity in California and the 2009 MPR calculates statewide average costs associated with electricity generated by a new natural gas combined cycle proxy plant. Because SB32 specifies that the tariff "shall include all current and anticipated environmental compliance costs…associated with the operation of new generation facilities in the local air pollution control or air quality management district," the emissions avoided by electricity generated by a PV installation are based on (i) the emissions rates for the 2009 MPR proxy plant and (ii) the regional market value of those avoided emissions compared to the statewide average value that is included in the 2009 MPR. Therefore, the above-MPR value of avoided emissions is calculated through the following three-step process:

- The emissions rate range for each pollutant in pounds per MWh ("lb/MWh") is determined by multiplying the 2009 MPR proxy plant emissions rate in lb/MMBtu by the 2009 MPR proxy plant heat rate range.
- The minimum and maximum amounts of physically-avoided emissions in lb/MWh are then valued at the end points of a range of regional emissions allowance prices to determine the range of total value for each type of avoided emissions in cents/kWh of PV electricity generated.
- The average cost of emissions allowances included in the 2009 MPR (where applicable) is then subtracted from the regional range of total value for each type of avoided emissions to ensure that only the above-MPR value is attributed to the small-scale PV installations.

The underlying assumptions and results for the avoided emissions and related health benefits calculations are summarized in Attachment B. Because there are not yet any market prices for CO_2 emissions allowances in California, there is no incremental value attributed to PV beyond what is already included in the 2009 MPR. There is, however, an incremental statewide Value of Avoided CH_4 Emissions attributed to PV systems in California that is calculated to be 0.005-0.043 cents/kWh (prior to TOD factor adjustment) compared to the 2009 MPR proxy plant. The combined incremental, above-MPR value of all other avoided emissions (prior to TOD factor adjustment) for PV compared to the 2009 MPR proxy plant varies by region and by utility, as follows:

- PG&E, Non-SJV: (0.004) - (0.077) cents/kWh
- PG&E, SJV: 0.111 - 0.472 cents/kWh
- SCE: (0.144) - 0.021 cents/kWh
- SDG&E: 0.262 - 0.554 cents/kWh

The specific derivation of these aggregate values will be discussed on an emissions-by-emissions basis below, with all values presented being prior to TOD factor adjustment.

In addition, assuming that the Value of Health Benefits associated with avoided emissions is not reflected in emissions allowance prices,[35] the statewide incremental Value of Health Benefits for PV is calculated to be 1.743-1.757 cents/kWh based on the avoided emissions of the 2009 MPR proxy plant. Specific details for each avoided pollutant and related health benefits are discussed below.

Value of Avoided CO_2 Emissions. Although CO_2 and other GHG emissions are not yet subject to mandatory regulation in the United States, there is increasing pressure for the implementation of some type of carbon regulation, particularly on the transportation and electric utility sectors of the economy. The CPUC in 2005 began requiring the investor-owned utilities that it regulates to "penalize" potential new generation resources with an \$8/ton CO_2 cost (escalating at 5% per year) for resource planning and bid evaluation,[36] and CO_2 markets in Europe have traded anywhere from €2-€35/metric tonne since October 2005.[37]

The 2009 MPR includes a CO_2 adder that reflects a CO_2 compliance cost of \$10.44/ton starting in 2012, escalating to \$90.17/ton over the 20-year period to 2029. The 2012 CO_2 compliance cost of \$10.44/ton of CO_2 in the 2009 MPR approximates the CPUC's \$8.00/ton CO_2 price escalated at 5 percent for 5-6 years. The fact that the 2029 CO_2 compliance cost of

[35] Inclusion of this value component in the analysis is subject to debate. In an efficiently operating market for emissions allowances, the Value of Health Benefits would be included in the price of the emissions allowances. However, current markets for emissions allowances in California are relatively thinly traded and likely do not (fully) reflect the Value of Health Benefits associated with the avoided emissions attributed to PV plants.

[36] Energy and Environmental Economics, Inc., October 25, 2004, the supporting documentation for the Updated E3 Electric Avoided Costs Workbook of March 20, 2006, uses a cost estimate of \$0.004/lb of CO_2 in its avoided cost calculations, equivalent to the \$8/ton of CO_2 penalty applied in the CPUC's Integrated Resource Planning process.

[37] Chicago Climate Exchange, various dates.

$90.17/ton of CO_2 is higher than CO_2 compliance costs seen in CO_2 markets in Europe is indicative of the uncertainty surrounding the magnitude of future CO_2 compliance costs. Annual proxy plant CO_2 emissions in the 2009 MPR are calculated based on a CO_2 emissions rate of 0.0585 tons/MMBtu of natural gas burned.[38] Because the 2009 MPR includes future CO_2 compliance costs associated with the proxy plant CO_2 emissions avoided by PV-generated electricity, there is no CO_2-related incremental value attributable to PV included in this analysis.

Value of Avoided Methane (CH_4) Emissions. The 2009 MPR does not include any consideration of the estimated 1.4% of gross natural gas production is lost to the atmosphere as fugitive emissions during natural gas "extracting, processing, transmitting, storing, and distributing."[39] Avoiding proxy plant natural gas use through the increased use of PV technologies therefore avoids this amount of fugitive natural gas emissions. Natural gas is 75-95% methane[40] and methane "is 21 times as potent as CO_2 as a global warming pollutant."[41] These factors are applied to the physical natural gas savings from the avoided proxy plant generator attributable to PV technologies at the 2009 MPR CO_2 compliance cost range of $10.44-$90.17/ton CO_2-equivalent emissions. The result is an additional Value of Avoided Methane (CH_4) Emissions attributable to PV of approximately 0.043 cents/kWh.

Value of Avoided NO_x Emissions. For purposes of calculating the above-MPR Value of Avoided NO_x Emissions, the proxy plant NO_x emissions rate calculation starts with the 0.0105 lb/MMBtu emissions rate used in the 2009 MPR Model.[42] Using the proxy plant's assumed heat rate range of 6,879-6,932 Btu/kWh, the resultant NO_x emissions rate is approximately 0.075-0.076 lb/MWh, including incremental losses. The full Value of Avoided NOx Emissions is determined based on observed prices for Emissions Reduction

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38 *See* California Public Utilities Commission, December 18, 2009, p. 9; line 9 of the "CF_Data_Set" tab in the 2009 MPR model 2009_MPR_Model_Final.xls.

39 Spath and Mann, February 2001, pp. 8-9.

40 Spath and Mann, February 2001, p. 8. The Value of Avoided Methane (CH_4) Emissions is calculated based on methane having a density of 0.717 kg/m^3 (Wikipedia) and making up 75% of total the energy content of natural gas.

41 California Air Resources Board, October 2008, p. 194.

42 Derived using proxy plant average annual emissions generation from the "Install_Cap" and "Var_Comp" tabs. Respectively, as found in the 2009 MPR model 2009_MPR_Model_Final.xls.

Credits ("ERCs") bought and sold in California over the past two years. The range of prices used is this analysis varies by region, as shown in greater detail in Attachment B.[43]
Since PV technologies have no generation-related emissions, all of the NO_x emissions from the avoided generating units are avoided. However, the 2009 MPR already includes NOx emissions costs of $20,000/tpy, which must be deducted from the full Value of Avoided NOx Emissions calculated above to avoid double counting.

The net incremental, above-MPR Value of Avoided NO_x Emissions attributable to PV for each region is determined through the three-step process described in the introduction to this section of the report. That is, the calculated range of avoided NO_x emissions is valued at the applicable range of NO_x emissions allowance prices for each region considered in this analysis, with the resultant range of value subsequently reduced by the proxy plant NO_x emissions allowance costs already included in the 2009 MPR.

Value of Avoided SO_2 Emissions. For the 2009 MPR proxy plant, the SO_2 emissions rate is calculated using the 0.0014 lb/MMBtu emissions rate in the 2009 MPR Model. This new-and-clean emissions rate is slightly over half of that estimated by the Societal Benefits Topic Team of the California Hydrogen Highway Network, which estimates SO_2 emissions from a natural gas combined cycle plant at 0.0026 lb/MMBtu of natural gas.[44] For the assumed heat rate range of 6,879-6,932 Btu/kWh for the 2009 MPR proxy plant, the resultant SO_2 emissions rate using the 2009 MPR Model is approximately 0.010 lb/MWh, grossed up for incremental losses; all of these SO_2 emissions are avoided by the electricity generated by solar PV.

As was the case for NO_x emissions, the region-specific value of the avoided SO_2 emissions is based on observed prices for ERCs bought and sold in California, as shown in Attachment B. Combining the calculated range of avoided SO_2 emissions and the applicable range of prices for each region yields a region-specific range of total Value of Avoided SO_2 Emissions

[43] All emissions prices used in this analysis are based on Market Price Index ranges reported online by CantorCO2e Environmental Brokerage for the period from mid-September 2007 to mid-September 2009.
[44] California Hydrogen Highway Network, May 2005, p. 1-60, Table 1-27.

attributable to PV. The 2009 MPR value of SO_2 emissions allowances of 0.011 cents/kWh is subtracted from the region-specific range of values to avoid double counting. The 2009 MPR value of SO_2 emissions allowances is based on an SO_2 emissions allowance price of $21,500/tpy and a proxy plant SO_2 emissions rate of 0.009 lb/MWh.

Value of Avoided VOC Emissions. The VOC emissions rate for the proxy plant is estimated to be 0.003 lb/MMBtu in the 2009 MPR Model.[45] Applying the applicable heat rate range of 6,879-6,932 Btu/kWh yields a range of VOC emissions of 0.021-0.022 lb/MWh for the 2009 MPR proxy plant, grossed up for incremental losses.

The Value of Avoided VOC Emissions attributable to PV relies on region-specific observed California VOC ERC prices, which are presented in detail in Attachment B. Combining the calculated range of avoided VOC emissions and the applicable range of prices for each region yields a region-specific range of Value of Avoided VOC Emissions attributable to PV. The 2009 MPR value of VOC emissions allowances of 0.027 cents/kWh is subtracted from the region-specific range of values to avoid double counting. The 2009 MPR value of VOC emissions allowances is based on a VOC emissions allowance price of $24,829/tpy and a proxy plant VOC emissions rate of 0.018 lb/MWh.

Value of Avoided PM10 Emissions. The methodology for calculating avoided emissions of particulate matter less than 10 microns in diameter ("PM10") is the same as that used for valuing avoided NO_x, SO_2 and VOC emissions. For ease of analysis, only direct PM10 emissions are included in the analysis, likely resulting in an underestimated Value of PM10 Emissions due to lack of consideration of secondarily-formed PM10 emissions. The PM10 emissions rate for the proxy plant of approximately 0.018 lb/MWh is calculated using the 0.003 lb/MMBtu emissions rate from the 2009 MPR Model and the proxy plant heat rate range of 6,879-6,932 Btu/kWh.

[45] Abt Associates, October 2000, Exhibit C-2, p. C-5, estimated a 0.012 lb/MMBtu VOC emissions rate for a natural gas combined cycle plant at that time.

The Value of Avoided PM10 Emissions attributable to PV uses region-specific observed California PM10 ERC prices, as shown in Attachment B. The same three-step process used in the previous calculations of the value of avoided emissions is used for PM10 emissions. That is, the 2009 MPR value of PM10 emissions allowances of 0.122 cents/kWh is subtracted from the region-specific range of calculated values to avoid double counting. The 2009 MPR value of PM10 emissions allowances is based on a PM10 emissions allowance price of $43,000/tpy and a proxy plant PM10 emissions rate of 0.003 lb/MWh, as shown in Attachment B.

Value of Avoided CO Emissions. The CO emissions rate is estimated to be 0.0213 lb/MMBtu for the 2009 MPR proxy plant.[46] Applying the applicable heat rate range results in a proxy plant range of CO emissions of 0.152-0.154 lb/MWh, including incremental losses.

The Value of Avoided CO Emissions is based on the region-specific observed California CO ERC prices shown in Attachment B. Multiplying the endpoints of these prices times the end-points of the avoided CO emissions results in a Value of Avoided CO Emissions attributable to PV that varies by region. The 2009 MPR does not include any cost for CO emissions allowances for the proxy plant, so there is no need to subtract anything from the region-specific calculated values. The 2009 MPR Model shows a $500/tpy cost of CO emissions allowances and a proxy plant CO emissions rate of 0.131 lb/MWh, but these values are not included in the 2009 MPR value. These placeholder values from the 2009 MPR Model are shown alongside the region-specific CO emissions allowance prices and average proxy plant emissions rates in Attachment B.

Value of Health Benefits. By far the largest contributor to the Value of Health Benefits associated with avoided emissions is any reduction in particulate matter, particularly any reduction in particulate matter less than 2.5 microns in diameter ("PM2.5"). PM2.5

[46] *Ibid.* Abt Associates estimated a 0.1095 lb/MMBtu CO emissions rate for a natural gas combined cycle plant.

emissions are a subset of PM10 emissions, but PM2.5 emissions are more damaging to health because they lodge deeper in the lungs, and cannot readily be coughed out.

PM2.5 emissions are estimated to comprise 98% of total PM10 emissions in California's electricity generation sector, based on the statewide estimated annual average emissions published by the California Air Resources Board for calendar year 2000 for electric generation and cogeneration.[47] Calendar year 2000 emissions of direct PM2.5 and PM10 provided the basis upon which to calculate the tons per day of each that would be required to achieve the 33% reduction underlying California-specific calculations of the health-related economic value of reducing PM2.5 and PM10 emissions.[48] [49] Combining results from these sources, the health-related economic value of the 33% reduction in PM2.5 and PM10 emissions was divided by the corresponding physical tons to calculate the Value of Health Benefits for PM2.5, which ranges from 1.724-1.738 cents/kWh for the 2009 MPR proxy plant; the additional value for avoided >PM2.5-PM10 emissions is approximately 0.008 cents/kWh.

The health benefits of reduced NO_x and SO_2 power plant emissions on a cents/kWh basis are derived using the results of an extensive October 2000 study by Abt Associates. The Abt Associates study provides both nationwide and state-specific estimates of health benefits in terms of avoided incidences of mortality, hospitalizations, and various categories of illness. These estimates were used to calculate the value of California-specific benefits based on the proportion of California-specific avoided health-related incidences to nationwide totals.[50]

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[47] California Air Resources Board, 2001, online Almanac Emission Projection Data.

[48] *See* Hall, *et al.*, 2006; California Environmental Protection Agency and California Air Resources Board, May 3, 2002, May 31, 2003, and March 21, 2006. (Note that Appendix A to the March 21, 2006 report was included in the September 2008 Public Health Analysis Supplement of the California Air Resources Board Climate Change Draft Scoping Plan.)

[49] *See* Hall, *et al*., 2008, for a more-recent analysis of the benefits of ozone and PM2.5 reductions in California's South Coast Air Basin and San Joaquin Valley. Derived benefits per avoided incident are similar to those in the Abt Associates study except in the instance of avoided Mortality, where the derived value of avoided Mortality is $6.6 million per incident in Hall, *et al.*, (pp. 78-83) compared to the Abt Associates derived value of $7.3 million (in 2008$). The Abt Associates derived value used in this study is approximately mid-way between the recent Hall, *et al.*, analysis and the $8.7 million (in 2008$) value of avoided Mortality in the California Environmental Protection Agency and California Air Resources Board March 21, 2006 report (p. A-67).

[50] Abt and Associates, October 2000, Exhibits 6-2 and 6-7.

Total California health benefits as derived from the Abt Associates study were divided by 75% of California's total 1997 NO_x and SO_2 power plant reductions to arrive at a value of $1.02/lb (1999$) of reduced emissions.[51] The $1.02/lb (1999$) of reduced emissions was inflated to 2009$ and then converted to cents/kWh using the estimated NO_x and SO_2 emissions rates for the 2009 MPR proxy plant heat rate range of 6,879-6,932 Btu/kWh. The Value of Health Benefits for avoided NO_x and SO_2 emissions is approximately 0.011 cents/kWh for the avoided 2009 MPR proxy plant.

The total Value of Health Benefits, calculated by combining the values for avoided PM2.5, PM10, NO_x and SO_2, is 1.743-1.757 cents/kWh for the 2009 MPR proxy plant. The specific components of the Value of Health Benefits are summarized in Attachment B. Since the 2009 MPR does not include any health-related costs associated with avoided emissions of any type from the proxy plant, no deductions were made from the calculated total Value of Health Benefits of 1.743-1.757 cents/kWh attributable to PV-generated electricity.

Value of Avoided Losses (Not Already In 2009 MPR). This category of incremental PV value accounts for the fact that distributed generation from small-scale PV does not have to pass through the electrical grid and thus does not incur the associated T&D line losses. This means that 6% less electricity has to be generated by central generating stations, with an equivalent percentage reduction in generation-related capacity requirements, O&M costs, fuel input, and emissions output.[52]

The 2009 MPR includes 0.50% transformer losses and 1.49% generation-related losses. This nearly 2% in losses has been subtracted from the avoided losses attributable to PV to avoid double counting. The above-MPR, incremental Value of Avoided Losses value for PV ranges from 0.145-0.436 cents/kWh, prior to application of the TOD factor.

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[51] A 75% reduction in NO_x and SO_2 was the underlying assumption in the health benefits calculated in the Abt Associates study. A 75% reduction in total 1997 California electricity utility emissions as reported by the U.S. Department of Energy was used to calculate the $/lb value, based on the total California-specific health benefits derived from the Abt Associates study. (*See* U.S. Department of Energy, Electric Power Annual, Table 5.1.)

[52] This value approximates the 5.52% volume-weighted average for California's three investor-owned utilities as agreed to by Working Group for use in 2007 market price benchmark calculation (CPUC, January 25, 2007, p.7).

Application of the utility-specific weighted average TOD factor is intended to replicate the fact that grid losses are highest during the highest load hours.[53]

Value of Improved Reliability/Blackout Avoidance/Power Quality. Electricity generated by small-scale PV reduces the amount of electricity generated at central stations that must pass through the electric grid, thereby relieving potential overloading of many grid components (*e.g.*, transformers). To the extent that reduced overloading reduces the likelihood of load loss, PV provides additional above-MPR value in improved grid reliability and blackout avoidance.

The calculated Value of Improved Reliability and Blackout Avoidance for small-scale PV in California is based on the following six factors:

- The percentage of the state's population affected by a blackout.
- The duration of a blackout.
- The penetration of small-scale PV.[54]
- The 60% ELCC of small-scale PV.
- California's daily per capita Gross State Product ("GSP"), as a surrogate measure of the direct costs of a blackout.[55]
- An assumption that indirect costs related to a blackout are 60% as large as the direct costs.[56]

The current calculated range of the Value of Improved Reliability and Blackout Avoidance is 0.009-0.742 cents/kWh, using 2007 values for GSP and PV penetration.[57] The lower end of the range is based on a 1-hour blackout that affects 10% of the state's population; the upper end is based on a 24-hour blackout affecting 33% of the state's population.

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[53] Energy and Environmental Economics, Inc., January, 2010, Appendix A, p. 13.

[54] The penetration of small-scale PV is calculated as the ratio of (ELCC-adjusted) PV-generated MWh to total California retail electricity sales in MWh. For 2007, this ratio was estimated to be 0.34%.

[55] Population and state GSP data as reported by the California Department of Finance, 2009.

[56] ICF Consulting, Summer 2003, estimates "Aggregate Indirect Costs" as 63% of "Aggregate Direct Costs" in its modeling of "Economic Costs of a Simulated Attack on the California Electric Grid."

[57] The Value of Increased Reliability/Blackout Avoidance/Power Quality of 0.010-0.853 cents/kWh combines the Value of Increased Reliability and Blackout Avoidance with the Value of Increased Power Quality (discussed below).

Results calculated using the methodology described above were compared to estimated losses derived by others for both California (in whole or in part) and for the Northeastern U.S. August 2003 blackout (as it affected New York City).[58] Although not identical, the results were such that the methodology used here was deemed to be a reasonable means of valuing the improved reliability and blackout avoidance attributable to distributed small-scale PV in California.

The calculated range of the Value of Improved Reliability and Blackout Avoidance is anticipated to increase significantly as the penetration of PV throughout the state increases. Assuming the California Solar Initiative goal of 3,000 MW of installed small-scale PV capacity is achieved by 2020,[59] PV penetration would increase nearly six-fold from today's level, potentially generating nearly 2% of the total MWh consumed in California, providing up to 4 cents/kWh (in 2007$) in Value of Improved Reliability and Blackout Avoidance.

Value of Improved Power Quality. The Value of Improved Power Quality is calculated as being 15% of the Value of Reliability and Blackout Avoidance.[60] This percentage is based on an analysis done for the New York State Energy Research and Development Authority ("NYSERDA") that provided separate estimates of the total U.S. cost of outages and of power quality problems. As defined in the NYSERDA report:

- "The ability of the electric system to deliver electric power without interruption is termed 100% *reliability*.
- The ability to deliver a clean signal without variations in the nominal voltage or current characteristics is termed high *power quality*." (Emphasis in original.)[61]

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[58] *See*, for instance, Anderson Economic Group, August 19, 2003; Consortium for Electric Infrastructure to Support a Digital Society ("CEIDS"), June 2001; Clean Power Research, LLC, March 17, 2006; Center for Risk and Economic Analysis of Terrorism Events ("CREATE"), May 31, 2005; Electricity Consumers Resource Council ("ELCON"), February 9, 2004; ICF Consulting, August 21, 2003; ICF Consulting, Summer 2003.

[59] California Public Utilities Commission, December 15, 2005, p. 5.

[60] Because of its relationship with the Value of Increased Reliability and Blackout Avoidance, the Value of Improved Power Quality is added to the Value of Increased Reliability and Blackout Avoidance under the category of Increased Reliability/Power Quality/Blackout Avoidance.

[61] Energy and Environmental Analysis, Inc., and Pace Energy Project, December 2005, pp. ES1 and ES3.

The calculated range for the current Value of Improved Power Quality for the representative small-scale PV system is 0.001-0.111 cents/kWh. This is value provided by small-scale PV over and above the 2009 MPR values. As was the case for the Value of Increased Reliability and Blackout Avoidance, this value is expected to increase significantly as the penetration of small-scale PV increases in California.

Other Values Not Yet Quantified. In addition to the components of above-MPR value attributed to PV that have been quantified above, there are other benefits of PV that are not reflected in the 2009 MPR and that have not yet been quantified. Two examples of such PV benefits not included in this analysis are discussed briefly below.

Value of Reduced Reliance on Natural Gas Imports. Although the market value of natural gas use by the 2009 MPR proxy plant is included in the 2009 MPR, the intrinsic value to Californians of reduced natural gas import reliance due to reduced natural gas use as the penetration of solar PV systems increases has not been quantified in this analysis. California imports more than 85 percent of its natural gas supply. California consumers pay both the fuel and interstate-pipeline shipping costs for imported natural gas. If more distributed PV systems were deployed, California consumers could avoid some of the costs of gas imports and reserved interstate pipeline capacity. California natural-gas generators and natural gas utilities share capacity on interstate pipelines with other Western states' gas-fired power plants and other natural-gas consumers. In effect, California is at the end of a leaky straw. When gas demand increases upstream due to cold weather or need for summer-time peak electricity generation, California is at risk of natural gas curtailments. For example, in the first week of February 2011, SDG&E had to curtail gas deliveries to 88 large commercial and industrial customers on "non-firm" gas service, because upstream states needed the gas supply and pipeline capacity to serve their own customers' space heating needs. SDG&E's non-firm customers included natural gas-fired power plants. Both the Federal Energy Regulatory Commission[62] and the National Electric Reliability Council[63] are concerned about

[62] http://www.ferc.gov/EventCalendar/Files/20110214172822-AD11-9-000.pdf
[63] http://www.nerc.com/fileUploads/File/News/Cauley_NM_Testimony_21FEB11.pdf

the impact on electric system reliability of natural gas curtailments to non-firm natural gas fired generators.

Value of Reduced Natural Gas Prices. The greater the number of PV systems that are installed in California, the greater will be the resultant natural gas savings. As natural gas consumption for central station electricity production (as represented by the 2009 MPR proxy plant) declines, a threshold of natural gas savings may occur such that natural gas prices in California begin to soften.[64] Because the benefits of this price impact would predominantly occur in future years, the value of this price impact has not been included in this analysis.

Value of Increased National Energy Security. The energy security benefits of using California's indigenous and bountiful solar resource are intuitive, but difficult to quantify. Any national energy security benefits attributed to increased use of California's indigenous solar resources must be net of any identifiable security risks related to increased solar-generated electricity. The (net) national energy security benefits of renewable energy resources are not included in the 2009 MPR and have not been quantified in this analysis.

Solar PV systems in California provide significant value to Californians *above and beyond* the threshold costs of the natural gas-fired proxy plant that are quantified in the 2009 MPR. This analysis has identified and quantified as a PV Adder those components of above-MPR value attributable to electricity generated by a representative PV system using California's bountiful and indigenous solar resource. These components of the PV Adder include the value of avoided T&D, the value of increased reliability, blackout avoidance and power quality, as well as the above-MPR value of incremental avoided air emissions associated with natural gas combustion and the associated health benefits. Depending on the specific region and utility service territory, solar PV generation provides a combined above-MPR PV Adder value ranging from 4.761-12.744 cents/kWh after the application of utility-specific weighted average TOD factors. When combined with the TOD-adjusted 2009 MPR value for a 20-

[64] *See*, for instance, Wiser, *et al*., January 2005.

year contract with a 2010 start date, the representative solar PV system directed south at a 10-degree tilt provides a total TOD-adjusted value ranging from 17.154-24.132 cents/kWh.

L. Customer indifference

SB 32 specifies:

> "(3) The commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff."

CALSEIA believes that customer indifference is achieved when ratepayers not utilizing the feed in tariff are no worse off, nor any better off, as a result of power purchased pursuant to the feed in tariff. The intent of SB 32 pricing was to capture the value of not only the energy from distributed generation systems but also the environmental, location, greenhouse gas, and time of delivery values. As discussed in the above pricing discussion, CALSEIA has quantified and substantiated the values for these attributes in this brief and believes that including fair compensation for renewable energy which includes the value of these benefits is consistent with the ratepayer indifference in that the non-participating ratepayer is no worse off, nor any better off.

M. Relevance, if any, of FERC Order Granting Clarification and Dismissing Rehearing, 133 FERC ¶ 61,059 (October 21, 2010) and FERC Order Denying Rehearing, 134 FERC ¶ 61,044 (January 20, 2011), to setting the tariff price

CALSEIA believes that the Commission has the authority to establish the feed in tariff pursuant to PURPA. The FERC orders affirms the Commission's authority.

N. Expedited interconnection procedures

Public Utilities Code 399.20 provides:

> "(e) An electrical corporation shall provide expedited interconnection procedures to an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit, if the electrical corporation determines that the electric generation facility will not adversely affect the distribution grid. The commission shall consider and may establish a value for

an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit."

CALSEIA is encouraged by recent activities by PG&E and SCE to reform the Wholesale Distribution Access Tariff (WDAT). While CALSEIA has a general preference to the Commission's Rule 21 process, we applaud that the IOUs have initiated reforms that will make the WDAT process more similar to Rule 21 and importantly, make the process work in a manner that does not inhibit new renewable distributed generation projects. The WDAT and Rule 21 processes are important because they provide that necessary assessment of whether the proposed project will or will not require utility system modifications to accommodate the new facility with respect to reliability and deliverability.

Further, the Commission may want to consider limiting SB 32 eligibility to projects that connect on the distribution system rather than the transmission system. This could help mitigate lengthy delays that may occur due to the permitting procedures established by the California Integrated System Operator. CALSEIA is open to a discussion on the merits of such a restriction.

Given the reforms that are underway, CALSEIA recommends that the Commission monitor the timeliness of interconnections made under this tariff to ensure that the interconnection process is responsive to adding new renewable generation. As more facilities are proposed we are certain that there will be important experiences that can be used to improve interconnection procedures with respect to streamlining the process.

O. Commission consideration of locational benefits

CALSEIA's recommendations on the pricing for location benefits are reflected in its comments in the pricing discussion in this brief.

P. Refunds of incentives pursuant to the California Solar Initiative and the Self-Generation Incentive Program

Public Utilities Code 399.20 specifies that recipients of incentives from either the California Solar Initiative or the Self-Generation Incentive Program may apply for a feed in tariff contract subject to the following provisions:

> "(k) (1) Any owner or operator of an electric generation facility that received ratepayer-funded incentives in accordance with Section 379.6, or with Section 25782 of the Public Resources Code, and participated in a net metering program pursuant to Sections 2827, 2827.9, and 2827.10 prior to January 1, 2010, shall be eligible for a tariff or standard contract filed by an electrical corporation pursuant to this section.
> (2) In establishing the tariffs or standard contracts pursuant to this section, the commission shall consider ratepayer-funded incentive payments previously received by the generation facility pursuant to Section 379.6 or Section 25782 of the Public Resources Code. The commission shall require reimbursement of any funds received from these incentive programs to an electric generation facility, in order for that facility to be eligible for a tariff or standard contract filed by an electrical corporation pursuant to this section, unless the commission determines ratepayers have received sufficient value from the incentives provided to the facility based on how long the project has been in operation and the amount of renewable electricity previously generated by the facility.

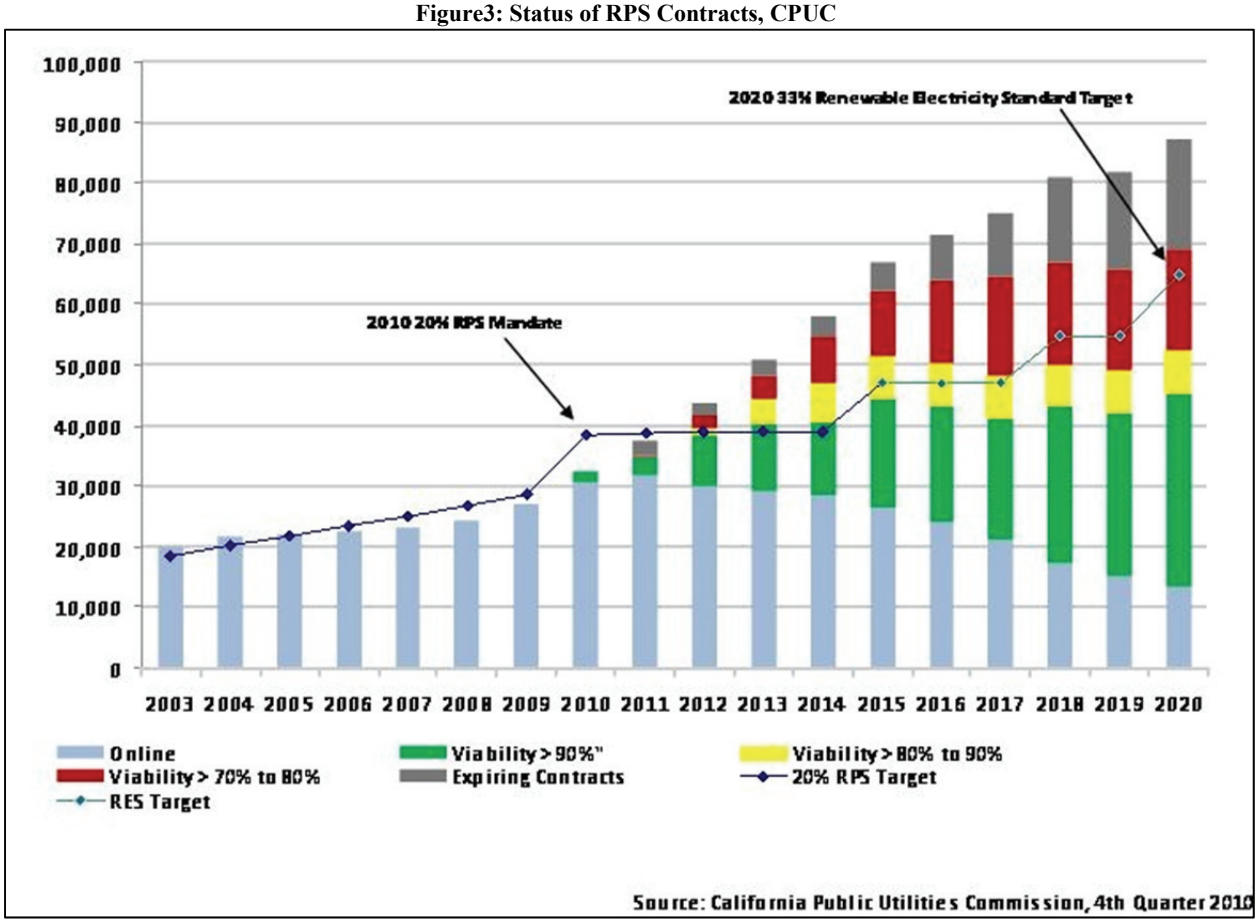
CALSEIA recommends that the feed in tariff applicants who have received incentives be required to refund incentives on a pro-rata basis based on a ten (10) year system life. CALSEIA suggests this based on the photovoltaic system warranty specified in Public Resources Code 25782(a)(4) which states that "The solar energy system has a warranty of not less than 10 years to protect against defects and undue degradation of electrical generation output." CALSEIA's proposal would thus mean that if a system has been placed in service for one year, a developer would return 90% of their incentive; if in service 5 years return half of their incentive; and if in service 9 years, return 10% of their incentive. If in service more than 10 years no refund of incentive refund would be required.

III. Other Issues Not Raised in the Ruling

A. Status of Projects Pending for the Renewable Portfolio Standard

CALSEIA recognizes that there is substantial activity by the utilities to meet the Renewable Portfolio Standard requirements and that many contracts and programs have been initiated in an aggressive effort to achieve California's renewable portfolio goals. CALSEIA believes that SB 32 will provide reinforcement and reduce risk of missing the State's targets. As shown below, the RPS goals rely on a number of contracts that have not yet come to fruition. While SB 32 provides (when SB 32 is implemented) 750MW of new generation, it is still useful, particularly in meeting the near term RPS requirements.

Figure3: Status of RPS Contracts, CPUC



B. Net Metering

CALSEIA wishes to point out that customers who have projects connected under the terms of a Net Metering Agreement would be required to forego their net metering tariffs to participate in the SB 32 feed in tariff, pursuant to Public Utilities Code 399.20:

> "(3) A customer that receives service under a tariff or contract approved by the commission pursuant to this section is not eligible to participate in any net metering program."

C. Utility Interconnection Charges

Solar developers report that SCE and PG&E are assessing charges on the order of $100,000 to $150,000 to interconnect a 1 MW or smaller facility and assessing an 'automatic' $250,000 or more on projects larger than 1MW. CALSEIA does not object to reasonable costs and understands that there are circumstances where fees such as these examples may be appropriate. However, it seems worthwhile to monitor and review these charges to determine if they are reasonable and justifiable in all circumstances. For example, if a project developer proposes a facility on a site where on-site energy consumption is greater than the facility will produce (such as a school or small commercial customer who develops their rooftop for a feed in tariff), this may be a circumstance where the utilities may not need to require extensive studies or assessments in order to safely allow interconnection. Or if a Distributed Generation system provided quantifiable benefits that would accrue to the utility and/or ratepayer (such as but not limited to: reliability, conservation voltage reduction potential, bulk system capacity, ancillary services capacity, system voltage security, energy in the load center and congestion-relief, loss reductions) the charges assessed could be adjusted to reflect ancillary benefits.

CALSEIA recommends the utilities to provide reports to the Commission and public on interconnection fees, trends, and lessons learned.

D. First come, first served

Public Utilities Code 399.20 establishes a first-come first-served procedure for establishing a queue for the SB 32 tariff:

> "(f) An electrical corporation shall make the tariff available to the owner or operator of an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the electrical corporation meets its proportionate share of a statewide cap of 750 megawatts cumulative rated generation capacity served under this section and Section 387.6."

CALSEIA has observed that some companies exhibit speculative behavior, queue-squatting, and aggressive pricing in other distributed generation programs (in this state and elsewhere) which have resulted in contracts, but no 'steel in the ground.' CALSEIA recommends the Commission set rigorous participation rules, such as those suggested earlier in this brief under our CALSEIA Proposed Pilot Program. If developers submit projects that have complicated and difficult interconnection issues, they should be quickly rejected from the queue to encourage developers to seek sites that can be developed more efficiently. If they cannot meet the construction completion date of one year for a project that is less than one megawatt the Commission should reject the project from the queue.

CALSEIA would also like to ensure that the rules do not discriminate against private property owners who would like to develop and finance their own projects with the use of a licensed contractor. This has the benefit of keeping the jobs and the revenue in California, where it can help California's economy the most. Both private owners and third-party financers should be able to participate in this program but not to the exclusion of one or the other. It is not important that a facility owner has developed prior projects but it is important that they do their due diligence to hire a competent contractor, secure equipment, obtain necessary permits and meet the utility's interconnection requirements. Those duties and responsibilities should remain with the owner and do not require Commission intervention under a Feed In Tariff program. It is critically important to allow opportunities for participation by land-owners, building owners, and government entities (local, regional, and the State of California). This will provide the necessary industry competition to drive down installed costs and increase quality. As has been observed in regions where feed in tariffs are available, the installed cost of solar is lower, [65] which may be due in part to higher volumes of market activity but may also because the feed in tariff facilitates

[65] The Installed Cost of Photovoltaics in the U.S. from 1998-2009http://eetd.lbl.gov/ea/emp/reports/lbnl-4121e.pdf, page 18

standardized installation packages and a higher degree of competition between companies and suppliers.

IV. SUMMARY AND CONCLUSION

CALSEIA appreciates the opportunity to file this opening brief on SB 32 implementation. CALSEIA strongly urges the Commission to adopt a phased in implementation of SB 32 and expeditiously move this proceeding forward so that projects could begin construction this year. We also acknowledge the key role the utilities serve in implementing this program and we encourage their assistance and support.

Respectfully submitted,

Sue Kateley
Executive Director
California Solar Energy Industries Association
P.O. Box 782
Rio Vista, CA 94571
916-747-6987
info@calseia.org
March 4, 2011

VERIFICATION

I am an agent of the California Solar Energy Industries Association (CALSEIA), and am authorized to make this verification on its behalf. The matters stated in the foregoing **OPENING BRIEF OF THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION ON IMPLEMENTATION OF SB 32** are true of my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.
I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed this 7th day of March, 2011, at Rio Vista, California

_*/s/ Sue Kateley*

Sue Kateley
Executive Director

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of:

OPENING BRIEF OF THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION ON IMPLEMENTATION OF SB 32

on all known parties of record in this proceeding by delivering a copy via email to the current service list for R. 08-08-009 or by delivering a copy via U.S. mail to those members of the current service list for R.08-08-009 with no or undeliverable email addresses.

Executed on March, 7, 2011 in Rio Vista, CA.

_*/s/ Sue Kateley*

Sue Kateley, Executive Director
California Solar Energy Industries Association
P.O. Box 782
Rio Vista, CA 94571
916-747-6987
info@calseia.org

Reserved on March 11, 2011

ATTACHMENT A
UTILITY-SPECIFIC TIME-OF-DELIVERY PERIODS AND FACTORS[66]
Pacific Gas and Electric[67]

Month	Period	Definition	Factor
June - September	Super-Peak	Hours Ending (HE) 13-20 Monday-Friday (except NERC holidays)	**2.20490**
	Shoulder	HE 7-12, 21 and 22 Monday-Friday (except NERC holidays); HE 7-22 Saturday, Sunday and all NERC holidays	**1.12237**
	Night	HE 1-6, 23 and 24 all days (including NERC holidays)	**0.68988**
October - February	Super-Peak	Defined above	**1.05783**
	Shoulder	Defined above	**0.93477**
	Night	Defined above	**0.76384**
March - May	Super-Peak	Defined above	**1.14588**
	Shoulder	Defined above	**0.84634**
	Night	Defined above	**0.64235**

Southern California Edison Company[68]

Season	Period	Definition	Factor
Summer June 1 - September 30	On-Peak	WDxH[1], noon-6 pm	**3.13**
	Mid-Peak	WDxH, 8-noon, 6-11 pm	**1.35**
	Off-Peak	All other times	**0.75**
Winter October 1 - May 31	Mid-Peak	WDxH, 8 am-9 pm	**1.00**
	Off-Peak	WDxH, 6-8 am, 9 pm-midnight; WE/H[2] 6 am-midnight	**0.83**

[66] 2009 MPR Resolution, Appendix B.
[67] PG&E 2009 RPS Solicitation, pro forma contract, pp. 45-46. http://www.pge.com/includes/docs/word_xls/b2b/wholesaleelectricsuppliersolicitation/FinalAttH2009RPSPPA(amendedforSTOffers)(00084346).DOC
[68] SCE 2009 RPS Solicitation, pro forma contract, Exhibit K, p. 2. http://www.sce.com/NR/rdonlyres/4F174486-40D2-470B-AB23-96A3A583C2E5/0/20090629_RFP_Appendix_B1_ProForma_Agreement.doc

	Super-Off-Peak	Midnight-6 am	**0.61**

1/ WDxH is defined as weekdays except holidays
2/ WE/H is defined as weekends and holidays

San Diego Gas &Electric[69]

Season	Period	Definition[1]	Factor
Summer July 1- October 31	On-Peak	Weekdays 11am-7pm	**1.6411**
	Semi-Peak	Weekdays 6am-11am; Weekdays 7pm-10pm	**1.0400**
	Off-Peak	All other hours	**0.8833**
Winter November 1 - June 30	On -Peak	Weekdays 1pm-9pm	**1.1916**
	Semi -Peak	Weekdays 6am-1pm; Weekdays 9pm-10pm	**1.0790**
	Off-Peak	All other hours	**0.7928**

1/ All hours during National Electric Reliability Council (NERC) holidays are Off-Peak.

[69] SDG&E 2009 RPS Solicitation, pro forma contract, pp. 39-40. http://www.sdge.com/documents/rfo/renewable2009/ModelPPA.doc

ATTACHMENT B
ASSUMPTIONS AND RESULTS FOR AVOIDED EMISSIONS
AND RELATED VALUE OF HEALTH BENEFITS
(Prior to Time-of-Delivery Adjustment)

	Heat Rate Range (Btu/kWh)	Emissions Rate (CO_2 in tons/MWh; all others in lb/MWh)					
		NO_x	SO_2	PM10	CO	VOC	CH_4
2009 MPR Proxy Plant	6,932 6,879	0.063	0.009	0.047	0.131	0.018	n/a
Emissions Prices	In-State:	NO_x ($/ton/year)	SO_2 ($/ton/year)	PM10 ($/ton/year)	CO ($/ton/year)	VOC ($/ton/year)	CO_2 ($/ton)
2009 MPR	Average	$20,000	$21,500	$43,000	$ 500	$24,829	$10.44 $90.17
PG&E – Ex. San Joaquin Valley (Bay Area ERCs)	Maximum	$ 11,750	$14,000	$ 42,500	$ 796	$13,250	$90.17
	Minimum	$ 9,500	$ 7,500	$ 27,500	$ 769	$ 8,450	$10.44
PG&E – San Joaquin Valley (SJV ERCs)	Maximum	$ 68,325	$44,667	$ 87,500	$ 769	$48,705	$90.17
	Minimum	$ 22,450	$22,250	$ 57,500	$ 769	$22,667	$10.44
SCE (South Coast ERCs)	Maximum	$ 55,450	$40,275	$300,000	$8,337	$18,667	$90.17
	Minimum	$ 47,000	$40,275	$ 53,000	$8,337	$ 6,633	$10.44
SDG&E (San Diego or South Coast ERCs)	Maximum	$132,500	$40,275	$136,668	$8,337	$63,750	$90.17
	Minimum	$ 87,500	$40,275	$ 53,000	$8,337	$40,000	$10.44
PV: Value of Avoided Emissions, Net of 2009 MPR Cost of Emissions Reduction Credits (cents/kWh)							
		NO_x	SO_2	PM10	CO	VOC	Total (All)
PG&E – Ex. San Joaquin Valley	Maximum	(0.022)	(0.003)	0.024	0.007	(0.010)	(0.004)
	Minimum	(0.032)	(0.007)	(0.028)	0.007	(0.016)	(0.077)
PG&E – San Joaquin Valley	Maximum	0.235	0.016	0.177	0.007	0.036	0.472
	Minimum	0.026	0.002	0.073	0.007	0.002	0.111
SCE	Maximum	(0.029)	(0.007)	0.065	0.014	(0.023)	0.021
	Minimum	(0.037)	(0.007)	(0.089)	0.014	(0.025)	(0.144)
SDG&E	Maximum	0.527	(0.007)	(0.037)	0.014	0.056	0.554
	Minimum	0.319	(0.007)	(0.089)	0.014	0.025	0.262
PV: Value of Health Benefits Associated with Total Avoided Emissions (cents/kWh)							
Statewide (Not Utility-Specific)		NO_x & SO_2	PM10	PM2.5*	. Total (All Emissions)		
vs. 2009 MPR Proxy Plant	Maximum	0.011	0.008	1.738	1.757		
	Minimum	0.011	0.008	1.724	1.743		

** PM2.5 = 98% of PM10 emissions by weight, per California Air Resources Board 2000 Emissions Inventory*